U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/90-13 and 50-323/90-13

Docket Nos: 50-275 and 50-323

License Nos: DPR-80 and DPR-82

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

Facility Name: Diablo Canyon Units 1 and 2

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

Inspection Conducted: April 22 through June 9, 1990

Inspectors: P. P. Narbut, Senior Resident Inspector

K. E. Johnston, Resident Inspector

Approved by: [signature] 7-13-90
S. A. Richards, Chief, Reactor Projects Branch Date Signed

Summary:

Inspection from April 22 through June 9, 1990 (Report Nos. 50-275/90-13 and 50-323/90-13)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 30702, 30703, 35502, 35702, 37700, 37701, 37702, 37828, 40500, 40704, 42700, 61726, 62702, 62703, 71707, 90712, 92701, 92702, 92720, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions on Strengths and Weaknesses:

The licensee completed the Unit 2 third refueling outage in 57 days, seven days ahead of schedule, and established a site record for the shortest refueling outage achieved at Diablo Canyon. The licensee demonstrated, by overcoming hardware problems encountered during startup, that they have become experienced at timely correction of hardware difficulties which potentially preclude operation.

In situations where operation is not in jeopardy, however, the licensee continues to be untimely on occasion in establishing the root cause of problems, particularly when personnel are involved, and continues to be untimely in determining and implementing corrective action to prevent recurrences. Additionally, the licensee management systems designed to recognize, raise and pursue the resolution of problems were lacking during the report period.

The circumstances surrounding the two violations identified in this report clearly illustrate the above weaknesses. The Unit 2 Auxiliary Feedwater Pump was oversped on April 24, 1990. The licensee quickly resolved hardware problems, including overpressurized piping, and brought the reactor critical on April 28, 1990. The timeliness of licensee action to determine the cause of the incident and to develop permanent corrective action was decidedly different. The licensee did not convene a technical review group for the incident until June 19, 1990, almost two months after the event, and at the urging of the NRC.

Quality Control independent review of the work order involved in the speed governor replacement did not identify that the instructions were lacking essential information which led to an overspeed. Personnel performing the work did not follow the procedure, but this essential fault was not noted by the licensee review of the event.

The report also describes a Unit 2 load rejection which occurred on May 5, 1990. The licensee had not yet convened a review group for the event as of June 22, 1990. The licensee has been requested at weekly meetings to hasten the resolution of these and other issues from previous monthly reports.

Significant Safety Matters: None.

Summary of Violations and Deviations:

One violation was assessed for an inadequate procedure and another for failure to follow a procedure. Both violations involved the circumstances surrounding the overspeed of the Unit 2 turbine driven auxiliary feedwater pump, as described in section 4b of this report.

Open Items Summary:

Two new items were opened for the violations described in Appendix A.

Sixteen open items were closed as discussed in sections 7 and 8 of this report.

DETAILS

1. Persons Contacted

*J. D. Townsend, Vice President, Diablo Canyon Operations & Plant Manager
*D. B. Miklush, Assistant Plant Manager, Operations Services
*M. J. Angus, Assistant Plant Manager, Technical Services
*B. W. Giffin, Assistant Plant Manager, Maintenance Services
W. G. Crockett, Assistant Plant Manager, Support Services
*W. D. Barkhuff, Acting Quality Control Manager
T. A. Bennett, Mechanical Maintenance Manager
D. A. Taggert, Director Quality Support
*T. L. Grebel, Regulatory Compliance Supervisor
H. J. Phillips, Electrical Maintenance Manager
*R. C. Washington, Acting Instrumentation and Controls Manager
*J. A. Shoulders, Onsite Project Engineering Group Manager
M. G. Burgess, System Engineering Manager
S. R. Fridley, Operations Manager
R. Gray, Radiation Protection Manager
E. C. Connell, Assistant Project Engineer

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

*Denotes those attending the exit interview on June 22, 1990.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 remained at power during the reporting period. Unit 2 started the reporting period in a refueling outage and completed the outage on April 30, 1990, when the unit output breakers were closed. The outage was a success for the licensee in that it was completed in 57 days, the shortest outage yet experienced by the licensee. On its return to full power, the unit experienced a load rejection from 42% power caused by a loose connection in a control device.

3. Operational Safety Verification (71707)

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 Operations (LCOs) as prescribed in the facility Technical Specifications (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, and trends were reviewed for compliance with regulatory requirements.

Shift turnovers were observed on a sample basis to verify that all pertinent information of plant status was relayed. During each week, the inspectors toured the accessible areas of the facility to observe the following:

(a) General plant and equipment conditions.

(b) Fire hazards and fire fighting equipment.

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

(d) Interiors of electrical and control panels.

(e) Plant housekeeping and cleanliness.

(f) Engineered safety feature equipment alignment and conditions.

(g) Storage of pressurized gas bottles.

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. Radiological Protection

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were generally aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA consideration was found to be an integral part of each RWP (Radiation Work Permit).

c. Physical Security (71707)

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Unit 2 Main Steam Isolation Valve Signal During Plant Heatup

On April 22, 1990, during the Unit 2 heatup following refueling, a main steam isolation signal was received, resulting in the closing of the open main steam isolation bypass valves. The signal was generated when two separate steam flow channels actuated on high steam flow signals. However, the signal was not generated by an actual high steam flow condition. Upon subsequent venting it was determined that gas had been entrained in the sensing lines for the two transmitters.

An NCR (DC2-90-TI-N031) and an LER (50-323/90-05, dated May 22, 1990) were issued by the licensee. The LER stated four possible causes of gas entrainment including improper backfill of the instrument and entrained gas from the integrated leak rate test of containment (ILRT). The LER concluded without any explanation that the most probable cause was improper backfilling by the technician. The LER did state that an absolute root cause could not be determined.

The inspector requested that the licensee reevaluate the LER based on the fact that the corrective action did not appear to be broad enough in scope. The corrective action was to revise the procedure for backfilling the main steam flow transmitters. If improper backfilling is considered the most likely cause, then instruction or training for the backfilling of all pressure transmitters is warranted, rather than a revision to a procedure applicable only to main steam flow transmitters. If the licensee concludes (as indicated by discussions with I&C engineers) that the problem is limited to main steam flow transmitters due to their history of performance during startup, then periodic blowdowns triggered by operations actions, such as venting off nitrogen, is indicated and should be controlled in operations procedures and not in an I&C calibration procedure.

The inspector concluded that the corrective action described in the LER had not been well developed. Based on discussions with the licensee, the LER was reviewed by all proper organizations. The licensee committed to revisit and revise the LER (LER 50-323/90-05-LO, Open).

b. Unit 2 Auxiliary Feedwater Pump Overspeed Trip

On April 24, 1990, the Unit 2 turbine driven auxiliary feedwater (TDAFW) pump oversped during cold start testing. The overspeed condition was terminated by the mechanical overspeed trip mechanism, a backup device. The primary device, the hydraulic turbine governor, had failed to control speed.

To evaluate the TDAFW pump overspeed trip, the licensee initiated an Event Response Plan (ERP). Information regarding the overspeed condition and the resultant pressure transient were provided by a

strip chart recording of system pressure and statements by operators and system engineers regarding observed speed. Test instrumentation indicated offscale as a result of the event. The licensee concluded that the overspeed trip mechanism operated as designed. This conclusion was based on successful repeated testing of the overspeed trip mechanism just prior to the overspeed event. The overspeed trip setpoint was previously established by design to maintain downstream pressure less than 2500 psi, providing adequate margin for system overpressure protection. A walkdown and visual inspection was performed by design engineering personnel and no piping distress was noted.

The strip chart recording of the test indicated that the TDAFW pump had operated as expected as it accelerated to its operating speed. However, at 18 seconds after it had been started and only shortly after achieving its operating point, the pump speed dropped slightly and then rose dramatically.

The staff involved in the ERP determined that the most likely cause of the overspeed condition was residual air in the oil of the turbine governor. The governor had been replaced during the refueling outage. According to the system engineer, steps had not been taken during the initial starts of the TDAFW pump to bleed air which may have been entrained in the oil during the replacement process. The system engineer and a vendor representative were in attendance during the initial speed adjustments. After the overspeed event, the licensee performed air removal operations. Subsequently, two cold starts were successfully performed as well as a number of hot starts, and the pump was declared operable.

In follow-up to the event the inspector observed that on May 19, 1990, nearly a month after the event, an NCR had not yet been initiated. This was discussed with licensee management during an exit meeting on May 19. Additional follow-up on June 12 showed that a non-conformance number had been assigned, but no further action had been taken to document the event, its causes, and the corrective action. The inspector also noted that the licensee's ERP formulated on April 24, 1990, had not been approved nor had the assigned action been completed. This tardiness of action was discussed with the licensee at the June 22, 1990, exit interview, along with the following problems uncovered by the inspector's examination.

Licensee Procedure NPAP-C-40, Revision 3, General Requirements for Plant Maintenance Programs, Paragraph 4.16.1 states in part that maintenance which can affect the performance of safety related equipment shall be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances.

The work order used by the licensee for the replacement of the AFW governor was work order C0056311. Step 2 of the work order was intended to adjust the newly installed governor and stated in part, "at the direction of the system engineer adjust the Woodward governor in accordance with Woodward manual, page 8 through 17."

The work order instructions were not appropriate to the circumstances in that the Woodward manual instructions pages 6 and 7 for venting the air out of the governor were not included. The lack of appropriate instructions is an apparent violation (Item 50-323/90-13-01).

Additionally, the system engineer in attendance during the adjustment evolution stated to the inspector that she was not aware that the work order required her to direct the adjustment of the governor. She stated that she and the pump vendor had assumed that the pump was vented prior to testing. She stated that the mechanic maintained possession of the work order and she had not seen the step.

The inspector reviewed the work order and discussed it with the mechanic. The mechanic stated that it was unclear who was in charge in the pump speed adjustment in that operations personnel ran the equipment; the maintenance mechanic had the work order and was present to assist; and a maintenance engineer, the system engineer, and the vendor representative were present. The mechanic was the individual who signed off all the steps in the work order activity (General Activity 2) to adjust the governor. It appears that the mechanic made inappropriate sign-offs in the work order. Specifically:

- o Prerequisite F stated in part, "Tailboard with the system engineer and the vendor representative if available." Based on the system engineer statement, the "tailboard", which is a preparatory meeting and a discussion of the job (in PG&E vernacular), was not done. The system engineer was unaware of the step to adjust the speed and her role in it.

- o Step 3 of activity 2 was to record the actual turbine speed, in RPM, achieved. The step is signed off by the mechanic, but the RPM is not recorded.

- o Step 4 requires inspecting for leaks and recording results on the work order summary sheet. The results were not recorded, but the step was signed off.

- o Step 6 requires the foreman, in the function of independent verifier, to ensure all signatures are entered and all work performed has been entered on the summary sheet. The mechanic inappropriately signed off this step on April 23, 1990; the foreman did not sign this verification.

- o The final review by maintenance (Page 05, "Final Review") was performed by the foreman and signed off on April 23, 1990. The review and signature was inappropriate in that the aforementioned discrepancies were not noted by the foreman.

The licensee's procedure for completing work orders, AP-C-40S3, Revision 12, Section 4.8.1, states in part that work shall be performed in accordance with the instructions provided by the work

order. Attachment 6.3 of the procedure, Step 13k, states in part that persons performing work shall identify completed steps by entering initials and the date under the "COMPLT" column.

The failure to complete work and documentation associated with the work order for adjusting the AFW governor in accordance with the work order is an apparent violation (Item 50-323/90-13-02).

Other weaknesses were identified in examining this item:

- Lack of Aggressive Resolution of Root Cause and Corrective Action

  Although the event happened on April 24, 1990, and an ERP was organized that day, the pursuit of action was conducted aggressively only to the point of declaring the pump operable. The ERP was not followed up, and the draft ERP was not signed for approval as of June 14, 1990. A non-conformance was not written until prompted by the NRC. A NCR number (DC2-90-TN-N040) was reserved on May 22, 1990. The licensee's actions in this matter are considered very untimely. This includes the fact that a technical review group was not convened to review the NCR until June 19, 1990. It is noted that PG&E's administrative procedures indicate that the technical review group shall be established in a timely manner, consistent with the significance of the problem. Additionally, the technical review group should also be convened within 10 working days of initiating an NCR.

- Inappropriate Absence of a Detailed Procedure

  The setting up of a governor is a complex task and should have been performed under the auspices of a detailed procedure instead of a one sentence invocation of a vendor technical manual, in the opinion of the inspector. The licensee's procedures (AP-C 40S3, Section 4 and NPAP-C-48, Section 4.16) suggest that the licensee's philosophy agrees, and that stated philosophy is to use detailed procedures for significant and/or complex maintenance tasks and to use a work order as a coordinating document. The licensee has existing detailed procedures for similar governors on the emergency diesel generators. The mechanical maintenance manager stated that he agreed with the inspector and that the cause of the absence of a detailed procedure would be addressed in the non-conformance.

- Lack of Effective Problem Management

  The tardiness of the licensee actions in reorganizing and dealing with the cause of and lessons learned from the overspeed problem appear to suggest that management oversight is not sufficient. None of the licensee's existing oversight systems appeared to recognize and track the problem to completion. The Quality Control organization was approached by the inspector, and they were not aware of a lack of progress on

the problem. As an aside, QC had approved the work order and therefore may have been part of the problem in that they did not recognize the inappropriateness of adjusting a complex new governor using a difficult vendor technical manual.

Additionally, the QC organization recently changed their procedure for review of completed work orders. Instead of reviewing all completed safety work orders, they are now obligated to review them on a surveillance basis only. The reduction in QC effort may be premature.

The violations and apparent weaknesses were discussed with licensee management at the exit interview on June 22, 1990.

c. Unit 2 Reactor Coolant Pump Bus Instrumentation Failure

On April 27, 1990, at 4:52 a.m., control room annunciators and indications were received on non-vital 12KV Bus E. The bus supplies power to two Reactor Coolant Pumps (RCP's) as well as other non-safety related loads, including one circulating water pump. It was apparent that the indications had resulted from an equipment problem and not a loss of bus voltage. Indications included the loss of potential lights on the control board switches for the Bus E motors, a 12KV bus undervoltage alarm, and trip lights for RCP undervoltage protection channel IV.

Upon initial review it was determined that all the failed instrumentation was fed from one set of potential transformers (PTs). It was postulated that the event had resulted from the failure of a PT fuse.

During subsequent troubleshooting activities on April 27, it was discovered that one of the three bus underfrequency relays was inoperable. The relay, which inputs to a 2 out of 3 reactor trip logic, was required to be tripped within 6 hours of it becoming inoperable in accordance with Technical Specification 3.3.1. This was not accomplished until 3:25 p.m.. In response to this failure to comply with the technical specifications, the licensee initiated a LER (LER 50-323/90-06). The consequences of failing to place the channel in a tripped status were limited since the remaining underfrequency relays on Bus E could have provided a reactor trip as well as all three of the underfrequency channels on 12KV Bus D. Since both 12KV Bus D and E were supplied by the same transformer, they would have sensed the same underfrequency condition.

The inoperable underfrequency relay had not been identified initially because there were no direct indications that the relay was inoperable, and the operators were unaware of the feature which inhibits relay actuation when the relay is deenergized. Corrective actions were taken to revise operating procedures and operator training to make operators aware of the inhibit feature and provide appropriate actions. This LER is closed (LER 50-323/90-06-LO, closed).

On May 11, 1990, the licensee entered Technical Specification (TS) 3.0.3 to examine the PT drawer to determine the cause of its failure. This required that the PT drawer be deenergized, making all three 12KV Bus E underfrequency relays inoperable and necessitating the entry into TS 3.0.3. The licensee had performed a safety evaluation to address the consequences of the job. The safety evaluation and work scope were approved by the Plant Safety Review Committee. The inspector reviewed the licensee's safety analysis and observed the inspection of the PT drawers. During the PT drawer inspection, it was determined that one PT had a fault and that its replacement was necessary. The licensee left the 12KV Bus E instrumentation in its as found condition.

The licensee made preparations to replace the failed PT. As part of the preparation, on June 1, 1990, the licensee requested a one time extension from the NRC of the action time of TS 3.0.3 from one to four hours to allow the replacement of the PT while at power. This request was approved and the transformer was successfully replaced on June 11, 1990.

d. Unit 2 Refueling Outage Ends

On April 28, 1990, Unit 2 achieved post refueling criticality and on April 30, the Unit outage officially ended when the turbine generator was paralleled to the grid. The licensee completed the outage in 57 days versus the originally scheduled 63 days.

e. Steam Flow Transmitters Installed Backwards

On April 30, 1990, the licensee was preparing to parallel the Unit 2 generator to the grid. With steam flowing for the first time since the refueling outage, the steam flow indicators did not respond properly to increasing flow. Investigation revealed that two main steam flow transmitters had been installed backwards; that is, their low side tubing had been installed on the high side of the transmitter and vice versa.

The licensee prepared a non-conformance report NCR DC2-90-TI-N039 and a LER 2-90-006-00 which states a supplemental LER will be submitted to provide the root cause and corrective action.

The inspectors review of the licensee's actions raised questions regarding the root cause established in the non-conformance report. The inspector had several meetings with licensee I&C personnel and will follow-up this item through the LER and NCR reviews when the licensee finalizes the root cause and corrective action. The licensee's initial root cause appeared to be in error based on the inspector's review of the transmitter calibration data.

This incident is a second example of licensee maintenance personnel not following their work instructions and is similar to the violation described in paragraph 4b of this report.

f. Diesel Generator Failed Test

On April 30, 1990, Diesel Generator 1-1 did not pass a periodic start test. The diesel's field did not flash, and the electric speed governor did not control the speed to 900 rpm as required. Licensee troubleshooting was extensive, but did not identify a definitive root cause. The relays and connections which could cause such a problem were examined and tested, but no problem was found. The operators repeated testing using normal and backup DC power sources, and no problems were identified. The licensee initiated an increased frequency of testing, weekly vice monthly for one month. No additional problems were encountered. The licensee suspects, but could not prove, operator error in switch selection while setting up the test run. The licensee issued a Quality Evaluation on May 2, 1990.

The licensee also issued a non-conformance, report NCR DC1-90 TN N038, and a Special Report to the NRC (Special Report 90-1, PG&E Letter No. DCL 90-141, dated May 30, 1990).

g. <u>Steam Transient on Unit 2 Due to Broken Steam Dump Valve to Condenser</u>

On May 1, 1990, Unit 2 experienced a steam transient. The transient was controlled by plant systems and did not result in a reactor trip. Operators stated that the newly installed digital feedwater control system controlled steam generator levels well and avoided the trip.

The transient occurred with the reactor at about 12% and steam dumps in manual control with steam going to the condenser through the steam dump system. One steam dump valve (PCV-8) rapidly opened for unexplained reasons. Reactor coolant temperature dropped quickly. Operators responded quickly and manually started closing the other dump valves. When the reactor coolant system cooled to Lo Lo Tave, the dumps quickly closed automatically. Reactor coolant temperature and steam generator pressure went up rapidly, and when the Lo Lo Tave permissive cleared, PCV-8 opened again. Operators manually opened other steam dumps to stabilize reactor coolant temperature, and some atmospheric dumps actuated. System stabilization, with normal temperatures and pressures, followed.

The root cause was assessed by the licensee and a vendor representative after isolation and disassembly of PCV-8. The root cause was a broken internal weld which the vendor stated has occasionally failed, but not often enough to warrant a vendor bulletin. PCV-8, however, moved with such force that valve operator parts were bent and deformed. The licensee was asked about their plans for replacement. As of June 21, 1990, the licensee had not decided on whether similar model valves would be examined and/or have an available newer internal kit installed (which the vendor stated would preclude additional failures). The licensee prepared QE 007588 at the suggestion of the inspector. The inspector suggested to the licensee at the exit that their actions in this matter were not timely.

h. Unit 2 Load Rejection

On May 5, 1990, Unit 2 experienced a load rejection from 42% power when the output breakers (PCBs 542 and 642) opened following the actuation of the generator backup relay (21G2). Relay 21G2 is a slow acting relay designed to detect faults from the generator output through the transmission lines. The unit, as designed, experienced a turbine trip but no reactor trip.

In the investigation of the cause of the trip it was determined that no actual electrical fault existed. Electrical maintenance, after an extensive search, discovered the root cause to be a loose fuse clip in the secondary side of the potential transformer supplying the backup relay. The loss of electrical contact as a result of the loose fuse clip also resulted in the actuation of generator undervoltage relay 27G2.

A similar event occurred on April 16, 1989, when Unit 2 was at 50% power. That load rejection resulted in a reactor trip because a circulating water pump motor did not transfer to startup power due to an equipment lineup error. Although extensive investigations were performed following the event, the cause was not found at that time. As a result of the investigation into the May 5, 1990, load rejection, the licensee considers the loose fuse clip to be the cause of both events. In addressing the issue of why the loose fuse clip was not found during the 1989 investigation, the licensee determined that the loose fuse clip and the intermittent contact which resulted were not easily apparent. Following both events, successful continuity checks were made across the fuse.

The licensee initiated a non-conformance report (NCR DC2 EM-N044). The inspector will review the licensee's evaluation, root cause determination, and corrective actions in conjunction with a review of the NCR. The inspector noted to licensee management that a technical review group meeting had not been held as of June 21, 1990.

i. Unit 2 Turbine Trip

On May 6, 1990, two turbine trips occurred while the licensee was attempting to quickly slow the spinning turbine for rebalancing and vibration reduction. Following the turbine trips, reactor power was stabilized at 3% power.

Prior to the first turbine trip, operators had brought the turbine to synchronous speed (1800 rpm) following an attempt to balance a low pressure turbine rotor. However, at 1800 rpm, the turbine had experienced excessive vibration, and the operators decided to decrease turbine speed to a point where vibrations were reduced. The operators were aware that a harmonic frequency existed at approximately 1000 rpm and were concerned that lingering at 1000 rpm in coast down could result in damaging vibration. The decision was made to hold speed at 1200 rpm, where vibration levels were acceptable, and develop a plan to bring the turbine to rest.

The operations shift developed a plan in the event vibration during coast down became unacceptable. Part of the plan was to break condenser vacuum, which would more rapidly slow the turbine, in the event vibration became critical.

One of the preparations taken to mitigate the effects of a loss of vacuum was to raise steam generator level manually above programmed level. This was done so that when the condenser became unavailable, the steam generator level shrink (which would result from the closure of the steam dumps, the loss of main feedwater and the initiation of the auxiliary feedwater pumps) would not cause a reactor trip on low steam generator level (7.2% of narrow range steam generator level).

However, the operator controlling feedwater flow misjudged the control of feedwater, and feedwater flow was increased too rapidly. As a result, one steam generator level "swelled" to the high level turbine trip setpoint (P-14). The steam generator swell primarily resulted from the heating in the steam generator of the increased mass of feedwater and the operation of the steam dumps, which were acting to reduce increasing steam header pressure.

The second turbine trip occurred during the attempts to stabilize steam generator level. The steam generator level transient was due to the swing in reactor power and difficulty in establishing digital feedwater and steam dump control.

The licensee initiated NCR DC2-90 DP-N037 and issued LER 2-90-007. The inspector will review the licensee's root cause determination and corrective actions to prevent recurrence in a future review of the LER.

j. Unit 2 Reactor Coolant Flow Measurement

On May 9, 1990, discussions with plant engineering personnel raised questions regarding reactor coolant flow measurements. During Unit 2 restart, reactor coolant system (RCS) flow measurement was performed at 50% power. RCS flow is determined by performing a heat balance of the secondary plant and comparing the result to the primary side. The differential temperature across the core was measured and found to be approximately 6% more than expected. The reactor coolant flow was then calculated to be slightly below technical specification limits. The licensee's investigation determined that actual RCS flow had not changed and calculated flow had apparently changed due to inaccuracies during the measurement process. Specifically, engineering had measured an increase in RCS hot leg temperatures which resulted in the apparent reduction in calculated RCS flow.

The licensee postulated, and was supported by Westinghouse, that thermal layers had developed in RCS hotleg flow as a result of a "low leakage" core design. The core design has older more depleted fuel assemblies on the core perimeter and newer assemblies towards the center in an effort to reduce neutron fluence to the reactor

vessel. As a result, the power produced by the perimeter elements is less than the power produced in the center of the core. This results in a reduced reactor coolant temperature rise on the core perimeter and an increased temperature rise at the core center. The thermal layer theory postulates that the coolant is not thoroughly mixed by the time it reaches the scoops for the hot leg temperature instrumentation, and an accurate realistic average hot leg temperature is therefore not measured. The licensee referenced evidence that this phenomenon had been experienced at other U.S. facilities and had been computer modeled in Japan.

The licensee had confidence that the reduced RCS flow measurement was not a physical reality based on the following:

- The direct reading of RCS flow, the RCS loop elbow tap flow instruments, were reading within 1% of their historical values.

- Modifications performed during the outage (the use of Vantage 5 fuel and steam generator tube plugging) should not have resulted in additional flow resistance.

- Core physics measurements and the secondary plant calorimetric performed during startup indicated that the steam generator or the lower core plate had not been unexpectedly blocked.

The first RCS flow measurement was made at 50% power. Flow measurements performed at 75% and 100% power indicated that RCS flow met Technical Specification limits but were not as great as the flow measured during the previous fuel cycle. Flow measurements made at higher power are more accurate than at low power.

Regional and NRC headquarters personnel discussed this phenomenon with licensee technical and management personnel. The licensee intends to work closely with the owners' group and is considering a technical specification change to provide greater margin in "minimum" flow values in the technical specification.

k. Unit 1 P-9 Setpoint Calculation

On May 16, 1990, the acting plant manager informed the NRC resident inspector that the licensee analysis performed to support a technical specification change had used improper data regarding steam dump actuation setpoints for Unit 1. Specifically, the licensee's NSSS vendor used Unit 2 steam dump actuation setpoints for analysis for both plants. Since Unit 2 steam dump actuation setpoints are different from Unit 1's, the analysis was not accurate nor conservative for Unit 1.

The calculation had been done to support a technical specification change to increase the P-9 (Turbine trip/reactor trip) permissive bistable setpoint from 10% to 50% power. The calculation was to demonstrate that during a turbine trip from 50% power, the reactor need not be tripped and that the pressurizer power operated relief valves (PORV) would not be challenged in the ensuing transient.

The licensee management considered that technical specifications were met as long as reactor power exceeded 50% in the realm where P-9 was not a factor. The licensee issued night orders to operators to not operate in the range to 10% to 50% power. The Unit was at 100% power at the time.

The P-9 setpoint was changed back to 10% on Unit 1 on May 26, 1990. A justification for continued operation was issued May 31, 1990, addressing the issue.

The licensee engineering organization stated that they had initiated a non-conformance on the subject which will address the root cause of the use of the wrong input by Westinghouse. The resident inspector discussed the issue with regional and NRC headquarters staff.

The licensee vendor did additional calculations presented in a letter, PGE 90-688, dated June 19, 1990, which showed the Unit 1 steam dump actuation setpoints and response times were acceptable as is and did not result in challenging a pressurizer PORV. The licensee changed the Unit 1 P-9 setpoint back to 50% on June 21, 1990.

The inspector will follow the licensee root cause analysis and actions through the non conformance report.

l. Unit 1 Charging Line Weld Leak

On May 21, 1990, the licensee discovered a cracked weld in a non-isolable portion of the charging system on a vent line. The licensee repaired the weld with a leak repair device with suitable external strength members, in accordance with proper procedures and a design change. The licensee issued a non-conformance report, DC1-90-TN N041, and will perform weld removal and examination for root cause during a suitable plant outage.

m. Unit 2 Letdown Line Leak

On June 5, 1990, a leak in a letdown line weld was discovered in containment. The leaking weld and its section of pipe were cut out and replaced. The removed pipe will be analyzed for root cause per the licensee.

The leak is in the same location as had occurred in June, 1989. The licensee plans a full investigation of the matter. The licensee stated a study of operational weld leaks would be performed to determine if additional broader actions are required.

n. Plant Air Compressors

During the reporting period, the licensee installed two new permanent plant air compressors. The compressors are water cooled and replace the temporary air cooled compressors the plant had been using. During the design change, the licensee encountered

difficulties in coordination of backup air between operations and construction, causing operators to be forced to connect service air to instrument air on May 22, 1990. The licensee performed sampling and analysis to demonstrate instrument air had not been contaminated. Additionally, other problems were encountered which plant management was examining. Specifically, maintenance personnel indicated an absence of documentation such as manuals for the compressors. Initial operation was unreliable due to improperly sized thermal overloads. The licensee stated that they would do a "case study" of the turnover problems.

5. Maintenance (62703)

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

Specific maintenance observations were made regarding the replacement of the Unit 1 potential transformer for Bus E, PCV-8 disassembly and repair including vendor interface, and plant air compressor installation.

In addition, specific maintenance activities on motor operated valves were observed by a specialist inspector during the report period. Also the maintenance attributes of the activities reported in section 4 were examined. Specifically, venting steam flow transmitters (section 4a), lack of venting the AFW pump turbine governor (section 4b), and the improper installation of steam flow transmitters (section 4e) were examined.

Two violations were identified as discussed in paragraph 4b.

6. Surveillance (61726)

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

Surveillance activities examined are described in section 4 of this report. Specifically, surveillance aspects were examined for auxiliary feedwater pump testing (section 4b), diesel generator 1-1 testing (section 4e), and reactor coolant flow measurements (section 4j).

No violations or deviations were identified.

7. Licensee Event Report Follow-up (92700)

The LERs identified below were closed out after review.

Unit 1: 90-06, 88-18-LI, 89-14-LO, 90-01-LO, 90-04-LO

Unit 2: 90-04, 89-12-LO

No violations or deviations were identified.

8. Open Item Follow-up (92703, 92702)

The following open items are closed based on inspector review, based on licensee commitments for action, or based on verification that the licensee has the item being tracked for resolution. Discussion regarding issues or findings are provided where necessary.

- Part 21 reports:

50-275/89-16-P	Part 21:	Limitorque Corp. - Model SMB-2, valve operator housing cover is mismachined.
50-275/89-20-P	Part 21:	Westinghouse/AMP Incorp. - Diffective clip connector in solid state protection systems.
50-275/90-25-P	Part 21:	Limitorque Corp. - potential common failure of SMB-000 & SMB-00 cam type torque switches.
50-275/90-29-P	Part 21:	Dresser pump division - potential failure of safety related injection pumps.

- Follow-up Items:

50-275/88-31-01	Task Force to Resolve RHR Water Hammer on Starts.
50-275/89-09-01	Independent verification of work planning center work order.
50-275/89-21-01	Licensee to evaluate program for floor drain inspection.
50-323/89-01-10	Review licensee's safety evaluation.

- Unresolved Item:

50-275/89-21-04	DG 1-3 control wiring not separated.

9. Exit (30703)

On June 22, 1990, 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.