APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-285/92-18 Operating License: DPR-40

Docket: 50-285

Licensee: Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

Facility Name: Fort Calhoun Station

Inspection At: Blair, Nebraska

Inspection Conducted: July 4-11, 1992

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TABLE OF CONTENTS

1. INTRODUCTION (93800)

The NRC has established and implemented a comprehensive program to provide for the timely, thorough, and systematic inspection of significant operational events at nuclear power plants. This program includes the use of an Augmented Inspection Team (AIT) to determine the causes, conditions, and circumstances related to an event and to communicate the findings, safety concerns, and recommendations to NRC management and the licensee. In accordance with NRC Inspection Manual Chapter 0325, "Augmented Inspection Team," and Inspection Procedure 93800, "Augmented Inspection Team Implementing Procedure," an AIT was sent to the Fort Calhoun Station (FCS) to review the loss-of-coolant event that occurred on July 3 and 4, 1992.

Region IV, in consultation with the Office of Nuclear Reactor Regulation and the Office of Analysis and Evaluation of Operational Data, formed an AIT on July 4, 1992. The AIT was dispatched to the FCS to gather the facts related to the cause of the loss-of-coolant event and to review the licensee's response to the event. The AIT arrived at the FCS on July 4, 1992.

The tasks of the AIT were defined in a letter, dated July 4, 1992, from J. Milhoan, Administrator, Region IV, to P. Harrell, AIT Team Leader. The letter defining the tasks of the AIT is provided as Attachment A to this report.

2. EVENT DESCRIPTION

The event descriptions provided below were derived from the available operational data and from interviews with various licensee personnel. The first section provides a general overview of the event. The second section provides a detailed sequence of events.

2.1 General Description of the Event

On July 3, 1992, the licensee experienced problems with Inverter 2 on three separate occasions. Inverter 2 is a nonsafety-related inverter that supplies 120 Vac power to various instrumentation and components in the plant. When repairs had been completed, after the third time the inverter experienced problems, Inverter 2 was placed back in service, at 11:36 p.m. on July 3, by connecting the inverter to the loads on the instrument bus. When connected to the bus, the inverter output voltage oscillated between 0 and 120 Vac and caused an electrical supply breaker, which provides power to Electrical Panel AI-50, to trip open on a high-current condition.

Electrical Panel AI-50 supplies various instrumentation and components in the plant, including the control circuitry for the main turbine. When power was lost, the circuitry caused the main turbine control valves to shut because a loss of power to the circuitry is an indication of zero pressure in the turbine steam supply line.

When the turbine control valves shut, the heat sink for the primary coolant system was lost, resulting in a pressure increase in the reactor coolant system. When pressure increased to approximately 2400 psia, a reactor and a subsequent turbine trip occurred. As pressure continued to rise, the power-operated relief valves, main steam safety valves, and a pressurizer code safety valve opened to reduce reactor coolant system pressure. The power-operated relief valves shut at 2350 psia. When pressure was reduced to approximately 1745 psia, a pressurizer code safety valve shut and reactor coolant system pressure increased to approximately 1925 psia. At this point, pressure began to drop rapidly. The operator shut the power-operated relief valve block valves when it was noted that the pressurizer quench tank level started to rise. The pressure drop continued and initiated safety injection, containment isolation, and ventilation isolation actuation signals. All systems functioned as designed in response to the actuation signals, except for Pressurizer Code Safety Valve RC-142, which reopened because internal damage reduced the setpoint of the safety valve, and remained open until pressure decreased to approximately 1000 psia, at which time Pressurizer Code Safety Valve RC-142 shut, but not completely. As a result, a loss-of-coolant event occurred because there was an uncontrolled loss of coolant from the reactor coolant system through Pressurizer Code Safety Valve RC-142.

The operators implemented the requirements stated in the emergency operating procedures and secured the four reactor coolant pumps. The plant was then cooled down, using natural circulation, to shutdown cooling entry conditions. Once the entry conditions were met, the shutdown cooling system was placed in service and the plant was further cooled down to approximately 120°F and depressurized.

2.2 Detailed Sequence of Events

The following listing provides a detailed sequence of events. The event sequence was reconstructed by review of documentation and by interviews with operations and other personnel.

July 3, 1992

- 4:33 a.m. The first trouble alarm was received on Inverter 2, which indicated an electrical problem with the inverter. Engineering and maintenance personnel were called to the site to assist in determining the cause of the alarm. Troubleshooting activities were performed; however, the specific cause of the trouble was not identified.

- 6:36 a.m. Inverter 2 was returned to service and appeared to function normally.

- 3:10 p.m. A second trouble alarm was received on Inverter 2. The inverter exhibited the same symptoms that were present when the first trouble alarm was received.

- 3:27 p.m. Operations personnel returned Inverter 2 to service when the trouble alarm cleared. The inverter appeared to function normally.

- 7:21 p.m. A third trouble alarm was received on Inverter 2. Engineering and maintenance personnel were again called to the site to assist in diagnosing the reason for the alarm. Two circuit boards in the inverter indicated signs of overheating and were replaced.

- 11:35 p.m. Inverter 2 was returned to normal service. When the inverter was placed in service, the voltage output oscillated between 0 and 120 Vac. The electrical supply breaker to Electrical Panel AI-50 tripped open, causing a loss of power to the main turbine control circuitry.

- 11:36 p.m. A reactor trip occurred at approximately 2400 psia, because of high pressure in the reactor coolant system. System pressure increased to approximately 2430 psia. The reactor trip was followed by a main turbine trip, lifting of the main steam safety valves, opening of the power-operated relief valves, and lifting of a pressurizer code safety valve. Alarms were received indicating a high pressurizer quench tank pressure and level. The steam dump and bypass valves opened to reduce reactor coolant system temperature. Because of problems with the inverter, miscellaneous alarms were received throughout the control room. Charging Pumps CH-1B and -1C started to supply water to the reactor coolant system. The operators initiated the actions required by Procedure EOP-00, "Standard Post Trip Actions."

- 11:37 p.m. The power-operated relief valves automatically shut when reactor coolant system pressure dropped to approximately 2350 psia. Reactor coolant system pressure continued to decrease to approximately 1745 psia and then pressure started to increase.

- 11:43 p.m. Reactor coolant system pressure increased to approximately 1925 psia and then started to rapidly decrease. The pressure and level in the quench tank increased again. The tail pipe temperature for Pressurizer Code Safety Valve RC-142 increased. The operator shut the block valves for the power-operated relief valves because of the increasing level and pressure in the quench tank and because of the continued pressure drop in the reactor coolant system. Emergency boration automatically initiated. The pressurizer pressure low signal automatically actuated the safety injection, containment isolation, and ventilation isolation actuation signals, resulting in the automatic initiation of the associated equipment and components. The containment isolation actuation signal automatically shut the component cooling water isolation valves for the reactor coolant pumps and control rod drive mechanisms. The component cooling water valves were manually reopened by the operators.

- 11:44 p.m. As directed by the emergency operating procedure, Reactor Coolant Pumps RC-3B and -3D were secured when reactor coolant system pressure dropped to approximately 1350 psia.

- 11:46 p.m. One channel of pressurizer level indicated level was at 100 percent and the other channel indicated level was at 0 percent. High Pressure Safety Injection Pumps SI-2B and -2C were manually shut down by the operators. High Pressure Safety Injection Pump SI-2A continued to operate.

- 11:49 p.m. Reactor Coolant Pumps RC-3A and -3C were secured, as required by the emergency operating procedure, when reactor coolant system pressure dropped below 1350 psia.

- 11:52 p.m. The shift supervisor declared an ALERT because one fission product barrier (i.e., the reactor coolant system pressure boundary) had failed. Charging Pumps CH-1B and -1C were stopped by the operators because pressurizer level indicated 100 percent. Charging Pump CH-1A continued to operate.

- 11:55 p.m. The disk on the pressurizer quench tank ruptured and the tank depressurized to containment pressure.

- 11:[illegible] [illegible]m. Alarms were received that indicated a high containment sump level. Charging Pumps CH-1B and -1C were restarted to ensure that emergency boration criteria were met.

- 11:[illegible] p.m. The emergency response organization was notified to report to the site.

<u>July 4, 1992</u>

- 12:03 a.m. Subcooling was verified to be greater than 20°F.

- 12:04 a.m. The operations crew verified that natural circulation flow was established and initiated a plant cooldown. Reactor coolant system pressure stabilized at approximately 1000 psia.

- 12:06 a.m. Containment Cooling Fans VA-7A and -7D were started to minimize containment pressure. Containment pressure reached a maximum of approximately 2.5 psig during the event.

- 12:07 a.m. Charging Pump CH-1C was manually secured by the operator.

- 12:10 a.m. Notification was made to the states of Iowa and Nebraska.
- 12:16 a.m. Charging Pump CH-1C was manually started by the operator.
- 12:20 a.m. The NRC senior resident inspector was notified of the ALERT.
- 12:24 a.m. Containment hydrogen analyzers were placed in service.
- 12:29 a.m. NRC Headquarters duty officer was notified of the ALERT.
- 12:34 a.m. The Group N nontrippable rods were fully inserted.
- 12:44 a.m. Charging Pumps CH-1B and -1C were manually secured by the operator.
- 12:46 a.m. Emergency boration of the reactor coolant system was terminated.
- 12:47 a.m. Verification of adequate shutdown margin was completed.
- 12:48 a.m. Charging Pump CH-1A was manually secured by the operator.
- 1:13 a.m. Low Pressure Safety Injection Pumps SI-1A and -1B, which started automatically on a safety injection actuation signal, were manually secured by the operator.
- 1:21 a.m. Site director responsibilities were transferred from the shift supervisor in the control room to the plant manager in the technical support center.
- 1:30 a.m. The NRC entered the standby mode of emergency response and manned the incident response centers.
- 1:31 a.m. Plant cooldown continued with natural circulation flow. The motor-driven auxiliary feedwater pump, which started automatically on a safety injection actuation signal, supplied feedwater to the steam generators and the main condenser was used as the heat sink.
- 1:51 a.m. Charging Pump CH-1C was manually started by the operator to establish charging and letdown flow.
- 2:09 a.m. The steam generators were sampled for activity. No activity was detected.
- 2:16 a.m. A reactor coolant system sample was obtained. The results indicated all isotope activities were normal.

- 2:33 a.m. Emergency Diesel Generator 1, which automatically started in idle speed on the reactor trip, was secured.
- 2:39 a.m. Emergency Diesel Generator 2, which automatically started in idle speed on the reactor trip, was secured.
- 3:14 a.m. Steam generator blowdown system was returned to service.
- 4:20 a.m. High Pressure Safety Injection Pump SI-2A was manually secured by the operator.
- 6:20 a.m. The operations crew confirmed that reactor coolant system leak rate was less than 5 gallons per minute.
- 6:30 a.m. The emergency classification was downgraded from an ALERT to a Notice of Unusual Event. Plant cooldown continued.
- 6:35 a.m. The NRC secured from the standby mode of emergency response.
- 10:24 a.m. The operators manually started Reactor Coolant Pump RC-3C to assist with plant cooldown.
- 6:40 p.m. The licensee exited the Notice of Unusual Event when the reactor coolant system was placed on shutdown cooling. Temperature was reduced to approximately 120°F and the reactor coolant system was depressurized.

3. PLANT SYSTEMS AND COMPONENTS

This section of the report discusses the response of the plant systems and components to the event. A detailed discussion is provided for the components that were identified as being contributors to the event.

3.1 Inverter 2

Inverter 2 is a nonsafety-related inverter that supplies various nonsafety-related instrumentation and components in the plant. The inverter normally functions to convert 125 Vdc, from Battery Bus 2, to 120 Vac to power instrumentation and components. The inverter is equipped with a bypass transformer, which converts 480 Vac to 120 Vac, that serves as a backup power supply to the normal mode of the inverter, thus providing assurance that the instrumentation and components supplied by the inverter will continually be powered. The inverter control circuitry contains provisions to automatically transfer the output to the backup ac power source when a problem is detected with either the dc power source or the dc-to-ac conversion (inverter) circuitry. This transfer is accomplished by a solid-state switching circuit, referred to as the static switch. When the backup transformer is in service, the inverter is in the bypass mode of operation.

3.1.1 Inverter 2 Failure

The licensee began experiencing problems with Inverter 2 at 4:33 a.m. on July 3, 1992, when inverter trouble and fan failure alarms were received. When the alarms were received, the inverter automatically switched from the normal to the bypass mode of operation, as designed.

Maintenance Work Order 927167 was initiated to allow crafts personnel to evaluate the cause of the inverter alarms and the electrical hot smell that had been detected by operations personnel. The crafts personnel performed an inspection of the inverter and found no evidence of overheating or other problems.

The inverter was returned to the normal mode of operation at 6:36 a.m. on July 3 and appeared to function properly. The work order was left open for possible further troubleshooting.

At 3:10 p.m., inverter trouble and fan failure alarms were again received and the inverter again automatically switched to the bypass mode of operation. Operations personnel checked the inverter and did not identify any problems. The inverter was returned to the normal mode of operation at 3:27 p.m. At 7:21 p.m., inverter trouble and fan failure alarms were received and the inverter automatically transferred to the bypass mode of operation for the third time.

A thorough internal inspection of the inverter was conducted by crafts personnel. No problems were identified during the inspection; however, evidence of possible overheating was observed on two of the inverter's printed circuit boards, as noted by a small section on each board being discolored. These two boards, the inverter drive and static switch drive boards were replaced by crafts personnel.

At 11:35 p.m., following the completion of the replacement of the circuit boards, the licensee attempted to return Inverter 2 to the inverter mode of operation. In accordance with vendor and facility instructions, the manual transfer switch was moved from the bypass to the normal static switch position. The inverter should have remained in the bypass mode of operation until the local transfer pushbutton was depressed. Crafts personnel noted that the inverter output began oscillating between 0 and 120 Vac as soon as the manual transfer switch was moved to its normal static switch position. These voltage oscillations and resultant current surges caused a number of problems, including the trip of Circuit Breaker AI-42B-CB2 for Electrical Panel AI-50, which provides electrical power to the control circuitry for the main turbine. A loss of electrical power to the circuitry resulted in the closure of the main turbine control valves and a subsequent reactor trip on high reactor coolant system pressure.

3.1.2 Inverter 2 History

An AIT member reviewed the operational history of Inverter 2 and noted that two nonsafety-related inverters were installed in 1986 to reduce the loading on the four safety-related inverters. The new devices were Elgar Corporation Inverter/Static Bypass Assemblies, Model 103-1-102. These nonsafety-related inverters are rated for 10 kVA and are designed to operate at an input voltage of 105 to 140 Vdc. Numerous nonsafety-related loads were disconnected from the safety-related inverters and connected to nonsafety-related Inverters 1 and 2, in accordance with Modification Request FC-86-049.

A plant event, similar to this event, occurred on July 2, 1986. In that instance, the initiating condition was the same as was experienced in this event. Electrical power was lost to the pressure transmitters, which provide signals to the control circuitry for the main turbine, and resulted in the turbine control valves closing.

In the 1986 event, a reactor trip occurred, because of a low level in Steam Generator B, followed by a turbine trip. The low steam generator level was because of operator error when controlling the level in the manual mode. The pressurizer power-operated relief and main steam safety valves lifted, but the pressurizer code safety valves remained closed. Peak reactor coolant system pressure was determined to be approximately 2400 psia.

In 1986 the control circuitry for the main turbine was powered by safety-related Inverter A, which, at that time, did not have fast transfer capability to a bypass transformer. In the 1986 event, the steam dump and bypass valves were unable to be opened and the feedwater control valves failed to automatically shut to a preset position. This resulted in a temporary overcooling event and water being lost through the main steam safety valves. The steam dump and feedwater anomalies occurred because the control circuitry necessary for proper operation of these components was also powered by Inverter A.

As corrective action to the 1986 event, the licensee transferred the power supply for the main turbine control circuitry from Inverter A to Inverter 2. Part of the logic behind the power supply transfer was:

- Inverter 2 had a fast transfer capability to the bypass transformer. Accordingly, the risk of losing power to the main turbine control circuitry would be reduced.

- If the event were to be initiated by failure of Inverter 2 and the associated bypass transformer supply, the resultant effects would be minimized since electrical power for feedwater rampdown and steam dump capability would remain available from Inverter A.

At that time, the licensee's corrective actions did not specifically focus on directly providing backup power to the main turbine control circuitry. Instead, the modification focused on providing redundant power to the entire control circuitry via the fast transfer capability of Inverter 2. Based on the NRC review performed at the time of the occurrence, the licensee's approach appeared to be satisfactory.

3.1.3 Licensee Response to the Inverter Failure

An AIT member reviewed the licensee's actions in response to the inverter alarms that occurred on July 3, 1992, and found them to be reasonable. The licensee stated that the inverter parameters were not routinely recorded; therefore no trending information was available. An AIT member visually observed the condition of the printed circuit boards that were removed from Inverter 2 and determined that the licensee's replacement of those two boards was advisable. The inside of Inverter 2 was inspected by an AIT member on July 6 and no apparent problems or damage were noted.

The licensee developed an action plan to investigate the improper operation of Inverter 2 and began troubleshooting activities on July 8. The licensee waited for the assistance of vendor representatives from Elgar before starting any inverter testing or component checks.

The licensee's plan for troubleshooting Inverter 2 was documented in Maintenance Work Order 922930. An AIT member reviewed the work order and found that it contained the appropriate precautions and checks, including quality control oversight and double verification of all lifted and landed leads. The troubleshooting activities were separated into two phases. The first phase was designed to identify and correct the malfunction of the inverter and the second phase was designed to verify proper inverter operation under loaded conditions.

The Elgar representatives examined the printed circuit boards that had been replaced in Inverter 2 and noted that the area around Resistor R-102, on the static switch drive board, was discolored and the solder connections were loose. The representatives stated that a bad connection at Resistor R-102 would explain why the inverter had automatically transferred to the bypass mode on July 3. Since the voltage from the inverter section is sensed across Resistor R-102, an intermittent poor connection would cause an apparent low inverted voltage and cause the assembly to switch to the bypass mode. When the circuit was allowed to cool, while the inverter was in the bypass mode, the solder joint would again make contact. This allowed the inverter assembly to be returned to operation and function normally.

The Elgar representatives also noted that a small metallic jumper, installed between Terminals 6 and 7 on the static switch drive board, had not been disconnected from the circuit board that had been removed from the inverter and installed on the replacement circuit board. The representative explained that the jumper provided the completion path for the voltage available and switch position circuit. Without the jumper installed, the static switch drive would cause the switch action to hunt, or toggle back and forth, between the normal and backup power sources. An AIT member witnessed the installation of the jumper on the installed static switch drive board on July 6. When the jumper was installed on the circuit board, the inverter operated satisfactorily.

An AIT member noted that the need to remove the jumper from the circuit board being replaced, and its installation on a replacement board, was not readily obvious. During review of the vendor's instruction manual, it was noted that the manual did not provide explicit instructions regarding the need to remove the jumper from the old circuit board and install it on the new circuit board. The jumper was depicted on the schematic diagram, but was not shown on the circuit board assembly diagram. The AIT considered the lack of clear instructions by the vendor concerning the existence of the obscure jumper, and the need to move it from the old to the new board, to be a contributing cause to the initiation of the event.

To verify proper operation of Inverter 2 after the jumper was installed on the new circuit board, the licensee provided power to Bus AI-42B, normally powered by Inverter 2, from Bus AI-42A, normally powered by Inverter 1. The jumper was installed in accordance with Temporary Modification 92-058. The modification was approved by the Plant Review Committee on July 8. An AIT member observed the connection of the temporary power supply, the connection of Inverter 2 to a load resistor bank, and the subsequent operation of the inverter. An AIT member noted that Inverter 2 had been operating properly for approximately 8 hours when it was again inspected at 8 a.m. on July 9.

During review of the installation of the inverter, the AIT noted that the licensee did not have a method for testing Inverter 2 without placing the inverter on the bus and connecting the normal loads to the output of the inverter. In this configuration, a failure of the inverter to operate properly could impact power operation, as occurred during this event. The AIT considered the lack of the capability for testing the inverter to be a contributing cause to the initiation of the event.

The AIT found the licensee's actions, in response to the failure of Inverter 2, to be technically sound and noted that conservative actions were taken. The AIT also noted that the licensee notified other licensees of the need to remove the jumper from the old circuit board and install it on the replacement board, via the industry's electronic notification system. In addition, the NRC is in the process of issuing an information notice to alert all licensees of the existence of the jumper on the circuit board.

The licensee stated that, as part of the restart plan, a modification would be performed to the design of the electrical system to allow testing of Inverters 1 and 2 without having to load the inverter on its normal bus. In addition, the licensee stated that the appropriate documentation would be revised to indicate that the jumper must be removed from the old circuit board and replaced on the new one.

3.2 Electrohydraulic Control System

The electrohydraulic control system is a nonsafety-related system that is provided with the main turbine. The system serves to supply control signals to the turbine steam admission valves, which consist of the main stop valves, intermediate stop/intercept valves, and the control valves. All valves are hydraulically operated and can be categorized as either positioning or nonpositioning valves. A nonpositioning valve is either fully open or fully shut, whereas positioning valves modulate to control turbine speed and steam pressure. There are four control valves, all of which are positioning valves. Modulation is accomplished by controlling hydraulic pressure against spring tension, which tends to close the valves.

The hydraulic system pressure is governed by electronic control circuitry, which senses various parameters including steam line pressure, turbine first-stage pressure, turbine speed, and turbine intermediate-stage pressure, to monitor the status of the main turbine. It then compares these parameters to fixed reference values and adjusts hydraulic pressure accordingly.

3.2.1 Electrohydraulic Control System Response

Electrical Panel AI-50 was lost upon the trip of Circuit Breaker AI-42B-CB2 because of the oscillating voltage output from Inverter 2. Electrical Panel AI-50 provides power to Pressure Transmitters PT-939, "Throttle Pressure Sensor"; PT-943, "Throttle Compensation Pressure Sensor"; PT-944, "Intermediate Pressure Transducer"; and PT-945, "First-Stage Turbine Pressure Sensor." Upon loss of power, the output voltages from Transmitters PT-943 and -945 drops to 0 Vdc, which corresponds to a sensed main steam line pressure of 0 psig. The transmitter output voltages are provided as inputs to the turbine control valve amplifier and the throttle pressure compensator which, in turn, provide input to the control valve positioning units. An input of 0 vdc to the positioning units results in a bleedoff of hydraulic pressure and subsequent full closure of the control valves. The closure of the control valves results in a loss-of-load condition (i.e., closing the control valves stops the flow of steam from the steam generators).

A turbine trip, which results in an immediate reactor trip, was not initiated upon closure of the control valves. Since a turbine trip signal is required for the steam dump valves to the condenser to operate, the steam dump valves were also not available. The steam dump valves are designed to allow steam to enter the main condenser without passing through the main turbine, thus preventing a loss-of-load condition.

A reactor trip is provided on turbine trip to limit the reactor coolant system stored energy and pressure caused by the loss of normal steam flow from the steam generators to the main turbine. A reactor trip is only generated when two of the four turbine stop valves come off their fully open seat, which did not immediately occur during this event since the loss of power to the transmitters affected only the control valves.

The malfunction of Inverter 2 resulted in a loss-of-load condition, by closure of the control valves, which resulted in a loss of the heat sink. The loss of the heat sink resulted in an increase in reactor coolant system pressure and a subsequent reactor trip.

3.2.2 Licensee Response to the Electrohydraulic Control System Design

In reviewing the power supply failure for the pressure transmitters, the AIT determined that the loss of power to or the failure of a single pressure transmitter could result in a loss-of-load condition. To address this vulnerability, the licensee stated that, as part of the recovery action plan, the electrohydraulic control system would be modified to remove the vulnerability by providing backup power to all the pressure transmitters, providing a turbine trip coincident with closure of the turbine control valves, or providing a turbine trip coincident with the loss of power to Electrical Panel AI-50.

Although the electrohydraulic control system is a nonsafety-related system (i.e., not required for safe shutdown of the plant,, the AIT concluded that the actions taken by the licensee to upgrade the electrohydraulic control system is appropriate to minimize safety system challenges.

The AIT noted that all systems associated with operation and protection of the main turbine functioned as designed. It was also noted that the absence of a backup power source to the main turbine pressure transmitters, which is a part of the electrohydraulic control system, was an initiator of the event. It appeared, based on the review performed by the AIT, that the actions proposed by the licensee to prevent a loss-of-load condition without a turbine trip will adequately address the vulnerability of the electrohydraulic control system.

3.3 Pressurizer Code Safety Valves

Pressurizer Code Safety Valves RC-141 and -142 are 3-inch, nozzle-type safety valves, Size 3K6, Style HB-86-BP, Type E, manufactured by the Crosby Valve and Gage Company. These valves are designed to operate at 2500 psia at 700°F, with hot water loop seals. Pressurizer Code Safety Valves RC-141 and -142 have setpoints of 2545 and 2500 (± 25) psia, respectively.

The pressurizer code safety valves are installed to limit reactor coolant system pressure to 110 percent of design pressure (2750 psia) following a loss-of-load condition on the main turbine, without a simultaneous reactor trip, while operating at 100 percent power. To accomplish this design objective, Pressurizer Code Safety Valve RC-142 relieves pressure at a rate to ensure that design pressure of the reactor coolant system is not exceeded and then shuts, with a blowdown of approximately 20 percent (i.e., shuts when pressure is reduced to approximately 2000 psia). Pressurizer Code Safety Valve RC-141 is installed, as required by the ASME Code, as a backup in the event that Pressurizer Code Safety Valve RC-142 fails to open during an increasing pressure transient.

3.3.1 Pressurizer Code Safety Valve RC-142 Response During the Event

As discussed above, after the turbine control valves shut, the turbine stop valves remained open. In absence of a turbine trip signal, the anticipatory reactor trip on turbine trip did not occur and the steam dump valves remained closed. Because of the loss of turbine load (i.e., main steam flow to the turbine was terminated), the reactor tripped on high reactor coolant system pressure at approximately 2400 psia.

When the reactor trip occurred because of high pressure in the reactor coolant system, a turbine trip occurred, as designed. The turbine trip enabled the steam dump system, which provides a heat sink for the steam generators.

The steam dump valves were not enabled in time to prevent lifting of the main steam safety valves, which discharged to the environment. The maximum pressure in the main steam line was approximately 1033 psig. The ten main steam safety valves have varying setpoints, which range from 1000 to 1040 psia.

After the reactor tripped, pressure in the reactor coolant system continued to rise to approximately 2430 psia. It appears, based on the review of available data, that Pressurizer Code Safety Valve RC-142 lifted and the power-operated relief valves opened to relieve excessive reactor coolant system pressure. The exact pressure at which Pressurizer Code Safety Valve RC-142 opened could not be definitely established; however, it appeared that Pressurizer Code Safety Valve RC-142 opened at a pressure lower than its normal setpoint of 2500 ± 25 psia. The setpoint for actuation of the diverse scram system is approximately 2450 psia and the diverse scram system did not actuate. Subsequent to the event, the licensee performed a calibration check on the diverse scram system setpoints and the as-found condition verified the setpoints were within specification. This is an indication that the reactor coolant system pressure did not reach 2450 psia.

It is apparent that Pressurizer Code Safety Valve RC-142 opened during the initial pressure transient because of an increased temperature in its discharge line. The initial pressure transient also caused the power-operated relief valves to automatically open. When Pressurizer Code Safety Valve RC-142 and the power-operated relief valves opened, reactor coolant system pressure was reduced to approximately 1745 psia. The power-operated relief valves automatically shut at approximately [illegible] psia; therefore, the continued drop of reactor coolant system pressure to approximately 1745 psia is an additional indication that Pressurizer Code Safety Valve RC-142 opened during the event. When reactor coolant system pressure reached approximately 1745 psia, pressure stopped decreasing and then began to increase. When pressure increased to approximately 1925 psia, pressure began dropping very rapidly. It appears that Pressurizer Code Safety Valve RC-142 opened again. When the operator noted the rapid pressure drop, he shut the power-operated relief valve block valves, in case the power-operated relief valves had inadvertently opened, to stop the pressure decrease. After the power-operated relief valve block valves were shut, reactor coolant system pressure continued to drop, an indication that Pressurizer Code Safety Valve RC-142 had reopened. Pressure eventually stabilized at approximately 1000 psia and coolant continued to leak into the quench tank. This was an additional indication that Pressurizer Code Safety Valve RC-142 had not properly shut.

3.3.2 Results of the Investigation of the Pressurizer Code Safety Valves

Region IV dispatched members of the AIT to the Wyle Laboratory, in Huntsville, Alabama, on July 9, 1992, to observe the receipt, testing, and inspection of Pressurizer Code Safety Valves RC-141 and -142, which were removed from the plant and sent to the Wyle Laboratory following the event.

Pressurizer Code Safety Valve RC-141 was inspected by licensee, Crosby (valve vendor), Stone and Webster, Wyle Laboratory, and AIT personnel. These same personnel were also present for most of the inspection and testing performed on Pressurizer Code Safety Valve RC-142.

For Pressurizer Code Safety Valve RC-141, no evidence existed to indicate that the valve had lifted during the event. An old piece of duct tape was found inside the outlet of the valve and was considered to be evidence that the valve had not lifted. No abnormalities were noted during the inspection of the valve. Pressurizer Code Safety Valve RC-141 was placed on a test stand and leak tested. The valve successfully passed the leak test and three sequential tests to verify the lift setpoint. Although no damage was noted during the inspection of Pressurizer Code Safety Valve RC-141, the licensee intended, as a conservative measure, to replace the bellows, nozzle, and disc insert.

On initial inspection of Pressurizer Code Safety Valve RC-142 (see Attachment C for a diagram of the valve), water (about 3 tablespoons) was found inside the discharge flange of the valve when the temporary outlet cover was removed. To check for possible bellows (Part 8, Attachment C) failure, it was decided to perform a pressure test on the valve through the discharge port, using 15 psig compressed air. At 2.6 psig, the duct tape over the bonnet vent ballooned, indicating significant bellows leakage. As a result of the test, the AIT, in consultation with Region IV and the Office of Nuclear Reactor Regulation, determined that leak testing and verification of the valve setpoint should not be performed with a failed bellows. The decision was based on the potential for causing additional damage to the internals of the valve and possibly destroying evidence of what may have caused the failure of the valve.

During the removal of the valve cap for Pressurizer Code Safety Valve RC-142, approximately 3/4 cup of borated water was removed from the upper valve internals. On inspection, it was noted that the adjusting bolt nut (Part 30, Attachment C) had backed off approximately 1/8 to 1/4 inch and could be turned by hand. Subsequently, on removal of the adjusting bolt (Part 29, Attachment C), it was noted to be 19.5 flats from the zero compression position of the spring. Crosby representatives calculated this position to correspond to a setpoint of approximately 1477 psia. The valve, prior to the event, was set at 2500 ± 25 psia. The adjusting bolt appeared to have backed out enough, during the event, to lower the setpoint by approximately 1000 psia. During removal of the valve internals, the bellows was found to have catastrophically failed at both ends. The bellows (Part 8, Attachment C) is designed to prevent steam on the discharge side of the valve from entering the upper portion of the valve and leaking out through the hole in the valve cap. The failures occurred at the first weld after the transition weld in both ends of the bellows. The bellows is a welded assembly made of Inconel-X750 and the failures occurred in Inconel-to-Inconel welds. The transition welds, at the upper end of the bellows where the bellows connects to the top flange and at the lower end of the bellows where the bellows connects to the disc holder, are a stainless steel-to-Inconel weld. No problems were noted with the transition welds.

As disassembly continued, there was considerable evidence of valve damage. It was concluded that valve chatter was the major cause of the damage to Pressurizer Code Safety Valve RC-142. Attachment B provides a detailed evaluation of the valve parts and the damage that occurred to each part. Attachment B also provides a list of the parts that are being replaced in Pressurizer Code Safety Valve RC-142. Of significance was that the disc insert (Part 9, Attachment C) was jammed into the disc holder (Part 5, Attachment C) and the disc insert was approximately 0.002 inches below the top surface of the disc ring (Part 7, Attachment C). The disc insert should have been 0.010 to 0.023 inches above the surface of the disc ring. This is an indication of the force that occurred as a result of valve chattering. The disc ring was seated on the nozzle ring (Part 3, Attachment C), as indicated by the nozzle ring not being able to be turned until the spring tension was released. This indicated that the valve was not seating properly and subject to leakage. The nozzle ring and adjusting ring (Part 12, Attachment C) were considered to have been set properly with allowance for the distortion noted above.

Based on the valve inspection and event data, it is apparent that Pressurizer Code Safety Valve RC-141 did not lift. Pressurizer Code Safety Valve RC-142 apparently lifted, at a pressure that can not be accurately determined, and appeared to reseat at approximately 1745 psia, based on reactor coolant system pressure starting to increase at that time. The safety valve then appeared to lift again at approximately 1925 psia, based on reactor coolant system pressure rapidly decreasing. The decrease in the setpoint pressure to 1925 psia was determined to be a result of chattering of the valve when it lifted the first time, which resulted in the loosening of the adjusting bolt nut and the backing out of the adjusting bolt. The valve appeared to at least partially reseat at approximately 1000 psia, as evidenced by continued leakage through the valve as a result of damage to the disc and nozzle rings.

In reviewing the instructions used by the personnel at the Wyle Laboratory to inspect and test the safety valves, the AIT noted that the procedure did not specify a torque value at which the adjusting bolt nut should be tightened. The instructions simply stated to tighten the nut. To address this apparent procedural inadequacy, the licensee, in consultation with Crosby, established that the adjusting bolt nut should be tightened to a torque value of 400 foot-pounds.

Valve chattering is a phenomena that occurs when a safety valve rapidly oscillates off its seat (i.e., opens and closes very rapidly). Chattering is caused by the valve disc striking the nozzle (seat) on each successive lift. A number of factors are related to chattering for a safety valve. Primarily, the reduction in flow to the safety valve can result in chattering. Piping geometry (i.e., the size and length of the inlet piping) can affect inlet piping losses. In addition, there is an acoustic factor during chattering that reduces steam flow to the safety valve. The internal ring setting (i.e., the adjusting and nozzle rings) can have a direct effect on valve stability and improper settings can result in valve chattering. The back pressure on the discharge side, because of the power-operated relief valves being open, may have had some affect, in particular, when the bellows on Pressurizer Code Safety Valve RC-142 failed. Transition from a steam to a water flow through a safety valve would also result in chattering.

During Electric Power Research Institute testing of Crosby safety valves in early 1980, in response to TMI (NUREG-0737) Action Item II.D.1, similar Crosby safety valves with loop seals and back pressure, which is considered to envelope the FCS plant conditions, were tested. Review of the testing performed is documented in a technical evaluation report, issued in June 1989, prepared for the NRC by the Idaho National Engineering Laboratory. During testing with loop seals, it was noted that the safety valve flutter and/or chatter, at partial lift positions, occurred during three of the loop seal discharges and was stable during the fourth. During the period when the loop seal was being discharged, the valve flutter and/or chatter occurred through partial lift positions at frequencies of approximately 170 to 260 Hertz. The valve oscillations caused water hammer type pressure oscillations in the valve inlet piping. Pressure oscillations, measured by the pressure transducer immediately upstream of the valve inlet, ranged from 0 psia to a pressure that exceeded the range of the transducer (3600 psia). There was also one transition test in which a filled loop seal, with a steam to water discharge, was performed. The valve exhibited partial lift/flutter during the loop seal discharge. The valve popped open when steam passed through the valve and the valve remained stable. When the transition from steam to water occurred, the valve began to flutter and subsequently chattered. The test was terminated after the valve was manually opened to stop the chattering.

Based on the test results provided by the Electric Power Research Institute, the FCS modified the loop seal for the pressurizer code safety valves in 1984 to minimize chattering. The volume of water in the loop seal was reduced from 5 gallons to about 1.2 gallons and the loop seal temperature was increased by the addition of insulation around the loop seal piping. In 1990, the FCS safety valve ring settings were changed, based on testing performed by the Electric Power Research Institute, to provide the most stability with the least chatter. The adjustment of the ring settings provided an 18 to 20 percent blowdown, as versus the previous 5 percent blowdown.

In view of this event, the initial lift of Pressurizer Code Safety Valve RC-142 probably produced valve chattering during discharge of the loop seal. The chattering resulted in the initial backing out of the adjusting bolt. Chattering for reasons other than identified may also have occurred. After the lift of Pressurizer Code Safety Valve RC-142, pressurizer level response ... ent. Since the safety valve appeared to have subsequently re... valve, based on the available data, passed water for approximately ... minutes. The Electric Power Research Institute testing indicated that the safety valve would have experienced severe chattering during this time. This would account for the adjusting bolt backing out further, causing a lower setpoint. It should also be noted that every time the spring is compressed, a torque force is created. This force can be translated ... the spring washer to the adjusting bolt and could cause the adjusting bolt to back out.

In discussions with AIT, Region IV, Office of Nuclear Reactor Regulation, and licensee corporate personnel, during a conference call on July 11, 1992, the licensee stated that action was being taken in three areas to address the problems identified with Pressurizer Code Safety Valve RC-142. First, the internal valve settings of the ... and adjusting rings would be reviewed with Crosby to determine if there were more optimal settings to minimize chattering. Stone and Webster personnel were assisting the licensee in this effort. Secondly, the licensee was working with Crosby to design and install an appropriate locking device to capture the adjusting bolt and adjusting bolt nut to prevent backing out if chattering occurs when the valve lifts. Thirdly, the licensee would fully inspect, refurbish, and test Pressurizer Code Safety Valves RC-141 and -142 to ensure proper operation, prior to reinstallation of the valves in the plant.

The licensee has notified other licensees of the problems identified with the pressurizer code safety valves via the electronic network used by the utility companies. In addition, the NRC is in the process of issuing an information notice to all licensees to make them aware of the specific problems identified with the safety valves.

3.3.3 Maintenance History of the Pressurizer Code Safety Valves

The AIT reviewed the maintenance history for Pressurizer Code Safety Valves RC-141 and -142 from 1980 to present. The AIT found that the nozzle and disc seats required lapping and polishing six of the nine times that the valves were tested. Other maintenance included machining of the eductor on Pressurizer Code Safety Valve RC-142 in 1992; nozzle and valve body machining on Pressurizer Code Safety Valve RC-141 in 1990; nozzle machining on Pressurizer Code Safety Valve RC-142 in 1990; polishing of galled surfaces on the upper and lower spring washers and spindle on Pressurizer Code Safety Valve RC-142 in 1985, machining of nozzle seat and replacement of the bellows assembly and disc insert on Pressurizer Code Safety Valve RC-141 in 1984; and replacement of the main spring, spring washers, bellows assembly, disc insert, and gaskets on Pressurizer Code Safety Valve RC-142 in 1983.

The AIT was informed that the licensee was performing a manual search of maintenance documents prior to 1980 to identify any earlier maintenance on the code safety valves. Based on the review performed by the AIT, it did not appear that any prior maintenance performed on Pressurizer Code Safety Valves RC-141 and -142 contributed to the failure of Pressurizer Code Safety Valve RC-142.

3.3.4 Industry Experience and Generic Communications for Pressurizer Code Safety Valves

Industry experience and generic communications are documented in Report AEOD/S92-02, "Special Study Safety and Safety/Relief Valve Reliability," dated April 1992. This event was related to other events, as discussed in Report AEOD/S92-02, only because a pressurizer code safety valve was involved. The AIT found no information to indicate that Crosby pressurizer code safety valves with loop seals have lifted for cause. The setpoint change was determined to be the result of severe vibration caused by valve chattering, not because of setpoint drift. Pressurizer Code Safety Valve RC-142 also failed to reseat properly after lifting because chattering caused a significant amount of damage to the valve internals. Additionally, the initiating event was unlike any other initiating event identified in Report AEOD/S92-02, because of the rapid transient, not as a result of a loss of the loop seal over a period of time.

3.4 Response by Other Systems to the Event

3.4.1 Safety Systems Response

As discussed above, when reactor coolant system pressure increased, a reactor trip occurred and the power-operated relief valves opened. The loss of the turbine load, without a steam dump capability, caused steam generator pressure to increase and resulted in lifting of the main steam safety valves when steam pressure increased to approximately 1033 psia. Pressurizer Code Safety Valve RC-142 lifted, in response to high reactor coolant system pressure at the beginning of the event. After the reactor trip, a turbine trip automatically initiated, which enabled the steam dump valves and established heat removal capabilities. Reactor coolant system pressure was rapidly reduced as a result of the opening of power-operated relief valves and Pressurizer Code Safety Valve RC-142 and system cooldown by the steam dump system. Charging Pumps CH-1A and -1B automatically started by the pressurizer level control system to provide water to the reactor coolant system.

After the power-operated relief valves and Pressurizer Code Safety Valve RC-142 shut, the reactor coolant system pressure began to increase. At approximately 1925 psia, pressure started to decrease rapidly. The operator closed the power-operated relief valve block valves when pressure in the reactor coolant system started decreasing. The operator secured two reactor coolant pumps, as required by an emergency operating procedure, when system pressure dropped to approximately 1350 psia. In response to low reactor coolant system pressure, the safety injection, ventilation isolation, and containment isolation actuation signals initiated. The auxiliary feedwater system automatically actuated to supply water to both steam generators. The component cooling water supply valves to the reactor coolant pump seals shut because of the containment isolation actuation signal, concurrent with low component cooling water pressure, when the component cooling water supply valves for the containment coolers opened. All three component cooling water pumps started automatically and reactor coolant pump seal cool was quickly reestablished by the operators manually reopening the supply va .

The operator shut down the remaining two reactor coolant pumps when reactor coolant system pressure dropped below 1350 psia in accordance with the emergency procedure. When the quench tank filled up and pressurized due to leakage past Pressurizer Code Safety Valve RC-142, the quench tank disk ruptured and reactor coolant began dumping onto the containment floor and then flowed into the containment sump. At this time, the reactor coolant system was being maintained at stabilized conditions of approximately 1000 psia with natural circulation established. In anticipation of high containment pressure, the operator started Containment Fan Coolers VA-7C and -7D, which limited containment pressure to 2.5 psig (design pressure is 60 psig). This prevented the containment spray system from actuating at 5 psig.

The operator started plant cooldown at a rate of approximately 60°F per hour to reduce system leakage. Group N rods were fully inserted to increase shutdown margin. Emergency boration was secured by shutdown of Boric Acid Pumps CH-4A and -4B, which started automatically on a safety injection actuation signal. The turbine-driven auxiliary feedwater pump was secured, since the motor-driven auxiliary feedwater pump was sufficient for decay heat removal and reactor coolant system cooldown. Normal pressurizer level control was reestablished by placing the charging and letdown systems in operation.

Containment Isolation Valves HCV-2506A, -2506B, -2507A, and -2507B and Valve HCV-2504 were opened to allow sampling of the steam generators and the reactor coolant system. The valves were subsequently closed after a reactor coolant system sample was obtained. The operator shut down both diesel generators, which had started automatically at idle speed as a result of the reactor trip. The operator opened the power-operated relief valve block valves. Component Cooling Water Pump AC-3C and Raw Water Pumps AC-10C and -10D, which had automatically started in response to the event, were shut down since they were not needed for mitigation of the event.

When reactor coolant system pressure and reactor coolant system cold leg temperature were reduced to approximately 400 psia and 329°F, respectively, the safety injection tanks were isolated to allow further reactor coolant system cooldown without the discharge of safety injection tanks. The operator started a reactor coolant pump to provide forced circulation for cooldown and depressurization. Low Pressure Safety Injection Pump SI-1A, which also serves as a shutdown cooling system pump, was started in preparation for shutdown cooling process. The shutdown cooling system was warmed up by alternately opening and closing the shutdown cooling system isolation valves (HCV-347 and -348). When the shutdown cooling system was warmed up, with reactor coolant system pressure at approximately 265 psia and reactor coolant system temperature below 300°F, shutdown cooling was established. The operator periodically verified all safety functions, as required by the emergency operating procedure. During the event, all safety functions, including reactivity control, were satisfied. At this time, the operator exited the emergency operating procedure and entered the system operating procedures for normal plant cooldown.

The AIT reviewed the sequence of events discussed above to verify that all systems actuated, as designed. The AIT noted that all plant safety-related equipment, except for Pressurizer Code Safety Valve RC-142, functioned as designed in that the equipment operated when it received an actuation signal

3.4.2 Equipment Anomalies Identified During the Event

The electrical transient initiated by problems with Inverter 2 resulted in the malfunction of equipment and instrumentation powered from Bus AI-42B, as noted below. In each case, the loss of equipment or instrumentation did not effect the capability of the operators to assess plant status or take actions to mitigate the consequences of an accident.

- Pressurizer Level Controller LRC-101Y operated erratically. The operators used the redundant controller to monitor and control pressurizer level.

- Power for Annunciator Panels AI-65B, AI-66B, and AI-106B was lost due to blown fuses. The operators used redundant Annunicator Panels AI-65A, AI-66A, and AI-106A to monitor the status of plant alarms.

- Loss of power to the toxic gas monitors caused the control room ventilation system to switch to the full-recirculation mode of operation, which isolated the control room from the outside environment.

- A blown fuse caused Shutdown Cooling Flow Control Valve FIC-326 to fail to open when the operator attempted to open the valve from the control room. The fuse was replaced and the valve operated with no problems. The blown fuse was caused by voltage oscillations on Inverter 2.

- Various parameters (safety injection flow, containment spray flow, subcooling margin, and containment temperature), monitored on the plant computer, provided incorrect information during the event. The operators immediately realized the incorrect data and used alternate indications.

Although some equipment and instrumentation failed to function properly during the event, redundant equipment and instrumentation were available to the operations crew for assessment and monitoring of plant parameters. The licensee stated, to ensure that all the necessary equipment and instrumentation was available during any postulated event, a review of the electrical components supplied by nonsafety-related Inverters 1 and 2 would be performed. If the review identified equipment or instrumentation that was required for the mitigation of the consequences of an event, the power supply for the instrumentation or equipment would be transferred to a safety-related inverter. In addition, the licensee stated that all the instrumentation that failed during this event would be tested, to verify proper operation, prior to plant startup.

4. OPERATOR AND MANAGEMENT RESPONSE

4.1 Response by Operations Personnel

The AIT reviewed documentation and conducted interviews with personnel involved with the response to and recovery from the event. Personnel interviewed included the shift supervisor, licensed senior operator, licensed operators (primary and secondary), shift technical advisor, and two individuals on the emergency response organization.

Multiple systems were affected by the loss of the inverter, resulting in a wide range of symptoms. The symptoms were quickly assessed by operations personnel and the operators determined that a loss-of-load event had occurred, which resulted in a reactor trip and a loss-of-coolant event. These events were complicated by the loss of various equipment and instrumentation caused by the voltage oscillations on Inverter 2.

When the reactor tripped, the operators followed Procedure EOP-00, "Standard Post Trip Actions." However, the operators immediately determined that a loss-of-coolant event was in progress and equipment and instrumentation problems occurred because of failure of Inverter 2; therefore, the operators opted to follow the requirements of Procedure EOP-20, "Functional Recovery Procedure," instead of using Procedure EOP-03, "Loss of Coolant Accident." The use of Procedure EOP-20 was appropriate more than one event was in progress simultaneously.

Based on interviews with personnel and analysis of available data, the AIT identified positive factors that contributed to the successful response to the event by the operations crew. These factors included the following:

- This event (loss of coolant from the reactor coolant system) was included in the simulator training program.

- Upgrade of the emergency operating procedures resulted in better guidance to the operators, as compared to the procedures that were available during the 1986 loss-of-inverter event.

- The site specific simulator has provided operators with increased training time and procedure confidence.

- Emergency planning actions are practiced weekly by operators in simulator training sessions.

- No failure of any major engineered safety features equipment occurred.

- Staffing, including a dedicated communicator, and the defined division of responsibility, allowed key control room personnel to perform their direction and/or oversight functions in a timely and efficient manner.

- When trouble alarms were initially received on Inverter 2, the operations crew reviewed the abnormal procedure that provided instructions on what actions to take if the inverter was lost.

The event revealed three areas where the technical content of the emergency operating procedures could be improved. The AIT noted that the content of the procedures, as written, did not hinder the response by the operators to the event. The procedure improvements are discussed below:

- A modification was installed during the last refueling outage to the safety injection actuation system logic, which trips Condensate Pumps A and C. Procedure EOP-00 directs the operators to ensure that a condensate pump is running. Unless the Condensate Pump B is selected by the operators to continue operating, a subsequent safety injection actuation signal may lead to a loss of all operating condensate pumps.

- At the point in the recovery where the emergency operating procedures directed that low temperature, overpressure protection be established, only resetting the pressurizer pressure low signal was addressed. Verifying that the power-operated relief valve block valves were opened was not addressed. Since the power-operated relief valves also provide low temperature overpressure protection, the block valves must be opened.

- One of the floating steps in Procedure EOP-20 allows the restart of a reactor coolant pump. When this evolution was discussed, the control room coordinator raised concerns that starting a reactor coolant pump, without establishing backfeed from the 345-kV system, could result in a electrical distribution system voltage dip and could cause an offsite power low signal. Subsequent discussions with the licensee established that this was a valid concern and was addressed in the original emergency operating procedure development by the sequence of steps. When this action statement was converted to a floating step, procedural step sequencing no longer ensured that a reactor coolant pump could be started without an unnecessary offsite power low signal.

In addition to the above, the AIT noted that operator action was required to restore the component cooling water system to operation. A pressurizer pressure low signal results in a containment isolation actuation signal, which maximizes component cooling water flow to the containment fan cooler units, and results in a momentary lowering of component cooling water system pressure. If component cooling water pressure drops to 60 psig, concurrent with a containment isolation actuation signal, component cooling water to the reactor coolant pumps and control element drive mechanisms is automatically isolated. Reliance on operator action to restore flow to the reactor coolant pumps and control element drive mechanisms could be eliminated by a design change to the system logic (e.g., a time delay) such that a momentary pressure drop would not initiate isolation of the component cooling water containment isolation valves.

Overall, the response by the operations staff was considered to be very good. Even though the event was complicated by the loss of some indication and equipment supplied by Inverter 2, operations personnel quickly diagnosed the plant status and took the appropriate actions in a timely manner. In addition, the operations staff appropriately implemented all emergency plan requirements, which included items such as the declaration of an ALERT, notification of state and local officials and the NRC, and notification of the licensee's emergency response personnel.

4.2 Response by Management

Upon notification of the declaration of an ALERT, the licensee's emergency response organization staffed the technical support center, operational support center, and emergency offsite facility in a timely manner. Within 1 hour and 28 minutes after declaration of the ALERT, the technical support center was fully staffed and command/control responsibilities were transferred from the control room to the technical support center. Accountability of all onsite personnel was completed in 18 minutes and site access control established in 23 minutes.

Throughout the event, the licensee maintained telephone contact with the NRC response centers and provided timely update of the status of the plant event. The timely updates enabled the NRC staff to independently assess the status of the plant.

Overall, the licensee effectively implemented the requirements of the emergency plan.

5. COMPARISON OF THE ACTUAL TO THE ANALYZED EVENT

Section 14.9.1 of the Updated Safety Analysis Report documents the design basis event for a loss-of-load condition to both steam generators. The acceptance criteria for this event state that the peak reactor coolant system pressure must remain below 110 percent of the design pressure (2750 psia) and that a sufficient thermal margin must be maintained in the hot fuel assembly to ensure that departure from nucleate boiling does not occur throughout the event. In the analysis, the event is initiated by a loss-of-load (i.e., termination of the main steam flow to the turbine) condition. Conservative assumptions are made in the analysis that the anticipatory reactor trip on turbine trip is not credited and the reactor trips on high reactor coolant system pressure. Also, the steam dump system is assumed to be unavailable. The results of the analysis indicates that the peak reactor coolant system pressure is 2576 psia, the peak main steam pressure is 1047 psia, and departure from nucleate boiling never decreases below the initial value during the event.

The event that occurred on July 3, 1992, at the FCS was essentially identical to the design basis loss-of-load event up to the time that a pressurizer code safety valve failed to properly function. The actual event started with the closure of turbine control valves, which produced the same effect as a loss-of-load condition to both steam generators. The reactor trip was initiated on high reactor coolant system pressure and the steam dump system did not open until a turbine trip was initiated by a reactor trip, which occurred after a time delay, causing the reactor coolant system to heatup. As a result, the pressurizer code safety and main steam safety valves and the pressurizer power-operated relief valves lifted. During the actual event, prior to the time the pressurizer code safety valve failed to fully shut, the plant responses were similar to the design basis loss-of-load event. The actual peak reactor coolant system pressure was 2430 psia and peak main steam pressure was 1033 psia. These peak primary and secondary pressures are below the values calculated in the safety analysis. The results of the licensee's preliminary assessment on the fuel performance during the event indicated that there was no departure from nucleate boiling throughout the event. Therefore, the AIT concluded that the results of the event, prior to the occurrence of the stuck open pressurizer code safety valve, are bounded by the design basis loss-of-load event, as documented in the Updated Safety Analysis Report.

6. LICENSEE EVALUATION OF THE EFFECTS OF THE EVENT ON THE EQUIPMENT IN CONTAINMENT

The AIT reviewed containment temperature, pressure, and radiation data to establish the environmental conditions that resulted from the event. The AIT was concerned that the resultant environment could have adversely effected the equipment located inside containment. The data indicated that the highest recorded containment pressure was approximately 2.5 psig, temperature was approximately 130°F, and radiation readings remained at their normal values.

The licensee conducted containment entries, on July 5, 1992, to assess and document the effects of the event. The initial containment entry was made to evaluate the steam generator bay, reactor coolant drain tank, pressurizer quench tank, and containment sump areas. An additional entry was made to evaluate the areas around the pressurizer safety valves and power-operated relief valves. The condition of the pertinent equipment was videotaped during both entries. The AIT viewed a copy of the videotape, on July 6, and did not observe any unexpected conditions.

On July 7 the NRC resident inspectors performed an extensive inspection tour of the containment. The inspectors reported that no problems were noticed with any equipment, except for the rupture of the disk on the pressurizer quench tank.

The licensee initiated a series of actions, as part of the recovery plan, to identify potential equipment damage inside containment. The licensee's plan included:

- Inspecting electrical and mechanical components for moisture damage.
- Inspecting the reactor coolant pump motor windings and oil systems for moisture intrusion.
- Inspecting the condition of equipment insulation.
- Completing an evaluation to verify that the environmental conditions had not exceeded the electrical equipments qualification provisions.

Based on the above observations, the AIT determined that reasonable assurance existed to conclude that, based on the initial inspections performed, the equipment required to maintain the plant shut down and to provide continued cooling of the core had not been degraded. The licensee stated that additional inspections of the equipment in containment would be performed to verify the results of the initial inspections.

7. PLANT RESTART

On July 4, 1992, the NRC issued a Confirmatory Action Letter to the Omaha Public Power District to describe the actions that would be required to be taken by the licensee prior to returning the plant to power operations. The Confirmatory Action Letter is provided in Attachment D. The letter contains the following requirements:

- An NRC inspection will be performed at the FCS to determine the causes of the reactor trip and apparent failure of Pressurizer Code Safety Valve RC-142. The AIT will perform an onsite inspection of the valve.
- NRC review of the licensee's response to and short-term corrective actions taken for the event.
- Conduct of a meeting in the Region IV office to provide the licensee's results of the investigation of the causes of the event.

On July 8, 1992, the Confirmatory Action Letter was amended to allow the licensee to ship Pressurizer Code Safety Valves RC-141 and -142 to the Wyle Laboratory. The amendment was issued because the licensee did not have the facilities on site to disassemble the valves. The amendment to the Confirmatory Action Letter is provided in Attachment D.

A restart plan was formulated by the licensee to identify all the short-term actions that would be taken prior to requesting permission from the NRC to return the plant to power operation. During the scheduled meeting with the NRC in the Region IV office, the licensee will provide the status of all the items on the restart plan.

The AIT reviewed the items on the restart plan and verified that the plan contained the items necessary to address all areas that should be reviewed. No problems were identified with the restart plan. Prior to returning the plant to operation, the NRC will independently verify that the licensee has adequately addressed all the restart plan items. The independent review will be documented in NRC Inspection Report 50-285/92-14.

8. FINDINGS AND CONCLUSIONS

The AIT made the following findings and reached the indicated conclusions during the performance of the inspection:

- The design of the electrical power distribution system did not provide the capability to verify the proper operation of the static switch assembly prior to returning the inverter to normal operation. The design also precluded performing a load test on the inverter power output without the prior installation of an alternate power supply to the distribution system. The inability to conduct thorough inverter testing prior to connecting the mechanism to its distribution system was found to be an contributing factor of the event.

- The lack of clear instructions for the installation of a jumper on the replacement printed circuit board was also found to be an initiating factor for the event.

- The instructions provided for inspection and testing of the pressurizer code safety valves did not specify a torque value for the adjusting bolt nut. The lack of instructions was identified as a contributing factor for the failure of Pressurizer Code Safety Valve RC-142.

- Chattering in Pressurizer Code Safety Valve RC-142, which resulted in damage to the valve, was also identified as a contributing factor to this event.

- The design of the electrohydraulic control system was vulnerable in that the loss of power to or the malfunction of a single pressure transmitter could initiate a challenge to safety-related systems. This was also identified as a contributor to this event.

- All safety-related systems and components functioned as designed, except for Pressurizer Code Safety Valve RC-142.

- The operations crew quickly diagnosed the loss-of-coolant event which was complicated by a coincident loss of an inverter, and took timely and appropriate corrective actions. The response of the operations crew was found to lessen the severity of the event and was considered to be a strength.

- The training received by the operations crew on the simulator was a significant factor in the mitigation of this event.

- The operating crew that performed the natural circulation cooldown during the event should observe a natural circulation cooldown on the simulator to compare the behavior of the simulator with what actually happened in the plant.

- Response to this event by management and emergency response personnel, in manning the technical support center and in notification of and communications with the NRC, was considered a strength.

ATTACHMENT A

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

JUL 4 1992

MEMORANDUM FOR: Phillip H. Harrell, Chief, Reactor Projects Section C

FROM: James L. Milhoan, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM AT FORT CALHOUN STATION

On July 3, 1992, at approximately 11:55 p.m. (CDT), there was a loss of an electrical inverter. This resulted in the loss of the main turbine and a reactor trip and a RCS pressure spike. A code-safety valve opened on the pressure transient and failed to reseat fully, resulting in loss-of-coolant to the containment sump.

In order for the NRC to better understand the initiating event and the resulting transient, the safety significance of these, and the potential generic issues, an augmented inspection team (AIT) will be utilized. The team's charter is to:

1. Ascertain and document the plant conditions and the sequence of events during this occurrence. Specifically, assess the causes for:

   - the loss of electrical inverter and the reasons for the subsequent reactor trip;

   - the premature lifting of the safety relief valve (RCS-142);

   - the failure of the code-safety valve to close fully after it had opened in response to the pressure transient.

2. Review and document the performance of plant systems, components, and structures during this event, including reactivity parameters that were impacted by the safety relief valve malfunction. In addition, review the licensee's evaluation of the effects of the conditions inside the containment on plant equipment.

3. Review and document the operational and maintenance history of the two Crosby safety-relief valves.

4. Review and document licensee operator and management response to this event, including activation of the Fort Calhoun emergency plan and implementation of Emergency Operating Procedures.

This memorandum designates you as the AIT team leader. The team composition will be discussed with you. All designated AIT members will be detached from their normal duties and will report to you for the duration of the team operation. The AIT will be conducted in accordance with the NRC Inspection Manual Chapter 93800, "Augmented Inspection Team Implementing Procedure."

The team is to emphasize fact finding in its review of this event and the related circumstances. The AIT is to determine the facts surrounding this event, it should concentrate on what happened, always being alert to identify safety issues. The AIT is not charged with responsibility for other regulatory matters that might result from this event.

The AIT should assemble in Blair, Nebraska, at the Fort Calhoun site on July 4, 1992. The onsite inspection should be completed no later than July 10, 1992. You should provide Region IV management with updates on the team's progress, including a daily briefing at 3:00 p.m. CDT for Region IV, NRR, and any other interested staff members.

James L. Milhoan

James L. Milhoan
Regional Administrator

cc:
A. Beach
S. Collins
L. Callan
E. Rossi, NRR
M. Virgilo, NRR
AIT members

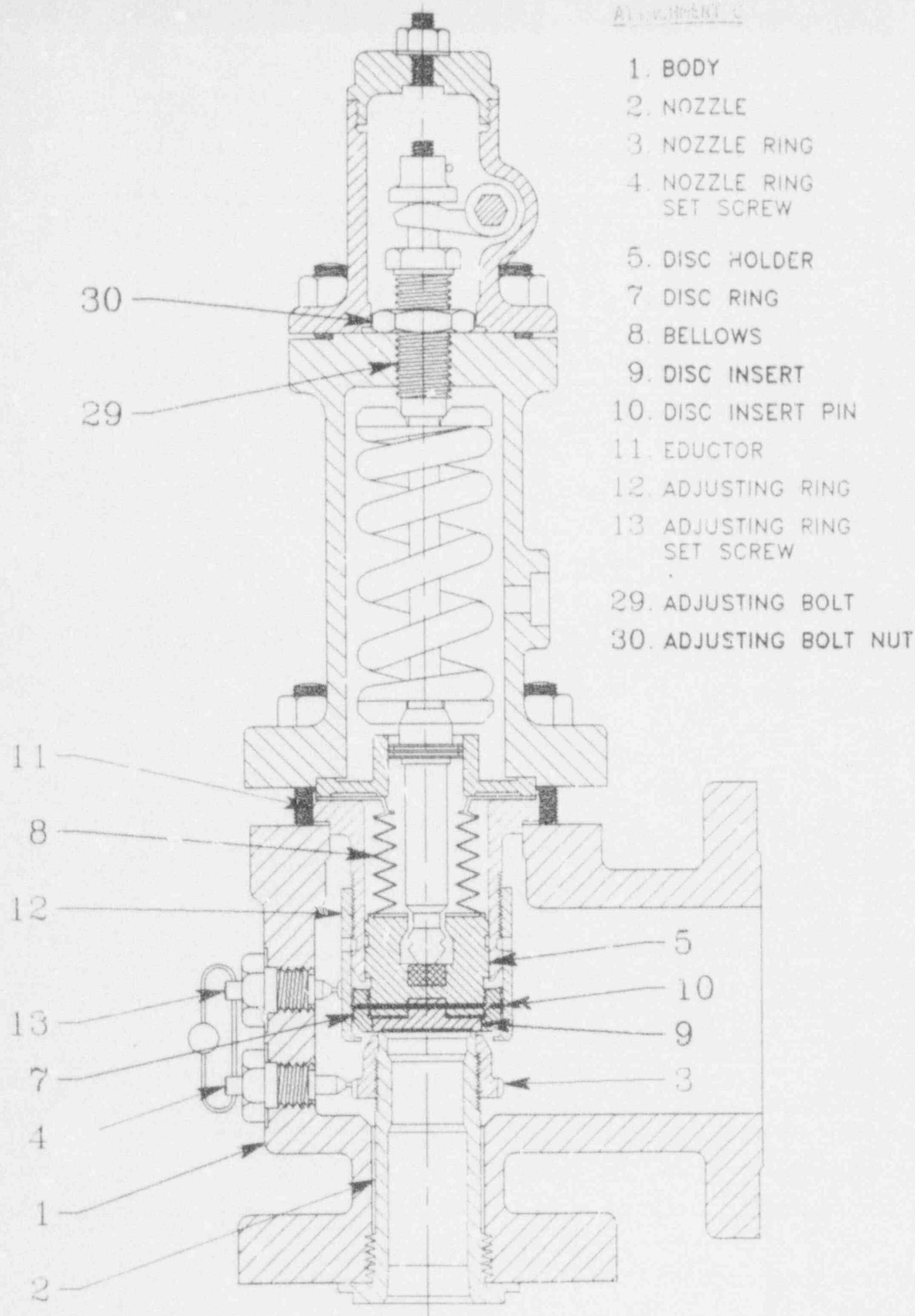
ATTACHMENT B

DISPOSITION OF THE INTERNAL PARTS OF PRESSURIZER CODE SAFETY VALVE RC-142

Part No.*	COMPONENTS	EVALUATION	DISPOSITION
2	Nozzle	No damage but met replacement criteria	Replace
3	Nozzle Ring	Impressions of disc ring on top surface	Machine
4	Nozzle Ring Set Screw	None	
7	Disc Ring	Marks due to impact with nozzle ring on top surface	Replace
9	Disc Insert	Disc insert was mushroomed into the disc holder. Seating surface of disc insert was approximately 0.002 inch below the top surface of disc ring. The disc insert protrusion should have been 0.010 to 0.023 inch above the top surface of the disc ring. Impact marks were visible on the seating surface of the disc insert.	Replace
12	Adjusting Ring	A 1/2-inch circumferential band of minor indentations was observed on the inner vertical surface of the adjusting ring. No affect on valve operation.	Use in the "as is" condition. No machining required.
13	Adjusting Ring Set Screw	None	
10	Disc Insert Pin	Although this pin should be contained within the disc holder (5), it was protruding from the disc holder by approximately 1/4 inch.	Replace
5	Disc Holder	Disc insert could not be removed from the disc holder. The eductor guiding surfaces of the disc holder displayed significant wear.	Replace
6	Disc Bushing	Uneven wear on the top spherical concave surface.	Replace

8	Bellows	The bellows assembly (Part Nos. 5, 6, and 8) was found broken into three pieces. The fractures occurred near the upper mounting plate and the top of the disc holder.	Replace
11	Educator	Minor wear on the disc holder guiding surface of the eductor.	Replace
14	Spindle	Chatter indications of the lower spring washer bearing surfaces of the spindle. Uneven wear of the bottom spherical surface of the spindle. This surface is a ball which is pressed into the bottom end of the spindle. The ball had rolled within the cavity.	Replace
40	Piston	Chatter indications on outer guiding surface of piston.	Replace
15	Bonnet Adaptor	Excessive wear on piston guiding surface of bonnet adaptor.	Replace
20	Spring Washers	Chatter indication on pressure bearing surfaces of both upper and lower washers.	Replace with new spring assembly
29	Adjusting Bolt	Galling on bearing surface	Replace
19	Spring	None (part of spring assembly with washers)	Replace
30	Adjusting Bolt Nut	Nut was found backed off of the bonnet surface approximately 1/4 inch of bonnet bearing surface. Sloppy fit with adjustment bolt.	Replace and add locking device

* See Attachment C


1. BODY
2. NOZZLE
3. NOZZLE RING
4. NOZZLE RING SET SCREW
5. DISC HOLDER
7. DISC RING
8. BELLOWS
9. DISC INSERT
10. DISC INSERT PIN
11. EDUCTOR
12. ADJUSTING RING
13. ADJUSTING RING SET SCREW
29. ADJUSTING BOLT
30. ADJUSTING BOLT NUT
30
29
11
8
12
5
10
13
9
7
3
4
1
2

ATTACHMENT D

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

JUL 4 1992

In Reply Refer To:
Docket No: 50-285
CAL 92-08

Omaha Public Power District
ATTN: W. G. Gates, Division Manager
Nuclear Operations
444 S 16th St Mall
Omaha, Nebraska 68102-2247

Gentlemen:

SUBJECT: CONFIRMATORY ACTION LETTER

The purpose of this letter is to confirm Omaha Public Power District's commitments to take certain actions as described below. These commitments were made during a telephone conversation between Mr. James L. Milhoan of NRC Region IV, and Mr. Terry Patterson and Mr. Jim Chase of your staff. Based on this conversation, we understand that Fort Calhoun will not return the reactor to a critical condition until the NRC has confirmed your actions for assuring that adequate safety exists for power operation. This assurance will be established by completing the following actions:

1. NRC inspection at your facility of the causes for the July 3, 1992 reactor trip and apparent failure of the safety relief valve (RCS-142) to fully reseat. The safety relief valve will be essentially left in the current condition until the Augmented Inspection Team completes its onsite inspection of the valve.

2. NRC inspection of your response to and the short term corrective actions taken for the July 3, 1992 event.

3. Conduct of a meeting in Region IV offices between the NRC and your staff regarding the results of your investigation of the July 3, 1992 event.

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

If your understanding of these commitments differs from the foregoing description, or if you decide for any reason to modify these corrective actions, please contact Mr. B. Beach of the Region IV staff immediately at (817)860-8223. Please inform Mr. Beach when you are prepared for the meeting indicated in Item 3 above.

Sincerely,

James L. Milhoan

James L. Milhoan
Regional Administrator

cc:
LeBoeuf, Lamb, Leiby & McRae
ATTN: Harry H. Voight, Esq.
1875 Connecticut Ave., NW
Washington, D.C. 20009-5728

Washington County Board
of Supervisors
ATTN: Jack Jensen, Chairman
Blair, Nebraska 68008

Combustion Engineering, Inc.
ATTN: C. B. Brinkman, Mgr.,
Washington Nuclear Ops.
12300 Twinbrook Pkwy., Suite 330
Rockville, MD 20852

Nebraska Department of Health
ATTN: Harold Borchert, Director
Division of Radiological Health
P.O. Box 95007
Lincoln, Nebraksa 68509

Fort Calhoun Station
ATTN: T. L. Patterson, Manager
P.O. Box 399
Fort Calnoun, Nebraska 68023

Nuclear Regulatory Commission
ATTN: Resident Inspector
P.O. Box 309
Fort Calhoun, Nebraska 68023

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

JUL - 8 1992

In Reply Refer To:
Docket No: 50-285
CAL 92-08

Omaha Public Power District
ATTN: W. G. Gates, Division Manager
Nuclear Operations
444 S 16th St Mall
Omaha, Nebraska 68102-2247

Gentlemen:

SUBJECT: REVISION TO JULY 4, 1992, CONFIRMATORY ACTION LETTER

The purpose of this letter is to document a revision to our Confirmatory Action Letter of July 4, 1992, that confirmed Omaha Public Power District's commitments to take certain actions as a result of the July 3, 1992, reactor trip/turbine trip and subsequent loss of coolant accident at Fort Calhoun Station. These commitments were made during a telephone conversation between Mr. James L. Milhoan of NRC Region IV, and Mr. Terry Patterson and Mr. Jim Chase of your staff. On the basis of this conversation, we understand that Fort Calhoun Station will not return the reactor to a critical condition until the NRC has confirmed your actions for assuring that adequate safety exists for power operation.

Commitment No. 1 of our July 4, 1992, letter confirmed, in part, that safety relief Valve RC-142 would be left in the condition that existed on July 4, 1992, until the NRC Augmented Inspection Team completed its onsite inspection of the valve. This action was completed on July 7, 1992. On the basis of a discussion between you and Mr. Phil Harrell of my staff, Commitment No. 1 has been revised.

Specifically, Commitment No. 1 has been revised so that Valve RC-142 can be removed from the reactor coolant system (RCS) for shipment to a vendor's facility, Wylie Laboratories, for inspection and testing. Valve RC-142 was removed from the RCS on July 7, 1992. We understand that no inspection or testing of Valve RC-142 shall commence until an NRC inspector is present to observe these activities, which are currently scheduled to commence on July 9, 1992. Further, a copy of the testing plan for Valve RC-142 shall be submitted to NRC for review prior to commencing testing and inspection at Wylie Laboratories.

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

We understand that all other commitments referenced in our July 4, 1992, letter remain unchanged. If your understanding of this change of commitment differs from the foregoing description, or if you decide for any reason to modify these corrective actions, please contact Mr. J. M. Montgomery immediately at 817/860-8226.

Sincerely,

James L. Milhoan
Regional Administrator

cc:
LeBoeuf, Lamb, Leiby & McRae
ATTN: Harry H. Voight, Esq.
1075 Connecticut Ave., NW
Washington, D.C. 20009-5728

Washington County Board
of Supervisors
ATTN: Jack Jensen, Chairman
Blair, Nebraska 68008

Combustion Engineering, Inc.
ATTN: C. B. Brinkman, Mgr.,
Washington Nuclear Ops.
12300 Twinbrook Pkwy., Suite 330
Rockville, MD 20852

Nebraska Department of Health
ATTN: Harold Borchert, Director
Division of Radiological Health
P.O. Box 95007
Lincoln, Nebraksa 68509

Fort Calhoun Station
ATTN: T. L. Patterson, Manager
P.O. Box 399
Fort Calhoun, Nebraska 68023

Nuclear Regulatory Commission
ATTN: Resident Inspector
P.O. Box 309
Fort Calhoun, Nebraska 68023

ATTACHMENT E

LIST OF ACRONYMS

ac - alternating current
AIT - Augmented Inspection Team
ASME - American Society of Mechanical Engineers
dc - direct current
EOP - emergency operating procedure
FCS - Fort Calhoun Station
kVA - kilovolt-amps
NRC - Nuclear Regulatory Commission
psia - pounds per square inch, absolute
psig - pounds per square inch, gage
Vac - voltage, alternating current
Vdc - voltage, direct current

ATTACHMENT F

PERSONS CONTACTED

The AIT contacted the following persons during this inspection, in addition to other personnel:

Omaha Public Power District

R. Andrews, Division Manager, Nuclear Services
W. Blessie, Shift Technical Advisor
J. Braun, Secondary Reactor Operator
C. Brunnert, Supervisor, Operations Quality Assurance
C. Boughter, Supervisor, Special Services Engineering
J. Chase, Assistant Manager, Fort Calhoun Station
R. Clemens, Nuclear Design Engineer
G. Cook, Supervisor, Station Licensing
J. Cook, Simulator, Operation Training
M. Core, Supervisor, Maintenance
K. Dworak, Electrician
J. Fleuhr, Senior Nuclear Design Engineer
M. Frans, Supervisor, Systems Engineering
S. Gambhir, Division Manager, Production Engineering
J. Gasper, Manager, Training
*W. Gates, Division Manager, Nuclear Operations
G. Guliani, Supervisor, Operations Training
J. Harkins, Stone and Webster, Boston Office
R. Jaworski, Manager, Station Engineering
*W. Jones, Senior Vice President
R. Kellogg, Senior Nuclear Design Engineer
L. Kusek, Manager, Nuclear Safety Review Group
D. Lakin, Nuclear Safety Review Group
T. McIvor, Manager Nuclear Projects
S. Miller, System Engineer
K. Naser, System Engineer
W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Manager, Fort Calhoun Station
*F. Peterson, President
R. Phelps, Manager, Design Engineering
W. Phillips, Relief Valve Engineer
R. Purdy, Senior Quality Assurance Lead Auditor, Procurement Quality Assurance
T. Reisdorff, Shift Supervisor
A. Richard, Assistant Manager, Fort Calhoun Station
R. Schreurs, Licensed Senior Operator
J. Sefick, Manager, Security Services
P. Sepcenko, Supervisor, Outage Projects
C. Simmons, Station Licensing Engineer
F. Smith, Supervisor, Chemistry
R. Short, Manager, Nuclear Licensing and Industry Affairs
J. Tills, Assistant Manager, Fort Calhoun Station
D. Trausch, Supervisor, Operations
S. Willrett, Manager, Nuclear Materials and Administration
J. Yeager, Primary Reactor Operator

* Denotes personnel that attended the public exit meeting on July 10, 1992

Crosby Valve and Gage Company

W. Greenlaw, Vice President, Engineering
R. Wright, Manager, Technical Services
S. Morse, Service Representative

Wyle Laboratories

P. Turrentine, Engineering Supervisor, Steam Test Services

ATTACHMENT G

DOCUMENTS REVIEWED

Manuals

Number	Revision	Title
OI-EE-4	9	Operating Instruction for 120-Vac System
TM E209	2	Technical Manual for Elgar Inverters and Associated Equipment
NA	NA	Systems Training Manual - Main Turbine and Turbine Auxiliaries
NA	NA	Systems Training Manual - Reactor Protection System
FC-886-86	NA	Cause and Effects of Unit Trip on July 2, 1986
LER 86-001	0	Reactor Trip Caused by Instrument Inverter Failure
EOP-00	0	Standard Posttrip Actions
EOP-20	0	Functional Recovery Procedure
EPIP-OSC-1	20	Emergency Classification
EPIP-OSC-2	25	Emergency Plan Implementing Procedure
AOP-16	0	Loss of Instrument Bus Power

Drawings

Number	Revision	Title
531-227-61	B	Overall Schematic
628-135-61	1	Schematic, DC-DC Converter
631-101-61	C	Schematic, Alarm Board
631-260-60	B	Master Schematic
631-264-60	C	Schematic, Static Switch Sense Board
643-105-40	B	Assembly, Static Switch Drive Board
643-105-60	A	Schematic, Static Switch Drive Board
643-125-40	C	Inverter Drive Board

643-125-60	A	Inverter Drive BoardCircuitry
643-131-60	C	Schematic, Static Switch Drive Logic Schematic
643-204-62	A	Inverter Panel Schematic
236 R 548	14	Electrohydraulic Control Circuitry