APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-361/94-03
50-362/94-03

Operating Licenses: NPF-10
NPF-15

Licensee: Southern California Edison Company
Irvine Operations Center
23 Parker Street
Irvine, California 92718

Facility Name: San Onofre, Units 2 and 3

Inspection At: San Onofre, San Clemente, California

Inspection Conducted: February 1 through March 7, 1994

Inspectors: J. A. Sloan, Senior Resident Inspector
J. J. Russell, Resident Inspector
D. L. Solorio, Resident Inspector
B. J. Olson, Project Inspector

Accompanying Personnel: M. B. Fields, NRR Project Manager

Approved By: [signature] for 4/1/94
H. J. Wong, Chief, Project Branch F Date

Inspection Summary

Areas Inspected (Units 2 and 3): Routine, announced resident inspection of operational safety verification, maintenance and surveillance observations, main turbine issues related to Fermi turbine failure, spent fuel pool rack Boraflex degradation, Onsite Review Committee meetings, nitrogen system contamination, corrective actions for contractor inattention-to-detail, failure to log a Security event, and followup of licensee event reports.

Results (Units 2 and 3):

Strengths:

- The licensee's review of the Fermi-2 turbine failure was aggressive and focused on exploring the vulnerability of the San Onofre main turbines to a similar failure mode. The licensee's past actions appeared to prevent or reduce degradation and were consistent with vendor recommendations (paragraph 5).

- The licensee's assessment of a letdown isolation valve failure in Unit 2 was thorough (paragraph 2.6).

- Efforts to reduce performance deficiencies by contractors appear to have been effective (paragraph 9).

- During a special meeting, the Onsite Review Committee (OSRC) was thorough in examining the proposed implementation of ethanolamine secondary chemistry control (paragraph 7).

Weaknesses:

- A violation occurred when the licensee failed to maintain required compensatory measures for a defective vital area intrusion alarm and did not log the deficiency as required. Additionally, supervisory personnel did not recognize the significance of the condition (paragraph 10).

- Poor maintenance was the apparent cause of the failure of an inverter providing power to a shutdown cooling valve (paragraph 3.1).

- Poor control of work activities resulted in work being performed on one train of the control room emergency air cleanup system (CREACUS) while the toxic gas isolation system (TGIS) in the other train was out of service. An error during maintenance rendered the second train inoperable (paragraph 4.1).

- Operators incorrectly performed a surveillance test on the excore nuclear instrumentation, resulting in all four channels being incorrectly calibrated and one of the channels being rendered inoperable (paragraph 2.5).

Summary of Inspection Findings:

- Violation 361/94-03-02 was identified (paragraph 10).

- Inspection Followup Item 361/94-03-01 was opened (paragraph 6).

- Licensee Event Reports 361/90-01-L1, 361/91-07-L1, 361/92-13-LO, 361/93-03-LO, 361/93-04-LO, 361/93-06-LO, and 361/93-08-LO were closed (paragraph 11).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 2

The unit operated at approximately 98 percent of rated thermal power throughout this inspection period.

1.2 Unit 3

At the beginning of this inspection period, the unit was operating at approximately 98 percent of rated thermal power. On February 4, 1994, the unit down-powered to 95 percent power to support an isothermal temperature coefficient surveillance test, then resumed 98 percent power operation the next day. On February 11, power was reduced to 60 percent to perform maintenance on main feedwater pump Turbine 3K006. The unit returned to 98 percent power on February 16 and operated at that power until February 19, at which time power was reduced to 60 percent to perform maintenance on a main feedwater pump turbine. Power was increased to 97 percent on February 22. The unit operated at approximately 97 percent power for the remainder of the inspection period, reflecting a minimum steam pressure limitation in assumptions in the licensee's core operating limits supervisory system (COLSS) program (see paragraph 2.1).

2 OPERATIONAL SAFETY VERIFICATION (71707 and 92701)

2.1 Power Operation Limitation - Unit 3

During this inspection period, Unit 3 became limited in power due to the inability to maintain steam line pressure above 850 psia. The low range of the steam pressure transmitter providing input to the COLSS secondary calorimetric calculation is 850 psia and, when pressure is less than 850 psia, COLSS senses that the instrument is out of range and flags the input as unreliable data. In order to utilize COLSS, the licensee is maintaining steam line pressure above 850 psia.

The reason for the reduced steam line pressure appeared to be fouling of the steam generator tubes. This has been observed over the operating life of the units, and the licensee is considering actions to improve the heat transfer performance of the steam generators. Additionally, in 1993 the licensee reduced the reactor coolant system cold leg temperature at which it normally operates, resulting in a step reduction in steam pressure.

2.2 Partial Loss of PAX Site Phone System Capability

On February 10, 1994, portions of the on-site PAX phone system were inoperable for approximately 5 minutes. The licensee determined that the event was not reportable in accordance with 10 CFR Part 72 requirements, because the primary phone lines remained available. Specifically, the licensee stated that the outage did not affect communication systems necessary to support emergency functions. The inspector reviewed the licensee's event reporting procedure, SO123-014, "Notification And Reporting Of Significant Events," Attachment 5, "Communications Systems Reportability Worksheet," and concluded that the licensee's evaluation was appropriate.

2.3 Stator Water Alarm Not Received In Control Room - Unit 2

On March 3, 1994, the inspector noted that the stator winding water strainer differential pressure high alarm on the generator unloading cubicle was in alarm. After notification by the NRC inspector, the operators responded, noted that the condition which had caused the alarm had cleared, and reset the alarm on the panel.

Upon further investigation, the inspector determined that the control room operators had not received indication of the alarm. Subsequently, the licensee tested the alarm circuit and determined that it was functioning properly. However, the inspector noted that the plant computer did not record the alarm, nor did the on-shift operator recall receiving the alarm. The inspector also noted that the plant operator sent out to respond to the inspector's concern did not question whether the control room had also received the alarm. The licensee agreed that the plant operator should have questioned control room operators to determine whether or not the alarm had been received in the control room. The licensee stated that they would incorporate the lesson learned from this incident into routine plant operator training in order to reinforce the expectation to maintain a questioning attitude. The inspector considered the licensee's corrective actions adequate.

2.4 Nitrogen Leaks From Main Steam Isolation Valve 3HV8205 - Unit 3

On March 2, 1994, the licensee contacted the NRC to initiate preliminary discussions directed at obtaining a Notice of Enforcement Discretion for an on-line repair of Main Steam Isolation Valve 3HV8205. The valve required recharging of its nitrogen dome (accumulator) approximately once every 5 days due to excessive leakage from the instrument and recharging fittings. However, while developing the repair plan for the valve, the licensee determined that one of the nitrogen instrument line fittings appeared not to be fully tightened. The fitting was subsequently tightened and the leak was stopped; therefore, a Notice of Enforcement Discretion was not needed. The inspector concluded that the licensee's actions were appropriate.

2.5 Excore Neutron Detector Miscalibration - Unit 3

On February 12, 1994, while Unit 3 was operating at approximately 60 percent power for feedwater system adjustments, the control room operators miscalibrated all four channels of excore nuclear instrumentation. The error was caused by transferring the wrong data from one section of the procedure to another section for use in a calculation and resulted in one of the four channels being outside the Technical Specification (TS) tolerances. The error was detected by the operators upon review of the surveillance test and the channel was placed into the bypassed condition approximately 56 minutes after the error was made. This was within the limits of the TS 3.3.1, which require affected reactor protection channels to be bypassed within 1 hour of a channel becoming inoperable. All four channels were recalibrated and returned to service later that day.

The licensee initiated a divisional investigation and intends to revise the procedure to require verification of the data and the calculation after each channel is calibrated, rather than reviewing the calculations after all four channels are calibrated. The inspector concluded that the licensee's corrective actions were appropriate.

2.6 Letdown Isolation Valve Failure - Unit 2

On February 4, 1994, chemical and volume control system letdown isolation Valve 2HV9204 failed with all valve position indications showing closed, but with letdown flow remaining normal. Unit 2 was operating at approximately 98 percent power at the time of the failure. The licensee demonstrated, by changing the charging pump configuration, that the valve could pass over 80 gpm flow; thus, demonstrating that the letdown flow path was not significantly obstructed by the valve.

This valve is one of four valves in series that receive a signal to close on a safety injection actuation. It does not act as a containment isolation valve. The purpose of the automatic closure function for this valve is to isolate the ASME Code Class-2 downstream piping and components from the ASME Code Class-1 system upstream. The licensee determined that the valve was not needed to close on safety injection actuation to mitigate any accident analyzed in the Updated Final Safety Analysis Report. Based on the operability review, the licensee determined that the safety injection system was operable despite the valve being declared inoperable. The inability of the valve to automatically close was determined to be a degradation from the design basis, but not from the licensing (i.e., operability) basis. Both classes of piping are designed to withstand 2485 psig, and the principal difference in the ASME classifications was that the Class-1 piping was analyzed for thermal fatigue for the 40-year life of the plant, while the Class-2 piping was not. The licensee determined that operating the system with the failed valve did not significantly increase the risk of thermal fatigue failure of the system. These conclusions were discussed in a conference call involving NRC Region IV (Walnut Creek Field Office) and Office of Nuclear Reactor Regulation personnel on February 4. The NRC personnel agreed that the valve's failure to fully close was not a significant safety issue in that the valve served as a ASME Code boundary principally for fatigue considerations.

The licensee subsequently revised its operability assessment, documented in Nonconformance Report 94020062, to take credit for the automatic closure of containment isolation Valve 2HV9267 on high regenerative heat exchanger temperature. In the event of a postulated letdown line rupture, this controlgrade function would isolate the break before a safety injection actuation would occur, so operator action would not be needed to terminate the event.

The licensee developed a work plan and made a containment entry to assess the condition of the valve. The valve appeared to be fully closed. Based on functional tests, it appeared that the solenoid valve coil had failed, in addition to whatever was allowing the apparently closed valve to pass flow so easily. The licensee determined that it was not feasible to repair the solenoid or the valve at power because of the high radiation field (approximately 5 rem/hour) at the valve location (inside the bioshield).

The inspector concluded that the licensee's actions were appropriate and that the operability evaluation was thorough.

2.7 Conclusions

The inspector concluded that the licensee appropriately assessed operational conditions during this period, including the degradation in communications capability, the failure of a letdown isolation valve, and a nitrogen leak in the control system of a main steam isolation valve. The operability evaluation of the letdown isolation valve failure was particularly thorough, demonstrating the integrated strength of the organization. The inspector also concluded that the miscalibration of excore nuclear instrumentation demonstrated poor attention to detail and a weakness in procedures that allowed the error to occur on all four channels before being detected. A minor deficiency was also noted regarding the failure of operators to realize that a stator water cooling panel annunciator might have been defective.

3 PLANT MAINTENANCE (62700 and 62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting.

Specifically, the inspector witnessed portions of the following maintenance activities:

Unit 2

- Troubleshoot and repair cause of blown fuse for shutdown cooling Valve 2HV9378 inverter.
- Common control room board modification.
- Remove overhaul and replace saltwater cooling Pump 2P112.

- Troubleshoot fluctuating level of Diesel Generator 2G002 fuel storage tank level transmitter.

Unit 3

- Investigate saltwater cooling Pump 3P113 seal water flow indicator abnormality.

- Charge Main Steam Isolation Valve 3HV8204 dome with nitrogen.

- Replace control transformer in Auxiliary Feedwater Pump 3P504 discharge Valve 3HV4712 breaker.

- Overhaul high pressure safety injection Pump 3P019.

3.1 Troubleshoot and Repair Cause of Blown Fuse for Shutdown Cooling (SDC) Valve 2HV9378 Inverter - Unit 2

On February 1, 1994, Inverter 2Y007 was declared inoperable when operators determined that the inverter input fuse had failed. The function of the inverter is to provide power to SDC system suction isolation Valve 2HV9378 from station emergency batteries. Maintenance Order 94020048000 was initiated to troubleshoot and repair the fuse failure. During troubleshooting activities, the licensee found a loose electrical connection, which blew another fuse when it was agitated. In addition, an accumulation of dust was noted on logic card connectors. As a result, the licensee speculated that the cause of the fuse failure was either a loose connection, an accumulation of dust on the logic card connector, or a combination of the two.

The licensee stated that the inverter had a history of input fuse failures and that they had evaluated several options to reduce the frequency of fuse failures. In addition, the licensee stated that the Engineering Department was still in the process of evaluating solutions to this problem. The inspector noted that SDC Valve 2HV9378 does not receive any engineered safety features actuation signals. However, the valve is used to provide long-term cooling for the reactor coolant system and to mitigate the effects of a small break, loss-of-coolant accident. The licensee provided the inspector with a limited scope probablistic risk assessment, which evaluated the risk of the valve's failure to be very small. The inspector reviewed the assessment and had no concerns.

The inspector reviewed the maintenance procedure used to clean the inverters, SO123-II-11.163, "Inverter Inspection and Cleaning." The inspector noted that the procedure contained general guidance to clean the inverter. However, the procedure did not contain specific guidance as to which components were especially important to clean. The procedure also required the inspection of connections and terminations "as necessary" to ensure electrical and mechanical integrity. Based on the licensee's speculation that the fuse failure might have been caused by dust or a loose connection and the fact that the inverter had been inspected and cleaned during the previous refueling outage, the inspector concluded that additional detail in the cleaning and inspection procedure appeared warranted.

The licensee stated that maintenance personnel had initiated efforts to improve the battery charger and inverter inspection and cleaning procedures prior to this event. In addition, the licensee stated that improvements would be implemented before the next refueling outage in which the procedure would be used. The inspector considered the licensee's proposed and completed corrective actions adequate.

3.2 Common Control Room Board Modification

On February 24, 1994, the inspector observed common control board modification activities which were in progress for human factor improvements under Design Change Package 3-6605.09, "Human Factors Control Room Modifications." Specifically, the inspector observed craft personnel grinding inside the common control board Panel 2/3CR-61 to remove paint for weld preparation in accordance with construction Work Order 94010628000.

The inspector questioned the craft supervisor in the control room regarding the potential for the sparks and debris from the grinding to impact safety-related controls and indicators in adjacent safety-related equipment. The supervisor terminated grinding activities to evaluate the inspector's concern. The licensee performed inspections of adjacent panels and found no evidence that the grinding activities had impacted the adjacent panels. Based on further review and discussion of the licensee's controls for the activity, the inspector concluded that the existing controls were in accordance with the maintenance procedures and were adequate for the activity.

3.3 Remove, Overhaul, and Replace Saltwater Cooling Pump 2P112 - Unit 2

The inspector reviewed records of work performed to remove and reinstall saltwater cooling Pump 2P112 in July 1993. The inspector verified that postmaintenance tests were performed prior to returning the pump to service. In addition, the inspector determined that postmaintenance tests were adequate to verify that the pump had been properly restored. The inspector concluded that pump maintenance and restoration were performed in accordance with the licensee's programs.

3.4 Conclusions

The inspector concluded that the Inverter 2Y007 failure was the apparent result of a poor maintenance procedure in that a termination was not tightened and portions of the circuitry were dirty despite a preventive maintenance task which was intended to clean the circuitry and tighten loose connections. The inspector also concluded that controls to ensure containment of grinding debris during control board modifications were adequate, and the maintenance of restoration of saltwater cooling Pump 2P112 in July 1993 was in accordance with licensee programs.

4 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the Technical Specifications were reviewed on a sampling basis to verify that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure existed for performance of the surveillance tests; (3) the surveillance tests had been performed at the frequency specified in the TS; and (4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 2

- 18-Month Fire Rated Assembly Inspection
- Saltwater Cooling System Check Valves
- Saltwater Cooling System Pump Inservice Test

4.1 18-Month Fire Rated Assembly Inspection - Unit 2

On February 10, 1994, emergency preparedness personnel tested fire dampers in accordance with plant Procedure SO23-XIII-57, "18 Month Fire Rated Assembly Inspection." When personnel removed a fusible link from fire Damper SAAC50309C5002FD to perform a damper drop test, the link fell down adjacent duct work and the damper could not be maintained open. Because the damper was located downstream of Unit 3 control room cabinet area emergency Cooling Unit ME426, CREACUS Train B was declared inoperable. Two days previously, the TGIS Train A had been removed from service for unrelated maintenance. With CREACUS Train B inoperable and TGIS Train A inoperable, the licensee determined that both trains of TGIS were inoperable. As required by TS 3.3.2, Table 3.3-3, Action 15, the operators manually initiated CREACUS Train A in the isolation mode of operation (by initiating TGIS Train A). Subsequently, the licensee replaced the fusible link and exited the action statement.

The licensee stated that a contributing factor to this event was that the surveillance procedure listing of equipment identifiers for the dampers did not specify the affected train. Specifically, when the operators reviewed the scope of work to be conducted under the surveillance procedure, the operators did not realize that inoperability of the damper would affect Train B CREACUS. As a result of this event, the licensee identified the train associated with the remaining dampers to be tested and controlled the testing activities.

The inspector noted that Cooling Unit ME426 would not normally be declared inoperable while performing the drop test on the damper. The function of the damper is to close in order to prevent smoke from a fire from entering the control cabinet area. The damper also needs to be open to provide cooling to the control room cabinet area by Cooling Unit ME426. The licensee stated that Cooling Unit ME426 was normally not declared inoperable during drop tests because emergency preparedness personnel maintained control of the fusible link and could quickly re-open the damper and reinsert the fusible link if required.

The licensee reported the event to the NRC in accordance with 10 CFR 50.72, but subsequently withdrew the report based on the licensee's need to take the action as required by TS and that the initiation of the system was not based on an actual need for the system due to the release of a toxic gas. However, the licensee indicated its intention of submitting a voluntary licensee event report.

The licensee stated that long term corrective actions included the performance of a division investigation to address the root causes and implement controls to prevent the recurrence of this event. The inspector considered that the licensee's proposed and completed corrective actions were adequate.

4.2 Saltwater Cooling Pump Seal Flow

On January 31, 1994, the inspector noted that saltwater cooling Pump 3P113 seal flow Indicator 3FISL6385 was reading 5.5 gpm while the pump was not running. The indicator should have indicated no flow. The inspector determined that, normally, flow was maintained around 8-9 gpm while the pump was running and that the minimum flow required was 2 gpm. The inspector verified that Maintenance Order 93121000 had been previously initiated to troubleshoot/repair the indicator. Maintenance personnel tested the indicator and found it to be within specifications. However, slight adjustments were made to bring the indicator closer to desired performance. The inspector was concerned that the 5.5 gpm minimum indication might mask a condition of inadequate flow (i.e., less than 2 gpm) to the pump seals during check valve surveillance testing. The inspector reviewed pump inservice test results for tests conducted on September 14 and November 20, 1993, and February 23, 1994 (performed after the flow indicator had been recalibrated), and verified that seal water flow acceptance criteria were met during the inservice tests. Based on a review of the pump inservice test results, the inspector concluded that adequate seal flow had been maintained to salt water cooling Pump 3P113.

4.3 Conclusions

The inspector concluded that poor control of work activities resulted in work being performed on one train of the CREACUS while the TGIS in the other train was out of service. An error during the maintenance rendered the second train inoperable. The inspector also concluded that the saltwater cooling pump seal flow indication abnormality did not mask a low seal flow condition.

5 MAIN TURBINE ISSUES RELATED TO FERMI TURBINE FAILURE (71500)

Units 2 and 3 have main turbines manufactured by English Electric, similar to the main turbine which failed at the Fermi nuclear station on December 25, 1993 (described in NRC Augmented Inspection Team Report 50-341/93-29). The inspector reviewed significant aspects of the licensee's turbine maintenance to determine if the licensee's actions prior to and following the Fermi turbine failure were appropriate.

The Fermi failure was initiated by degradation due to wobbling of the last stage blades in a low pressure turbine. The wobbling occurred while the turbine was rotating at 20 rpm on the turning gear. This resulted in excessive wear at the stabilizing spool holes near the end of the turbine blades and in wear at the connection point of the blade with the shaft. Prior to the Fermi failure, the licensee had evaluated this condition and implemented several corrective and preventative measures. The licensee performed repairs to worn blades; replaced the turning gear motor with a larger motor that turns the turbine at 27 rpm, minimizing or eliminating the wear at the spool holes; and installed springs under the blades at the shaft to reduce wobbling. Additionally, the licensee minimized the duration of turning gear operations. The licensee has aggressively followed the situation at Fermi, including sending its cognizant engineer to Fermi to gain direct information regarding the failure.

The licensee stated that all vendor recommendations related to the turbine were dispositioned and implemented to the degree deemed prudent by the licensee. No vendor recommendations were deferred or not dispositioned.

The inspector concluded that the licensee's actions were aggressive and appropriate.

6 SPENT FUEL POOL (SFP) RACK BORAFLEX DEGRADATION (86700)

Following the January 17, 1994, earthquake in the Northridge area of Los Angeles, the Unit 3 SFP purification filter (F-16) clogged. Further review revealed that this was not a new problem, but had been observed following the 1991 Landers earthquake. Additionally, the Unit 2 SFP purification filter had been bypassed due to inability to adequately flush it. While the licensee's evaluation of the condition is ongoing, it appears that Boraflex from the spent fuel racks clogged the filters.

The inspector was informed that the licensee had initiated a more detailed review of this issue following issuance of NRC Information Notice 93-70, "Degradation of Boraflex Neutron Absorber Coupons," and had established two groups to review the potential degradation. The licensee has an inspection program which inspects the Boraflex coupons each quarter for degradation. These inspections have shown that the coupons have decreased slightly in dimension and increased significantly in hardness. The licensee believes that substantial shutdown margin exists in the SFPs and is performing an evaluation to quantify the reactivity effects of the Boraflex degradation. The licensee is also evaluating the source of the Boraflex particles that clogged the filters to establish whether the particles were dislodged from the Boraflex panels gradually or catastrophically as a result of earth tremors. The inspector will review these issues in a future inspection (Inspection Followup Item 361/94-03-01).

7 ONSITE REVIEW COMMITTEE (OSRC) (40500)

The inspector attended the special OSRC meeting convened on February 4, 1994, to review the proposed implementation of a significant change in secondary plant chemistry from ammonia to ethanolamine for pH control. The review had been requested by the licensee's Chemistry Manager. The OSRC Chairman verified that a quorum was present and queried those present to establish the purpose of the OSRC review of the issue. The OSRC members were active in the discussions and focused on the nuclear safety aspects of the issue, consistent with the OSRC functions delineated in TS 6.5.1. Based on oral presentations at the meeting, the OSRC reviewed the 10 CFR 50.59 safety evaluation and the impact of the chemistry change on various aspects of plant operations. The OSRC concluded that no significant issues were apparent. The OSRC approved the chemistry change, conditional on the resolution of two non-nuclear safety issues, to the satisfaction of the OSRC Chairman. The inspector concluded that the OSRC was thorough in its special review and consistent with its TS function.

8 NITROGEN SYSTEM CONTAMINATION (92701)

In mid-February 1994, the licensee determined that portions of the normally noncontaminated nitrogen system were contaminated with minor levels of noble gas from the waste gas decay tanks.

During January 1994, the licensee experienced small increases in activity detected by Unit 3 air ejector radiation Monitor 3RT7870. The increases lasted for approximately 1 hour. On one occasion, a barely perceptible increase was also noted on the other air ejector radiation monitor, 3RT7818. The licensee sampled the condensers for activity and assessed steam line activity with temporary Nitrogen-16 monitors. Trace amounts of Xenon-133 were detected in the condenser, and no activity was found in the steam lines. Because Xenon-135 was expected to be significantly more prevalent than Xenon-133, if the source of the activity was a primary-to-secondary leak in an active steam generator tube, the licensee determined that an active tube leak was not likely to be the cause of the activity. Leakage from the waste gas decay tanks was suspected because it appeared that the shortest-lived nuclides were decaying away before reaching the condenser and because the decay tanks were connected to the condensers via the nitrogen system.

The licensee sampled the nitrogen system upstream and downstream of the regulator servicing the waste gas system. Samples taken on February 8, 1994, indicated total activity at these locations of 7.527E-4 μCi/cc and 8.135E-5 μCi/cc, respectively, with the nuclides Kr-85, Xe-133, Xe-133M, and Xe-131M detected. By temporarily isolating the nitrogen system from the Unit 3 condenser, the licensee confirmed the activity was coming from the nitrogen system. The licensee determined that the activity was leaking from the decay tanks, past several valves in the nitrogen header, and being swept into the Unit 3 condenser. The piping configuration precluded activity from going to the Unit 2 condenser. The licensee believed that very little activity migrated to the various "dead loads" on the nitrogen header, although confirmatory samples were not taken.

To temporarily prevent further contamination of the nitrogen system, the licensee implemented an abnormal alignment. The isolation valve from the nitrogen system to the waste gas surge tank was opened, providing a low pressure sink for leakage from the decay tanks. Gas from the surge tank is compressed back into the in-service decay tank. The licensee is developing additional corrective actions.

The inspector concluded that the licensee's evaluation and interim corrective actions were appropriate and noted that NRC Region IV (Walnut Creek Field Office) has scheduled an inspection to be documented in NRC Inspection Report 50-206/94-06, 50-361/94-06, 50-362/94-06 to further review the radiological implications of this event.

9 CORRECTIVE ACTIONS FOR CONTRACTOR INATTENTION TO DETAIL (92720)

The inspector reviewed a letter from the licensee to NRC, dated December 1, 1993, which outlined the licensee's actions in regard to issues raised by the licensee's Nuclear Oversight Division (NOD) and the NRC, concerning control of contractors during the Unit 2, Cycle 7, refueling outage. The letter was in response to NRC Inspection Report 50-206/93-19; 50-361/93-19; 50-362/93-19. The letter discussed areas in which contractor attention to detail was considered lacking by both the licensee and the NRC and described the licensee's corrective actions.

The inspector reviewed licensee and NRC observations during the Unit 3, Cycle 7, refueling outage, described in NRC inspection reports and an NOD report, dated January 19, 1994, "Nuclear Oversight Outage Coverage Final Report, Unit 3 Cycle 7 Refueling Outage." The inspector reviewed observations during the Unit 3 outage because it directly followed the Unit 2 outage and both outages had a relatively high amount of contractor work activity inside the protected area. The inspector noted that during the Unit 3 outage the NRC had identified relatively few instances that could be attributed to contractor inattention to detail, as opposed to the Unit 2, Cycle 7, outage, during which numerous instances of contractor inattention to detail were identified. The inspector also noted that, despite an increase in NOD's monitoring of the Unit 3 outage as opposed to the Unit 2 outage, the number of and significance of occurrences involving contractors observed by the NOD also decreased. The inspector considered that this apparent decrease in the number of occurrences could be attributed to the increased training of contractors and the increased licensee emphasis in this area, indicating that licensee corrective actions to Unit 2 observations appeared adequate.

The inspector noted that approximately 30 contract personnel in the Nuclear Projects division and approximately 55 contract personnel in the Maintenance division were performing work in the protected area during this report period, which was significantly less than the number of contract personnel during the refueling outages discussed above. The inspector interviewed a sample of these contract personnel and considered that they understood their responsibilities in adhering to licensee procedures and paying attention to detail during the course of work activities.

The inspector considered the licensee's corrective actions as discussed above adequate and will continue to monitor contractor, as well as licensee personnel, attention to detail as a part of normal inspection activity.

10 SECURITY EVENT NOT LOGGED (62703 and 92701)

In mid-February 1994, the NRC inspector questioned the circumstances regarding the performance of a surveillance test. The inspector questioned the short period that an access manhole cover had been open during the surveillance test based on the licensee's security computer records. The inspector questioned whether the surveillance test had been performed properly. Subsequently, the licensee's reconstructed the event details.

On February 2, 1994, licensee personnel removed manhole Cover MH-8 under Maintenance Order 94010412000 to allow maintenance personnel to perform preventive maintenance on a vault flood switch in a diesel generator feeder cable vault. The manhole was removed for approximately 30 minutes without the Security Central Alarm Station receiving an alarm from the manhole tamper alarm switch. The licensee determined that security personnel had noted the absence of the alarm when the manhole cover was replaced, but had failed to log the initial failure of the alarm on opening the manhole cover. Licensee personnel then initiated compensatory actions of hourly rounds. The inspector noted that the manhole cover provided access to a vital area which contained Train B diesel generator cables. The event was subsequently logged as a security loggable event in accordance with licensee procedures and NRC requirements.

The inspector verified that a security officer was stationed at the vital area portal for the duration of the period the manhole cover was removed. When the manhole cover was secured on February 2, the alarm was received and cleared, which security personnel interpreted as sufficient justification to terminate compensatory measures. The manhole cover was subsequently removed on February 8 and the tamper alarm functioned as designed. Based on the NRC inspector's questions regarding the performance of a surveillance test, the licensee initiated a work order to investigate the functioning of the tamper alarm. On February 23, the manhole cover was removed and the tamper alarm did not actuate. The inspector verified that compensatory measures were initiated on February 23 until the alarm switch was repaired.

The inspector concluded that the significance for not implementing the required compensatory measures was low for the following reasons: (1) the manhole cover was locked with a security padlock, (2) the keys were controlled and issued only to authorized Security and Operations personnel, (3) the manhole cover weighs in excess of 400 pounds, (4) the manhole was patrolled and inspected every 4 hours, (5) the manhole cover was located on the primary personnel access route to Units 2 and 3 from the only access point to the protected area, and (6) this was an isolated incident.

10 CFR Part 73, Appendix G, Part II, requires recording of safeguards events in a log within 24 hours of discovery. These events include: (1) any failure in a safeguards system that could allow unauthorized or undetected access to a protected area or vital area for which compensatory measures have not been employed; and (2) any other . . . committed act not previously defined in Appendix G with potential for reducing the effectiveness of the safeguards system. The inspector concluded that the licensee's failure to log the failure of the tamper alarm switch to annunciate when MH-8 was removed on February 2, 1994, was in violation of 10 CFR Part 73, Appendix G, requirements (Violation 361/94-03-02).

In response to this incident the licensee performed a division investigation to determine the root causes and to identify corrective actions. The inspector reviewed the investigation and concluded that the licensee's proposed and completed corrective actions, which included a Quality Assurance department audit of the Security equipment maintenance process, were thorough.

11 IN-OFFICE REVIEW OF LICENSEE EVENT REPORTS (90712)

The following licensee event reports were closed based on in-office review:

- 361/90-01, Revision 1: Technical Specification Violation Involving a Missed Firewatch Due to a Procedural Inadequacy
- 361/91-07, Revision 1: Manual Reactor Trip on Loss of Reactor Coolant Pump Bleedoff Flow
- 361/92-13, Revision 0: Inconclusive Check Valve Testing Methodology
- 361/93-03, Revision 0: Pressurizer Pressure Bypass Removal Setpoint
- 361/93-04, Revision 0: Incomplete Once-a-Shift Operations Surveillance
- 361/93-06, Revision 0: Licensing Basis for Units 2 and 3 Auxiliary Feedwater Piping Tornado Generated Missile Barriers Not Fully Met
- 361/93-08, Revision 0: Inoperable Waste Gas System Monitor

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*R. Ashe-Everest, Nuclear Fuels Services Engineer
*D. Axline, Licensing Engineer, Onsite Nuclear Licensing
*C. Balog, Supervisor, Nuclear Construction
*D. Breig, Manager, Station Technical
*P. Champion, Supervisor, Security Compliance
*L. Cash, Maintenance Manager
C. Chiu, Manager, Quality Engineering
*R. Douglas, Licensing Engineer, Onsite Nuclear Licensing
*T. Elkins, Supervisor, Nuclear Construction
V. Fisher, Assistant Operations Manager
*S. Giannell, Fire Protection Engineer
G. Gibson, Supervisor, Onsite Nuclear Licensing
*R. Giroux, Licensing Engineer, Onsite Nuclear Licensing
*D. Herbst, Manager, Quality Assurance
*M. Herschthal, Manager, Nuclear Systems Engineering
*J. Hirsch, Manager, Power Generation
*D. Irvine, Supervisor, Technical Support
*B. Katz, Manager, Nuclear Oversight
P. Knapp, Manager, Health Physics
*R. Krieger, Vice President, Nuclear Generating Station
*W. Marsh, Manager, Nuclear Regulatory Affairs
*M. Neu, Shift Commander
H. Newton, Manager, Site Support Services
J. Reeder, Manager, Nuclear Training
J. Reilly, Manager, Nuclear Engineering & Construction
M. Short, Manager, Site Technical Services
*K. Slagle, Manager, Outage Management
*M. Speer, Manager, Site Security
*R. Rosenblum, Vice President, Nuclear Engineering and Technical Support
*T. Vogt, Plant Superintendent, Units 2/3
*R. Waldo, Operations Manager
*M. Wharton, Manager, Nuclear Design Engineering
*T. Yackle, Manager, Nuclear Engineering Design Organization, NU/MECH
*M. Zenker, Emergency Planning Engineer
*W. Zintl, Manager, Site Emergency Preparedness

1.2 Other Personnel

*R. Erickson, Site Representative, San Diego Gas and Electric

1.3 NRC Personnel

*J. Russell, Resident Inspector
*J. Sloan, Senior Resident Inspector
*D. Solorio, Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes personnel that attended the exit meeting.

2 EXIT MEETING

An exit meeting was conducted on March 9, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.