ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
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Dates:	February 23 through April 5, 1997
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Attachment: Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/97-05; 50-362/97-05

This routine announced inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of a regional inspection of the control of radioactive materials.

Operations

- Operations were characterized by conservative actions and methodical progress through the extended Unit 2 refueling outage. Relatively few personnel errors were observed, compared to previous outages. Operations management oversight of control room activities during the outage was essentially continuous, and the active involvement of Station Technical and Nuclear Engineering Design was apparent in the resolution of various emergent issues (Section O1.1).

- Operator performance in starting a reactor coolant pump (RCP) in Unit 2 was strong, and included a thorough prejob briefing, good communications and cross-checking during the evolution, and proper annunciator response (Section O1.2).

- Operator performance during the reactor startup at the end of the Unit 2 refueling outage was good. Operations supervision and Reactor Engineering demonstrated a good oversight of the startup evolution. Operators and Reactor Engineering personnel communicated well and independently performed inverse count rate ratio (ICRR) plotting during the startup. Operators demonstrated good procedure usage and conservative actions (Section O1.3).

- A violation was identified by the inspectors when the pressurizer was cooled down at a rate greater than allowed by Technical Specifications (TS). Operators failed to verify the cooldown rate was within the limit every 30 minutes, as required by Surveillance Requirement (SR) 3.4.3.1.1. Two steps in the Operations procedure for the evolution that would have prevented the violation were not followed. This represented a lapse in the attention to detail by the operator. Additionally, the licensee did not provide the operators with adequate tools (procedures, training, and oversight) to properly perform a pressurizer cooldown and collapse the pressurizer bubble (Section O4.1).

- A lapse in attention to detail in the use of procedures occurred when operators failed to follow the procedure for the mode of withdrawing control element assemblies (CEAs) for a rod drop timing test in Unit 2. This was a noncited violation (Section O4.2).

- Shortly after cooling down to Mode 5, operators did not know the correct shutdown cooling (SDC) flow rate limits. However, the actual flow rate was within the correct limits. This is an example of a lack of awareness of important information, in part due to an incomplete prejob briefing (Section O4.3).

- An operator did not know why one of two SDC isolation valves had position indication and the other did not, when both were required to be open and deenergized. This represented a lapse in attention to detail and a weakness in the awareness of control board indications. The operator's knowledge of the system design and operation was incomplete (Section O4.4).

- A minor noncited violation was identified by the inspectors when operators set the automatic makeup flow rate of the boric acid controller to a value less than allowed by the procedure. This was another example of weakness in the operator's attention to detail (Section O4.5).

<u>Maintenance</u>

- The inspectors observed that the control room emergency air cleanup system (CREACUS) filter unit was open, with personnel and equipment inside, while the CREACUS was still considered operable. Maintenance personnel had inappropriately applied a 1-hour allowance, for CREACUS boundary doors being open, to the CREACUS filter unit access doors. The licensee's subsequent evaluation concluded that the CREACUS remained operable while the doors were open. Licensee management conservatively decided to declare the CREACUS inoperable during future performance of a surveillance activity (Section M1.3).

- The repair of a failed pressurizer instrument nozzle, which had resulted in reactor coolant system (RCS) pressure boundary leakage, satisfied the proper sections of the ASME Code, and was performed as required by the applicable weld procedure specification (WPS). Licensee oversight of contract welders was good (Section M1.4).

- The licensee's actions in response to the identification of pressure boundary leakage through a SDC isolation valve packing leak-off plug were prompt and thorough. The failed plug had met all regulatory requirements for the application, and the internal defects in the plug could not have been identified by the techniques required or implemented for receipt inspection of the plug. The licensee's visual inspection of the plug, that resulted in identifying the failure, exceeded regulatory requirements. Corrective actions were thorough and effective (Section M2.1).

<u>Engineering</u>

- Reactor Engineering proactively used the four safety power channels, in addition to the required use of the two startup channels, to provide criticality projections. An

extra hold point was also added during the startup to ensure that the projections were conservative (Section O1.3).

- A noncited violation was identified after licensee engineers determined that 18 of 65 environmentally- qualified (EQ) Raychem splices exceeded the minimum bend radius criterion in Unit 2. The licensee aggressively inspected all susceptible Unit 2 splices, corrected all identified deficiencies, and performed a thorough operability determination for the Unit 3 splices (Section E1.2).

- A noncited violation was identified after the licensee identified that both Unit 2 pressurizer safety valves had lift setpoints that were outside the TS limits (Section E8.2).

Plant Support

- An adequate program was in place to control radioactive material outside the radiologically controlled area/radioactive material area. No problems were identified with security personnel's involvement with the release of items from the restricted area. Some Health Physics (HP) personnel did not know to perform aggregate surveys of items being released from the restricted area. Radiological areas within the restricted area were properly posted (Section R1.1).

Report Details

Summary of Plant Status

Unit 2 began this inspection period in Mode 5, in the 85th day of the Unit 2 Cycle 9 refueling outage. The unit entered Mode 4 on March 2, 1997, and reentered Mode 5 on March 4, due to RCS pressure boundary leakage from a pressurizer instrument nozzle (Section M1.4). Repairs were made to the nozzle and the RCS was again heated up on March 14, 1997.

While Unit 2 was in Mode 3 on March 19, 1997, leakage from an SDC valve plug caused the unit to again be cooled down (Section M2.1). Mode 5 was entered on March 20. Repairs to the valve were completed and Mode 4 was entered on March 21. However, a steam generator (SG) primary manway leak was discovered, and the unit was returned to Mode 5 on March 23 for repairs (Section E1.1). After the repairs, Mode 4 was reached on March 27, and Mode 3 on March 28, 1997. The unit was started up on March 30 (Section O1.3). The unit entered Mode 1 on March 31, and was synchronized to the grid on April 1, 1997, ending the 122-day Unit 2 Cycle 9 refueling outage. Unit 2 ended this inspection period operating at essentially 100 percent reactor power.

Unit 3 operated at essentially 100 percent reactor power throughout this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Operations during this inspection period were characterized by conservative actions and methodical progress through the challenges of the Unit 2 Cycle 9 outage. Decisions made by operators and management led to successful completion of the outage with relatively few personnel errors. Operations management oversight of control room activities was essentially continuous throughout the outage. Active involvement of Station Technical and Nuclear Design Engineering was also apparent during the outage.

Activities in Unit 3 were kept at a minimum to avoid distractions during the performance of complex activities in Unit 2.

O1.2 RCP Start - Unit 2 (71707)

On March 21, 1997, the inspectors observed the operators perform a start of RCP 2P001, in accordance with Procedure SO23-3-1.7, "Reactor Coolant Pump Operation," Revision 17. The operators used good communications and cross-checking during the evolution. Prior to the pump start, the control room supervisor performed a detailed briefing of pressure control expectations and operator response. The operators appropriately responded to the annunciators received during the performance of the evolution. The inspectors concluded the operators exhibited a strong performance during the RCP start.

O1.3 Reactor Startup - Unit 2

a. Inspection Scope (71707, 37551)

On March 29, 1997, the inspectors observed the reactor startup of Unit 2 following the refueling outage. The inspectors reviewed Procedure SO23-3-1.1, "Reactor Startup," Revision 13, and discussed the startup with Reactor Engineering and Operations personnel.

b. Observations and Findings

Operators performed a detailed prestartup briefing. The operator dedicated to monitoring the startup and withdrawing the CEAs remained focused on the startup evolution. Operations supervision directed the operator withdrawing the CEAs to stop the withdrawal every 25 inches to ensure proper instrument response. This was a more conservative measure than that required by procedure.

Reactor Engineering and a reactor operator independently performed the ICRR plots. The reactor engineer conservatively allowed counts to stabilize for a period greater than the minimum required by Procedure SO23-3-1.1, and used more than the minimum number of count rate readings. In addition to using the two startup channels of nuclear instrumentation, Reactor Engineering also utilized the four excore safety log channels for comparisons of the ICRR plots. Operations and Reactor Engineering thoroughly discussed the results of the ICRR plots to determine if the next hold point was acceptable, and, in one instance, inserted an additional hold point to ensure that the startup proceeded as expected. The inspectors observed good communications between operators and a good Operations and Reactor Engineering supervisory presence.

c. Conclusions

Operators and Reactor Engineering utilized good communications and independent ICRR plotting during the reactor startup. Operations supervision and Reactor Engineering demonstrated a good oversight of the startup evolution. Reactor Engineering proactively used the four log power channels to provide additional criticality projections. Operators demonstrated good procedure usage and conservative actions during the reactor startup.

O2 Operational Status of Facilities and Equipment

O2.1 Safety System Walkdown (71707)

The inspectors performed a walkdown of the Unit 3 auxiliary feedwater system. Only one minor material deficiency was identified (a valve packing leak), which was brought to the attention of Operations personnel. The system was operable and

appeared capable of performing its design functions. Housekeeping in the pump area was excellent, and no discrepant conditions were identified.

O4 Operator Knowledge and Performance

O4.1 Pressurizer Cooldown Rate Limit Exceeded - Unit 2

a. Inspection Scope (71707, 37551, 42700)

On March 4, 1997, the inspectors identified that the operators exceeded the TS limiting condition for operation cooldown limit for the pressurizer. The inspectors discussed the safety consequence of the pressurizer and surge line cooldown with Engineering. The inspectors interviewed the operators involved in the excessive cooldown, reviewed the Procedure SO23-5-1.8, "Shutdown Operations (Mode 5 and 6)," Revision 5, for adequacy, and discussed the cooldown process with the Operations manager.

b. Observations and Findings

Operator Performance

On March 4, 1997, the operators cooled down the pressurizer and collapsed the pressurizer bubble. The inspectors identified that the operators exceeded TS Limiting Condition for Operation 3.4.3.1, which limits the pressurizer maximum cooldown rate to 200°F in any 1-hour period. The inspectors observed that the maximum 1-hour cooldown was approximately 265°F and notified the shift superintendent (SS). The pressurizer temperature had reached its minimum value and was heating up. Therefore, no immediate operator action was required to stop the cooldown. The licensee entered, and complied with, the appropriate action statement for the excessive cooldown.

The inspectors reviewed the operators' plot of the pressurizer cooldown as part of the event followup. The operators plotted the following pressurizer temperatures: at 2:30 p.m., 420°F; at 3 p.m., 380°F; and at 3:30 p.m., 160°F. However, the operators did not evaluate the results to determine the cooldown rate. The inspectors informed the SS at approximately 4 p.m. that the pressurizer cooldown rate limit had been exceeded. The inspectors considered that had the operators not just plotted the pressurizer temperature but also verified the cooldown rate every 30 minutes, as required by SR 3.4.3.1.1, they would have identified the excessive pressurizer cooldown rate. The failure of the operators to verify the pressurizer cooldown rate every 30 minutes is a violation of TS SR 3.4.3.1.1 (Violation 361/97005-01).

The inspectors interviewed the operators involved in the pressurizer cooldown evolution. The operators indicated that they were focused on monitoring pressurizer pressure and level during the bubble collapse, and not the pressurizer

cooldown rate. The operators were all aware of the TS cooldown rate limit of 200°F in a 1-hour period, but possessed a mind set that there was a large limit and could not be exceeded. During interviews, operators indicated that there were minimal distractions, and that they felt they had proceeded in a controlled manner. The operator specifically assigned the function of monitoring the cooldown rate plotted the pressurizer temperature as required by Procedure SO23-5-1.8, but failed to recognize that a procedural and TS limit on cooldown rate had been exceeded.

The inspectors determined that several of the operators possessed minimal familiarity with collapsing the pressurizer bubble. None of the reactor operators performing the pressurizer bubble collapse had previously performed that evolution. However, the senior reactor operators and Operations management present in the control room did have previous experience with collapsing the pressurizer bubble. Licensed operator training had briefly discussed collapsing the pressurizer bubble in classroom training in 1992 and had emphasized having heaters on with plenty of spray to control the cooling of the metal masses. This practice was not used during the cooldown on March 4. The Operations superintendent indicated that the licensee planned to include pressurizer cooldown methodology in upcoming licensed operator training.

Technical Review and Safety Consequence

The pressurizer bulk water temperature experienced a cooldown of approximately 265°F in 1 hour, the surge line experienced a cooldown of approximately 320°F in 1 hour (430 to 110°F), and the spray line experienced similar temperature fluctuations of approximately 320°F. In addition, the 200°F cooldown limit of the pressurizer bulk water temperature was exceeded in a 26-minute period. The licensee initiated an evaluation of the effects on the pressurizer and related components (spray nozzle, surge line, and surge line nozzle).

The licensee documented the evaluation in a letter to the NRC dated March 14, 1997. The licensee concluded that, during the thermal transient, the pressurizer vessel remained within the acceptance criteria of the ASME Code, Section XI, Appendix G. The conclusion was based on the fatigue and pressurized thermal shock evaluations performed on the critical locations in the pressurizer.

Procedure Review

The inspectors reviewed Procedure SO23-5-1.8, used by Operations to cooldown and collapse the pressurizer bubble. The procedure contained steps that, had they been followed, would have precluded the excessive pressurizer cooldown and the violation of TS SR 3.4.3.1.1. Attachment 13, Step 2.5, required that the pressurizer cooldown rate shall not exceed 190°F per hour. Additionally, Attachment 4, Step 1.3, required operators to maintain the pressurizer temperature between 50°F and 200°F above the RCS cold leg temperature (the actual temperature differential during the cooldown was 320°F).

The Operations manager stated that Procedure SO23-5-1.8 provided steps to cooldown the pressurizer, but did not provide adequate guidance to ensure the evolution could be performed successfully every time. He indicated that a revised procedure should be issued prior to the Unit 3 outage.

After this event, the licensee developed another method for collapsing the pressurizer bubble. The inspectors observed that, during the subsequent plant heatup, the new method resulted in avoiding a severe temperature transient. Additionally, the licensee briefed the operating crews on the event, and was working to develop a better method for tracking and evaluating the temperature changes.

c. Conclusions

The licensee did not provide the operators with the adequate tools (procedures, training, oversight) to properly perform a pressurizer cooldown and bubble collapse. A violation was identified because the operators failed to verify that the pressurizer cooldown rate was less than 200°F in any 1-hour period, as required by SR 3.4.3.1.1. This represents a lapse in attention to detail by the operators.

O4.2 CEA Withdrawal for Rod Drop Timing Test - Unit 2

a. Inspection Scope (71707)

The inspectors observed the operators withdraw the CEAs using Procedure SO23-3-2.19, "Control Element Drive Mechanism Control System Operation," Revision 7, and discussed the operators' performance with Operations management.

b. Observations and Findings

On March 17, 1997, the inspectors observed a reactor operator withdraw the CEAs using Procedure SO23-3-2.19, in preparation for a CEA drop time test. During the regulating group CEA withdrawal, Procedure SO23-3-2.19, in part, directs the operator to withdraw and insert all the regulating group CEAs 5 inches and then to fully withdraw the regulating group CEAs using manual sequential mode. The reactor operator performing the evolution withdrew and inserted the regulating Group 1 CEAs 5 inches as required, and then proceeded to completely withdraw Group 1 using the manual group mode. The reactor operator performed the similar 5-inch exercise of regulating Group 2 CEAs, and then requested authorization from the control room supervisor (CRS) to withdraw the CEAs in manual group mode. The CRS informed the reactor operator that the regulating group CEAs were to be withdrawn in the manual sequential mode.

Operators suspended the withdrawal activities to evaluate the condition. The Operations crew and the Operations superintendent discussed the situation and

concluded that since the reactor was significantly shutdown, by greater then two percent, the incorrect CEA withdraw sequence had minimal effect on the core. The operators then exercised the remaining regulating group CEAs and withdrew them in manual sequential. Operations concluded that the abnormal CEA withdrawal sequence had minimal effect on the core and that the method used to withdraw the remaining regulating group CEAs was acceptable.

Operations management debriefed the event with the Operations crew after the test and discussed ways to improve Procedure SO23-3-2.19 to prevent recurrence of the situation. The Operations superintendent initiated an action request (AR) to evaluate the problem. On March 19, 1997, a preshift briefing was initiated to inform all Operations crews of the situation and avoid similar problems. On March 27, 1997, the licensee revised Procedure SO23-3-2.19 to clarify the inadequate procedure steps that led to the abnormal CEA withdrawal sequence and to improve additional steps of the procedure that operators identified as needing enhancement. In addition, the Operations superintendent issued a memorandum to control room supervision emphasizing control room oversight responsibilities. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 361/97005-02).

c. Conclusions

The operators failed to adhere to the requirements of Procedure SO23-3-2.19 during a CEA withdrawal activity resulting in the use of a wrong mode for CEA withdrawal. However, the event had minimal safety consequence and Operations management performed acceptable corrective actions.

O4.3 Operator Awareness of SDC Flow Rate Limits - Unit 2

a. Inspection Scope (71707)

The inspectors observed activities in the control room on March 4, 1997, shortly after Unit 2 was cooled down to Mode 5.

b. Observations and Findings

About 30 minutes after Unit 2 was cooled down to Mode 5, the inspectors asked the Assistant Control Operator (ACO), who was monitoring the cooldown, what the SDC flow rate limits were, and if they were specified in a procedure. The ACO stated that the limits were 3500 to 4500 gpm, and that the ideal flow rate was 4200 gpm. The inspectors observed that the actual flow rate was 4200 gpm.

The ACO then opened Procedure SO23-3-2.6, "Shutdown Cooling System Operation," Revision 11, Section 6.2, which contained a table stating the SDC flow rate limits and preferred rate for various pump configurations and modes. The flow

rate limits stated by the ACO were for one low-pressure safety injection pump operating in Mode 4. The limits for Mode 5 (2300 to 4500 gpm, with a preferred flow of 3500 gpm) were broader, but different than, the limits given by the ACO. The preferred flow rate for Mode 5 was lower than for Mode 4. Additionally, the CRS was not aware that the Mode 5 limits were different than the ACO had stated.

The CRS consulted with the SS, and determined that the SDC flow rate should remain at the higher value in support of the continued plant cooldown. The inspectors determined, through discussions with the ACO and CRS, that the SDC flow rate limit changes had not been discussed during the tailboard for the cooldown.

c. Conclusions

The ACO and CRS were not fully aware of the procedurally-specified SDC flow rate limits. The tailboard conducted prior to the cooldown was incomplete, in that it did not address the change of limits that occurred when the mode was changed. However, there was no safety consequence to the oversight, because the actual flow rate was within the correct limits.

O4.4 Control Board Indication Knowledge - Unit 2 (71707)

On March 25, 1997, the inspectors observed that SDC isolation Valves 2HV9377 and 2HV9378, both motor-operated valves, were deenergized in the open position as indicated by a clearance tag on the control board, and that Valve 2HV9377 still had valve position indication while Valve 2HV9378 did not. The inspectors questioned a reactor operator about the difference in the indications. The reactor operator was unable to explain the difference. The CRS indicated that Valve 2HV9378 has an independent power supply for valve indication as indicated by the valve label. The inspectors discussed the reactor operator's weakness in knowledge of the board indications with the Operations superintendent. The Operations superintendent indicated that he would discuss the knowledge issue with the reactor operator.

O4.5 Boric Acid Makeup (BAMU) Flow Rate Setpoint Less than Procedurally Required - Unit 3

a. Inspection Scope (71707)

On April 2, 1997, with Unit 3 at 99 percent power, the inspectors walked down the Unit 3 main control boards, interviewed some members of the Operations crew, and reviewed Operating Instruction SO23-3-2.2, Revision 10, "Makeup Operations."

b. Observations and Findings

The inspectors observed that the BAMU flow rate set on BAMU Flow Controller FIC-0210Y was 1.2 gpm. Volume control tank (VCT) level control was selected to automatic. In automatic, if VCT level decreased to the low level setpoint of 37 percent, then a blend of boric acid and pure water would initiate. The flow rates of boric acid and pure water were set on the controllers, and the blend would continue until the high level termination setpoint of 51 percent was reached. The inspectors reviewed Procedure SO23-3-2.2 and observed that in Section 6.2, "Automatic Makeup Mode," the operators were cautioned not to use a BAMU flow rate setpoint of less than 1.5 gpm when in automatic makeup mode, due to instrument and control inaccuracies. The operators were also cautioned in the procedure that this set a lower limit of 100 ppm for the blend concentration. Contrary to this procedure, the operators had set in the 1.2 gpm boric acid flow, with a pure water flow rate of approximately 100 gpm, to match a RCS boric acid concentration of approximately 30 ppm. This was a violation of Procedure SO23-3-2.2. This procedure was applicable to Regulatory Guide 1.33 and Unit 3 TS 5.5.1.1.a.

This violation involved reactivity control of the unit; however, due to VCT level maintenance practices and end of core life, the inspectors found that the safety significance of this violation was minor. Operators normally maintained VCT level approximately 51 percent, by manually raising level as it lowered; consequently, an automatic blend rarely initiated. This was not a procedural requirement, but was generally a standard operating practice. Also, if an automatic makeup had occurred, then the boric acid flow rate may have deviated from demand, due to the low flow rate. Operators would have been able to manually compensate for a blend that contained too much boric acid (the probable result), which would have caused reactor power and, consequently, RCS temperature, to lower. The inspectors considered the guidance of the NRC Enforcement Manual in assessing the significance of this issue. This failure constitutes a violation of minor safety significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 362/97005-03).

In response to the inspectors' observations, the Operations crew raised the boric acid flow setpoint to 1.6 gpm. Operations management also began evaluating whether to change the makeup procedure in order to accommodate operation in automatic, with RCS boric acid concentrations less than 100 ppm. This normally occurred towards the end of a refueling cycle. The inspectors found that the licensee's response to the immediate concern was satisfactory.

Based on conversations at the time of the observation, the inspectors found that the CRS was generally unaware of the procedural restriction against low boric acid flow rates. This illustrated a weakness in knowledge of an operating limit in effect.

c. Conclusions

A minor violation was identified, but not cited, because the demanded boric acid flow to the VCT was less than procedurally allowed. The CRS was generally unaware of the procedural restriction, illustrating a weakness in knowledge of an operating limit.

O4.6 Conclusions Regarding Operator Performance and Knowledge

While operators generally demonstrated excellent knowledge and performance, occasional lapses were observed. The above examples are significant in that they involved reactivity control and the maintenance of important RCS parameters, including temperature, SDC flow rate, and SDC system alignment. In these examples, operators demonstrated weakness in attention to detail in the performance of their duties.

O7 Quality Assurance in Operations

O7.1 ility Management Audit Review (71707)

The inspectors reviewed the report for the Joint Utility Management Audit, conducted March 3 through March 10, 1997.

O8 Miscellaneous Operations Issues (90712)

O8.1 (Closed) Licensee Event Report (LER) 50-362/96005-00: reactor head vent valve mispositioned. This issue was discussed and resolved in NRC Inspection Report 50-361; 362/96-17.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- Eddy current testing of pressurizer Thermowell 2T101 (Unit 2)
- Weld repair of pressurizer nozzle for pressurizer Thermowell 2T101 (Unit 2)
- SG hot leg primary manway removal and gasket replacement (Unit 2)
- Auxiliary feedwater pump ammonia check valve repair (Unit 2)
- Repack charging Pump 3P190 (Unit 3)

b. Observations and Findings

The inspectors found the work performed under these activities to be thorough. All work observed was performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of maintenance observed under Sections M1.4, E1.1, and E1.2, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance activities:

- CEA Trip Verification (Unit 2)
- Verification of RCS Heatup Rates Within Limits (Unit 2)
- Low Pressure Safety Injection Pump 3P015 Leakrate Test (Unit 3)
- High Pressure Safety Injection Pump 3P019 Inservice Test (Unit 3)

b. Observations and Findings

The inspectors found all surveillances performed under these activities to be thorough. All surveillances observed were performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of surveillances observed under Section M1.3, below.

M1.3 CREACUS Doors Left Open - Units 2 and 3

a. Inspection Scope (37551, 61726, 62707)

The inspectors observed Heating, Ventilation and Air Conditioning (HVAC) technicians perform portions of Procedure SO23-I-2.44, "CREACUS - Control Room Emergency Air Cleanup System Operation and Operability Test Surveillance," Revision 6, and discussed the performance with the HVAC technicians, Maintenance supervision, and Engineering.

b. Observations and Findings

On February 25, 1997, the inspectors observed technicians perform a replacement of a high efficiency particulate air filter. During the replacement of the filter, one technician indicated that the CREACUS unit was considered operable during Surveillance Test SO23-I-2.44 until one of the high-efficiency particulate air filters failed its efficiency test. The inspectors questioned the technician about the operability of the CREACUS unit with the doors open and test equipment installed in the unit. The technicians stated that their guidance provided that as long as the test equipment can be removed within an hour after the unit starts, the unit was considered operable.

The inspectors questioned the licensee's practice of performing the surveillance test without declaring the CREACUS unit inoperable. The HVAC system engineer initiated an AR and an operability assessment to evaluate the past performance of the surveillance test on the unit operability in both the toxic gas isolation signal and control room isolation signal modes of operation. The licensee performed an operability evaluation which concluded that with the door open and the test equipment inside, the unit was still capable of performing its design function and, therefore, would remain operable.

In the toxic gas isolation signal and control room isolation signal modes of operation, the engineer concluded that bubble-tight dampers isolate the system from the outside environment. Infiltration of toxic gases or radioactivity into an open CREACUS unit access door would [illegible] occur since the unit is located within the CREACUS boundary. In addition, [illegible] engineer determined that expeditious compensatory actions to remove the test equipment and ensure the doors are closed should take less then one minute. The engineer calculated that the maximum air flow velocity in the unit is approximately 3 miles per hour. At that velocity no equipment or other materials would move or affect the air flow distribution.

The inspectors determined that the technicians' perception that 1 hour was available for closing the CREACUS unit door was inappropriately based on establishing compensatory measures within 1 hour of identifying a deficient control room boundary door/doorway. Maintenance supervision conducted shop training for the HVAC planner and technicians to correct the potential discrepancy. In addition, the HVAC system engineer changed the work authorization requests to declare the CREACUS unit inoperable during future 18-month surveillances.

c. Conclusions

The licensee thoroughly evaluated the previous CREACUS unit maintenance activities for operability and concluded that operability was maintained. The inspectors assessed the licensee's evaluation and found it adequate.

M1.4 Repair of Temperature Element 2TE0101, Pressurizer Liquid Space Temperature Nozzle - Unit 2

a. Inspection Scope (62707, 37551)

On March 9, 1997, the inspectors observed machine gas tungsten arc welding being performed by contract welders in the Unit 2 containment. The work was required to weld a new, partial, Inconel 690 nozzle in place on the pressurizer. The nozzle was used to provide an opening for pressurizer liquid space temperature Thermowell 2TE0101. The old Inconel 600 nozzle weld to the pressurizer had cracked in the heat-affected zone of the weld. Repairs were being made by welding a new partial nozzle in place, and placing a pressure boundary weld on the exterior of the pressurizer. This substituted for the old pressure boundary weld on the interior of the pressurizer. An Inconel weld buildup of a carbon steel base plate was performed. Then an Inconel-to-Inconel weld was performed to install the new, partial nozzle. The interior portion of the old nozzle was left in place, requiring the pressure boundary weld to be the exterior nozzle to pressurizer weld.

The inspectors reviewed the settings on the welding machine, argon flow, and the performance of the machine during in-progress welding. The inspectors reviewed Welding Procedure Specification (WPS) 2 A03249 and Procedure Qualification Record A03256-N3432-52, Revision 2. Both were written by the weld contractor, Weld Services Incorporated, and approved by the licensee. The inspectors also reviewed Nonconformance Report 970300092, which contained the safety evaluation for the repair, as well as portions of ASME Code Section XI, 1992, and Code Case N-432, approved in 1986 and reaffirmed in 1994. In addition, the inspectors reviewed a letter from the NRC Office of Nuclear Reactor Regulation to the licensee dated February 13, 1996, which granted relief to the licensee to use a portion of the 1992 ASME Code for welds such as were performed for this repair.

b. Observations and Findings

The ASME Code allowed nonessential variables to be, within set limits, varied from the weld qualification, as the weld was actually performed on March 9, 1997. Essential variables had to be maintained, consistent with the weld qualification. For the portions of the actual welding that the inspectors observed, the essential variables, including total heat flux, were maintained. Current, voltage, machine travel speed, and filler metal travel speed varied from the weld qualification, as allowed.

The 1992 Code and Code Case N-432 were applicable to this weld, and the WPS and procedure qualification record conformed to these requirements. The planned nondestructive examination also conformed to these requirements. The safety evaluation in the nonconformance report was adequate to confirm that the repair was not an unreviewed safety question.

Based on the observation of portions of the actual performance of the weld, and on review of the documents mentioned above, the inspectors found that licensee oversight of the contract welders was good.

c. Conclusions

The repair plan for the 2TE0101 nozzle satisfied the proper sections of the ASME Code, and the weld was performed in accordance with the applicable WPS. Licensee oversight of contract welders was good.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Pressure Boundary Leakage due to Faulty Packing Leak-off Plug

a. Inspection Scope (62707, 37551)

The inspectors monitored the licensee's actions in response to the failure of a packing leak-off plug on SDC isolation Valve 2HV9339 on March 19, 1997.

b. Observations and Findings

On March 19, 1997, while Unit 2 was in Mode 3 being prepared for its return to service at end of the Cycle 9 refueling outage, plant personnel identified a small leak (approximately 3 gallons per hour), coming from a packing leak-off plug on SDC isolation Valve 2HV9339. This valve is inside the containment and is the isolation valve closest to the RCS. The leak was determined to be through the center portion of the solid plug. The licensee classified the leak as pressure boundary leakage, and initiated a plant cooldown as required by TS 3.4.1.13.

The licensee had procured the plug in 1983. Of the ten plugs procured at that time, eight had been installed in various plant components. The plugs were procured as safety-related, but not as ASME Class 1. The design drawing for Valve 2HV9339 designated the plug as a "nonpressure retaining part nonessential to function." The inspectors confirmed that this designation was consistent with ASME Code requirements.

The licensee identified the applications of all eight of the plugs that had been installed. Of those that remained installed, most had been installed for several years. The licensee inspected those that were accessible. Some were seal welded. Other than minor leakage at the threads, none of the plugs had experienced similar problems.

The licensee's initial root cause evaluation showed that the plug had microstructure porosity inclusions. The failed plug had been installed in Valve 2HV9339 earlier during the Cycle 9 refueling outage. The inspectors examined the plug and observed an irregular hole, through the length of the plug, that was

approximately 1/8" x 3/16". The licensee planned on performing destructive examination of the plug.

The licensee replaced the failed plug with an ASME Class I plug. The retest of the plug was satisfactory.

c. Conclusions

A failed plug resulted in pressure boundary leakage from the RCS. The plug met all regulatory requirements for the application, and the internal defects in the plug could not have been identified by the techniques required or implemented for receipt inspection of the plug. The licensee's visual inspection of the failed plug exceeded regulatory requirements and identified the failure. Corrective actions were thorough and effective.

III. Engineering

E1 Conduct of Engineering

E1.1 Procurement and Use of Faulty SG Manway Gasket - Unit 2

a. Inspection Scope (37551)

The inspectors monitored the licensee's actions in response to the identification of leakage from the SG 2E089 cold-leg manway. The inspectors reviewed the maintenance and procurement documentation associated with the manway gasket, and met with Procurement personnel to discuss the issues identified by the licensee's investigation of the cause of the leakage.

b. Observations and Findings

On March 22, 1997, after the plant was heated up to Mode 3, the licensee identified a small amount of leakage from the SG 2E089 cold-leg manway cover. The licensee determined that the gasket was leaking. The licensee reviewed the maintenance records and verified that the gasket was new and that the correct stud tension had been achieved during installation. The design was such that a substantial margin should have existed, and leakage was not expected to occur. Because the leakage indicated an unusual condition, licensee management decided to return to Mode 5 to evaluate the cause of the leakage.

The licensee determined that the gasket installed was not correct for the application. The gaskets had been classified as nonsafety-related in a change made in 1989 by Asea-Brown Boveri (ABB) and accepted by the licensee. The installed gasket was designed for 900 psi application, not 2500 psi as required for the RCS pressure boundary. The gasket had been ordered from a third-party vendor, Pacific Mechanical Supply, with the intent that the vendor would obtain the gasket from

ABB. The purchase order did not provide design specifications for the gasket, but listed the Combustion Engineering part number and provided a general description (nominal dimensions, materials, and gasket type). The design specifications were proprietary to ABB. The licensee had met with Pacific Mechanical Supply and other vendors in mid-1996 to explain that if a part was ordered by part number, substituted parts would not be accepted. However, this condition was only verbal. Prior to 1996, this condition had been included as part of the written purchase order.

In the past, the licensee had procured the gaskets from ABB, which obtained them from Flexitallic or other manufacturers, using the proprietary design specification. The licensee's Quality Control and Maintenance personnel did not have the design specifications to use to verify that the correct gaskets were received and used. Only general information was available to validate that the correct items were received.

The licensee determined that Pacific Mechanical Supply had worked with another company to manufacture the gaskets according to the general description provided on the purchase order. The purchase order did not mention the pressure or service application, and did not provide dimensional tolerances. The vendors made assumptions regarding this information, and manufactured the gaskets without notifying the licensee that the locally-manufactured gaskets would be substituted for the ABB parts.

In response to the identification of the incorrect gasket, the licensee replaced all the primary manway gaskets (including the pressurizer manway gasket) with the proper gaskets. After more details of the design of the correct gaskets became known, the licensee was able to confirm that the secondary manways had the correct gaskets installed. Additionally, the licensee initiated a review of all nonsafety-related components that are part of larger safety-related components, with the intent of identifying those components that should be more strictly controlled.

A similar event, involving incorrect gaskets substituted for Flexitallic gaskets for a RCP heat exchanger occurred in 1993, and was documented in Division Investigation Report DIR-SSS-93-02. As a corrective action, the licensee credited the Augmented Quality Program that had been put in place after the original material codes had been processed. Additionally, the licensee removed inappropriate gaskets from stock and reviewed existing material codes from gaskets that affect primary plant components.

The licensee determined that changes made to the procurement process in 1996 to implement "strategic sourcing" of nonsafety-related parts unintentionally reversed some of the controls that had been established to prevent such problems. In this case, the licensee observed that grouping highly-engineered items such as Flexitallic

gaskets along with other nonsafety-related gaskets inappropriately led to a relaxation of the procurement controls. Corrective Action Report 007-97 was issued to ensure that the weaknesses in the procurement process were identified and corrected.

The inspectors reviewed Maintenance Order (MO) 97021201001, by which the primary manway covers for SG 2E089 were installed. The MO was classified as Quality Class 1 and ASME III, Class 1. The MO specified the material requirements, Items 1 and 2, as Combustion Engineering Part Number 119-04. Because of the procurement errors described above, the licensee actually installed a gasket that was not a Combustion Engineering Part Number 119-04. This item is unresolved, pending review of the licensee's response to Corrective Action Report 007-97 (Unresolved Item 361/97005-04).

c. Conclusions

A gasket that was installed in the Unit 2 SG 2E089 cold-leg manway leaked. The gasket was not the same as had been ordered, and was not rated for RCS pressure. The incorrect gasket was received as a result of a change in the procurement process for nonsafety-related gaskets. The installation of the incorrect gasket is an unresolved item pending a review of the response to Corrective Action Report 007-97.

E1.2 Environmentally-Qualified (EQ) Splice Deficiencies - Unit 2

a. Inspection Scope (37551, 62707)

The inspectors reviewed ARs and met with EQ personnel regarding the identification of defective Raychem splices in safety-related systems in Unit 2.

b. Observations and Findings

On March 18, 1997, while evaluating damaged wire insulation in an EQ assembly for a Unit 2 RCS temperature instrument, a licensee EQ engineer identified that the bend radius of the Raychem splice (WCSF-N shrink tubing) on the Kapton leads in the condulet was smaller than allowed by Procedure SO123-I-4.61, "Conax Seal Assembly - Removal, Cleaning, Inspection, Repair, and Installation," Temporary Change Notice 1-2, and the Raychem "WCSF-N In-Line Splice Application Guide," dated March 1991. These documents stated that the splices should not be bent to a radius tighter than five times the outside diameter of the splice. The licensee determined that the planner had not included a reference to Procedure SO123-I-4.61 in the work document because Drawing 39646 for that assembly stated that Procedure SO123-I-4.59 applied to that portion of the assembly. Procedure SO123-I-4.59, "Wire/Cable Inspection," Temporary Change Notice 1-3, lacked the bend radius restriction. This was documented in AR 970300834.

The licensee inspected a sample of six other splices in small condulets for some other RCS temperature instruments and identified another similar deficiency. The licensee performed a review and determined that 65 EQ installations (wiring inside small condulets) were potentially susceptible to the same deficiency in each unit, and performed an inspection of each such assembly in Unit 2. Of the 65 installations inspected in Unit 2, 18 were found to be deficient.

The licensee performed corrective maintenance on the deficient Unit 2 EQ configurations, removing the affected areas of the leads, and, in some cases, installing larger connection boxes for the terminations. At the time, Unit 2 was operating in Mode 5. The corrective actions were completed before the mode was changed. The licensee also determined that some of the deficient installations had been performed earlier in the Unit 2 outage, and that some were older.

Unit 3 was operating in Mode 1, and the licensee performed on operability assessment, documented in AR 970300904, that concluded that the Unit 3 systems remained operable. The inspectors reviewed the operability assessment and determined that it provided an adequate basis for the licensee's conclusion. The licensee planned to conduct inspections of the similar configurations in Unit 3, most of which are in containment, during the next refueling outage.

The licensee established a task force, headed by Nuclear Oversight, to review the broader scope of EQ issues revealed by these deficiencies, including the adequacy of procedures and training, the cause of the other deficiencies, and the controls for ensuring that EQ requirements are incorporated into work documents. AR 970301068 was initiated to document the results of the task force's investigation.

c. <u>Conclusions</u>

The licensee was aggressive in inspecting, identifying, and correcting deficient EQ splices in Unit 2. An operability assessment for Unit 3 splices that had not been inspected, but may also be deficient, was thorough.

The procedure specified for the splicing of Temperature Element 2TE9178-3 was inadequate, in that it did not provide the minimum bend radius criterion for the Raychem splice. This was a violation of 10 CFR Part 50, Appendix B, Criterion V. This licensee identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the <u>NRC Enforcement Policy</u> (NCV 361/97005-05).

E8 Miscellaneous Engineering Issues (90712, 92700)

E8.1 (Closed) LER 361/96008-00: RCP oil collection system - voluntary report. This issue was discussed and resolved in NRC Inspection Reports 50-361; 362/96-11 and 50-361; 362/9702.

E8.2 (Closed) LER 50-361/97003-00: pressurizer safety valve setpoints out of tolerance. Following pressurizer safety valve setpoint testing, the licensee identified that the two pressurizer safety valves were out-of-tolerance high by 1.72 percent and 1.04 percent. These out-of-tolerance setpoints exceeded the TS allowable tolerance of ±1 percent. The licensee believed the cause to be setpoint drift. Following discovery, the licensee reset the safety valve setpoints within the allowable tolerance and evaluated the safety significance of the "as found" out-of-tolerance safety valves. The licensee's evaluation concluded that there was no safety consequence to the event, since the conditions were bounded by a previous analysis that showed that design conditions would be maintained. A recently completed analysis confirmed that the TS values for acceptable out-of-tolerance conditions on the pressurizer safety valves could be expanded to +3 percent and -2 percent without impacting the design basis. The licensee was considering applying for a change to the TS to allow for such an increase in setpoint tolerance. The inspectors concluded that the licensee's corrective actions, following discovery of the out-of-tolerance pressurizer safety valves, were timely and thorough.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Control of Radioactive Materials and Contamination, Surveying, and Monitoring

a. Inspection Scope (83750)

Selected radiation workers and radiation protection personnel involved with the control of radioactive material outside the radiologically controlled area were interviewed. Areas reviewed included:

- Control of radioactive material;
- Release survey methods;
- Frequency of surveys performed in the restricted area; and
- Posting of radiological areas within the restricted area.

The inspectors reviewed HP Procedure SO123-VII-8, Revision 7, "Control of Radioactive Material," and a memorandum to file, dated April 23, 1993, "Evaluation performed to determine the need to survey trash from the Restricted Area."

b. Observations and Findings

The amount of radioactive material items found outside the radiologically controlled area/radioactive material area boundary, and the origin of these items for the period of August 1995 to December 1996, were reviewed by the inspectors. The inspectors concluded, and the licensee agreed, that 25 radioactive material items documented in 18 radiological observation reports were found outside a radiologically controlled area/radioactive material area. The origin of the items was as follows:

- six radioactive material items and one magenta-colored item originated inside a radiologically controlled area/radioactive material area.
- sixteen radioactive material items originated outside a radiologically controlled area/radioactive material area.
- the origin of two radioactive material items could not be determined.

The inspectors interviewed security officers assigned to the restricted area exit points (security hold down area) and determined that all personnel were aware of the requirement to have HP personnel approval prior to releasing vehicles carrying plant-related components from the restricted area. The inspectors reviewed Security Procedure SO123-IV-5.3.3, Revision 3, "Search and Inspection." No problems were identified with security personnel's involvement with the release of items from the restricted area.

In general, no problems were found with the surveys performed prior to the release of items from the restricted area. However, when the inspectors first asked the Acting HP Manager if an aggregate survey was performed to detect an accumulation of low level contamination, the inspectors were informed that this type of survey was not performed. In later discussions with the Acting HP Manager, the inspectors were informed that the licensee's program included the requirement for aggregate surveys, as described in Section 6.1.3 of Procedure SO123-VII-20.9.2, "Material Release Surveys," Revision 1, and that this survey was performed prior to the release of items from the restricted area. However, the Acting HP manager also stated that he identified that some HP technicians not normally assigned to the release of radioactive material from the restricted area were not aware of the requirement to perform this survey. The Acting HP manager stated that the need to perform aggregate surveys will be clarified with the staff.

The inspectors interviewed HP personnel assigned to release items from the restricted area, and determined that all personnel knew to perform aggregate surveys prior to the release of items from the restricted area.

The inspectors reviewed Nuclear Training's on-the-job training manual,"Material Release Qualification," and determined that the requirement to perform aggregate surveys was adequately addressed in the material release qualification section.

The inspectors reviewed the material release log, which documented whether a radiological survey or evaluation was performed prior to releasing items from the restricted area. No problems were identified with the material release log documentation.

The inspectors interviewed a number of mechanical maintenance workers and determined that they knew to contact HP personnel prior to removing valves and other plant components from the restricted area. However, the workers stated, they normally placed plant-related components for disposal or recycle in skiffs (metal boxes) located in various areas within the restricted area. The inspectors determined that there were no controls pertaining to the removal of items from these skiffs.

HP personnel stated that they remove and survey items from the skiffs as necessary, and that they do not control the items that are placed in, or removed from, the skiffs until they are surveyed. The inspectors observed that radioactive material has been found by the licensee during these surveys.

During discussion with HP management, the inspectors were informed that "clean" trash dumpsters were not surveyed because a licensee-conducted study, dated April 23, 1993, determined that "the risk of an uncontrolled, inadvertent release of a detectable quantity of licensed radioactive material to a sanitary landfill via clean trash from the Restricted Area at SONGS is less than one chance in a million." The inspectors determined that this study was conducted during a time in which plant related components were brought to a HP survey station (dogpound) where HP personnel were stationed to survey these items. The inspectors determined that the licensee eliminated this HP survey station in November 1996.

The inspectors commented that, with the present way of discarding plant-related components, there was a possibility of an item being discarded in a "clean" trash dumpster. The licensee acknowledged the comment, and stated that the release of "clean" trash dumpsters would be reevaluated.

The inspectors conducted several tours of the restricted area and noted that all areas were properly posted in accordance with licensee procedures.

c. Conclusions

Overall, an adequate program was in place to control radioactive material outside a radiologically controlled area/radioactive material area. No problems were identified with security personnel's involvement with the release of items from the restricted area. Some HP personnel did not know to perform aggregate surveys of items

being released from the restricted area. Radiological areas within the restricted area were properly posted.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at exit meetings on March 28 and April 9, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Some price information in procurement documents reviewed (Section E1.1) were confidential. No other proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Brieg, Manager, Station Technical
J. Fee, Manager, Maintenance
G. Gibson, Manager, Compliance
D. Herbst, Manager, Site Quality Assurance
R. Krieger, Vice President, Nuclear Generation
J. Madigan, Acting Manager, Health Physics
H. Newton, Manager, Support Services
J. Scott, Supervisor, Health Physics
S. Schofield, Supervisor, Health Physics
D. Nunn, Vice President, Engineering and Technical Services
T. Vogt, Plant Superintendent, Units 2 and 3
R. Waldo, Manager, Operations

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 42700:	Plant Procedures
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 83750:	Occupational Radiation Exposure
IP 90712:	Inoffice Review of LER
IP 92700:	On Site LER Review

ITEMS OPENED AND CLOSED

Opened

50-361/97005-04	URI	procurement and use of faulty SG manway gasket

Opened and Closed

50-361/97005-01	VIO	pressurizer cooldown rate limit exceeded
50-361/97005-02	NCV	CEA withdrawal sequence for rod drop testing
50-362/97005-03	NCV	improper BAMU flow rate setpoint
50-361/97005-05	NCV	EQ splice deficiencies

Closed

50-362/96-005-00	LER	reactor head vent valve mispositioned
50-361/96-008-00	LER	RCP oil collection system
50-361/97-003-00	LER	pressurizer safety valve setpoints out of tolerance

LIST OF ACRONYMS USED

ABB	Asea-Brown Boveri
ACO	assistant control operator
AR	action request
BAMU	boric acid makeup
CEA	control element assembly
CREACUS	control room emergency air cleanup system
CRS	control room supervisor
EQ	environmentally qualified
HP	health physics
HVAC	heating, ventilation, and air conditioning
ICRR	inverse count rate ratio
LER	licensee event report
MO	maintenance order
PDR	Public Document Room
RCP	reactor coolant pump
RCS	reactor coolant system
SDC	shutdown cooling
SG	steam generator
SR	surveillance requirement
SS	shift superintendent
TS	Technical Specification
VCT	volume control tank
WPS	weld procedure specification