U. S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos. 50-275/84-40 and 50-323/84-27

Docket Nos. 50-275 and 50-323 License No: DPR-80
Construction Permit No: CPPR-69

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

Inspectors: R T Dodds for 1/18/85
M. M. Mendonca, Sr. Resident Inspector Date Signed

R T Dodds for 1/18/85
M. L. Padovan, Resident Inspector Date Signed

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Approved by: R T Dodds 1/18/85
R. T. Dodds, Chief Date Signed

Summary:

Inspection from November 18 through January 5, 1985, (Report Nos. 50-275/84-40 and 50-323/84-27)

Areas Inspected: Routine inspection of plant operations, conditions, and events; hot functional test program; startup test program; independent inspection; and followup of open items, allegations, and LERs. This inspection effort required 392 inspector-hours for Unit 1, and 359 inspector hours for Unit 2 by four resident inspectors.

Results: No violations or deviations were identified.

## 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
*C. L. Eldridge, Quality Control Manager
*R. G. Todaro, Security Supervisor
*D. B. Miklush, Supervisor of Maintenance
*J. A. Sexton, Supervisor of Operations
*J. V. Boots, Supervisor of Chemistry and Radiation Protection
*W. B. McLane, Material and Project Coordination Manager
*L. F. Womack, Engineering Manager
B. W. Giffin, Acting Instrumentation and Control Manager
*E. T. Murphy, Regulatory Compliance Supervisor
*D. A. Taggert, Supervisor of Quality Assurance
*M. N. Norem, Lead Startup Engineer
*R. A. Hobgood, General Construction Quality Control Supervisor
*T. J. Martin, Training Manager
T. W. Rapp, OSRG Supervisor
*W. A. Wogsland, Technical Assistant to NPO Manager

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 on January 11, 1985.

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 limiting conditions for operation as prescribed in the facility Technical Specifications (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 on 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) Operability of selected Engineered Safety Features (ESF) systems by performing comprehensive walkdowns of the system's components.

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. Turbine Trip and Associated Reactor Trip

On December 5, 1984 at 4:36 p.m., Diablo Canyon Unit 1 experienced an inadvertent reactor trip resulting from a manual trip of the main turbine. Just prior to this event, at approximately 30% power, the licensee identified a steam leak on the #1 main steam line turbine drain line to the condenser. In order to repair the steam leak, the licensee planned to reduce main turbine load and reactor power to less than 10%, and then manually trip the main turbine. This would permit the turbine drain line repair to be performed while the reactor was maintained at a low power level.

Main turbine load and reactor power were being reduced in accordance with Operating Procedure (OP) L-5 "Plant Cooldown From Minimum Load to Cold Shutdown." OP L-5 directed the operator to verify the P-10 (Power Range Permissive) status light on control board annunciator panel PK-08 was off, and the P-13 (Turbine Low Power Permissive) and P-7 (Low Power Permissive) status lights were illuminated. With this status light configuration, the Reactor Protection System (RPS) would not automatically trip the reactor when the main turbine was tripped; however, prior to manually tripping the main turbine, the control operator failed to verify that status lights were in the configuration required by OP L-5. Accordingly, when the main turbine was manually tripped, an unexpected reactor trip immediately resulted.

In discussions with licensed operators and members of the licensee's technical staff, the inspector determined several factors contributed to the inadvertent reactor trip. First, operators did not follow OP L-5, in that the correct status light conditions were not verified prior to manually tripping the turbine. This oversight occurred due to the operator's momentary confusion about the interface between P-10, P-13, and P-7 permissives. The operator had verified reactor power was below 10% (as indicated by the illuminated P-10 status light), and was aware turbine load had been decreased below 10%. From these observations, the operator momentarily assumed the reactor trip signal was blocked by the P-7 permissive. However, the control operator subsequently realized P-7 and P-13 annunciator status lights were not in the anticipated condition and meekly voiced his awareness to other operators in the control room. But, these operators were preoccupied with activities to manually trip the turbine and did not acknowledge the control operator's concern.

A second factor contributing to this event was the tendency of the Diablo Canyon licensed operators to focus their attention on non-routine control manipulations (in this case, the manual turbine trip) and neglect concurrent normal routine plant evolutions (such as the permissive signal annunciator status lights). A previous example of this situation at Diablo Canyon Unit 1 was the inadvertent power operated relief valve (PORV) actuation on November 4, 1984. The licensee attributed the inadvertent PORV actuation to the control operator being "momentarily distracted by the power loss to the instrument inverter and did not observe RCS pressure increasing to the PORV lift setpoint" (the timing of these events were such that operator actions were considered appropriate by the inspector).

The inspector discussed these findings with licensee management. Regarding the first item, an Incident Review Board was convened to discuss methods to prevent recurrences of similar problems and reduce the number of operator errors in general. Plant management also addressed the inspector's findings concerning event followup, in that the dissemination of operating information was not as timely as warranted by the event. An operating experience logbook, which will be updated by plant operators and maintained by the Shift Technical Advisor, may improve performance in this area. In response to the inspector's second finding, licensee management agreed to additional management consultation with operations personnel to assure control operators maintain their attention on overall plant activities, rather than focusing their concentration on any one specific control manipulation. The results of management's response will be followed up during normal inspection activities.

Another factor contributing to this event was the existence of temporary setpoints on the turbine impulse pressure instrumentation that licensed operators were not aware of. These setpoints are by general practice set conservatively and then adjusted as plant specific data is obtained during startup testing. Licensed operators were trained that the P-13 permissive signal would be available whenever turbine first stage impulse pressure (load) was less than 10%. In actuality, during startup testing, the P-13 signal at Diablo Canyon Unit 1 was not discovered to be generated until approximately 5.1% turbine load. Plant Technical

Specifications (TS) specify the turbine impulse chamber pressure P-13 setpoint shall be set at "less than 10% rated thermal power (RTP) turbine impulse pressure equivalent." For conservatism, the licensee limits the setpoint to 9.5% RTP, and sets the P-13 pressure instrument bistable trip at an equivalent value for increasing turbine load. However, for decreasing turbine load, the bistable reset was adjusted for 8.5% turbine impulse pressure trip and reset functions were adjusted for a 1% span in accordance with the licensee's instrumentation and control practices. Additionally, other turbine impulse chamber pressure vs. turbine power instrumentation calibration inaccuracies (inherent in turbine design) further reduced the 8.5% setpoint to about 5.1% turbine impulse pressure. These inaccuracies were corrected during startup testing at the 50% power level. However, until startup testing is completed, and appropriate instrumentation calibrations are not finalized. The Instrumentation and Controls (I&C) Department has reviewed setpoints, and communicated tentative instrumentation setpoint information to the Operations Department to avoid such problems in the future.

c. Reactor Trip and Subsequent Safety Injection

On November 24, 1984, while at approximately 32% power, a malfunction of the Unit 1 main turbine digital electro-hydraulic (DEH) control system caused a sudden load reduction. Since the rod control system was in manual for flux mapping, the load reduction caused an increase in the average temperature of the reactor coolant (Tavg). The 40% condenser dump valves failed to open, and Tavg accordingly increased to approximately 570 degrees F before the 35% atmospheric dump valves opened. Opening of the 35% dump valves depressurized the steam generators and, coincident with the high Tavg, created a swell in steam generator water levels sufficient to trip the main turbine on high-high steam generator level (greater than 67% level on narrow range instrumentation). The turbine trip directly caused a corresponding reactor trip.

In accordance with Emergency Procedure OP-0.1 "Reactor Trip Response with no Safety Injection," steam dump control was switched from the "Tavg" to the "Steam Pressure" mode of control. This resulted in an unexpected, immediate opening of the 40% condenser steam dump valves, which produced a high steam flow and reactor coolant system cooldown to the low-low Tavg setpoint. The high steam flow coincident with low-low Tavg initiated a safety injection.

The licensee's investigation of this event revealed that the rapid load reduction was caused by a loose connection on a DEH pressure transmitter. The 40% condenser steam dump valves failed to open because their controls had been wired in accordance with a PG&E wiring drawing which did not correctly implement the design logic (two leads were reversed in the connection from the Hagan racks to the auxiliary relay panel). The error was missed during review of the drawing and again during early startup testing (due to the nature of the startup test), but the licensee indicated that the wiring error would have been revealed by a 50% load rejection startup test. Both the drawing and the reversed electrical connections have been corrected on Unit 1 and Unit 2. In discussions with the inspector, the licensee indicated that an engineering review of all other candidate wiring connections from the Hagan rack to the auxiliary relay panel was performed. No incorrect wiring diagrams were identified.

The safety injection was caused by personnel error, in that a licensed operator had previously failed to reset steam dump valve pressure controller HC 507 for normal operation when the turbine was placed on line. To prevent recurrence of this event, Procedures EP 0.1 and OP L-2 have been revised to include instructions to check the controller setting and ensure that Tavg is near the no-load value before changing to "Steam Pressure" mode. In addition, the Shift Turnover Checklist is being revised to require the listing of abnormal controller settings. A logbook of controller settings has also been established to assure operator awareness of all such controllers.

d. Feedwater Isolation and Turbine Trip

While aligning the 40% (Condenser) Steam Dump Valves, the control setpoint for these valves was raised by the operators to prevent inadvertent dump valve operation. During this evolution reactor power was at 2% and steam generator 1-2 pressure increased to approximately 1040 psig. The 10% (atmospheric) steam dump valves, which were set at 1035 psig, did not open prior to the lowest setpoint steam generator 1-2 relief valve (RV-7) lifting. The lifting of RV-7 caused a swell in steam generator 1-2 level and the associated steam generator high-high level permissive (P-14) actuated the required feedwater isolation and turbine trip signals. The feedwater system was unisolated, the main feed pump restarted, the turbine trip reset, and the plant startup continued.

The licensee declared a significant event at 11:57 a.m. on December 15, 1984. The event was subsequently determined to be non-reportable; however, LER 84-35 will be issued by the licensee for information only.

This event has been documented in the operating experience logbook. During future operations of unisolating the 40% steam dump valves, the 10% steam dump valve setpoints will be lowered to prevent lifting of the safety valves prior to the 10% steam dump valves, thereby preventing a recurrence of this event. Additionally, the licensee will evaluate the safety valve setpoint and steam dump control system to assure appropriate operation in the future.

e. Diesel Generator 1-2 Start

On December 15, 1984, at 11:16 p.m. diesel generator (DG) 1-2 started due to loss of power to 4KV Bus G. The event occurred while manually transferring from startup to auxiliary power. The operator did not verify auxiliary power feeder breaker (52-HG-13) was shut before opening startup power feeder breaker (52-HG-14). As a result, power was lost to Bus G, DG 1-2 started, and all applicable safety related equipment was automatically loaded on the bus.

Licensee management has briefed all licensed operators on the importance of ensuring incoming power supply breakers are shut and power sources are correctly paralleled before opening the on-line power source breakers. The licensee declared a significant event and will follow up with LER 84-34.

f. Unit 2 Containment Integrity

The inspectors observed construction activities associated with the Unit 2 containment. Applicable administrative controls were examined to assure containment integrity was maintained following completion of the integrated leak rate test. Construction activities have been less extensive than those for Unit 1 at a comparable time. The administrative controls were identical to those for Unit 1, both in procedural requirements and actual implementation. Additionally, the construction work activities for Unit 2 have been extended in time with a commensurate reduction in work density. The inspector concluded that Unit 2 containment integrity has been acceptably maintained and associated administrative controls have been properly implemented. Open item 50-323/84-16-01 is closed.

g. General Work Controls

Ongoing observation by inspectors of work controls for contractor personnel have continued. Furthermore, the resident inspectors have conducted a meeting with newly formed Bechtel Construction Site Support Group (BSSG) management, which included a discussion of construction/operations interface. Improvements in this area have been observed. Construction management (both licensee and contractor) plan to continue aggressive control of work activities. Accordingly, open item 50-275/83-28-01 is closed.

h. Reactor Trip on Net Load Rejection Startup Test

At 7:45 pm on January 2, 1985, while performing the net load rejection startup test from 50% power, a reactor trip was experienced. The startup test required opening main transformer bank high side breakers, PCB 632 and 532. The turbine governor and intercept valves closed to provide turbine overspeed protection as designed; however, the turbine governor and intercept valves did not reopen in time to avoid a drop in generator frequency. This frequency drop resulted in a loss of reactor coolant system flow rate which caused a reactor trip about 23 seconds after the grid output breakers were opened. All four reactor coolant pumps were stripped from their normal power supplies (auxiliary bus) on under frequency, such that natural circulation existed for about four minutes before reactor coolant pumps were restarted.

All safety-related systems responded as designed. Diesel generator 1-2 unexpectedly started on undervoltage, but did not pick up any loads as power was being provided to the applicable vital bus by an alternate power supply (startup bus). The diesel generator was manually shutdown upon verification of acceptable power supplies. Automatic diesel generator starts due to the non-safety related automatic transfer feature, from auxiliary power to startup power, have been previously experienced, and will continue to be experienced (January 5, 1985 Diesel 1-1 started during startup testing). Finally, two Containment Fan Cooler Units failed to restart at high speed on bus transfer from auxiliary to startup. This failure is not safety-related and has previously been experienced due to the breaker size. The licensee is evaluating these non-safety related equipment problems.

Plant operators responded in accordance with plant procedures for reactor trip. The plant was stabilized, trip review and analysis of the initiating event were acceptably complete, prior to restart and continuation of the testing program. Results from the event analysis determined that failure of the governor and intercept valves to reopen, and allow the turbine to pick up generator load, was due to a failure of a solenoid valve in the electro-hydraulic control system. This valve has been replaced. A four hour report was made via the Emergency Notification System to the NRC Operations Center at 8:59 p.m. January 2, 1985.

i. <u>Reactivity Excursion Causes Reactor Trip from Turbine Trip</u>

A reactor trip occurred during power ascension operations, at about 1:55 p.m. on January 4, 1985, as a result of reactor power exceeding 10% with the turbine in a tripped condition.

Just prior to the event, initial plant conditions were as follows: reactor power at 8%, both motor driven auxiliary feedwater (AFW) pumps operating, main feedwater (MFW) pump 1-1 in manual operation maintaining steam generator water level (SGWL) via the FW bypass valves, MFW pump 1-2 in standby, main turbine rolling at 1800 rpm under no-load, and one condensate and booster pump set in operation. Plant operators were preparing to synchronize and parallel the main generator to the offsite electrical distribution grid and then raise plant power to 50%.

Almost immediately after an operator started condensate and booster pump set 1-2, at about 1:47 p.m., MFW pump 1-1 tripped from low lube oil pressure. Operators attempted to re-establish MFW flow commensurate with steam flow by running up standby MFW pump 1-2. However, MFW pump 1-2 experienced speed control problems and proved unstable. SGWL's were decreasing due to the steam flow/feed flow mismatch, as both AFW pumps can only provide enough flow for up to about 4% power. In order to minimize steam flow, operators manually tripped the main turbine and reduced reactor power by manually inserting control rods (in effect reducing heat generation and steam dump demand). With reactor power lowered to about 1%, a significant cooldown affect of the RCS began when AFW flow exceeded steam flow, and control systems continued to demand maximum AFW flowrate inorder to recover SGWL's. The rapid overfeeding of colder FW into the SG water volume caused Tavg to steadily drop. When Tavg fell below the minimum allowed temperature of 541° F, TS 3.1.1.4 required the operator to restore the lowest loop Tavg within fifteen minutes or shutdown the plant. Thus, inorder to compensate for cooldown and restore RCS Tavg, the operator raised reactor power by manually withdrawing control rods. The combined reactivity additions from simultaneous control rod withdrawal and a negative moderator temperature coefficient were sufficient to increase reactor power above the P-10 setpoint of 10%. Once P-10 was made up, the low power permissive P-7 was defeated resulting in a reactor trip from a turbine trip as turbine trip signal will remain locked in until the main turbine is re-latched.

During the event, in conjunction with efforts to operate MFW pump 1-2, operator attempts to manually start turbine driven AFW pump 1-1 were unsuccessful. The steam inlet isolation motor operated valve FCV-95 did not respond to operator manipulation of the remote valve position control switch. AFW pump 1-1 was then declared inoperable and the applicable TS action statement was entered. The automatic start feature was not challenged during the transient. A few hours later, after minor torque switch adjustments, FCV-95 was satisfactorily cycled several times and AFW pump 1-1 was returned to operable status. In addition, the maintenance department has performed a review of other motor operated valves to ensure similar adjustments were not required. These licensee actions were deemed appropriate and timely.

The major cause contributing to this event appears to have been an unexpected voltage reduction on the supporting 12 KV bus due to the large starting current associated with the simultaneous energization of a condensate-booster pump set. During this voltage transient lube oil pump discharge pressure for MFW pump 1-1 dropped below the low pressure trip setpoint. Although subsequent operator actions did not preclude a reactor trip, the licensee considered them to be appropriate. The inspector discussed this event with the operations staff and attended the applicable technical review group meeting. For corrective action, the licensee has instituted an engineering study to evaluate recommendations regarding transformer tap changes. Futhermore, the entire event and its causes were discussed in subsequent pre-shift operation briefings. Also, the training department for licensed operators has begun reviewing the feasibility of incorporating this event into a training scenario on the simulator. The inspector considers the licensee's assessment and proposed corrective actions to be acceptable.

No violations or deviations were identified.

3. Maintenance

The inspectors observed portions of, and reviewed records on safety related components, to assure that the activities were conducted in accordance with approved procedures, technical specifications, and appropriate industry codes and standards for the following maintenance activities.

a. Rigging and Hoisting Equipment Inspection and Maintenance

The inspector observed portions of the subject maintenance activity. This activity was conducted to comply with the requirements of NUREG 0612 and the licensees preventive maintenance program. The inspector observed the disassembly, inspection and reassembly of a three-quarter ton come-a-long. Work was performed in accordance with Maintenance Procedure M-50.1 and was documented on the appropriate maintenance history card. The maintenance personnel involved were familiar with the procedural and mechanical aspects of the work.

b. Preventive Maintenance on Control Room Ventilation Fan

The inspectors observed selected portions of preventive maintenance on control room ventilation fan CR 35. This work was in accordance with preventive maintenance worksheet activity number 52678. Work activities included bearing inspection and lubrication, motor alignment, and visual examination of belts, filters, and cooling coils. The inspectors verified compliance to applicable equipment clearance and technical specification operability requirements.

No violations or deviations were identified.

4. Surveillance

By direct observation and record review of licensee surveillance testing, the inspectors verified that the following activities were performed in accordance with technical specification requirements and implementing plant procedures.

a. Functional Test of a Containment Pressure Channel

The inspectors observed a functional test of containment pressure channel 936. This test verified that the containment pressure channel was operable; and that the associated alarm and protection setpoints, for containment high and high-high pressure, were within required acceptance criteria.

Surveillance was performed in accordance with licensee reviewed and approved surveillance test procedure (STP) I-15A, in order to satisfy the technical specification monthly analog channel operational test requirements. Channel 936 was removed and later returned to service in accordance with the STP. Associated procedural steps were verified by an additional qualified technician. The technicians maintained proper communication with the control room operators during alarm and protection channel actuations to assure operator awareness on TS operability requirements. Equipment used for this test was as specified in the procedure, and was properly calibrated. Data sheets for STP I-15A were accurately and neatly kept, and subsequently reviewed by an Instrumentation and Controls foreman.

b. Triaxial Accelerometer Channel Check

The inspectors observed selected poritons of STP I-37C, Recording Triaxial Accelerometer Channel Check", which provided a qualitative verification of the functional status of the Kinemetrics Strong Motion Accelerograph System. The Shift Foreman was properly informed prior to testing and upon completion of testing by I&C technicians performing this STP. The results of STP I-37C were reviewed by the Instrument Maintenance Foreman and Instrumentation and Control Supervisor.

c. Main Turbine Valve Testing

The inspectors observed portions of STP M-21C, "Main Turbine Valve Testing." Turbine overspeed protection operability required by TS 4.3.4.1.2, was tested by this STP. All main steam stop, governor, reheat stop, and interceptor valves were determined to be operable. The results of STP M 21C were reviewed by the Shift Foreman and Power Production Engineer.

d. Calibration of Source Range Nuclear Instrumentation Channel

Source range (SR) channel N-32 was removed from service in accordance with STP-I-4B1 (revision 3), "Removal of a Source Range Channel from Service", in order to perform a required 18 month re-calibration. The inspector monitored step-by-step performance, and documentation, of this activity by I&C technicians using a required SR Channel Calibration/Maintenance Summary Sheet.

Installation of in-calibration test equipment and collection of as-found data in accordance with STP-I-4B2 (revision 4), "Calibration Procedure for SR Channel," was also monitored by the inspector. Several data points were observed to be outside allowed acceptance criteria, and were appropriately referred to the I&C foreman for evaluation.

No violations or deviations were identified.

5. Technical Specification (TS) Review and Comparison to As-built Condition (Unit 2)

Proposed Technical Specifications (TS) for Unit 2 were examined by the inspectors for clarity, enforceability, and consistency with plant configuration. This overview also included detailed examinations of selected limiting conditions for operation, surveillance requirements, design features, and administrative controls of the TS. Several minor administrative discrepancies with TS and the updated Final Safety Analysis Report (FSAR) were noted and subsequently brought to the licensee's and NRR's attention for resolution.

A unit specific checklist was developed by the inspector to identify mode dependent TS which could be verified by control room indications. Walkdowns using this checklist demonstrated that a large percentage of Unit 2 TS were clearly verifiable within the control room, and were consistent with control board and equipment configuration. Furthermore, the consistency of FSAR and TS requirements with actual plant configuration outside the control room was examined by walkdowns of four Engineered Safety Feature fluid systems, and selected instrumentation and controls associated with these systems. This established confidence that plant configuration was in accordance with FSAR requirements, and compliance to TS could be verified by in-plant observations.

No violations or deviations were identified.

6. Safety Review Committee Activity

Continuous review and audit of overall activities affecting nuclear power plant safety during licensed operation are conducted by on-site and off-site review committees. Commitments in FSAR section 13.4 and requirements in T.S. sections 6.2 and 6.5 describe the composition, purpose, and responsibility of: 1) General Office Nuclear Plant Review and Audit Committee (GONPRAC), an independent offsite committee to review and audit activities related to nuclear safety and environmental concerns; 2) Onsite Safety Review Group (OSRG), an independent onsite group to continuously examine and verify overall quality of plant operations; and 3) Plant Staff Review Committee (PSRC) an onsite, advisory body for the Plant Manager to review operating plant activities related to nuclear safety. Each of these safety review organizations has a written charter which prescribes a program necessary to implement T.S./FSAR requirements and commitments. Additional written procedures are used to supplement committee charters with detailed instructions which address the objectives for conducting meetings, performing reviews/audits of required plant related activities, content and distribution of minutes, and specific responsibilities.

The inspection scope was to verify that each safety review organization has:

a. established a written charter in conformance with applicable FSAR commitments, ANSI recommendations, and requirements of T.S.;

b. developed written program procedures to define methods for implementing the charter prescribed responsibilities for review of plant activities related to safety; and

c. worked in a fashion that acceptably fulfills all charter requirements.

During the course of inspection, the following documents pertaining to OSRG, PSRC, and GONPRAC were examined in detail by the inspector:

- Committee charters for OSRG (dated 10/17/84), GONPRAC (dated 2/1/84), and PSRC (dated 6/1/84)

- T.S. sections 6.2.3., 6.5.1, and 6.5.2, respectively
- FSAR update sections 13.4.2.1, 13.4.2.2, and 13.4.2.3, respectively
- ANSI 18.7-1976 section 4 (applies to PSRC and GONPRAC only)
- Safety Evaluation Report (SER) section 13.4 (applies to PSRC and GONPRAC only)
- Supplement 12 to the SER section I.B.1.2 (applies to OSRG only)
- Nuclear Plant Administrative Procedure (NPAP) A-2 Rev. 3 (applies to PSRC only)
- Nuclear Power Generation (NPG) Proc. 5.11 Rev 0 (applies to OSRG only) and 5.13 Rev. 0 (applies to GONPRAC only)
- OSRG, PSRC, and GONPRAC meeting minutes of 1984
- OSRG open items list and recommendations letter file

The inspector also conducted interviews and/or discussions with the OSRG chairman, PSRC members (acting chairman and secretary), and a GONPRAC member (Technical Assistant to the Vice President). Furthermore, the inspector attended an OSRG meeting and several PSRC meetings.

After evaluating the information identified above, the inspector determined that the charters for OSRG, PSRC, and GONPRAC satisfactorily meet the Technical Specifications and intent of the FSAR.

Certain weaknesses concerning procedural guidance for program implementation were identified. First, programmatic instructions in NPG-5.11 require OSRG members to develop and implement working procedures describing, "the methodology required to conduct the reviews, perform evaluations and make recommendations." These working procedures have not been developed. Secondly, NPAP A-2 requires the PSRC to review proposed procedure changes, tests or experiments, to determine whether or not they involve an "unreviewed safety or environmental question." A standard methodology of evaluation and analysis for performing 10 CFR 50.59 reviews of proposed procedure changes, test or experiments, has not been defined by procedure. And finally, GONPRAC charter requirements in NPG-5.13 state, "this committee will also review activities of the OSRG and assure that appropriate corrective actions and recommendations of this group are effectively implemented." The methodology for followup by GONPRAC and the applicable affected department responsibility for timely response, to OSRG recommendations, have not been proceduralized.

The licensee had also identified most of the preceding procedural weaknesses and certain corrective actions were being initiated.

The conduct of safety committee activities will be evaluated further during a future inspection. Although, at this formative stage of assessment, the inspector has perceived some particular problems with: (1) an excessive number of long outstanding OSRG open items and unresolved recommendations, which have received marginal GONPRAC attention; and (2) not all areas subject to OSRG review identified in the charter were being addressed.

Until followup inspection effort ascertains adequate resolution of these concerns and those identified earlier. The inspector considers the following items will require further review and/or corrective action by the licensee:

- Development and implementation of procedural guidance for OSRG and PSRC activities - Open Item 84-27-01.
- Increased involvement and/or development of procedural/policy guidance by GONPRAC to assure OSRG recommendations are effectively resolved - Unresolved item 84-27-01.

7. Unit 2 Operational Staffing

The inspector reviewed the FSAR and proposed Technical Specifications to verify operational staffing requirements. The licensee has committed to American National Standards Institute (ANSI) N 18.1 - 1971, "Selection and Training of Nuclear Power Plant Personnel." Qualification records of licensed operators, unlicensed operators, radiochemist, mechanics, welders, electricians, instrumentation and control technicians, and repairmen were examined on a sample basis for compliance to ANSI N 18.1. Although, only a few minor errors in documentation were noted by the inspector, licensee management has agressively pursued this area. In response to the inspector's findings, ANSI qualification records have been reorganized and a complete audit of the program has been initiated by the licensee.

Current proposed staffing levels appear to be adequate for operation of Unit 2. There are a few specific areas which are not up to proposed staffing levels; these areas have been discussed with the appropriate licensee managers. The licensee's Personnel Department is currently pursuing staffing of these vacancies with qualified personnel.

No violations or deviations were identified.

8. Training

An inspector reviewed the licensee's overall training and retraining program for nonlicensed employees. Additionally, general training of licensed employees and training of Shift Technical Advisors (STAs) was evaluated. Craft, technical, and other nonlicensed employees were interviewed to determine if their level of training was commensurate with licensee training commitments. Initial employee training and requalification training (such as, industrial safety, security procedures, emergency plan, and radiological health and safety training) appeared consistent with program requirements and industry standards. Training records for STAs also indicated that STA training was also conducted in accordance with licensee commitments.

The licensee is developing a training program which will meet the Institute for Nuclear Power Operations (INPO) Accreditation Criteria for the following areas:

- Non-licensed Operator Training
- Licensed Operator Training
- Licensed Operator Requalification Training
- STA Training
- Instrumentation and Control Technician Training
- Electrical Maintenance Personnel Training
- Mechanical Maintenance Personnel Training
- Chemistry Technician Training
- Radiological Protection Technician Training
- Manager and Technical Staff Training

Currently, a "self evaluation report" of proposed operator training and requalification programs is being developed by the licensee. This report is scheduled to be submitted to INPO in June, 1985. Another self evaluation report encompassing maintenance and technical personnel training programs will be submitted to INPO by June, 1986. Accreditation is normally awarded following a favorable INPO Accrediting Board decision based upon satisfactory review of self evaluation report contents and site team visits.

No violations or deviations were identified.

9. Unit 1 Plant Shutdown from Outside the Main Control Room (MCR)

S/U TP 41.1 for "Plant Shutdown from Outside the Main Control Room" was reviewed in inspection report 50-275/84-22. An inspector witnessed the conduct of this test between 5:30 p.m. and 9:30 p.m. on January 5, 1985.

In accordance with S/U TP 40.0, "Startup Program Master Document", a reactor trip from 50% power was accomplished by performing S/U TP 43.5, "Rod Group Drop and Plant Trip." At about 6:35 p.m., the inspector observed a negative rate reactor trip caused by the planned dropping of two group 1 rods in control bank C from the fully withdrawn position (228 steps). S/U TP 43.5 initialized plant conditions for S/U TP 41.1.

Immediately following the reactor trip initiated from outside the main control room (MCR) a limited test crew of six, selected from the previous operating shift, manned the Hot Shutdown Panel (HSDP) and Dedicated Shutdown Panel (DSP). During "simulated control room inaccessibility" the test crew was in constant, direct telephone communication with licensed operators in the MCR. Control of vital plant components were transferred from the MCR to the HSDP by the test crew. After approximately 90 minutes, stable hot standby plant conditions were established (in accordance with applicable NPO emergency and operating procedures) within operational limits prescribed by S/U TP 41.1 for the following parameters: SG pressure, SG water level, Pressurizer level and pressure, and RCS cold leg and hot leg temperatures. These conditions were maintained and monitored from the HSDP and DSP for 30 minutes.

Upon successful completion of S/U TP 41.1, "to demonstrate that hot standby conditions can be established and maintained from outside the MCR," control of plant components were transferred back to the MCR. Except for unanticipated lifting of the lowest setpoint SG 1-2 safety valve, auto-start of DG 1-1, and failure of CFCU's to restart (refer to inspection report item 2.i), all equipment and I&C systems appeared to function appropriately. SG safety valve RV-7 has been recently observed to lift at lower than its normal setpoint (refer to inspection item 2.d in this report). The maintenance and operations departments are aware and pursuing this item accordingly.

Personnel conducting the tests appeared to conduct the tests in a competent and professional manner. The performance of the tests was accomplished in a well coordinated fashion.

No violations or deviations were identified.

10. Unit 2 Preoperational Emergency Procedures

The inspectors reviewed plant emergency operating procedures related to recovery from a reactor trip and recovery from a reactor trip coincident with a safety injection. These procedures were the same as for Unit 1. They were formulated in accordance with nuclear plant administrative procedural requirements, and appropriately address the required elements for the specific events.

No violations or deviations were identified.

11. License Event Report (LER) Follow-up (Unit 1)

Circumstances and corrective actions described in the LERs listed below were examined. The inspectors verified that these LERs were reviewed by the licensee and reported to the NRC within required time intervals. The inspectors also ensured appropriate corrective actions were established and applicable events were accurately described. Accordingly, the following LERs are considered closed.

LER No. 84-26: Resolution of mispositioned moveable incore detectors has been reviewed in Inspection Reports 84-26 and 84-32.

LER No. 84-27: This diesel generator start has been reviewed in Inspection Report 84-33.

LER No. 84-28: Resolution of excess oxygen concentration in the Gaseous Radwaste System has been reviewed in Inspection Report 84-33.

LER No. 84-29: Containment ventilation isolation on loss of power to radiation monitors has been reviewed in Inspection Report 84-33.

LER No. 84-30: This event is discussed in section 2.c of this report and has been acceptably reported.

LER No. 84-31: This turbine trip and subsequent reactor trip were due mainly to equipment malfunction on a flow control valve for steam generator feedwater flow. The controller was replaced and acceptably tested.

LER No. 84-32: This event is discussed in section 2.b of this report.

LER No. 84-33: During a startup, the source range nuclear instrumentation trip setpoint on high flux was reached prior to the intermediate range permissive that blocks the trip. Corrective action included compensation for core burnup on the intermediate range nuclear instrumentation.

No violations or deviations were identified.

12. Allegation Followup

Task: Allegation or Concern No. 1189

ATS No: RV-84-A069

a. Characterization

Material used to fabricate certain Unit 2 pipe hangers was substandard. Specifically, a sample of square steel tubing from purchase order number 14817 had a variation in corner radii and an internal lamination with inclusions extending most of the way around the piece.

b. Implied Significance to Plant Design, Construction, or Operation

Failure to utilize high quality fabrication material might result in pipe hangers which would not be capable of performing their intended functions.

c. Assessment of Safety Significance

As a result of shop fabrication cutting operations, Pullman Power Products found an 8 foot length of 3 x 3 x 1/4 inch structural steel tube which contained an unacceptable mid-thickness lamination (seam) through the entire circumference. Additionally, two of the tubing's four corners had improper corner radii (less than twice the wall thickness). These discrepancies were found prior to installation. This condition was documented in Pullman Discrepancy Report (DR) #8488.

An investigation of the DR revealed that 1,000 feet of the 3 x 3 x 1/4 inch steel tube was procured under Pullman Purchase Order #7177-14817. The previously mentioned 8 foot section was rejected from the original lot to prevent use. Another 200 feet of the steel tube, from the same purchase order, was found in Pullman's Class 1 material storage area. Inspection confirmed this tube steel had proper corner dimensions. Additionally, when pipe supports were fabricated from this 200 feet of steel, no laminations on the cut ends were identified by craft or QC personnel.

Prior to discovery of the substandard piece of tube steel, 128 pipe supports (utilizing 710 feet of the original 1000 feet of tube steel) were installed in Unit 2. These pipe supports were identified, and in all cases the licensee indicated that QC inspection verified proper corner geometry. During the inspection, no visible laminations were reported, either.

Based upon available documentation of the material used for pipe supports, the licensee deduced that the remaining 82 feet of unaccountable tubing was not used for fabrication of pipe supports. The 82 feet of steel tube was considered to be an acceptable amount of scrap for this type of fabrication activity.

In summary, the licensee contends the lamination problem was limited to the one 8 foot section of structural tubing, and this tubing section was not used at Diablo Canyon.

The licensee's investigation results of the 128 pipe supports installed in Unit 2 was independently verified by the inspector on a sampling basis. The inspector randomly selected installed pipe supports which were fabricated from the 3 x 3 x 1/4 structural tubing, and performed an inspection of the corner radii using a skewed fillet gauge. Approximately 12% of the pipe supports were examined. In all cases, the inspector found the tubing corner radii to be uniform.

The licensee's investigation revealed that laminations and incorrect squareness (corner radii) were the result of transitory conditions at the start of tube steel fabrication and forming operations.

d. Staff Position

The staff finds that the licensee properly identified this item and dispositioned it accordingly and concludes that there is acceptable assurance that substandard steel tubing was not utilized in pipe supports at Diablo Canyon Unit 2.

e. Action Required

No further action is required.

No violations or deviations were identified.

13. Open Item Followup

a. Unit 1

(1) Power Ascension Test Procedure for Shutdown from Outside the Control Room (Open Item 84-22-01, Closed)

Startup Test Procedure (S/U TP) No. 41.1 for "Plant Shutdown for Outside the Main Control Room", was reviewed in inspection report 50-275/84-22. Several issues of concern were addressed to the licensee's S/U engineering staff for resolution. The inspector has since reviewed the resultant procedure revisions, which included revision three of S/U TP 41.1 and a new addendum to S/U TP 37.20 (pre-op test,"Control Room Inaccessibility"). These changes satisfactorily address all previously identified inspection findings. This open item is closed.

(2) Power Ascension Test Procedure "Net Load Rejection" (Open Item 84-22-02, Closed)

S/U TP 43.2 for "Net Load Trip from 100% Power" was reviewed in inspection report 50-275/84-22. Several issues of concern were addressed to the licensee's S/U engineering staff for resolution. The inspector has since reviewed the updated FSAR and revision three of S/U TP 43.2. These changes satisfactorily address all previously identified inspection findings. This open item is closed.

(3) Maintenance Trending Program (Open item 83-12-02, Closed)

The licensee's nuclear plant administrative procedure C-40 supplement 2 requires each department to establish a schedule of trending activities. This open item is closed.

No violations or deviations were identified.

14. Unit 2 Hot Functional Test (HFT)

The inspectors reviewed selected HFT procedures (identified below) and witnessed their performance. In general, these procedures acceptably established test conditions, precautions, prerequisites, test instructions, and acceptance criteria. Where applicable, system walkdowns were specified and performed for thermal movement and leakage observations. All tests witnessed by the inspectors were acceptably performed, e.g., procedural compliance, staffing, prerequisites met and data collected for evaluation. Preliminary test results indicated that acceptance criteria were met or would be addressed.

The inspectors noted a large number of startup problems were discovered during the HFT program implementation which were subsequently resolved or will be resolved. Along with equipment and I&C system problems, many procedure discrepancies and deficiencies were also identified which required on-the-spot changes. The licensee's startup and operations organizations know these problems require considerable attention and that this work may impact upon established schedules. In the past the licensee has carefully addressed such problems, and did not allow schedule pressures to impact on acceptable resolution of problems identified during the testing program. The licensee's Startup and Operations departments plan to continue this careful process to assure Unit 2 startup proceeds as effectively as Unit 1. Future startup testing plans have been discussed by the inspectors with licensee management to assure they will be consistently implemented throughout all levels of the organization.

Tests which were witnessed by the inspectors included:

- Residual Heat Removal System Test During Cooldown
- Steam Dump System Performance
- Plant Cooldown from Outside Control Room
- Control Room Inaccessibility
- 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
- Incore Thermocouple and Resistance Temperature Detector Cross Calibration

In addition, an inspector reviewed the completed maintenance work package, which included documented test data, for the Pressurizer Safety Valve Setpoint Verification accomplished by Nuclear Plant Operation maintenance personnel.

No violations or deviations were identified.

15. <u>Unresolved Items</u>

Paragraph 6 contains an unresolved item. An unresolved item is a matter about which more information is required in order to ascertain whether it is an acceptable item, an open item, a deviation, or a violation.

16. <u>Exit Meeting</u>

On January 11, 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.