U. S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos: 50-275/85-17 and 50-323/85-17

Docket Nos: 50-275 and 50-323

License Nos: DPR-80 and DPR-81

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: April 7 - May 25, 1985

Inspectors: R T Dodds for — 6/6/85
M. M. Mendonca, Sr. Resident Inspector — Date Signed

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R. T. Dodds, Chief, Reactor Projects Section 1 — Date Signed

Summary:

Inspection from April 7, 1985 through May 25, 1985
(Report Nos. 50-275/85-17 and 50-323/85-17)

Areas Inspected: Routine inspection of plant operations, maintenance and surveillance activities, Unit-2 preoperational and startup test program evaluations, Unit-2 initial fuel load, Unit-2 Master Completion List, maintenance program, and receipt/storage/handling program. Followup of on-site events, open items, and LER, as well as selected independent inspection activities.

This inspection effort required 385 inspector-hours for Unit 1, and 372 inspector hours for Unit 2 by four resident inspectors.

Results of Inspection: One violation was identified that related to the load timing being out of specification for a diesel generator (paragraph 2.c).

This inspection report completes the preoperational inspection program for Unit 2. Future inspection of Unit 2 will center on startup and operational activities.

DETAILS

1. Persons Contacted

*R. C. Thornberry, Plant Manager
R. Patterson, Assistant Plant Manager, Superintendent
*J. M. Gisclon, Assistant Plant Manager for Technical Services
W. B. Kaefer, Assistant Plant Manager for Support Services
W. A. Wogsland, Technical Assistant to Nuclear Power Operations Manager
*D. S. Taggert, Supervisor of Quality Assurance
*C. L. Eldridge, Quality Control Manager
*R. G. Todaro, Security Supervisor
D. B. Miklush, Supervisor of Maintenance
J. A. Sexton, Supervisor of Operations
*W. G. Crockett, Instrumentation and Control Maintenance Manager
*T. W. Rapp, Onsite Safety Review Group Chairman
R. L. Fisher, Senior Power Production Engineer
*J. V. Boots, Superviosr of Chemistry and Radiation Protection
*W. B. McLane, Material and Project Coordiantion Manager
*L. F. Womack, Engineering Manager
B. L. Peterson, Instrumentation and Control General Foreman, Unit 1
*T. L. Grebel, Regulatory Compliance Supervisor
*T. J. Martin, Training Manager
R. S. Weinberg, News Service Representative
V. R. Foster, Senior Power Production Engineer
G. W. Hessli, Senior Quality Assurance Engineer
M. L. Barham, Quality Assurance Training Supervisor
S. R. Fridley, General Operations Foreman
M. J. Angus, Senior Nuclear Engineer
P. G. Sarafian, Nuclear Engineer
*R. M. Nanninga, Senior Maintenance Engineer
R. P. Powers, Senior Chemistry and Radiation Protection Engineer

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 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 LCO as prescribed in the facility TS. Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, trends, and compliance with regulations. 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:

(1) General plant and equipment conditions.

(2) Surveillance and maintenance activities.

(3) Fire hazards and fire fighting equipment.

(4) Radiation protection controls.

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

(6) Interiors of electrical and control panels.

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

(8) Plant housekeeping and cleanliness.

(9) 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. <u>Reactor Coolant System Leakage Detection System</u>

A review of the SFM's log indicated that on May 5, with the reactor at approximately 27% power, one of three RCS leakage detection systems (containment sump level and flow monitoring system) was made inoperable when the reactor cavity sump totalizer (FI-60) was declared to be inoperable. With two of the three leakage detection systems operable, the TS ACTION statement for LCO 3.4.6.1 permitted continued reactor operation for up to 30 days. Subsequently, on May 6, with the reactor at approximately 47% power, a second RCS leakage detection system became inoperable when the pump to the containment atmosphere particulate radioactivity monitoring system tripped and would not reset. With only one leakage detection system remaining operable, the LCO ACTION statement required the plant be in at least hot standby within the next 6 hours, and be in cold shutdown within the following 30 hours.

The inspector noted the shift foreman did not make an entry into the SFM log to indicate that two of the three RCS leakage detection systems were simultaneously inoperable, and that entry into the hot standby mode would be required if at least one RCS leak detection

system could not be returned to service. Item 1.c.1 of NPAP E-6S1 "Operator Logs" specifies that the TS LCO Action Status Sheet attached to the SFM Log Turnover Checklist "shall include any entry to document the date, time, and general details necessary each time the unit is placed in a TS action statement except for momentary entries covered by approved plant procedures."

In discussions with plant management, the inspector indicated that inoperability of the second RCS leak detection system represented new information of the type required to be entered into the TS Action Status Sheet, even though the SFM expected the radioactivity monitoring system to be inoperable for a relatively short period of time. The licensee agreed that entry of this type of information into the operator's logs would result in a better indication of plant status and an improved exchange of operating information with other operations shift crews. This position has been discussed the Operations Department.

c. Entry Into Mode 4 With An Inoperable Diesel Generator

On April 27, with Unit 1 in Mode 5, STP M-13B "Engineered Safequards Automatic Timers Setting Verification" was performed on the bus F ESF timers associated with DG 1-3. Timers used for CFCU 1-1 and ASW pump 1-1 were found to be outside the acceptance limits specified in TS 4.8.1.1.2.b.2). The CFCU "as found" timer setting was 15.18 seconds and the ASW pump timer setting was 19.98 seconds. TS limits were 13 to 15 seconds for the CFCU and 20.8 to 23.2 seconds for the ASW pump.

In accordance with provisions of the STP, the licensee issued NPPRs to have the timers reset, but the licensee failed to declare DG 1-3 inoperable. On April 30, the Unit 1 reactor entered Mode 4 of operation without the timers having been reset (i.e., with only two operable DGs).

On May 10, with Unit 1 at 100% power, individuals from the Maintenance Department reviewed the NPPRs and realized that the timers had not been reset. Accordingly, this information was transmitted to the SFM, who in consultation with Engineering, incorrectly determined the DG to be operable and entered this information into the SFM's log. Later that day, the timers were reset to values within the TS specified range.

In reviewing the SFM Log, the inspector noted the incorrect log entry, and discussed the issue with the SFM and plant management. The inspector's investigation revealed that the plant had been in a Mode 1-4 condition for ten days with only two DGs operable, in violation of TS LCOs 3.0.4 and 3.8.1.1 (see Notice of Violation for details). After several days of discussions with the licensee, the licensee agreed that operation of Unit 1 in violation of the TSs continued for a period of 10 days. However, the inspector and licensee also agree that the DG would have functioned had it been called upon to actuate.

Interviews with Engineering and Operations personnel were held to determine reasons why the DG was not declared inoperable. The inspector was informed that it is standard practice for operations personnel to obtain more specific acceptance criteria from associated STPs when operability of a component or system is in question. In this case, STP M-13B indicated that if timer values fall outside the procedure's acceptance criteria (which are identical to the TS values) NPPRs are to be issued. As no reference to DG operability was provided in the STP, the DGs were thought to be operable. Furthermore, Engineering reasoned that since the timers were only marginally out of the acceptable tolerance, the additional diesel starts required by the TS ACTION statement (upon declaring DG 1-3 inoperable) would not be in the long-term best interest of the DGs.

The inspector attended the licensee's TRG sessions where the cause of the event and required corrective actions were discusseed. As corrective action, the licensee will revise STP M-13B to specify a DG to be inoperable if timer values are outside acceptance criteria. All other STPs (approximately 450) will be reviewed by the Quality Support Organization to determine if similar revisions are necessary. Additionally, the Manager of NPO's Engineering Department has discussed this incident with Engineering personnel who interface with the STP program to redefine their responsibilities for assuring compliance with TS. Therefore, this violation is issued as a result of the licensee's failure to strictly comply with the provisions of the TS, even though the equipment would have operated. This violation will be followed as open item 50-275/85-17-01.

d. Weld Crack

The inspector identified a crack in a RHR vent line weld on Unit 2 during an ESF system walkdown. The weld crack had an accumulation of BA crystals and moisture around it. The licensee is in the process of repairing the weld. The inspector will followup on the weld repair. The two similar socket weld cracks have occurred in Unit 1 on Class 1 systems one of which was identifed by the inspector. The licensee's leak minimization program will be examined as part of a future inspection effort. The licensee should also evaluate why their extensive system walkdowns did not find this cracked weld and the other cracked weld that the inspectors found as documented in report 50-275/84-32. Additionally, the licensee is evaluating the generic implications of this and other discovered weld failures and will consider submitting this information to the NRC.

One violation and no deviations were identified.

3. Event Followup

a. Unit 2 Containment Evacuation Alarm

FSAR Section 14.1.4.1 "Fuel Loading" and OP B-8D S-2 "Core Loading Sequence Unit 2, Initial Core" specify that the containment evacuation alarm is to be coupled to the source range channels/high flux at shutdown alarm during fuel loading. The purpose of the evacuation alarm is to automatically alert the fuel loading crew (and other personnel inside containment) to the detection of a high neutron count rate in the core.

For the first 36 hours of Unit 2 fuel loading, the automatic containment evacuation alarm was inadvertently defeated. The input error inhibit switches on Solid State Protection System trains A and B were placed in the "inhibit" position to prevent unnecessary actuations of reactor protection and Engineered Safety Feature functions (such as safety injection, reactor trip, and feedwater isolation) during fuel loading. The licensee recognized that placing the switches in the inhibit mode would cause the source range detectors to be de-energized, and accordingly jumpers were installed on slave relays to keep power on the detectors. However, the licensee neglected to realize that placing the switches in the inhibit mode also causes the source range blocking relay to defeat both the automatic high flux at shutdown alarm (located in the control room) and the automatic containment evacuation alarm. This condition was realized when the licensee observed a spurious source range channel spike, without the containment evacuation alarm being automatically initiated.

TS LCO 3.9.2 "Refueling Operations - Instrumentation" requires that during fueling operations, 1) two source range neutron flux monitors, with continuous visual indication in the control room, are operable and 2) one monitor must provide audible indication in containment and in the control room. These functions were not affected by placing the switch in the inhibit position, and accordingly LCO 3.9.2 was met. With visual and audible indication available in the control room, the operator could manually initiate the containment evacuation alarm if he observed high count rates on the source range channels.

In discussions with the licensee, the inspector determined that STP I-16B will be revised to specify that when placing the input error inhibit switches in the inhibit position, specific relay leads must be lifted to prevent blocking of the high flux at shutdown alarm, and jumpers must be installed to keep the containment evacuation alarms operable.

b. Reactor Coolant Pump Seal Leakage

On May 7, with the Unit 1 reactor at 100% power, an increase in the RCP 1-1 #3 seal leakoff flow rate was identified by the licensee. This leakage to the containment structure sump increased to approximately one-half gallon per minute (as compared to the normal

flow of approximately 400 cubic centimeters per hour). The licensee obtained a sample of the leakoff water for chemistry analysis to determine if the leakage was from the non-radioactive primary water supply to the seal or if the leakage was from the RCS. A boron analysis indicated that the water contained no boron, thus no leakage from the RCS (through the RCP #2 seal to the #3 seal) existed. As this amount of primary water leakoff from #3 seal does not affect RCP operation, the licensee continued to run the RCP and monitor the leakoff flow. The inspector will provide follow-up coverage under the normal inspection program.

c. Unplanned Release from Unit 1 Waste Gas System

On May 8 and 9 an unplanned release of radioactive gases (primarily Xenon-133 and 135) to the environment occurred . This release did not represent a threat to public health or environmental safety.

An upset in the auxiliary steam system caused a pressure transient within the BA evaporator which actuated an installed rupture disc (set at approximately 3 psi). The BA evaporator normally vents to, or receives cover gas from, a waste gas vent header cross-tied to a LHUT and GDT. When the rupture disc blew out, this created an indirect vent path from the LHUT and GDT 1-2 to the auxiliary building atmosphere. Auxiliary operators promptly removed the BA evaporator from service, but failed to recognize and isolate the uncontrolled vent path from GDT 1-2. Once initiated, the radioactive release continued for approximately 10 hours until operator action isolated the waste gas header from the auxiliary building atmosphere. By this time, GDT 1-2 had completely discharged from 75 psig to zero. The auxiliary building ventilation system exhausted the radioactive release into the environment via the plant stack. Although, radioactive gases escaped the auxiliary building via this exhaust path, any particulates would have been captured by ventilation filters.

A licensee estimate of the total activity of all radioactive gases released was calculated at .022 curies. Extrapolation of this total activity to the site boundary, indicated a concentration of 1.88E-18 curies per mililiter and a whole body dose of 7.54E-9 rem. The resultant concentrations of released gases were insignificant fractions of the limits defined in Appendix B of 10CFR20. Furthermore, activity levels during the release event were significantly below the detectable threshold of the plant stack radiation monitor RE-14.

Actuation of this BA evaporator rupture disc has happened twice before causing unplanned releases. A TRG meeting was held to discuss the associated contributing causes and corrective actions of this event. System design and operator error were the chief identified causes. To preclude similar events in the future, the TRG has proposed the following corrective actions: a) pursuit of hardware design changes by engineering to replace the rupture disc and/or install some kind of low pressure protection from the WGS and b) issue a SFM memorandum describing the event and its

ramifications. The inspector has since reviewed the SFM memo dated May 10, 1985, "Incident resulting in discharge of GDT to auxiliary building." In this memo the Operations Department prescribed further corrective action: a) Plant operators were instructed to assure all such problems/abnormalities are promptly reported to the SCO and/or SFM; b) Operator duties in the auxiliary building were clarified. Responsibilities are now divided into a designated radwaste operator and equipment operator, who shall spend at least 6 hours per shift in the RCA; c) SFM were to verify adequate knowledge of all auxiliary operators on the WGS. These committments were considered acceptable by the inspector, and follow-up of their implementation will be conducted during routine inspection activites.

This event will be described by the licensee in the next Semi-Annual Radioactive Effluent Release Report, under a sub-section for "unplanned releases from the site to unrestricted areas." Reportability in this fashion is considered to be consistent with regulatory requirements of TS 6.9.1.6.

d. Condensate Polishing System Water Spill

While the Unit 1 was at 100% power, approximately 30,000 gallons of non-radioactive water was spilled from the Unit 1 condensate polishing system in a period of 10 to 15 minutes. This loss of condensate was discovered when control operators observed a rapid decrease in main condenser hotwell level, which was aggravated by makeup water to the hotwell having been previously isolated for main turbine warranty testing. The operators promptly restored makeup water flow to the condenser, and dispatched an auxiliary operator to close all valves associated with the 1-2 condensate demineralizer bed.

Subsequent investigation by the licensee disclosed that the discharge of condensate water was through valve FCV-927 on the 1-2 demineralizer drain line to the condensate polishing system pump. This situation occurred after the demineralizer bed was removed from service, and FCV-927 was cleared in the open position, to allow cleaning of the demineralizer's well screen. Upon completion of the work, the clearance on the bed was removed, but FCV-927 was not returned to the closed position. The incorrect valve positioning resulted from either, an auxiliary operator failing to move the valve control switch to the "auto" position or from problems with a switch on the condensate polisher computer (which positions the valves). Subsequently, instrumentation and control personnel initiated work under a separate clearance, on the main outlet valve (FCV-924) from the 1-2 vessel, and opened FCV-924. This provided a flow path from the demineralizer outlet header (which connects the outlets of all seven demineralizers together) to the condensate polishing sump through FCV-924 and FCV-927. The sump overflowed to the yard area, and the condensate flowed into Diablo Creek.

After isolating the flow, the licensee took samples of the condensate for chemistry analysis. Sample results indicated the

water to be essentially clean, condensate with no detectable activity. Licensee biologists also verified that no harm occurred to Diablo Creek. The Central Coast Regional Water Quality Control Board was notified of the release.

As corrective action, the licensee issued a Shift Foreman's memo describing the spill, and requiring auxiliary operators to be aware of the effect of manual valve operations on the system. Additionally, the auxiliary operators were instructed to be attentive for condensate polisher computer problems.

e. Unit 1 Reactor Trip and Safety Injection Events

At 7:13 a.m. (PDT) on May 18 and again at 5:20 a.m. (PDT) on May 20, a reactor trip and safety injection occurred due to loss of vital instrument AC power.

With the reactor plant at 100% power on May 18, the first event happened when a transformer inside vital instrument AC inverter IY-13 burned-up. Subsequent loss of 120 VAC power to panel PY-13 de-energized protection set III which caused a reactor trip from false indication of an open RCP breaker. Almost immediately, a safety injection was initiated due to high steam line flow coincident with low steam pressure. The high steam line flow signal turned out to be an valid input to the SSPS, whereas low steam pressure was yet another false indication that resulted from de-energization of protection set III. High steam line flow conditions were actually in effect for just a moment, due to reactor trip permissive P-4 reset of the high steam flow SI setpoint to a zero load value. This reset occurred faster than the turbine trip signal could shut the main turbine governor valves. Thus for a brief time period, the steam demand was at 100% and the SI setpoint was at 40%.

An "Unusual Event" was declared at 7:14 a.m.. Plant conditions were stabilized in accordance with emergency operation procedures and the event was terminated at 8:01 a.m.. All safeguard systems operated appropriately except DG 1-3, which shutdown after only a few minutes of operation when a belt broke on the engine driven fuel oil pump. As required by TS, the licensee has planned to write a 30 day special report (85-06) concerning failure of DG 1-3.

On May 20, the reactor plant was at 55% power. Another reactor trip and SI occurred when the output breaker of vital instrument AC inverter IY-12 tripped open due to loose breaker connections. Loss of 120 VAC power to panel PY-12 de-energized protection set II, causing a similar reactor trip from a false SSPS input of an open RCP breaker. SI was initiated almost immediately due to high steam line flow coincident with low low TAVG. The high steam line flow signal was a false indication that resulted from de-energized protection set II, whereas low low TAVG was a valid result of plant cooldown during the SI event. An "Unusual Event" was declared at 5:20 a.m. and terminated at 5:49 a.m. at which time all plant

conditions had been stabilized. All safeguard systems operated acceptably.

Both events were promptly reported to the NRC as required by regulation. Acceptable issuance of LERs 85-14 and 85-15 by the licensee will satisfy the requirements for written reportability. The multiple failure of vital instrument AC power supplies will be addressed in a TRG meeting planned for early June. The TRG will formally identify the specific causes associated with both events, and establish corrective actions to preclude recurrence. In the mean time, IY-12 and IY-13 have been repaired and all inverters were re-inspected. Furthermore, the plant superintendent has committed the electrical maintenance shop to performing monthly tightness checks of all applicable vital instrument AC inverter output breaker connections until such time as these connections have been replaced with a locking nut termination in accordance with an ongoing replacement program. Licensee activities to resolve questionable AC inverter reliability will be closely followed by the resident NRC staff.

f. Reactor Trip of Shutdown Banks

At 3:40 p.m. (PDT) on May 20, a voltage spike was generated while transferring static inverter IY 12 from the backup to the normal power source. This spike caused a high source range count rate which generated a reactor trip signal inserting the shutdown control rod banks, which had been withdrawn in anticipation of a reactor startup. The control operators responded promptly, declared an significant event and made all appropriate notifictions. The reactor remained in mode 3 during the entire event. The inspector present in the control room when this event occured, observed all immediate actions taken by the licensee and the subsequent stabilization of plant conditions.

g. Unit 1 Power Excursion to 103%

On May 16, at approximately 8:45 a.m., Unit 1 experienced an unexpected and uncontrolled load demand transient which resulted in a reactor power excursion from 100% to 103%. Plant operators quickly stabilized plant conditions and returned reactor power to its' previous level of 100%.

This event was caused by personnel error from outside the control room. An I&C technician inadvertantly removed and re-installed a power supply fuse to the Unit 1 main turbine first stage pressure transmitter (PT-8). The resultant perturbation of the impluse signal input to the DEH system caused a sudden artificial increase in load demand on the main turbine. In response to main turbine demand for more steam reactor power ramped up accordingly. Control operators promptly recognized the reactor power transient and placed the DEH system in manual. In only three or four minutes reactor power had increased approximately three per cent until operators terminated the event by taking manual control. Shortly, thereafter plant conditions were stabilized and Unit 1 was returned to the 100%

power level. Normal automatic operation of the main turbine was not restored for several shifts, due to subsequent trouble shooting of the DEH system by the I&C Department.

No violations or deviations were identified.

4. Maintenance

a. Installation of Unit 2 Control Rod Drive Shafts

MM and QC personnel worked together to clean, inspect and install fifty-three Unit 2 control rod drive shafts during preparation for initial fuel load. These work activities were conducted in accordance with SWF MM-2-84-135 and QCI 84-1640. The inspector reviewed both documents and observed their implementation in the field. Satisfactory performance of the SWF and QCI was witnessed by the inspector for approximately ten per cent of the control rod drive shafts.

QC verification of control rod guide tube boroscope examinations was not accomplished as requirerd by QCI-1640. Apparently, as a result of miss-communication, these examinations were conducted by MM and Westinghouse without QC involvement. This discrepancy has been documented by NPPR DC 2-85-WP-P0038.

b. Unit 1 CFCU Bearing Spacer Plate Replacement

Excessively high vibration levels have been a chronic problem for some Unit 1 CFCUs during high speed mode of operation. Design change, DC 1-SM-27398, was approved as a method to reduce CFCU vibration levels by replacing existing bearing spacer plates with, thicker, one inch plates. Working instructions necessary to perform and document this modification were provided by SWF MM-1-85-085 and QCI-85-0358. All five CFCUs were scheduled for electrical motor overhaul and vibration damping modification during the 30-day Unit 1 strainer outage in April. Due to concurrent electrical and mechanical work activities, release of this plant equipment for maintenance was controlled by several overlapping clearances.

The inspector reviewed all aformentioned documents and observed the bearing spacer plate replacement of CFCU 1-4. This work also included re-alignment of the CFCU motor coupling to the fan shaft. All maintenance activities witnessed by the inspector were performed in accordance with SWF instructions, and conducted within the constraints of the applicable equipment clearance.

c. DG 1-3

Apparent fuel starvation caused DG 1-3 to shutdown after starting following routine maintenance. The primary fuel filters were examined and a small amount of diesel fuel sludge was detected on the filter. The diesel fuel day tank was inspected and some sludge

was found. As a precautionary measure the day tank was flushed and the fuel filters replaced.

The DG still exhibited fuel starvation problems after corrective actions were taken. The problem was investigated again and the DG 1-3 governor was found to have been improperly vented using MP M-21.8. The licensee is revising MP M-21.8 to include the manufacture's recommendation for properly venting the DG governor.

d. Tensioning of Unit 2 Reactor Closure Head Studs

After fuel load operations were completed, SWF MM-2-85-008 and associated QCI 85-017 were issued to "Install Reactor Head." As part of the installation sequence, reactor closure head studs were tensioned to ensure the closure head would remain seated during anticipated operating conditions. Stud tensioning was performed in accordance with revision 5 of MP M-7.2, "Install Reactor Closure Head." The inspector reviewed MP M-7.2, the SWF and QCI.

Second pass tensioning for twenty-one of fifty-four studs, and elongation measurements of all studs, were witnessed by the inspector. Subsequent review of the elongation data revealed that almost one-third of all studs were outside the acceptance criteria (.051 inches plus-or-minus .002) and required a further adjustment pass. The inspector witnessed tension adjustments of several studs. Recorded results were reviewed by the inspector. Upon completion of the adjustment pass, a final elongation measurement was performed on all studs.

With one exception, MM and QC personnel activities observed by the inspector were considered to be conducted in accordance with plant procedures and work instructions. Elongation measurements of reactor closure head studs were performed using a dial indicator which had exceeded its' calibration due date. This anomaly was brought to the MM foreman's attention by the inspector. The dial indicator of concern was originally controlled by a defunct contractor's calibration program, but has since been turned over to the MM Department. Dial indicators have not been considered by the MM Department as a measurement tool which required calibration; thus, the due date of this particular dial indicator was allowed to lapse. These details were discussed with Maintenance Department management. The inspector considers that certain uses of dial indicators would fall within the scope of NPAP D-5, "Control of...Measurement and Test Equipement." Follow-up of the licensee's response will be conducted as part of the independent inspection program.

No violations or deviations were identified.

5. Surveillance

By direct observation and record review of licensee surveillance testing, the inspectors verified compliance with TS requirements and implementing plant procedures for the following items:

a. Steam Flow and Pressure Calibration

The inspector observed selected portions of STP I-12B6 "Calibration of Steam Generator Flow and Pressure Channels Protection and Safeguards (and Alarms) Functions." The test equipment used was in current calibration. The STP was properly reviewed and accepted.

b. Functional Test of Temperature Channels

The inspector observed selected portions of STP I-5A "Functional Test of OT delta T, OP delta T, Tavg and delta T Channels," and subsequently examined the reviewed and accepted data after completion. All test equipment used was in current calibration and all data was within allowable acceptance limits.

c. Calibration of Unit 1 Accumulator Level Transmitters

One out of every two narrow range level channels was calibrated for each accumulator during the Unit 1 April outage. Accumulator narrow range LTs 951, 953, 955, and 957 and associated Hagan module loops were calibrated in accordance with STP I-30B. This surveillance activity is required every 18 months by TS 4.5.1.2.b. The inspector witnessed calibrations of Accumulator 1-1 narrow range LT-951 and its associated loop. Operational release of the Accumulator 1-1 level channel, for surveillance, was controlled by equipment clearance 9-1278-85. Prescribed clearance points and affected work boundaries were verified in place by the inspector.

The "as found" output data of LT-951 was discovered to be in violation of allowable limits. Appropriate adjustments of the level transmitter were made, and subsequent "as left" data proved to be acceptable. NPPR DC 1-85-TI-P0367 was promptly written up to assure this identified condition would be properly evaluated. A review by the inspector of other completed STP I-30B data sheets (LT-953, 955, and 957) revealed that "as found" data for every narrow range accumulator level transmitter calibrated during the outage failed to meet allowable limits. NPPRs for these transmitters had also been written.

All surveillance related activities observed by the inspector were accomplished in accordance with the applicable STP, clearances and plant administrative procedures. But, due to the questionable reliability demonstrated by the previously mentioned transmitters, the inspector conducted a detailed examination into the historical calibration records of all eight accumulator LTs (950-957). From subsequent evaluation of these records, and those generated during the most recent surveillance activities, the inspector determined that the failure rate of LTs to meet established calibration limits for "as found" data exceeded 90%. This information was brought to the Unit 1 I&C general foreman's attention as poor indication of equipment performance, required to be operable by TS. Further discussions between inspector and I&C general foreman centered upon I&C responsibilities for trending and re-evaluating surveillance

frequencies. Particular emphasis was directed towards addressing the problems associated with older, less reliable transmitters still in service (such as those used for measuring accumulator narrow range levels).

In response to the above inspector's concerns, the I&C general foreman re-emphasized his department's plans to: 1) establish an agressive trending program as soon as personnel and equipment resources become available and 2) replace all older model transmitters with new, more reliable and accurate transmitters. But, until such time these programs become fully implemented, the general foreman has agreed to: 1) reduce the surveillance period of accumulator narrow range LTs to six month intervals, and 2) assemble a complete list of other old model transmitters still used as part of critical channels in the plant. Those transmitters listed would be evaluated for any trend which suggested poor performance, and then dispositioned accordingly (i.e. replacement, increased surveillance frequency, etc.).

No violations or deviations were identified.

6. Routine Inspection

a. Hot Functional Tests Result Evaluation

The following completed Unit 2 HFT procedures were selected by the inspectors for test result evaluation:

- Residual Heat Removal System Test During Cooldown
- Steam Dump System Performance
- Plant Cooldown from Outside Control Room
- Control Room Inacessibility
- Main Steam Isolation Valve Test
- Letdown, Charging & Seal Water Performance
- Pressurizer Pressure & Level Control Test
- Auxiliary Feed & Steam Generator Level Control
- Rod Control System Functional Test
- Incore Thermocouple and Resistance Temperature Detector Cross Calibration

Witnessing and review of these HFT procedures were documented in NRC Inspection Report 50-323/84-27.

In overview, the inspectors verified that the licensee's administrative controls for test conduct, review and acceptance were performed in a satisfactory fashion. Test results were reviewed and approved by the lead startup engineer, and complied with established acceptance criteria. Any deviations or deficiencies were identified and dispositioned. In some cases, revisions to the test procedure, and/or retesting of functions or systems requiring an addenda to the procedure, were considered necessary. The inspectors have determined from test procedure review, witness and evaluation that these HFTs acceptably demonstrated system function in accordance

with test objectives. However, based on inspection findings, continued close scrutiny of the licensee's startup program for Unit 2 is considered essential in light of the significant magnitude of required revisions and retests.

b. Preoperational Test Result Evaluation

The inspectors reveiwed the licensee's log which tracks preoperational tests procedure preparation, conduct and acceptance process. Through this review, and through discussions with the lead startup engineer, the inspectors verified that startup testing process on the following areas, or systems, has been completed:

- Systems Flush
- Component and Pipe Expansion
- Leak Detection
- Communication Systems
- Instrument Air
- Electrical Systems
- Reactor Components Handling System
- Refueling Equipment
- Fuel Handling and Fuel Storage System
- Closed Drain System
- Reactor Coolant Pump Seal and Cooling Water System
- Component Cooling Water System
- Fire Protection System
- Service Water System
- Seismic Instrumentation
- Control Rod Drive Monitor Cooling System
- Cold Hydrostatic Test

c. Receipt, Storage, and Handling of Equipment and Materials

The inspector reviewed the licensee's program for receipt, storage, and handling of equipment and materials. The program was reviewed against FSAR Chapter 17, Section 13, ANSI N 45.2.2-1972, and the applicable NPAPs as part of this inspection. Additionally, the inspector toured warehouses and observed receipt inspections of safety related items.

The inspector examined a warehouse QC hold area and found three items with both a hold tag and a reject tag on them. These discrepancies were resolved to the inspector's satisfaction by the QC manager; in addition, further segregation of rejected items and hold items is being considered.

The licensee's procedures contain requirements for performing receipt inspections, dispositioning of nonconforming items, controlling conditional release of items, and handling of safety related material. The licensee is in the process of issuing additional receipt inspection working instructions in the form of QC procedures to supplement existing administrative procedures.

d. Master Completion List

Acceptable resolution of all mode-specific items in the MCL is required as a condition of the Unit 2 license. Todate, the MCL has been reviewed and tracked by the inspectors inorder to verify satisfactory completion of those items required prior to entering Modes 5 and 6 of reactor operation.

The licensee has acceptably addressed all Mode 5 and 6 requirements identified within the MCL. A few items were re-designated for completion at some later mode. This was necessary since the work to be accomplished (generally testing) requires system configuraitons not available until later modes.

e. Maintenance Program

The inspector examined the licensee's maintenance program in NRC Inspection Report 50-275/84-26. In that inspection, the licensee's compliance to TS and FSAR commitments, for both the corrective and preventive maintenance programs in the procedure and implementation areas, was verified. This current inspection re-examined the NPAPs which have since been revised to verify TS and FSAR requirements and commitments are still being met. Additionally, the implementation of corrective and preventive maintenance programs of selected departments, as well as the licensee's work planned center interface, was reviewed. The inspector found all procedures reviewed to be in compliance with requirements and the program implementation to be adequate for two unit operation.

f. Unit 2 Initial Fuel Load Procedure Review

As part of the routine inspection program, the inspector performed an evaluation of the Unit 2 initial fuel load procedures. The objective of this inspection was to verify these procedures comply with regulatory requirements and are consistent with commitments in the FSAR, QAM and applicable regulatory guidance.

The following literature related to initial fuel load of Unit 2 were reviewed in detail by the inspector:

- FSAR Update section 14.1.4.1 "Fuel Loading"
- QAP 6.3, Revision 0 - "Inspection, Testing, and Operation of Nuclear Fuel Handling Equipment"
- QAP 9.1, Revision 0 - "Handling, Storage, and Shipping of Nuclear Material"
- NRC Regulatory Guide 1.68, Revision 2 - "Initial Test Programs for Water-Cooled Nuclear Power Plants"
- Unit 2 TS

- 10CFR20 and 50
- OP B-8D, Revision 4 - "Core Loading Prerequisites"
- OP B-8D S-2, Revision 0 - "Core Loading Sequence Unit 2, Initial Core"

Upon completion of the aforementioned review activities, the inspector determined that the licensee's procedures for conducting initial fuel loading operations were acceptable, except for the following deficiencies:

1) Detailed written procedures approved by the Plant Manager for "fuel handling operation" and "operation of nuclear fuel handling equipment" were not established as required by QAP 6.3 and 9.1.

2) "The composition, duties, and emergency procedure responsibilities of the fuel handling crew" were not adequately specified as recommended by Regulatory Guide 1.68.

3) Verification by the Plant Manager "that nuclear fuel handling equipment meets the requirements of Title 8 of the California Administrative Code" was not addressed as required by QAP 6.3.

4) Control of personnel access to the containment during fuel load was not prescribed by written procedure as committed to in the FSAR.

5) Fuel load procedure OP B-8D S-2 offered an alternate method, not allowed by the FSAR, for alerting fuel load personnel of high count rates that would require immediate cessation of all operations.

6) The specific criteria used to terminate fuel load operations, established by the FSAR for unanticipated increases in neutron count rate, was incorrectly incorporated into the fuel load procedure.

7) Conduct of dry runs, on the use and operation of fuel handling tools and equipment, were not specified in the fuel load procedures as described by the FSAR.

All of the above were presented to plant management by the inspector at a PSRC meeting held May 1. Subsequent licensee response to the inspector's concerns was prompt, agressive, and complete. Each and every deficiency was addressed by plant management, discussed with the inspector, and satisfactorily resolved by the following: 1) OP B-8D and OP B-8D S-2 were revised, 2) Operation's Department memos (to supplement the fuel load procedures) were issued to provide additional guidance concerning crew compositions, responsibilities, and special operating instructions, 3) Temporary procedure TO-8502,

"Fuel Handling Operating Instructions" was issued, and 4) Dry runs were conducted prior to each shift with all fuel load personnel.

Independent inspection of the licensee's Commitment Management Data Base revealed that some of the above commitments were not properly identified. Plant Management has requested aid from General Office personnel to establish what steps are required inorder to create a useful system. This and subsequent licensee efforts to correctly identify and implement all its' commitments will be followed during routine inspection activities. Furthermore, licensee QA and Plant Management have been appraised that such commitments should be clearly agreed upon and implemented effectively throughout the company. The licensee agreed to consider the need for more effective communication concerning these particular procedural inadequacies.

g. Initial Fuel Load of Unit 2

From May 1 (establishing initial conditions/prerequisites) through May 18 (installation of reactor closure head) the inspectors witnessed selected portions of almost all significant aspects related to initial fuel load of Unit 2. In general, the inspection objectives during this major evolution were to verify licensee conformance to procedural requirements, observe Operations and Engineering shift performance, and ascertain the adequacy of fuel loading records. OP B-8D and OP B-8D S-2 (reviewed in section 6.e of this report) were the primary procedures for controlling Unit 2 initial fuel loading operations. Some of the more important aspects of initial fuel load operations verified by the inspectors were :

- Prerequisites, initial conditions and TS requirements were met and maintained
- Fuel load staffing and communications were properly in place
- Shift turnover, training, and equipment/alarm checks were conducted satisfactorily
- Step-by-step fuel loading operations were conducted in accordance with applicable procedures by Operations, Engineering, and C&RP personnel stationed in the FHB, Containment, and Control Room
- Controlled access to the containment and FHB was established and maintained in accordance with written procedure
- Data sheets, logs, inverse multiplication plots, and refueling status boards were properly maintained
- Procedure changes, fuel load evolution interruptions, and unforseen problems were acceptably dispositioned

The first fuel assembly was loaded in the reactor vessel at 7:12 a.m. (PDT) on May 7, and the last at 6:13 p.m. (PDT) on May 15. In general, fuel loading operations were performed in a slow, smooth

and methodical fashion except for the following unforseen interruptions and/or problems:

- Fuel load operations were interrupted May 7 when RHR boron concentration exceeded 20 ppm of nominal.

- Fuel load operations were interrupted May 8 when foreign material was discovered in the reactor vessel.

- Containment evacuation alarm coupled to high flux at shutdown alarm were inoperable for approximately 36 hours during May 6 and 7 (see section 3.a of this inspection report).

- Containment integrity was violated May 9, when the inner and outer doors of the personnel access airlock were opened simultaneously (no core alterations were conducted during this time).

- Fuel assembly M04 was slightly damaged May 13 during handling operations in the FHB; this necessitated insertion of a replacement fuel assembly B52 in the reactor vessel May 15.

- Visual verification of the completed core load was performed instead of by video tape due to focus/lighting difficulties.

After Unit 2 initial fuel load activities were finished and the reactor closure head was installed, the inspector reviewed the completed fuel load procedures data sheets (OP B-8D and OP B-8D S-2). The review revealed the following:

a) Several RHR, VCT, BAST, AND RWST boron concentration data points were not recorded on Table II of OP B-8D during May 16 and 17

b) Data reviews of Table II (OP B-8D) were not consistently conducted by the C&RP manager and SFM

c) Data sheet 4 of OP B-8D S-2 was not consistently reviewed by the power production engineer, nor was the individual recording the data correctly identified

d) Failure to perform Table I (OP B-8D) boron concentration samples of the RCS during fuel load was not promptly dispositioned

Aside from the above, the licensee's overall performance acceptably conformed to TS and procedural requirements, although item (a) and (b), were considered to be of particular importance by the inspector. Apparently on May 17 (during RCCA drag tests) the RHR, VCT and RWST boron concentrations were not adequately verified. Attachment C of OP B-8D required these verifications to be performed every 4 hours for RHR and every 24 hours for VCT and RWST whenever core alterations were in progress. In the opinion of the inspector, failure to comply with these procedural requirements, were

exacerbated by marginal management reviews (see item b) that also failed to recognize the discrepancies and disposition them appropriately. These particular circumstances demonstrated a noticeable degradation of administrative controls and management scrutiny during the later stages of Unit 2 initial fuel load activities.

h. Review of Quality Assurance Activities During Preoperational Testing

The inspector's review of QA activities associated with Unit 2 preoperational testing included the following areas:

- QA program management
- QA surveillance and inspection activities
- QA audits
- Training and qualification of QA personnel

The QA program management organization is defined in the licensee's QAM. QAM descriptions relating to authorities and responsibilities of individuals managing the QA program were reviewed for consistancy with FSAR Chapter 17 "Quality Assurance." QAM Policy Section 1 "Organization" assigned responsibilities for executing the licensee's QA program, and delineated the duties and authorities of persons performing QA functions. A review of Policy Section I indicated that the QAM descriptions were not in agreement with the information presented in Chapter 17 of the FSAR. This disparity was previously recognized by the licensee, and has been factored into ongoing efforts to develop an enhanced QA program.

Over the past one year period, the licensee has been involved in a comprehensive QA program review, and the resultant revisions to the QAM are expected to be completed by August 1, 1985. Within ninety days of issuance of the revised QAM, departmental procedures which implement the QAM will be revised to reflect the enhanced QA program. The inspector will provide routine followup of the licensee's efforts to implement the upgraded QA program.

The inspector verified that required QA inspection and surveillance activities were being performed by the licensee on a regular basis. Recently completed QA surveillance activities were reviewed by the inspector, especially those activities directly pertaining to preoperational testing of the Unit 2 facility. All reviewed activities were performed in accordance with the QAM.

An indepth review of the licensee's QA Audit Program was previously performed by the inspector and documented in NRC Inspection Report No. 50-275/84-30. The report findings are being addressed by the QA organization. As described earlier, revised procedures to address the report findings are to be issued shortly.

Training and qualification of QA personnel was verified by reviewing resumes, job descriptions, training ledgers, and qualification requirements. QA personnel were found to meet position

requirements. The training program for QA inspectors was adequate for general QA orientation, but developemnt of job specific training requirements for Quality Support Services personnel is recommended. The licensee is in the process of developing these requirements. However, the present Quality Support Services Staff is highly qualified. Followup of development of specific training requirements will be performed under the routine program.

No violations or deviations were identified.

7. Independent Inspection

a. Mispositioned Control Rod

In response to Technical Instruction 2515/67, the inspector reviewed the licensee's operating procedures "control rod misalignment" (OP AP-12E) and "inoperable control rod position indication malfunction (OP AP-12D). The procedure on control rod misalignment specified the steps recommended by INPO's SOER 84-2. Additionally, the procedure provided acceptable instructions for recovery of the mispositioned rod, including a step for compliance with TS. Finally, the procedure on inoperable control rod position indication specified alternate means for position indication and actions to comply with TS.

b. Steam Binding of Auxiliary Feedwater Pump

TI 2515/76 requests inspection on the subject topic. The licensee acceptably addressed and considered INPO SOER 84-3 on check valve leakage which resulted in AFW steam binding. The licensee instituted a surveillance requirement for check valve leakage. Additionally, a control room annunciator design change to detect check valve leakage from high AFW pipe temperature is in progress. AFW testing and analysis, and inspection of the check valves, has shown that no damage is anticipated. Inspection and evaluation of the problem will continue to assure no steam binding of the AFW pumps.

c. Reactor Trip Breakers

The inspector verified compliance with selected vendor recommendations to increase reactor trip system reliability. Specifically, installation of a shunt coil trip relay on each reactor trip breaker was verified during this inspection period. Additionally, use of the recommended lubricant was verified in NRC Inspection Report number 50-275/83-36. Additionally, the inspector reviewed reactor trip breaker maintenance, surveillance, and procurement activities to assure program requirements and implementation were acceptable in NRC reports 50-275/84-02 and 50-323/84-02. Finally, during routine inspection activities, the inspector has observed the licensee's conduct of post trip reviews to acceptably identify and resolve the cause of trips.

No violations or deviations were identified.

8. Open Items Followup

a. Storage of Class 1 Materials (Open Item 50-323/84-03-02, Closed)

In NRC Inspection Report 84-03, the inspector identified inadequacies in the licensee's access control to Unit 2 Class 1 material storage areas. In response to the identified deficiencies, the licensee revised GC QAM Procedure (GCP)-11.1 "Receipt, Handling and Storage of Equipment and Material" to specify access control requirements for Class 1 materials. The procedure requires that access be restricted to prevent entrance of unauthorized presonnel into areas storing ANSI N 45.2.2 protection level A, B, and C materials. For level D materials, the procedure does not require access control. Similiar requirements were also added to Bechtel Field Procedure FP-8 "Requisition and Control of Material, Equipment and Services." Accordingly, this item is considered closed.

No violations or deviations were identified.

9. Licensee Event Report Follow-up (Unit 1)

Circumstances and corrective actions described in LER 85-12 were examined. Review of the LER, and reporting to NRC within required time intervals by the licensee, was verified by the inspectors. The inspectors also ensured appropriate corrective actions were established and applicable events were accurately described. Accordingly, LER 85-12 is considered closed. This reactor trip event was discussed in NRC Inspection Report No. 85-08.

No violations or deviations were identified.

10. Exit

On May 24, 1985, 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.

In overview, several instances during the inspection report period were observed that demonstrate a need for greater attention to detail by the plant staff.

1. Use of non-calibrated instrument for a critical measurement (Section 4.d)

2. Loss of high flux at shutdown containment evacuation alarm (Section 3.a)

3. A reactor power excursion (Section 3.g)

4. An unplanned radiation release (Section 3.c)

5. Unit 2 initial fuel load procedure deviations from established licensee committments and inadequacies of the Commitment Management Data Base (section 6.f)

6. Procedural discrepancy during conduct of Unit 2 initial fuel load (Section 6.g)

7. Inadequate log entry on RCS leakage detection system inoperabilty (Section 2.b)

8. A weld crack on the RHR vent line (Section 2.d)

9. Trending of level transmitter calibration results (Section 5.c)

10. Required revisions and retests for startup testing (Section 6.a)

These items were discussed with applicable plant management. Additional management action appears to be warranted in order to instill a general plant staff attitude of self-critical assessment during all activities affecting plant operations.

The licensee agreed to consider these findings and the need to examine activities affecting plant operation to assure the continuation of an attitude of self-critical assessment.

11. INDEX OF ACRONYMS

AFR	-	Audit Finding Report
ANS	-	American Nuclear Society
ANSI	-	American National Standards Institute
ADME	-	American Society of Mechanical Engineers
ASW	-	Auxiliary Saltwater System
AFW	-	Auxiliary Feedwater
BA	-	Boric Acid
C&RP	-	Chemistry and Radiation Protection
CFCU	-	Containment Fan Cooler Unit
CFR	-	Code of Federal Regulations
CO	-	Control Operator
CRVS	-	Control Room Ventilation System
CVCS	-	Chemical and Volume Control System
DCN	-	Design Change Notice
DEH	-	Digital Electro-Hydraulic
DER	-	Department of Engineering Research
DG	-	Diesel Generator
DR	-	Discrepancy Report
ECP	-	Estimated Critical Position
EOF	-	Emergency Offsite Facility
ESF	-	Engineered Safety Features
FEMA	-	Federal Emergency Management Agency
FHB	-	Fuel Handling Building
FCV	-	Flow Control Valve
FSAR	-	Final Safety Analysis Report
GAP	-	Government Accountability Project
GC	-	General Construction
GDT	-	Gas Decay Tank
GONPRAC	-	General Office Nuclear Plant Review and Audit Committee
HFT	-	Hot Functional Test

I&C	-	Instrumentation and Control
IE	-	Inspection and Enforcement
INPO	-	Institute of Nuclear Power Operations
IR	-	Inspection Report
ISI	-	Inservice Inspection
LER	-	Licensee Event Report
LCO	-	Limiting Conditions for Operation
LCV	-	Level Control Valve
LHUT	-	Liquid Holdup Tank
LLNL	-	Lawrence Livermore National Laboratory
LT	-	Level Transmitter
MCL	-	Master Completion List
MIDS	-	Moveable Incore Detector System
MM	-	Mechanical Maintenance
MP	-	Maintenance Procedure
MT	-	Magnetic Particle Test
MVR	-	Minor Variation Report
NDE	-	Nondestructive Examination
NED	-	Nuclear Engineering Department
NOV	-	Notice of Violation
NPAP	-	Nuclear Plant Administrative Procedure
NPO	-	Nuclear Power Operations
NPPR	-	Nuclear Plant Problem Report
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSSS	-	Nuclear Steam Supply System
OIR	-	Open Item Report
OP	-	Operating Procedure
OPEG	-	Onsite Plant Engineering Group
OSRG	-	Onsite Safety Review Group
PCV	-	Pressure Control Valve
PN	-	Preliminary Notification
PASS	-	Post Accident Sampling System
PG&E	-	Pacific Gas and Electric
PORV	-	Power Operated Relief Valve
PRT	-	Pressurizer Relief Tank
PSRC	-	Plant Staff Review Committee
PSI	-	Preservice Inspection
PWR	-	Pressurized Water Reactor
QA	-	Quality Assurance
QAM	-	Quality Assurance Manual
QAP	-	Quality Assurance Procedure
QC	-	Quality Control
QCSR	-	Quality Concern Summary Report
QCI	-	Quality Control Instruction
RCA	-	Radiological Controlled Area
RCCA	-	Rod Control Cluster Assembly
RBP	-	Radiation Base Point
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RM	-	Radiation Monitor
RO	-	Reactor Operators

RVLIS	-	Reactor Vessel Level Indications System
RWP	-	Routine Work Permit
SCO	-	Senior Control Operator
SFM	-	Shift Foreman
SI	-	Safety Injection
SOER	-	Significant Operating Experience Report
SPDS	-	Safety Parameter Display System
SRO	-	Senior Reactor Operators
SSER	-	Supplemental Safety Evaluation Report
SSPS	-	Solid State Protection System
STP	-	Surveillance Test Procedure
S/U	-	Start-up
SWP	-	Special Work Permit
SWF	-	Shopwork Follower
TI	-	Temporary Instruction
TMI	-	Three Mile Island
TRG	-	Technical Review Group
TS	-	Technical Specification
USNRC	-	United States Nuclear Regulatory Commission
UV	-	Under Voltage
WGS	-	Waste Gas System