U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/86-18 and 50-323/86-18

Docket Nos: 50-275 and 50-323

License Nos: DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

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

Inspection Conducted: From May 25, through July 5, 1986

Inspectors: _____ for 7/14/86
M. L. Padovan, Acting Senior Resident Inspector Date Signed

_____ for 7/14/86
T. M. Ross, Resident Inspector Date Signed

_____ for 7/14/86
T. J. Polich, Resident Inspector Date Signed

Approved by: _____ 7/14/86
M. M. Mendonca, Chief, Reactor Projects Section 1 Date Signed

Summary:

Inspection from May 25, 1986 through July 5, 1986 (Report Nos. 50-275/86-18 and 50-323/86-18)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of on-site events, open items, and LERs, as well as selected independent inspection activities. Additionally, during this period the Unit 2 S/U testing phase (IE manual chapter 2514) of the light water reactor inspection program was concluded during this period. Inspection Procedures 71707, 30703, 71710, 62703, 61726, 93702, 50095, 90712, 92702, 72616, 72301, 65051, 83301, 61700 94703, 72600, 72624, and 92700 were applied during this inspection.

Results of Inspection: One violation and no deviations were identified.

DETAILS

1. Persons Contacted

*G. A. Maneatis, President, Pacific Gas and Electric Company
*R. C. Thornberry, Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
*J. M. Gisclon, Assistant Plant Manager for Technical Services
*J. D. Townsend, Assistant Plant Manager for Support Services
*C. L. Eldridge, Quality Control Manager
K. C. Doss, On-site Safety Review Group
R. G. Todaro, Security Supervisor
D. B. Miklush, Maintenance Manager
D. A. Taggert, Acting Director Quality Support
T. J. Martin, Training Manager
W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
L. F. Womack, Engineering Manager
T. L. Grebel, Regulatory Compliance Supervisor
*S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative

The inspectors interviewed several other licensee employees including shift supervisors, reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, quality assurance personnel and general construction/startup personnel.

*Denotes those attending the exit interview.

Note: Acronyms are used throughout this report; refer to the Index of Acronyms at the back of the report.

2. Operational Safety Verification

a. General

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis.

On a daily basis, the inspectors observed control room activities to verify compliance with selected LCOs as prescribed in the facility TS. Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, and trends were reviewed for compliance with regulatory requirements. Shift turnovers were observed on a sample basis to verify that all pertinent information of plant status was relayed. During each week, the inspectors toured the accessible areas of the facility to observe the following:

(a) General plant and equipment conditions.

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(b) Surveillance and maintenance activities.

(c) Fire hazards and fire fighting equipment.

(d) Radiation protection controls.

(e) Conduct of selected activities for compliance with the licensee's administrative controls and approved procedures.

(f) Interiors of electrical and control panels.

(g) Implementation of selected portions of the licensee's physical security plan.

(h) Plant housekeeping and cleanliness.

(i) Essential safety feature equipment alignment and conditions.

The inspectors talked with operators in the control room, and other plant personnel. The discussions centered on pertinent topics of general plant conditions, procedures, security, training, and other aspects of the involved work activities.

b. Auxiliary Saltwater Pumps

During a routine ESF walkdown of Unit 1 and 2 ASW systems, the inspector observed radial surface cracking in the rubber material of several ASW pump discharge expansion joints. Mechanical maintenance was previously aware of this problem which has also been exhibited by the non-safety related screen wash pumps. An inspector discussed the possible adverse effects these cracks may have on ASW system operability with the maintenance manager, mechanical engineers, and OPEG. The licensee consensus was that physical integrity of the expansion joints was not significantly degraded by the cracks. A design change request was issued to replace all ASW pump expansion joints with a more durable design. This will be followed under routine inspection activities.

c. Unit 1 Diesel Generators

During a routine ESF walkdown of DGs 1-1, 1-2, and 1-3, the inspector observed several minor mechanical, electrical, and housekeeping problems. This included mechanical flange air leaks, broken electrical conduits, and poor housekeeping within confined areas. All findings were discussed in detail with the maintenance manager and were promptly resolved or scheduled for repair. None of the inspector findings appeared to have any significant adverse impact upon DG operability, but were addressed by licensee corrective actions to assure Unit 1 DGs are maintained in an optimum functional condition.

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(1) [illegible]

(2) [illegible]

(3) [illegible]

(4) [illegible]

(5) [illegible]

(6) [illegible]

d. Unit 1 Containment Penetration 82

The existence of an unidentified spare instrument line through Unit 1 containment penetration 82 was documented by an OPEG report (dated May 2, 1986) to DCPP on-site engineering. This report was issued as part of the corrective actions prescribed by approved NCR DC2-86-TN-N022 (dated February 26) which addressed a similar unidentified spare line discovered passing through Unit 2 containment penetration 82. The integrity of the Unit 1 spare line was not physically established, nor incorporated into the containment surveillance program, until May 21. NRC IR 50-323/86-05 issued a violation against Unit 2 for failing to comply with the TS surveillance requirements for verification of containment integrity.

Unlike Unit 2, the spare Unit 1 line did not penetrate through the insulation covering on the auxiliary building side of penetration 82, and as such was not discernible by visual examination outside of containment. The OPEG report was based upon a review of various containment piping penetration drawings and a QC verified installation drawing. This discrepancy between previous visual walkdowns and the OPEG report was not resolved until May 21. At that time on-site engineering coordinated the removal of obstructing insulation, and found an uncapped spare instrument line through penetration 82. Further investigations revealed the line was indeed capped in containment and was proven to be leak tight by a local leak rate test. The spare line was subsequently capped and sealed on the auxiliary building side, and added to the applicable surveillance test procedure.

Several opportunities were missed by the licensee to have resolved this problem in a more timely fashion: 1) OPEG management did not recognize and/or promptly communicate the TS implications associated with the report; 2) low priority pursuit of this discrepancy by on-site engineering due to a predisposition that the line did not exist; or, if it did, it was probably capped; and 3) penetration 82 was not visually examined from inside containment during a routine operations entry conducted May 14. Failure to initiate prompt corrective action upon notification of a non-conforming condition was a violation of the DCPP QA program and administrative procedures (86-18-01).

One violation and no deviations were identified.

3. Event Follow-up

a. Unit 2 Reactor Trip - 12 KV Bus Undervoltage

On June 27, 1986 a reactor trip occurred due to undervoltage on both 12KV buses for approximately 2 cycles. The undervoltage was caused by an electrical fault on CWP 2-2. The CWP tripped on indication of a phase "B" to phase "C" differential current and instantaneous overcurrent.

Investigation of the CWP trip subsequently revealed that some stator winding spacers had become loose and slid down such that the stator winding and the spacer came in contact and wore the insulation from the windings. The licensee plans to examine the Unit 1 CWPs during the refueling outage in September. Twenty to thirty windings in CWP 2-2 are currently being replaced and the spacers are being tightened.

The reactor was stabilized within a half hour of the trip and the reactor was brought critical on June 28 and paralleled to the grid on June 29 with a load restriction of 50% while CWP 2-2 is being repaired.

b. Unit 2 Reactor Trip Breakers Opening - Intermediate Range High Flux

On June 27, 1986 at 3:07 p.m. the Unit 2 reactor trip breakers opened due to an intermediate range high flux trip signal. The trip signal was initiated by an I&C technician who failed to follow a surveillance test procedure. The reactor was in Mode 3 at the time of this event (see section 3.a).

While performing STP I-3A, "Nuclear Intermediate Range Channel Analog Channel Operational Test," an I&C technician failed to place the "Level Trip" switch in the "Bypass" position before removing the instrument power fuses thus generating a reactor trip signal. The technician should have positioned the switch and initialed the data sheet. Also, a second technician should have verified the correct switch position and initialed the data sheet prior to the fuses being removed. The second technician was present, but due to the proximity of the fuses to the switch, he was unable to prevent the first technician from removing the fuses before turning the switch.

The licensee feels the procedure is adequate and changes to the procedure could not have prevented this type of error. The technicians have been counseled on procedural compliance and verification.

c. Reactor Trip Breaker "A" Failure to Open

On May 28, 1986 while attempting to remove Unit 1 reactor trip breaker (RTB) 52 RTA from service for preventive maintenance, the RTB did not open when the automatic shunt trip test button was pushed. The RTB was replaced with a backup breaker, and again the RTB would not open when the test button was depressed. This RTB was then "racked out," and I&C verified continuity through the RTB circuitry and took resistance measurements on the contacts of the automatic shunt trip block switch. These readings were found to be acceptable. The RTB was racked back into service, and subsequently functioned properly each time the test button was pushed. STP I 33C "Time Response Testing of Reactor Trip Breakers" was then successfully completed on the breaker.

The licensee's investigation determined the auto shunt trip test switch contacts were not opening when the button was depressed.

Pushing the button should have caused relay UVXA to energize the RTB shunt trip coil, opening the breaker. The operator and I&C technician, each having depressed the button, indicated the switch did not "click" until the replacement RTB was racked back into service the second time (as previously described). After exercising the switch several times, the breaker correctly functioned on all subsequent actuations of the automatic shunt trip test button. Relay UVXA and the associated circuitry were diagnosed to be performing correctly. Furthermore, the breaker would have functioned correctly upon receipt of a reactor trip signal from the SSPS.

A licensee's records review indicated the same preventative maintenance activity has been previously performed five times on the Unit 1 breakers and twice on the Unit 2 breakers, without failure of the test switches, Additionally, in licensee discussions with the manufacturer of the switch, the manufacturer indicated they were unaware of any problems with that particular type of switch. To further investigate the problem, the licensee decided to monthly test the automatic shunt trip test feature on breaker RTA in an effort to duplicate the failure and positively identify the failure mechanism. The licensee is also investigating replacement of these switches on all Unit 1 RTBs during the upcoming refueling.

d. Unit 2 Reactor Trip and Safety Injection

On July 3, 1986 at 7:30 p.m., Unit 2 experienced a reactor trip due to turbine trip on loss of condenser vacuum and SI due to a momentary high steam flow coincident with low-low TAVG signal from the plant's solid state protection system. Prior to the reactor trip, the plant was operating at approximately 9 percent power, in preparation for a semiannual turbine overspeed trip test. When the operators opened the 500 KV generator main output breakers to separate the generator from the grid, the main condenser began losing vacuum, slowing the turbine and causing the automatic turbine control system to open the turbine valves. This resulted in lowering of the reactor coolant temperature, causing reactor power to increase to about 10 percent. Subsequently, the turbine tripped on loss of condenser vacuum which generated a reactor trip signal. TAVG dropped to 543 degrees F (the low-low TAVG setpoint), and the high steam flow bistables momentarily flickered as a result of a pressure pulse propagated up the steam lines from fast closure of the turbine stop valves. The pressure pulse was of sufficient duration (about 16 milliseconds) to initiate SI, but was too brief to cause closure of the main steam isolation valves. An Unusual Event was declared, the SI was terminated, and the plant was maintained in a hot standby condition while the licensee investigated the cause of the loss in condenser vacuum.

Loss of condenser vacuum was attributed to failure of a moisture separator reheater (MSR) relief valve to reseat after lifting during the transient. Lifting of the MSR relief valve occurred since the relief valve's sealing steam had been isolated due to a previous operational problem.

On July 4, the resident inspector arrived on-site and evaluated the licensee's understanding of the event prior to restart. Additionally, licensee management briefed Headquarter's personnel and the resident inspector on the event later in the day on July 4. The inspector will follow under routine inspection effort, the licensee's investigation of operational problems associated with the relief valve sealing steam.

e. Diesel Generator Starts

On June 27, 1986 two DGs were inadvertently started by a non-licensed AO. At 1:14 p.m. DG 1-3 started when the 2F bus potential transformer fuses were removed instead of the 2F bus auxiliary feeder breaker potential transformer fuses. The same error was made moments later on the 2G bus which resulted in DG 2-1 starting.

The error was made due to the wrong fuse location being specified on the switching order which the AO was following to remove the fuses. The location of the fuses was changed by a design change, but the switching order was never updated for this design change. Also, the exact title of the fuses was not specified on the cubicle.

The two DGs started but were prevented from sequencing the loads on to the 4 KV vital buses due to the bus potential transformer fuses being removed. The power was restored to the 4 KV buses F&G within five minutes.

The switching order used has been corrected to update the potential transformer fuse locations, and new labels have been placed on all bus potential transformers. The licensee is examining all switching orders to ensure actual equipment locations are correct. Also, the procedures which govern switching orders are under review to incorporate switching orders into individual procedures. These individual procedures will be updated and reviewed on a periodic basis.

No violations or deviations were identified.

4. Maintenance

The inspectors observed portions of, and reviewed records on, a selected maintenance activity to assure compliance with approved procedures, technical specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified the maintenance activity was performed by qualified personnel, in accordance with fire protection and housekeeping controls, and replacement parts were appropriately certified.

a. Centrifugal Charging Pump 2-1

An inspector observed mechanical maintenance performance of various PMs, inspection of the low speed shaft key (that drives the speed increaser lube oil pump) for proper size and fit, and repairs to

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Unit 2 CCP 2-1 to correct for excessive pump seal leakage. Job related SWFs, SWP, and clearance forms were reviewed by the inspector. Mechanical maintenance personnel activities within the defined SCA were scrutinized to verify compliance with posted radiological controls. Additionally, the inspector walked down established clearance boundaries and reviewed the TS status sheets.

b. Circulating Water Pump 2-2

The inspectors observed various portions of the CWP 2-2 stator winding repair that was being performed by contract personnel. This repair was due to the phase to phase ground that occurred on June 27, 1986 see section 3.a. The work consisted of stator coil replacement and tightening stator coil spacer to prevent slipping.

No violations or deviations were identified.

5. Surveillance

By direct observation and record review of selected surveillance testing, the inspectors assured compliance with TS requirements and plant procedures. The inspectors verified that test equipment was calibrated, and acceptance criteria were met or appropriately dispositioned.

a. Unit 1 Control Room Air Particulate Monitor

The inspector observed certain aspects of the calibration activities performed on RM-21 in accordance with STP I-108B3. I&C technicians also performed a semi-annual discriminator check, in accordance with STP I-108B5, that was observed by the inspector. During this evolution the I&C technicians appeared well versed in the procedures and very knowledgeable concerning RM-21 response characteristics. The test equipment in use were within the calibration due date and appropriately connected.

b. Fire Detection System Detector Functional

The inspector observed various portions of STP I-34A. The STP was performed by qualified technicians and the results were reviewed by the I&C foreman.

No violations or deviations were identified.

6. Independent Inspection

a. Control Panel Bolting

In a memo to the Commission Chairman dated April 18, 1986 the NRC EDO discussed an issue concerning missing control panel anchor bolts at Dresden. An inspector reviewed the memo for any applicability to DCPP. Furthermore, in the company of a licensee's representative from GC electrical engineering, the inspector walked down the as-built structural supports of the Unit 1 and 2 control panels and SSPS cabinets. The base anchorage for all panels and cabinets were

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verified against applicable DCNs and as-built drawings with no apparent discrepancies. It should be noted that anchor bolts have not been used at DCPP, rather all panels and cabinets were welded to embedded base plates.

b. Steam Generator Snubbers

The inspector reviewed plant records for the subject snubbers. The snubbers installed on the steam generators at DCPP are rated for 1300 kips. These snubbers were custom designed and manufactured for PG&E by Paul-Monroe. Approximately two and one-half years ago these snubbers were overhauled, including installation of new long-life seals, and functionally tested. There was no evidence to indicate any snubber has failed or locked-up.

Change-out and maintenance of the Unit 1 SG snubbers was witnessed by a resident inspector and documented in NRC IR 50-275/84-21. On-site maintenance engineering also indicated these Paul-Monroe snubbers were built with the modified hydraulic control valves design, recommended to minimize particulate clogging.

c. Operational Mode Transition

DCPP Operating Procedure L-0 "Mode Transition Checklists" provides guidance for the SFM to ensure all TS requirements are met prior to entry into an ascending operational mode. Each ascending operational mode transition checklist (e.g. Mode 6 to 5, Mode 5 to 4, etc.) also establishes a documentary record that all LCOs and associated surveillances required by TS 3.0.4 and 4.0.4 have been reviewed and verified by the SFM prior to mode entry.

Throughout this year the inspector has observed various mode transitions made by Units 1 and 2 in accordance with OP L-0 and other applicable operating procedures. The inspector reviewed in-process and completed mode transition checklists as they were implemented to track and verify compliance with TS requirements prior to mode entry. Compliance with selected TS requirements, documented as satisfactorily complete by the SFM on mode transition check lists, were independently verified by the inspector. In all cases, applicable checklists were completed, reviewed and approved by the SFM prior to mode entry.

d. Thermal Expansion Considerations in Design Changes

Thermal expansion has been considered in the design, initial startup and hot functional test performed on both units. No seperate procedure for thermal expansion for design changes exists at this time; however, there are procedures which exist that govern how design change verification walkdowns (thermal expansion considerations) should be performed. The mechanism that triggers the performance of these walkdowns is somewhat subjective at this time for hot walkdowns, and more clear-cut for cold system walkdowns. The engineering manager is currently drafting a

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procedure to coordinate all aspects of startup from mode 5 to 100% power which would include triggers for such walkdowns.

No violations or deviations were identified.

7. Startup Testing

a. Quality Assurance for Unit 2 Startup

Selected licensee QA surveillances for the Unit 2 S/U test program were reviewed by the inspector and all related QA findings were dispositioned in accordance with the licensee procedures. The inspector also independently tracked the disposition of S/U test discrepancies in the review of selected test procedures identified in section 7.b below.

b. Startup Testing - Unit 2

The following S/U TP results were reviewed and approved by the lead S/U Engineer, and accepted for DCPP by the Plant Superintendent:

36.1 Rod Drive Mechanism Timing Test
38.2 Automatic Steam Generator Level Control
38.6 Startup Adjustment of Reactor Control System
42.1 Doppler Power Reactivity Coefficient Measurement
42.5 Statepoint Data Collection
42.8 Operational Alignment of Reactor Coolant System Temperature Instrument
42.9 Operational Alignment of Nuclear Instrumentation
43.1 Load Swing Tests

Test results of these completed procedures were evaluated by the inspectors; including a review that all test procedure changes and test deficiencies were incorporated or dispositioned in accordance with administrative guidelines. This review completes the NRC's S/U testing phase (IE Manual Chapter 2514) of the Light Water Reactor Inspection Program for Diablo Canyon, Unit 2.

No violations or deviations were identified.

8. Open Item Follow-up

a. Notice of Violation on Radiological Controls (Open Item 86-09-01, Closed)

An inspector reviewed the licensee's response letter to the Notice of Violation (Level V) in NRC IR 50-275/86-09. PG&E letter DCL-86-151 dated May 30, 1986 describes the corrective actions taken, and planned to be taken, concerning the failure of personnel to comply with radiological control procedures. The inspector reviewed and observed field implementation of a new plant policy encouraging greater first line supervision participation and monitoring of work inside the RCA. Furthermore, the inspector witnessed that additional emphasis on adherence to radiological

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controls associated with work in-and-around SCAs has been incorporated into radiation worker requalification training. Based upon the licensee's timely response and corrective actions, this violation is considered closed (86-09-01).

b. Enforcement Action on Inoperable Main Steamline Isolation Valve (Open Item 50-323/86-04-01, Closed) and Followup of Management Involvement to Address Problems (Open Item 50-323/85-32-03, Closed)

On February 12, 1986 NRC Region V issued Enforcement Action EA 86-04, comprising a Notice of Violation and Proposed Imposition of Civil Penalty for a Severity Level III violation involving the inoperability of one channel of the actuation logic of one main steam isolation valve.

The inspector has reviewed the licensee's response letter DCL-86-071 and finds the corrective actions to have been implemented. This was accomplished by record review, observation of maintenance performed, and attending TRGs. Thereby, open items 86-04-01 and 85-32-03 are closed.

c. Auxilary Feedwater Pump Oil Slinger Rings (Open Item 50-275/86-15-01, closed)

NRC IR 50-275/86-15 prepared by the Performance Appraisal Section (PAS) of the Office of Inspection and Enforcement contained one unresolved item concerning operability of the AFW pumps during corrective maintenance situations. Specifically, the PAS inspectors questioned the licensee's determination of pump operability of AFW pumps 1-2 and 1-3 when contaminated oil was found in both pumps in December 1985.

The resident inspector reviewed the circumstances surrounding this issue and investigated the action taken by the licensee in December. These actions were determined to be acceptable. Upon identifying contaminated bearing lube oil in AFW pump 2-2, the licensee sequentially removed AFW pumps on both units from service, inspected, flushed and replaced oil, bearing and slinger rings as deemed appropriate by the licensee. Due to the design and material of the bearings, slinger rings, and housings, it was determined the presence of brass contamination in the bearing oil would not necessarily require that all AFW pumps be immediately declared inoperable. This unresolved item is closed.

9. Licensee Event Report Follow-up

Based on an in-office review, the following LERs were closed out by the resident inspectors:

Unit 1: 84-37, 84-38, 86-05

Unit 2: 85-27, 86-15

The LERs were reviewed for event description, root cause, corrective actions taken, generic applicability and timeliness of reporting. The LER identified below was also closed out after in-office review and on-site follow-up inspections were performed by the inspectors to verify licensee corrective actions:

Unit 2: 86-14 was closed out based upon the inspector's witnessing of selected portions of the licensee's verification of breaker cubicle terminations.

No violations or deviations were identified.

10. Spent Fuel Pool Re-racking

All sixteen of the Unit 1 high density spent fuel racks have been installed in the Unit 1 spent fuel pool, and leveling operations on the most recently installed rack are continuing. The inspector observed that installation instructions were followed during insertion of the racks, including installation of bearing plates under each foot of the racks. Also, QA participation was noted by the inspector. Drag testing of each individual cell, utilizing a dummy fuel assembly was performed on twelve of the sixteen racks. A total of four cells in racks 1A1, 1D1 and 1D3 did not pass drag testing and will require re-work. Fabrication of the shipping cask restraint was also observed by the inspector.

The inspector also reviewed the licensee's receipt inspections records and evaluated the manufacturer's documentation supplied with the racks for compliance with the purchase specification. The licensee had not obtained certifications onsite for the Boraflex material used in the high density racks. Receipt of this information is expected shortly. Three Unit 2 high density spent fuel racks have been received onsite, and are in storage.

No violations or deviations were identified.

11. Exit

On July 11, 1986 an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.

Index of Acronyms

AO	Auxiliary Operator
AFW	Auxiliary Feedwater
ASW	Auxiliary Saltwater System
CCP	Centrifugal Charging Pump
CWP	Circulating Water Pump
DG	Diesel Generator
DCN	Design Change Notice
DCL	Diablo Canyon Letter
DCPP	Diablo Canyon Power Plant
EDO	Executive Director of Operations
ESF	Engineered Safety Features
GC	General Construction
I&C	Instrumentation & Control
IE	Inspection and Enforcement
IR	Inspection Report
KV	Kilo Volt
LER	Licensee Event Report
LCO	Limiting Conditions for Operation
MSR	Moisture Separator Reheater
NCR	Non-Conformance Report
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
OPEG	Onsite Plant Engineering Group
PG&E	Pacific Gas and Electric
PM	Preventative Maintenance
QA	Quality Assurance
QC	Quality Control
RCA	Radiological Controlled Area
RM	Radiation Monitor
RTB	Reactor Trip Breaker
RWP	Routine Work Permit
SCA	Surface Contamination Area
SFM	Shift Foreman
SG	Steam Generator
SI	Safety Injection
SSPS	Solid State Protection System
STP	Surveillance Test Procedure
S/U	Start-up
SWF	ShopWork Follower
SWP	Special Work Permit
TAVG	Average Temperature
TP	Test Procedure
TRG	Technical Review Group
TS	Technical Specification