UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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September 28, 2001

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, CA 93424

SUBJECT: DIABLO CANYON INSPECTION REPORT 50-275/01-06; 50-323/01-06

Dear Mr. Rueger:

On August 25, 2001, the NRC completed a routine resident inspection which was conducted from July 8, through August 25, 2001, at the Diablo Canyon Nuclear Power Plant, Units 1 and 2, facility. The enclosed report documents the inspection findings that were discussed on August 29, 2001, with Mr. James R. Becker and members of your staff.

This inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Two issues were evaluated under the Significance Determination Process and were determined to be of very low safety significance (Green). An additional issue of No Color was also identified. These issues have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report.

Pacific Gas and Electric Company operated under voluntary bankruptcy proceedings during this inspection period. The NRC has exercised communications channels to better understand your planned and implemented actions, especially as they relate to your responsibility to safely operate the Diablo Canyon reactors. NRC inspections, to date, have confirmed that you are operating these reactors safely and that public health and safety is, thus far, assured.

In response to these conditions, there will continue to be two differences in how the region communicates its inspection findings. First, we will continue the 6-week periodicity of our integrated inspection reports (the other reactors in Region IV implemented a quarterly report frequency, with the exception of San Onofre Nuclear Generating Station). In some cases the scope and/or the findings section of the individual inspection activities will be more detailed. This is being done to keep the public more fully informed of the breadth and depth of the NRC's inspection and oversight activities.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document

Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

William B. Jones, Chief
Project Branch E
Division of Reactor Projects

Docket Nos: 50-275
50-323
License Nos: DPR-80
DPR-82

Enclosure:
NRC Inspection Report No.
50-275/01-06; 50-323/01-06

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket Nos:	50-275 50-323
License Nos:	DPR-80 DPR-82
Report No:	50-275/01-06 50-323/01-06
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Unit 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	July 8 through August 25, 2001
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector G. A. Pick, Senior Project Engineer, Project Branch E, DRP G. A. Larkin, Project Engineer, Project Branch E, DRP
Approved By:	W. B. Jones, Chief, Project Branch E Division of Reactor Projects

ATTACHMENTS:

Attachment 1 Supplemental Information

SUMMARY OF FINDINGS

IR 05000-275-01-06, IR 05000-323-01-06, on 7/8/01 to 8/25/01; Pacific Gas and Electric. Co.; Diablo Canyon Nuclear Power Plant Units 1 and 2; Report. Maint. Risk and Control, Refuel Outage Activities, Perf. Indic. Verif.

This report covers a 7-week routine resident inspection, and a 2-week project engineer inspection, July 8 through August 25, 2001. Two Green findings and a finding of No Color were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609 "Significance Determination Process." Findings for which the Significance Determination Process does not apply are indicated by No Color or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Initiating Events

Green. The inspectors identified that the licensee's maintenance risk assessment program had not included surveillance activities, which required placing the reactor trip system bistables in the tripped condition, in their maintenance activity risk evaluations. The licensee failed to categorize surveillances that included tripping of reactor protection system bistables as trip risk significant on a programmatic basis, despite plant specific and industry events in which reactor trips occurred partially because of a reactor protection channel being in the tripped condition. The licensee's risk management procedure prohibited performing high trip risk evolutions concurrently with removing trip mitigation systems from service. This finding was determined to have a credible impact on safety because of the potential for an increased trip risk and that an important mitigating system could be removed from service. However, no instances were identified where reactor protection bistables were placed in the tripped position and mitigating systems were removed from service. This item was placed in the corrective action system as Action Request (AR) A0539532.

The inspectors evaluated this finding using the Significance Determination Process. The Phase 1 screening identified that the finding could contribute to the likelihood of a reactor trip and mitigating systems not being available. The inspectors noted that this programmatic finding did not lend itself to evaluation using Phase 2 of the Significance Determination Process. This finding was evaluated by the inspectors, along with a senior reactor analyst, using the licensee's plant specific probabilistic risk assessment and determined that the potential risk increase of this finding was below the moderately risk significant threshold (by approximately a factor of 10). The inspectors determined, along with the senior reactor analyst, that the overall significance of this finding was very low (Section 1R13).

Cornerstone: Mitigating Systems

Green. The inspectors identified that diverse reactor vessel level instrumentation, used during midloop operation, was not fully integrated resulting in operational distractions during midloop evolutions. The licensee had missed opportunities to ensure the level instrumentation and associated alarms were coordinated through simulator training and midloop procedures. The inspectors determined that the issue could have a credible impact on safety because an alarm was in that was not understood and the applicability of certain level indications at different times was not well understood. This was identified as a cross cutting issue based on the finding involved elements of operator training, control room alarms and procedures that contributed to distractions to the operators during midloop operations.

The inspectors evaluated this finding using the Significance Determination Process. Specifically, Manual Chapter 0609, Appendix G, Shutdown Operations Significance Determination Process, was considered. The finding did not result in a loss of control as defined by Appendix G, TABLE 1, Losses of Control for Loss of Thermal Margin or Loss of Level PWRs. The inspectors, along with a senior reactor analyst reviewed PWR Hot Shutdown operation with a time to core boiling less than 2 hours. The core heat removal guidelines and inventory control guidelines were considered. Item II of the Core Heat Removal Guidelines, A, Instrumentation, specifying 2 independent pressurizer level instruments with a Hi/Lo alarm or level deviation annunciator was determined to be impacted requiring a Phase 2 evaluation. The senior reactor analyst reviewed the actual conditions, observed the control room and plant simulator instrumentation and discussed the finding with the cognizant inspectors who observed the midloop operation. The inspectors determined, along with the senior reactor analyst, that adequate reactor vessel level indication and alarms were available such that the overall significance of this finding was very low (Section 1R20.1).

Cornerstone: Miscellaneous

No Color. The inspectors identified that the licensee had not taken action to docket a justification and schedule to correct a nonconservative Technical Specification. On March 4, 2000, the licensee identified that the reactor coolant system activity Technical Specification limit for dose equivalent iodine was nonconservative. Engineers determined that instead of the Technical Specification limit of 1 µci/g, the licensee must control reactor coolant system activity to .71 µci/g when normal letdown was in service and .47 µci/g when excess let down was in service. The licensee implemented administrative controls to prevent exceeding the new limits, but took no action to docket a justification and schedule to correct Technical Specification 3.4.12 until prompted by the inspectors in August 2001. This finding was determined to be of regulatory concern because the licensee had not taken regulatory action to correct the nonconservative Technical Specification. This item was entered into the corrective action program as Action Request A0540317.

The safety significance of the finding was evaluated initially using Manual Chapter 0610 Group 2 Questions for Reactor Safety-Initiating Events, Mitigating Systems, and Barrier Integrity. A No Color determination was made based on the finding was determined not to: cause or increase the frequency of an initiating event; affect the operability, availability, reliability, or function of a system or train in a mitigating system; affect the integrity of fuel cladding, the reactor coolant system, reactor containment or control room envelope; or, involve degraded conditions that could concurrently influence any mitigation equipment and an initiating event (Section 4OA1).

B. Licensee Identified Violations

Violations of very low significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee appear reasonable. These violations are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On August 1, 2001, operators reduced power on Unit 1 to 90 percent because of high radio-frequency indications on the main generator. The licensee identified that the high radio-frequency indications on the Unit 1 main generator resulted from an instrumentation problem. Operators returned Unit 1 to 100 percent power the same day. Unit 1 continued to operate at essentially 100 percent power until the end of this inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power and continued to operate at essentially 100 percent power until the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Planning

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns

Diesel Engine Generators 1-1 and 1-3

a. Inspection Scope

On July 11, 2001, with Diesel Engine Generator 1-2 inoperable, the inspectors performed a partial walkdown of systems associated with Diesel Engine Generators 1-1 and 1-3. The inspectors reviewed Chapter 8 of the Final Safety Analysis Report Update and utilized system lineup procedures, performed partial system lineup verifications for the starting air, fuel oil, cooling water, and electrical lineups.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Monthly Routine Inspection

a. Inspection Scope

The inspectors performed fire protection walkdowns to assess the material condition of plant fire detection and suppression, fire seal operability, and proper control of transient combustibles. The inspectors reviewed the Individual Plant Evaluation for External Events and Section 9.5 of the Final Safety Analysis Report Update for guidance. The suppression equipment and fire doors for compliance with the regulatory requirements and conditions specified in Procedures STP M-69A, “Monthly Fire Extinguisher Inspection,” Revision 30, STP M-69B, “Monthly CO2 Hose Reel and Deluge Valve

Inspection," Revision 13, and STP M-70C, "Inspection/Maintenance of Doors," Revision 5. Specific risk-significant areas inspected included:

- Battery and inverter rooms on July 18, 2001
- Control room (refer to PI&R observation in Section 4OA2), on July 16
- Radiologically controlled area of the auxiliary building, on August 1
- Intake structure, on August 3

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the heat exchanger cleaning and inspection report associated with Component Cooling Water Heat Exchanger 2-2 on August 9, 2001 (Work Order R021862). In addition, the inspectors observed the condition of the heat exchanger tubes. The inspectors witnessed portions of the heat exchanger cleaning, reviewed the completed work order, and reviewed Macro- and Micro-fouling reports. The licensee concluded that the levels of fouling were light and therefore no additional hydrolancing was required.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

.1 Routine Reviews

a. Inspection Scope

The inspectors reviewed the licensee's maintenance rule implementation for equipment performance problems. The inspectors determined if the equipment was properly placed into the scope of the rule, if the failures were properly characterized, and if goal setting was recommended, if required. Procedure MA1.ID17, "Maintenance Rule Monitoring Program," Revision 8, was used as guidance. The inspectors reviewed the following action requests (ARs):

- AR A0536239, Valve FW-1-FCV-437 Leaking By
- AR A0533311, Automatic Start of Diesel Engine Generator 2-2

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

Risk Assessments

a. Inspection Scope

Throughout the inspection period, the inspectors reviewed daily and weekly work schedules to determine when the licensee had scheduled risk-significant activities. The inspectors reviewed selected activities regarding risk evaluations and overall plant configuration control. The inspectors verified that the licensee established the applicable contingencies, as discussed in the risk assessments. The inspectors used Procedure AD7.DC6, "On-Line Maintenance Risk Management," Revision 5, as guidance and reviewed the activities associated with the following:

- Diesel Engine Generator 1-2 maintenance outage window, on July 10-11, 2001
- Reactor trip breaker testing in accordance with Procedure STP I-38-B.2, "SSPS Train B SI Reset and Slave Relay K602 Test in Modes 1, 2, 3, or 4," Revision 4, on July 13, 2001
- Auxiliary Feedwater Pump 2-3 maintenance outage window concurrent with Steam Generator Level calibrations, on July 24, 2001
- Residual Heat Removal Pump 2-2 maintenance outage window, on August 1, 2001

b. Findings

The inspectors identified that the licensee's maintenance risk assessment program did not require surveillance activities, which required placing the reactor trip system bistables in the tripped condition, be included in their maintenance activity risk evaluations. This finding was determined to have a potential credible impact on safety and to be of very low risk significance (Green).

The inspectors noted that the risk assessment for the Auxiliary Feedwater Pump 2-3 maintenance outage window stated that since Auxiliary Feedwater Pump 2-3 was a trip mitigation system, no other trip risk-significant items would be performed in parallel. This statement was consistent with procedure AD7.DC6. The inspectors noted that the steam generator level calibrations being performed required manipulation of the bistables associated with the Lo-Lo Steam Generator Level reactor trip logic. These calibrations were performed in accordance with Procedure STP I-4-L539 "Steam Generator 3 Narrow Range Level Channel LT-539 Calibration," Revision 2. The licensee did not consider manipulation of bistables to be risk significant, and thus performed these evolutions concurrently. Procedure STP I-4-L539 did not require placing reactor trip system bistables in the tripped condition, but just bypass. Therefore, the inspectors concluded that the licensee's approach for this instance was appropriate.

However, upon further review, the inspectors noted that the licensee did not categorize surveillances that included placing one channel in the tripped condition as being trip-risk significant. The inspectors reviewed the licensee's and industry databases of licensee event reports and noted numerous examples in which reactor trips occurred while one channel of reactor protection was in the tripped condition. Procedure AD7.DC6 did not mention the trip risk of surveillances and operators did not consider surveillances as having any trip risk. The inspectors discussed this issue with the probabilistic safety analysis supervisor who directed AR A0539532 be written to evaluate this issue.

The probabilistic risk assessment personnel determined that numerous surveillances existed in which one channel of reactor protection would be placed in the trip condition. The licensee evaluated these surveillances for trip risk and determined qualitatively that performance of these procedures would constitute a high trip risk, (as defined by the licensee) and thus should not be performed in parallel with removal of trip mitigation systems (e.g. auxiliary feedwater, diesel engine generators, offsite power sources, etc.) from service. The licensee initiated a temporary standing order for operators to implement this new risk management philosophy, and were revising procedure AD7.DC6 at the end of the inspection period.

This finding was determined to have a credible impact on safety because of the potential for an increased trip risk and that an important mitigating system could be removed from service. However, no instances were identified where reactor protection bistables were placed in the trip position and an important mitigating system was removed from service. The licensee has placed this finding into their corrective action system as AR A0539532.

The inspectors evaluated this finding using the Significance Determination Process. The Phase 1 screening identified that the finding could contribute to the likelihood of a reactor trip and mitigating systems not being available. The inspectors noted that this programmatic finding did not lend itself to evaluation using Phase 2 of the Significance Determination Process. This finding was evaluated by the inspectors, along with a senior reactor analyst, using the licensee's plant specific probabilistic risk assessment and determined that the potential risk increase of this finding was below the moderately risk-significant threshold (by approximately a factor of 10). The inspectors determined, along with the senior reactor analyst, that the overall significance of this finding was very low (Green).

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations and supporting documents to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specification (TS) Bases and Final Safety Analysis Report (FSAR) Update sections in support of this inspection. The inspectors reviewed the following ARs:

- AR A0537029. Residual Heat Removal Pump 1-2 pump flow greater than the upper bound during an inservice test - on July 12, 2001. The inspectors evaluated whether documented flow remained satisfactory and within normal operating history. The inspectors reviewed that historical flows for the four residual heat removal pumps to ensure they remained consistent and that the high flow measured did not indicate pump degradation. The inspectors also considered the system engineer's determination that the pump had an improper inservice test baseline value established following repairs during the last Unit 1 outage. The inspectors considered the individual's conclusion that the reason for the invalid baseline flow value was the test did not use a suction pressure that would be expected during operating conditions. The discharge pressure and flow were dependent upon the available suction pressure during test performance.

- AR A0537708. Calculation M-786 not updated with inputs that may impact Technical Specifications. The inspectors evaluated the minimum diesel engine generator fuel oil storage requirements of Technical Specification 3.8.3. This Technical Specification requires a minimum of 65,000 gallons of fuel oil to ensure that at least 7 days of fuel remained on site. AR A0537708 identified that the licensee did not update the diesel fuel oil storage requirements when changes were made to the postaccident sequence of diesel engine generator loading, and were thus nonconservative. The inspectors review considered that although several revisions to the diesel fuel oil storage calculations were not made as necessary, the licensee maintained far in excess of the minimum level (approximately 100,000 gallons) (Section 4OA7).

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors evaluated portions of postmaintenance testing to determine if the test adequately demonstrated that the maintenance activity was performed properly. The inspectors reviewed the work orders, the completed data reduction, and witnessed portions of the postmaintenance tests associated with the following:

- Diesel Engine Generator 1-2 testing following planned maintenance in accordance with Procedure STP M-9A, "Diesel Engine Generator Routine Surveillance Test," on July 11, 2001

- Component Cooling Water Pump 2-3 test run following routine maintenance in accordance with Work Order R0189036, on July 31, 2001

- Diesel Engine Generator 1-1 testing following failed start and repairs in accordance with Procedure STP M-9A, on July 31, 2001

- Residual Heat Removal Pump 2-2 test run following routine maintenance in accordance with Work Order R0176207, on August 1, 2001

- Auxiliary Feedwater Pump 2-3 test run following routine maintenance in accordance with Procedure STP P-AFW-23, “Routine Surveillance Test of Motor-Driven Auxiliary Feedwater Pump 2-3,” on August 3, 2001

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Midloop Operations

a. Inspection Scope

The inspectors evaluated several outage activities during Unit 2 Outage 2R10 to verify Technical Specification compliance, and to ensure that the licensee appropriately considered risk in developing schedules, plant configurations, mitigation strategies, and protection of key safety functions.

The inspectors provided continuous control room coverage from May 18-19, 2001, when the reactor coolant system was in a condition of reduced inventory (i.e. midloop) to remove steam generator nozzle dams, which was a risk-significant evolution. The inspectors used Procedure OP A-2:III, “Reactor Vessel - Draining to Half Loop with Fuel in the Vessel,” Revision 18, as guidance. The inspectors evaluated the calibration of the reactor vessel refueling level indicating system (RVRLS) and the cross-calibration of the incore thermocouples and resistance temperature detectors. The inspectors verified adequate inventory control and contingency plans and verified containment closure and containment closure capability were in accordance with Technical Specification and outage risk plans.

b. Findings

The inspectors identified that diverse reactor vessel level instrumentation, used during midloop operation, was not fully integrated resulting in operational distractions during midloop evolutions. The licensee had missed opportunities to ensure the level instrumentation and associated alarms were coordinated through simulator training and midloop procedures. The inspectors determined that the issue could have a credible impact on safety because an alarm was in that was not fully understood as well as the applicability of certain level indications at different times. The inspectors noted that this was a missed opportunity to resolve the problems with instrumentation. This finding was determined to be of very low safety significance (Green).

The inspectors observed operator actions as reactor vessel level was lowered to the midloop target level of 107' 10". According to Procedure OP A-2:III, the Alarm PK02-21, “MID LOOP TROUBLE,” should not be in when level is between 107' 8" and 108' 0". The inspectors observed that PK02-21 did not clear from the time level decreased below 108' (approximately 1:45 AM on 5/19) to and until the inspectors left the control room 7 hours later. The shift foreman later stated that a faulty thermocouple input may be keeping the alarm active. The shift foreman did not indicate that work would be performed to correct the alarm condition. Following the refueling outage, the licensee determined the cause for PK02-21 not clearing is the pre-installment of the new RVRLIS system input into the alarm system. Both the old and new RVRLIS system would give a high and low warning if they were not between 107' 9" and 107' 11". Since both systems were not within that band simultaneously, PK02-21 would not clear. The operators were aware that the new RVRLIS had inputs to the alarm system, but the operators did not know why PK02-21 would not clear until approximately 7 hours later. Had other alarm parameters, such as large residual heat removal pump amp swings and high in-core thermocouple readings, come in while PK02-21 was active, the alarm would have reflashed. Additionally, the control operator had all the parameters feeding PK02-21 before him on the plant process computer screen.

In addition to PK02-21 not clearing during the time period noted above, the inspectors observed that another alarm intermittently came in and out when reactor vessel level was between 108' 0" and 107' 10". The intermittent alarm PK02-22, “RX VSL REFUELING LVL,” has as its inputs RVRLIS Narrow Range Level High/Low, RVRLIS Wide Range Level High/Low, RVRLIS Ultrasonic Level Low, and RVRLIS Wide/Narrow Range Transmitter Off-scale. The licensee determined that the cause of the intermittent alarms was coming from an ultrasonic level transmitter. As level was reduced, air bubbles began to form and travel through the hot legs, which caused the ultrasonic level to fluctuate. Since the input from the ultrasonic level transmitter was not required by procedure, it was disconnected from PK02-10A.

OP A-2:III states that LI-400 reactor vessel level indication is to be available to control room operators via closed circuit television or by an operator stationed at the LI-400 standpipe who is in continuous communication with the control room. While Unit 2 was in midloop operation, the inspectors observed that the closed-circuit television in the control room, which had LI-400 displayed on the screen, was switched to a channel displaying an overhead view of containment. The inspector asked the midloop coordinator if LI-400 was no longer needed. The operators responded that the new RVRLIS system was being placed into operation. Upon asking the midloop coordinator a second time if LI-400 was needed, the midloop coordinator conferred with the shift foreman and placed the television channel back to LI-400. Following the refueling outage, the inspectors learned that the new RVRLIS system had been accepted and was the primary level instrumentation to be used. Also, maintenance personnel had received approval from operations to begin isolating the old RVRLIS system. The shift foreman was not confident that LI-400 would provide an accurate reading when maintenance began to dismantle the old level indication system. Furthermore, operators had been briefed that LI-400 is not needed once the new RVRLIS system is accepted and it should not be used during the vacuum refill. Therefore, the shift foreman decided to turn the channel from the LI-400 indicator in the control room.

Although operators were briefed that the new RVRLIS system provided inputs to the alarm system, they were not briefed that it would cause PK02-21 to remain in past 108' level. The control operator had the same parameters which feed into PK02-21 before him on the plant process computer screen. Also, other alarm parameters (thermocouple temperatures and residual heat removal pump amps) would cause the alarm to reflash. These items indicated that the planning process for midloop operations with respect to the temporary instrumentation required improvement.

The inspectors noted that while there is a procedure to install and calibrate the ultrasonic level instrument for midloop operations, the alarm response Procedure, AR PK02-22 does not have operator actions if the instrument activates the alarm. Second, no procedure provided operators with pertinent information on ultrasonic level instrument performance during midloop (i.e., air bubbles causing momentary fluctuations in level indication) even though such performance was known prior to 2R10. Since the ultrasonic level instrument is connected to the alarm system, it impacts the control room when it causes the alarm to come in. Third, there are no tolerance bands for agreeing with other level instrumentation. For example, tolerance bands are prescribed for the old and new RVRLIS and LI-400. During the vacuum refill, the only level indication available is the new RVRLIS system and the ultrasonic level instrument. The vacuum refill procedure (OP A-2:IX) states that the ultrasonic level instrument is the most accurate instrument during vacuum refill. However, there is no statement on how much it and the new RVRLIS system should agree.

The inspectors noted that the following issues occurred with respect to instrumentation: Procedure OP A-2:III stated that the MID LOOP TROUBLE annunciator should not be illuminated while reactor vessel water level is at the normal midloop band (107 foot-8 inch to 108 foot elevation) however, (1) The licensee entered the first midloop with an inoperable in-core thermocouple selected as the alarm input, thus the MID LOOP TROUBLE annunciator did not clear until the inspectors prompted the operators, (2) During the second midloop, the MID LOOP TROUBLE annunciator never cleared because of tolerance discrepancies between the old and new instrumentation, (3) the RX VSL REFUELING LVL annunciator reflashed numerous times because of problems with the ultrasonic level indicator, (4) operators removed the control room display of Indicator LI-400 from service when time for vacuum refill was approaching because of concerns with its accuracy, because no procedure provisions existed to take this action, (5) annunciator response procedures did not provide clear direction of action to take in the event of an alarm, and (6) the licensee did not provide full simulator training to ensure that potential instrumentation issues were resolved prior to the evolution.

The inspectors evaluated this finding using the Significance Determination Process. Specifically, Manual Chapter 0609, Appendix G, Shutdown Operations Significance Determination Process, was considered. The finding did not result in a loss of control as defined by Appendix G, TABLE 1 Losses of Control, for Loss of Thermal Margin or Loss of Level PWRs involving: inadvertent loss of 2 feet of RCS inventory when not in midloop; inadvertent entry into midloop conditions, or; inadvertent loss of 2 inches of RCS inventory when in midloop conditions. The inspectors, along with a senior reactor analyst reviewed PWR Hot Shutdown operation with a time to core boiling less than 2 hours. The core heat removal guidelines and inventory control guidelines were considered.

The Core Heat Removal Guidelines instrumentation specifies 2 independent pressurizer level instruments with a Hi/Lo alarm or level deviation annunciator was determined to be impacted requiring a Phase 2 evaluation. The senior reactor analyst reviewed the actual conditions, observed the control room and plant simulator instrumentation and discussed the finding with the cognizant inspectors who observed the midloop operation. The inspectors determined, along with the senior reactor analyst, that adequate reactor vessel level was available such that the overall significance of this finding was very low.

This was identified as a cross-cutting issue based on the finding involved elements of operator training, control room alarms and procedures that contributed to distractions to the operators during midloop operations.

.2 Overtime Usage

a. Inspection Scope

The inspectors reviewed Technical Specification 5.2.2.d which states, in part, "administrative procedures shall be developed and implemented to limit the working hours of personnel performing safety related functions. The controls shall include guidelines on working hours that ensure adequate shift coverage without routine heavy use of overtime. Any deviations from the guidelines shall be authorized in advance by the plant manager or his designee, in accordance with approved administrative procedures, with documentation of the basis for the deviation. Routine deviation from the guidelines shall not be authorized." The inspectors noted that Technical Specification 5.2.2.d contained an abbreviated version of the original Technical Specification on overtime use, which contained significantly more detail. During conversion to Improved Technical Specification, the licensee received a license amendment that allowed the licensee to relocate the details of Technical Specification 5.2.2.d to administrative procedures. The amendment stated that no technical review of the amendment was necessary, because the revision was only administrative in nature (i.e. the requirements did not change).

Procedure OM14.ID1, "Overtime Restrictions," Revision 10A, implemented Technical Specification 5.2.2.d and contained the details of the overtime restrictions formerly located in the Technical Specifications. The inspectors reviewed Procedure OM14.ID1 to ensure that the requirements contained therein were consistent with the previous version of the Technical Specification 5.2.2.d and NUREG 0737 (TMI-2 Action plan). Section 5.5.1 of Procedure OM14. ID1 provided exceptions to the requirement that overtime use be approved on an individual basis, and shall not contain blanket authorizations. Valid exceptions included unforseen operational problems, extended shutdown periods, refueling outages, and major plant modifications. These exceptions were reviewed for consistency with the previous Technical Specifications and NUREG 0737. The inspectors further noted that the licensee's procedure went beyond the NRC's requirements. The licensee's procedure required Station Director approval to exceed working 6 days in succession and Vice President approval to exceed working 13 days in succession. Neither of these restrictions is contained in the previous Technical Specifications or NUREG 0737.

The inspectors reviewed the working hours of 60 licensed and nonlicensed operators. This included reviewing 52 authorizations for exceeding the Procedure OM14.ID1 administrative limits. In addition, the inspectors reviewed letters from approximately 50 individuals to volunteer to temporarily work overtime for the duration of the outage.

b. Findings

The inspectors identified a violation of Technical Specification 5.2.2.d for one individual where the licensee failed to provide written justification for exceeding operator overtime limits. This violation was determined to be minor and is of very low safety significance. This issue is being documented to provide a detailed accounting of the NRC staff's inspection activities related to refueling outage activities.

The inspectors identified an isolated instance where the licensee failed to follow the guidelines in Procedure OM14.ID1. Specifically, the licensee failed to provide written justification for exceeding the overtime limits. The inspectors considered the failure to be a minor administrative oversight. This failure constituted a violation of Technical Specification 5.2.2.d for failure to provide a documented basis for exceeding the overtime limits. Although this violation should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

The inspectors noted that a number of individuals were listed on a blanket authorization to temporarily exceed the overtime limits of Procedure OM14.ID1 for the duration of outage 2R10. The authorization stated that each of the individuals were volunteers. The inspectors requested, and were provided with, letters from each of the individuals to operations management, which explicitly stated their desire to work overtime during outage 2R10.

The inspectors noted that a total of six individuals worked greater that 90-hour weeks during outage 2R10. These individuals each worked a total of over 200 hours of overtime for the 30 day duration of 2R10. Each of these individuals submitted a letter to the licensee volunteering for overtime. The inspectors noted that a significant number of the licensed and nonlicensed operators assigned to midloop operations, had been granted extensions to Procedure OM14.ID1 administrative limits.

1R22 Surveillance Testing (71111.22)

Routine Observations

a. Inspection Scope

The inspectors evaluated several routine surveillance tests to determine if the licensee complied with the applicable Technical Specification requirements. The inspectors performed a technical review of the procedure, observed the test, and reviewed the completed test data. The inspectors evaluated the following:

- Procedure STP M-75, "4KV Vital Bus Undervoltage Relay Calibration," Revision 27, on July 11, 2001
- Procedure STP I-38-B.2, "SSPS Train B SI Reset and Slave Relay K602 Test in Modes 1, 2, 3, or 4," Revision 4, on July 13, 2001
- Procedure STP I-36-SIR02, "Protection Set I, Rack 2 Channels Operational Test," Revision 4, on July 18, 2001

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors evaluated the Unit 1 Volume Control Tank Argon Injection Jumper. The Argon Injection Jumper will aid in detecting a primary to secondary leak should one develop, by raising the primary system activity. The licensee implemented this temporary modification so that they can comply with industry requirements and the requirements in Procedure OP O-4, “Primary to Secondary Steam Generator Tube Leak Detection,” Revision 11A, which requires the ability to monitor for leakage of 30 gallons per day. With no fuel leaks the source term in the primary system, the condenser off-gas monitor cannot detect leakage from the primary to the secondary systems. The off-gas monitor uses naturally occurring argon since it is the dominant gas and because argon goes into solution during outages. The jumper will inject Argon-40 that becomes Argon-41, which allows the licensee to monitor the activity of the condenser off-gas. The inspectors reviewed the ARs A0527475 and A0497145, Licensing Basis Impact Evaluation Screen, and 10 CFR 50.59 screening. From interviews, the inspectors considered whether this temporary modification would affect the function of plant mitigating systems, specifically the volume control tank and that the licensee processed the temporary modification in accordance with Procedure CF4.ID7, “Temporary Modifications-Plant Jumpers and M & TE,” Revision 8.

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed and evaluated the emergency preparedness drill of August 17, 2001. The drill scenario consisted of a challenging event that included a General Emergency following a steam generator tube rupture. Each of the emergency response facilities was effectively exercised and required liaison with state and local authorities. The inspectors observed performance in the control room/simulator and the Technical Support Center. Following the drill, the inspectors reviewed the critique of the exercise by the emergency planning organization. The inspector reviewed several procedures that specified notification and classification requirements; including: (1) EP G-1, “Emergency Classification and Emergency Plan Activation,” Revision 29; (2) EP G-2, “Activation and Operation of the Interim Site Emergency Organization,” Revision 22; (3) EP G-3, “Notification of Off-Site Agencies and Emergency Response Organization Personnel,” Revision 35; and (4) EP RB-10, “Protective Action Recommendations,” Revision 7.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed the following performance indicators for the period from the third quarter of 2000 through the second quarter of 2001 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and licensee monthly operating reports to support this inspection. The inspectors used NEI 99-02, "Regulatory Assessment Performance Indicator Verification," Revision 0, as guidance for this inspection.

- Unplanned power changes
- Reactor coolant system (RCS) activity

b. Findings

The inspectors identified a finding that the licensee had not amended the reactor coolant system activity Technical Specification 3.4.16 nor docketed any actions to reflect a more conservative analysis of record. The finding was determined to be No Color but is being documented to address the conditions behind a licensee's administrative control for a nonconservative Technical Specification.

The inspectors verified the unplanned power changes and reactor coolant system activity indicator submittals were complete and accurate. However, the licensee submitted information that the reactor coolant system activity limit was subject to administrative values, lower than the actual Technical Specification limits. Technical Specification 3.4.12 required the reactor coolant system activity to be less than 1µci/g dose equivalent iodine. The licensee indicated that the limit would be administratively controlled to less than the Technical Specification limit because of nonconservatisms in the calculations for a postulated steam generator tube rupture. The licensee indicated that reactor coolant system activity was limited to 0.71µci/g, during normal letdown operations, and 0.47µci/g while excess letdown was in service.

Upon further review, the inspectors noted that the licensee had employed the administrative limits for RCS activity since March 4, 2000, a period of approximately 17 months. AR A0504352, stated that because of nonconservatisms in the calculations for a postulated steam generator tube rupture, the licensee must place administrative restrictions on maximum RCS activity. AR A0504352, stated, however, that these administrative controls would remain in effect until the vendor completed a reanalysis of the steam generator tube rupture scenario, at which time the licensee would submit the results of the analysis to the NRC. Following NRC approval of the new analysis, the licensee could implement new Technical Specification limits for RCS activity, or reimplement the existing Technical Specification limit of 1 μci/g.

The NRC staff considered the regulatory requirements of 10 CFR 50.36 which states that the TS will be derived from the analyses and evaluation included in the safety analysis report. TS 3.5.16 and Section 15.5.20 of the Final Safety Analysis Report conservatively assume an initial RCS activity of 1μci/g when a steam generator tube rupture is postulated. The NRC staff also reviewed NRC Administrative Letter 98-10 "Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety." The administrative letter further states that imposing administrative controls was an acceptable short-term action, but a docketed justification and schedule accompanying an amendment request must be promptly submitted. In the case of the Diablo Canyon licensee, the condition existed for approximately 17 months (from March 2000 to August 2001) prior to notifying the NRR program office of the nonconservatism in Technical Specification 3.4.12. The NRC staff determined that this specific example did not result in a violation.

The inspectors reviewed the operating history of the plant and noted that the RCS activity never exceeded the temporary limits imposed for Unit 1. For Unit 2, the licensee exceeded the temporary limits for very short periods of time during transients, and well within the 72 hour allowed outage time of Technical Specification 3.4.12.

The safety significance of the finding was evaluated initially using Manual Chapter 0610 Group 2 Questions for Reactor Safety--Initiating Events, Mitigating Systems, & Barrier Integrity. A No Color determination was made based on the finding was determined not to: cause or increase the frequency of an initiating event; affect the operability, availability, reliability, or function of a system or train in a mitigating system; affect the integrity of fuel cladding, the reactor coolant system, reactor containment or control room envelope; or, involve degraded conditions that could concurrently influence any mitigation equipment and an initiating event. No additional offsite consequences were identified because of the licensee's administrative limits that had been implemented (No Color).

4OA2 Problem Identification and Resolution

Fire Protection (71111.05Q)

a. Scope

On July 12, 2001, the inspectors evaluated the fire protection group resolution of deficient penetration seals documented in ARs A05523869 and A0524070. The licensee had identified that fire penetration seals had black, pliable material installed instead of the expected grout. The inspectors confirmed through interviews with fire protection engineers and review of corrective maintenance documentation that the barriers were properly installed. The documents reviewed included the plant design database data, results of individual penetration reviews documented in ARs A0474302 and A0468622, Drawing 066689, "Penetration Seal Typical Design Details," and Work Order C0160095.

b. Findings

The inspectors found that the fire protection personnel had made appropriate and effective use of the corrective action process when they resolved this deficiency. No findings of significance were identified.

4OA5 Other

Evaluation of Diablo Canyon Safety Condition in Light of Power and Financial Conditions

a. Inspection Scope

Because of the tight energy situation in California, Region IV initiated special review processes for Diablo Canyon. The inspectors evaluated the following factors each week to determine whether the financial condition and power needs of the station impact plant safety. The inspectors brief the responsible managers in Region IV on these factors. The factors reviewed include: (1) impact on staffing, (2) corrective maintenance backlog, (3) corrective action system backlogs, (4) changes to the planned maintenance schedule, (5) reduction in outage scope, including risk-significant modifications, (6) availability of emergency facilities and operability of emergency sirens, and (7) grid stability (i.e., availability of offsite power to the switchyard, status of the operating reserves especially onset of rolling blackouts, and main generator VAR loading)

Additionally, the inspectors provide daily status on the energy supply situation, operating reserves, available in the California market. Managers have increased their presence by performing monthly visits to assess site conditions, including employee morale, licensee initiatives, and specific technical issues.

Detailed assessment of corrective maintenance backlog

On July 12-13, 2001, the inspectors performed a detailed review of the corrective maintenance backlog to determine whether the licensee had scheduled the repair activities commensurate with its safety/risk significance. The inspectors found that the average cycle time from initiation to closure of a corrective maintenance AR for the last 7 months was 48 days. Subsequently, the inspectors reviewed a sort of all corrective maintenance ARs that had been open longer than 50 days. The inspectors identified that the licensee had classified 151 of the 264 ARs as overdue or quality class other than nonsafety-related. The inspectors sampled this population and identified 33 ARs that had the potential to affect risk-significant components or had any impact on safety. The inspectors performed detailed evaluation of the ARs listed in Attachment 1 under Corrective Maintenance Backlog Action Requests. The inspectors found that the licensee had placed an appropriate priority on scheduling the corrective maintenance commensurate with the safety significance of the deficiency.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Becker, Station Director, and other members of licensee management at the conclusion of each regional inspection during the inspection period. The resident inspection results were presented on August 29, 2001. 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.

4OA7 Licensee Identified Violations. The following finding of very low significance was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600 for being dispositioned as noncited violations (NCV). If you contest the violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U. S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon, Units 1 and 2, facility.

NCV Tracking Number	Requirement Licensee Failed to Meet
275; 323/0106-01	Green. The licensee identified a failure to implement design control measures for changes to postaccident operations as described in the Final Safety Analysis Report Update. The licensee changed the loading sequence of the diesel engine generators as described in the Final Safety Analysis Report for several items but did not input these changes into the diesel fuel oil storage capacity calculations. This issue required significant revisions to the calculations to resolve the fuel oil storage requirement. The inspectors determined this to be a violation of 10 CFR 50, Appendix, Criterion III for failure to implement design control measures to changes to postaccident operations. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. This item was entered into the corrective action program as AR A0540317. This issue could become a more significant safety concern if not corrected based on less than the required amount of diesel fuel oil onsite if additional revisions to the loading sequence occurred without input to the fuel oil storage capacity requirements. The inspectors evaluated the issue using the Significance Determination Process Phase 1

worksheet. Each of the questions related to mitigating systems was answered no resulting in the issue screening out as having very low safety significance.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. R. Becker, Station Director
D. D. Christensen, Engineer, Nuclear Quality Assurance and Licensing
R. E. Hite, Director, Radiation Protection
S. C. Ketelsen, Supervisor, Regulatory Services
D. B. Miklush, Director, Engineering Services
P. T. Nugent, Director, Regulatory Services
D. H. Oatley, Vice President
J. W. Tompkins, Director, Nuclear Quality Analysis and Licensing
R. A. Waltos, Director, Maintenance Services

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed during this Inspection

275; 323/2001006-01	NCV	Violation of 10 CFR 50 Appendix B, Criterion III for failure to implement design control measures for changes that impacted diesel fuel oil capacity calculations (Section 4OA7)

Previous Items Closed

None

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
AR	action request
CFR	Code of Federal Regulation
FSAR	Final Safety Analysis Report
gpd	gallons per day
LER	Licensee Event Report
NEI	Nuclear Energy Institute
NCV	noncited violation
NRC	Nuclear Regulatory Commission
RCS	reactor coolant system
RVRLIS	reactor vessel refueling level indication system
VAR	volt-amperes reactive

PARTIAL LIST OF DOCUMENTS REVIEWED

Corrective Maintenance Backlog Action Requests

A0511732	A0525619	A0529313	A0533113
A0512441	A0526242	A0531751	A0533453
A0519094	A0527329	A0532059	A0533813
A0525247	A0528906	A0532337	A0553518