UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

February 16, 2000

Harold B. Ray, Executive Vice President
Southern California Edison Co.
San Onofre Nuclear Generating Station
P.O. Box 128
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SUBJECT: NRC ROUTINE INSPECTION REPORT NO. 50-361/99-19; 50-362/99-19

Dear Mr. Ray:

This refers to the inspection conducted on December 12, 1999, through January 22, 2000, at the San Onofre Nuclear Generating Station, Units 2 and 3, facility. The enclosed report presents the results of this inspection.

During the 6-week period covered by this inspection, your conduct of activities at the San Onofre facility was generally characterized by safety-conscious operation, sound engineering and maintenance practices, and careful radiological work controls.

Based on the results of this inspection, the NRC has determined that two Severity Level IV violations of NRC requirements occurred. These violations are being treated as noncited violations (NCVs), consistent with Section VII.B.1.a of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the San Onofre Nuclear Generating Station, Units 2 and 3, facility.

In accordance with 10 CFR 2.790 of the NRC's “Rules of Practice,” a copy of this letter, its enclosure, and your response, if any, will be placed in the NRC Public Document Room.

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Linda Joy Smith, Chief
Project Branch E
Division of Reactor Projects

Docket Nos.: 50-361
50-362
License Nos.: NPF-10
NPF-15

Enclosure:
NRC Inspection Report No.
50-361/99-19; 50-362/99-19

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E-Mail report to Document Control Desk (DOCDESK)
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E-Mail report to Frank Talbot (FXT)

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E-Mail notification of issuance of all documents to Nancy Holbrook (NBH).

bcc to DCD (IE01)

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-361 50-362
License Nos.:	NPF-10 NPF-15
Report No.:	50-361/99-19 50-362/99-19
Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	December 12, 1999, through January 22, 2000
Inspectors:	J. G. Kramer, Acting Senior Resident Inspector J. J. Russell, Resident Inspector J. A. Sloan, Senior Resident Inspector A. B. Earnest, Physical Security Specialist P. A. Goldberg, Reactor Inspector M. F. Runyan, Senior Reactor Inspector
Approved By:	Linda Joy Smith, Chief, Project Branch E Division of Reactor Projects

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report No. 50-361/99-19; 50-362/99-19

This routine announced inspection included aspects of licensee operations, maintenance, engineering, and plant support. This report covers a 6-week period of resident inspection.

Operations

- Operators thoroughly and methodically prepared for and conducted evolutions. Management and supervisors provided close oversight of operational activities. Procedure use and operator communications were generally consistent with written licensee management expectations (Section O1.1).

- Planning and preparation for the Year 2000 transition were thorough. Licensee oversight was good. An information center was established, the Technical Support Center was partially manned, and control room oversight was increased from normal. No problems were observed during the transition period (Section O8.1).

Maintenance

- Licensee personnel performed maintenance and surveillance activities in a thorough manner with the work package present and in active use. Technicians were knowledgeable and professional. Supervisors and system engineers frequently monitored job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place (Sections M1.1 and M1.2).

- Machinists and Operations Work Control personnel had a weak understanding of the scope of the barrier analysis performed for planned maintenance. This resulted in using an ocean intake water level work window restriction that had no technical basis (Section M1.3).

- A violation of Technical Specification Surveillance Requirement 3.7.5.2 occurred because the licensee failed to perform a surveillance of an auxiliary feedwater pump every 31 days on a staggered basis four times since 1998. In each case, the pump subsequently developed the required head and passed the surveillance. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Request 991100156 (Section M8.2).

Engineering

- The licensee's evaluation of vulnerabilities, performed in response to NRC Generic Letter 98-02, "Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition," May 28, 1998, was considered adequate (Section E8.1).

Plant Support

- Health Physics personnel were not proactive in maintaining a vacuum cleaner free of loose surface contamination, which resulted in a personnel low level contamination occurring in a nonradioactively controlled area. The personnel were also not proactive in generating an action request for the occurrence. Although corrective actions in response to the contamination were reasonable, failure to generate an action request resulted in the condition not being directly recorded and trended in the licensee’s overall site corrective action program (Section R1.1).

- A violation of paragraphs 5.1.2 and 5.1.3 of the Physical Security Plan resulted from the failure to prevent unauthorized access to the protected and vital areas by verifying the correct identity of the personnel requesting access. This allowed an individual to enter the protected area with access to areas not normally accessible although the individual did not actually enter these areas. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The violation was entered into the licensee's corrective action program as Action Request 990100654 (Section S8.1).

Report Details

Summary of Plant Status

Unit 2 began this inspection period at 100 percent power. On January 8, 2000, Unit 2 reduced power to 86 percent for turbine valve testing and was returned to 100 percent power the following day. Unit 2 operated at essentially 100 percent power for the remainder of this inspection period.

Unit 3 began this inspection period at 100 percent power. On January 7, 2000, Unit 3 reduced power to 65 percent to perform repairs on feedwater Pump 3P063 because of a high inboard bearing temperature. On January 9, Unit 3 was returned to 100 percent power and operated at essentially 100 percent power for the remainder of this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors observed routine and nonroutine operational activities throughout this inspection period. Some of the activities observed included:

- Removal of high pressure turbine stop and governor valves from service (Unit 3)
- Response to a high pressure turbine stop valve closure (Unit 3)
- Switchyard breaker manipulation (Units 2 and 3)
- Auxiliary feedwater Pump 2P140 operation (Unit 2)
- Shift turnover (Units 2 and 3)
- Attempted synchronization of Emergency Diesel Generator (EDG) 2G003 to the grid (Unit 2)

Operators thoroughly and methodically prepared for and conducted evolutions. Management and supervisors provided close oversight of operational activities. Procedure use and operator communications were generally consistent with written licensee management expectations.

O8 Miscellaneous Operations Issues

O8.1 Year 2000 Transition - Units 2 and 3

a. Inspection Scope (71707)

On December 31, 1999, through January 1, 2000, the inspectors observed Units 2 and 3 systems transition into the Year 2000. The inspectors reviewed licensee contingency plans, walked down both units' main control boards both before and after the transition, and observed both the information center the licensee had established and the personnel manning the Technical Support Center.

b. Observations and Findings

In preparation for the Year 2000 transition, the licensee established an information center to monitor the transition as it occurred world wide, partially manned the Technical Support Center, and increased control room oversight. Previous to the transition, the licensee had conducted an extensive review of systems to identify and correct any malfunctions that could occur as a result of the date change from the Year 1999 to 2000. The review was documented in NRC Inspection Report 50-361/99-08, 50-362/99-08, Section E8.1.

The transition did not result in any malfunctions or misoperations of Units 2 and 3 systems. Licensee oversight during the transition was comprehensive. Testing of systems, both operating and in standby, after the transition, also was comprehensive. Monitoring of world-wide events was timely. The minor problems that were evidenced at other sites were evaluated correctly for applicability to Units 2 and 3.

c. Conclusions

Planning and preparation for the Year 2000 transition were thorough. Licensee oversight was good. An information center was established, the Technical Support Center was partially manned, and control room oversight was increased from normal. No problems were observed during the transition period.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62707)

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

- Replace Charging Pump 2P192 suction relief Valve 2PSV9224 (Unit 2)
- Replace a junction box on Charging Pump 2P192 (Unit 2)
- Attempted repair of Control Element Assembly 40 reed switch position transmitter (Unit 2)

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 a specific discussion of maintenance observed in Section M1.3.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

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

- Engineered safety features subgroup relay semiannual test (Unit 3)
- Excore log Channel D calibration (Unit 3)
- Battery 2D4 terminal resistance check (Unit 2)
- Salt water cooling Pump 3P114 inservice test (Unit 3)
- Qualified safety parameter display system Train A quarterly surveillance (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.

M1.3 Saltwater Cooling Pump 3P112 Discharge Gasket Replacement - Unit 3

a. Inspection Scope (62707)

On January 4, 2000, the inspectors observed machinists preparing to replace a leaking discharge piping flange gasket on Unit 3 Saltwater Cooling Pump 3P112. The inspectors reviewed Maintenance Order (MO) 99083041, Work Authorization Record 3-9903207, and Procedure SO123-I-1.7, “Maintenance Order Preparation and Processing,” Revision 7. The inspectors also discussed the maintenance activity with Maintenance and Emergency Preparedness (EP) personnel.

b. Observations and Findings

The saltwater cooling pumps take a suction from the units’ ocean intake. The saltwater pump being worked on was adjacent to Unit 3 saltwater cooling Pump 3P113, which was roped off as a protected component due to an EDG maintenance outage. Two other saltwater cooling pumps were also in the same space. A combination of high intake water level and a design basis ocean swell could cause flooding in the space through the open piping. This flooding could affect the protected pump as well as other safety-related equipment in the space.

The inspectors asked the machinists if the times that the piping was breached were restricted due to intake water level. The machinists stated that a 4.5-foot intake level above mean ocean level was the maximum allowable for the breach to be in effect. However, the machinist could not find this limitation in the MO or the work authorization record. The inspectors discussed this with Operations Work Control personnel, who stated that the limitation should have been included in the MO during a barrier analysis performed as the MO was planned. The licensee stopped the work and generated Action Request (AR) 000100155. The machinists continued the work after obtaining a tide table and work window based on ocean level.

The inspectors reviewed the analysis performed as a result of AR 000100155, which concluded that, given a pipe opening approximately ½ inch (the opening created during gasket replacement), there was no tide restriction. The amount of water that would enter the space through the opening was less than the design flooding, a main condenser boot seal failure. As a result, the protected saltwater cooling pump would not have flooded and would have remained operable.

The EP personnel who performed the barrier analysis stated that a barrier analysis was not performed for MO 99083041 because barrier analysis was only performed for breaches in walls, ceilings, floors, and doors -- not for breaches in systems. The inspectors reviewed Procedure SO23-XV-4.500, “Control of SONGS 2 and 3 Barriers,” Temporary Change Notice 2-1, which limited barrier analysis to those items discussed by the EP personnel in Attachment 1, “Definitions.” The inspectors discussed system breaches with the EP manager. The EP manager planned to evaluate formally incorporating assignments to address system breaches during maintenance concerning barrier analysis and whether these analyses, when needed, would generally be performed by Station Technical personnel.

Since the flooding analysis performed after the gasket replacement concluded that the design of the plant had been maintained, no violations were identified. However, a misunderstanding of the scope of barrier analysis performed during MO planning by the machinists and Operations Work Control personnel resulted in using a 4.5-foot intake water level restriction that had no technical basis.

c. Conclusions

Machinists and Operations work control personnel had a weak understanding of the scope of the barrier analysis performed for planned maintenance. This delayed the return to service of a saltwater cooling pump and resulted in using an ocean intake water level work window restriction that had no technical basis.

M8 Miscellaneous Maintenance Issues (92700, 92902)

M8.1 (Closed) Licensee Event Report (LER) 362/1999-005-00: low temperature overpressure protection (LTOP) relief valve inoperable.

On April 12, 1999, the licensee removed shutdown cooling inside containment pressure relief Valve 3PSV9349 in accordance with MO 98070177 to verify the relief valve setpoint. On April 13, the licensee installed a replacement relief valve. On June 30 the licensee performed lift setpoint testing of removed Valve 3PSV9349. The valve failed two lift tests, the first at 420 psig and the second at 419 psig. Since both test results exceeded the Technical Specifications upper limit of 416 psig, the licensee evaluated past operability.

Technical Specification 3.4.12.1.a requires, in part, with reactor coolant system cold-leg temperature less than or equal to 246°F, that the shutdown cooling system relief valve have a lift setting of 406 ± 10 psig. Action E requires, in part, with a shutdown cooling system relief valve inoperable, that operators reduce T_{avg} to less than 200°F, depressurize the reactor coolant system, and establish a reactor coolant system vent path greater than or equal to 5.6 square inches within 8 hours. On March 28 the licensee performed a cooldown of the Unit 3 reactor coolant system and entered the condition of applicability for Technical Specification 3.4.12.1 at approximately 3:12 a.m. The Action E requirements were not met by 11:12 a.m., as required for an inoperable shutdown cooling system relief valve. The licensee concluded that the LTOP relief valve had likely been inoperable during periods of required operability and therefore reported the condition. The licensee documented this condition in AR 990601587.

The licensee evaluated the safety consequence of the valve lifting high. The LTOP setpoint used in the Updated Final Safety Analysis Report was approximately 430 psig. The as-found setpoint of 420 psig was less than the value assumed in that analysis. Therefore, the licensee concluded that LTOP could have performed its intended function and that the event had no safety consequence.

The inspectors agreed with the licensee's conclusion that the relief valve had likely been inoperable during periods of required operability; however, it was not clear exactly when the relief valve became inoperable. After considering the lack of safety consequences and the uncertainty related to setpoint drift, the inspectors concluded that, for enforcement action in this case, the time of inoperability was the time of discovery. Since the licensee had already replaced the inoperable relief valve with an operable valve at the time of discovery, the Technical Specification-required actions were satisfied and therefore no violation of Technical Specification 3.4.12.1.a occurred.

M8.2 (Closed) LER 361; 362/1999-007-00: missed Technical Specification surveillance for auxiliary feedwater pumps

This LER involved licensee identification that a Technical Specification surveillance interval for Units 2 and 3 auxiliary feedwater pumps had not been met. New standardized Technical Specifications had been implemented for both units in August 1996. The new Technical Specifications changed the surveillance interval of the auxiliary feedwater pumps from every 31 days to every 31 days on a staggered test basis with a 25 percent time extension allowable. In the LER, the licensee stated that the computerized system used to schedule the surveillance had not been properly changed from the old interval to the new interval, thus causing the event.

The inspectors reviewed 1998 and 1999 surveillance data for both units' auxiliary feedwater pumps. Each unit has three auxiliary feedwater pumps, Pumps P140, P141, and P504. Technical Specification Surveillance Requirement 3.7.5.2 states, in part, that the developed head of each auxiliary feedwater pump shall be verified to be greater than or equal to the required head every 31 days on a staggered basis. Contrary to this requirement, the time interval between testing Unit 3 Pump 3P504 and Pump 3P141 was 61 days when Pump 3P141 was tested on November 2, 1999. Also, the time interval between testing Unit 2 Pump 2P140 and Pump 2P504 was 50 days when Pump 2P504 was tested on June 4, 1998, the interval between Pump 2P140 and Pump 2P504 was 63 days on August 27, 1998, and the interval between Pump 2P140 and Pump 2P504 was 50 days on November 17, 1998. The required head was developed during each of these late surveillances, mitigating the severity of this event. The licensee tested Pump 3P141 within 24 hours of when this error was discovered on November 2, 1999, in accordance with Technical Specification Surveillance Requirement 3.0.3, in order to maintain Pump 3P141 operability. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 361; 362/99019-01). This violation was in the licensee's corrective action program as AR 991100156.

Corrective actions for this event included revising the surveillance scheduling program with respect to the auxiliary feedwater pumps and verifying that the program was adequate for other staggered and nonstaggered Technical Specification surveillance intervals. The inspectors concluded that the corrective actions were adequate.

M8.3 (Closed) LER 361/1998-025-00: three Unit 2 main steam safety valve as-found setpoints greater than setpoint tolerance.

The licensee reported that 3 out of the 15 main steam safety valves tested had as-found setpoints that exceeded their Technical Specifications tolerance. The valve tolerance was +1/-3 or +2/-3 percent depending on the valve. The licensee attributed one of the failures to setpoint drift (+1.3 percent above nominal setpoint) and reset the valve. The other two valves were sent back to the valve manufacturer to determine the root cause. These valves failed at +2.1 percent and +4.0 percent. The licensee reviewed the overhaul and test data and confirmed that the valves had been set correctly when installed. The licensee also analyzed the as-found setpoints and determined that they were within existing (although not submitted) safety analyses. The licensee concluded that there was no safety consequence to this event.

The three valves discussed in this LER had a flat-disc design. The licensee stated that, by the end of the 10th refueling outage for both units, the original flat discs had been replaced with the manufacturer's flexi-disc design in all the main steam safety valves. The flexi-discs were designed to improve seat leakage performance and, therefore, set pressure performance. The inspectors determined that the licensee had taken adequate corrective actions.

Unit 2 Technical Specification 3.7.1 requires, in part, that the main steam safety valves have an as-found setpoint tolerance as specified in Table 3.7.1-2. to be considered operable and that the valves be operable during operation in Modes 1, 2, and 3. The licensee determined that the valves had likely not been operable during part of Cycle 9 power operation and that the requisite actions for that condition had not been performed and therefore reported the condition. The licensee documented this condition in ARs 981201690, 981201691, and 990100017.

The inspectors agreed with the licensee's conclusion that the main steam safety valves had likely been inoperable during periods of required operability; however, it was not clear exactly when the valves became inoperable. After considering the lack of safety consequences and the uncertainty related to setpoint drift, the inspectors concluded that, for enforcement action in this case, the time of inoperability was the time of discovery. Since the licensee had reset the inoperable valves within the Technical Specification required completion time, no violation of Technical Specification 3.7.1 occurred.

III. Engineering

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Temporary Instruction 2515/142: draindown during shutdown and common-mode failure (Units 2 and 3)

a. Inspection Scope (TI 2515/142)

The inspectors reviewed the licensee's July 7, 1998, evaluation of certain vulnerabilities, required by NRC Generic Letter 98-02, "Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition," May 28, 1998.

b. Observations and Findings

The licensee determined that San Onofre Units 2 and 3 were not susceptible to the failures described in NRC Generic Letter 98-02, because the emergency core cooling system pump trains do not share a common supply header from the refueling water storage tanks and because the shutdown cooling return lines to the pump suctions are isolated from the supply headers by two check valves in series. The inspectors could not identify any vulnerabilities that the licensee had not considered.

c. Conclusions

The licensee's evaluation of vulnerabilities, performed in response to NRC Generic Letter 98-02, "Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition," May 28, 1998, was considered adequate.

E8.2 (Closed) LER 361; 362/1999-006-00: pressurizer heaters and emergency diesel power requirements.

The licensee submitted the LER to address a Technical Specification change of the EDGs' allowed outage time from 72 hours to 14 days and the affect on pressurizer heaters. The inspectors had previously documented Technical Specification submittal weaknesses in NRC Inspection Report 50-361/99-16; 50-362/99-16, Section E8.1. In the LER, the licensee indicated that there may have been one or more instances when an EDG was out of service for more that 72 hours between September 9, 1998, and

November 22, 1999, and therefore Technical Specification 3.4.9 allowed outage time for the pressurizer heaters may have been exceeded. The inspectors reviewed the control room operator logs for that period of time and did not identify EDG outages greater than 72 hours that affected the pressurizer heaters. This LER is closed.

E8.3 (Closed) Inspection Followup Item 361; 362/96010-02: review of the evaluation of Information Notice 96-48.

The inspectors verified that the licensee was in the process of acceptably addressing the motor-operated valve performance issues discussed in NRC Information Notice 96-48, “Motor-Operated Valve Performance Issues,” and the associated Supplement 1. The results of this verification were documented NRC Inspection Report 50-361/99-18; 50-362/99-18. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Personnel Contamination

a. Inspection Scope (71750)

The inspectors reviewed records of loose radioactive material personnel contamination during October, November, and December 1999. The inspectors reviewed portions of the “Topical Quality Assurance Manual,” Revision 13, and the “Topical Report - Quality Assurance Program,” Amendment 20, November 1999. The inspectors also reviewed portions of Procedure SO123-VII-20, “Health Physics Program,” Revision 5, and had discussions with Health Physics personnel and the Health Physics manager.

b. Observations and Findings

Personnel Contamination Record 991209-008 documented a December 9, 1999, contamination of an individual at the south yard facility on site. The south yard facility was used to prepare radioactive material for shipment. The area the individual was working in was not posted as a surface contamination area or a radiologically controlled area, but was posted as a radioactive materials storage area. The individual was preparing to use a vacuum cleaner, marked as radioactive material but not anticipated to have loose surface contamination, to recover sand used to sand blast radioactive material shipping containers. The individual was not signed onto a radiological exposure permit, which was acceptable per the licensee’s program. The individual became contaminated with low levels of loose surface contamination on the skin, with approximately 200 counts per minute above background as measured with a beta/gamma pancake probe. The individual was decontaminated. The vacuum was found to have low levels of surface contamination, 80 counts per minute as measured from a large area smear. This was below licensee limits to require characterizing the vacuum as contaminated material. The licensee stated that the vacuum had been stored for a period of time and that contaminated material inside the vacuum had, probably, leached its way to the surface of the vacuum hose. The licensee also surveyed the work area. No significant dose occurred as a result of the contamination.

The inspectors found that licensee actions in response to the contamination seemed reasonable, but no AR had been generated in order to incorporate the incident into the licensee's corrective action program. Initially, Health Physics supervisory personnel informed the inspectors that ARs were not generated for personnel contaminations. Later, the Health Physics manager indicated that the expectation was that an AR would be generated when a personnel contamination occurred in an area that should have been free of loose surface contamination. The licensee generated AR 000100076.

The inspectors found that contamination of an individual in an area that was supposed to be free of loose surface contamination was a condition adverse to quality. The "Topical Report - Quality Assurance Program," Section 17.2.16, "Corrective Action," provided that an AR would be generated for conditions adverse to quality, but also allowed other programs that met corrective action requirements stipulated in the topical report to be used to document and resolve the condition. Health Physics performed quarterly audits of personnel contaminations, which satisfied the corrective action requirements in the topical report. Consequently, failing to generate an AR was not a violation. However, generating an AR allowed more direct trending and increased visibility and oversight of the occurrence than inclusion in the quarterly audit.

c. Conclusions

Health Physics personnel were not proactive in maintaining a vacuum cleaner free of loose surface contamination, which resulted in a personnel low level contamination occurring in a nonradioactively controlled area. The personnel were also not proactive in generating an AR for the occurrence. Although corrective actions in response to the contamination were reasonable, failure to generate an AR resulted in the condition not being directly recorded and trended in the licensee's overall site corrective action program.

S8 Miscellaneous Security and Safeguards Issues (92904)

S8.1 (Closed) Unresolved Item 361; 362/99007-01: positive access control for personnel not maintained.

A review of the safeguards event logs revealed an incident that occurred on January 8, 1999. The incident was described as an unresolved item in NRC Inspection Report 50-361/99-07; 50-362/99-07.

A contractor worker entered the security access building to gain access to the plant protected area. The worker retrieved the wrong badge from the badge rack and attempted to enter the protected area through the hand geometry system. The system refused the worker access. The worker contacted a security officer and requested re-entry into the hand geometry system computer. The worker did not check the badge to determine if it was the correct one. The security officer re-entered the worker's hand geometry without determining that the worker had the wrong badge. The hand geometry system required two passwords to enter a person into the system. After entering the worker's hand geometry into the computer, a second security officer was called to confirm the information entered and provide the second password to complete the process. The second security officer also did not reconcile the identity on the badge with the worker's true identification.

The worker was then able to use the wrong badge with the worker's own hand geometry to enter the protected area. The worker normally only had access to Vital Areas 2 through 11. The incorrect badge used to enter the protected area had Vital Areas 2 through 12. Although the worker did not enter Vital Area 12, the worker could have accessed Vital Area 12 using the incorrect badge.

Pertinent to this matter, on October 3, 1996, a plant employee entered the protected area with the wrong badge. After the employee attempted to enter the protected area and was denied access by the hand-geometry system, the employee approached a security officer who enrolled the individual in the hand geometry system without verifying employee identification. AR 961000228 described this incident. Corrective action included a change to the procedure to require two security officers to re-enroll an employee.

Physical Security Plan, Revision 61, paragraph 5.1.2, stated that unauthorized protected area access is prevented by the card-reader/hand-geometry reader incorporated systems. Paragraph 5.1.3 stated that routine protected area access through electronically controlled, locked, full-length turnstiles is via a card-reader, in conjunction with a hand-geometry reader. Further, verifying identity consists of verifying the identity of an individual by comparing the individual's badge with an additional picture identification or by personal knowledge of the individual's identity.

Security Procedure SO123-IV-4.4, Revision 5, “Security Lock and Key Control,” paragraph 6.6.2.1, required security officers to compare security photo-identification badge pictures with the individuals requesting enrollment in order to verify identification. Paragraph 6.6.2.1.1 required that the security officer request an additional photo identification to confirm identity. Paragraph 6.6.2 required that a second security officer conduct a verification of the above process. To re-enroll an individual, in the event that the hand-geometry reader failed to open the turnstiles, paragraph 6.6.3.1 required the security officers to start the enrollment process at paragraph 6.6.2.2, after the identification verification process. The failure to prevent unauthorized access to the protected and vital areas by verifying the correct identity of the personnel requesting access is a violation of paragraphs 5.1.2 and 5.1.3 of the Physical Security Plan. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 361; 362/99019-02). The violation was entered into the licensee's corrective action program as AR 990100654.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on January 25, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Brieg, Manager, Station Technical
J. Fee, Manager, Maintenance
J. Hirsch, Manager, Chemistry
R. Krieger, Vice President, Nuclear Generation
J. Madigan, Manager, Health Physics
D. Nunn, Vice President, Engineering and Technical Services
A. Scherer, Manager, Nuclear Regulatory Affairs
K. Slagle, Manager, Nuclear Oversight
T. Vogt, Units 2 and 3 Plant Superintendent, Operations
R. Waldo, Manager, Operations

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	On Site LER Review
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
TI 2515/142	Temporary Instruction - Draindown During Shutdown and Common-Mode Failure

ITEMS OPENED AND CLOSED

Opened and Closed

361; 362/99019-01	NCV	missed Technical Specification surveillance for auxiliary feedwater pumps (Section M8.2)
361; 362/99019-02	NCV	positive access control for personnel not maintained (Section S8.1)

Closed

362/1999-005-00	LER	LTOP relieve valve inoperable (Section M8.1)
361; 362/1999-007-00	LER	missed Technical Specification surveillance for auxiliary feedwater pumps (Section M8.2)

361/1998-025-00	LER	three Unit 2 main steam safety valve as-found setpoints greater than setpoint tolerance (Section M8.3)
361; 362/2515/142	TI	draindown during shutdown and common-mode failure (Section E8.1)
361; 362/1999-006-00	LER	pressurizer heaters and emergency diesel power requirements (Section E8.2)
361;362/96010-02	IFI	review of the evaluation of Information Notice 96-48 (Section E8.3)
361; 362/99007-01	URI	positive access control for personnel not maintained (Section S8.1).

LIST OF ACRONYMS USED

AR	action request
CFR	Code of Federal Regulations
EDG	emergency diesel generator
EP	emergency preparedness
IFI	inspection followup item
LER	licensee event report
LTOP	low temperature overpressure protection
MO	maintenance order
NCV	noncited violation
NRC	Nuclear Regulatory Commission
TI	Temporary Instruction
URI	unresolved item