ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-275 50-323
License Nos.:	DPR-80 DPR-82
Report No.:	50-275/98-02 50-323/98-02
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 1/2 miles NW of Avila Beach Avila Beach, California
Dates:	January 4 through February 14, 1998
Inspector(s):	David L. Proulx, Senior Resident Inspector Donald B. Allen, Resident Inspector Ian B. Barnes, Technical Assistant, Region IV
Approved By:	Howard J. Wong, Chief, Reactor Project Branch E

ATTACHMENTS:

Attachment 1:	Supplemental Information
Attachment 2:	Discussion Materials

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report 50-275/98-02; 50-323/98-02

Operations

- The licensee took conservative action in response to adverse weather conditions by reducing power when high swells were noted. In addition, the licensee provided continuous management coverage and extra operators to ensure emergency response capability was not degraded when severe weather conditions existed (Section O1.2).

- A violation was identified for several examples of failure to implement the sealed valve program. The widespread examples of failure to seal safety-related valves properly indicated weaknesses in training of nonlicensed operators (Section O1.3).

- An operator was not aware that he was expected to closely monitor reactor coolant Pump 2-2 parameters, and if flow was greater than 6 gallons per minute to take action, including tripping the reactor. This was indicative of a poor turnover of information between operators in that the operator was not aware of the applicable limit for seal leakoff flow (Section O1.4).

- The operations department displayed good sensitivity to the potential impact of control room modifications. The modifications were well planned and had a minimal impact on safety (Section O2.1).

Maintenance

- Improved design and maintenance of intake structure components contributed to good response of the plant to high ocean swells (Section O1.2).

- A noncited violation was identified for failure to properly implement the clearance tagging procedure by hanging a red danger tag on the wrong component. This item was indicative of the continuing weakness in the licensee's implementation of the clearance process (Section M1.1).

- Technical maintenance personnel did not reflect a questioning attitude in dealing with a problem during Solid State Protection System (SSPS) testing (Section M1.3).

Engineering

- The operability assessment associated with a decrease in the limit on component cooling water temperature was timely and technically sound (Section E1.1).

- A noncited violation was identified for failure to provide a 10 CFR 50.72 report for identifying that greater than 1 percent of the steam generator tubes in Unit 1 were defective (Section E8.2).

Plant Support

- The inspectors identified three examples of failure to properly log out of the radiologically controlled area, which was indicative of inattention to detail on the part of plant personnel. Errors in logging into the radiologically controlled area had been previously identified (Section R4.1).

- The emergency operating facility was maintained in a good state of readiness with all associated equipment operable (Section P1.1).

- Transient combustibles were properly controlled in Unit 2 in preparation for outage 2R8 (Section F1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On January 30, 1998, Unit 1 was reduced to.50 percent power because of high differential pressure across one half of the main condenser due to sea grass intrusion. Unit 1 remained at 50 percent power due to main feedwater pump control oil valve problems until February 1, when reactor power was returned to 100 percent. Unit 1 was reduced to 50 percent power on February 2, as a precautionary measure, in anticipation of high seas in the Pacific Ocean due to storms. Unit 1 was returned to 100 percent power on February 3 after weather and ocean conditions improved. Unit 1 continued to operate at essentially 100 percent power until the end of this inspection period.

Unit 2 began this inspection period at 100 percent power. On January 26, Unit 2 was reduced to 53 percent power to troubleshoot problems with the main feedwater pumps' control oil valves. Following correction of the problem, Unit 2 was returned to 100 percent power. On February 1, Unit 2 was reduced to 48 percent power to clean the main condenser and test the main feedwater pumps' turbine control oil valves. Unit 2 remained at 48 percent power as a precautionary measure in anticipation of high seas in the Pacific Ocean. Unit 2 was returned to 100 percent power on February 4, after ocean and weather conditions improved. 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 was professional and reflected a focus on safety. The utilization of three-way communications continued to improve, and operator responses to alarms were observed to be prompt and appropriate to the circumstances.

O1.2 High Ocean Swells and Severe Weather Response

a. Inspection Scope (93702, 71707)

The inspectors evaluated the licensee's response to high seas and severe weather. The inspectors witnessed control room activities, toured the facility, and interviewed licensee personnel to ensure that licensee response was appropriate.

b. Observations and Findings

On January 30, 1998, at 10 a.m. PST, Unit 1 was reduced from 100 to 50 percent power. This action was taken in response to increasing pressure differential across one of the two halves of the main condenser. The pressure differential increase was due to grass intrusion because of abnormally high seas in the Pacific Ocean.

The circulating water system uses water from the Pacific Ocean to cool the main condensers. On January 30, abnormally high swells (17 to 20 feet) resulted in grass intrusion and rising differential pressure on one half of the Unit 1 main condenser. When the operators noted that the differential pressure was 9.5 psid and increasing (normally 6 psid), the operators commenced a down power to 50 percent power. When the plant achieved 50 percent power, the licensee sequentially isolated and cleaned each half of the Unit 1 main condenser. In addition, Unit 1 remained at 50 percent power to test main feedwater pump turbine control oil system valves (racine valves). Because the racine valves for main feedwater Pump 1-2 initially failed the tests, Unit 1 remained at 50 percent power for troubleshooting and repairs until February 1.

After returning Unit 1 to 100 percent power, the licensee reduced power on Unit 2 to 45 percent to test its racine valves. The racine valves for main feedwater Pump 2-1 failed this testing and were replaced. The licensee decided to clean each half of the Unit 2 condenser as well because of forecasts of abnormally high swells (22 to 26 feet) in the Pacific Ocean through February 3. Unit 2 remained at 45 percent power until February 4 when weather and ocean conditions improved.

Operators reduced power on Unit 1 to 50 percent at 6 p.m. on February 2 in anticipation of high ocean swells and severe weather. The resident inspectors monitored the Unit 1 down power and noted that operators controlled the down power in a conservative manner in accordance with procedures. The inspector concluded that the operations department took conservative action in response to the potential impact of high seas on the plant and prior to exceeding the condenser differential pressure shutdown guidelines of 10 psid.

The licensee experienced similarly high ocean swells in 1995. However, during previous high swell conditions the licensee experienced a dual-unit reactor trip and forced shutdown to clean the ocean debris from the traveling screens. In 1997, the licensee installed a stronger traveling screen design that could better handle high seas. In addition, the licensee installed a debris grinder in the intake structure to aid in the removal of debris. These improvements contributed to the plant's ability to withstand the ocean conditions of this inspection period.

In addition to the potential for problems with the main condensers, the licensee was concerned about the potential for severe weather to affect site access. In 1995, the access road to the site became impassible because of a mud slide during heavy rains. On February 2, when heavy rains were forecasted for the area near the site, the licensee provided continuous management coverage during backshifts to ensure that in the event that the plant was inaccessible, the minimum personnel for onsite emergency response could be maintained. The inspectors provided continuous coverage to observe licensee actions in response to the severe weather and noted that the licensee's actions were appropriate.

c. Conclusions

The licensee took conservative action in response to adverse weather conditions by reducing power when high swells were noted. In addition, the licensee provided continuous management coverage and extra operators to ensure emergency response capability was not degraded when severe weather conditions existed.

O1.3 Sealed Valve Program

a. Inspection Scope (71707)

On January 7, 1998, the inspectors walked down portions of the chemical and volume control system to ensure that the system was aligned and operable in accordance with licensee procedures.

b. Observations and Findings

The inspectors noted that all valves in the injection flow paths were in their required positions. Minor boric acid leaks were identified and scheduled for repair by the licensee. However, the inspectors identified ineffective seals on valves.

The licensee sealed these valves to meet Technical Specification requirements and for configuration control. These seals were credited by the licensee and allowed an extended period for verification of the valve position. The Technical Specifications required all valves that are not locked sealed or secured in their positions that are in the injection flow paths to be checked every 30 days. The valves that were sealed did not require a 30-day verification.

While reviewing the Unit 2 centrifugal charging pumps and valve alignments, the inspectors noted that several valves were ineffectively sealed. The seals were attached to the valve label plates, which were hanging around the valve stems. The handwheels on these valves could have been turned without breaking the seals. The valves were:

CVCS-2-485A	CVCS-2-485B	CVCS-2-484A
CVCS-2-487A	CVCS-2-489A	CVCS-2-487B
CVCS-2-498B	CVCS-2-499B	CVCS-2-486B
CVCS-2-489B		

The inspectors notified the shift supervisor who initiated Action Request (AR) A0450497 to enter this item into the licensee's corrective action program.

Procedure OP1.DC20 "Sealed Components," stated, in Section 4.1.7, that "All component seals shall be installed in a manner to physically impede the operation of the component so that its operation requires that the seal be broken. On nonthrottle valves, it is acceptable if some minor movement (less than a half turn of the handwheel) is

allowed as long as the seal must be broken to permit significant operation." Because the above listed valves were sealed such that the valve handwheel could be turned significantly, the licensee did not meet Procedure OP1.DC20. The failure to seal valves in accordance with Procedure OP1.DC20 is a violation of Technical Specification 6.8.1.a (50-275; 323/98002-01).

Following the inspectors' identification of the 10 sealed valve discrepancies, the licensee performed a 100 percent review of the sealed valves in both units. The licensee identified 42 additional examples of improperly sealed valves. These improperly sealed valves were found on the diesel generators, component cooling water system, containment cooling system, safety-related ventilation systems, main steam system, and additional examples on the chemical and volume control system. No valves were found out of position. The licensee replaced all of the deficient seals and verified their installation.

Licensee investigation revealed that the improper sealing of valves spanned several nonlicensed operators and operating crews. Therefore, the inspectors concluded that there was a general knowledge deficiency among the nonlicensed operators of Procedure OP1.DC20.

This event had little actual safety consequences because all of the ineffectively sealed valves were in their correct positions, and therefore posed no operability questions. However, this issue was indicative of a problem with securing valves as specified in Procedure OP1.DC20.

As corrective actions, the licensee: (1) walked down all accessible sealed valves to ensure compliance with the procedure, (2) modified several valve handwheels to allow for proper sealing, (3) provided required reading for each of the operating crews on this event and proper valve sealing methods, (4) committed to verify all valves in containment and high radiation areas during the next refueling outage on each unit, and (5) committed to provide training to all of the crews during a training week, to be completed by August 7, 1998. The inspectors considered these corrective actions to be satisfactory.

c. Conclusions

A violation was identified for several examples of failure to implement the sealed valve program. The numerous examples of failure to seal safety-related valves properly indicated weaknesses in training of nonlicensed operators.

O1.4 Excessive No. 1 Seal Leakoff Flow For Reactor Coolant Pump 2-2

While observing the Unit 2 control panels, the inspectors noted that the No. 1 seal leakoff flow for reactor coolant Pump 2-2 was indicating greater than 5 gpm and was significantly higher than the other reactor coolant pumps. When the control operator was questioned as to the upper limit on this flow, he referenced the precaution and

limitations of operating Procedure OP A-6:I, "Reactor Coolant Pumps-Place in Service," Revision 18. This gave an upper limit of 4.8 gpm and referenced Figure 1. Figure 1 of this procedure shows a safe operating region under a curve which has an upper limit of 4:8 gpm and a statement to shutdown the reactor coolant pump within one-half hour above the curve. The shift foreman directed the operator to the annunciator response Procedure AR PK05-02, "Reactor Coolant Pump No. 22," Revision 10A, which allows continued pump operation with flow less than 6 gpm. This was consistent with vendor technical bulletin for the reactor coolant pump.

The inspectors concluded that the operator was not aware that he was expected to closely monitor reactor coolant Pump 2-2 parameters, and if flow was greater than 6 gpm to take action, including tripping the reactor. In addition, the inspectors concluded that the difference between the operating procedure precautions and limitations and the annunciator response procedure could cause confusion. The licensee was evaluating enhancing Procedure OP A-6.1 to note that the procedure was only applicable during reactor coolant pump starts. This event was indicative of a poor turnover of information between operators in that the operator was not aware of the applicable limit for seal leakoff flow.

O2 Operational Status of Facilities and Equipment

O2.1 Control Room Modifications

a. General Comments (71707)

On January 5, 1997, the licensee commenced modifications of the control room. These modifications were designed to raise the shift foremen's work stations approximately 1 foot off of the floor so as to provide better oversight of the crew's activities. In addition, the modifications provided alarm monitor screens for each of the shift foremen, so that the shift foreman could have up-to-date information on annunciators.

The inspectors reviewed the licensee's plans for the installation. The licensee's plans were to minimize control room distractions. The inspectors observed that much of the materials were staged outside of the control room, and were only brought into the control room as necessary to support the work. The individuals performing the modifications were briefed on minimizing noise and distractions and that the shift supervisor had the authority to secure the work as necessary. The shift supervisor used this authority and stopped the work on January 6, when an excessive amount of construction personnel were in the control room. On January 10, the control room modifications were completed without incident.

The inspectors concluded that operations department displayed good sensitivity to the potential impact of the control room modifications. The modifications were well planned and executed with minimal impact on plant operations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707)

The inspectors observed portions of the following work activities:

- Remove and reinstall component cooling water heat Exchanger 2-1 seawater outlet thermowell (TI-186) to support performance of PEP M-234, Work Order C0155746
- Clean and inspect seawater side of component cooling water heat Exchanger 2-1 Work Order C0155853
- Replace diesel generator fuel injection tubing and snubber valve, Work Order CO155980

b. Observations and Findings

On February 10, 1998, the inspector observed the conditions inside the heat exchanger prior to cleaning. Very few tubes appeared blocked by debris and little fouling could be detected by visual inspection. An enclosed space permit was properly displayed and good ventilation and lighting were established for the work. The maintenance personnel were knowledgeable of the tasks to be performed. The System Engineer was present and discussed with the technicians the need to remove as much macro fouling as possible to improve the accuracy of the test to be performed the next day. The purpose of the test was to determine the amount of micro fouling that occurred after an extended operating cycle (21 months verses 18 months).

Man-on-line tags were hung to protect the equipment and personnel. However, the inspector found one clearance tag (red tag) that appeared to be hung on the wrong breaker. The description of location stated on the tag was 480 volt breaker Cubicle 52-2H-42, which was the power supply for flow control Valve FCV-496, auxiliary saltwater supply to auxiliary saltwater crosstie. The tag was hanging on 4160 volt breaker cubicle 52-HF8, which was the power supply for the auxiliary saltwater Pump 2-1. Breaker 52-2H-42 was open and tagged with a man-on-line tag, but did not have a red tag. The shift foreman was notified of the discrepancy between the red tag's location and the description of location on the tag. Upon review by the maintenance supervisor responsible for this work, it was determined that the tag was hanging on the location intended by the person who filled out and hung the tag, but that he had inadvertently copied the location description incorrectly from clearance request.

Procedure OP2.ID2, "DCPP Tagging Requirements," Revision 6, defined red tag as hung and removed by the maintenance department or outage services and is used as an administrative control point to enhance personnel protection to workers by insuring that a clearance point will not be altered. The procedure required that at least one red tag will be hung anytime a craft performs work associated with a sub-clearance containing man-on-line tags. The man-on-line tags were the tags required by the clearance process to ensure that a safe working boundary was established and controlled, which isolated plant personnel from actual or potential sources of steam, water, electricity, compressed air, gases or chemicals.

In Procedure OP2.ID2 DCPP stated, in Section 5.1.1 that "all tags shall be properly filled out before being placed on equipment." Contrary to this requirement, Procedure OP2.ID was not implemented in because the red danger tag indicating Breaker 52-2H-42 (associated with the auxiliary saltwater crosstie valve) was hung on Breaker 52-HF8 (associated with Auxiliary Saltwater Pump 2-1). The failure to implement Procedure OP2.1D2 is a violation of Technical Specification 6.8.1.a . However, this failure constitutes a violation of minor significance and is treated as a noncited violation consistent with Section IV of the NRC Enforcement Policy (50-275;323/98002-02).

The inspectors reviewed the licensee's operations quality plan and noted that clearance errors have been a continued challenge for the licensee. In addition, clearance errors were noted as a principal concern of the previous Systematic Assessment of Licensee Performance Report (50-275;323/96-99).

c. Conclusions

The maintenance activities were performed in accordance with the procedural requirements. The results of the heat exchanger cleaning appeared to be effective in removing macro-fouling and ensuring the results of the heat exchanger test would be valid. A noncited violation was identified for failure to properly implement the tagging procedure. The error in filling out the information on the red tag indicated a lack of attention to detail and was indicative of a continuing weakness in this area.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed the following surveillances:

- STP M-11B Measurement of Station Battery Voltage and Specific Gravity, Revision 16
- STP M-9X Diesel Generator Operability and Verification Test

b. Observations and Findings

On February 10, the inspectors observed the performance of surveillance test procedure (STP) M-11B, "Measurement of Station Battery Voltage and Specific Gravity," Revision 16, on Battery 2-1. This was a quarterly test to satisfy Technical Specification Surveillance Requirement 4.8.1.b. The technician drawing the sample used proper safety precautions. A battery thermometer was used to measure temperature, as specified in the procedure. The samples were drawn from the sample tube appropriately. The voltmeter used to measure cell voltage was within its calibration interval. The cells showed no cracks or signs of electrolyte leakage. The terminals showed no sign of corrosion. The results of the data reduction was reviewed by the inspectors, and found to be correct. The data met the acceptance criteria for the test; however, the specific gravity for two cells were more than 0.010 below the average specific gravity for all the cells, thus requiring the battery be placed on an equalizing charge. The inspectors observed that the Battery 2-1 was on an equalizing charge following this surveillance.

c. Conclusions

The inspectors found that the surveillance observed was being scheduled and performed at the required frequency. The procedure governing the surveillance test was technically adequate and personnel performing the surveillance demonstrated an appropriate level of knowledge. The test results were appropriately dispositioned.

M1.3 SSPS Testing (Unit 1)

a. Inspection Scope (61726)

The inspectors witnessed portions of SSPS testing in accordance with Procedure STP I-38-B.1, "SSPS Train B Actuation Logic Test in Modes 1, 2, 3, and 4," Revision 4A, on February 1, 1998.

b. Observations and Findings

The inspectors noted that Procedure I-38-B.1 required operators to rack in, test, and close the reactor trip bypass breakers. The inspectors noted that the operators performed this activity carefully and followed procedures. Following the closure of the reactor trip bypass breakers, technical maintenance personnel performed testing at the bypass breaker panels.

During testing of the SSPS slave relays per Section 8.7.1 and Table T7, technical maintenance personnel observed unusual indications. The indicating light for Relay K611 indicated "ON" when the light was required to be indicating "OFF," and no test current had been applied. The technicians toggled the selector switch between position 17 and 18 to attempt to clear the indicator. The light did not clear. The

technicians depressed the "TEST" push button and noted that all of the indicating lights were illuminated as required and signed off the step satisfactorily. When questioned, the technicians stated that they encountered this problem frequently and that they did not normally document these types of minor items. The technicians then continued on with the SSPS testing and signed off all completed steps satisfactorily.

On February 2, the inspectors discussed this testing with the technical maintenance director and determined that the unexpected light for Relay K611 had not been documented on an action request for the February 1 SSPS testing. The technical maintenance director stated he was unaware of this issue, as was the general foreman. The technical maintenance director discussed this issue with the technicians and an action request was initiated.

The technical maintenance director briefed the technical maintenance shop personnel on the need to promptly initiate action requests when anomalies were noted during surveillance testing. The inspectors considered this action to be appropriate.

The inspector determined through discussions and a review of drawings that the illuminated light was indicative of a sticking switch and that the surveillance test was a satisfactory test of the performance of the relay .

c. Conclusions

Technical maintenance personnel did not reflect a questioning attitude when dealing with a problem with SSPS testing.

III. Engineering

E1 Conduct of Engineering

E1.1 Component Cooling Water Temperatures

a. Inspection Scope (37551)

The inspectors evaluated the licensee's response to Action Request A0451991, which discussed incorrect assumptions for the component cooling water system temperatures.

b. Observations and Findings

On January 30, 1998, the licensee identified that the maximum normal operating temperature limit for the component cooling water system was 100°F, whereas design documentation and licensee operating procedures indicated a maximum temperature limit of 120°F. Because the design documents and procedures were in error, the licensee was concerned that the operability of component cooling water components was in question.

The licensee initiated a prompt operability assessment for this issue. The licensee determined that the component cooling water system was operable because the operating temperature of the system was normally less than 85°F, which was a significant margin to the new limit of 100°F. However, since the annunciator response procedures were still based on 120°F, the licensee took the following compensatory actions: (1) operators were provided with shift instructions that indicated the new normal operating temperature until procedures could be revised, and (2) the annunciator alarm point for component cooling water supply temperature high was lowered to 85°F. With the evaluation of past operating practice and the compensatory actions in place, the licensee considered the component cooling water system to be operable. The inspectors reviewed the licensee's operability assessment and compensatory actions and had no concerns.

c. Conclusions

The operability assessment associated with component cooling water temperature limit was timely and technically sound.

E2 Engineering Support of Facilities and Equipment

E2.1 Improvements to the Intake Equipment and Enhanced Ability to Withstand Ocean Swells

a. Inspection Scope (37551)

The inspectors discussed the improvements made to the traveling screens and related equipment with system engineering personnel.

b. Observations and Findings

As the result of previous difficulties with condenser biofouling during high swells and high kelp loading conditions, the licensee created a team of engineering, maintenance and operations to develop plans to improve the traveling screens and other related equipment. The hardware on the circulating water traveling screens was upgraded during routine maintenance. This included screen baskets that were welded rather than bolted to improve strength. The traveling screens supports were upgraded from a two-post to a four-post design. Racks were added to some baskets to improve their ability to catch the kelp and seaweed. The reliability of the screen spray system was improved with longer lasting nozzles and by improving the availability of spare pumps. A debris grinder was added to the inlet of the refuse sump to cut up the kelp and debris and, thereby, improve the ability of the refuse pumps to remove the debris.

A dedicated maintenance team was created to focus on maintaining the equipment in the intake. An Operating Order O-28, "Intake Management," Revision 1, was created to establish strategies and practices for mitigating the effects of kelp influx that can occur during high energy ocean swells. This operating order directed the actions to be taken during high swell warnings. These actions included increased monitoring, continuous

manning of the intake by operations personnel, and additional support from maintenance and a biofouling control representative.

c. Conclusions

The inspectors concluded that the licensee's design and maintenance actions taken to improve the plant's ability to withstand high ocean swells and kelp attacks have been effective as evidenced by the success in avoiding curtailments during the current storm season, one of the most severe for this site. The performance of this equipment demonstrated a strength in the use of focus teams to resolve problems.

E2.2 Engineering Organization Improvements

In discussions with NRR and Region IV managers, the licensee discussed performance improvements in the engineering area. Of particular note were: the initiatives of an engineering fix-it-now team, a significant reduction in the engineering backlogs (up to 50 percent), clarification of system engineer roles and responsibilities, and consolidation of engineering staff to the site. The licensee discussion material is attached.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) LER 50-275/95-013-00: component cooling water system may have operated outside its design basis due to nonconservative assumptions. This LER is being administratively closed. Revision 1 to the LER remains open and will be used to follow the item. In addition, inspection for IFI 50-275/97-202-01 will cover aspects of this issue.

E8.2 (Closed) LER 50-275/1-94-021-00: 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 Generator 1-2 during Unit 1 Refueling Outage 1R6 had been identified to be defective.

The inspectors ascertained from review of the steam generator tube examination history for Unit 1 Refueling Outage 1R6 that the number of tubes in Steam Generators 1-1, 1-2, 1-3, and 1-4 that were found by eddy current examination to contain defects were, respectively, 21, 36, 4, and 7. All of the defective tubes were removed from service by plugging. The plugging total for Steam Generator 1-2 represented 1.06 percent of the 3,388 tube population and was thus reportable in accordance with Technical Specification 4.4.5.5c. Active tube corrosion degradation mechanisms were indicated by the eddy current examination results to be: (1) primary water stress corrosion cracking at dented and nondented tube support plate intersections, Rows 1 and 2 low radius U-bends, and at the tube sheet below the tube expansion transition region; (2) outside diameter stress corrosion cracking at non-dented tube support plate intersections; and (3) cold leg thinning. Eight tubes were also plugged during Refueling Outage 1R6 because of tube wear at anti-vibration bar supports.

The 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). The licensee was found to have both significantly improved secondary water chemistry performance over a 5-year period prior to the inspection, and to have implemented comprehensive steam generator tube integrity initiatives to minimize steam generator tube degradation. Specific initiatives implemented by the licensee included the following:

- Thermal stress relief of Rows 1 and 2 low radius U-bends in 1986 (Unit 2) and 1988 (Unit 1), to minimize the tubing susceptibility to Primary water stress corrosion cracking;

- Implementation in 1988 (Units 1 and 2) of boric acid additions to the secondary side to arrest tube denting and limit initiation of outside diameter stress corrosion cracking;

- Replacement in 1988 (Units 1 and 2) of 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 of the inside diameter surface of the tubes in the tube sheet region in 1992 (Unit 1) and 1993 (Unit 2), to minimize development of Primary water stress corrosion cracking at this tubing location;

- Adoption in 1992 (Units 1 and 2) of 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;

- Replacement of ammonia (for pH control) with ethanolamine in 1993 (Unit 1) and 1994 (Unit 2), in order to reduce iron transport to the steam generators and thereby minimize its contribution to development of outside diameter stress corrosion cracking;

- Adoption in 1993 (Units 1 and 2) of 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;

- Ongoing use of eddy current examination scopes and 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.

The inspectors were also informed during the current inspection that the licensee had adopted in 1988 a policy to maintain a steam generator blowdown rate of 1 percent of the main steaming rate, in order to minimize steam generator contaminate levels.

During a subsequent refueling outage (i.e., Unit 2 Refueling Outage 2R6), the licensee performed an evaluation of whether the plugging results from both Refueling Outage 2R6 and previous Units 1 and 2 refueling outages were required to be reported to the NRC in accordance with 10 CFR 50.72. This evaluation concluded that the plugging results for Steam Generator 1-2 during Unit 1 Refueling Outage 1R6 should have been placed into Category C-3 for reporting purposes, and reported to the NRC in accordance with 10 CFR 50.72 prior to resumption of plant operation. On November 3, 1994, the licensee made a late 4-hour nonemergency report to the NRC in accordance with 10 CFR 50.72(b)(2)(iii)(C) to report that more than 1 percent of the tubes inspected in Steam Generator 1-2 during Refueling Outage 1R6 were defective.

The inspectors ascertained that the Refueling Outage 1R6 plugging results for each steam generator had been previously reported to the NRC, after completion of tube examinations, in a 15-day Special Report dated April 14, 1994. The inspectors also verified that planned corrective actions had been accomplished. Specifically, Procedure XI1.ID2, "Regulatory Reporting Requirements and Reporting Process," was revised in Revision 2 to add a requirement for a prompt 4-hour notification to the NRC via the Emergency Notification System when greater than 1 percent of the inspected tubes are found to be defective. A "reportability determination worksheet" was also included in Revision 2 of Procedure AD5.ID4, "Steam Generator Tube Inspections," to provide guidance for determining if steam generator tube inspection results were reportable to the NRC as a 4-hour nonemergency notification.

The inspectors determined that the failure to make a 4-hour nonemergency report in regard to the Refueling Outage 1R6 results constituted a violation of 10 CFR 50.72. This nonrepetitive, licensee identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-275/98002-03).

E8.3 (Closed) LERs 50-275/1-95-018-01 and 50-323/2-96-003-00: 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, respectively, in Steam Generator 1-2 during Unit 1 Refueling Outage 1R7 and Steam Generators 2-1, 2-2, and 2-4 during Unit 2 Refueling Outage 2R7 had been identified to be defective.

The inspectors ascertained from review of the Unit 1 Refueling Outage 1R7 examination history that the number of tubes found by eddy current examination to contain defects in

Steam Generators 1-1, 1-2, 1-3, and 1-4 were, respectively, 28, 70, 3, and 16. All of the defective tubes were removed from service by plugging. The defective total for Steam Generator 1-2 represented 2.06 percent of the 3388 tube population and was thus reportable in accordance with Technical Specification 4.4.5.5c. A prompt 4-hour nonemergency notification was made in accordance with 10 CFR 50.72(b)(iii)(C). The most notable change from Refueling Outage 1R6, in detected degradation, was the increase in primary water stress corrosion cracking at dented tube support locations in the four steam generators (i.e., from a total of 23 tubes in Refueling Outage 1R6 to a total of 75 tubes in Refueling Outage 1R7).

During Refueling Outage 1R7, the licensee pulled portions of four tubes from Steam Generator 1-2 that were indicated by eddy current examination to contain Primary water stress corrosion cracking at dented tube support locations. Destructive examination of the pulled tubes confirmed that the Plus Point eddy current probe had: (1) correctly identified the morphology of the defects present as Primary water stress corrosion cracking, (2) identified all of the Primary water stress corrosion cracking defects present, and (3) provided accurate sizing of length and average depth of the Primary water stress corrosion cracking defects. Burst testing results exceeded the Regulatory Guide 1.121 $1.4\Delta P_{SLB}$ (steam line break) steam generator tube structural integrity safety margin. Flaw growth rate studies were also performed by the licensee which showed that an axial Primary water stress corrosion cracking indication, that was below the eddy current detection threshold at the beginning of Cycle 8, would not grow to exceed the Regulatory Guide 1.121 $1.4\Delta P_{SLB}$ structural limit for a free span axial crack by the end of the cycle. These results thus justified the planned 18-month operating cycle for Unit 1, Cycle 8.
The inspectors ascertained from review of the Unit 2 Refueling Outage 2R7 examination history that the number of tubes found by eddy current examination to contain defects in Steam Generators 2-1, 2-2, 2-3, 2-4 were, respectively, 34, 82, 27, and 88. All of the defective tubes were removed from service by plugging. The defective totals for Steam Generators 2-1, 2-2, and 2-4 represented, respectively, slightly over 1 percent, 2.42 percent, and 2.60 percent of the 3388 tube populations in each steam generator and were, thus, reportable in accordance with Technical Specification 4.4.5.5c. Prompt 4-hour nonemergency notifications were made in accordance with 10 CFR 500.72(b)(iii)(C) following the identification in each of the three steam generators of greater than 1 percent of the tubes being found to be defective. Active Unit 2 tube corrosion degradation mechanisms were indicated by the eddy current examination results to be the same as in Unit 1 (i.e., primary water stress corrosion cracking at tube support plate intersections, Rows 1 and 2 low-radius U-bends, and at the tube sheet; outside diameter stress corrosion cracking at tube support plate intersections; and cold leg thinning). Two tubes were also plugged during Refueling Outage 2R7 because of tube wear at anti-vibration bar supports.

As discussed in E8.1 above, the licensee has implemented comprehensive actions in both units to increase tubing stress corrosion resistance and minimize steam generator tube degradation.

E8.4 (Closed) LER 50-323/2-94-006-00: feedwater ring degradation. The licensee made a voluntary report pertaining to the discovery in Steam Generator 2-4 during Unit 2 Refueling Outage 2R6 of erosion and through-wall holes in the plugs, welds, and base metal at the location of the original bottom outlet nozzles in the feedwater ring.

During Unit 2 Refueling Outage 2R6, a vendor recommended 10-year inspection was performed in each steam generator of the J-tubes in the feedwater ring. This inspection identified the presence in Steam Generator 2-4 of several through-wall holes in installed plugs, plug welds, and adjacent base metal. (The plugs were installed in the original bottom outlet nozzles during Refueling Outage 2R1, as a result of implementation of a design change to J-tube outlet nozzles). The cause of the holes was attributed by the licensee to flow accelerated corrosion. No significant degradation was observed in the other three steam generators. The inspectors verified that the licensee had weld repaired the holes in the Steam Generator 2-4 feedwater ring. The inspectors also ascertained that the licensee had established that a correlation existed between the extent of flow accelerated corrosion and the chromium content of the steel (i.e., steel containing greater than 0.1 percent chromium provided greater resistance to flow accelerated corrosion). Chromium analyses were made of the feedwater ring components to facilitate determination of the locations where future inspections should focus. The inspectors verified that a similar inspection had been performed of the feedwater rings in the Unit 1 steam generators during Unit 1 Refueling Outage 1R7 and required weld repairs made. The licensee believed that the higher secondary plant pH resulting from the replacement of ammonia control with ethanolamine (1993, Unit 1; 1994, Unit 2) should reduce the flow accelerated corrosion rate. The inspectors considered this view to be reasonable. During the 1995 steam generator tube integrity inspection, a review of the effect of use of ethanolamine indicated that it resulted in a significant reduction in iron transport to the steam generators. The inspectors, therefore, considered its adoption should reduce flow accelerated corrosion.

E8.5 (Closed) Inspection Followup Item 50-275;323/95010-01: review of eddy current examination procedures. Conformance of eddy current examination procedures to Appendix H of Electric Power Research Institute Document EPRI NP-6201, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 3, was reviewed.

The inspectors reviewed an eddy current site qualification document that was being finalized by the licensee for use during Unit 2 Refueling Outage 2R8. This qualification document utilized the essential variables of Revision 5 of the Electric Power Research Institute "PWR Steam Generator Examination Guidelines." The inspectors noted that Revision 5 specifically required utility cognizance of examination technique qualifications and applicability to site-specific conditions. Accordingly, the adoption of Revision 5 assures the use of essential variables that are consistent with the supporting technique qualifications.

E8.6 (Closed) Inspection Followup Item 50-275/;323/95010-02: review of structural analysis and growth study for cold leg thinning indications.

The inspector noted from review of Westinghouse Report "Diablo Canyon 1 & 2 Cold Leg Thinning Structural Integrity Evaluation," dated September 1996, that Westinghouse developed a cold leg thinning structural model that showed that cold leg thinning indications with a length of 0.7 inches and a depth of 84 percent would be the expected requirements of $1.43\Delta P_{SLB}$ and Regulatory Guide 1.121. Testing also showed that pressurization of cold leg thinning indications within tube support plates does not result in a burst, and, therefore, $1.43\Delta P_{SLB}$ was considered the appropriate structural limit. Licensee statistical evaluation of degradation growth rates, for 56 cold leg thinning indications, which were identified in consecutive outages from 1R6 to 1R7, showed a maximum growth rate of 36 percent through-wall and an average growth rate of 6.4 percent (with a standard deviation of 8.5 percent). The 95 percent confidence value was 23.4 percent growth. The inspectors considered that the data appropriately showed that cold leg thinning indications did not challenge Regulatory Guide 1.121 structural limits or pose other than a small leakage risk during operation.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiation Protection & Chemistry

R4.1 Radiologically Controlled Area Access

a. Inspection Scope (71750)

The inspectors observed personnel entering and exiting the radiologically controlled area in the auxiliary building.

b. Observations and Findings

On January 14, 1998, the inspector noted three personnel electronic dosimeters (PED) in the wall rack with indications in the display window. When the PED is properly read by the computer prior to exiting the radiologically controlled area, the display window has no indication. A radiation protection technician checked the status of the three PEDs in the computer and noted that they had not been properly logged out of the computer.

c. Conclusions

Failure to properly log out of the radiologically controlled area was indicative of inattention to detail on the part of plant personnel. Errors in logging into the radiologically controlled was previously identified to be a problem area.

P1 Conduct of Emergency Planning Activities

P1.1 Emergency Operations Facility (71750)

On January 9, 1997, the inspectors toured the offsite Emergency Operations Facility. The inspectors noted that the facility was maintained in a good state of readiness and that selected equipment was operational.

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 General Comments (71750)

During plant tours conducted during this inspection period. The inspectors toured areas of Unit 2 to ensure that outage preparations did not impact fire protection activities. Transient combustible permits were reviewed satisfactorily to ensure that the area fire loading was not adversely affected.

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 February 25, 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 1

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. L. Becker, Assistant Manager, Maintenance
M. A. Crockett, Manager, Nuclear Quality Services
R. D. Gray, Director, Radiation Protection
T. L. Grebel, Director, Regulatory Services
D. T. Miklush, Manager, Engineering Services
J. P. Molden, Manager, Operations Services
D. R. Oatley, Manager, Maintenance Services
R. P. Powers, 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 92903	Followup - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

50-275;323/ 98002-01	VIO	Failure to implement sealed valve program (Section O1.3).

Closed

50-323/95-003	LER	(Technical Specification 3.5.2 not met during emergency core cooling on-line maintenance (Section O8.1).
50-275/95-013	LER	Component Cooling Water system operated outside of design basis due to nonconservative assumptions (Section E8.1).
50-275/94-021	LER	Greater than one percent of steam generator tubes defective (Section E8.2).
50-275/95-018	LER	Greater than one percent of steam generator tubes defective (Section E8.3).
50-323/96-003	LER	Greater than one percent of steam generator tubes defective (Section E8.3).
50-323/94-006	LER	Feedwater ring degradation (Section E8.4).
50-275;323 95010-01	IFI	Review of eddy current examination procedures (Section E8.5).
50-275;323 95010-02	IFI	Review of structural analysis and growth study for cold leg thinning indications (Section E8.6).

Opened and Closed

50-275;323/ 98002-02	NCV	Danger tag hung on wrong component (Section M1.1).
50-275/98002-03	NCV	Failure to provide 10 CFR 50.72 report for greater than one percent defective steam generator tubes (Section E8.2).

DIABLO CANYON POWER PLANT ENGINEERING SERVICES ORGANIZATIONAL PERFORMANCE

January 22, 1998

Dave Miklush - Manager, Engineering Services

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ATTACHMENT 2

Overview

- Engineering has improved
- Engineering has organizationally improved
- Challenge is to ensure knowledge transfer
- Workload management initiated and making progress
- Problems are identified and resolved
- Licensing and design basis is adequate and improving

Organizational Performance

- Improvements
- Actions in progress
- Future changes

Communication Improvements

- Emerging Issues meeting
- Engineering Fix It Now (EFIN) Team
- 6 am daily planning meeting
- Engineering directors assigned to interface with operating crews
- 8 am daily engineering meeting
- Engineering manager participation in 9 am Plant Manager's meeting

Management Improvements

- Single engineering manager
- All engineering onsite
- Centralized system and design engineering
- Improved OPS/maintenance support
  - Clearer understanding of SE role
  - EFIN
  - SE role in Maintenance Rule
  - Outage maintenance leadership roles
  - Assignment of engineering directors to interface with designated OPS crews

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Processes Improvements

- Issue manager
- EFIN
- Work control team participation
- Process owners
- Quality plan

Actions in Progress

- Aggressively addressing engineering workload
- Additional engineering resources to support licensing and design basis work
- Engineering is involved in NPG's reengineering efforts to improve processes and make them less burdensome
- SF engineering knowledge
  - Knowledge transfer
  - Work transfer
  - Consultant option
  - Attraction to DCPP
- Positioning engineering for sustainable performance in a competitive market

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Future Changes

- Consolidate engineering resources at DCPP with one manager over the year
- Reduce engineering staffing as capital projects are completed and workload is reduced
- Focus internal engineering resources on day-to-day support of DCPP and more extensively use external resources
- Ensure SF engineering knowledge transfer/ availability

Problem Identification and Resolution

- Problem identification
- Problem resolution
- Prompt operability assessments
- Design change effectiveness

Problem Identification

- A long-standing strength - several issues have become generic industry issues
- Sometimes miss early opportunities to identify some problems
  - RCP oil collection
  - ASW check valves
- Improvements being taken include:
  - SPIGOT
  - 8 am daily Engineering Meeting
  - Emerging Issues meeting and check list

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Problem Resolution

- Thorough actions on recognized significant issues (e.g., MSSVs, transformers, and ASW piping)
- Sometimes untimely between identification and resolution
  - FSAR control room instrument accuracy
  - Smoke detector sensitivity testing
- Recent examples of timely resolution
  - ECCS pump case venting
  - ASW cable separation
  - Inadvertent SI/Pressurizer overfill
  - Containment penetration vent and drain control

POA Process Enhancements

- Engineering responsible for POAs
- Process owner
- Streamlined procedures
- All engineering personnel, supervisors, and directors trained by process owner
- Review of potential and emerging operability issues at daily engineering meeting and bi-weekly Emerging Issues meeting
- POA and OE status reviewed at bi-weekly Emerging Issues meeting
- Quality Plan tracking
- Process owner critique of all POAs

Design Change Effectiveness

- Good design process with flexible vehicles (AT-MM, MMP, and DCP)
- Design changes have been a strength - they are well engineered
- The number of design changes will be less in the future
- Process is well positioned for the future state engineering organization
- Recent successes
  - Diesel fuel oil storage tank replacement
  - Startup transformer replacement

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Examples

Problem	Resolution
CCW CFCU Flashing	Added pressurization system, GL issued
CCW heat load	Replaced oil coolers and raised system qualified peak temperature to restore margin
230 kV voltage variability	Replacing startup transformers with load tap changing transformers, capacitors being added to transmission system
MSSV setpoint drift	Extensive research and testing, replaced disks
ASW piping corrosion	Added bypass piping and enhanced flow instrumentation and cathodic protection
Fuel oil tank environmental compliance	Replaced tanks and piping to comply, and added capacity
4 kV breaker capacity	Replaced breakers
SI throttle valve clearances	Modified sump screens and extensive bench flow testing

Examples (cont'd)

Problem	Resolution
RWST inventory and channel instrumentation	Increased Tech Spec inventory and additional level
Main bank transformer degradation	Replacing main bank transformers
CFCU timers	Upgraded timers
RVLIS normalization	Revised procedures, performed testing. IE notice issued
EDG exhaust bellows cracking	Upgraded bellows
MSSV tailpipe gap clearance	Modified gaps
Cold reheat piping crack	Repaired piping, inspections of similar piping welds
Train separation post-LOCA	Revised procedures
Unqualified epoxy grout	Complete qualification testing

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Examples (cont'd)

Problem	Resolution
GL 96-01	Timely untested circuit testing completion
Containment penetration	Thorough review and surveillance completion of vents, drains, and test connections

Workload/Backlog Management Current Status

- Engineering has significantly reduced the total workload
- Content of the workload/backlog is better understood
- Ability to manage the workload has improved
- Improved tools exist for managing workload and monitoring performance
- 50% reduction, < 5% overdue

Workload/Backlog Management 1997 Actions

- Dedicated workload management team established
- Goals for workload reduction established
- Workload management manual developed
- Standardized PIMS report tools developed
- Complete characterization of the workload/backlog performed
- Modification reduction review performed
- Increased effectiveness of the engineering organization

Workload/Backlog Management 1998 Actions

- Backlog/workload review of ARs and AEs
- Continue to develop the E-FIN Team and its effectiveness
- Implementation of the "Pull" model
- Establish new workload management goals
- Implement a workload management tool that is integrated with the work control process
- Improved effectiveness of the system engineering program
- Centralized both system and design engineering

WLM
Performance Indicators

> Indicators reported in the ES quality plan

> Favorable overall trends with workload reduction effort in light of challenges

- Outage design milestone
- Quality problem workload
- PIMS workload
- Drawing backlog
- Modification backlog
- Temporary modifications
- Operator work-arounds and burdens
- POA status and closure

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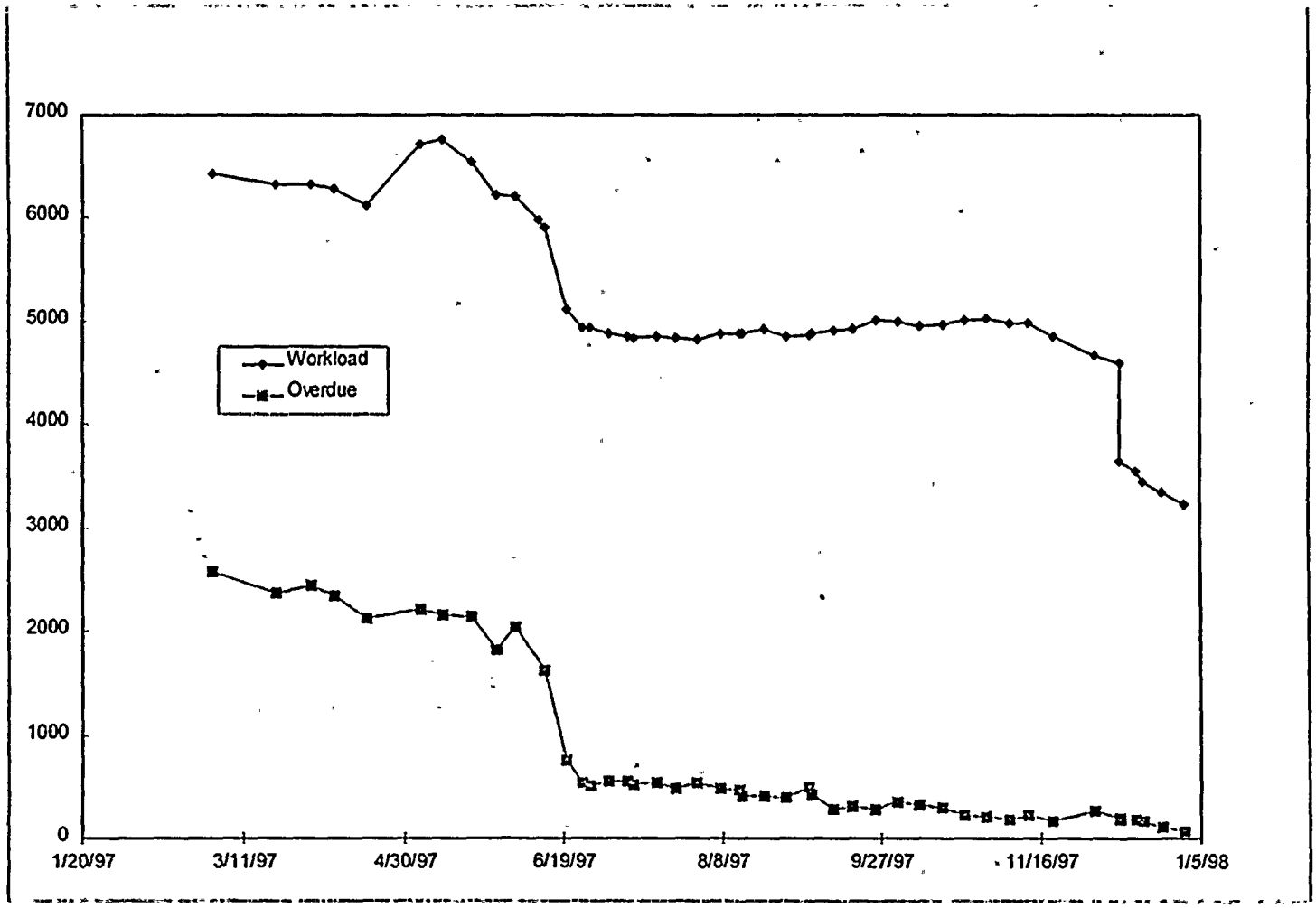
1997 Engineering AR/AE Workload and Overdue



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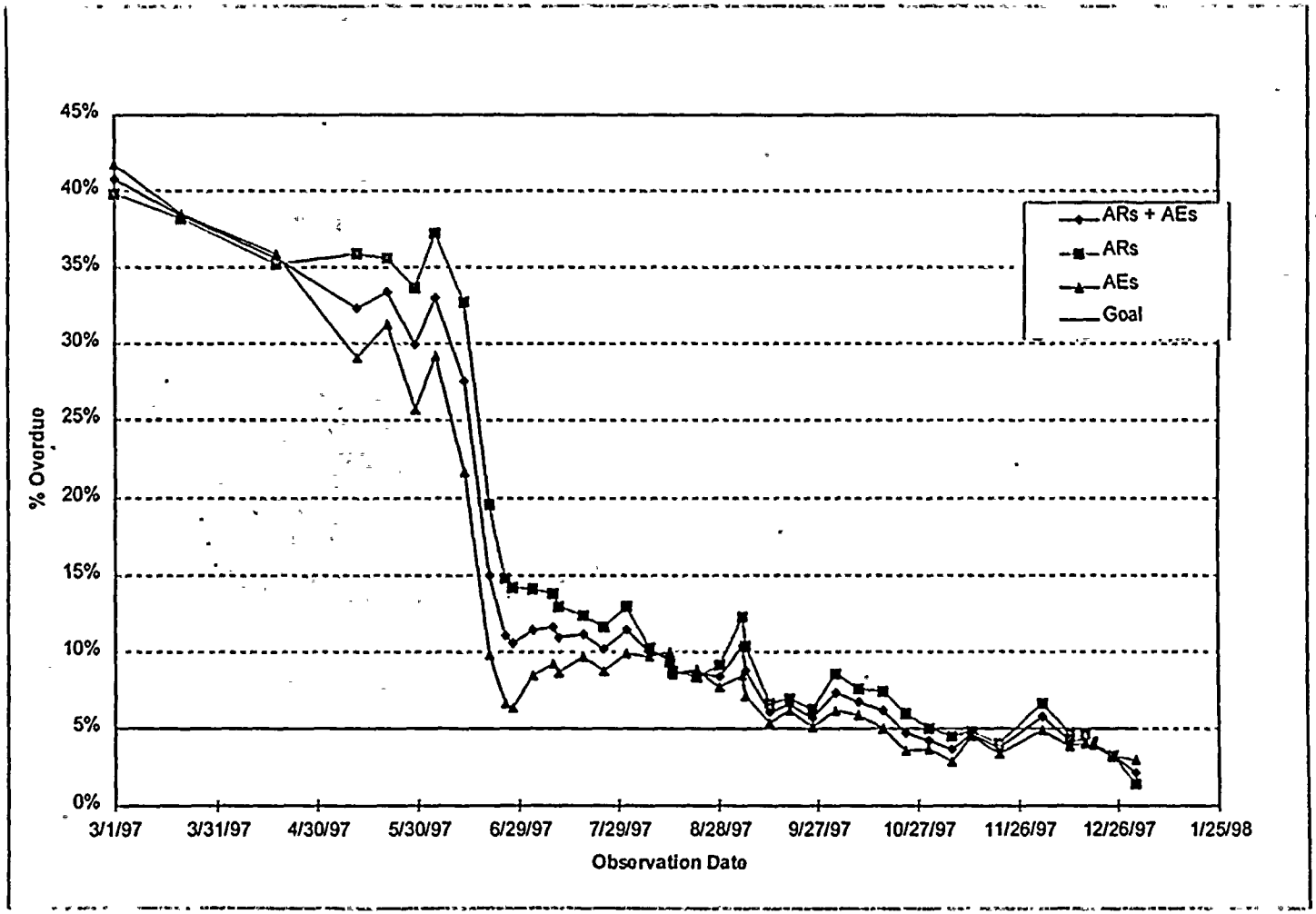
NTS Workload (AR/AE) Overdue Status (% Overdue)



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NTS Transition

- Strong management focus on how we maintain improved engineering performance in light of general office closure - 2 full time project managers
- Learned the lessons from the past reorganization and downsizing
- Multiple strategies to mitigate risk
  - Attract people from SF to DCPP
  - Hire as PG&E employees key contractors at DCPP
  - Consultant option to keep critical mass intact and accessible

NTS Transition (cont'd)

- Knowledge transfer - transfer knowledge of design/licensing basis and information infrastructure
- Work transfer - take ownership for all work in the GO at DCPP, no surprises at the end

• Comprehensive approach to managing the transition

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Conclusion

- Technically strong organization
- Strengths in problem identification and resolution, design change quality and safety review programs
- Significant engineering problems have been resolved in a thorough and comprehensive manner
- Significant reduction in Engineering backlog (50%) and understanding of its content
- Continuing self-critical and pro-active attitude is resulting in actions to improve overall performance
- Areas for continued improvement include design basis maintenance and knowledge transfer

DIABLO CANYON POWER PLANT ENGINEERING PERFORMANCE

January 22, 1998

Engineering Directors

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System Engineering Program

- System engineering roles broadened
  - Added design change qualifications
  - Maintenance Rule Program implementation
- Benefits
  - Improved system engineering understanding of design requirements
  - Improved understanding of licensing basis
  - Very effective in identification and resolution of plant equipment issues
    - CCP recirculation orificies erosion
    - Flow measurement orifice installation details
    - ECCS flow balancing valves throttle position

System Engineering Program

- Challenges
  - Increased system engineer workload
  - Competing priorities - SE vs. design role
  - System engineer expectations

System Engineering Ongoing / Future Improvements

- Consolidated system engineering
  - Design change responsibilities with design organization
  - Improve consistency of expectations
  - Consistent management direction
- System Manager role
  - More long term system health focus
  - Increased involvement in PM Program
  - Ownership of system licensing and design basis

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System Engineering Ongoing / Future Improvements

- Improved OPS/maintenance support
  - Integration with Maintenance Asset Teams
  - Close alignment of Asset Team / system engineer responsibilities

Maintenance Rule Program Assessment

- Solid program foundation
- Strong civil MR implementation
- Strong self-assessments
- Strategic role for system engineers
- Implementation weaknesses
  - System engineer MR knowledge
  - System engineer involvement and ownership
  - Implementation details for some systems

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Maintenance Rule Program Actions Taken

- MR responsibility transferred to engineering
- MR technical staff training for ESP
- System engineer qualification checkout
- System engineer MR training
- MR validation project
- ES Quality Plan indicators

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Maintenance Rule Program Future Actions

- System engineer expectations
- Benchmark other utilities
- Utility peer evaluation
- Self assessment of system engineering MR qualification program
- Monitoring status and effectiveness of corrective actions for SSCs in (a)(1)

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Design and Licensing Basis Maintenance

- FSAR
- 10 CFR 50.59
- LDBAP

FSAR

- Non-Conformance in Jan 1996
- Numerous Procedure Improvements
- Process Owner Assigned
- Any discrepancies identified to be assessed for USQ Potential, Operability, and Reportability within one week
- Since 1996, have identified about 650 discrepancies
  - 0 USQs, 0 reportable, 0 operability issues
  - Currently 38 remain to be incorporated in FSAR (increased due to LDBAP findings)
- Follow-on FSAR review as part of LDBAP
- Appropriate organizational sensitivity to FSAR

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10 CFR 50.59

- Non-conformance in December 1996
- Management expectations promulgated
- Process owner identified
- Procedure improvements made
- Training conducted
- Increased scrutiny of licensing aspects and earlier communication with NRC

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10 CFR 50.59 Actions

- Licensing assessment as part of project authorization
- Establishment of a 6 month project safety evaluation completion lead time goal
- 10 CFR 50.59 review board with licensing, engineering and quality assurance representation
- Benchmarking of other utility programs
- Improved documentation availability

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Licensing and Design Basis

- 50.54(f) design basis letter
- LDBAP pilot program completed
  - Program's purpose is to identify and resolve licensing and design basis inconsistencies and issues
- Findings to date
  - No operability or safety significant issues, no system which could not perform its safety function or was degraded
  - Some programmatic issues that will require improvements
- Follow-on program in progress

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Self-Assessments

- Maintenance Rule assessments and benchmarking
- Workload management team
- Self-assessment and audit of ESP training program
- INPO assist and review visits
- Engineering manager's review of forced outage performance
- IST Program
- Reengineering work control process
- Employee concerns program
- Quality plans
- LDBAP
- AE Inspection self-assessment

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1998 Self-Assessments / Benchmarking

- Knowledge transfer
- Operations and Maintenance support
- GL 96-01 post review
- Drawing revision process
- Component/system engineer interface
- LDBAP

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