ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-275; 50-323
License No.:	DPR-80; DPR-82
Report No.:	50-275/98-21; 50-323/98-21
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Unit 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	December 4 to 18, 1998
Inspectors:	Scott A. Boynton, Senior Resident Inspector, WNP-2 Richard M. Pelton, Office of Nuclear Reactor Regulation
Contributing Personnel:	David L. Proulx, Senior Resident Inspector
Approved By:	Linda J. Smith, Acting Chief, Project Branch E

ATTACHMENTS:

Attachment 1	Supplemental Information
Attachment 2	Sequence of Events

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Unit 2
NRC Inspection Report 50-275/98-21; 50-323/98-21

Operations

- Overall, the operating crew responded satisfactorily to the degraded conditions in the circulating water system and the manual reactor trip by effectively stabilizing the plant in a safe condition. However, the generally successful response to the event was adversely impacted by several performance issues (Section O4.1).

- The crew did not understand the response of the intake screen differential pressure indication to a unit trip, which led them to improperly leave Circulating Water Pump 2-2 operating and resulted in the screen differential pressure exceeding the design limits. Weak fidelity among the annunciator response procedures and an abnormal procedure and the crew's narrow focus on pump motor amps also contributed to the delay in securing the circulating water pump. One example of a violation of Technical Specification 6.8.1 was identified for failure to secure the pump in accordance with abnormal operating procedures; however, because the licensee implemented effective corrective actions, no response was required (Section O4.1.b.4).

- The crew's misunderstanding of the effects of atmospheric dump valve pressure setpoint adjustments on the reactor coolant system, coupled with a communication error between the control operator and the shift foreman, resulted in a pressure setting of the atmospheric dump valves that exceeded the setpoint specified in the procedure. The higher pressure setting unnecessarily challenged the main steam safety valves when it contributed to the lifting of Main Steam Safety Valve RV-7. A second example of a violation of Technical Specification 6.8.1 was identified for failure to implement emergency operating procedure requirements; however, because the licensee implemented effective corrective actions, no response was required (Section O4.1.b.5).

- The management process for collecting plant process information and evaluating equipment response to the manual reactor trip was rigorous in identifying and addressing equipment performance problems (Section 07.1).

- The process for evaluating human performance lacked the same degree of formality and structure as the management process for evaluating equipment response. The lack of structure, coupled with poor operating logs, made it difficult to reconstruct event details and assess the root cause of specific operator performance issues (Section O7.1).

Maintenance

- With the exceptions of the early lift of Main Steam Safety Valve RV-7 and the autostart of Diesel Emergency Generator 2-2, plant equipment responded to the plant trip as designed. The licensee implemented appropriate corrective actions to address the low

setpoint on the main steam safety valve. The autostart of the diesel emergency generator resulted from a long-standing design deficiency that had been previously identified by the licensee and was not a safety concern. The licensee had initiated action to correct the deficiency prior to the plant trip (Section O2.1).

Report Details

Summary of Plant Status

On December 4, 1998, Unit 1 operated at 50 percent power because of a failed expansion joint in the intake cooling system. Operators returned Unit 1 to 100 percent power on December 5. On December 17, operators shut down the reactor after identifying increased containment sump leakage. The licensee identified that the leak was from a weld on the component cooling water supply line to Reactor Coolant Pump 1-3 upper bearing cooler. Unit 1 was in Mode 3 at the end of the inspection period.

Unit 2 was in Mode 3. Operators had manually tripped the reactor on December 1 because of high kelp loading on the traveling screens. Operators returned Unit 2 to full power on December 9 following repairs to balance of plant equipment.

O2 Operational Status of Facilities and Equipment

O2.1 Plant Equipment Performance

a. Inspection Scope (92901)

The inspectors reviewed the sequence of events and compared it to the plant process parameter data recorded during the event to determine the adequacy of plant equipment performance. Also, the inspectors evaluated corrective actions in which equipment performance was not as expected.

b. Observations and Findings

In general, the plant responded as expected to the manual reactor trip, turbine trip, and main steam isolation valve closure. However, two safety-related components did not respond to plant conditions as designed: Main Steam Safety Valve RV-7 and Diesel Emergency Generator 2-2. Main Steam Safety Valve RV-7 (nominal setpoint of 1065 psig) lifted unexpectedly when operators inappropriately raised steam generator pressure to 1035 psig. The main steam safety valve lifted at a pressure just below its Technical Specification pressure band of 1044 - 1097 psig. Subsequent testing of the main steam safety valve showed an as-found setpoint of 1039 psig, a pressure consistent with the setting of the atmospheric dump valve pressure controllers. The main steam safety valve was declared inoperable and its setpoint adjusted within 1 percent of its Technical Specification-required value. Valve RV-7 was the low setpoint safety valve on Main Steam Lead 2.

To evaluate the generic implications of the low lift point on Main Steam Safety Valve RV-7, the licensee tested Main Steam Safety Valves RV-3 and RV-8 on Steam Leads 1 and 2, respectively. The as-found pressure setpoints for both valves were found to be within Technical Specification limits and the licensee concluded it was not necessary to test other valves. The licensee selected these main steam safety valves because the valves had low values for their pressure setpoint and had been refurbished at the same time as Main Steam Safety Valve RV-7. The inspectors determined that corrective actions associated with Main Steam Safety Valve RV-7 were appropriate.

Following the reactor trip, the electrical supply to the 4160V vital busses transferred to the startup transformer. Although the transfer to startup power is designed to preclude a start of the diesel emergency generators, Diesel Emergency Generator 2-2 autostarted; however, Diesel Emergency Generator 2-2 did not load onto its associated vital bus, Bus H. This phenomenon, which had occurred on two previous plant trips, was previously evaluated by the licensee and determined to result from relatively light electrical loading on Bus H. This light bus loading translated to a slow voltage decay when the auxiliary feeder breaker opens. The slow voltage decay allows the first level undervoltage relay to time-out and start Diesel Emergency Generator 2-2 prior to reaching the low voltage setpoint that closes the startup feeder breaker to Bus H. The phenomenon had also been observed, in one instance, with Diesel Emergency Generator 1-1 on Unit 1.

To determine the impact of the inadvertent starts of Diesel Emergency Generators 1-1 and 2-2, the inspectors compared the number of inadvertent starts to the total number of start demands placed upon the two diesel emergency generators. Since 1992, there had been over 500 start demands placed on Diesel Emergency Generators 1-1 and 2-2. Of those starts, four resulted from a slow voltage decay on the vital bus following a unit trip. Therefore, the inspectors concluded that the inadvertent starts did not significantly impact component aging or reliability of the diesel emergency generators.

To correct the deficiency, the licensee submitted a license amendment request in October 1998 to set the first level undervoltage relays to a lower value. The lower value is expected to limit the time between the start of the first level undervoltage relay timer and the low voltage setpoint that closes the startup feeder breaker. Thus, the timer would not time-out prior to restoring bus voltage from startup power.

c. Conclusions

With the exceptions of the early lift of Main Steam Safety Valve RV-7 and the autostart of the Diesel Emergency Generator 2-2, plant equipment responded to the plant trip as designed. The licensee implemented appropriate corrective actions to address the low setpoint on the main steam safety valve. The autostart of the diesel emergency generator resulted from a long-standing design deficiency that was not a safety concern. The licensee had initiated action to correct the deficiency prior to the plant trip.

O4 Operator Knowledge and Performance

O4.1 Operator Response to Loss of Main Condenser and Manual Reactor Trip

a. Inspection Scope (92901)

The inspectors evaluated operator performance in preparing for and responding to the degraded intake conditions and manual reactor trip. Specifically, the inspectors evaluated command and control, operator knowledge, internal and external communications, and procedure use and adequacy.

In responding to the plant conditions produced by the high sea state, operators utilized the following procedures:

- ARP PK13-04, "Condenser Delta P HI PPC," Revision 3
- OP AP-7, "Degraded Condenser," Revision 17
- OP L-7, "Plant Stabilization Following Reactor Trip," Revision 2
- OP O-28, "Intake Management," Revision 2
- EOP E-0, "Reactor Trip or Safety Injection," Revision 12
- EOP E-0.1, "Reactor Trip Response," Revision 13

b. Observations and Findings

b.1 Communications

Attachment 1 to Procedure OP1.DC11, "Conduct of Operations - Abnormal Plant Conditions," Revision 12, stated that three-way communications were the standard for communication. This standard was established during the 1998 training cycle and had been in place for approximately 6 months. From operator interviews, the inspectors determined that three-way communications were not consistently utilized during the event and tended to degrade as the event progressed. The inspectors validated this finding through direct observation of two separate crews on the plant simulator and control room observations of the Unit 2 plant startup. In each observation, inconsistent use of three-way communication indicated that three-way communication had not yet become a habit with the operators. The lack of complete three-way communications only resulted in one identified human performance error. Specifically, inadequate three-way communications between the control operator and the shift foreman contributed to the improper setting of the 10 percent atmospheric dump valve controllers discussed below in Section 04.1.b.5.

Prior to the manual reactor trip, the operating crew was cognizant of the degrading conditions in the Unit 2 main condenser and established a conservative action level to reduce plant load when condenser quadrant differential pressure reached 9 psid (plant procedures require load reduction at 10 psid). Subsequently, condenser quadrant differential pressure continued to increase at a rate of between 0.5 and 1.0 psid/hr. Procedure OP O-28, "Intake Management," Revision 2, recommended notification of the operations services manager and the operations director if it was likely that a load decrease will be required. However, operations management was not notified of the potential need to reduce plant load. Early notification of operations management would have allowed management to be involved in the decision process regarding continued plant operations.

b.2 Command and Control

Overall, the shift foreman demonstrated good performance in carrying out his control room command responsibilities. Assignment of the senior control operator to monitor circulating water and condenser conditions ensured timely closure of the main steam isolation valves when Circulating Water Pump 2-2 was secured. Proper focus of the

balance-of-plant control operator on auxiliary feedwater allowed for timely identification of the feedflow mismatch on Steam Generator 2-2 and investigation of a possible steam or feedwater leak.

One weakness was identified in regard to crew briefings. Crew briefings were not performed when the operators transitioned to Procedure EOP E-0.1, "Reactor Trip Response," Revision 13, or when they transitioned to Procedure OP L-7, "Plant Stabilization Following Reactor Trip," Revision 2. The lack of briefings was inconsistent with management expectations as specified in Procedure OP1.DC11. The briefings would have been beneficial in: (1) highlighting the overall strategy of the procedures, (2) emphasizing specific actions and the thresholds at which they are taken, and (3) assigning specific crew responsibilities for those actions, as necessary. Detailed briefings were also not conducted prior to use of Procedures OP O-28 and OP AP-7, "Degraded Condenser," Revision 17. These procedures addressed the potential consequences of the high swell warning in effect and provided specific strategies for protecting the normal plant heat sink. Discussing the strategies could have highlighted the requirement to immediately secure a circulating water pump when the intake screen differential pressure exceeded the design limit of 50 iwg specified in Procedure O-28, Section 6.3.

The shift foreman also failed to ensure that actions were completed to reset the atmospheric dump valve pressure controllers in accordance with Procedure EOP E-0.1, as discussed below in Section 04.1.b.5.

b.3 Procedure Use and Adequacy

Prior to the reactor trip, operators responded to several alarms associated with main condenser and intake screen differential pressures. No information was found to indicate that the annunciator response procedures associated with the alarms were not properly implemented. However, the inspectors noted a gap between Procedures ARP PK13-04 and OP AP-7 that did not provide for a smooth transition between the two procedures and contributed to a delay in taking actions. The entry criteria for Procedure ARP PK13-04 were lower than the action criteria in Procedure OP AP-7. Specifically, Procedure ARP PK13-04 was entered when an alarm was received for one or more of the following conditions:

- Condenser quadrant differential pressure at 9.5 psid
- Condenser quadrant differential pressure at 12.5 psid
- Rate-of-change in differential pressure is greater than 0.5 psid/hr when quadrant differential pressure is greater than 7.0 psid in any quadrant.

If any of the above conditions was determined to be valid, then operators were directed to implement Procedure OP AP-7. However, Procedure OP AP-7 did not require any actions to be taken until condenser quadrant differential pressure exceeded 10.0 psid. With differential pressures below this criterion, Procedure OP AP-7 directs operators to return to the procedure and step in effect (e.g., Procedure ARP PK13-04). Thus, prior

to the plant trip at 3:47 a.m. with condenser quadrant differential pressures less than 10.0 psid, the operating crew did not believe they had formally entered Procedure OP AP-7. This contributed to the crew briefing weakness discussed above in Section 04.1.b.2.

At 3:45 a.m., when Circulating Water Pump 2-2 intake screen differential pressure exceeded 100 iwg, operators promptly initiated a rapid downpower of the unit to prepare to remove the circulating water pump from service. Within approximately 1 minute, with screen differential pressure remaining greater than 100 iwg, the shift supervisor recommended and the shift foreman directed a manual reactor trip. Although not required by procedure, operators initiated the manual reactor trip based upon already degraded conditions in the main condenser. The inspectors concluded that the decision by the shift supervisor and shift foreman was appropriate and demonstrated a good awareness of plant conditions.

b.4 Circulating Water Pump 2-2 Trip

Although the manual reactor trip was initiated based upon the threat of damage to Circulating Water Pump 2-2 and loss of the normal heat sink, operators did not secure the circulating water pump. Both Procedures OP O-28 and OP AP-7 provided direction to immediately secure the circulating water pump under the high differential pressure conditions observed. Procedure OP O-28 stated that "if screen differential pressure increases to the point where failure is imminent, or if the screens stop running, the [circulating water pump] must be immediately secured, even if this requires a reactor trip." Procedure OP AP-7 specifically requires the circulating water pump to be secured when screen differential pressure exceeds 50 iwg, the design differential pressure for screen integrity.

Following the reactor trip and entry into Procedure EOP E-0, the senior control operator continued to focus on the condition of Circulating Water Pump 2-2 by monitoring the pump motor amps to look for indication of pump cavitation. In addition, the transfer of electrical power to the startup transformer resulted in the temporary loss of the Unit 2 intake screen differential pressure signal and an erroneous indication of 0 iwg across the intake screens for Circulating Water Pump 2-2. The senior control operator, believed the indication was valid and took no action to secure the pump.

Although valid indication of the intake screen differential pressure was restored in approximately 2 minutes, the continuing high differential pressure was not recognized for another 4 minutes when pump motor amps began to fluctuate from pump cavitation. Thus, the failure to secure the circulating water pump before damage occurred to the intake screens resulted from both a lack of understanding of the response of the screen differential pressure indication following a Unit 2 trip and a narrow focus on pump motor amps. The licensee indicated they would implement a method to ensure the screen differential pressure indications are more reliable. In addition, the licensee will discuss this error in licensed operator training.

The failure to immediately secure Circulating Water Pump 2-2 when its associated screen pressure exceeded 50 iwg was identified as one example of a violation of Technical Specification 6.8.1 for failure to implement the procedural requirements of Procedure OP AP-7 (50-323/98021-01).

b.5 Improper Pressure Setting for Atmospheric Dump Valves

When implementing the requirements of the "response not obtained" column in Procedure EOP E-0.1, Step 10.d, because of the unavailability of the main condenser, the control operator began lowering the pressure setpoint of the atmospheric dump valves to 1005 psig. However, when the atmospheric dump valves began to open in response to lowering the setpoint, the operator mistakenly believed that the valve response would result in an excessive cooldown of the reactor coolant system and improperly returned the setpoints to 1035 psig. As noted above, an apparent miscommunication between the control operator and shift foreman also contributed to the improper setting. Shortly thereafter, Steam Generator 2-2 Main Steam Safety Valve RV-7 lifted because of the proximity of its lift setpoint to steam generator pressure.

Personnel statements and operator interviews indicated that, following the resetting of the atmospheric dump valve pressure controllers to 1035 psig, the intent was to slowly lower the pressure setpoints to 1005 psig. However, plant computer data showed that the setpoints were not adjusted until 8 a.m. when pressure was lowered to approximately 980 psig to successfully reseat Main Steam Safety Valve RV-7. Both Procedures EOP E-0.1 and OP L-7 directed that operators reset the pressure controllers for the atmospheric dump valves from a setpoint of 1035 psig to a setpoint of 1005 psig when the main condenser is unavailable. This action would allow the atmospheric dump valves to stabilize reactor coolant system temperature at the no-load average temperature of 547°F. It also prevents interaction between the atmospheric dump valves and the low setpoint main steam safety valves that are set at 1065 psig.

In an incident summary developed by the operations director, the performance issues that resulted in the improper setting of the atmospheric dump valve pressure controllers were identified and corrective actions were developed. Specifically, the licensee corrective actions included: (1) having procedure writers ensure that the wording is properly human factored, and (2) describing the error as part of the trip response discussion in industry events training. The failure to set the pressure controllers for the atmospheric dump valves in accordance with Procedure EOP E-0.1 is a second example of a violation of Technical Specification 6.8.1 for failure to follow procedures (50-323/98021-01).

b.6 Operator Knowledge

Two operator knowledge deficiencies were identified that adversely impacted the event response. In evaluating the condition of Circulating Water Pump 2-2 and its associated intake screens, the crew was unaware that, upon a Unit 2 trip, indication of intake

screen differential pressure is temporarily lost and will indicate as 0 iwg until the signal is restored. Believing the indication of 0 iwg was valid following the manual reactor trip, the crew delayed securing the circulating water pump.

In stabilizing the plant in accordance with Procedure EOP E-0.1, the control operator misunderstood the response of the plant to adjustments of the pressure controllers of the atmospheric dump valves. The control operator, believing that adjustment of the pressure controllers to 1005 psig could result in an excessive cooldown, reset the controllers back to 1035 psig, contrary to procedural requirements. However, an adjustment of 30 psig on the pressure controllers equates to less than a 5°F change in reactor coolant system temperature.

c. Conclusions

Overall, the operating crew responded satisfactorily to the degraded conditions in the circulating water system and the manual reactor trip effectively stabilized the plant in a safe condition. However, the generally successful response to the event was adversely impacted by several performance issues.

The crew's misunderstanding of the effects of atmospheric dump valve pressure setpoint adjustments on the reactor coolant system, coupled with a communication error between the control operator and the shift foreman, resulted in a pressure setting of the valves that exceeded the setpoint specified in the procedure. The higher pressure setting unnecessarily challenged the main steam safety valves when it contributed to the lifting of Main Steam Safety Valve RV-7. One example of a violation of Technical Specification 6.8.1 was identified for failure to implement emergency operating procedure requirements; however, because the licensee planned effective corrective actions, no response was required.

The crew did not understand the response of the intake screen differential pressure indication to a unit trip, which led them to improperly leave Circulating Water Pump 2-2 operating and resulted in screen differential pressure exceeding the design limits. Weak fidelity among the annunciator response procedures and an abnormal procedure and the crew's narrow focus on pump motor amps also contributed to the delay in securing the circulating water pump. A second example of a violation of Technical Specification 6.8.1 was identified for failure to secure the pump in accordance with abnormal operating procedures; however, because the licensee planned effective corrective actions, no response was required.

O7 Quality Assurance in Operations

O7.1 Licensee Event Reconstruction and Assessment

a. Inspection Scope (92901)

The inspectors reviewed documentation available to support event reconstruction and assessment. Based upon the available information, an evaluation was made of the depth and scope of the self-critique.

b. Observations and Findings

The self-assessment of the event was generally thorough; however, it was hampered by poor documentation. The operating logs of the shift foreman, the control operator, and the turbine building watch were inadequate to reconstruct the significant activities associated with the event response. Neither the shift foreman nor the control operator logs document the closure of the main steam isolation valves, indications of the lifting of Main Steam Safety Valve RV-7, or the entry into Procedure OP L-7. Between 3:47 a.m. and 6 a.m., a period when actions were being taken in accordance with Procedures OP AP-7, EOP E-0, EOP E-0.1, and OP L-7, no entries were made in the shift foreman's log. The level of detail in the operating logs was not consistent with the recommendations in Procedure OP1.DC37, "Plant Logs," Revision 12.

Although a postshift critique with the operators involved in the trip response is recommended by Procedure OP1.DC1, "Administrative Program to Control the Return to Power After a Reactor Trip," Revision 2A, the licensee did not complete the review after shift change immediately following the event. The use of a group debriefing is also recommended by Procedure XI1.ID3, "Event Investigation Team, Event Response Team, and Event Investigation Report," Revision 0. The licensee determined that this was a missed opportunity to collect information details that are forgotten over time and to identify the improper setting of the atmospheric dump valves, which was first identified by the NRC resident inspectors. The licensee determined that they would have eventually identified the improper setting of the atmospheric dump valves during their posttrip review.

Procedure XI1.ID3 required written statements to be obtained from each person involved in the event that describe their observations and actions regarding the circumstances of the event. It further states that the statements should be obtained as soon as practical after the event and prior to the involved individuals leaving site. However, personnel statements regarding the event did not meet this recommendation. Only three statements were obtained immediately after the event, while the last statement, from the shift technical advisor, was not obtained until 3 days later. Further, the information provided in the personnel statements did not provide sufficient detail to fill in the gaps in the operating logs. This included information regarding entry into and exit from Procedure OP AP-7, time of exit from the emergency operating procedures, and the basis for not returning the pressure control setpoint of the atmospheric dump valves to 1005 psig after reseating Main Steam Safety Valve RV-7.

To help fill in the information gaps in the control room logs and personnel statements, the operations director met with the operating crew involved with the trip response 2 days after the event to develop an incident summary and lessons learned. The incident summary effectively captured the significant performance issues.

In reviewing the requirements and guidance in Procedure OP1.DC1, the inspectors concluded that the procedure provided adequate requirements for collection and archiving of information related to equipment and plant performance concerns. However, the requirements for collecting information and assessing human performance were not as clear. As stated above, it was only recommended to conduct a postshift critique with the involved crew. Additionally, the procedure did not give specific guidance to operators regarding the appropriate level of detail needed in their personnel statements. Attachment 6.1 of Procedure OP1.DC1 did not require an assessment of human performance.

c. Conclusions

The management process for collecting plant process information and evaluating equipment response to the manual reactor trip was rigorous in identifying and addressing equipment performance problems. The process for evaluating human performance lacked the same degree of formality and structure. The lack of structure, coupled with poor operating logs, made it difficult to reconstruct event details and assess the root cause of specific operator performance issues.

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 18, 1998. 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 1

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Molden, Operations Services Manager
W. Garrett, Operations Director
B. Lewis, Senior Operations Supervisor
J. Haines, Operations Training
G. Goelzer, Shift Supervisor
M. Wright, Shift Foreman
W. Bumen, Senior Control Operator
R. Kline, Control Operator
A. Duracher, Balance of Plant Control Operator

INSPECTION PROCEDURES USED

IP 92901: Followup - Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-323/98021-01	VIO	failure to secure circulating water pump in accordance with abnormal procedures and failure to properly set atmospheric dump valve pressure controllers in accordance with emergency operating procedures (Sections O4.1.b.4 and O4.1.b.5)

Attachment 2

SEQUENCE OF EVENTS
(All times are noted in PST)

Date/Time	Event
11/30/98 8:00 p.m.	High swell warning in effect. Circulating water differential pressure across the Unit 2 condenser approximately 5 psid. A senior control operator is stationed at the intake structure in accordance with Procedure OP O-28, "Intake Management."
12/1/98 ~ 12:00 a.m.	Because of rising differential pressure across the Unit 2 condenser (6 psid), the shift supervisor and Unit 2 shift foreman agree to curtail the unit to 50 percent power if differential pressure reaches 9 psid. Note: Procedure OP AP-7, "Degraded Condenser," directs curtailment when condenser differential pressure exceeds 10 psid.
12/1/98 ~ 2:00 a.m.	Differential pressure across the Unit 2 condenser increased to approximately 7 psid.
12/1/98 ~ 3:00 a.m.	Maximum condenser limiting differential pressure is greater than 8 psid and rising at approximately 2 psid/hr. Large bed of kelp observed floating in front of the Unit 2 intake screens. Based upon conditions in the condenser, Procedure AR PK13-04, "Condenser Delta P Hi PPC," directs entry into Procedure OP AP-7. No actions currently required by the abnormal procedure.
12/1/98 3:15 a.m. - 3:30 a.m.	Several manual and automatic actions were taken to vary intake screen speed in response to high screen differential pressure and a continuing rise on condenser differential pressure. Unit 2 condenser limiting differential pressure approaching 9 psid.
12/1/98 3:45 a.m.	Rapid rise observed on the differential pressure across the circulating water Pump 2-2 intake screens to greater than 100 iwg. The Unit 2 shift foreman directs a rapid power decrease at a ramp rate of 50 percent. NOTE: Procedure OP AP-7 required the affected circulating water pump to be tripped when its associated intake screen differential pressure is greater than 50 iwg.
12/1/98 3:47 a.m.	Based upon the high differential pressure across the Circulating Water Pump 2-2 intake screen, the shift foreman directs the control operator to trip the reactor. The reactor trip was not required by procedure.

Date/Time	Event
12/1/98 3:47 a.m.+	Circulating Water Pump 2-1 trips as expected upon transfer of Unit 2 electrical loads to startup power. Light electrical loading on vital 4160V vital Bus H results in a relatively slow bus voltage decay and a start of Diesel Emergency Generator 2-2. Operators leave Circulating Water Pump 2-2 operating based upon an erroneous pressure indication of 0 iwg. The 0 iwg pressure reading from the plant process computer is actually the result of a temporary loss of power to its associated signal processor during the transfer to startup power.
12/1/98 3:49 a.m.	Unit 2 intake screen differential pressure signal is restored in the control room and reads greater than 100 iwg. However, this is not observed by control room operators.
12/1/98 3:53 a.m.	Senior control operator observes Circulating Water Pump Motor 2-2 current swings of approximately 20-30 amps and secures the pump. This action is consistent with Procedure OP AP-7. With loss of all circulating water, the senior control operator recommends and the shift foreman directs the closure of the main steam isolation valves.
12/1/98 3:54 a.m.	Procedure EOP E0.1, "Reactor Trip Response," is entered. Source: control operator log.
12/1/98 4:10 a.m.	Control operator adjusts atmospheric dump valve pressure control setpoints from 1035 psig to 1005 psig in accordance with Procedure EOP E0.1.
12/1/98 ~ 4:12 a.m.	Because of a miscommunication with the shift foreman, the control operator readjusts the atmospheric dump valve pressure control setpoints back to 1035 psig.
12/1/98 4:17 a.m.	Steam Generator 2-2 pressure increases to approximately 1040 psig and Main Steam Safety Valve RV-7 opens. Steam Generator 2-2 pressure falls to approximately 1005 psig and stabilizes with the relief valve remaining partially open. This valve has a nominal setpoint of 1065 psig.
12/1/98 ~ 4:45 a.m.	Procedure OP L-7, "Plant Stabilization Following a Reactor Trip," is entered.
12/1/98 4:55 a.m.	Vacuum broken on the Unit 2 main condenser. This action is directed by Procedure EOP E0.1. Source: plant process computer
12/1/98 ~ 5:30 a.m.	Operators observe a low water level condition in Steam Generator 2-2 and a higher than expected auxiliary feedwater flow. Actions are initiated to restore water level in Steam Generator 2-2 and operators are dispatched to investigate a possible steam leak. Source: PSRC meeting minutes

Date/Time	Event
12/1/98 ~ 6:30 a.m.	Observations at the Steam Lead 2 pipe rack area identify that Main Steam Safety Valve RV-7 is open. Shift turnover to the oncoming operating crew is in progress and the shift supervisor and shift foreman make a conscious decision to delay actions to reseat the main steam safety valve until completion of turnover. This decision was based upon the stability of reactor plant parameters and the desire to carefully plan those actions.
12/1/98 8:19 a.m.	Lowering of the Steam Generator 2-2 atmospheric dump valve pressure control setpoint successfully reseats Main Steam Safety Valve RV-7 at a pressure of 987 psig.