ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/95-14
50-323/95-14

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

Inspection At: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: August 6 through September 16, 1995

Inspectors: M. Tschiltz, Senior Resident Inspector
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Approved: H. J. Wong, Chief, Reactor Projects Branch E — Date 10/26/95

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of onsite followup to events, operational safety verification, plant maintenance, surveillance observations, onsite engineering, and plant support activities, followup plant operations.

Results (Units 1 and 2):

Operations:

- Operators effectively responded to a Unit 1 reactor trip minimizing reactor coolant system (RCS) cooldown and pressurizer level decrease (Section 2.1.3).

- Improperly performed new fuel inspections resulted in the damage of eight new fuel assemblies. Procedural guidance for the inspections had been removed without justification and operators performed the inspection using a bent inspection tool (Section 3.1).

- Minor emergency diesel generator (EDG) synchroscope and voltage oscillations were promptly identified by a control operator during testing and test engineers were summoned. Based on the operator's concern testing was halted and the EDG declared inoperable. Troubleshooting revealed a problem with the electric governor assembly (Section 5.5).

Maintenance:

- EDG testing was not consistently conducted in accordance with the Technical Specification (TS) testing requirement to perform diesel engine starts from ambient conditions. The failure to accomplish appropriate TS testing resulted in the licensee declaring EDG 1-2 inoperable until the testing could be satisfactorily accomplished. A violation was identified (Section 5.4).

Engineering:

- Compensatory actions established in the event of the loss of one of the two 230 kV offsite power sources would have resulted in the units being placed outside their design bases. A violation was identified (Section 6.1.4).

Summary of Inspection Findings:

- Violation 275/9514-02 was identified (Section 5.4.4).
- Violation 275/9514-03 was identified (Section 6.1.4).
- Inspection Followup Item 275/9514-01 was opened (Section 4.1.5).
- Unresolved Item 275/9514-04 was opened (Section 6.1.7).
- Inspection Followup Item 275/9512-01 was closed (Section 8.1).
- Inspection Followup Item 323/9507-08 was closed (Section 8.2).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On September 6, 1995, a reactor trip occurred due to a turbine trip. The turbine tripped due to a loss of autostop oil pressure caused by the failure of a solenoid valve pilot valve. On September 8, 1995, the unit returned to 100 percent power and operated at 100 percent power for the remainder of the inspection period.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power. On August 19, 1995, power was reduced to 50 percent to clean the marine growth fouling from the west half of the condenser. Following the condenser cleaning the unit was returned to 100 percent on August 20, 1995. On August 25, 1995, power was reduced to 50 percent to perform cleaning of the seawater cooling system and perform maintenance to correct an elevated main feedwater pump thrust bearing temperature. The unit returned to 100 percent power on August 27, 1995, and operated at 100 percent power for the remainder of the inspection period.

2 ONSITE FOLLOWUP TO EVENTS (93702)

2.1 Unit 1 Reactor Trip

Background - On September 6, 1995, Unit 1 experienced a reactor trip resulting from a turbine trip caused by the loss of autostop oil pressure. During the turbine trip investigation, a solenoid valve (SV-171) was found stuck open. Valve SV-171 normally opens on a turbine trip to depressurize the autostop oil system which in turn causes the interface valve to open and depressurize the electro-hydraulic control system.

The plant response to the trip was normal and uncomplicated with the following exceptions: pressurizer heater group 4 breaker would not close from the control room, due to a DC toggle switch on the front of the breaker being incorrectly positioned; and EDG 1-1 autostarted.

2.1.1 Autostop Oil Solenoid Valve Failure

Upon disassembly of Valve SV-171, the valve internal pilot valve seat was noted to be severely degraded allowing leakage past the seat that caused the solenoid valve to reposition. The failed valve was an ASCO model number 8223A10 valve. In 1989, ASCO changed the pilot valve seat material from a teflon based material (RULON) to urethane. Since changing the seat material there have been several inservice failures at other facilities in applications where the urethane seat was subjected to lube oil and water.

The licensee had previously contacted the ASCO valve vendor representative in March 1995 based on another plant's experience to determine if any of the valves purchased by Diablo Canyon Power Plant (DCPP) contained the cast urethane seats. Information obtained by the licensee at that time indicated that valves purchased by DCPP did not have cast urethane seats. Based upon the information obtained from the vendor, the licensee's Independent Safety Engineering Group closed the issue. This information from ASCO turned out to be inaccurate.

Initially, the failed valve was replaced with a valve containing a cast urethane seat since no other replacement valves were immediately available. Subsequent to the initial replacement, and prior to Unit 1 restart, the valve was replaced a second time after the licensee obtained a valve with a RULON seat. The licensee performed additional reviews and determined that there were no other valves with urethane seats in safety-related applications.

2.1.2 EDG 1-1 Autostart

EDG 1-1 autostarts had previously occurred during slow bus transfers to startup power. These starts were attributed to the slow decrease in 4 kV Bus H voltage due to the characteristics of Bus H loading. In this instance, the transfer to startup power was initiated 30 seconds after the reactor trip when the auxiliary transformer feeder breaker opened. During a slow bus transfer, the startup feeder breaker supplying the 4 kV bus closes after bus voltage has decreased to 25 percent of rated voltage. The first level undervoltage relay protection is actuated after a time delay when bus voltage decreases below 69 percent of rated voltage. The first level undervoltage relay actuation sends a start signal to the associated bus EDG. In this particular instance, the time required for Bus H voltage to decrease from 69 percent to 25 percent of bus voltage was sufficient to actuate the first level undervoltage relay.

The 4 kV Bus H voltage decreased to less than 25 percent of rated voltage approximately 1.5 seconds after the auxiliary breaker opened allowing the startup transformer feeder breaker to close and restore 4 kV Bus H voltage. During that time, EDG 1-1 received an auto-start signal but had not reached rated voltage when startup power restored voltage to 4 kV Bus H.

The inspector questioned whether the slow voltage decay affected the ability of EDG 1-1 to start and load onto the bus within the required time period (10 seconds). The licensee responded that surveillance testing, accomplished by the performance of Surveillance Test Procedure (STP) M-9Y, "Determination of Diesel Loading Time on a Real Time Demand Situation," Revision 1, verified the time from actuation of the first level undervoltage relay until closing of EDG output breaker. The EDG 1-1 test results indicated that this time was less than 10 seconds. This resolved the inspector's concerns in this area.

2.1.3 Control Room Operator Response

The inspector observed the control room operators response to the reactor trip and noted that changes made to the Emergency Operating Procedure (EOP) E-0.1, "Reactor Trip Response," appeared to improve the operators' ability to control and limit RCS cooldown following a reactor trip. The licensee had changed EOP E-0.1 to incorporate the evaluation of RCS cooldown into a continuous action step in the procedure. This allowed the operators to throttle the flow of auxiliary feedwater, which was cooling the steam generators earlier in the response as soon as temperature was noted to be less than 547°F. In addition, operators were noted to have placed a centrifugal charging pump in service shortly after the reactor trip to limit pressurizer level decrease. Both of these actions had been put into procedures in response to concerns raised following a previous reactor trip.

Operators were observed to be knowledgeable of the reactor trip response procedure changes and used formal closed-loop communications. The shift foreman provided explicit and concise directions to shift personnel and kept operators involved with the response up to date by holding briefings at several points to ensure that the operators understood the current conditions and actions that were planned. The shift foreman was noted to be in an effective position for oversight throughout the response to the reactor trip.

2.1.4 Conclusion

There were a minimal number of equipment problems following the trip. Operator response to the trip was conducted in a formal and methodical manner. Operators were knowledgeable of recent procedural changes which enhanced their ability to limit RCS cooldown.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 New Fuel Receipt Inspection for Cycle 1R8

Background - On August 23, 1995, during receipt inspection of a new Westinghouse reconstitutable fuel assembly, the top nozzle instrument guide tube plug, commonly called the thimble plug, was noted to have been broken loose. The plug is normally held in place by four welds and is approximately 0.56 inches in diameter by 0.20 inches thick with a 0.104 inch hole in the center. The purpose of the thimble plug is to limit core bypass flow through the instrument guide tube and prevent flow induced instrument guide tube vibration. The loose plug was noted during a check of the instrument guide tube which entailed insertion of a metal rod the entire length of the tube to verify the tube was free of obstructions. The thimble plug was found resting on the top of the nozzle block. The licensee determined that the plug had been knocked out during the inspection process as a result of inserting the inspection tool too far and with too much force into the instrument guide tube causing it to impact the thimble plug and break the welds attaching it to the nozzle. The tool had been inserted too far because the tool was bent and extra force was needed to push the tool the full length of the thimble tube.

After discovering this problem the possibility of loose plugs in Units 1 and 2 was investigated.

3.1.1 Fuel Assembly Inspections

At the Westinghouse fuel fabrication facility, inspection of the fuel assembly included inspection of the instrument guide tube by insertion of a probe the full length into the instrument guide tube. Following the inspection, the thimble plug is welded to the top of the nozzle block to limit reactor coolant flow through the tube during reactor operation.

Following receipt of new fuel assemblies at Diablo Canyon for Unit 1, Cycle 8, the licensee performed an instrument guide tube inspection prior to loading the new fuel assemblies into the new fuel storage vaults. This inspection was similar to the inspection performed by Westinghouse in that it required the insertion of an inspection tool the entire length of the instrument guide tube to verify the tube is clear and would allow insertion of incore instruments.

Following the discovery of the dislodged thimble plug, three new fuel assemblies, which had been previously inspected and stored in the new fuel storage vault, were inspected for thimble plug weld damage. Of the three assemblies, one was found with the thimble plug laying loose on top of the fuel rods, another was found with three of four welds broken, and the last was found with the thimble plug intact.

Based upon inspection results, the licensee determined that other fuel assemblies of the same top nozzle design were susceptible to the same type of damage. An inspection of the remaining 57 new fuel assemblies in the Unit 1 spent fuel pool was then performed which revealed another 6 assemblies with cracked thimble plug welds. In addition, the core video maps, taken following the core reloads for Units 1 and 2, Cycle 7, were reviewed. These videos provided a view of the top nozzles of approximately two-thirds of assemblies. None of the thimble plugs were noted to be missing on the videos. Units 1 and 2 spent fuel assemblies with the susceptible thimble plug design were also inspected; no additional missing or cracked thimble plugs were noted.

In total, approximately 750 fuel assemblies were inspected. Two fuel assemblies were noted to have missing thimble plugs and six were noted to have cracked thimble plug welds. All of the damaged assemblies were new fuel assemblies and had been inspected during the receipt of new fuel for Cycle 1R8.

3.1.2 New Fuel Inspection Procedures

The licensee's procedure for performing inspection of new fuel, Operating Procedure (OP)-B8C, Revision 6A, "Inspection of New Fuel," did not contain specific directions on how to perform the thimble tube inspection. The only reference to the inspection was contained on the nuclear fuel inspection data sheet, where following the inspection, the fuel handling operator was required to indicate whether any binding was noted during the insertion of the

instrument guide tube gauge. Section 5.7 in the previous revision of OP-B8C contained specific instructions to slowly insert the gauge fully into the instrument guide tube. These instructions were removed in Revision 6 to the procedure. The procedure history sheet did not indicate the reason for removing the instructions.

Discussions with Westinghouse revealed that the instrument guide tube inspection was not required to be performed onsite. Further review revealed that the licensee's onsite inspection had been initiated prior to commercial operation after concerns were raised regarding spent fuel pool foreign material exclusion resulted in instrument guide tube inspections to verify that the tubes were free of foreign material. Although the licensee no longer had the concern regarding spent fuel pool foreign material exclusion controls, the inspections were still being performed.

The operators who had performed the previous operating cycle new fuel inspections were interviewed to determine how the instrument guide tube inspection was performed. Based on these interviews and the absence of any other damaged fuel assemblies, the licensee concluded that the operators performing previous inspections were aware that the precaution that fuel assembly instrument guide tube inspections were to be performed using only minimal force.

Examination of the failed plug welds revealed that the weld failures were ductile. The normal operational force on the plug is about 5 to 10 pounds. The force required to have sheared the welds was estimated at 440 pounds. The inspector noted that the calculated force required to shear the thimble plug welds was not consistent with the cautious handling of new fuel assemblies. The licensee addressed this concern as an issue that would be covered during future fuel handling training.

3.1.3 Safety Assessment of Potential Missing Thimble Tube Plugs

The licensee performed an assessment of the potential effects of missing thimble tube plugs on reactor operation. The fuel manufacturer (Westinghouse) was consulted on certain technical aspects of the assessment, which addressed the potential for the following concerns: increased core bypass flow through the instrument guide tube; increased peak centerline temperature (PCT); reduced departure from nucleate boiling ratio (DNBR) margin; vibrational effects (fretting) on the instrument guide tubes; and loose parts concerns..

As a part of the assessment of the effect on DNBR and PCT margins, the accident analyses for large and small break loss of coolant accidents (LOCAs) as well as LOCA hydraulic forcing functions and post LOCA long term cooling were evaluated. The licensee initially arbitrarily picked 30 to be the number of missing plugs causing increased core bypass flow for the bounding analyses. The assessment concluded that 30 missing plugs did not have a significant adverse effect on DNBR and PCT margins.

The evaluation of increased instrument guide tube wear due to fretting concluded that the high axial flow velocity could lead to excessive vibration and wear, and eventually result in thimble tube leakage. The increased flow could also result in flow induced vibration and wear of fuel rods. For these reasons operation with loose or missing thimble plugs was evaluated as highly undesirable.

Loose parts concerns were initially evaluated to have been bounded by the existing loose parts analysis. This turned out not to be the case since a loose thimble plug could potentially lodge in a rod control cluster assembly (RCCA) instrument guide card and prevent insertion of an RCCA. Upon recognition of this potential the licensee noted several factors that greatly reduced the likelihood of a stuck rod occurring. First, a loose thimble plug would most likely become entrained in coolant flow and be swept into the reactor vessel discharge nozzle. Additionally, the RCCAs are drop-tested during plant startup and are required to be periodically exercised during operation. These tests, as well as reactor trips experienced during the current operating cycle, appeared to provide adequate assurance that the upper internals were free of loose parts acting to impede RCCA insertion.

3.1.4 Licensee Corrective Actions

Revision 6 to OP-B8C was issued, which deleted the requirement to perform the instrument guide tube inspection and stated that training would be conducted on the handling of new fuel assemblies. Additionally, the licensee scheduled the repair of the eight damaged fuel assemblies.

3.1.5 Safety Significance

The only fuel assemblies with cracked thimble plug welds were six new fuel assemblies which had also just been received from Westinghouse and inspected onsite. Based upon the results of the inspections, the licensee concluded that it was unlikely that any fuel assemblies currently loaded into the core were missing thimble plugs.

3.1.6 Conclusion

The initial operability assessment did not consider the potential for the loose plug to become lodged in an RCCA guide card and prevent the insertion of an RCCA. After subsequent evaluations and discussions with the NRC, this issue was addressed. The inspector concluded that the fuel assembly inspections, in combination with the licensee's safety assessment, appeared to adequately address the areas of concern and provided reasonable assurance for operability.

3.2 <u>EDG Governor Oil Level</u>

During a routine tour of the EDG rooms, the inspector noted that the actuator oil for EDG 1-2 Woodward governor was slightly below the sight glass mid-level mark, with the engine operating. The inspector noted that the vendor manuals

for the actuator stated that the oil level should be checked to ensure that it is at or above the mid-level mark after engine starting. The inspector reviewed the applicable Operating Procedure, STP M-9A, "Diesel Generator Routine Surveillance Test," Revision 31, Attachment 8.1, and determined that the licensee did not require that the actuator oil be checked until after the engine had operated for 60 minutes. The inspector noted that during prestart checks the licensee only required that the oil in the actuator be visible. The inspector considered that the licensee's procedure did not meet the intent of the vendor procedure to ensure adequate oil for engine operation. The inspector discussed actuator oil level with the licensee. The licensee stated that they planned to make a procedure change to have the oil level verified after starting. During a subsequent operation of EDG 1-2, the inspector noted that the actuator had sufficient oil. The licensee initiated a change to STP M-9A which required that governor oil level be verified when performing checks on the diesel immediately after starting.

3.2.1 Conclusion

The licensee's procedure revision appeared to ensure actions which were consistent with the vendor instructions to ensure adequate actuator oil during engine operation. The inspector concluded that licensee's response adequately resolved the concerns regarding EDG governor operability.

4 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with the maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. Specifically, the inspector reviewed the work documentation or witnessed portions of the following maintenance activities:

4.1 Maintenance Observations

Unit 1

- Containment Fan Cooler Unit 1-3 Redundant Breaker (52G-1G-01R) Troubleshooting and Repair

Unit 2

- Installation of Valve Test Connections on Component Cooling water Heat Exchanger No. 2 Saltwater Inlet Valve FCV-603
- Installation of Residual Heat Removal 2-8700B Torque Switch Bypass Logic

These activities were performed adequately.

4.2 40 Percent Steam Dump Valve Inspections

Background - During the refurbishment of 40 percent steam dump valve internals that had been removed from MS-2-PCV-1 during 2R6, the licensee noted the valve plug was cracked in several locations. The cracks were visible on both sides of the plug and across the top of the plug and into the stem boss area. Cracks were also noted on a second plug in warehouse stock that had been removed from another 40 percent steam dump valve (MS-1-PCV-7). Research of the history of the two cracked plugs indicated that they were from the same purchase order which was for 24 plug assembly trim sets. Of the 24 plug assemblies from the purchase order, 22 were identified to be installed in the 40 percent steam dump valves for both Units 1 and 2. The presence of the cracking found during inspections raised concerns of the potential affect on operability of the 40 percent steam dump valves.

4.2.1 Investigation of Plug Cracking

To investigate whether the inservice 40 percent steam dump valves had similar cracking the licensee isolated and disassembled MS-2-PCV-10, which was leaking past it's seat and MS-2-PCV-3 which did not show any evidence of seat leakage. MS-2-PCV-3 inspection did not reveal any plug cracks. MS-1-PCV-10 plug was removed and was found to have cracks. Subsequently additional 40 percent steam dump valves were disassembled and more cracked valve plugs were discovered.

4.2.2 MS-1-PCV-3 Inspection

The inspector observed portions of the disassembly, inspection, and reassembly of MS-1-PCV-3. During reassembly of the valve, when torquing the valve body cover plate, the inspector noted that the mechanics were not torquing the studs using a criss-cross pattern as specified in MP M-51.34, "35 Percent and 40 Percent Steam Dump Valve Maintenance," Revision 2. The inspector questioned the mechanic who indicated that he was performing a final leveling pass to verify all of the studs were torqued to the required range of 1050-1150 ft-lbs.

Upon questioning maintenance management on torquing sequence, the inspector was provided with a copy of Section 7.3.12 of MP M-54.1, "Bolt Tensioning," Revision 8, which provided instructions for performing leveling passes. The instructions in Section 7.3.12 specified that the leveling pass to the final torque value be performed in a clockwise or counterclockwise direction. The inspector questioned whether the information included in the bolt tensioning procedure was considered to be skill of the craft since it was not referenced in the procedure for performing maintenance on the 35 percent and 40 percent steam dump valves. The inspector was informed that the information was not considered skill of the craft. The inspector observed that the instructions for torquing of the cover plate in MP M-54.34 were inadequate if the intent was to perform a final leveling pass without using a criss-cross torquing pattern. The licensee subsequently revised MP-51.34 to include instructions to perform a leveling torque pass in a clockwise or counterclockwise

direction. This resolved the inspector's concern regarding the adequacy of the instructions for torquing in the procedure.

4.2.3 Potential Impact on Operability

There are twelve 40 percent steam dump valves per unit. The valves are Class II with no specified safety function. However, the valves are required to close upon receipt of a RCS low-low T_{AVE} signal to prevent RCS overcooling. Westinghouse had previously performed an analysis for the condition of a main steam line break with all of the steam dump valves failed open, which enveloped the current situation. The 40 percent steam dump valves can be isolated by closing the main steam isolation valves. Operators were notified of the potential for failure of the 40 percent steam dump valves. There were no additional compensatory measures implemented since existing EOPs already require operators to assess RCS cooldown with specific actions to be taken to mitigate cooldown.

The licensee's preliminary investigation attributes the cracking to stress corrosion cracking and hydrogen embrittlement. The valve plug material is 420 stainless steel that has been treated for hardness. All valve plugs which were found to be cracked were obtained from the same purchase order and the susceptibility to cracking is believed to have been caused by the heat treatment during manufacturing.

4.2.4 Potential Impact on Operability of 10 Percent Steam Dump Valves

The 10 percent steam dump valves, which are safety-related, contain valve plugs, which are manufactured from the same material as the 40 percent steam dump valves. The 10 percent steam dump plug design differs in size and shape and because of this difference the licensee believed that it was unlikely that the valves could have received concurrent heat treatment.

4.2.5 Conclusion

The licensee's preliminary evaluation concluded that the failure mechanism was stress corrosion cracking and hydrogen embrittlement that was caused in part by the heat treatment of the valve plug material during manufacture. The inspector considers that there is a potential for the 10 percent steam dump valves to have similar cracking based on the fact that the valve plugs are: made of the same material; heat treated using the same process; and operate in an environment similar to the 40 percent steam dump valves. The inspector will review this issue further to determine the potential impact on the operability of the safety-related 10 percent steam dump valves and the adequacy of corrective actions (Followup Item 275/9514-01).

5 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the TS were reviewed on a sampling basis to verify that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure

existed for performance of the surveillance tests; (3) the surveillance tests had been performed at a frequency specified in the TS; and (4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillance tests were observed by the inspector during this inspection period:

5.1 Surveillance Tests

Unit 1

- STP V-3R6, Exercising Steam Supply to Auxiliary Feedwater Pump Turbine Isolation Valves

Unit 2

- STP M-16D, Operation of Train B Slave Relay K608 [Safety Injection (SI)]

These surveillances were performed adequately.

5.2 SI Pump 2-2 Testing

Background - The inspector observed portions of STP P-SIP-22, "Routine Surveillance Test of Safety Injection Pump 2-2," Revision 5. As discussed in NRC Inspection Report 50-275/95-08; 50-323/95-08, SI Pump 2-2 was replaced in March 1995 due to degradation in pump performance. Subsequent to pump replacement, the licensee determined the root cause of the pump performance degradation to have been the failure to apply Loctite to the impeller locknuts, which allowed them to loosen causing axial movement of the impeller. As a result of that finding, the licensee attempted to, but could not verify that Loctite had been applied to the locknuts on the replacement pump. Consequently, the periodic pump STP P-SIP-22, was revised to provide for increased monitoring of the replacement pump during performance of the surveillance.

5.2.1 Equipment Observations

The inspector observed the pretest briefing and accompanied operators to the pump room to observe set-up and performance of the test. The test involved the operation of the pump for a sufficient period of time to allow for monitoring of pump d/P and pump acoustic performance, observing any reverse rotation of the non-operating pump, and to ensure a representative oil sample could be drawn by mechanical maintenance. A Honeywell high-accuracy d/P transmitter was temporarily installed to measure pump d/P, and personnel from predictive maintenance were present to take acoustical data on the pump and motor. Precautions and limitations of the procedure were briefed by the Shift Foreman and properly observed by the operators during the test. Radiological controls practices were observed to be adequate for the potential hazards associated with the installation of the d/P gauge, drawing the oil sample and

the acoustic monitoring performed within the surface contamination area of the pump.

5.2.2 Noise Transient and Pump Performance Degradation

Immediately following the pump start, a loud noise, thought to have been caused by water hammer or check valve slam, was heard by personnel in the pump room. Also noted during the test was a slight decrease in the pump d/P of 2.5 psid from the previous test in June. In response to these test results, the licensee performed a system walkdown to evaluate any physical consequences of the potential water hammer on the SI system, ultrasonic testing on the suction and discharge piping of SI Pump 2-2 to determine if any significant voids existed and venting of associated suction and discharge piping. In addition, the licensee reperformed the surveillance test to troubleshoot the noise. The second surveillance test did not reproduce the loud noise; however, another apparent drop in pump d/P of 2.5 psid was noted. To ascertain the significance of the drop in pump d/P, the licensee ran the surveillance test a third time. The results of the third test were essentially identical to the second. A post-test calibration of the d/P cell adjusted the results of the second and third tests to show a total pump d/P drop of approximately 3.5 psid from the baseline data in March 1995. Through subsequent discussions with the pump vendor, the licensee discovered that this drop in pump d/P is not unusual for a new pump installation. The licensee, in evaluating the surveillance test data, including additional acoustical data obtained during the second and third tests, concluded that the drop in pump d/P is not associated with the absence of thread locking compound on the impeller locknuts.

5.2.3 Conclusion

Although some reduction in SI Pump 2-2 performance was noted, the licensee and inspector considered the magnitude of the decrease small. Repeated testing did not indicate the potential for rapid degradation of pump performance. In addition the measured pump d/P in each of the tests was well above the minimum d/P limit established in TS.

Each of the three surveillance tests were well planned and briefed. The licensee's response to the noise transient and pump d/P degradation was timely and comprehensive. The licensee's evaluations were thorough and their conclusions appeared to be consistent with the available information.

5.3 <u>Pressurizer Power-Operated Relief Valve (PORV) Block Valve Testing</u>

Background - The inspector observed portions of the Unit 2 STP V-3J1, "Exercising the Block Valves to the Pressurizer PORVs, Valves RCS-8000A, RCS-8000B, and RCS-8000C," Revision 10. The purpose of the test was to measure the stroke time of the pressurizer PORV block valves from their open to close position. Stroke time was measured using a valve control switch actuated electronic timer and position indicating light in the control room. In addition, motor-operated valve engineers were coordinating a test to

measure motor current of the PORV block valves in conjunction with the stroke time surveillance.

The licensee had recently replaced the valve stems on all Units 1 and 2 PORV block valves. The replacement stems were made of Inconel material. The stems were replaced because the licensee found the previous stem material to be susceptible to radiation and high temperature embrittlement. Though still within specified tolerances, the replacement PORV block valve stems were found to have slightly larger diameters than those of the stems which they replaced. The licensee was trending motor current traces on these valves to verify that motor current had not increased. Increased motor current would be expected, if clearance problems existed. The motor current measurements provided a periodic check to assure that the refurbished PORV block valves were operating properly.

5.3.1 Conclusion

The inspector determined that while minor setup problems occurred, none affected the ability to determine valve performance; the surveillance tests were valid, and acceptance criteria were met.

5.4 <u>EDG 1-2 Routine Surveillance Test</u>

Background - On August 11, 1995, the inspector observed EDG 1-2 conditions immediately prior to performance of the surveillance test and noted that the diesel had not fully cooled down from previous testing. The lube oil and jacket water temperatures for EDG 1-2 were observed to be 112°F and 110°F, respectively. EDGs 1-1 and 1-3 had not been run within the previous 24 hours and were observed to have jacket water temperature and lube oil temperatures at least 10°F less than EDG 1-2. Immediately after noting the temperatures EDG 1-2 was started to accomplish TS required testing. The licensee was required to perform EDG 1-2 operability testing at frequency of at least once every 7 days after experiencing two valid failures during the last 20 tests. The licensee performed the testing more frequently than required by TS to complete increased frequency testing prior to the Unit 1 refueling outage.

5.4.1 EDG 1-2 Test Requirements

TS 4.8.1.1.2.a.(2) requires surveillance testing which verifies that the diesel starts from ambient conditions and accelerates to at least 900 rpm in less than or equal to 10 seconds. An additional note is provided within the TS which states in part that "all diesel generator starts for the purpose of this test may be preceded by an engine prelube period. Further, all surveillance tests with the exception of once per 184 days, may also be preceded by warmup procedures (e.g., gradual acceleration and/or gradual loading >150 sec), as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized."

DCPP diesel generators are equipped with lube oil and jacket water heaters (keep warm systems), and prelube systems. The heaters are designed to

maintain the respective systems at approximately 100°F. The inspector observed that it was the licensee's practice to continuously operate the keep warm systems and when the systems were inoperable and temperatures dropped below the range maintained by the keep warm systems the licensee declared the EDG inoperable.

The governors utilized for the control of EDGs do not allow gradual acceleration of the diesel after starting. The licensee gradually loads the EDGs during all testing with the exception of the 184 day surveillance. The licensee was not aware of any other manufacturer recommendations for reducing mechanical stress and wear on the diesel engine.

The inspector reviewed STP M-9A, "Diesel Engine Generator Routine Surveillance Test," Revision 31, to determine the procedural requirements for verifying ambient conditions prior to performing operability testing. This review revealed that the procedure did not contain specific requirements or guidelines with regard to ambient conditions. After observing the surveillance test and reviewing the TS, the inspector questioned whether the testing performed at elevated jacket water and lube oil temperatures satisfied the TS testing requirements, and whether past testing had been performed at temperatures greater than ambient conditions.

5.4.2 Licensee Investigation

The licensee's investigation confirmed that STP M-9A did not contain any test requirements to ensure testing was accomplished from ambient conditions. On August 18, 1995, the licensee issued an on-the-spot change to STP M-9A which defined ambient conditions for the EDG as being jacket water and lube oil temperatures less than 110°F. Based on this criteria, the licensee determined that the EDG 1-2 test observed by the inspector on August 11, 1995, as well as two other tests that were performed subsequent to that date, had not performed in accordance with TS requirements. The licensee's review of past surveillance tests revealed numerous other surveillance which had been performed with initial engine temperatures greater than ambient. With the exception of EDG 1-2, the most recent TS testing of EDGs had been accomplished from ambient conditions.

On September 1, 1995, action request A0376396 documented that during the investigation of the inspector's concerns, it was noted that the most recent 184 day surveillance test for EDG 1-2, conducted on July 20, 1995, was performed with an initial jacket water of 169°F and initial lube oil temperature of 162°F; both of these temperatures were significantly greater than ambient. On September 6, 1995, a Technical Review Group concluded that since the most recent fast start (184 day) surveillance for EDG 1-2 had not been performed at ambient conditions, the EDG was inoperable. After coming to this conclusion, the licensee performed a fast start (184 day) test of EDG 1-2 within the next 24 hrs.

The resolution of this issue is not considered to have been timely. The question regarding the testing requirements was first raised by the inspector

to engineering management on August 11, 1995. A week later the procedure for performing EDG routine surveillance was revised and testing results invalidated for three previous EDG 1-2 starts, two of which were performed after August 11, 1995. On September 1, 1995, review of previous test data revealed that the most recent 184 day test of EDG 1-2 was performed at elevated temperatures. EDG 1-2 was not declared inoperable until September 6, 1995.

5.4.3 Safety Significance

The licensee's preliminary review performed of monthly test results indicated that starts from temperatures elevated above 110°F did not have a significant effect on starting times. The inspector informed the licensee that in situations where the licensee considers the required conditions for performing the surveillance do not provide any additional assurance regarding EDG operability, it is incumbent upon the licensee to establish a technical basis for the judgement and pursue changing the TS requirements. The inspector noted that the testing of EDGs, which demonstrates the fast start capability from ambient conditions, is considered necessary since the design basis of the plant requires such a capability.

5.4.4 Conclusion

TS 4.8.1.1.2.(a) requires that each diesel generator shall be demonstrated operable in part by verifying that the diesel starts from ambient conditions and accelerates to 900 rpm within 10 seconds. Contrary to the TS requirement, on July 20, 1995, the surveillance test for EDG 1-2 was conducted with the diesel at temperatures significantly above ambient conditions. The failure to perform surveillance testing, which verifies that the diesel starts from ambient conditions and accelerates to at least 900 rpm in less than or equal to 10 seconds is a violation of TS 4.8.1.1.2.a.(2) (Violation 275/9514-02).

5.5 <u>EDG 1-2 Full and Partial Load Rejection Tests</u>

The inspector observed the pre-evolution briefing for the performance of STP M-9D1, "Diesel Generator Full Load Rejection Test," Revision 1, and STP M-9D2, "Diesel Generator Partial Load Rejection Test," Revision 3. EDG 1-2 was running at the time the testing was commenced. Operators satisfactorily accomplished the full load rejection test. During the preparation for the partial load rejection test, the operator noted minor oscillations in EDG voltage. The synchroscope was also noted to be rotating in an irregular motion. The operator voiced his concern regarding these indications to the engineers who were observing the testing. An inspection of the diesel was performed which revealed that the EDG fuel racks were oscillating with the diesel at a steady load, indicating an abnormality in governor performance. EDG 1-2 testing was secured; the EDG was declared inoperable. The licensee's troubleshooting revealed a problem with the EGA governor. Following corrective maintenance, EDG 1-2 was tested satisfactorily.

5.5.1 Conclusion

The senior control operator performing the testing was observed to closely monitor available EDG indications during the testing. When abnormal indications were detected, a prompt investigation was initiated. This questioning attitude led to the identification and correction of a material problem that affected EDG 1-2 operability, and avoided a potential problem with "on demand" operation of the diesel generator.

6 ONSITE ENGINEERING (37551)

6.1 OPERABILITY OF OFFSITE POWER

Background - Early in August 1995, the licensee notified the inspector that they had planned to take out of service for maintenance (outage) one of two 230 kV lines supplying offsite (startup) power to Diablo Canyon. During the review of this planned outage, the licensee determined that this source of offsite power could become inoperable with this line out. The inspector then asked the licensee if they had addressed whether safety equipment could also be subject to an unanalyzed double sequencing as described in NRC Information Notice (IN) 93-17, "Safety Systems Response to Loss of Coolant And Loss of Offsite Power," Revision 1. The following paragraphs provide: (1) a brief description of the offsite power at Diablo Canyon, (2) the licensing basis, (3) current analysis, operability and compensatory measures, (4) timeliness and adequacy of licensee actions since early August, (5) apparent delays in recognizing and addressing the adequacy of the 230 Kv system prior to August 1995, (6) discussion, and (7) conclusions.

6.1.1 System Description

Diablo Canyon has two offsite power sources to safety busses. The first source is a 230 kV system which is connected to the Diablo Canyon switchyard by two separate lines, one from Morro Bay and one from Mesa. However, the Mesa line actually originates at Morro Bay, is routed to the Mesa and then to Diablo Canyon. During power operation, the unit turbine generator provides power to safety and nonsafety busses. After a reactor trip, safety loads are slow bus transferred to the 230 kV system. Unless an independent turbine trip signal is received, the reactor trip will trip the turbine after a 30 second delay. When the turbine trips, nonsafety loads are fast bus transferred to the 230 kV system. Since some design basis accidents cause a turbine trip before the 30 second delay, the nonsafety loads may transfer from 0 to 30 second after a reactor trip. The only power generation on the 230 kV system is four gas fired boilers at Morro Bay (two large and two smaller units), but due to economic considerations typically only one unit has been operating. There are no capacitors on the 230 kV system to maintain system voltage.

The second source of offsite power is a 500 kV (auxiliary) system, which is the output of the main transformers. This is a delayed source of power. After a reactor trip, operators must open a main generator motor-operated

disconnect switch and restore power to the safety and nonsafety busses by backfeeding through the main transformers. The Diablo Canyon switchyard is connected to the 500 kV system by three separate lines.

The 230 kV system is connected to the 500 kV system via four separate lines and associated transformers in the California central valley.

The safety busses at Diablo have several undervoltage schemes including secondary undervoltage relays (SLURs). The SLURs were set to ensure that voltages to safety equipment recovered to 90 percent of rated voltage after a time delay for transient loading. Following a reactor trip, the safety and nonsafety loads would transfer from the unit transformers to the 230 kV system. If sustained low voltage existed for approximately 10 seconds, the EDGs would start, and if the low voltage condition continued for another 10 seconds, the SLUR would strip the bus and transfer the safety loads to the EDGs (double sequence). Since the EDGs would be running, the emergency loads would sequence onto the bus after only a 2 second delay, in lieu of waiting an additional 10 seconds for the EDGs to start.

6.1.2 Licensing Basis

The licensee stated that they considered that their licensing basis required either 230 kV line to be capable of supplying the required offsite power to Diablo Canyon. The licensee stated that their design basis accident is a LOCA in one unit, with a deferred shutdown of the second unit.

The Diablo Canyon Final Safety Analysis Report stated in Section 8.1 that the offsite system complied with Regulatory Guide 1.32 and IEEE 308-1971. As noted in Section 8.2 of the NRC's Safety Evaluation Report for offsite power, either of the 230 kV lines was considered capable of supplying offsite power to Diablo Canyon.

6.1.3 Current Analysis, Operability, and Compensatory Measures

The licensee determined that 230 kV system loads had increased significantly since the original plant design. This increased load caused additional line voltage drop. During peak loading with the Morro Bay to Diablo line out of service or with no generation at Morro Bay, the licensee calculated that a design basis event could cause offsite 230 kV line voltage at Diablo Canyon to stay below the SLUR setpoint, and cause transfer of safety-related loads to the EDGs (double sequencing). As noted above, the licensee considered the design basis event for offsite power to be a reactor trip/engineered safeguard feature actuation in one unit followed by a slow shutdown of the other unit.

The licensee performed calculations, which indicated that with all lines in service and at least one large unit operating at Morro Bay, the system would remain operable under worst case loading conditions. The licensee's short term corrective action included keeping this equipment in service. The licensee determined that by maintaining the voltage at Diablo Canyon at or above 234 kV the system would remain operable.

The licensee stated that they would declare the 230 kV offsite power inoperable upon loss of a 230 kV line. The inspector questioned the adequacy of this action since the consequences of double sequencing ECCS loads did not appear to have been thoroughly evaluated by the licensee. In response to the inspector's questions, the licensee provided the inspector with Westinghouse Safety Analysis (WSA) 91-025, Revision 0. This safety analysis evaluated the impact of a LOCA followed by a transfer to 230 kV power, and a subsequent SLUR relay actuation, which double sequences the safety-related loads. In reviewing the WSA, the inspector noted that the effect of double sequencing on containment integrity had not been thoroughly evaluated. The WSA concluded that the LOCA containment integrity analysis had many interrelated variables that were associated with the safeguards equipment and that the competing effects of these variables made the assessment of the impact of double sequencing difficult without reanalysis. The inspector concluded that the containment integrity evaluation in the WSA did not provide adequate assurance that the consequences of double sequencing during a LOCA were within the design basis. Therefore, the inspector questioned the adequacy of the licensee's compensatory actions.

After reviewing the inspector's concerns, the licensee concluded based upon the available information that double sequencing was an unanalyzed condition and that the compensatory actions that had been established to be taken in the event of the loss of a 230 kV line were inadequate. The licensee revised the compensatory actions to block the transfer to startup power whenever a 230 kV line was removed from service. It was later noted by the licensee that the method initially specified for blocking the transfer did not prevent double sequencing. After noting this discrepancy, the licensee revised the compensatory actions to prevent the transfer to startup power without double sequencing.

The licensee issued instructions to transmission personnel, who control and monitor the 230 kV system, to keep the voltage at Diablo Canyon above 234 kV, and notify operators of any line or generation losses.

The licensee identified that the 230 kV lines to Diablo Canyon had been taken out of service (one at a time) 121 times since 1990, including 20 times since late in 1992. The licensee determined that none of the out of service times approached the 72 hour shutdown time from TS 3.8.1.1, Action a, for an inoperable offsite source. Transmission personnel stated that the Diablo Canyon operators were notified of each of the line outages.

6.1.4 Timeliness and Adequacy of Licensee Actions Since Early August

Throughout the ongoing discussions with the inspector, the licensee stated that they had analyzed the double sequencing of safety equipment and had determined that this sequencing would not preclude satisfactory safety equipment response to design basis accidents. To support this statement, the licensee provided the inspector with a variety of analyses accomplished by the licensee and Westinghouse. The inspector was concerned about the acceptability of the these analyses, which in many cases were based on

judgement, in lieu of calculations. The inspector noted that some of the analyses had not been formally approved for Diablo Canyon by the NRC staff.

6.1.5 Apparent Delays in Recognizing and Addressing Adequacy of 230 kV System Prior to August 1995

Preliminary licensee and inspector review indicated that the licensee had many opportunities prior to August 1995 to identify that 230 kV system loading had degraded the voltage to Diablo Canyon. For example, recent licensee review identified:

> A July 11, 1989, load study which showed marginally acceptable 230 kV voltage at Diablo Canyon, with peak loading and all lines in service.
>
> An April 30, 1991, study which indicated that the 230 kV system would not support the required voltage at Diablo Canyon under all conditions.
>
> A November 20, 1992, memorandum which noted the potential for degraded 230 kV system voltage and directed corrective actions to maintain adequate voltage to Diablo Canyon. It was not clear whether this memorandum was followed during the twenty 230 kV line outages which occurred after the memorandum was sent.

In addition, the inspector identified that:

> In early 1991, the license identified that the setting of the SLUR did not ensure that 90 percent voltage was supplied to 480 volt and 120 volt loads, as required by the Diablo Canyon Final Safety Analysis Report. The licensee raised the setpoint for the SLUR relay, causing these relays to trip at a higher voltage. It was not clear if the licensee considered the acceptability of the 230 kV system to support this higher setting. The 10CFR 50.59 evaluation associated with the SLUR change did not address the higher 230 kV system voltage requirement.
>
> In response to an Electrical Distribution System Functional Inspection question, on May 21, 1991, the licensee stated that transmission personnel "continually" perform power system transient stability analyses for present and future system configurations.
>
> The licensee's review of IN 93-17 stated that actions taken per NRC IN 92-53, "Potential Failure of Emergency Diesel Generators Due to Excessive Rate of Loading," were adequate for NRC IN 93-17. However, NRC IN 93-17 discussed potentially degraded offsite power in addition to EDG issues. The licensee did not address the offsite power issues.

6.1.6 Discussion

As noted above, the inspector had been following the licensee's response to this issue since early August 1995. The inspector reviewed the 230 kV system loading and determined that recent peak system loads during hot days were

approximately 90 percent of the maximum load used in licensee calculations. Transmission personnel informed the inspector that winter loads were similar, with typical spring/fall loads at 85 percent of maximum calculated. The inspector concluded that the calculations used a reasonable maximum load, but that area growth could invalidate this load in the future.

The inspector noted that the licensee's analysis did not include loss of any of the four 230 kV lines and associated transformers that provide power from the 500 kV system to the Morro Bay site. The inspector questioned the licensee concerning this issue. The licensee stated that they were calculating what loss of these lines/transformers would cause, and would include their loss in their final system analysis. In addition, it was not clear to the inspector how the voltage was controlled on the 500 kV system and what the minimum voltage was. During a reactor trip on September 6, 1995, 500 kV system voltage rose considerably because the tripped unit had been importing VARs. The inspector considered that if a unit trip occurred on a unit which was exporting VARs, the resultant drop in the 500 kV system voltage may further drop the 230 kV system voltage. The licensee stated that this item would be addressed in the more complete system analysis they were currently performing.

The inspector noted that although it is not clear that a dual unit trip was part of the Diablo Canyon licensing basis, this event would cause lower 230 kV system voltage than the analyzed design basis event. Addition of a LOCA in either unit would add loads which would further lower system voltage.

The inspector noted that the licensee had again performed the calculation for the setpoint for the SLUR using Instrument Society of America setpoint standards and concluded that the current setting was slightly nonconservative with respect to supplying 90 percent power to all safety-related equipment. The inspector noted that the licensee may have to raise the SLUR setpoint again, further challenging the 230 kV system operability.

The inspector toured the local switchyard control center and noted that transmission personnel had adequate indication for conditions on the 500 kV and 230 kV systems. Transmission personnel stated that they had recently added an alarm for the 230 kV system, set at approximately 234 kV, and that they were aware of the special system requirements for offsite voltage to Diablo Canyon.

6.1.7 Conclusions

The licensee's initial actions for coping with the degraded 230 kV system were inadequate. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, states, in part, that measures shall be established to assure that conditions adverse to quality, such as deficiencies and deviations, are promptly identified and corrected. Contrary to the above, following the identification of the limitations of the 230 kV system, the compensatory actions established for removing one of two 230 kV power supply lines from service were inadequate in that the specified actions would have resulted in the both units being

outside their design bases. The failure to develop adequate corrective actions as required by 10 CFR Part 50, Appendix B, Criterion XVI, is a violation (275/9514-03).

As noted above, 230 kV system voltage degradation was known by the licensee as early as 1991, but preliminary information indicated that actions to ensure operable offsite 230 kV power between that time and now were not well coordinated or timely. In addition, the licensee's failure to independently review and consider IN 93-17, was a missed opportunity to have identified the problem in 1993. From the information available, the inspector was unable to specifically determine whether any of the line outages after 1990 caused the 230 kV system to be in an unreported inoperable condition.

Based on the information available to date, the inspector concluded that the licensee's immediate corrective actions were adequate to ensure that offsite power remains operable and will be declared inoperable if it degrades. However, the adequacy of past licensee performance on this issue; including review of the final root causes, determination of the adequacy of 50.59 review associated with the SLUR change, and evaluation of the time required to evaluate the effect of system load increases, will be further reviewed as an unresolved item (URI 275/9514/04). Preliminarily, the inspector concluded that part of the licensee staff recognized the degrading 230 kV system but failed to translate this information into an operability evaluation. In addition, the inspector will review licensee corrective actions and the additional system analysis, as they become available.

The inspector noted that the original design of Diablo Canyon considered the 230 kV system to be independent of the 500 kV system with four operating generators at Morro Bay. Today, typically only one generator is in operation at Morro Bay, and system loading has doubled. Thus, external plant changes have occurred which have significantly altered the design margin and independence of the offsite power to Diablo Canyon.

7 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during these evaluations.

7.1 Housekeeping

During a routine tour of the Unit 2 SI Pump rooms, the inspectors noted that following work on SI Pump 2-2, the licensee had left behind a rubber glove covering the drain to the pump skid. As a consequence, had a leak occurred, potentially contaminated water might have spilled over onto the floor. The inspectors brought this poor housekeeping practice to the attention of the licensee. The licensee removed the protective cloths from the pump skid and brought the matter to the attention of maintenance supervisors.

8 FOLLOWUP PLANT OPERATIONS (92901)

8.1 (Closed) Inspector Followup Item 275/9512-01: Auxiliary Seawater (ASW) Pump Start Due to ASW Pump Transfer in the Other Unit

This followup item involved pressure oscillations during ASW pump transfers. When starting and stopping ASW pumps, pressure oscillations were observed. An initial increase of pressure was followed by a pressure decrease. The pressure oscillation was observed to be transmitted through the closed ASW cross-tie valve between Units 1 and 2. Occasionally the pressure drop would be of sufficient magnitude to cause an autostart of the opposite unit pump on low pressure. NRC inspectors, observing a TS surveillance, noted that operators were instructed to place the opposite unit ASW pump in the manual mode for the duration of the surveillance procedure, which required an ASW pump transfer. This was of concern for two reasons: (1) that operators were, in effect, having to perform a work-around to compensate for the system anomaly; and (2) that there might not have been sufficient consideration of the effects of the pressure oscillation on the structural integrity of the ASW system.

8.1.1 Operator Work-Arounds

The inspector interviewed cognizant licensee personnel and reviewed various documents including a sample of operating procedures. Surveillance procedures and operating procedures which required ASW pump transfers referenced OP.E-5:IV, "ASW System - Changing Over Pump and Heat Exchanger Trains," Revision 4, the current revision of this procedure, contained a step to advise the opposite unit control operator to place the unit standby pump in manual to prevent a possible autostart. The inspector also noted that putting the standby ASW pump in manual would not defeat any of the pump's required safety functions or actuations. Although placing the pump in the manual mode was a work-around, the action did not appear to impose a significant increase to an operator's duties.

8.1.2 Cause and Effect of the Pressure Oscillation

The licensee first initiated an action request in December 1991 to evaluate the ASW pump transfer problem. Some of the initial investigations focused on possible leakage through the cross-tie valve between the units. The cross-tie valve is a butterfly valve and as such is not expected to maintain a leak tight boundary. Subsequent calculations by the licensee determined that an opening amounting to 1 percent of the valve's flow area would transmit only 4 percent of the maximum observed pressure pulse. Further investigation by the licensee determined that an acoustic wave of sufficient magnitude could be transmitted through the closed valve to generate a pressure drop of sufficient magnitude to actuate the autostart signal on low pressure. Testing was performed at the plant to simulate the various pump transfer scenarios. The testing involved recording traces of the oscillating pressure pulses. The testing confirmed the licensee's theory of acoustical wave transmission through the closed cross-tie valve.

The test data was used by the licensee's dynamic analysis group to evaluate the increased loads from the pressure pulses occurring from transfer of the ASW pumps. The dynamic analysis group determined that the increased loads would not have a significant effect on the ASW system components. Furthermore, the licensee considered that the pressure pulses could possibly occur concurrent with a seismic event. Consideration of the additional stresses caused by the pressure pulses acting concurrently with design pressure, deadweight, and seismic loads did not result in primary stresses exceeding their code allowable stresses.

In reviewing the licensee's test data, the inspector observed that the pump transfers on Unit 1 were performed differently from those on Unit 2. The Unit 1 operators would start the second pump and immediately stop the first pump before establishing flow to its respective heat exchanger. The Unit 2 operators would start the second pump and allow flow to its respective heat exchanger for a few minutes before stopping the first pump. The test data showed that the pressure oscillations following the taking out of the first pump were less severe than those which resulted when flow to the second heat exchanger had not been established. In fact, no autostarts of the opposite unit ASW pump were noted when both heat exchangers were in operation at the time of pump transfer. The inspector questioned if the licensee had considered establishing a consistent approach to ASW pump transfer which would involve transferring ASW pumps only after flow to both heat exchangers was established. The licensee was considering the feasibility of such an approach.

8.1.3 Conclusions

The inspector concluded that the licensee had appropriately evaluated the conditions observed during ASW pump transfers and found no adverse consequences. The need for operators to put a standby ASW pump into manual was not considered to be a significant operator work-around nor did it disable any safety function.

8.2 <u>(Closed) Inspector Followup Item 323/9307-08: Preparation for Refueling</u>

Licensee Event Report (LER) 323/93-004 was issued based on this inspector's followup item. LER 323/93-004 was closed in NRC Inspection Report 50-275/93-29 and 50-323/93-29, Section 8.a. Therefore, this inspector followup item is administratively closed.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

M. J. Angus, Manager, Regulatory and Design Services
*J. R. Becker, Director, Operations
S. Bednarz, Engineer, System Engineering
*D. H. Behnke, Senior Engineer, Regulatory Services
*F. Bosseloo, Assistant to Vice President, Nuclear Power Generation Business Unit
*K. H. Bych, Supervisor, Independent Safety Evaluation Group
W. G. Crockett, Manager, Engineering Services
*T. F. Fetterman, Director, Electrical and Instrumentation and Control Systems Engineering
W. H. Fujimoto, Vice President and Plant Manager, Diablo Canyon Operations
*W. H. Goelzer, Engineer, Balance of Plant
T. L. Grebel, Director, Regulatory Support
*C. R. Groff, Director, Secondary Systems Engineering
*C. D. Harbor, Engineer, Regulatory Support
*S. LaForce, Engineer, Regulatory Services
D. B. Miklush, Manager, Operations Services
J. E. Molden, Manager, Maintenance Services
P. T. Nugent, Senior Engineer, Regulatory Support
D. H. Oatley, Director, Mechanical Maintenance
*J. L. Portney, Senior Engineer, Balance of Plant
R. P. Powers, Manager, Quality Services
G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Buisness Unit
*J. C. Sopp, Director, Quality Control
*D. A. Taggart, Director, Nuclear Safety Engineering
R. A. Waltos, Director, Balance of Plant Engineering
L. F. Womack, Vice President, Nuclear Technical Services

1.2 NRC Personnel

*M. D. Tschiltz, Senior Resident Inspector
*S. A. Boynton, Resident Inspector

*Denotes those attending the exit meeting on September 21, 1995.

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on September 21, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

ASW	auxiliary seawater
d/P	differential pressure
DCPP	Diablo Canyon Power Plant
DNBR	departure from nucleate boiling ratio
EOP	emergency operating procedure
EDG	emergency diesel generator
FCV	flow control valve
IN	information notice
kV	kilovolt
LOCA	loss of coolant accident
OP	operating procedure
PCT	peak centerline temperature
PORV	power-operated relief valve
psid	pounds per square inch differential
RCCA	rod control cluster assembly
RCS	reactor coolant system
SI	safety injection
SLUR	secondary level undervoltage relay
STP	surveillance test procedure
SV	solenoid valve
TS	Technical Specification
WSA	Westinghouse Safety Analysis