U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-206/86-16

Docket No. 50-206

License No. DPR-13

Licensee: Southern California Edison Company
P. O. Box 800, 2244 Walnut Grove Avenue
Rosemead, California 92770

Facility Name: San Onofre Unit 1

Inspection at: San Onofre, San Clemente, California

Inspection conducted: March 10-14 and March 28 through May 12, 1986

Inspectors: P H Johnson 6/2/86
for F. R. Huey, Senior Resident Inspector, Units 1, 2 and 3 — Date Signed

P H Johnson 6/2/86
for J. P. Stewart, Resident Inspector — Date Signed

P H Johnson 6/2/86
for A. D'Angelo, Resident Inspector — Date Signed

P H Johnson 6/2/86
for J. E. Tatum, Resident Inspector — Date Signed

P H Johnson 6/2/86
for R. C. Tang, Resident Inspector — Date Signed

F. Wenslawski 6/2/86
for G. A. Brown, Emergency Preparedness Analyst — Date Signed

Approved By: P H Johnson 6/2/86
P. H. Johnson, Chief, Reactor Projects Section 3 — Date Signed

F. Wenslawski 6/2/86
for R. F. Fish, Chief, Emergency Preparedness Section — Date Signed

Inspection Summary

Inspection on March 10-14 and March 28 through May 12, 1986
(Report No. 50-206/85-16)

Areas Inspected: Special emergency preparedness inspection of issues related to the November 21, 1985 water hammer event. Routine resident inspection of Operations Program including the following areas: operational safety verification, monthly surveillance activities, monthly maintenance activities, refueling activities, independent inspection, licensee events report review, and follow-up of previously identified items. Inspection Procedures 37701, 71707, 73051, 62703, 73052, 73753, 62700, 72701, 62703, 60710, 82201, 82203, 82206, 92700, 92701, 61726, 60705 and 92702 were covered.

Results: No violations or deviations were identified.

DETAILS - PART 1

Resident Inspection Staff - March 28 - May 12, 1986

1. Persons Contacted

Southern California Edison Company

H. Ray, Vice President, Site Manager
*G. Morgan, Station Manager
*M. Wharton, Deputy Station Manager
*D. Schone, Quality Assurance Manager
D. Stonecipher, Quality Control Manager
*R. Krieger, Deputy Station Manager
*D. Shull, Maintenance Manager
J. Reilly, Technical Manager
P. Knapp, Health Physics Manager
*B. Zintl, Compliance Manager
J. Wambold, Training Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
*J. Reeder, Operations Superintendent, Unit 1
H. Merten, Maintenance Manager, Unit 1
*R. Santosuosso, Instrument and Control Supervisor
*T. Mackey, Compliance Supervisor
G. Gibson, Compliance Supervisor
*C. Cowser, Compliance Engineer
*P. King, Quality Assurance Supervisor
*R. Waldo, Plant Computer Supervisor

San Diego Gas & Electric Company

*R. Erickson, San Diego Gas and Electric

*Denotes those attending the exit meeting on May 1, 1986.

The inspectors also contacted other licensee employees during the course of the inspection, including operations shift superintendents, control room supervisors, control room operators, QA and QC engineers, compliance engineers, maintenance craftsmen, and health physics engineers and technicians.

2. Operational Safety Verification

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the Tag Out log and verified proper return to service of affected components. Particular attention was given to housekeeping, examination for potential fire hazards, fluid leaks, excessive vibration, and verification that maintenance requests had been initiated for equipment in need of maintenance.

3. Monthly Surveillance Activities

The inspector observed portions of the diesel generator load test on diesel generator No. 2, which is required by technical specifications every 31 days. The test was observed to be conducted in accordance with procedure SO1-12.3-10, TCN 4-7.

No deviations or violations were identified.

4. Monthly Maintenance Activities

The following post maintenance testing activities for Unit 1 were observed by the inspector during the current inspection period. No deviations or violations were identified.

(a) In-Service Leak Test for Miniflow Orifice FO-1405 for South Charging Pump

The inspector observed the in-service leak test (VT-2) on flow orifice (FO-1405) and the piping downstream of the flow orifice located on the miniflow line of Unit 1 south charging pump. FO-1405 and this section of piping were replaced during the current outage.

The test was conducted in accordance with procedure SO123-V-4.16, Revision 2, TCN 2-2, as well as the pre-established and pre-approved test requirements and acceptance criteria which are delineated in Traveler No. SO1-056-85, Revision 2. There were no leakages observed through the flow orifice and/or the replacement piping downstream of it. The inspector noticed that several entries in the Oil Monitoring Data Form (posted in the charging pump room) lack specificity. On January 24, 1986, (south charging pump) and on February 15, 1986, and March 20, 1986 (north charging pump), it was recorded that oil had been added to the "reservoir" or "OB" (outboard bearing). It is not clear whether the lube oil had been added to the pump or motor bearing. The SCE Maintenance Lube Oil Manual specifies that Chevron GST oil 46 be used for the charging pump motor (no substitute allowed), and Chevron GST oil 32 be used on the charging pump bearing (DTE light can be used as emergency substitute). The inspector was informed by the plant equipment operator that anytime they add lube oil to safety related equipment, a phone call must be made to the control room to verify the type of oil used. The inspector reviewed this item with the Unit 1 superintendent, who agreed to ensure that oil additions are more clearly recorded.

(b) Letdown Isolation Valve CV-525 Stroke Test

During the current outage, cables and conduit for CV-525 were rerouted to avoid interference with piping. In addition, the valve actuator was overhauled due to excessive leakage noted during recent LLRT. The valve initially failed the post-maintenance stroke test which is part of the Operations In-Service Valve Testing (SO1-12.4-2, TCN 5-7). The inspector observed the licensee efforts to correct the stroke time of CV-525 by adjusting the flow control valve on the valve actuator. The valve was subsequently tested and the stroke time was found to be satisfactory.

(c) South Charging Pump In-Service Testing

The inspector observed the in-service test (IST) of the south charging pump (G-8B) which is performed to demonstrate the operability of the pump in compliance with the Unit 1 technical specifications requirement 3.2. The overall in-service testing program for pumps is addressed in procedure SO1-V-2.14, Revision 6, TCN 6-2. Detailed IST for charging pumps is delineated in Procedure SO1-V-2.14.11, Revision 1. The IST was conducted in accordance with applicable procedures and no discrepancies were identified. The inspector is currently reviewing IST data associated with this test. The results of this review will be documented in the next routine inspection report.

(d) Diesel Generator No. 2 Post Maintenance Testing

The diesel generator was overhauled during the current outage. The inspector observed the licensee preparations for the 15-minute and one-hour no load tests as part of the restoration and maintenance verification testing. The inspector also observed the cold crankshaft web deflection measurements. All measurements were within the acceptance criteria as stated in procedure SO1-I-8.15, Revision 0, TCN 0-10.

No violation or deviation was identified.

5. Followup of Water Hammer Event

a. Check Valve Design

(1) Following the Unit 1 water hammer event on November 21, 1985, the licensee determined that the water hammer was caused by the simultaneous failure of five safety related check valves in the main feedwater system. All of the valves which failed were Pacific swing type check valves. Two of the valves (FWS-345 and 346) had failed completely, in that the valve disk had become disconnected from the hinge arm and was found lying in the bottom of the valve body. Three of the valves (FWS-398, 438, and 439) had degraded to the point of inoperability in that the disk to hinge arm nut had come loose, allowing the disk to offset such that disk antirotation lugs became wedged under the hinge arm, preventing proper seating of the disk.

(2) As a result of the failure of these check valves, the licensee initiated a program to evaluate the adequacy of Unit 1 check valve design and application. The first part of this program involved a determination of the cause of the failure of the five feedwater check valves. As documented in the April 8, 1986 "Investigation Report", the licensee has determined that the failure of the five feedwater check valves was the result of a combination of effects involving: dangling of the valve disk in the flow stream; excessive flow turbulence due to the close proximity of three of the check valves to their respective flow regulating valves; and susceptibility to

degradation of the specific disk-to-hinge arm fastening configuration under these particular flow conditions. To correct this set of problems, the licensee took several actions. The Pacific check valve design was replaced with an Atwood Morrill design that eliminated the two piece disk and hinge configuration. The three feed regulator check valves were moved further downstream from their respective feed regulating valves. The licensee conducted testing of the new check valve design and flow configuration to demonstrate satisfactory performance under varying flow conditions. The licensee reviewed all available NPRDS check valve data, reviewed over 500 LER's involving check valves over the last 10 years, and conducted a telephone survey of 22 utilities regarding their experiences with check valves. The licensee has concluded that their corrective actions will preclude recurrence of similar check valve failures. The results of additional NRC inspection of the above activities will be included in the report to be issued by the IE, Vendor Program Branch, documenting a March 1986 site visit.

(3) The second part of the licensee check valve review program involved efforts to determine whether any other Unit 1 check valves may have experienced similar failure mechanisms. The licensee implemented a four part program to make this determination.

(a) Every Pacific check valve (29 total) in the plant was disassembled and inspected. One additional valve failure was discovered involving a feedwater heater check valve (FWH-437), on which the hinge pin had failed resulting in the disc and hinge arm falling to the bottom of the valve body.

(b) A review of maintenance histories for all Unit 1 swing check valves (141 total maintenance orders) identified five check valves which had required corrective maintenance involving problems with valve internals. These valves were disassembled and inspected and no problems were observed.

(c) Calculations were performed to identify which Unit 1 swing check valves would be expected to be less than fully open during nominal operating conditions. A total of 15 check valves were identified, disassembled and inspected. All of these valves were classified as involving turbulent flow in accordance with the 10 pipe diameters upstream and 5 pipe diameters downstream turbulence rule. Only one of these valves was determined to be inoperable, a service and domestic water valve (SDW 002), which was observed to have excessive corrosion of the valve seat.

(d) A review of NPRDS check valve data indicated that certain models of Borg Warner, Crane, Kerotest and Pacific check valves have a higher than normal failure rate. The licensee has identified four check valves (one Borg Warner, one Crane and two Kerotest) at SONGS 1 of those experiencing the higher failure rate. Disassembly and inspection of these valves identified no problems with the exception of one Kerotest spring loaded check valve on the gaseous nitrogen system (GNI 102), which required seat lapping.

(4) The resident inspectors independently reviewed the maintenance and testing histories for Unit 1 check valves and concluded that the valves selected by the licensee for inspection were proper and sufficient. The inspectors also reviewed the check valve configuration for several safety related systems to identify check valves whose failure could prevent proper safety system function. As a result of this review, the inspector requested the licensee to inspect discharge check valves associated with the electric auxiliary feedwater pump. These valves were disassembled, inspected and found to be satisfactory. The inspectors also observed several of the disassembled check valves and concurred with the licensee operability determinations. (This inspection activity completes resident action on items 1.b.1, 1.b.2, 1.b.3, 1.b.4 and 1.e.1 of NRC Action List II for Unit 1 Return to Service).

b. <u>Check Valve Testing</u>

(1) The Unit 1 water hammer event clearly demonstrated that the manner in which the in-service testing (IST) program implemented by the licensee was not effective in detecting the failure of several safety related check valves. One of the most significant failings of the program appears to be a lack of dedicated cognizant engineering leadership of the program in order to ensure proper interpretation of test results and priority of test performance. This appears to be of special importance for Unit 1, which involves several unique plant design configurations.

(2) The generic aspects of the adequacy of IST program implementation by licensees is currently under evaluation by the NRC offices of IE and NRR, and their evaluations will be reported separately. In light of the specific problems noted at San Onofre, the resident inspectors addressed their IST program concerns with the licensee and requested that the specific program changes intended by the licensee for Unit 1 return to service be identified. The licensee identified that the following IST program changes would be implemented for Unit 1 return to service:

(a) The Station Technical organization will assume responsibility for the control of testing of all valves. The program will be revised to require that a minimum of

25% of all cold shutdown valves be tested each Mode 5 outage. The goal will be to test all valves, if time allows.

(b) Station Technical will organize and maintain a comprehensive, computerized data base for all valves in the IST program. The cognizant IST engineers will utilize this data base to:

- Track the testing status of each valve.

- Establish a technical performance base for each valve.

- Provide maintenance and testing visibility to the IST engineer in order for him to adjust valve program testing frequency to ensure that the program remains responsive to current conditions.

- Provide for data base review by the IST engineer to ensure that maintenance outage work on valves takes into account the valve's program performance. The Engineer will adjust testing interval on the basis of the Code requirements and his professional judgment.

- Cold shutdown interval valves will be selected on the basis of the testing performance and the maintenance history (i.e., the worst performing valves will get tested more than others).

- Reports will be provided to the cognizant engineer to identify problem valves which need design upgrading.

- The IST engineer will, on a periodic basis, issue trend reports to management identifying problem areas and to highlight trends. Trends that are of concern will be brought to the attention of the On-Site Review Committee.

c) The IST procedure for the six 10 inch feedwater check valves downstream of the feed regulators will be revised to require a quantitative leak check.

d) The two 12 inch feedwater check valves on the feed pump discharge will be disassembled and inspected each refueling outage.

e) Station Technical will evaluate the current test requirements for all safety related check valves to ensure that the specified tests are adequate to provide assurance of proper reverse flow check operability.

(3) The licensee identified that the following IST program changes were being evaluated and would be implemented within the next six months:

a) Station Technical will complete an engineering review to develop new test techniques to allow more valves to be tested during Mode 1 operation.

b) Station Technical will determine whether additional check valves warrant a quantitative leak check.

c) Station Technical will determine whether additional check valves which can not be readily tested warrant periodic disassembly and inspection.

This is an open item (50-206/86-16-01).

6. <u>Exit Meeting</u>

On May 1, 1986, an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in this report.

DETAILS - PART 2

Inspector: G. A. Brown, Emergency Prepardness Analyst (March 10-14, 1986)

1. Persons Contacted

R. Krieger, Operations Manager
J. Schramm, Supervisor of Coordination
G. Moore, Shift Superintendent
R. Zamonas, Nuclear Operations Assistant
D. Peacor, Supervisor Emergency Preparedness
D. Bennette, Emergency Preparedness
C. Wells, Program Coordination, Emergency Management Division, Orange County Fire Department
T. Dailey, Fire Chief, City of San Clemente, California
J. Stubb, Emergency Planning Officer, City of San Clemente, California
C. Ferguson, Emergency Planning Officer, Public Works Department, City of San Juan Capistrano, California

2. Background

a. Emergency Preparedness-Related Events Prior to Reactor Trip

The regular shift Control Room crew was actively involved in tracing the origin of a ground fault along the electrical system supplied through Bus 1C. It became apparent to the crew early in the proceedings that Bus 1C might have to be de-energized to locate the ground. Since this bus supplied safety-related equipment, its de-energization would involve the declaration of an Unusual Event in accordance with their emergency plan. To expedite handling of this anticipated Unusual Event, the Shift Superintendent (SS) had directed that, to the extent possible, necessary paperwork be completed in advance of the declaration. He also directed members of his crew, such as the Nuclear Operations Assistant (Shift Communicator), to review applicable portions of the Emergency Plan Implementing Procedures (EPIPs). Additionally, the Shift Superintendent's (SS) immediate superior, the Supervisor of Coordination, was also present to assist in preparations. Thus, prior to the event, the licensee had a reinforced crew available, that was already preparing for the declaration of an Unusual Event, although it was not the event that actually occurred.

b. Emergency Preparedness-Related Events After the Reactor Trip

At the time of the reactor trip, five operators were in the Control Room. The Supervisor of Coordination had left the Control Room prior to this occurrence but immediately returned when he heard the sounds of the reactor shutdown. He arrived at the Control Room before the lost power was restored. He observed that Control Room personnel were engrossed in mitigating the event and felt that any attempts on his part to actively participate would cause confusion.

among the crew members. He remained passive, observing the actions of the crew. He did take part in frequent conferences with the SS and others about proposed actions. This decision of the Supervisor of Coordination to remain passive, while proper, gave the SS the erroneous impression that the Supervisor of Coordination was fully informed on the plant status when he (SS) requested the Supervisor of Coordination to relieve him of his responsibilities as the Emergency Coordinator.

Shortly after power was restored, the Supervisor of Coordination, at the request of the SS, assumed the responsibilities of Emergency Coordinator, with a minimal turnover. The Emergency Coordinator's primary function is to direct the implementation of applicable provisions of the emergency plan and EPIPs. His first actions were to declare the Unusual Event and begin notification of offsite authorities.

c. <u>Chronological Sequence of Emergency Preparedness Events</u>

Time	Event
0450	Loss of power. Reactor manually tripped.
0451	Initial Licensee's contact, via ENS, with NRC Operations Center
0501	Second licensee contact, via ENS, with NRC Operations Center
0506	Unusual Event declared
0507	Began notifying offsite authorities. Ring-down phones fail. Begin sequential notification using commercial phone system.
0520	Notified dispatcher of Unusual Event
0525	Completed notification of offsite authorities
0532	NRC Resident Inspector contacted by licensee. He had already been advised of situation by NRC Headquarters.
0547	Third licensee contact, via ENS, with NRC Operations Center
0558	Open-line communications established with licensee, NRC Headquarters, and NRC Region V
0620	(Approximate) Licensee notifies NRC of Unusual Event
0640	Emergency Coordinator responsibilities

transferred to the Plant Manager from the Supervisor of Coordination. Basis of Unusual Event classification changed.

0940 Closed Unusual Event

3. Evaluation of Plant Performance

a. Program Basis

In compliance with 10 CFR 50.47 and 10 CFR 50.54(q), the licensee is required to maintain an approved emergency response plan that provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. The licensee's emergency plan addresses the duties and responsibilities of each member of the emergency response organization. It also provides for a standard emergency classification and emergency action level scheme. These Emergency Action Levels (EALs) provide criteria for the standard classification of the severity of an emergency. Each level invokes specific response actions by the licensee's emergency organization as well as local, State and Federal agencies. During this occurrence, the least severe classification, Notification of Unusual Event, was declared. Actions in response to this level of severity require only notification of offsite agencies and the NRC. Licensee actions toward the mitigation of the event are discussed elsewhere in this report.

The following areas of the licensee's response were addressed during this special inspection:

(1) Emergency Detection and Classification
(2) Notifications and Communications
(3) Knowledge and Performance of Duties

b. Event Related Aspects

(1) Emergency Detection and Classification

Pursuant to 10 CFR 54.47(b)(4) and 10 CFR Part 50, Appendix E, Sections IV.B and IV.C, this area was inspected to determine whether the licensee used and understood the standard emergency classification and action level scheme during this event.

The inspector interviewed Control Room personnel and reviewed logs and other documents to determine the licensee's response to the event. The interviews and records examined showed that the licensee promptly and properly classified the event using the appropriate classification procedures. However, the following adverse actions related to the event were noted:

The SS did not refer to the emergency classification procedure SO1-VIII-1 when he made the initial status report to the NRC. In that report (the second ENS call), the SS alluded to the possibility of an Alert declaration. This information was based on his own personal assessment of the situation and was given prior to any reference to the EALs. This action was not consistent with the licensee's Procedure SO1-VIII-1 which requires the SS, within 15 minutes of recognition of off normal conditions, to review the Event Category Tabs (EALs). The requirement implied that this review be done prior to making any attempts at classifications. Procedure SO1-VIII-1 was revised to clearly require comletion of a notification form for use in making notifications. The licensee also added coverage of this process to the EP training program.

No violations were identified in this area.

(2) Notifications and Communications

Pursuant to 10 CFR 50.47(b)(5) and (6) and 10 CFR Part 50, Appendix E, Section IV.D, this area was inspected to determine whether the licensee's ability to notify and communicate with its own personnel, offsite agencies and Federal authorities was adequate.

The inspector reviewed the licensee's notification procedures and records of notification. Representatives of offsite local government agencies were interviewed and their records pertaining to the event were examined to determine if they were in agreement with those of the licensee.

Notification of STA. The licensee's Emergency Operating Procedure (EOP) No. SO1-1.0-11, in connection with an emergency declaration, requires the SS to verify the presence of the Shift Technical Advisor (STA), or, if not present, to notify him of the event. The STA is then required to report to the Control Room within 10 minutes. Contrary to this provision in the EOP, the SS did not notify the STA as required. However, the STA reported to the Control Room of his own volition in about 11 minutes of the event. It was noted that the requirement to notify the STA was located in an obscure position in the EOP. The licensee revised this EOP to provide higher visibility and priority for notification of the STA. This procedure revision relocated the STA notification requirement to the first step after the completion of immediate actions. The notification requirement was also added to the EOP at steps where the procedure could be terminated. This corrective action appears adequate.

General Announcement of Emergency Coordinator Change. A provision in the licensee's EPIP No. SO123-VIII-10 requires that a general announcement be made to all personnel notifying them when a change in Emergency Coordinators occurs. The Supervisor of Coordination did not make this announcement when he assumed the responsibilities of the Emergency Coordinator. His failure to make this announcement resulted in confusion regarding the identity of the Emergency Coordinator. For example, the station log erroneously indicated that the Station Manager relieved the SS as Emergency Coordinator, when, in fact, it was the Supervisor of Coordination who was relieved. This will be examined during a future inspection (Followup Item No. 50-206/86-16-02).

NRC Notification of Unusual Event Classification. It was determined that offsite notifications were made in a timely manner. The content of the emergency messages was reviewed and discussed with licensee representatives as well as representatives of local government agencies. The messages met the guidance of NUREG-0654, Sections II.E.3 and II.E.4. However, the NRC was not specifically made aware of the Unusual Event declaration within the time required. 10 CFR 50.72(a)(1)(i) and 10 CFR 50.72(a)(3) require that the licensee notify the NRC of the declaration of any emergency class immediately after notification of appropriate State and local agencies, and not later than one hour after the time the licensee declares one of the Emergency Classes. The Unusual Event was declared at 0506, but it was after 0615 before the words "declared an Unusual Event" were spoken to the NRC. However, since the NRC was cognizant of the plant status through open-line communications established at 0558 and had been apprised of the licensee's situation on three prior communications, the only action lacking was providing the official statement of Unusual Event. This lack of formal statement was not construed as a violation of the requirement. It was noted, however, that had the licensee adhered to provisions in the EPIPs, the NRC would have been properly notified of the declaration in a timely manner as a matter of course. As corrective action, the licensee revised Procedure S0123-VIII-30.1, "Shift Communicator Duties," to make the shift communicator responsible for the initial NRC notification (of change in emergency classification) immediately following notification of offsite authorities. This corrective action is considered appropriate.

Training provided to members of the emergency response organization was also reviewed. It was noted that the licensee's program provided a great deal of training which addressed the more serious emergency events, but relatively little training in handling the levels of emergency which personnel are more likely to encounter, e.g., the Unusual Event and Alert level emergencies. This was addressed by improvements in the licensee's EP training program.

(3) Spurious Ringing of ENS Phones

Loss of power at the onset of the event initiated spurious ringing of the Emergency Notification System telephones at both the site and NRC Headquarters. This spurious ringing initiated communications prematurely between the site and NRC, before the licensee had an opportunity to assess the situation. This premature contact resulted in confusion for both parties during the early stages of the event. An investigation by the licensee for the cause of this spurious ringing revealed that it was due to a Lorain inverter cycling. When main power was interrupted, the inverter could take up to 700 milliseconds to cycle through and transfer to the battery power source. The inverter is activated only after a drop to 10 volts from the normal 120 volts. The Lorain inverter normally cycles in 14-22 milliseconds, however, if a longer time span occurs during cycling, such as during a transformer shift, the signalling frequency tone will drop to an abnormally low level, causing the phone to inadvertently ring. The licensee has corrected this problem by switching the main power source to DC power and using AC power as its back-up source. This corrective action by the licensee appears adequate to prevent recurrence.

(4) Emergency Notification Ring-Down Phones

Because three separate emergency notification systems failed, The licensee was forced to rely on individual sequential telephone calls over the commercial system to make the required offsite notifications. These failures caused a delay in completing the notifications. Notifications to the counties were completed within 15 minutes and to all offsite agencies within an acceptable 19 minutes of the declaration. However, had the ring-down systems been operable, notification could have been completed sooner. The licensee must ensure that emergency notification ring-down phone systems are reliable after loss of power events. This will be tracked as Followup Item No. 50-206/86-16-03.

No violations were identified in this area.

(5) Knowledge and Performance of Duties

Pursuant to 10 CFR 50.47(b)(15) and 10 CFR Part 50, Appendix E, Section IV.F, this area was inspected to determine whether emergency response personnel understood their emergency response roles and performed their assigned functions during this event.

The inspector examined logs and documents relating to this event and conducted interviews with selected key members of the emergency organization during this event. The inspector concluded that, in general, the individuals performing emergency response roles during this event were familiar with emergency procedures and equipment. However, the following adverse actions related to the event were noted:

The SS and the Supervisor of Coordination did not follow the procedure in transferring the responsibilities of the Emergency Coordinator position. Attachment 2 to Procedure SO123-VIII-10, "Turnover Status", requires that the plant status be recorded at the time of the turnover. Failure to follow this procedure resulted in an inadequate turnover to the Supervisor of Coordination with subsequent inaccurate information being provided to the NRC regarding plant conditions. This concern was addressed by revision of procedure S01-VIII-1 as discussed in paragraph 3.b(1).

(6) Documentation

A review of the licensee's documentation and recordkeeping during the event revealed several instances of erroneous and conflicting data. For example:

(a) There was no indication in either the Station Log or the Shift Superintendent's Log that the Supervisor of Coordination had ever assumed the duties of Emergency Coordinator. In fact, the Station Log erroneously indicated that the SS was acting as the Emergency Coordinator up until the time he was relieved by the Plant Manager.

(b) The Emergency Coordinator's Log conflicts with the Station Log and the Shift Superintendent's Log regarding the time of transfer of the Emergency Coordinator's duties to the Plant Manager. The Emergency Coordinator's Log indicates that the transfer took place at 0640 while the other two logs indicate that it occurred at 0702 hours.

(c) Message No. 4 to offsite authorities contained conflicting and confusing times. It indicated that it was issued at 0850, but its purpose was to close out the event at 0941, 51 minutes in the future.

(d) The Shift Communicator Log was maintained alternately by several unidentified individuals. No means is provided for identifying which individual made a particular entry. This makes reconstruction of an event difficult when a particular entry needs clarification.

No violations were identified in this area. However, the following should be considered for program improvement:

o Place more emphasis in proper recordkeeping in the training program.

4. Exit Interview

At the conclusion of the March 11-14, 1986 special inspection a summary of the findings was presented to the licensee. Messrs. D. Peacor and D. Bonnette represented the licensee. The licensee was informed that none of the findings appeared to be violations of NRC regulations.