U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/87-42 and 50-323/87-43

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: November 15 through December 19, 1987

Inspectors: M. M. Mendonca for ---- 1/19/88
L. M. Padovan, Resident Inspector — Date Signed

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Summary:

Inspection from November 15 through December 19, 1987 (Report Nos. 50-275/87-42 and 50-323/87-43)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of on-site events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 25026, 30703, 50095, 61726, 62703, 71707, 71710, 90712, 92701, 92702, and 93702 were applied during this inspection.

Results of Inspection: Two violations in the areas of design control and procedure adherence were identified.

## DETAILS

1. Persons Contacted

J. D. Townsend, Acting Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
J. M. Gisclon, Acting Assistant Plant Manager for Support Services
C. L. Eldridge, Quality Control Manager
*W. D. Barkhuff, Quality Control Lead Engineer
K. C. Doss, On-site Safety Review Group
*S. G. Banton, Engineering Manager
D. B. Miklush, Maintenance Manager
*D. A. Taggert, Director Quality Support
T. J. Martin, Training Manager
*W. G. Crockett, Instrumentation and Control Maintenance Manager
*M. W. Stephens, I&C General Maintenance Foreman
J. V. Boots, Chemistry and Radiation Protection Manager
L. F. Womack, Operations Manager
*D. A. Vosburg, Operations Shift Supervisor
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor

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

* Denotes those attending the exit interview on December 30, 1987.

2. Operational Status of Diablo Canyon Units 1 and 2

During the reporting period of November 15 through December 19, 1987, the Diablo Canyon Units were at power operation and spent fuel pool reracking activities were in progress. Events during the report period are discussed later in this report. A brief description of events and significant occurences follows:

- On November 28, the Unit 2 Fuel Handling Building Ventilation failed and on being reset went into the ESF mode. A 4 hour non-emergency report was made.

- On November 30, Unit 2 valve 8029 containment isolation for pure water supply to containment failed its periodic stroke time test. The valve was subsequently examined, repaired, tested, and declared operable. However, as discovered on December 18, during a subsequent stroke time test, the valve failed again due to the fact that the valve had the wrong springs installed originally in construction and this was not noted during the November repair.

- On December 9, the Unit 2 boric acid evaporator rupture disk failed causing a noble gas release in the Auxiliary Building. The

evaporator had been secured but steam leakage caused heatup and pressurization.

- On December 10, a small fire in a temporary trailer was extinguished by the site fire brigade (see Section 4.a).
- On December 13, Unit 1 had a reactor trip caused by loss of a main feedwater pump during scheduled relay testing.
- On December 16, Unit 1 aborted an attempt to achieve criticality due to a failed circuit card in the rod position overlap counter.
- On December 17, Unit 1 experienced a turbine trip while attempting to increase power due to erratic steam dump operation.
- On December 17, Unit 1 made a mode transition from Mode 2 to Mode 1 with the Containment Spray Tank nominally inoperable due to being below minimum technical specification concentration for NaOH. The basic error was that chemistry personnel rounded the calculation results to an integer (i.e. 29.6 percent was considered to be 30 percent).
- On December 19, Unit 1 returned to power operations but experienced indications of high steam flow at above 40 percent power due to an interlock contact not made up. The contact was repaired and the return to full power resumed.
- On December 20, a hot particle was discovered in the Unit 1 Fuel Handling Building and triggered automatic transfer of the ventilation system to the iodine removal mode. Further fuel storage rack work was suspended to determine corrective action.
- Throughout the period intermittently both units had power reductions to clean condensers due to heavy seas and marine debris.

3. 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 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) Radiation protection controls.

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

(e) Interiors of electrical and control panels.

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

(g) Plant housekeeping and cleanliness.

(h) Essential safety feature equipment alignment and conditions.

(i) 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. Unit 2 Steam Generator Blowdown Temporary Header

On December 8, 1987, during a walkdown of the Unit 1 100' containment penetration area, the inspector discovered a temporary pressure hoses attached from it to drain valves upstream from each of the four steam generator blowdown containment isolation valves. A tag on the header dated October 1, 1987, identified it as "N2 Temporary Manifold" and listed an Action Request (AR) number.

The inspector reviewed the AR which noted that the manifold had been identified on an engineering walkdown and required removal. The inspector discussed this with a senior power production engineer who stated that the manifold had been identified by himself and the site engineering manager during a plant walkdown.

The inspector asked the licensee what controlling document had been used to install the manifold. At the end of the report period, the department which had installed the manifold had not been identified nor had a controlling document been identified. The inspector noted on a walkdown on December 18, 1987, that the header had been removed. This item appeared to be an instance where temporary equipment was installed and left without design control similar to the temporary gauge issue discussed in section 11.a.. At the exit interview, the licensee was requested to address the circumstances of the installation of this temporary manifold in their response to the violation discussed in paragraph 11.a.1) and further to discuss the apparent lack of aggressive investigative and corrective action subsequent to the identification of this problem by plant engineering management on October 1, 1987.

c. Containment Spray Additive Tank NaOH Concentration.

On December 17, 1987, Unit 1 made a Mode transition from Mode 2 to Mode 1 while the Unit 1 Containment Spray Addition Tank was technically inoperable. Chemistry personnel had performed a periodic (6 month frequency) sampling of the tank for NaOH concentration. Technical specifications require a concentration of 30 to 32 percent NaOH. The chemistry personnel obtained a result of 29.6 percent and rounded the result to 30 percent. The inappropriate action was discovered by chemistry supervisory personnel in the morning and corrective action were taken including adding NaOH and initiating a non-conformance (DC1-87-TC-133) for corrective action.

There does not appear to be technical significance to this event since the technical specification allow tank level to be as low as 47 percent with the concentration at 30 percent, whereas the condition was tank level at 77 percent with the concentrations at 29.6 percent.

The inspectors will follow-up the licensees corrective action through the non-conformance process.

No violations or deviations were identified.

4. Onsite Event Follow-up

a. Fire in Temporary Tool Storage Trailer

At 1:27 p.m. on December 10, 1987, the licensee declared an Unusual Event after requesting assistance of the California Department of Forestry (CDF) with a fire in a temporary tool storage trailer. The trailer was located inside the protected area in the vicinity of the Unit 2 main generator transformers. The licensee's fire brigade put out the fire by 1:35 p.m. and the Unusual Event was terminated at 1:57 p.m. when it was determined there was no possibility of a reflash.

The licensee determined that the fire was caused by a 120 volt junction box, possibly overloaded by a portable space heater. The fire burned portions of office equipment and the trailer wall. Assistance of CDF was not required to put out the fire; however, the licensee requested assistance in its investigation.

At no time did the fire jeopardize plant equipment.

b. Reactor Trip Due to Source Range Channel Failure

At 2:27 p.m. on December 13, 1987, with Unit 1 in Mode 3, a reactor trip signal and a subsequent turbine trip signal was generated due to the failure of the detector voltage supply for source range channel N-32. All automatic safety functions responded as required. The unit remained in Mode 3. A 10 CFR 50.72, four hour non-emergency report was made at 3:25 p.m..

The high voltage power supply failed high causing the high source range flux signal and damaging the detector signal pre-amp. The high voltage power supply and the detector signal pre-amp were replaced. The cause of the power supply failure has not been determined, but was considered to be a random electrical component failure. No additional corrective action was deemed necessary by the licensee since this failure was determined to not be a recurring problem. Proper operation of the source range detector and circuitry was verified by test prior to placing the components into service.

Additional followup on this event will be subject of Licensee Event Report 50-275/87-024.

c. Reactor Trip Following a Main Feedwater Pump (MFWP) Trip

At 3:25 a.m. on December 13, 1987, with Unit 1 at 100 percent power, a steam generator 1-4 low low water level reactor trip occurred shortly after a trip of MFWP 1-1. All automatic safety functions responded as required, but some erratic behavior was observed in the operation of the 10 percent atmospheric and 40 percent condenser steam dumps.

The MFWP trip occurred during routine quarterly continuity testing in the safeguards test panel for the solid state protection system (SSPS) MFWP trip circuit.

The operations personnel were performing surveillance test procedure STP M-16P2 which checks continuity of protection circuits. The test involves passing current through the actual actuation circuit using a built-in test circuit which provides enough resistance to prevent actuation solenoid, but enough current to light a test lamp indicating circuit continuity.

The test methodology is not unique to Diablo Canyon and is a relatively standard design. The operator had successfully tested seven relays and upon testing the eighth (relay K621B) received immediate word that the main feedwater pump 1-1 had tripped. Operators properly commenced a rapid load reduction but the reactor tripped on low steam generator level about 45 seconds later.

Slave Relay Testing

In an effort to determine the cause of the trip the licensee took certain actions as described below:

- Interviewed the involved operations personnel and determined that the procedure was followed and no personnel errors were made.

- Performed special testing to evaluate the slave relay circuit to determine if an identifiable failure had occurred. The testing showed that the actuation coil resistance and actuation current were per design and consistent with other coils

(installed and replacement parts). The testing showed that with a shorted test lamp, the resultant current (in static conditions) was below but close to the actuation current and may have caused actuation. The test lamp was found burned out after the reactor trip event.

- Replaced suspect parts, i.e. the test lamp socket, but subsequent testing and examination of the socket did not indicate a problem.

The licensee determined that sufficient troubleshooting had been performed on the slave relay circuit to warrant restart based on a lack of similar problems in the past. The licensee further identified a post startup action to have engineering further evaluate the test circuits since the results of investigation showed the test currents to be surprisingly close to actuation levels. The licensee did not identify a definitive root cause but could not identify additional meaningful actions which could be taken. Additional event description and licensee corrective action is described in Licensee Event Report 50-275/87-23.

Steam Dump Actions

Prior to reactor restart following the trip, the inspectors reviewed the licensee's corrective actions for steam dumps. The licensee determined the following:

- Ten percent atmospheric steam dump PCV-21 operated erratically because the drive arm had become disconnected from the drive rod which transmitted valve stem position to the valve positioner mechanism. The arm was re-attached and a locking compound was applied to the holding nuts on all the 10 percent steam dump valves. PCV-21 was then tested and returned to service.

- Ten percent atmospheric steam dump PCV-22 did not function properly due to a broken position cam support collar, which allowed the positioning cam to shift and become wedged in the cam follower bushing. The support collar and a drive arm that later broke during troubleshooting were repaired.

- Forty percent steam dumps, groups 1 and 2, were isolated and stroke tested using the controller in the control room. They were deemed to be performing correctly by personnel stationed at the valves observing mechanical movement.

The inspector concluded the licensee's review and corrective actions associated with the steam dump systems were inadequate. Through discussions with plant management the inspector expressed the following concerns:

- The necessity for application of locking compound on the 35 percent and 40 percent holding nuts should be determined.

- o Broken drive arms on steam dump positioners had been experienced previously at Diablo Canyon. Actions should be taken to inspect the positioning of the drive rods on the drive arms of all 10, 35, and 40 percent steam dump positions.

- o Incorrect 40 percent steam dump operation was a recurring, uncorrected problem. Operators indicated that 1) during the trip the group 1 dumps were slow to respond, 2) the dumps did not sequence correctly, and 3) the group 2 40 percent dumps (PCVs 8, 10, 11, and 12) initially opened fully and then did not smoothly respond to the controller (HC-507). However, the licensee evaluated the operators concerns and concluded, after simple stroke testing, steam dump operation was satisfactory without any additional repairs.

As a result of these discussions, the licensee addressed the following additional actions:

- o The positioning of the drive rods on the drive arms of the positioners for all steam dumps were inspected, documented and found to be satisfactory.

- o The licensee committed to performing monthly stroke tests of the 40 percent condenser steam dumps utilizing an operating procedure and scheduling this as a recurring task activity which would generate a monthly work order.

- o Develop a plan to remove "wind up" (zero offset) on the eight condenser dump current to pneumatic (I/P) converters (pressure modules), to be scheduled for completion by February 1, 1988.

- o Before criticality, the 40 percent condenser steam dumps were stroked to their mechanical stops and the spring beam assemblies in the positioners were verified to not fall off the positioning cam knees. Prior to exceeding 2 percent reactor power, the 10 percent atmospheric steam dumps were likewise stroked and inspected.

The actions taken for steam dumps were not fully effective as evidenced by the results of an attempted restart. Specifically during plant startup on December 17, 1987, while at 6.5 percent power, Unit 1 experienced a turbine trip on steam generator 1-1 high level (P-14). Since the reactor and turbine were below 10 percent power (P-7), a reactor trip did not occur as designed. While transitioning from Mode 2 to Mode 1 (with feedwater controlled utilizing the manual feedwater bypass control valves); the combination of increasing feedwater flow, increasing Tavg due to manual rod withdrawal, and further steam dump instabilities, resulted in steam generator 1-1 level swell to the P-14 setpoint. The unit was stabilized in Mode 2, and reassessment of the steam dump system was initiated by the licensee.

Licensee management committed that prior to increasing reactor power, the following additional actions would be performed:

- All group 1 40 percent dump valve linkages would be re-inspected for any incurred damage. None was found.

- All 40 percent dump valves would be verified to stroke smoothly in response to slow signal changes from the pressure controller and controller settings would be verified. It was considered the stroke tests previously performed were too rapid to detect a lack of smooth operation under small demand changes.

- Upgrade Group 1 40 percent steam dump valves calibration procedures (loop tests) would be upgraded.

- A complete calibration on the control loops for each group 1 and group 2 40 percent steam dump valves would be performed.

- Temporary monitoring equipment for steam pressure control and group 1 40 percent dump valves would be set up for information purposes should the steam dumps not perform well during attempted restart.

- A shift foreman memorandum would be issued to operations personnel in regard to not attempting restarts with important automatic controls not performing adequately. This was issued as a result of the operations personnel attempting restart on December 17 even though steam dump control had to be placed in manual operation three times to maintain adequate control.

- A new operations order would be issued requiring that additional management personnel must be on shift for any startup. The management personnel designated was the recently created shift supervisor position, which is an adjunct to the Unit shift foreman.

As a result of calibration of the control loops for the group 1 and group 2 40 percent steam dump valves, one group 1 controller and 3 group 2 controllers were found to have "wind-up." Additionally, three out of the four I/P converters on the group 2 valves required replacement. Replacement of one of three I/P converters was observed by the inspector as described in Section 4. b. of this report.

On December 18, 1987, the plant superintendent authorized restart. The 40 percent steam dumps operated smoothly and a return to power was achieved during the night.

Conclusion

The inspectors expressed concerns over several aspects of this reactor trip and return to power.

- First, historically, poor steam dump operation during startup resulting in turbine trips and reactor trips has been discussed with the licensee in the past as an area requiring management attention. This subject was discussed extensively after the

July 1987 return to power of Unit 2; in which, poor steam dump operation in conjunction with a positive moderator temperature coefficient resulted in several aborted attempts to return to power. The NRC inspector believed at that time that the licensee had decided to similarly mechanically and electronically groom the steam dumps prior to all future restarts. While the licensee did isolate the 40 percent steam dumps and cycle them from the hand controller in the control room to verify proper valve sequencing and smooth operation, the inspector believed the grooming did not include many facets of the grooming performed on Unit 2 (such as inspection and adjustment of valve packing and more elaborate electronic testing). Additionally, the NRC believed the licensee had instructed operations personnel not to attempt startups with less than optimum steam dump operation. Nonetheless, restart was attempted and aborted due to less than optimum steam dump operation after minimal maintenance.

o Secondly, the inspectors were concerned regarding plants management's tone to plant staff in the need to return to power. Even though the root cause of the reactor trip, the slave relay circuit was extensively examined, it appeared that the attendant problem of the steam dumps were not properly examined by plant management. In fact, an NRC inspector raised questions regarding the steam dumps on the evening of December 15, when management appeared to be done with the subject. The questions resulted in other actions being taken including full stroking valves to ensure cam followers would not be jammed due to over-travel. The licensee, however, indicated discussions were previously held on the subject of full stroking the valves, but no management direction had occurred prior to the NRC raising the issue.

  Even though some pre-startup grooming of the steam dumps was performed, it was not until after the turbine trip on December 17 that the plant staff embarked on a full electronic grooming of the steam dumps that proved to be the successful approach previously used in July 1987 in the Unit 2 restart.

o Thirdly, the inspectors were concerned with the lack of a formal approach to defining and verifying actions required prior to restart. The licensee's post reactor trip restart review primary procedure,AP A-100S1, does not provide for a specific action definition and tracking methodology. The licensee's recently issued procedure for significant events NPAP C-18 does provide that methodology and could be invoked but was not for this event. The result of the lack of formality was a less than clear definition of actions to be taken and a statement of surprise by corporate and plant management when the steam dumps did not operate smoothly on the December 17 attempted restart and surprise that shift operations personnel continued an attempt to restart with indications of less than optimum steam dump operation. This perception was heightened on December 29, 1987, when reviewing

the Technical Review Group meeting minutes of December 28, 1987, wherein only two corrective actions were identified as a result of the steam dump problems. The identified actions were:

- o Operations to generate a memorandum to address manual to automatic change over of the steam dump controller.

- o Operations to provide GETARS (data gathering computer on turbine trips).

Many actions discussed during the multiple meetings that the plant superintendent held, were not documented in the TRG minutes (which serve as the record of corrective actions taken with respect to the non-conformance). Some of the more important actions include:

- o I/P outputs drift above 3 psi. Informal I&C actions were taken in Unit 2 to periodically check I/P outputs in Unit 2. No commensurate action was taken in Unit 1. No proceduralized action was taken in either Unit. Action appears warranted.

- o A temporary procedure was issued for the Unit 2 restart in July 1987 regarding steam dump grooming. A permanent procedure appears to be required to preclude another plant trip induced by the steam dumps.

- o I/P converters were found with water in them. This has occurred previously in Units 1 and 2. Corrective action appears to be worthy of consideration.

- o I&C personnel stated on December 15, 1987, that the I/P converters were not serviced during the Unit 1 refueling outage. Action to examine the required frequency of this task appears to be warranted.

- o The operations supervisor stated at the December 15, 1987, plant superintendents meeting that operations would initiate a recurring task activity to stroke check valves periodically and that this would be done by February 1, 1988. This action appears to be warranted.

- o On the morning of December 17, 1987, after the turbine trip, plant management personnel decided that future restarts would be done with a shift supervisor on shift. If this action is warranted then a procedure change appears warranted.

- o A locking compound was applied to holding nuts on the drive arm on the 10 percent steam dumps. Consideration was given to doing the same on the 35 percent and 40 percent steam dumps.

- o If determined to be warranted the requirement for locking compound should be incorporated in a maintenance procedure.

The above concerns were discussed with licensee management on December 30, 1987, at the exit meeting. The licensee was requested to carefully consider appropriate actions. Subsequent to that meeting, the licensee indicated the above actions were not included in the TRG meeting minutes because the actions were not contributors to the reactor trip, and all other corrective actions were documented in Action Requests. The licensee's actions will be examined in a future inspection (Follow-up Open Item 50-275/87-42-01).

d. Unit 2 Inoperable Main Steam Seismic Restraint

On December 2, 1987, the onsite project engineering group (OPEG) discovered a seismic pipe restraint on Unit 2 main steam line four to have its south side gap larger than that allowed by its design. The Unit was in Mode 1, power operation. Shortly after the discovery, members of the Plant Staff Review Committee (PSRC) decided that Technical Specification (TS) 3.7.7.1 "Snubbers" was applicable to the restraint, since seismic restraints and snubbers serve similar functions, declared the restraint inoperable, and entered the Action statement related to the TS. This allowed 72 hours to restore the restraint to an operable status and perform an engineering evaluation or declare the attached system inoperable and follow the appropriate Action statement for that system. On December 5, the licensee exited the Action statement when the restraint had been restored to an operable configuration.

On July 6, 1987, following the Unit 2 first refueling outage, during a power ascension walkdown performed by OPEG, the north side shim on restraint 414-415R was found askew with its welds to the restraint broken. The licensee required resolution of this problem prior to exceeding 30 percent power. In the hot condition the shim was pinned by the steam line and could not be moved, As a result, an evaluation was performed and a design change issued to weld the shim in place. This work was completed on July 22, 1987.

A second design change was issued to return the restraint to its original configuration. Physically this required the main steam line to be cold so that it would not rest on the north side shim. The package allowed no due date. The package did specify the work to be done required the line to be cold.

The design change package was issued for work on November 10, 1987, while Unit 2 was in hot standby, using condenser steam dumps for heat removal, following the November 7 motor operated disconnect shutdown. The work was approved by the work planning construction coordinator, and the shift foreman had been notified. This was an error for two reasons. First, the steam line was still hot and rested against the north side support with 80,000 pounds force. Second, the unit was in a mode which required the operability of the steamline and therefore, the restraint.

A third error was made when the workers, who found that the shim was pinned by the steam line, made an unauthorized change to the work

package to remove the whole north side tube support. At this point the restraint became inoperable. In addition, when the north side tube support was removed, the steam line shifted one half inch in the north direction. General construction quality control wrote a minor variation report documenting the unauthorized change to the work package after it had occurred.

On November 14, 1987, Unit 2 returned to power operation. On November 24 the restraint work package was amended and sent back to the field. The tube support with the shim, which had been modified in the shop to correct the askew condition, was welded back into place. In accordance with the drawing, the proper north side gap of 1/32" was allowed. The drawing also specified that the total gap for the north and south side should be no more than 1/8". The south side gap was not inspected at that time.

The oversized gap on the south side of the restraint was discovered on December 2, 1987, when in response to a quality control inspector's request to look at a north side weld crown, OPEG found a half inch at the south side. The OPEG engineer informed the shift foremen of the apparent inoperability of the restraint.

Once the licensee entered the Action statement for TS 3.7.7.1, engineering performed a seismic evaluation of the steam line with the north side support in its as-found condition, and the south side shimmed to leave a total 1/8" gap. When the licensee found the results fell inside design criteria, this modification was performed and completed prior to the expiration 72 hours action time. In addition, the licensee evaluated whether the force relieved at the restraint had affected any other restraint or snubber and found the results to be acceptable. Following this, engineering performed a final evaluation which did not take credit for the restraint. The results of this evaluation determined that stresses to the steam line would have remained below design criteria.

The licensee is currently investigating the program differences which led to this incident and evaluating corrective action including a review of general construction work control and sensitivity of plant personnel to work that may affect configurations assumed in the plants design. Since the corrective actions pending were extensive, the licensee had not completed its non-conformance evaluation prior to the end of the report period.

The activities discussed in this section involved apparent or potential violations of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V. However, since the implications of this incident are serious in that work was authorized which could have rendered a main steam line inoperable during power operations, the adequacy of the corrective actions to prevent recurrence will be carried as a follow-up item (Open Item 50-323/87-43-01)

5. Maintenance

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.

a. Rod Control Bank Overlap

The inspector observed I&C technicians perform corrective maintenance on the Unit 1 rod control bank overlap unit. This maintenance activity consisted of replacement of the "most significant digit" card in the overlap counter, as specified in Work Order C0026067. Required approvals were obtained prior to performance of the activity, and the work and post maintenance testing were conducted in accordance with the work order.

b. Steam Dump Valve Pressure Module Replacement

The inspector observed replacement of pressure module (I/P converter) PM-11 on Unit 1 40 percent steam dump valve PCV-11. In response to Action Request AR A0094336, Work Order C0026192 was issued to perform this corrective maintenance. Replacement of the PM was performed in accordance with the work order, and necessary approvals and equipment clearances were obtained prior to starting the work. Bench calibration of the module was also observed by the inspector.

c. Unit 1 Boron Injection Tank (BIT) Inlet Flow Transmitter (FT-917)

The inspector observed portions of maintenance activities performed to replace the valve manifold for BIT inlet flow transmitter FT-917. The manifold was replaced to eliminate a harmonic in the system which in certain normal operating conditions caused the flow transmitter to read upscale. The licensee had the transmitter vendor representative investigate this anomaly. The representative determined that it was a unique problem caused by the system and not the transmitter. It was determined that slight changes in configuration would eliminate the harmonic so the decision was made to replace the valve manifold with a design easier to manipulate.

The inspector reviewed the I&C portion of the work order to correct the anomalous behavior of FT-917 and discussed the work order with the I&C foreman responsible for the job. The problem first appeared in June 1986 and was identified as a harmonic problem in December 1986. The instrument was taken out of service in accordance with its calibration procedure, STP I-20, in December 1986 and never fully returned to service.

STP I-20 indicated that FT-917 was considered "necessary attendant instrumentation" as defined by the definition of "Operable,"

Technical Specification (TS) 1.21. However, the procedure stated that if the channel fails in Modes 1-4, "complete repairs expeditiously and notify the operator that it will be necessary to infer BIT flow using the developed head of centrifugal charging pumps." However, if FT-917 was considered "necessary attendant instrumentation," it would have required the entry into the Action statement of TS 3.5.2 or 3.5.3, "ECCS Subsystems," for an inoperable flow path from the RWST on a safety injection signal. If FT-917 was not considered "necessary attendant instrumentation," STP I-20 was misleading. Emergency Procedure E-0 required that during a safety injection that BIT flow be verified by checking FI-917 for flow. Since FT-917 was out of service for year it appears that this step should have been expanded to direct the operators to another method of verifying flow. The apparent inconsistency in procedure requirements regarding FI-917 should be resolved. This was discussed with the licensee and will remain an Open Item (follow-up item 50-275/87-42-02).

The inspector observed the welding of fittings to the manifold. The welding was performed in the machine shop by a certified welder under the observation of an inservice inspection (ISI) examiner. The examiner performed preweld and post weld inspections as well as a post weld dye penetrant test. The inspections were performed in accordance with procedures ISI C-852 and N-PT-1. The inspections were not required by he ISI program. The welding was performed in accordance with WPS 4.0. The inspector observed that the procedure covered the welding performed and that the appropriate filler metal was used.

No violations or deviations were identified.

6. Surveillance

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

a. Analog Channels Removal from Service

Surveillance Test Procedure (STP) I-5A "Analog Channel Operational Test - OTDT, OPDT, Tavg, and Delta-T Channels" described analog channel operational testing of the above channels for protection sets I, II, III, and IV. In preparation for this testing the inspector observed I&C technicians removing Unit 1 channels 421 and 422 from service in accordance with STP I-5B1 "Removal from Service..." and Work Order R0033117. The inspector verified required approvals were obtained prior to performing the STP, and the removal from service steps were accomplished as specified in the procedure. Independent verification of the steps was also observed.

b. Unit 2 Steam Generator Pressure Analog Channel Operational Test

The inspector witnessed portions of the Analog Channel Operational Test performed on Unit Steam Generator Pressure Channels 525 and 545. The tests, performed in accordance with Surveillance Test Procedure (STP) I-12, were required to be performed monthly by Technical Specification Table 4.3-2 "Engineered Safety Features Actuation System Instrumentation Surveillance Requirements." The pressure channels provide a comparison of the main steam line pressure for lines two and four which inputs to the differential steam line pressure safety injection initiation logic.

The inspector noted that the test was performed in accordance with the procedure by qualified personnel. The as-found data was found to be within the acceptance criteria. The test was also witnessed by a Quality Control inspector.

No violations or deviations were identified.

7. Engineering Safety Feature Verification

a. Unit 2 Auxiliary Feedwater System Walkdown

The inspector performed a walkdown of the physically accessible portions of the Unit 2 Auxiliary Feedwater System including electrical breakers and control room indication.

No violations or deviations were identified.

8. 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).

No violations or deviations were identified.

9. Physical Security

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.

10. Licensee Event Report Follow-up

a. Status of LERs

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

Unit 1:

Unit 2:

The LERs were reviewed for event description, root cause, corrective actions taken, generic applicability and timeliness of reporting.

The LERs identified below were also closed out after in-office review and on-site follow-up inspections were performed by the inspectors to verify licensee corrective actions:

Unit 1: 87-17, 87-18, 87-20, 87-21, 87-22

Unit 2: 87-24

No violations or deviations were identified.

11. Open Items

a. RHR Temporary Test Gauges (Unresolved Item 50-323/87-38-02 Closed)

Inspection Report (IR) 50-323/87-38 listed five questions the inspector had asked the licensee as a result of the discovery of temporary test gauges on the Unit 2 RHR system. The following is a status of the list of questions at the end of this report period.

1) Was there a design change package or any form of procedural control for the installation of DP gauges 709.5.1 and 709.5.2 to the RHR system instrument lines.

The licensee could find no design and procedural control for the installation of 709.5.1 and 709.52. Both gauges were installed in April 1985, and removed in November 1987 as a result of the inspector's questions. The plant engineering group had initiated a Design Change Request (DCR) in May 1985 to have differential pressure gauges permanently installed, however, due to low priority the DCR never progressed past the review stage.

10 CFR Part 50 Appendix B, criterion III "Design Control" states that: "Design changes...shall be subject to design control measures commensurate with those applied to the original design and approved by the organization that performed the original design unless the applicant designates another responsible organization." In partial implementation of this requirement, Administrative Procedure (AP) C-1 SI Revision 3, "Onsite Review and Handling of Plant Modifications," in affect in April 1985, describes the onsite handling of plant

modifications. This procedure assures that an appropriate design change review is performed.

The licensee did not perform a design change review in accordance with this procedure which would have ensured that design considerations such as seismic qualification were taken into account. Nor did the licensee use any other form of procedural control to assure that the gauges would be removed. As a result, the gauges were installed in April 1985 and remained installed until November 1987, a period of 31 months. This is an apparent violation (50-323/87-43-02).

2) Could the gauges have caused the instrument lines to fail during a seismic event, and if so, what would have been the consequences? (Question 3 in IR 50-323/87-38).

This item remains open with resolution currently scheduled for January 1988. The onsite project engineering group (OPEG) had completed an analysis on December 2, 1987. However, following questions by the inspector, OPEG, plant engineering, and I&C performed a walkdown of the system and committed to perform additional analysis.

3) Was there a design change package or any form of procedural control for the installation of DPI-635x and DPI-647x for Unit 1 other than Nuclear Plant Problem Report (NPPR) DCI-79-TN-P0106?

The licensee could find no design or procedural control, other than the NPPR, for the installations of DPI-635x and DPI-647x. The NPPR was not the appropriate controlling document for the installation of the gauges. The appropriate design control procedure in November 1979, when the gauges were installed was AP C-1 Revision 2, "Design Changes." Step 3 of this procedure required that when a design change is involved in the resolution of a NPPR, the NPPR should be transmitted to the power plant engineer to perform the initial review of the proposed design change. This was not done.

The licensee was requested at the exit interview to verify that the installation of the Unit 1 gauges was satisfactory and to address that verification in their response to the violation discussed in paragraph 11.a.1).

4) What is the appropriate calibration frequency for these gauges and are they out of calibration if the due date has expired?

Due to the confusion as to whether the instrument was temporary or permanent, the calibration frequency was inconsistently established. The standard calibration frequency for a temporary DP gauge was six months, which was the frequency established for the gauges in I&C documentation. In 1985, the standard calibration frequency for a permanently installed DP gauge was three years, which was the frequency displayed on the

calibration sticker. The method of tracking and the standard calibration frequency has changed since October 1985, which should be adequate corrective action to prevent this confusion from recurring. At the close of this reporting period, the licensee had not yet performed a calibration check of the instrumentation.

5) Are there test gauges on other plant safety related systems which have not had the appropriate design review?

   At the end of this report period, the licensee was in the process of establishing a program to identify where temporary gauges have been left on equipment important to safety and where temporary gauges are routinely used. The intent of the program is to establish controls on temporary gauges so that they are installed only when needed and installed in an analyzed configuration.

The open item also discussed an instance where a shift foreman did not have temporary gauges removed following the test of RHR pump 2-2 in accordance with test procedure STP P-3B. Instead the step was marked "N/A" for not applicable and a note was made in the shift foreman's log that the I&C department had been requested to remove the gauges.

The inspector discussed this incident with the licensee. The licensee made the case that the procedure is not closed without the review by the power plant engineer and that the engineer would have noted that the gauges were installed and had them removed. The inspector concurs that due to the increased sensitivity to temporary gauges that this oversite would have been identified. However, the inspector reviewed AP E-4 "Procedures." Step 4.5.2 "Sequence of Steps" says, in part: "A person may alter the sequence of steps in a procedure without approval...when the sequence of steps is clearly arbitrary, the alteration is of a minor nature, and the intent of the procedure, basic methodology, and results could not be affected by the change." In this case the methodology and results of the procedure were not affected by not performing the step. However, the sequence of steps is not clearly arbitrary since it was not the intent of the procedure nor the shift foreman to have the engineer be responsible for having the gauges removed.

The author of STP P-3B stated that intent of the "N/A" box for this step was to allow the step to be bypassed on Unit 1 where the gauges have been permanently installed. However, this is not noted in the procedure.

The inspector discovered the gauges had not been removed five days following the performance of the test. The engineer reviewed the test 10 days following the test. Not removing the temporary gauges in the correct sequence as specified by STP P-3B is an apparent violation of NPAP E-4. This violation is minor, however it another example of plant personnel failing to follow procedure. Other examples include violations issued on June 23, July, 9, and August

7, 1987. In response to these violations the licensee has taken comprehensive corrective actions. Additional action should be considered by the licensee (Open Item 50-323/87-43-03).

The resolution of items 2 and 3, seismic qualification of unit 1 and 2 gauges, item 4, unit 2 gauge calibration, and item 5, planned gauge programs, will be followed in Open Item 50-323/87-43-03. This closes Unresolved item 50-323/87-38-02.

Two violations and no deviations were identified.

12. Independent Inspection

a. Fastener Testing to Determine Conformance with Applicable Material Specifications (NRC Compliance Bulletin 87-02)

On November 6, 1987, the NRC issued NRC Compliance Bulletin 87-02, "Fastener Testing to Determine Conformance with Applicable Material Specifications." The bulletin requested that licensees 1) review their receipt inspection requirements and internal controls for fasteners and 2) independently determine, through testing, whether fasteners (studs, bolts, cap screws and nuts) in stores at their facilities meet required mechanical and chemical specification requirements.

Specifically, the Bulletin requested that licensees select a sample of 10 safety related fasteners (studs, bolts, or cap screws) and 10 non safety related fasteners, including in the sample typical nuts to be used with each fastener, for testing. The testing requirements for the fastener and nuts was specified in the Bulletin. In addition, the Bulletin requested the licensee to review receipt inspection of fasteners and controls utilized during storage and issuance from stock.

At the end of the report period, the licensee had completed its sample selection and had shipped the fasteners and nuts to a contractor to be tested. The inspector observed the sample selection and reviewed the licensee's test instructions.

The licensee selected for testing 20 safety related fasteners, 20 safety related nuts, 14 nonsafety fasteners, and 11 non safety nuts. The Bulletin lists nine fastener material specifications and one nut material specification of interest. The sample of fasteners included representatives of nine material specifications including seven of those listed in the Bulletin. The sample of nuts included representatives of four material specifications including the one recommended by the Bulletin.

The source of fasteners was the site warehouse and general construction stock. The fasteners in the site warehouse represent those currently being used for modifications and maintenance. The fasteners from general construction stock represent those used for plant construction. The majority of the fasteners in the site warehouse were procured from one manufacturer. The fasteners

selected from general construction stock were from a wide variety of manufacturers. A number of the fasteners chosen had markings which were identified in Temporary Instruction 2500/26 as being of interest.

The inspector observed the selection of fasteners and nuts from the site warehouse and general construction stock and noted it was random. In one case the inspector found that one of four nuts pulled from a bin containing SA 194 grade 7 nuts, was marked with a "4" instead of a"7" as the other three were. As a result, the licensee has put the bolts from that bin on hold until testing is complete and an evaluation of cause and corrective action can be identified. Prior to the discovery, no nuts had been issued for use from the bin. The inspector will follow-up the licensee's evaluation in a future report.

The inspector reviewed the licensee's test instructions sent to the testing laboratory. The testing required met or exceeded that specified in the Bulletin. The inspector also found the samples were properly tagged and fastener testing data sheets for each sample contained the right information.

The inspector will conduct a review of the licensee's receipt inspection program and procedures and the licensee's maintenance and warehouse procedures for control of safety-related and non safety-related fasteners in a future report.

13. Exit

On December 30, 1987, 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.