ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-482/96-05

License: NPF-42

Licensee: Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas

Facility Name: Wolf Creek Generating Station

Inspection At: Coffey County, Burlington, Kansas

Inspection Conducted: February 6-15, 1996

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1 INTRODUCTION

1.1 Purpose and Scope of the Inspection

The NRC has established a policy to provide for the timely, thorough, and systematic inspection of significant operational events at nuclear power plants. This includes the use of an Augmented Inspection Team to determine the causes, conditions, and circumstances relevant to an event and to communicate its findings and conclusions to NRC management. In accordance with NRC Inspection Manual Chapter 0325, the Region IV Regional Administrator dispatched an Augmented Inspection Team to the Wolf Creek Nuclear Generating Station to review the circumstances surrounding a manual reactor trip on January 30, 1996, with the failure of five control rods to fully insert into the core, a failure of the turbine-driven auxiliary feedwater pump, and the subsequent loss of one train of the essential service water system.

The Augmented Inspection Team consisted of five NRC personnel, including the team leader and specialists in operations, emergency response, engineering, and reactor fuels. In the Augmented Inspection Team Charter (Attachment 1) the Regional Administrator directed the team to conduct fact finding to determine the following:

- The initial conditions prior to the event,
- The sequence of events that resulted in the reactor trip,
- The performance of plant equipment during the event,
- The licensee's emergency response, and
- The operator response during the event.

In addition, in keeping with the NRC's emphasis on encouraging licensee self-assessment and corrective actions, the Augmented Inspection Team was directed to utilize the findings of the licensee's internal Incident Investigation Team to the maximum extent possible. Licensee-provided information was not independently developed; however, some of the information was verified to confirm the licensee's investigation.

The Augmented Inspection Team developed a detailed sequence of events provided in Attachment 3 based upon a review of the licensee's documentation, personnel interviews, and briefings by plant management personnel. A simplified flow diagram of the essential service water system is provided as Attachment 4. In addition, Attachments 5 and 6 provide a diagram of the essential service water system pumphouse and circulating and service water systems pumphouse, respectively. A list of documents that the Augmented Inspection Team reviewed is contained in Attachment 7. Attachments 8 and 9 identify the principal attendees at both the inspection entrance and exit meetings, as well as the list of personnel contacted during the inspection.

1.2 Licensee's Incident Investigation Team

In response to the event, the licensee initiated an Incident Investigation Team in accordance with Administrative Instruction 28B-003, "Incident Investigation," on February 2, 1996. In a letter, dated February 2, 1996, (Attachment 2) the licensee's vice president-plant operations appointed the licensee's nuclear safety review committee chairman (the retired vice president-engineering) as the Incident Investigation Team leader. The team originally consisted of 19 personnel divided into operations and engineering sub-teams. The team was later increased in size to 26 members with support from the US Army Corps of Engineers, the Architect-Engineers (Bechtel, and Sargent and Lundy), and licensed shift supervisors from the Institute for Nuclear Power Operations and the Cooper Nuclear Station.

The licensee's Incident Investigation Team conducted interviews with the operating crew who were on shift at the time of the event, and other licensee staff and management personnel. The licensee also reviewed records documenting system and plant response to the event and conducted formal root cause analyses for the system and operational failures. The licensee also reviewed the design basis of the essential service water system and performed thermal-dynamic modelling of the actual plant configuration.

After an initial briefing by the Incident Investigation Team at the entrance meeting on February 5, 1996, the NRC Augmented Inspection Team reviewed all the interview notes developed by the licensee, reviewed records documenting system and plant response during the event, reviewed the root-cause analyses and engineering evaluation of the design basis of the essential service water system, and interviewed members of the operating crew directly involved in the event.

1.3 Effectiveness of Combined Inspection Process

Throughout the performance of the Augmented Inspection Team inspection the licensee's Incident Investigation Team provided excellent support and was willing to share any and all information they had developed. In addition, they pursued additional questions and concerns that the Augmented Inspection Team developed. As a result of this combined process, the impact of the NRC inspection on the licensee's staff was reduced. The majority of issues identified in this inspection report were first identified by the licensee's detailed interviews with the individuals involved in the event. In fact, the engineering errors discussed in Section 2.2.1, the operator errors discussed in Section 2.3.4, and the information regarding the degradation of Train "B" of the essential service water system were all independently identified by the licensee's Incident Investigation Team before the Augmented Inspection Team's involvement.

The licensee's Incident Investigation Team demonstrated a very credible self-assessment capability in identifying the facts and concerns regarding this event. By virtue of its size alone, the licensee's team was able to conduct more documented interviews with the personnel involved in the event than the Augmented Inspection Team. In addition, the depth of the licensee's

engineering analysis of the event could not have been duplicated by the NRC in the same time period. As a result, the scope of the licensee's effort allowed both the licensee and the NRC to come to a clearer understanding of the root causes and effects of the event in a much shorter time frame.

2 EVENT DESCRIPTION

2.1 Detailed Sequence of Events

As previously indicated, the detailed sequence of events is provided in Attachment 3. The plant was initially at 100 percent reactor power in coastdown to a refueling outage with reactor coolant system boron concentration at 1.0 ppm. Trains "A" and "C" circulating water system pumps were running.

Prior to the events of January 30-31, 1996, the plant had experienced low temperatures approaching 6° F occurring after midnight, and winds in excess of 24 mph gusting from the northwest at times. These weather conditions were prevalent on both the nights of January 29 and 30, 1996. Although the daytime high temperatures had not exceeded 25° F on January 28 or 29, 1996, an ice cover had not fully developed on the Wolf Creek reservoir. However, the bulk water temperature of the reservoir was approaching 32° F.

Early in the morning of January 30, 1996, the control room received alarms indicating that the circulating water system traveling screens were becoming blocked. The operators became concerned about the potential loss of the circulation water and service water systems and the effect on turbine loads. Operators started Train "B" of the essential service water system; however, they failed to isolate the service water system from the essential service water system as required by the operating procedure. Specifically, the reactor operator opened the essential service water system return to service water system isolation valves and closed (throttled) the essential service water system to ultimate heat sink isolation valves, thus, restricting warming line flow to the essential service water system suction bays.

The operators stopped the Train "A" circulating water system and service water system pumps. Anticipating further problems with the circulating water system, the operators started reducing turbine load. The shift supervisor directed a manual reactor/turbine trip, in anticipation of the need to trip the circulating water system pumps. Following the manual reactor trip, the operators noted that five control rods did not fully insert. During the transition to the post-trip recovery procedure, the operators found that a copy of the procedure was missing from all four control room copies of the emergency management guidelines. The operators obtained a copy of the missing procedure and began emergency boration in accordance with the emergency procedures. The operators terminated emergency boration when all control rods were fully inserted.

The control room declared the turbine-driven auxiliary feedwater pump inoperable after receiving a report that the pump's inboard packing gland was leaking. The operators entered Technical Specification 3.7.1.2, whose Limiting Condition for Operation action statement required restoration in

72 hours or entry into Mode 3 (Hot Standby) within the next 6 hours and into Mode 4 (Hot Shutdown) in the following 6 hours. The operators also entered Technical Specification 3.4.8, whose Limiting Condition for Operation action statement required entry into Mode 3 (Hot Standby) within 6 hours after receiving a chemistry report that the reactor coolant system's dose-equivalent iodine level was elevated. The operators exited this latter action statement when activity levels decreased to normal.

With the plant in a shutdown, stable condition with all control rod bottom lights on, the operators began a shift turnover. During the turnover, the oncoming reactor operator noted that the system operating procedure for the essential service water system was not correctly performed; however, he did not take any immediate corrective action. At about 8 a.m., the operators stopped the Train "A" essential service water system pump due to low discharge pressure and high strainer differential pressure. The operators entered Technical Specifications 3.8.1.1 and 3.7.1.2, whose Limiting Condition for Operation action statement required entry into Mode 3 (Hot Standby) within 6 hours and into Mode 4 (Hot Shutdown) in the following 6 hours because one diesel generator and its associated auxiliary feedwater pump were inoperable.

Soon after shift turnover, the supervising operator recognized the essential service water system alignment error and properly isolated the service water and essential service water systems using the system operating procedure. Shortly thereafter, a relief-crew reactor operator located at the essential service water system pumphouse reported to his relief-crew supervising operator working in the control room that the bay level of the operating essential service water train (Train "B") had become degraded and decreased about 6 to 10 feet below normal. However, this information was not clearly communicated to the shift supervisor or control room operators. The shift supervisor declared a Notification of Unusual Event at 8:46 a.m., due to the loss of the Train "A" essential service water system and after declaring the turbine-driven auxiliary feedwater pump inoperable.

The operators commenced a cooldown to Mode 4 (Hot Shutdown), as required by Technical Specification 3.8.1.1; however, the time for the Technical Specifications required mode entry was missed by about 1-1/2 hours due to inefficiencies in the operator's use of the cooldown procedure. Later in the afternoon, the operators reset the turbine-driven auxiliary feedwater pump locally after the packing had been replaced. The operators considered the pump functional, even though the required surveillance test had not been performed to declare the pump operable.

At 3:43 p.m., the operators started the Train "A" essential service water system pump and declared the system operable about two hours later. The The shift supervisor terminated the Notification of Unusual Event at about 6 p.m. because Train "A" essential service water system pump had been declared operable. Nevertheless, the operators had to stop the Train "A" essential service water system pump after about 1-1/2 hours, due to further oscillations in flow and pressure. The shift supervisor did not make an emergency declaration because the Train "B" essential service water system pump was operating properly and the turbine-driven auxiliary feedwater pump was not required for Mode 4 (Hot Shutdown).

Throughout the night, the operators noted additional level oscillations in Train "B" of the essential service water system bay with a slow decrease to about 15 feet below normal. The levels recovered after additional heat loads were placed on Train "B" of the essential service water system.

At about 10:15 p.m., the operators again started the Train "A" essential service water system pump, but secured it approximately 15 minutes later when oscillations in flow and pressure continued. Soon after midnight on January 31, 1996, the relief shift supervisor was directed by the operations manager to staff the technical support center. The outage support center staff was relocated to the technical support center and the center's staffing was completed by about 6 a.m. on the morning of January 31, 1996.

The operators declared a second Notification of Unusual Event at 10 a.m., based on a diver's report of ice buildup and complete blockage of the Train "A" essential service water system trash racks. The operators commenced cooling down to Mode 5 (Cold Shutdown). Maintenance personnel began injecting air to the Train "A" essential service water system vent line to clear the ice blockage. Divers again entered the water to inspect the Train "A" essential service water system bay and reported that the Train "A" essential service water system trash racks were clear of ice by 8:45 p.m.

The plant entered Mode 5 (Cold Shutdown) at about 11:00 p.m., and exited Technical Specifications 3.7.4 and 3.8.1.1. The licensee terminated the Notification of Unusual Event on February 1, 1996, at 10:05 a.m.

2.2 Initial Conditions

2.2.1 Essential Service Water System

Design Basis

As indicated in the Updated Safety Analysis Report for the Wolf Creek Nuclear Generating Station, the essential service water system removes heat from plant components, which require cooling for safe shutdown of the reactor or following a design basis accident. The essential service water system consists of two redundant cooling water trains, provides emergency makeup to the spent fuel pool and component cooling water systems, and is the backup water supply to the auxiliary feedwater system. The system is safety-related and is protected from the effects of natural phenomena, such as earthquakes, tornadoes, hurricanes, floods, and external missiles. In addition, the system is designed to remain functional after a safe-shutdown earthquake. Its safety functions can be performed assuming a single active component failure coincident with the loss of offsite power.

As indicated in the simplified flow diagram provided in Attachment 4, the essential service water system consists of two separate 100-percent capacity trains of traveling screens, pumps, pump pre-lube storage tanks, self-cleaning strainers, piping, valves, and instrumentation. One pump supplies cooling water to each flow path. Each flow path draws water directly from the ultimate heat sink (the Wolf Creek Generating Station reservoir) through a suction bay in a common essential service water screen house. A trash rack is

situated between each of the suction bays and the reservoir. The pumps draw water from the ultimate heat sink at a maximum temperature of 95° F and a minimum temperature of 32° F from a common screen house. An elevation drawing of the seismic Category 1 screen house is provided in Attachment 5.

Each flow path is protected by interior walls from internally generated missiles, jet impingement, and flooding that may result from failures in adjacent flow path piping. Each train is also interconnected with the service water system. Two motor-operated isolation valves for each train are provided in the suction (EF HV-23, -24, -25, and -26) and discharge (EF HV-39, -40, -41, and -42) cross-tie headers, where the essential service water system connects to the service water system.

A minimum submergence of the pump suction piping of 8 feet ensures that vortexing or cavitation of the vertical centrifugal pump will not occur. A traveling water screen is provided on each train to protect the pump suction from large debris. Water is sprayed on the screens to clean the debris that may collect. Freeze protection is provided by warming lines from each discharge line during accident and normal operation. The warming lines discharge directly in front of the trash racks. The warming line flow is controlled by manual isolation valves (EF HV-262, -263, -264, and -265) connected to the system's return line to the ultimate heat sink. The return lines also have motor-operated isolation valves (EF HV-37 and -38), which have mechanical stops to prevent full closure. These stops were provided to ensure adequate flow to inhibit the growth of microbiologically induced corrosion.

During normal operation, the essential service water system pumps are left in standby and cooling water for the safety-related components and the air compressors is provided by the service water system. After cooling the equipment, some of the heated water is returned to the service water system return header, a portion is directed through the essential service water warming lines and the rest is discharged to the ultimate heat sink. Following a design-basis accident, auxiliary feedwater system low suction pressure, loss of offsite power, or a safety-related initiation signal, the essential service water system is isolated from the service water system by automatic closure of the associated motor-operated isolation valves. The essential service water system pumps are automatically started by the emergency diesel load sequencer, and receive power from the preferred power source or the emergency diesel generators.

Original Design Errors

The licensee's Incident Investigation Team reviewed the available design information in order to understand why the essential service water system warming line flow did not prevent the formation of the frazil ice that occurred on January 30, 1996 (see Section 2.2.3 of this report for a discussion of the frazil icing phenomenon). The licensee found that Bechtel Calculation C-K-20-01-F, "Wolf Creek ESW Pumphouse," dated May 17, 1976, determined that 4000 gpm of warming line flow was required for each of the essential service water system trains to prevent frazil ice accumulation on their respective trash racks. However, the calculation incorrectly assumed

that the temperature of the warming line flow would be at least 3° F above freezing (i.e., 35° F). During the event, the licensee determined that the warming line return temperature to the Train "A" suction bay was only about 3/4° F above freezing (i.e., 32.75° F). Based on these initial conditions, the US Army Corps of Engineer's Cold Region's Technical Digest No. 91-1, "Frazil Ice Blockage of Intake Trash Racks," dated March 1991, indicated that a warming line flow rate of 3600 to 7200 gpm would be required to prevent frazil ice blockage.

To complicate the situation further, the licensee determined that Bechtel calculation failed to recognize that the minimum required flow of 4000 gpm was insufficient to obtain fully developed pipe flow and that voiding in the essential service water keep-warm pipe would occur at flow rates less than about 6000 gpm. As a result of this pipe voiding, the licensee determined that the flow rate through the essential service water system warming lines had been reduced to about 2500 gpm. In addition, valve misalignment errors during the event (discussed in Section 2.3.4 of this report) further reduced this flow rate to about 1700-2000 gpm.

Cold Weather Protection Configuration

The Augmented Inspection Team verified that the licensee had implemented their cold weather provisions on November 2, 1995. The system alignments were conducted in accordance with Procedure STN GP-001 "Plant Winterization." These alignments ensured that the essential service water system was configured to supply discharge water through the essential service water system intake warming lines. The alignment for winterization required the warming line isolation valves (EF HV-260, -261, -262, and -263) to be open and the essential service water system to ultimate heat sink isolation valves (EF HV-37 and -38) to also be fully open.

Subsequent to the event, the licensee's Incident Investigation Team identified that one valve in the Train "B" essential service water system warming line was not aligned fully open as required. Specifically, the warming line Isolation Valve EF HV-263 was only 50 percent open when the valve position indicator showed that the valve was fully open. However, an engineering analysis concluded that the flow rate was not appreciably affected by the misposition of the valve because it was a butterfly valve. No other anomalous conditions were identified to have existed prior to the event.

2.2.2 Turbine-Driven Auxiliary Feedwater Pump

The Augmented Inspection Team reviewed the previous maintenance that had been conducted prior to the packing failure of the turbine-driven auxiliary feedwater pump on January 30, 1996. There were two maintenance activities conducted after the last refueling outage (Cycle 7) that pertained to the pump packing.

Specifically, Performance Improvement Request 94-1918, dated October 30, 1994, indicated that following the refueling outage, the packing on the turbine-driven auxiliary feedwater pump had been installed too tightly, had become

glazed during subsequent packing adjustment and run-in, and could not be adjusted properly. Work Request 5905-94 was written on October 29, 1994, to replace the packing in order to resolve the problem. However, due to operational considerations, the operators did not want the mechanics to run-in the packing for 20-30 minutes as required by the work instruction. Therefore, the packing run-in requirement was changed to simply "run the pump."

During post-maintenance testing, the mechanics left the packing gland leak-off for the inboard packing at 2400 cc/min and the outboard packing leakage at 1800 cc/min. As indicated in Performance Improvement Requests 94-1925 and 94-2095, dated October 30 and November 25, 1994, respectively, the work instruction called for "approximately 230 cc/min" packing gland leakage, but subsequent guidance was provided by engineering (in consultation with the pump vendor) that packing gland leakage should be adjusted to something greater than 240 cc/min. The work instruction did not provide an upper limit for the packing gland leakage, and the packing vendor was not consulted.

The Augmented Inspection Team also noted that a generic pump packing procedure was added to the pump Technical Manual M-021-00061-W13, "Instruction Manual for Auxiliary Feedwater Pumps," by a change notice dated April 5, 1995, which was based on the recommendations of the Fluid Sealing Association. The Augmented Inspection Team reviewed the generic instructions and found that they were very good and addressed the critical elements associated with packing installation, such as shaft inspection following packing removal, presoaking of packing, packing installation and placement of the packing gland follower in the stuffing box, and packing run-in and adjustment.

The second maintenance activity associated with the turbine-driven auxiliary feedwater pump packing occurred on January 25, 1996, just a few days before the event. In this instance, the shaft sleeve retaining nut was found to be unthreaded and dangling on the shaft. The licensee determined that the retaining nut had been loose for some time and had caused some minor damage to the threaded section of the pump shaft.

The licensee's maintenance department removed the packing gland follower, and inspected the area. The craftsmen dressed up a couple of the threads with a file, and reassembled the shaft sleeve retaining nut and packing gland in accordance with Work Package 108952 (Tasks 1-3, 5, and 6) and Component Change Package 06310, dated January 25, 1996. During this evolution, the packing was not removed or replaced. The packing gland leakage was measured to be 1000 cc/min at the inboard packing gland and 1480 cc/min at the outboard packing gland during post-maintenance testing in accordance with Surveillance Test STS AL-103, "TDAFW Pump Inservice Pump Test," performed on January 26, 1996. The Augmented Inspection Team noted that the enhanced guidance for packing run-in and adjustment that was added to the pump technical manual in April of 1995 was not referenced, nor included, in the work instructions for this repair activity.

2.2.3 Frazil Icing Phenomenon

Background

The Augmented Inspection Team found that the licensee's operational and engineering staff were generally aware of the phenomenon of frazil ice formation. However, as discussed further in this section of the report, the training for this issue was inadequate. Subsequent to the event, the licensee obtained the assistance of Mr. Steven F. Daly of the US Army Corps of Engineers, to review the environmental conditions and circumstances which led to the loss of the essential service water system on January 30, 1996. Mr. Daly had published a very good discussion of the frazil ice phenomenon in the Cold Regions Technical Digest No. 91-1, "Frazil Ice Blockage of Intake Trash Racks," in March 1991. In order to provide a more complete explanation of the ice blockage, some of the information contained in Technical Digest 91-1 is presented in this section as background information.

Frazil icing is a phenomenon that affects the operation of water intakes in regions where cold weather occurs. The accumulation of frazil ice on intake trash racks can completely block the flow of water into the intake. The process starts when the water flowing into the intake is subcooled (a condition where the water is below its freezing point). The subcooling may be very small, on the order of a few hundredths of a degree.

The subcooling occurs with a loss of heat from a large surface area such as a lake with open water and clear nights. High winds contribute to the subcooling by providing mixing of the subcooled water to depths as great as 20 to 30 feet. The frazil ice, which is very small crystals of ice with little buoyancy because of their size, is carried along in the water and mixed throughout the depth of the subcooled water.

The suction of the subcooled water and the suspended frazil ice crystals through an intake structure brings the frazil ice crystals in contact with the trash rack bars. Because the frazil ice is in subcooled water the crystals are growing and will stick to any object that is not heated. The ice will collect first on the upstream side of the trash racks, then steadily grow until the space between the trash racks is bridged. This bridging results in rapid blockage of the trash racks. Trash racks are designed to cause little head loss under normal conditions. Because of this low head loss, large amounts of frazil ice can accumulate on trash racks before symptoms of the accumulation become noticeable from head losses. The accumulation of ice can withstand high differential pressures, thereby, effectively damming the intake suction.

Previous Cold Weather Experience

The Augmented Inspection Team verified that from the winter of 1985 (the first operational winter after initial licensing) until the present, there had been 17 previous occasions, consisting of a total of 34 days, when the Wolf Creek Generating Station reservoir temperature was at or below 34.0° F, as measured

at the circulating water system intake. Of these 17 time frames, 8 fall into the time period from the winter of 1992 until the present, where daily minimum lake temperatures are readily available from the plant computer. Prior to the winter of 1992, this data is not easily retrievable.

For the eight time frames within the winter 1992 to present time period, lake temperatures below 33.0° F had been recorded for 7 of the 37 days when the temperature was at or below 34.0° F. Of these 7 days, only 1 had a temperature less than 32.4° F. This occasion was on January 30, 1996, when the reservoir temperature was recorded as 32.2° F. While this temperature would not allow the formation of frazil ice, instrument inaccuracies or the location of the temperature instruments on circulating water piping within the turbine building could allow the actual lake temperature to be below 32.0° F.

For the nine time frames prior to the winter of 1992, the licensee determined that nine occasions where lake temperature could have approached 32° F based on a review of records. However, during six of the nine times there was sufficient ice cover on the lake to provide an insulating blanket and preclude frazil ice formation. During the three other occasions, the essential service water system was not operated and there was no opportunity for the frazil icing phenomenon to affect the system's operation. These cold temperatures did not cause frazil ice formation on the circulating and service water systems because their warming flows were designed correctly.

Training for Frazil Ice Recognition and Prevention

The Augmented Inspection Team examined the training the licensee conducted both for initial licensed operator training and for requalification training to determine the extent of training for recognition and prevention of frazil ice conditions. The Augmented Inspection Team reviewed the following lesson plans:

- NO 12 089 00, "Essential Service Water System," Revision 9
- NO 16 089 04, "Essential Service Water System," Revision 2
- NO 12 075 00, "Circulating Water System," Revision 6

The Augmented Inspection Team noted that the lesson plans discussed frazil ice only briefly, and did not note that the facility is susceptible to the phenomenon. There was no mention of symptoms of frazil icing or preventive measures other than a brief discussion of the warming lines. There did not appear to be sufficient instruction provided to apprise the operators of what actions would prevent frazil ice from affecting the essential service water or circulating water systems.

During interviews with several operators, the Augmented Inspection Team asked the operators to recall what they remembered from training. The operators responses indicated that little information was retained. Specifically, the Augmented Inspection Team asked if they had remembered any subject matter related to icing phenomenon or frazil icing. The operators indicated that the subject of ice formation had been brought up in training, but did not recall anything about frazil ice. The training records indicate that all of the operators had attended training either in initial license training or during

requalification training. The Augmented Inspection Team concluded that the training was sparse and retention was clearly lacking. Further, the training was not adequate to prepare the operators for the possibility of frazil ice phenomenon.

Engineering Interpretation of Technical Specifications

The licensee's Incident Investigation Team concluded that a previous Technical Specification interpretation provided a basis for the operating staff's lack of recognition of the frazil icing condition during the event on January 30, 1996. The licensee's engineering staff had previously indicated that frazil icing was not a concern at the Wolf Creek Generating Station. Specifically, Technical Specification Interpretation No. 003-88, Revision 2, dated January 23, 1991, established the following guidance:

> "An ESW train shall be considered inoperable if its associated warming line is unavailable and lake temperature is less than 32° F. With lake temperature less than 32° F, Ice Formation in intake bays is a concern. The lake temperature limit of 32° F is based on Letter NP 90-2162, attached. Frazzle [sic] Ice Formation is not a concern due to ESW Pumphouse being enclosed and heated . . . ."

The referenced letter (NP 90-2162, dated December 21, 1990) provided an engineering response to a question regarding the flow requirements for the essential service water warming lines. The letter stated that active frazil ice formation on the trash racks and traveling screens was not a credible event because the essential service water pumphouse was normally heated and the traveling screens were enclosed by the structure. The engineering response also stated that bulk freezing of the essential service water intake water was not expected to occur due to the return flow to the ultimate heat sink through the warming lines, and that no specific flow requirement exists for freeze protection other than that required to maintain the intake water above the freezing point.

The Augmented Inspection Team concluded that the position expressed by engineering in this Technical Specification interpretation was confusing and inappropriate. The interpretation did not recognize the need for a minimum warming line flow as a condition for operability of the essential service water system, as such the interpretation was inconsistent with the design basis requirements for the warming lines (see Section 2.2.1 of this report). Further, frazil ice formation cannot be prevented simply by heating the pumphouse structure since this area heating will not appreciably influence intake water temperature (see Section 2.2.3 of this report for a discussion of the frazil ice phenomenon).

2.2.4 Emergency Plan Implementing Procedures

The licensee's radiological emergency response plan must be developed in accordance with 10 CFR Part 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities," and maintained in accordance with 10 CFR Part 50.54, "Conditions of (Operating) Licenses." The

plan must contain information on the organization for coping with radiation emergencies, assessment actions, activation of emergency organization, notification procedures, emergency facilities and equipment, training, maintaining emergency preparedness, and recovery following an accident. Detailed instructions necessary to implement the plan must be included in the emergency plan implementing procedures.

The Augmented Inspection Team noted that the NRC had previously identified deficiencies in the licensee's use of the emergency action levels to classify emergencies during past drills and exercises. For example, NRC Inspection Report 50-482/92-13, dated July 20, 1992, identified an exercise weakness related to the capability of control room operating crews to accurately and promptly classify emergency conditions during simulated accident scenario walkthroughs. In addition, NRC Inspection Report 50-452/93-26, dated October 13, 1993, identified a violation involving the failure to correct the emergency classification weakness identified during the previous inspection (i.e., NRC Inspection Report 50-482/92-13). Furthermore, NRC Inspection Report 50-482/93-20, dated December 23, 1993, identified a weakness during the 1993 annual emergency preparedness exercise that involved an inappropriate emergency classification and the subsequent errors in recognition of initiating conditions. The licensee's corrective action response to this exercise weakness, dated February 4, 1994, noted that the new NUMARC-based emergency action levels, submitted for NRC approval on December 15, 1993, should eliminate the potential for ambiguity in determining the appropriate emergency classification.

Since the NRC approval of the licensee's NUMARC-based EALs on August 2, 1994, the Augmented Inspection Team noted that programmatic weaknesses related to emergency classification errors had not been identified in subsequent NRC inspections prior to the icing event. The Augmented Inspection Team also noted that NRC Inspection Report 50-482/95-09, dated June 22, 1995, indicated that the NRC violation and two weaknesses related to emergency classification were closed out during the follow-up inspection.

At the time of the event on January 30, 1996, the control room shift supervisor had four key emergency plan implementing procedures that provided instructions for emergency classification, activation of emergency organization, and notification of offsite response organizations. Each of these procedures are discussed below.

- Control Room Organization EPP 01-1.0 "Control Room Organization," Revision 12, described the initial responsibilities and tasks of control room personnel upon the declaration of an emergency classification until the activation of technical support center. Specifically, the procedure directed the shift supervisor to become the shift supervisor/duty emergency director during the early phase of an emergency declaration. The shift supervisor is responsible for emergency classification, authorizations of notification of State and County agencies, protective action recommendations, and emergency organization activation. The shift clerk or a nuclear station operator performs the function of the

offsite communicator responsible for immediate and follow-up notifications to State and County agencies. The procedure transfers these responsibilities to technical support center personnel upon activation of the center.

- Immediate Notifications EPP 01-3.1, "Immediate Notifications," Revision 17, provided guidance for conducting immediate notifications to Federal, State and County authorities in the event of a declared emergency. Specifically, the procedure required the shift supervisor to approve the immediate notification forms prior to technical support center activation. Control room personnel are required to notify the plant security, and State and County agencies within 15 minutes. In addition, the control room personnel are required to notify the NRC resident inspector promptly after the completion of State and County notifications and the NRC Operations Center, located in Rockville, Maryland, via the emergency notification system, but no later than 1 hour following an emergency classification. The control room emergency notification system communicator maintains continuous communications with the NRC Operations Center unless the NRC agrees continuous communications are no longer needed. Control room personnel make all immediate notifications until the activation of the technical support center.

- Follow-up Notifications EPP 01-3.2, "Followup Notifications," Revision 14, provides guidance for update notifications to State and County agencies. Specifically, the procedure required follow-up notifications at approximately 30 minute intervals or as soon as more definitive information becomes available. The procedure also required the shift supervisor to approve the follow-up notification forms prior to technical support center activation. Control room personnel make all follow-up notifications until the activation of the technical support center.

- Emergency Classification EPP 01-2.1, "Emergency Classification," Revision 15, provided guidance to evaluate plant conditions during an actual or potential emergency situations, to assess those emergency action levels exceeded and to classify the emergency according to its severity. The procedure is implemented by the shift supervisor immediately upon recognition of an emergency or off-normal conditions.

The emergency classification procedure (EPP 01-2.1) contained three attachments: (1) 13 emergency action levels charts, (2) indications of a loss of function, and (3) explanation/bases for emergency action levels. The first attachment, EP 01-2.1-1, Revision 2, "Emergency Action Levels," contained 13 flowcharts that described the following event recognition categories:

- Radioactive Effluent Release
- Steam Generator Tube Failure
- Loss of Reactor Coolant Boundary
- Main Steam Line Break
- Fuel Element Failure
- Loss Electrical Power/Assessment Capability

- Fuel Handling Accident
- Safety System Failure or Malfunction
- Loss of Plant Control/Security Compromise
- Fire
- Natural Phenomena
- Other Hazards
- Administrative

Each emergency action level chart included the initiating conditions with the emergency action level associated for two or more emergency classes (Notification of Unusual Event, Alert, Site Area Emergency, and General Emergency) related to an event recognition category. The chart was arranged in a decision flow chart format. The emergency action levels for an initiating condition were summarized in blocks. Each block had a yes or no path that either flowed to the next unrelated initiating condition (if answered no) or flowed to the next related emergency action level and eventually to an emergency classification (if answered yes).

The second procedure attachment, EPP 01-2.1-2, "Indications of a Loss of Function", Revision 2, provided criteria for a complete loss of function needed to achieve or maintain hot shutdown. The safety system failure or malfunction emergency action level chart referenced this attachment. The third procedure attachment, EPP 01-2.1-3, "Explanation/Bases for EALs", Revision 3, provided detailed discussion for each flowchart block.

The licensee's emergency action level charts were developed using industry guidance provided by NUMARC/NESP-007, "Methodology for Development of Emergency Actions Levels," Revision 2. NRC Regulatory Guide 1.101, "Emergency Planning and Preparedness For Nuclear Power Reactors," Revision 3, endorsed the industry guidance provided by the NUMARC report. The Augmented Inspection Team noted that the licensee had supported the industry's emergency action level redevelopment effort and provided two members to the NUMARC emergency action level task force. The Augmented Inspection Team determined that emergency action level charts applicable to the event conformed to industry guidance provided by NUMARC/NESP-007. The emergency action level charts applicable to the event were:

- Fuel Element Failure
- Loss Electrical Power/Assessment Capability
- Safety System Failure or Malfunction
- Natural Phenomena
- Other Hazards
- Administrative

The Augmented Inspection Team verified that the licensee's emergency action level charts did not have initiating conditions for ice-related events. In addition, the Augmented Inspection Team verified that this specific guidance is not provided in either: (1) NUMARC/NESP-007, Revision 2,

(2) NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 2, or (3) the emergency classification emergency action levels for six of the following cold weather nuclear power plants: D.C. Cook, Davis-Besse, Fitzpatrick, Palisades, Point Beach, and Nine Mile Point.

The Augmented Inspection Team also noted that the licensee's Emergency Classification procedure (EPP 01-2.1, Revision 15) and the corresponding training lesson plan (TIN LR 00 356 00, Revision 1) lacked clear guidance on the use of the administrative emergency action level chart. Specifically, Precaution Step 6.2.1 required the user to review all emergency action level charts during an emergency classification assessment. However, implementation Step 8.5 required the use of professional judgement if the event did not fit the general description for any the of emergency action level charts. In addition, the Augmented Inspection Team identified during interviews with senior managers that the licensee did not consider the administrative chart applicable for emergency classification if the event matched another chart. In other words, the administrative chart should not be used to classify an emergency if an event can be matched with one or more emergency action level charts, whether a classification was made or not.

The Augmented Inspection Team concluded that this interpretation was not in accordance with the NUMARC and NRC guidance for the use of emergency action levels. Furthermore, the Augmented Inspection Team concluded that professional judgement must be used to classify an emergency for all events including those events which can be matched to one or more emergency action level charts.

2.2.5 Environmental Conditions Prior to Reactor Trip

The weather conditions prior to the events of January 30-31, 1996, were overnight temperature lows of 6° F, with winds in excess of 24 mph gusting at times. These conditions were prevalent both the night of January 29 and 30, 1996. The daytime high temperatures did not exceed 25° F on January 28 - 29, 1996. An ice cover had not fully developed on the Wolf Creek Generating Station reservoir and the bulk water temperature of the reservoir was approaching 32° F. As previously discussed in Section 2.2.3 of this report, the low temperatures and wind conditions were precursors to the formation of frazil ice. Nevertheless, the shift supervisor and control room logs for January 28-29, 1996, did not indicate any substantial concerns related to the weather or equipment problems.

2.3 Operator Response

2.3.1 Loss of Circulating Water System Suction

At 1:48 a.m. on the morning of January 30, 1996, the operators began to receive alarms indicating that the circulating water system traveling screens were icing. Both the "A" and "C" circulating water system pumps were running at this time. The initial level in the Train "A" circulating water system bay

was at 8 feet below normal. The site watch was dispatched to the circulating water system pumphouse to investigate the conditions. Upon arrival, the site watch reported to the control room that there was a high differential pressure in Bay 3. Several alarms were being received at this time indicating that severe icing was occurring on the traveling screens. The alarms included:

- ALR 00-005A "CWSH Bay 1 Emergency,"
- ALR 00-005B "CWSH Screen Trouble," and
- ALR 00-006B "CWSH Screen Block."

Because of the reports of traveling screen icing, indications of service water system discharge pressure being low, and rising temperature in the turbine lube oil system, the shift supervisor directed the reactor operator to ". . . divorce service water from essential service water . . . ." and to start the essential service water system pumps. This action was directed at approximately 1:59 a.m. following the receipt of Alarm ALR 00-005A. The reactor operator initially started to retrieve the applicable Procedure EF-200, "Operation of the ESW System;" however, sensing an urgency to proceed, the shift supervisor indicated that he wanted the essential service water system immediately started.

At about 2 a.m., the site watch reported that the screens in Train "A" circulating water system suction bay were frozen. At 2:23 a.m., the Train "B" circulating water system traveling screen was placed in manual "fast" and the Train "B" circulating water system pump was started. Shortly thereafter, the Train "A" circulating water pump was stopped and the Train "A" service water system pump was also stopped due to the low level in the Train "A" bay. The site watch reported that the Train "B" bay level was low and that the Train "B" traveling screens were frozen. The operating crew took action to throttle circulating water system flow to maintain discharge pressure and stop or slow the level decrease. At 3:35 a.m., the low pressure alarm for the service water system came in, the electric fire pump started due to low service water system pressure, and the site watch reported circulating water system bay levels were 12 feet below normal. Due to the continuing problems with both the circulating water and service water systems the shift supervisor decided, after consulting with the supervising operator, to trip the reactor, stop the circulating water system pumps and break condenser vacuum.

2.3.2 Manual Reactor Trip

Prior to the decision to trip the reactor, the shift supervisor provided the operators in the control room a strategy for the post-trip actions. Those included first tripping the reactor manually, then stopping the circulating water system pumps and breaking condenser vacuum. The operators planned to use the atmospheric dump valves as the mode of cooldown for the reactor trip. The shift supervisor noted that the compelling reason for the decision centered on two important factors. First, during the event condenser vacuum had decreased in one of the three condensers to the point that the C-9 condenser available permissive was not enabled. This indicated that a loss of the condenser was likely and that the steam dumps would not be

available. Secondly, the service water system was unstable, with discharge pressure low and the main turbine lube oil temperature rising. The shift supervisor also indicated that the stimulus for the decision was the start of the electric fire pump, which clearly indicated that service water system pressure was low.

2.3.3 Post-Trip Response and Emergency Boration

Following the manual reactor trip at 3:37 a.m., the operators conducted the actions as described above and entered Emergency Management Guideline (EMG) E-0 "Reactor Trip or Safety Injection." The operators immediately noted that five control rods had not fully inserted into the reactor core. The operators proceeded through the immediate actions of E-0 Step 1.a., which required verification that all rod bottom lights were illuminated. The "Response Not Obtained" column required manually tripping the reactor. If reactor power had been greater than or equal to 5 percent or intermediate range power was increasing, the procedure would have directed performing EMG FR-S1, "Response to Nuclear Power Generation [Anticipated Transient Without Scram] ATWS," Step 1. Since the reactor power was less than 5 percent and the intermediate range nuclear instrumentation indicated a normal post-trip, 1/3-decade per minute negative startup rate, the operators continued through the rest of EMG E-0 as required. The Augmented Inspection Team concluded the operators' immediate actions were in accordance with the instructions in EMG E-0.

The operators continued through EMG E-0 and completed EMG F-0, "Critical Safety Function Status Trees," then transitioned to EMG ES-02, "Reactor Trip Response." At this point, the operators determined that a copy of EMG ES-02 was not in any of the four EMG procedure sets in the control room. The shift supervisor instructed the crew to proceed from knowledge while a copy of EMG ES-02 was obtained from the file net computer-based information system. A copy was printed within approximately 4 minutes. The operators proceeded through EMG ES-02 performing all the required actions until reaching Step 8.

Step 8 of EMG ES-02 required that if two or more control rod bottom lights were not lit then emergency boration was required. Step 8 required that Procedure OFN BG-009 "Emergency Boration," be used. Procedure OFN BG-009 required increasing the reactor coolant system boric acid concentration 130 ppm for each control rod not inserted. The operators commenced emergency boration at 3:55 a.m. The Augmented Inspection Team concluded that the time the operators took to complete the emergency boration was not excessive. However, the lack of the emergency procedure in the control room was an unnecessary operational burden, which delayed the post-trip response actions.

2.3.4 Alignment of Essential Service Water System

As discussed in Section 2.3.1 previously, the shift supervisor directed the reactor operator to divorce the service water system from the essential service water system and to start the essential service water pumps. This action was directed at approximately 1:59 a.m. following the receipt of Alarm ALR 00-005A, "CWSH Bay 1 Emergency." The reactor operator initially started to retrieve the applicable Procedure EF-200 "Operation of the ESW

System," however, the shift supervisor indicated that he wanted the essential service water system started immediately, indicating to the operator to proceed with the realignment without using the procedure. While procedure use is emphasized at Wolf Creek Generating Station, the Augmented Inspection Team verified that proceeding without a procedure in a situation such as this was not inconsistent with the licensee's administrative requirements, management expectations, and training.

Following the instruction from the shift supervisor, the reactor operator proceeded to align the system as follows:

- Train "A" essential service water/service water cross-connect Valves EF HV-23 and -25 were closed.
- Train "B" essential service water/service water cross-connect Valves EF HV-24 and -26 were closed.
- Train "A" essential service water/service water isolation Valves EF HV-39 and -41 were left open.
- Train "B" essential service water/service water isolation Valves EF HV-40 and -42 were left open.
- Train "A" essential service water to ultimate heat sink Valve EF HV-37 was closed (throttled).
- Train "B" essential service water to ultimate heat sink Valve EF HV-38 was closed (throttled).

These manipulations had the net effect of reducing the warming line flow to about 1700-2000 gallons per minute by diverting some flow out through the service water system discharge lines, and by restricting flow to the ultimate heat sink and, thus, to the essential service water system warming lines. This alignment was not as expected considering the circumstances and most likely contributed to the eventual accumulation of frazil ice on the trash racks at the essential service water system pumphouse. During interviews with the shift supervisor, the supervising operator, and the reactor operator, the operators acknowledged that this alignment did not meet the intent of the shift supervisor's directions. In fact, the reactor operator indicated that he had taken these actions in an attempt to supplement the service water system cooling flows and stabilize the increasing lube oil temperatures on the turbine.

Following the realignment, the reactor operator indicated to both the shift supervisor and the supervising operator that he was not comfortable with the alignment he had implemented and requested that someone verify the alignment. Both the shift supervisor and the supervising operator indicated to him that they would review the alignment, but due to other problems occurring during this period they did not review the alignment prior to shift turnover at 7 a.m. that morning. The shift supervisor noted that he did notice, during a

walk past the panel, that some valves (either EF HV-37 or -38, he could not precisely recall) were in positions he did not expect. The shift supervisor indicated that he assumed the reactor operator was still making changes to the alignment and did not question the reactor operator about the unusual valve positions.

The reactor operator did eventually obtain a copy of Operational Procedure EA-120, "Service Water System Startup," which in Section 6.3 provided instruction for alignment of the essential service water system warming lines and was applicable for the operational conditions. However, the reactor operator did not review the alignment prior to shift turnover due to the workload following the plant shutdown. When asked by the Augmented Inspection Team why he aligned the system in the way he did, the reactor operator stated that he thought it would assist the service water system in maintaining pressure and that he did not conceive that the configuration would seriously affect the operation of the essential service water system.

The Augmented Inspection Team concluded that the control room staff missed multiple opportunities to identify and correct the system misalignment due to poor communications and self-checking techniques. As previously indicated in Section 2.2.1, this alignment error contributed to the icing and, therefore, degradation of the essential service water system.

2.3.5 Termination of Emergency Boration

At approximately 4:37 a.m., a reactor engineer completed a shutdown margin calculation determination using Worksheet SDM-1, "Shutdown Margin Calculation Worksheet." The calculation was done as required in Step 9 of OFN BG-009. The calculation indicated that shutdown margin was met with 0 ppm boron. The calculation was made using the assumption that essentially all rod worth was inserted. The Augmented Inspection Team calculated that boric acid concentration at this time was approximately 570 ppm based on the final boron concentration achieved when boration was terminated. At about this time, a discussion was held between the shift supervisor, shift engineer, reactor engineering supervisor (via telephone), and the reactor engineer to determine if the emergency boration should be terminated. Reactor engineering advised that the emergency boration could be terminated because the two control rods that remained partly out were in the dashpot region of the control rod guide tubes and essentially had all of their reactivity inserted. The operators questioned this advice based on the observation that the boration for the remaining two control rods would require injection of 2350 gallons per control rod or 4700 gallons total. The Augmented Inspection Team noted that the reactor coolant system boron concentration at this time provided at least 130 ppm boron apiece for the two control rods that were not fully inserted.

At 4:39 a.m., the operators noted that the two remaining control rod bottom lights illuminated and terminated the emergency boration. The Augmented Inspection Team concluded that the operators did not act upon the advice given by reactor engineering. Although the advice was well-founded from a technical basis, the Augmented Inspection Team noted that it was contrary to the procedures in use at the time. The operators appeared to be well aware of the requirements for complying with the procedure and exhibited a willingness to

question the advice provided by reactor engineering. The Augmented Inspection Team noted that the operator's actions to emergency borate 2350 gallons of boric acid for each control rod not fully inserted was conservative, since the boration of approximately 4400 gallons raised the reactor coolant system boron concentration to about 600 ppm from 1 ppm.

2.3.6 Recognition of System Misalignment

Based on interviews with the reactor operators, there was no discussion of the system misalignment at the shift turnover at 7 a.m. Although the relieving reactor operator did notice the unusual alignment of the essential service water system during the shift turnover, he did not pursue the reason for the alignment, nor did he communicate the discrepancy to his supervising operator. The shift supervisor was not aware of the misalignment until after the Train "A" essential service water pump was stopped at 7:47 a.m., due to the loss of level in the Train "A" essential service water system suction bay. The essential service water system was realigned at about 8 a.m. using Procedure EA-120, "Service Water System Startup."

The Augmented Inspection Team verified that the failure of the relieving reactor operator to recognize the significance of the essential service water system alignment and convey this information to his supervising operator was not in accordance with the licensee's administrative requirements and management expectation. In addition, the failure of the off-going shift supervisor and supervising operator to make their reliefs aware of the essential service water system alignment by not following through with confirmation of the system alignment were also departures from expected practices. The Augmented Inspection Team concluded that these actions demonstrated inadequate communication and self-checking skills, which allowed continued degradation of the operation of the Train "B" essential service water system.

2.3.7 Delay in Making Technical Specification Mode Change

At 5:14 a.m., the operators had declared the turbine-driven auxiliary feedwater pump inoperable due to the failure of the inboard shaft packing gland. When the operators stopped Train "A" of essential service water system pump at 7:47 a.m., various safety-related components in Train "A" also became inoperable (e.g., the motor-driven auxiliary feedwater pump and the emergency diesel generator associated with Train "A"). These failures resulted in the entry into the Technical Specification 3.8.1.1, Limiting Condition for Operation action statement for two inoperable auxiliary feedwater pumps. The action statement required that the plant be placed in Mode 4 (Hot Standby) within 6 hours (i.e., by 1347 hours or 1:47 p.m.).

Following the manual reactor trip and stabilization of the plant, the operators entered Procedure GEN 00-005, "Minimum Load to Hot Standby." Attachment A, "Entry Into Mode 3 Due to Reactor Trip," of GEN 00-005 provided instructions for system alignments and reconfigured the plant for normal shutdown operations. The attachment included numerous prerequisites and checkoffs for that purpose. The supervising operator began performance of the attachment at approximately 4:30 a.m. The procedure was completed through

Step A.17 when the Train "A" essential service water system pump was stopped. Step A.17 required verification that the atmospheric dump valves were set to maintain T_{avg} at between 552° F and 562° F, which is the no-load temperature for zero power. The steps that followed Step A.17 included surveillance and rod control system alignments. The licensee later noted that many of the remaining steps could have been accomplished in parallel with the continued cooldown of the plant.

Interviews with the supervising operator indicated that he believed that the steps in Attachment A of GEN 00-005 should be completed in the specified order. The shift supervisor inquired twice (at about 10 and 10:30 a.m.) about the supervising operator's progress in commencing the cooldown. Although the shift supervisor noted that cooldown was proceeding slowly, he did not want to direct the supervising operator to ignore procedural requirements. However, it is not apparent that the shift supervisor reviewed the procedure to determine what steps needed to be accomplished prior to commencing the cooldown.

The cooldown started at 11:07 a.m. in accordance with Procedure GEN 00-006, "Hot Standby to Cold Shutdown," with an initial cooldown rate of around 90° F per hour. This cooldown rate complicated the operation of the charging and letdown systems. Maintaining pressurizer level on its program setpoints required the operators to switch to a smaller orifice and increase the charging system flow rate. Eventually, the operators had to reduce the cooldown rate to allow control to be maintained. However, a letdown isolation did occur. The cooldown rate from 11:07 a.m. to 1:47 p.m. was on average only 70° F per hour due to these complications. This meant that the required entry conditions for Mode 4 (Hot Shutdown) could not be met in accordance with the Technical Specification Limiting Condition for Operation action statement by 1:47 p.m. The shift supervisor recognized the inability to meet this requirement and directed the crew to continue the cooldown emphasizing that plant stability was more important and to not proceed with haste.

The Augmented Inspection Team concluded that the cooldown was not overly complicated by the effort to cool down within the time remaining from 11:07 a.m. to 1:47 p.m. If the operators had started the cool down earlier, the time requirements of the Technical Specification action statement could have been met; however, the operators appeared to be unfamiliar with performing a rapid cooldown using the general operating procedures. While the procedures were written for normal conditions, there was no indication that the procedures could not have been accomplished for the event as it transpired.

The operators stated that they had not been in this situation in the past, either in an event or in simulator training, and that they were uncomfortable with the haste required. In addition, some support was late in arriving (the operators stated that reactor engineering was late in providing support to calculate the shutdown margins). Nevertheless, the Augmented Inspection Team

concluded that the delay in the cool down was not adversely affected by support personnel or the procedure itself. The operators' unfamiliarity with a rapid cooldown using a general operating procedure and inefficiencies in implementing the procedure resulted in the late entry to Mode 4 (Hot Shutdown) at 3:31 p.m.

2.3.8 Maintenance of Shutdown Margin During Cooldown

The Augmented Inspection Team noted that there were several on-the-spot-changes (OTSP) made to Procedure GEN 00-006 "Hot Standby to Cold Shutdown," during the recovery from the event. On-the-spot Procedure Change 96-0050, issued January 30, 1996, and set to expire February 1, 1996, was made to Procedure GEN 00-006 to remove the requirement for calculating shutdown margin using xenon-free conditions. This change involved changes to five procedural steps (Steps 6.11.2.1, 6.18.1, 6.21.1, 6.24.1, and 6.31.1). Step 6.38.1, which calculated the cold shutdown xenon-free shutdown margin was not changed. In each instance, the OTSP change deleted the reference to calculate the shutdown margin using xenon-free conditions. Although these changes did not affect the intent of the procedure. The changes removed a conservatism, in that xenon provided a considerable amount of negative reactivity at the time of the calculations.

The Augmented Inspection Team reviewed the OTSC with the supervisor of reactor engineering, to determine the basis for the changes. The changes were made as a result of operational questions during the cooldown regarding the procedural requirement for multiple shutdown margin calculations. A shutdown margin calculation had been done at the beginning of the cooldown that determined that the reactor coolant system boron concentration was sufficient to meet the Technical Specification requirements for a Mode 4 (Hot Shutdown) temperature of 340° F. Therefore, additional shutdown margin calculations appeared to be redundant.

After consultation, reactor engineering determined that the procedure required a shutdown margin calculation at each 50° F interval during the cooldown. However, the need to calculate the shutdown margin for xenon-free conditions was questioned. The Technical Specifications allowed the use of xenon in the core to satisfy the shutdown margin; however, the procedure did not allow the use of this additional shutdown margin. The licensee determined that GEN 00-006, "Hot Standby to Cold Shutdown," should be changed to remove the requirement for the xenon-free calculations, with the exception of the calculation for entry to Mode 5 (Cold Shutdown) at 200° F. This change allowed the cooldown to proceed more rapidly, with boration for the Mode 5 (Cold Shutdown) entry to be done after the cooldown to Mode 4 (Hot Shutdown) was completed. The Augmented Inspection Team verified that the need for the changes to the procedure were identified prior to the performance of the step and that the procedural requirements were satisfied during the cooldown.

Specifically, when the reactor was initially shutdown and all control rods were finally inserted, the Technical Specification shutdown margin requirement was met with no boron present in the reactor coolant system and a temperature of 557° F. As a result of the emergency boration, the reactor coolant system boron concentration was 609 ppm at 11:05 a.m. January 30, 1996, just prior to

the commencement of the cooldown to Mode 4 (Hot Shutdown). The reactor engineer who conducted the first shutdown margin calculation at that time, indicated on the surveillance routing sheet that at an anticipated temperature of 340° F, the shutdown margin would be maintained until 11 a.m., January 31, 1996. This prediction was based on the expected rate of decay of xenon in the core. Entry into Mode 4 (Hot Shutdown), at 350° F, was scheduled for 3:51 p.m. on January 30, 1996. A calculation done just prior to entry to Mode 4 (Hot Shutdown) at 3:30 p.m. indicated that a boron concentration of 359 ppm with xenon present was required to maintain the shutdown margin. The routing sheet further indicated that for a cooldown to 200° F for cold shutdown xenon-free conditions the boron concentration would have to be 882 ppm. The reactor coolant system was borated to 978 ppm at 5:35 p.m., January 30, 1996. At 8:37 p.m. on January 31, 1996, boron concentration was 1112 ppm. Mode 5 (Cold Shutdown) was entered at 10:48 p.m., January 31, 1996.

Based on a reviews of these calculations and the OTSP change to GEN 00-006, the Augmented Inspection Team concluded that the reactor was maintained with an adequate shutdown margin that met the requirements of the Technical Specifications at all times during the period from 11:07 a.m., January 30, 1996, through and past 10:48 p.m., February 1, 1996. The Augmented Inspection Team concluded that additional boration to comply for the Mode 5 (Cold Shutdown) entry would only have complicated the cooldown effort at the time and was not required for compliance with the Technical Specifications.

2.3.9 Restoration of Essential Service Water System

Following the manual reactor trip of January 30, 1996, the operators secured and declared the Train "A" essential service water system pump inoperable on two occasions. The first instance occurred a few hours after both essential service water system pumps were initially started to provide cooling water to critical plant equipment and the second instance occurred later that evening after the pump had been declared operable.

Specifically, the Train "A" pump was secured at 7:47 a.m. and declared inoperable when the operators noted that the pump's suction bay level was decreasing, pump discharge pressure was low, and pump discharge strainer differential pressure was abnormally high. During this period, the Train "B" essential service water system pump suction bay level also dropped and stabilized at about 6 feet below the normal level; however, pump performance did not appear to be significantly affected. During the next several hours, the licensee provided supplemental heaters to heat the air surrounding the essential service water system pump suction bay areas; stationed watchstanders at the essential service water system pumphouse to watch for icing, observe suction bay levels, and monitor heater performance; and filled and vented the Train "A" essential service water system. The Train "A" essential service water system pump suction bay levels returned to normal, and the Train "A" pump was started and appeared to be functioning normally. Based on these actions and compensatory measures, the operators declared Train "A" operable at 5:45 p.m. on January 30. The operators declared the Train "A" pump inoperable for a second time at 7:23 p.m. that evening due to fluctuations in pump flow and discharge pressure. The site watch subsequently reported that the Train "A" pump suction bay level was 10 feet below normal.

The shift supervisor based his conclusion regarding the pump's operability on an engineering evaluation provided by engineering. This evaluation indicated that Train "A" of the essential service water system was operable because:

- The Train "A" essential service water system pump had been running properly for approximately 2 hours,
- Supplemental room heaters installed at the essential service water system pumphouse were properly functioning (i.e., one diesel-fired space heater in each essential service water system train ducted and tented to each outside bay between the trash rack and travelling screen; one electric heater per train ducted to each bay inside the pump room between the traveling screen and pump suction), and
- A continuous fire watch had been posted in the essential service water system pumphouse to observe bay levels, watch for icing and monitor diesel fired heaters.

The Augmented Inspection Team also reviewed the licensee's basis for declaring the Train "A" essential service water system pump operable at 5:45 p.m.

The shift supervisor's log specifically indicated that the compensatory measures discussed above had been taken to ensure continued operability. The log indicates that these actions were developed based on discussions with operations manager, vice president-operations, and system engineering. In addition, the control room logs indicated that engineering considered the essential service water system operable as long as essential service water system strainer differential pressures are within allowable values (i.e., not alarming). The Augmented Inspection Team noted that this evaluation was incomplete, in that it did not address the root cause of the inoperability of the essential service water system. Its conclusions appear to be based on the satisfactory operation of the system for two hours and did not address the root cause of the degraded suction bay levels and their impact on the pump's performance.

As discussed above, the licensee established compensatory measures to ensure the continued operability of the essential service water system. Based on information contained in Cold Regions Technical Digest No. 91-1, "Frazil Ice Blockage of Intake Trash Racks," dated March 1991, the Augmented Inspection Team concluded that the compensatory measures that were established to assure continued operability of the Train "A" essential service water system pump were not adequate for frazil ice situations. Because the installed room heaters have a negligible effect on intake water temperature, they cannot prevent the formation of frazil ice. Also, monitoring the essential service water system bay levels will not assure operability of the essential service water system unless means have been established to immediately clear the frazil ice blockage (typically through mechanical removal processes) as soon as the condition has been identified.

Even though the licensee's compensatory measures were not appropriate for the frazil ice condition, based on discussions with the plant operators, the Augmented Inspection Team found that the compensatory measures to observe the essential service water system bay levels and icing conditions had not been accomplished from about 6:15 p.m. on the evening of January 30 until the Train "A" essential service water system pump experienced additional ice blockage problems and was secured by the control room operator at about 7:23 p.m. The licensee was unable to determine who was responsible for implementing these actions and why the actions had not been accomplished. The Augmented Inspection Team noted that the compensatory actions to monitor the essential service water system bay levels and to watch for icing conditions had not been incorporated into a written procedure or fire watch instruction.

The Augmented Inspection Team concluded that the initial decision to declare the essential service water system pump operable at 5:45 p.m. on January 30, 1996, was not appropriate because the cause of the problem was not understood at that time, and corrective measures appropriate for the situation had not been implemented. In addition, the Augmented Inspection Team concluded that the compensatory actions taken in response to this inoperability were not fully implemented and were not adequate for the frazil ice condition.

2.4 Equipment Response

2.4.1 Failure of Rod Cluster Control Assemblies to Insert

During the January 30, 1996, reactor trip, 5 of the 53 rod cluster control assemblies (control rods) failed to fully insert. The five control rods paused at various steps (the greatest being 36 steps where 1 step = 5/8 inch) and then continued to insert. At one minute after the trip, Control Rods K10 and H08 were at 12 steps, Control Rods F06 and K06 were at 18 steps and Control Rod H02 was at 30 steps. Control Rods K10 and H08 were fully inserted 8 minutes after the trip, Control Rod F06 was fully inserted after 30 minutes, the other two control rods were fully inserted after 1 hour and 15 minutes. As discussed in Section 2.3.3, the licensee initiated emergency boration when all the control rods did not insert fully.

The licensee subsequently performed cold, full-flow testing of all control rods. During this testing, 8 control rods (including the 5 control rods that did not fully insert following the trip) did not fully insert. Control Rod H02 paused at 96 steps, stopped at 90, and slowly inserted to 30 steps over the next 2 hours. The operators manually inserted the control rod. The other 7 control rods stopped at various heights in the dashpot region (i.e., below 32 steps). Five of the control rods fully inserted within 22 minutes. One control rod drifted to the bottom within 1½ hours and the operators manually inserted the remaining control rod. The remaining 45 control rods fully inserted when dropped; however, a number of control rods did not exhibit the expected number of recoils. The licensee retested all control rods that stuck, as well as those control rods that failed to recoil more than twice, and the results were generally similar to those of the first test.

All of the affected control rods were located in Control Bank C except for Control Rod H08, which was in Control Bank D. The lone control rod in Bank C that fully inserted both during the trip and the testing was Control Rod F10. Because it did not recoil more than twice, the licensee tested this control rod two more times. The control rod continued to fully insert in less than 2 seconds (the Technical Specification limit is 2.7 seconds at hot conditions) and the traces were nearly identical.

The Augmented Inspection Team noted that Control Rod H02 is a hafnium control rod while the remaining 52 control rods in the core are composed of silver-indium-cadmium. The licensee had replaced the silver-indium-cadmium control rod with the hafnium control rod because the original control rod had exhibited higher than normal drag during testing prior to the Cycle 8 startup. The Augmented Inspection Team noted that this is the only known hafnium control rod currently in use in a domestic Westinghouse plant. The licensee had scheduled replacement of the control rod at the end of the current refueling cycle.

The Augmented Inspection Team noted that all of the control rods that failed to fully insert were positioned in fuel assemblies with fuel burnup greater than 48,000 megawatt-days per metric ton (MWD/MTU). The licensee had scheduled all of these high burnup fuel assemblies to be discharged at the end of this cycle. The fuel assembly in location F10 was the only rodded assembly with burnup over 48,000 MWD/MTU that was not involved. The next highest burnup for a rodded assembly was just under 45,000 MWD/MTU and involved four assemblies associated with the Shutdown Bank E control rods. These four control rods fully inserted during the trip and also during each of the three tests; however, none of them recoiled more than two times. Their measured drop times were all under 1.9 seconds.

At the end of the inspection the licensee was developing a testing program to determine the root cause of the control rods failing to fully insert. The licensee planned to include drag tests in the reactor vessel. The licensee planned to perform additional testing on the fuel assemblies and the control rods after the core was off loaded.

2.4.2 Turbine-Driven Auxiliary Feedwater Pump Packing Leakage

Following the manual reactor trip on January 30, 1996, the auxiliary feedwater pumps automatically started at 3:38 a.m. on low steam generator water level (a normal response). At 5:14 a.m., a security officer/fire watch reported that the turbine-driven auxiliary feedwater pump was spraying water from the pump inboard packing gland. Subsequent investigation found that the packing had been washed out of the inboard packing gland stuffing box. The system engineer estimated that the leak rate from the packing gland was 20-30 gallons per minute. Although water was being sprayed on the inboard pump bearing and was leaking into the bearing oil, the system engineer concluded that the turbine-driven auxiliary feedwater pump would have been able to perform its design-basis function.

While packing leakage is a normal condition and gross leakage is anticipated to some extent, a complete packing failure is not expected to occur. In order to understand why the turbine-driven auxiliary feedwater pump packing failed in the manner that it did, the Augmented Inspection Team reviewed the recent maintenance history associated with the pump packing and information contained in the pump technical manual (as discussed in Section 2.2.2 of this report), reviewed the specific pump packing application with a representative of the packing vendor (the John Crane Company), and gathered additional information by reviewing operator log sheets and by interviewing plant operators, maintenance personnel, and the system engineer.

The packing used in this particular application was a ½-inch square, braided graphite, John Crane Style N1636 with an external coating of zinc dust. According to the vendor, the packing has no binders and, therefore, is fragile and requires special care and attention during installation. The packing vendor indicated that there were two possible explanations for why the packing failed as it did. First, the packing may have been installed too tightly causing the yarns to fracture and subsequently wash out. Alternatively, the packing may have been installed too loosely such that it was rotating with the pump shaft and ultimately disintegrated and washed out.

The Augmented Inspection Team noted that the pump maintenance history indicated that the second scenario most likely occurred, in that the packing was loosely installed on October 29, 1994, with an inboard packing gland leakage of 2400 cc/min (Work Request 5905-94); and on January 26, 1996, the inboard packing gland leakage was measured to be 1000 cc/min (STS AL-103).

The Augmented Inspection Team concluded that the turbine-driven auxiliary feedwater pump packing failed as a result of poor packing installation and adjustment practices. In particular, as previously indicated in Section 2.2.2 of this report, engineering provided guidance to maintenance personnel that was not appropriate and contrary to standard practice, including:

- The packing run-in time was deleted from the work instructions (Work Request 5905-94, Revision 1); and

- The packing leakage rate criteria was changed from a nominal value of 230 cc/min to something greater than 240 cc/min without an upper limit (Performance Improvement Requests 94-1925 and 94-2095).

The Augmented Inspection Team also noted that, although packing installation and adjustment instructions had been added to the pump technical manual (Performance Improvement Request 94-2095), subsequent work procedures did not refer to or otherwise implement these instructions (Work Packages 108952 and 109087).

Finally, the Augmented Inspection Team concluded that there was no basis for the system engineer's conclusion that the turbine-driven auxiliary feedwater pump would have been able to perform its design-basis function with water present in the pump inboard bearing oil. While the Augmented Inspection Team agreed with the licensee's conclusion that the pump was functional with increased leakage, its long-term availability was seriously jeopardized.

2.4.3 Icing of Circulation Water System Traveling Screens

Just after midnight on January 30, 1996, the operators began to experience problems maintaining service water and circulating water system flow rates, and observed that ice was forming on the traveling screens for these systems. Because sufficient cooling water system flow for the turbine plant could not be maintained, the reactor was manually tripped. As part of the followup action to this event, the licensee's Incident Investigation Team consulted with the US Army Corps of Engineer's Cold Region Research and Engineering Laboratory to determine the most likely cause of the icing that had occurred.

In a report prepared for the licensee, "Summary of Ice Problems at the Wolf Creek Power Plant," a representative of the Corps of Engineers, Mr. Steven F. Daly, concluded that the ambient conditions (i.e., reservoir water temperature, wind speed, and air temperature) at the time of the event most likely caused the screen wash water to freeze and form ice on the traveling screens. As shown in Attachment 7, the traveling screens for the circulating and service water systems are not enclosed in the pumphouse and, therefore, are subject to ambient conditions. The report also concluded that the formation of frazil ice did not appear to be a factor because there were no indications of ice blockage of the trash racks that are upstream of the circulating water and service water system traveling screens. The Augmented Inspection Team reviewed the report and found that the conclusions were well supported by the conditions that were observed to exist at the time of the event.

2.4.4 Icing of Essential Service Water System Trash Racks

When plant operators began to experience problems maintaining service water and circulating water system flow rates on January 30, 1996, the essential service water system was started to assure cooling water to critical plant heat loads. On three separate occasions (at 7:47 a.m., 7:23 p.m., and 10:27 p.m.), the Train "A" essential service water system pump had to be secured due to fluctuations in flow and pump discharge pressure. The licensee later determined that the trash racks for the Train "A" essential service water system pump had become completely blocked by the formation of a sheet of ice. As indicated previously, the licensee's Incident Investigation Team consulted with the US Army Corps of Engineer's Cold Region Research and Engineering Laboratory, to determine the most likely cause of the icing that had occurred on the essential service water system.

A report prepared for the licensee concluded that the ambient conditions at the time of the event most likely resulted in the formation of frazil ice in Wolf Creek Generating Station reservoir, which was drawn into the Train "A" essential service water system pump trash racks and resulted in the rapid formation of frazil ice blockage. The report cited the following observations in support of this conclusion:

- Photographs that were taken on January 30, 1996, show that the ice at the surface of the water immediately upstream of the intake trash rack has the white appearance of frazil ice slush that is drained of water.

- Divers who inspected the trash rack on January 31, 1996, reported that the trash rack was blocked with ice over its entire length and that ice was confined to the upstream side of the trash rack, which is characteristic of frazil ice.

- The water level in the Train "A" essential service water system suction bay downstream of the trash rack experienced a rapid and sudden decrease, which is characteristic of frazil ice blockage.

The Augmented Inspection Team reviewed the report and found that its conclusions were well supported by the conditions that were observed to exist at the time of the event. The licensee's Incident Investigation Team's findings relative to essential service water system warming flow design inadequacies (discussed in Section 2.2.1 of this report) also indicates that frazil ice blockage of the Train "A" essential service water system trash rack at the time of the event would not have been prevented by the actual warming line flow.

2.4.5 Reactor Conoseal Leakage

During discussions between the NRC Operations Center and the operators following the manual reactor trip on January 30, 1996, the licensee informed the NRC of a boric acid leak from a conoseal connection on the reactor vessel head. The licensee had previously identified the leak during a routine boric acid inspection that was performed during an earlier forced outage that occurred on March 8, 1995. As directed by the charter, the Augmented Inspection Team assessed the significance of the conoseal leak on the event.

The leaking conoseal was associated with Penetration No. 77 on the reactor vessel head, which is one of four in-core thermocouple connections. The other three conoseal connections had not leaked. In accordance with Work Request 1257-95, dated March 10, 1995, the licensee removed approximately 200 grams of boric acid from the conoseal connection during the March 8, 1995, outage. The leak did not appear to be active at the time of its discovery. The licensee took corrective action to tighten the connection and made plans to monitor the situation during the next outage. Following the manual reactor trip, the operators examined the conoseal connection and identified a small wisp of steam.

The licensee planned to rework the conoseal connection during the current outage to achieve a leak-tight joint. The Augmented Inspection Team concluded that the licensee's corrective actions were appropriate for the condition identified and that the leakage did not have a significant effect on the event.

2.4.6 Indication of Main Steam Safety Valve Lifting

An entry in the shift supervisor's logs at 9 a.m. on January 30, 1996, stated that ABV-045 (a main steam safety relief valve associated with Steam Generator "D") was reported to be lifting. The log indicated that the steam

generator pressure at the time was 1100 psig and that the main steam safety valve set pressure was 1185 psig. A subsequent log entry at 5:10 p.m. stated that the safety valve was not leaking, but that the steam t at was observed was coming from the drains associated with the atmospheric relief valves.

The Augmented Inspection Team reviewed the safety parameter display system's historical trend of steam generator pressures for January 30, 1996; Work Package 109096, dated January 30, 1996; previous test data for Valve ABV-045 recorded on September 19, 1991, obtained in Surveillance Procedure STS MT 008-V045; and interviewed the system engineer and the plant operator who initially reported the abnormal condition.

The Augmented Inspection Team found that the maximum pressure reached in Steam Generator "D" was about 1112 psig, and that the last surveillance test recorded a lift pressure of about 1187 psig for ABV-045. Based on further evaluation by the system engineer and a mechanical maintenance engineer, the licensee concluded that Valve ABV-045 was not cycling as originally thought, but that steam was coming up through the condensate drain lines that are common to the safety valves and the atmospheric relief valves.

The Augmented Inspection Team confirmed that the atmospheric relief valves were cycled on January 30, 1996, to limit steam generator pressures and to assist in the plant cooldown. The plant operator who reported the condition agreed that the steam that he observed could have been coming from the atmospheric relief valves. In addition, he thought that the ventilation alignment and atmospheric conditions at the time may have caused the steam leakage to be greater than what might otherwise have been expected. Although Valve ABV-045 is one of the initial group of steam generator main steam safety valves that was previously selected to be tested during the current outage, the Augmented Inspection Team agreed with the licensee's assessment that Valve ABV-045 did not lift following the manual reactor trip on January 30, 1996.

2.4.7 Reactor Coolant System Dose Equivalent Iodine

Following the manual reactor trip on January 30, 1996, reactor coolant system dose-equivalent iodine-131 levels rose to 2.16 microcuries (μCi) per gram. This was over the Technical Specification limit of 1.0 μCi per gram. The Limiting Condition for Operation action statement required the activity level to be less than 1.0 μCi per gram when in Modes 1 (Operation) through Mode 3 (Hot Standby) for more than 48 hours or place the reactor in Mode 4 (Hot Shutdown) within the next 6 hours. The reactor was in Mode 3 following the reactor trip at 3:37 a.m. At 5:28 a.m., chemistry reported the increased activity levels to the control room. However, the operators were not overly concerned because the concentration was not appreciably high with respect to the number of potential fuel pin failures (estimated at the time of the event to be from 3 to 5 pins). The concentration was reduced to less than 1.0 μCi per gram at 5:35 p.m., which met the Technical Specification requirements for all operational modes. The Augmented Inspection Team verified that the

activity concentration in the reactor coolant system at the time prior to the event was representative of the number of possible fuel pin failures and that the increase in activity level following the reactor trip was consistent with expectations for transient conditions.

2.4.8 Reactor Coolant Pump Oil Leakage

An entry in the shift supervisor's logs on January 30, 1996, stated that Reactor Coolant Pump "A" was secured for an oil addition at 4:45 p.m. As directed by the charter, the Augmented Inspection Team reviewed the circumstances that required the reactor operator to take this corrective action.

The Augmented Inspection Team reviewed Operations Information Report 96-BB-001, "RCP Motor Upper Reservoir Oil Level," dated January 23, 1996; and the reactor coolant pump Technical Manual M-712-00068, "TM for Reactor Coolant Pump." In addition, the Augmented Inspection Team discussed the oil leakage with the system engineer and plant operators.

On the morning of January 30, 1996, the operators notified the system engineer for the reactor coolant pumps that the upper bearing oil reservoir for Reactor Coolant Pump "A" was slowly decreasing. Specifically, the level had decreased from 13 percent on August 6, 1995, to 5 percent on January 3, 1996 (where 0 percent level corresponds to the bottom of a "bullseye" sight glass indicator and not to actual oil reservoir level).

The system engineer evaluated the low oil level condition and determined that the oil level was stable at around 5 percent and that the upper bearing temperature was stable and well below the maximum allowed temperature of 190° F. The system engineer referred to a study that was performed by the reactor coolant pump motor vendor (Westinghouse Electric Corporation) for the Callaway plant that demonstrated that upper reactor coolant pump motor bearing temperature was stable and did not exceed 175° F even when the upper reservoir oil level was 3/4 inches below the bottom of the bullseye indicator. In addition, Operations Information Report 96-BB-001 provided guidance for the continued monitoring of the reactor coolant pump upper motor bearing temperature and reservoir oil level, and for actions to be taken should the upper bearing temperatures start to increase to unacceptable levels. The system engineer concluded that continued operation of the reactor coolant pump was acceptable.

Through discussions with the system engineer and plant operators, the Augmented Inspection Team learned that the operators secured Reactor Coolant Pump "A" on January 30, 1996, to add oil to the upper bearing oil reservoir in order to clear the control room annunciator. Approximately five gallons of oil were added to the upper bearing oil reservoir and the reactor coolant pump was returned to service at around 12:45 p.m. on January 31, 1996.

Based on a visual inspection of the reactor coolant pump motor following the event, the system engineer concluded that oil had leaked from a fitting associated with the upper motor bearing temperature detector. Since the rate of oil leakage seemed to decrease over time, he concluded that the upper

reservoir oil level had slowly dropped to a point somewhere below the height of the leaking fitting and that the oil leak was self-limiting in this respect. Because the oil was spread thinly over the surface of the reactor coolant pump motor and there were no ignition sources in the vicinity of the reactor coolant pump, the system engineer concluded that the oil did not represent a significant fire hazard and that the motor's operability was not in jeopardy.

The Augmented Inspection Team agreed with the licensee's assessment of oil leakage from the reactor coolant pump motor and concluded that the licensee's corrective actions were appropriate for the condition that was identified. The Augmented Inspection Team also noted that the reactor coolant pump motor was scheduled to be exchanged for a refurbished motor during the planned refueling outage.

2.5 Emergency Response

2.5.1 Immediate Notifications

At 4:32 a.m., the shift supervisor made the NRC 4-hour event notification 55 minutes after the manual reactor trip, which was well within the 4-hour notification requirement for a reactor protection system actuation. In addition, control room personnel notified the NRC resident inspector within 15 minutes of the manual reactor trip.

At 8:46 a.m., the shift supervisor assumed the role of duty emergency director and declared a Notification of Unusual Event. The shift supervisor reviewed the Notification of Unusual Event classification decision with the operations manager, vice president-plant operations, and the shift engineer. The Augmented Inspection Team verified that the control room shift clerk notified the State of Kansas and Coffey County officials of the Notification of Unusual Event within the 15 minutes as required by 10 CFR Part 50, Appendix E.IV.D.3, and Emergency Procedure Plan EPP 01-3.1, "Immediate Notifications." The operators also notified the NRC of the Notification of Unusual Event at 9 a.m., which was within the 1-hour notification requirement for unusual events. The licensee made periodic update notifications to State and County officials at approximately 30-minute intervals as required by Emergency Procedure Plan EPP 01-3.2, "Followup Notifications". The followup notifications were stopped when the Notification of Unusual Event was terminated at 5:58 p.m.

The Augmented Inspection Team concluded that all initial and follow-up notifications to offsite organizations were completed within the NRC's and the licensee's time requirements. In addition, initial licensee actions associated with the first Notification of Unusual Event were performed in accordance with the licensee's emergency plan implementing procedures.

2.5.2 Use of Emergency Action Levels

The Augmented Inspection Team's charter required an evaluation of the licensee's emergency response actions and why these actions were taken. The Augmented Inspection Team verified that the operators evaluated the emergency

action level charts numerous times during the event of January 30, 1996. In fact, the operators specifically logged their consideration of the emergency classification at each major change in plant status. A chronology of emergency action level evaluations and results are provided below.

- At 3:48 a.m., the operators entered the fuel element failure emergency action level chart when a reactor coolant activity alarm was received following the manual reactor trip. The control room immediately requested a reactor coolant sample analysis. A Notification of Unusual Event would have been required if the analysis showed the coolant activity greater than 63 microcurie/gram gross activity (emergency action level Block 6). However, an emergency classification was not necessary because the gross reactor coolant activity level was much less than the emergency action level.

- At 8:46 a.m., the operators entered the administrative emergency action level chart based on the loss of both the Train "A" essential service water system pump and the turbine-driven auxiliary feedwater pump. The shift supervisor declared a Notification of Unusual Event because conditions existed which indicated a potential degradation of the level of safety in the plant.

- At 7:36 p.m., the operators again reviewed the emergency action level charts when the Train "A" essential service water system pump was secured at 7:23 p.m. due to fluctuations in pump discharge pressure and flow. The shift supervisor determined that an emergency classification was not necessary because the Train "B" essential service water system pump had been operating properly throughout the day, the plant was in Mode 4 (Hot Shutdown), and the turbine-driven auxiliary feedwater pump was not required to be operational.

- At 8:02 p.m., the operators reviewed the emergency action level charts when the Train "B" essential service water system bay level was observed to decrease. At 8:12 p.m., the operators increased the heat loads on the Train "B" essential service water system, thus increasing the warming line return temperature. At 8:21 p.m., the suction bay level started to recover. Although an event classification was not made, the shift supervisor's log indicated that a Notification of Unusual Event would be declared if the Train "B" essential service water system pump was lost with Train "A" pump inoperable. The shift supervisor determined that Block 1 of the loss of electrical power/assessment capability emergency action level chart would be applicable due to the loss of component cooling to both emergency diesel generators.

- At 9 p.m., the operators reviewed the emergency action level charts when Train "B" essential service water system bay level was observed to fluctuate below normal level. Although no event classification was made, the shift supervisor's log indicated that a Site Area Emergency would be declared if the Train "B" essential service water system bay level reached dropped below 1070 feet or if the Train "B" pump was declared inoperable. The applicable emergency action level was Block 7 to the safety system failure or malfunction emergency action

level chart which stated, ". . . Plant in Modes 1-4 AND Total loss of any function needed to reach and maintain hot shutdown (Mode 4). Refer to Form EP 01-2.1-2." The referenced Form EP 01-2.1-2, "Indication of a Loss of Function," Revision 2, defined an inoperable ultimate heat sink as a complete loss of function. An inoperable ultimate heat sink was based on a suction bay level of less than 1070 feet.

- At 10 a.m., on January 31, 1996, the operators used the administrative emergency action level chart to classify a Notification of Unusual Event when divers found significant ice buildup on the Train "A" essential service water system bay trash rack. The Incident Investigation Team's interviews identified that senior licensee managers decided to declare the second Notification of Unusual Event so that the licensee's emergency response organization would more closely match the NRC emergency response status. At this time, senior managers identified criteria for escalating the classification based on essential service water system bay levels. Specifically, the licensee would declare an Alert when bay level reached 1083 feet and a Site Area Emergency when level reached 1070 feet while in Mode 4 (Hot Shutdown).

Despite the basis for these decisions, the Augmented Inspection Team identified that there was sufficient information available to the operators to question the function of the ultimate heat sink. During the review of the licensee's documentation of interviews with operators involved in the event, the Augmented Inspection Team noted that a relief-crew reactor operator was sent to the essential service water system pumphouse at 7:20 a.m. on January 30, 1996, by his relief-crew supervising operator who was providing support to the shift supervisor. The reactor operator noticed the Train "A" essential service water system bay level was lower than the Train "B" bay level. The reactor operator also noted that he looked very closely at both levels to determine reference points. The reactor operator concluded that the Train "A" bay level was approximately 10 feet lower than the Train "B" bay level. The Train "B" bay level was at the upper ladder platform, which was approximately at the 1086-foot elevation. The reactor operator communicated the level information on both essential service water system bays directly to the shift supervisor in the control room. In fact, the reactor operator indicated that he took extra effort to clearly communicate not only the information, but the significance of the information because he knew that this information indicated that the operability of Train "A" was in jeopardy due to some type of blockage.

Approximately 30 minutes after the operators had secured the Train "A" essential service water system pump, the relief-crew reactor operator noted that the Train "B" bay level had dropped and was now approximately 6 feet lower than his previous observation. Again, the reactor operator indicated that he was absolutely sure that the Train "B" bay level had decreased. Instead of communicating the decrease in level to the shift supervisor or another reactor operator in the control room, the reactor operator notified his relief-crew supervising operator (who was assisting the control room

staff) of the level decrease of the Train "B" bay level. The reactor operator noted that the Train "B" bay level remained unchanged approximately 6 feet below the 1086-foot ladder platform through his stay in the essential service water system pumphouse which ended at 12 noon.

The licensee's interviews also identified that a mechanical engineer observed the lower Train "B" bay level at the essential service water system pumphouse about the same time as the reactor operator reported the lower level to his relief-crew supervising operator. The engineer noted that the Train "B" bay level did fluctuate 5 to 10 feet below the 1086-foot ladder platform.

When the shift supervisor (in consultation with the senior operations managers) declared the first Notification of Unusual Event at 8:46 a.m. on January 30, 1996, the shift supervisor used the administrative emergency action level chart to classify the event based on two independent initiating events: (1) the declaration of the Train "A" essential service water system pump inoperable at 7:47 a.m., and (2) the declaration of the turbine-driven auxiliary feedwater pump inoperable at 5:14 a.m. Specifically, the shift supervisor determined that Block 1 was applicable and Block 2 was not applicable. Block 1 states, that, "Other conditions exist which in the judgement of the SS/DED/DEM indicate a potential degradation of the level of safety in the plant."

The Augmented Inspection Team concluded that the shift supervisor appropriately used the administrative emergency action level chart. The Augmented Inspection Team noted that Block 2 would have required declaration of an Alert if it was considered appropriate. Block 2 indicated that, ". . . Other conditions exists which in the judgement of the SS/DED/DEM indicate plant safety systems may be degraded and increased monitoring of plant systems is warranted." Clearly, the operators believed that increased monitoring of the essential service water system was warranted and implemented. However, the Augmented Inspection Team concluded that plant safety systems may have been degraded because: (1) the circulating water and service water systems had been degraded due to the loss of suction caused by icing of the traveling screens; (2) the Train "A" essential service water system pump had been secured due to oscillations in flow and discharge pressure with very low suction bay levels; and, (3) the Train "B" essential service water system pump exhibited a degraded suction bay level whose cause was unknown.

The Augmented Inspection Team recognized that this latter point may not have been clearly communicated to the shift supervisor. However, the licensee's Incident Investigation Team identified and the Augmented Inspection Team verified that the information had been obtained by a qualified and licensed reactor operator who had the ability to interpret the level and recognize the information's safety significance. Based on an interview with the relief-shift supervising operator, the Augmented Inspection Team concluded that the relief-shift supervising operator discounted the significance of the information provided by the reactor operator and failed to clearly communicate this concern to the shift supervisor based on his interpretation that essential service water system discharge pressures had not significantly

degraded; therefore, the system's operability was not challenged. The Augmented Inspection Team concluded that a reasonable interpretation of a rapid decrease in suction bay levels would be blockage of the bay suction with potential jeopardy to the operation of the essential service water system.

2.5.3 Activation of Technical Support Center

The control room logs indicated that the shift supervisor called the operations manager at 2:12 a.m. on January 30, 1996, and requested support from off-duty personnel to help cope with the icing problems in the circulating water system pumphouse. The licensee staffed the outage control center throughout the morning. The Incident Investigation Team identified and the Augmented Inspection Team verified that the center provided coordination of response activities similar to an outage management organization, adequately supported the shift supervisor resource needs, supplemented the operating staff with additional off-duty and engineering staff, and reviewed pre-established contingency plans and developed new contingencies for the potential loss of both offsite power and Train "B" of the essential service water system.

The Augmented Inspection Team identified that the outage control center had a predefined organization of engineers, mechanical and electrical technicians all reporting to a single outage control center director. All work and assessment activities were coordinated in the outage control center. Although the shift supervisor was ultimately responsible for all activities that affected plant operations, the outage control center director provided the central point of contact for additional resources, as is normally done in an outage. Nevertheless, the shift supervisor was still responsible for emergency classification assessments and followup notifications to County and State agencies. In interviews the shift supervisors did not indicate that they were overburdened with the emergency classification and notification tasks.

The licensee's Incident Investigation Team identified and the Augmented Inspection Team verified that the outage control center had devised numerous contingency plans for the potential loss of offsite power and Train "B" of the essential service water system. The contingency plans included:

- Repair the turbine-driven auxiliary feedwater pump, return the pump back to functional status, and run the pump upon the loss of all electrical power.

- Obtain the highest priority for offsite electrical power, and ensure that no work had been planned on the grid that could disrupt power.

- Run emergency diesel generator "A" with one running service water system pump at less than normal flow upon the loss of Train "B" essential service water system pump.

- Implement reactor coolant system feed and bleed to provide core cooling if the loss of all electrical power occurred and a loss of heat sink resulted.

- Feed the steam generators using the condensate system to provide an ultimate heat sink.

- Procure temporary portable diesel generators to power the motor-driven auxiliary feedwater pumps.

- Connect the fire main (i.e., diesel fire pump) to cool the emergency core cooling system pumps.

- Connect the fire main (i.e., diesel fire pump) to the refueling water storage tank to replenish inventory.

- Allow the plant to heat up to Mode 4 (Hot Shutdown) to permit heat removal from one steam generator upon the loss of both essential service water system trains.

- Run the Train "B" essential service water system pump with the bay level less than 1070 feet until the discharge pressure was lost.

- Connect a portable makeup water truck to supplement station water sources.

At approximately 1 a.m. on January 31, 1996, the licensee decided to staff the technical support center immediately after a teleconference between the licensee's vice president-plant operations and NRC senior managers. The Augmented Inspection Team verified that activation of the technical support center relocated the entire outage control center staff, relocated emergency notification system communications from the control room, and supplemented the outage control center staff with additional staff trained in emergency response, which included the technical support center director and engineering coordinator.

The Augmented Inspection Team verified that the licensee had staffed most technical support center positions by 6 a.m. with the exception of electrical, mechanical, instrumentation and control, and radiological field team technicians. These technicians could be called from normal plant duties if needed. The Augmented Inspection Team also verified that public information and State and County liaison functions were relocated into the technical support center. In addition to technical support center staff, the licensee developed rosters for the emergency offsite facility and ensured public information staff was available in case a Site Area Emergency was declared. The Augmented Inspection Team concluded that the licensee took appropriate action to ensure that personnel were available and capable of responding to the technical needs of the control room staff.

2.5.4 Notification of State and County

The Incident Investigation Team identified and the Augmented Inspection Team verified that state and county agencies were notified of the technical support center staffing at around 4 a.m. on January 31, 1996. Both agencies took the

message and requested the licensee to hold further calls until the emergency preparedness coordinator had arrived in the office later that morning. At 7:15 a.m., the licensee notified the state legislative representative from the Wolf Creek area of the icing event and the technical support center staffing.

At around 8 a.m., the licensee contacted the state and county emergency preparedness coordinators and informed them that the technical support center was staffed, but not activated. However, the Incident Investigation Team identified that the state and county coordinators were not informed during the 8 a.m. notification of the possibility of a Site Area Emergency declaration if the Train "B" essential service water system pump was lost. The state emergency preparedness coordinator called the licensee at around 10 a.m. to discuss this possibility after the state coordinator had received this information in a call from the NRC state liaison officer.

The Incident Investigation Team also identified that the state emergency preparedness coordinator did not want a protective action recommendation from the licensee that recommended the automatic evacuation of John Redmond Reservoir upon declaration at a Site Area Emergency. At 12:50 p.m., the licensee coordinated a teleconference with state and county officials to discuss the concern. At 1:15 p.m., the licensee, state and county officials discussed their concerns with Federal Emergency Management Agency and NRC management and decided that the most appropriate action was to not evacuate the reservoir if a Site Area Emergency was declared for this one particular event.

3 FINDINGS AND CONCLUSIONS

The team made numerous findings, observations, and conclusions that are detailed in this report. The following summarizes the more significant inspection findings and conclusions:

Findings

- Contrary to the assumptions in Bechtel Calculation C-K-20-01-F, "Wolf Creek ESW Pumphouse," dated May 17, 1976, the flow rate through the essential service water system warming lines was insufficient to prevent the formation of frazil ice on the essential service water trash racks (Section 2.2.1).

- The licensee had adequately implemented their cold weather provisions. Although one valve in the Train "B" essential service water system warming line was not aligned fully open as required, a licensee analysis concluded that the warming line flow rate was not appreciably affected by this mispositioning (Section 2.2.1).

- Since initial plant licensing, there have not been any opportunities for the frazil icing phenomenon to affect the essential service water system's operation prior to the January 30, 1996 event (Section 2.2.3).

- The formation of frazil ice did not appear to be a factor in the loss of the circulating water and service water systems because their warming flows were designed properly. However, the formation of frazil ice in Wolf Creek reservoir resulted in the formation of blockage of both trains of the essential service water system (Sections 2.2.3, 2.4.3, and 2.4.4).

- The licensee did not provide sufficient training to the operators on what actions would prevent frazil ice from affecting the operation of the essential service water or circulating water systems (Section 2.2.3).

- The licensee's engineering department had provided confusing and inappropriate guidance to the operators concerning the potential for frazil ice formation in the essential service water system (Section 2.2.3).

- The licensee's emergency action level charts did not address the potential loss of the ultimate heat sink by means other than actual damage (i.e., frazil ice formation). Also, the licensee's emergency plan implementing procedure and the corresponding training lesson plan lacked clear guidance on the use of the administrative emergency action level chart. In addition, the licensee did not consider the administrative chart applicable for emergency classification if the event matched another chart. This interpretation was not in accordance with current industry guidance on the use of emergency action levels (Section 2.2.4).

- The turbine-driven auxiliary feedwater pump packing failed as a result of poor packing installation and adjustment practices (Sections 2.2.2 and 2.4.2).

- There was no engineering basis for the system engineer's conclusion that the turbine-driven auxiliary feedwater pump would have been able to perform its design-basis function with water present in the pump inboard bearing oil (Section 2.4.2).

- During the post-trip recovery actions, a copy of EMG ES-02, "Reactor Trip Response," was missing from each of the four emergency procedure sets in the control room. This administrative error unnecessarily complicated the operator's event response (Section 2.3.3).

- Reactor engineering provided advice concerning termination of emergency boration which was contrary to the emergency procedure the operators were using (Section 2.3.5).

- Operator errors in aligning the essential service water system reduced the warming line flow by diverting some flow out through the service water system discharge lines, and by restricting flow to the ultimate

heat sink. The control room staff missed multiple opportunities to identify and correct the system misalignment due to poor communications and self-checking techniques. This error contributed to the degradation of essential service water system (Section 2.3.4 and 2.3.6).

- The delay in beginning a Technical Specification required cooldown, the operator's unfamiliarity with performing a rapid cooldown using the general operating procedures, and inefficiencies in their use of the procedure, resulted in the late entry to Mode 4 (Hot Shutdown) (Section 2.3.7).

- The operators maintained an adequate shutdown margin that met the requirements of the Technical Specifications at all times following the manual reactor trip (Section 2.3.8).

- The licensee's operability assessment of the essential service water system performed on January 30, 1996, was insufficient because the root cause of the problem was not understood at that time (Section 2.3.9).

- The licensee did not fully implement compensatory measures to assure continued operability of the Train "A" essential service water system. In addition, the licensee's compensatory measures were not adequate for frazil ice situations (Section 2.3.9).

- The licensee had not determined the root cause of the failure of the five control rods to fully insert into the core. However, all five control rods were located in fuel assemblies with fuel burnup greater than 48,000 megawatt-days per metric ton. The licensee was in the process of developing a testing program to determine the root cause of this failure at the end of the inspection (Section 2.4.1).

- Following the manual reactor trip, the licensee corrected a previously identified leak in the reactor conoseal connection on the reactor vessel head. This leakage did not have a significant effect on the event (Section 2.4.5).

- Contrary to previous reports, the atmospheric relief valve on Steam Generator "D" did not lift following the manual reactor trip (Section 2.4.6).

- The increase in reactor coolant system iodine levels following the reactor trip was consistent with the transient condition (Section 2.4.7).

- A small oil leak developed on a fitting associated with a temperature detector on the upper bearing of Reactor Coolant Pump "A" following the manual reactor trip; however, the leakage was self-limiting and too small to create a fire hazard (Section 2.4.8).

- The licensee's initial actions associated with the Notification of Unusual Events were timely and in accordance with the emergency plan implementing procedures (Section 2.5.1).

- There was sufficient information available to the operators to question the function of the ultimate heat sink on the morning of January 30, 1996, because low suction bay levels on both trains of the essential service water system indicated a blockage of the trash racks. However, this information was not fully communicated to the shift supervisor because the operator who received the information discounted its significance (Section 2.5.2).

- Although the technical support center was not activated until about 6 a.m. on January 31, 1996, the licensee took appropriate action to ensure that personnel were available and capable of responding to the technical needs of the control room staff (Section 2.5.3).

Conclusions

- The licensee's actions in response to the icing conditions were effective in returning the plant to a safe, stable, shutdown condition and in preventing further degradation of the essential service water system.

- Although the event did not pose a significant risk to the public health and safety, the event was safety significant due to: (1) ice formation on the essential service water system trash racks of the ultimate heat sink, and (2) inadequate maintenance jeopardized the continued availability of the turbine-driven auxiliary feedwater pump following an actual demand signal.

- The licensee failed to recognize the potential for the loss of both trains of the essential service water system (the plant's ultimate heat sink) due to the formation of frazil ice during sustained cold weather conditions. This lack of recognition was due, in part, to engineering errors in the original design of the system and the failure of the licensee's engineering staff to recognize and correct the original design errors, which led to the belief that suction bay warming flow would preclude this unusual condition.

- This event was exacerbated by operator errors in aligning the essential service water system during the event and multiple failures to recognize and correct these errors. The operators response to the event was unnecessarily complicated due to significant weaknesses in their communications and ability to self-check, multiple failures to recognize and correct these errors, as well as poor control room administrative support and the failure of all control rods to fully insert, as designed.

- Despite the negative impact that the engineering errors had on the operator's recognition of frazil icing conditions, there was sufficient information obtained by licensed operators to conclude that Train "B" of the essential service water system was significantly degraded at the same time that Train "A" became inoperable on the morning of January 30, 1996. However, this information was not clearly communicated to the shift supervisor.

- The operators took reasonable actions to ensure that qualified personnel were available who were capable of responding to the informational and technical needs of the control room staff, the NRC, the State of Kansas, and Coffey County.

- The licensee's Incident Investigation Team demonstrated a very credible self-assessment capability. As a result, the scope of the licensee's effort allowed both the licensee and the NRC to come to an understanding of the root causes and effects of the event in a timely manner.

ATTACHMENT 1

NRC AUGMENTED INSPECTION TEAM CHARTER

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

FEB - 6 1996

MEMORANDUM TO: C. A. VanDenburgh, Chief, Engineering Branch, Division of Reactor Safety

FROM: L. J. Callan, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM AT WOLF CREEK

On January 30, 1996, with the reactor at 98 percent power, operators began a controlled power shutdown because of decreasing water level in the pump house bays. The decreasing levels occurred because of icing on the intake screens. The icing occurred as a result of the screen wash system spray in conjunction with near 0 degree F ambient temperature and locally high winds. At 3:37 a.m., the licensee manually scrammed the reactor from 80 percent power because a low-flow service water pump began to cavitate. Following the manual scram, 5 control rods failed to fully insert. In addition, the licensee declared the turbine-driven auxiliary feedwater pump inoperable because of a packing leak. Reactor coolant iodine spiking was noted following the scram. Therefore, in accordance with Manual Chapter 0325-05.02.f. an augmented inspection team (AIT) is appropriate.

An AIT will be dispatched to better understand the actions of operators involved, the procedure requirements, the safety significance of the event, shift crew practices regarding plant operating procedures, and management expectations and response. The team is expected to perform fact finding in order to address the following:

(1) <u>With respect to the conditions leading to the event:</u>

Determine the conditions which led to the event. Identify the plant conditions (including the position of Valve EF HV-037) prior to the development of the ice in the essential service water/circulating water bays; identify the design bases for the essential service water system (especially the suction bays); identify whether the conditions, including the relevant system operating lineups, were in accordance with the system design and in compliance with license operating procedures; identify the licensee's procedural requirements and actions for providing adequate cold weather protection.

(2) <u>With respect to the event chronology:</u>

Develop and validate a detailed sequence of events associated with the icing of the essential service water/circulating water event, to include what cold weather preparations were made by the licensee.

(3) With respect to the performance of equipment prior to and during the event:

Determine the performance of the control element assembly (CEA) system. Specifically, document the performance of the CEAs during the reactor trip associated with the event and the rod testing conducted on February 2-3, 1996.

Determine the performance of the turbine driven auxiliary feedwater pump, with specific emphasis on the failure of the inboard pump seal.

Determine the cause and any potential adverse effects of the leak in the reactor conoseal.

Identify the conditions associated with the apparent early lifting of the main steam safety valve, to include the indications seen by the operators and whether an actual valve lift occurred.

Evaluate whether the reactor chemistry associated with the event was indicative of the predicted fuel conditions. If not, identify what fuel conditions would have resulted in the observed chemistry results.

Identify the conditions associated with the oil leak in the reactor coolant pump and its contribution to the event.

(4) With respect to the emergency response of the license:

Determine the emergency action level options available to the operating staff, the actions which were taken and (through interviews with the key decision-makers) why these actions were taken.

Evaluate the communications channels which were exercised between the licensee and the State and local response organizations. Identify the emergency response information that was provided to State and local decision-makers.

(5) With respect to licensed and non-licensed operator performance:

Identify the actions taken by the plant staff (licensed and non-licensed operators, maintenance technicians, engineers, etc.) in response to the event. Determine the procedural guidance that was available.

Determine the emergency response command and control structures implemented by the licensee during the event, with emphasis on overall effectiveness, unity of command, compliance with license conditions (e.g., LCOs) and compliance with the relevant (emergency plan implementation) procedures.

During the conduct of this inspection, the team will utilize the findings of the licensee's internal event review process to the maximum extent possible. This is in keeping with the NRC's emphasis on encouraging licensee self-assessment and corrective actions. Licensee-provided information need not be independently developed; however, portions of the information should be verified to confirm the licensee's investigation.

The scope of the investigation does not include assessing for any violations of NRC rules or requirements, reviewing the design and licensing bases for the facility, assessing reasonable assurances of off-site emergency response capabilities of State and local organizations, or determining the resumption of normal operations.

This memorandum designates you as the AIT Leader. Your duties will be as specified in Manual Chapter 0325-04.02. The team composition will be discussed with you directly. During the performance of the AIT, designated team members are separated from their normal duties and report directly to you. The AIT is to be conducted in accordance with NRC Manual Chapter 93800, "Augmented Inspection Team Implementing Procedure." The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The AIT should report to the site on February 5, 1996. Tentatively, the inspection should be completed by February 9, 1996, with a report documenting the results of the inspection issued within 2 weeks of the completion of the inspection. While the team is on site, you will provide daily status briefings to Region IV management, who will coordinate with NRR to ensure that all other parties are kept informed.

Should you have any questions concerning this Charter, contact Ken Brockman, Deputy Director, Division of Reactor Safety at (817)860-8140.

cc:
J. Mitchell, O-17-G21
W. Russell, O-12-G18
T. Kress, T-2-E26
A. Chaffee, O-11-A1
E. Jordan, T-4-D18
J. Rosenthal, T-4-A9
F. Congel, T-4-D28
R. Jones, O-8-E23
K. Perkins, c/o O-8-E2
J. Stone, O-13-E16
F. Ringwald, SRI
S. Collins
T. Gwynn
J. Dyer

ATTACHMENT 2

WOLF CREEK'S INCIDENT INVESTIGATION TEAM CHARTER

WOLF CREEK
NUCLEAR OPERATING CORPORATION

INTEROFFICE CORRESPONDENCE

TO: F. T. Rhodes (AD-AD) WO 96-0024

FROM: O. L. Maynard (AD-AD)

DATE: February 02, 1996

SUBJECT: **Incident Investigation Team For Plant Shutdown Due To Circulating Water Intake Icing And Subsequent ESW Intake Icing (IIT-002)**

This letter is to appoint you as the Team Leader for investigating the root cause of the circulating water intake ice blockage, which required removing the plant from service, and subsequent essential service water intake ice blockage which occurred on January 30, 1996. Richard Meister has been assigned to assist you as the Investigation Coordinator. In accordance with AI 28B-003, "Incident Investigation Team", you have the authority to augment your team with additional resources as needed. I should be kept informed of any changes or additions to the makeup of the team.

At a minimum, the team's investigation should, address and provide answers to the following short term questions prior to the decision for unit startup:

1. How will ESW operability be assured under the icing conditions experienced during this event?
2. What are the proposed temporary modifications, administrative controls, and compensatory measures that will be used to anticipate and mitigate the ESW intake icing conditions?
3. What is the justification for using these temporary modifications to provide for system operability?
4. Is the installed warm-up line adequate to mitigate the icing conditions experienced? If so, why didn't it prevent the icing condition from occurring?
5. Is there a need for any additional operator training or any changes to operating procedures?

The teams investigation, in addition to the above short term questions, should determine, as a minimum the following:

1. Is Wolf Creek's Cold Weather Protection Plan adequate.
2. Was there equipment, either individually or in combination, that was degraded or out of service that had an impact on the event or could have provided better mitigation.
3. Is the design of the Circulating and Service Water Systems, and their auxiliary equipment adequate for the climatic conditions.
4. Is the design of the Ultimate Heat Sink, (UHS), adequate for the climatic conditions. Was the potential for this situation to occur recognized in the plant design basis. Why is there a level indication installed in the "B" ESW bay and not the "A" bay.
5. Were surveillance's and/or preventive maintenance procedures adequate and up to date.
6. What was the proximate cause to the event, and was the response appropriate.
7. Were subsequent actions taken prudent with respect to protection of the UHS.

8. Did plant equipment respond appropriately to and throughout the event, and were known exceptions adequately dealt with.
9. Were procedures correct, and were they adhered to.
10. Was the Emergency Response Plan followed.
11. Are changes to the Emergency Action Levels, (EAL's), needed to better classify the event
12. Were communications adequate with the NRC, State, County, Public and employees.
13. Are restart plans thorough, well understood and well communicated.
14. Were the Emergency Response Facilities, which were manned, adequate and appropriately staffed.
15. Why did this icing situation occur now, but not during any past operations.

As a result of the teams root cause investigation, corrective actions to prevent recurrence should be provided in accordance with AI 28B-003. Additionally, any recommended enhancements to the Radiological Emergency Response Plan or facilities should be identified and provided.

The team's initial composition is identified on the attachment. You are to communicate with me daily as to your plans and findings. If you or your team discovers anything that puts the operability of the ESW Pump(s) in question you should immediately notify myself and the duty Shift Supervisor.

Please reference the IIT number, along with the controlling PIR number in your final report.

OLM/MGW/meg

Attachment:

cc: N. S. Carns (GB-EX), w/a
W. B. Norton (GB-ENG), w/a
R. N. Johannes (GB-EX), w/a
Document Services (GB-DS), w/a

Team Assignment For IIT (96-002)
Circulating Water and ESW Intake Icing

Name	Mail Stop	Phone
F. T. Rhodes - Team Leader	AD-AD	4002
R. A. Meister	SE-RC	4559
L. L. Parmenter	AD-OP	4538
N. R. Guyer	TR-TR	5092
D. K. Eccles	AD-EM	4653
R. L. Gerdes	SE-MO	4749
B. D. Brooks	SE-NSE	4507
W. H. Ketchum	GB-NE	6950
J. J. Dagenette	GB-EP	4077
S. R. Wahlmeier	GB-SYS	8886
C. B. Stone	SE-QE	8737
J. D. Mc Gregor	GB-DES	8381
G. D. Boyer	TR-TR	5040
Steve Daly	Corp of Engineers	
Hank Barry	Bechtel	
Adnon Alsafar	Bechtel	
*(TBA)	Cooper Operations	
*(TBA)	Sargent & Lundy	
*(TBA)	INPO	
*(TBA)	INPO	

*(TBA - To be announced)

ATTACHMENT 3

DETAILED SEQUENCE OF EVENTS

(Note: All times are expressed as Central Standard Time).

Time	Event
May 5, 1976	
None	A letter by the Architect-Engineer (Bechtel Corporation) instructed an individual performing evaluation of frazil ice conditions to assume that essential service water system return flow will enter the warming line at 35° F. The Bechtel Corporation letter also changed the location of the warming line from in front of the essential service water system pumphouse intake to in front of the trash racks. The subsequent calculation determined that a 4000 gpm flow rate is required to prevent frazil ice formation.
1990	
None	Plant Modification Request 2149 modified the essential service water system (including warming line) to prevent microbiologically induced corrosion.
October 30, 1995 to November 2, 1995	
	Procedure STN GP-001 "Plant Winterization" was implemented.
January 30, 1996	
0148	Control room received alarms indicating that the circulating water system traveling screens were becoming blocked. The site watch reported that the level in the Train "A" circulating water system bay was 8 feet lower than normal. The operators became concerned about impending loss of the circulation water and service water systems and the effect on turbine loads.
0154	The site watch at the circulating water system pumphouse reported high differential pressure in Suction Bay 3.
0159	Operators started the Train "B" essential service water system pump; however, the operators failed to isolate the service water system from the essential service water system as required by the operating procedure. Specifically, the shift supervisor instructed the reactor operator to start the Train "A" and "B" essential service water system pumps and to isolate the service water system. For expediency, the shift supervisor instructed the reactor operator not to wait until he had a copy of System Operating Procedure SYS EF-200, "Operation of the ESW System," and to perform the system alignment from memory. The reactor operator opened the essential service water system return to service water system isolation valves and closed (throttled) the essential service water system to ultimate heat sink Isolation Valves EF HV-37 and -38, thus, restricting warming line flow to the essential service water system suction bays.

Time	Event
0200	The site watch reported that the traveling screens in the Train "A" circulating water system suction bay were frozen. The control room operators called for additional operational support.
0211	The operators started the Train "A" essential service water system pump. The loads on Train "A" included containment coolers, the control room air conditioning unit, and the safety-related air conditioning unit.
0212	The shift supervisor contacted the operations manager, informed him of the plant status, and requested additional support.
0223	After placing the traveling screens in Train "B" circulating water system suction bay in fast manual mode, the operator started the Train "B" circulating water system pump.
0224	Operators stopped the Train "A" circulating water system pump and Train "A" service water system pump due to low levels in the suction bay. The site watch reported that the traveling screens were frozen and that level had decreased in the Train "B" and "C" bays.
0230	Between 0224 and 0255 the site watch reported that the Train "B" circulating water system traveling screens were frozen and that level had decreased in the Train "B" and "C" bays. The operators throttled the circulating water system discharge valves to stop the level decrease.
0255	Anticipating problems with the circulating water system, the operators started reducing turbine load at 1/2-percent power per minute (30 percent per hour) in accordance with previous reactor engineering guidance concerning controlling differential currents in the axial flux detectors of the nuclear instrumentation system. The operators initiated a plant cooldown with the rod control system in manual.
0302	The operators noted a 2.5° F mismatch between T_{ave} and T_{prog} in the control room logs, because the rod control system was in manual.
0316	The auxiliary boiler tripped. Operator interviews indicated that this is a recurring problem. This boiler provided critical heating to water storage tanks (i.e. reactor water storage tank and condensate storage tank).
0324	Control room personnel discussed the plant status and developed a plan of action if plant conditions deteriorated further.
0335	The service water system low pressure alarm illuminated. The circulating water system bay levels were later determined to be at 12 feet below normal. An automatic start of the electric fire pump due to low service water system pressure occurred shortly after.

Time	Event
0337	The shift supervisor directed a manual reactor/turbine trip, in anticipation of the need to trip the circulating water system pumps. Operators planned to break condenser vacuum and use the steam generator atmospheric dump valves for the cooldown. Following the manual reactor trip, the operators noted that five control rods did not fully insert. The site watch reported to the control room operators that ice had formed on the circulating water system traveling screens. During the transition to Emergency Management Guideline ES-2 "Reactor Trip Response," from E-0 "Reactor Trip or Safety Injection," the operators could not locate a copy of ES-2 in any of the four control room copies of the emergency management guidelines. The operators began printing a copy of the missing procedure from the computer system.
0338	The auxiliary feedwater pumps started on low steam generator levels. The operators manually fast closed the main steam isolation valves.
0341	Operators obtained a copy of the missing emergency procedure and entered ES-2 "Reactor Trip Response."
0345	The shift supervisor's log entry noted that the five control rods that failed to fully insert into the core had drifted inward and were 6 to 18 steps from the bottom of the reactor core.
0348	The shift engineer initiated the first review of the emergency action levels and critical safety function status trees. All critical safety status trees were green, with the exception of the heat sink indicating yellow, as expected. The operators again reviewed the emergency action level charts when the control room received a hi-hi radiation level alarm caused by high dose-equivalent iodine levels in the reactor coolant system.
0355	The operators began emergency boration in accordance with Emergency Procedures ES-2 "Reactor Trip Response," and PFM BG-009, "Emergency Boration."
0408	The shift engineer answered the NRC Operations Officer's morning telephone check and informed the NRC of the plant status.
0432	The shift supervisor made an event notification to the NRC in accordance with 10 CFR Part 50.72(b)(2)(ii) due to the reactor protection system actuation (i.e., manual reactor trip).
0439	The operators terminated emergency boration when all control rod bottom lights were on, indicating that all control rods were fully inserted.
0503	A security officer reported to the control room that the turbine-driven auxiliary feedwater pump was spraying water on a wall and cabinets.

Time	Event
0505	The turbine watch reported that the turbine-driven auxiliary feedwater pump inboard shaft gland was leaking. The control room notified mechanical maintenance.
0514	The operators declared the turbine-driven auxiliary feedwater pump inoperable due to the inboard packing gland leak. The operators entered Technical Specification 3.7.1.2, whose Limiting Condition for Operation action statement required restoration in 72 hours or Mode 3 (Hot Standby) within the next 6 hours and in Mode 4 (Hot Shutdown) in the following 6 hours.
0517	The shift supervisor received a report that the shear pins on all circulating water system traveling screens were broken.
0528	Chemistry reported that the reactor coolant system's dose-equivalent iodine level was at 2.16 μCi/gm. The operators entered Technical Specification 3.4.8, whose Limiting Condition for Operation action statement required Mode 3 (Hot Standby) within 6 hours.
0600	With the plant in a shutdown, stable condition with all control rod bottom lights on, the operators began a shift turnover. (During the shift turnover, the oncoming reactor operator noted that System Operating Procedure SYS EF-200, "Operation of the ESW System," was not correctly performed; however, he did not take any immediate corrective action.)
0710	The oncoming shift supervisor assumed the shift.
0747	The operators stopped the Train "A" essential service water system pump due to low discharge pressure and high strainer differential pressure. The operators entered Technical Specifications 3.8.1.1 and 3.7.1.2, whose Limiting Condition for Operation action statement required Mode 3 (Hot Standby) within 6 hours and Mode 4 (Hot Shutdown) in the following 6 hours because one diesel generator and its associated auxiliary feedwater pump were inoperable.
0800	The operators recognized the alignment error in the essential service water system and isolated the service water system from the essential service water system using the system operating procedure. (This action was not mentioned in either the shift supervisor or control room logs.)
0815	A relief-crew reactor operator located at the Train "B" essential service water system pumphouse reported to his relief-crew supervising operator that the bay level had decreased. (This information was not communicated to the shift supervisor or control room operators.)
0846	The shift supervisor declared a Notification of Unusual Event due to the loss of the Train "A" essential service water system and the failure of the turbine-driven auxiliary feedwater pump using the administrative chart of the emergency action levels. The state and county agencies were notified within 15 minutes.

Time	Event
0900	The control room received a report that the main steam safety valve on Steam Generator "D" main steam line lifted. A control room operator notified the NRC of the Notification of Unusual Event. The NRC entered a monitoring phase and initiated open telephone line to the control room over the emergency notification system.
0925	Plant technicians initiated installation of temporary heaters at the essential service water system pumphouse.
1107	The operators commenced a cooldown to Mode 4 (Hot Shutdown) required by Technical Specification 3.8.1.1 with a target temperature of 340° F. The licensee started diesel-fired space heaters at both essential service water system bays blowing down into the trash rack area.
1112	The operators reduced the reactor coolant system letdown flow rate to 75 gpm (the minimum orifice flow rate).
1134	The operators isolated reactor coolant system letdown flow because pressurizer level was not being maintained on program during the cooldown.
1200	At approximately 1200, the site watch reported that five of the traveling screen panels at the circulating water pumphouse were buckled due to ice buildup.
1224	The operators placed the Train "A" service water system pump and low-flow service water system pump switches in pull-to-lock.
1230	The licensee energized temporary electric space heaters at both essential service water bays.
1347	The time passed for Mode 4 (Hot Shutdown) entry as required by Technical Specification 3.8.1.1. Mode 4 was subsequently achieved at 1531 hours.
1353	Operators closed the safety injection accumulator isolation valves because reactor coolant system pressure was approaching 600 psig.
1406	The operators restored reactor coolant system letdown flow.
1411	The operators reset the turbine-driven auxiliary feedwater pump locally. (The packing had been replaced and the operators considered the pump functional, even though the required surveillance test had not been performed to declare the pump operable.)
1430	The reactor coolant system boron concentration was at 900 ppm. (This was the concentration required for control rod drop time testing and eventually for Mode 5 (Cold Shutdown) entry.)
1451	The operators started the Train "B" residual heat removal pump to ensure proper operation prior to Mode 4 (Hot Shutdown) entry.
1531	Mode 4 (Hot Shutdown) was entered.

Time	Event
1543	The operators started Train "A" essential service water system pump.
1549	Operators stabilized the plant from cooldown with the intent of eventually cooling down to between 204° F and 206° F, which is just above Mode 5 (Cold Shutdown).
1552	The auxiliary boiler tripped again.
1630	The first firewatch at the essential service water system pumphouse was staffed by security personnel. However, the post orders issued did not require observation of ice and water levels.
1701	Operators completed the reactor coolant system boration.
1735	The operators exited the Technical Specification 3.4.8 action statement with dose-equivalent iodine activity levels below 1.0 μCi/gm.
1745	The operators declared the Train "A" essential service water system operable because: (1) the system was filled and vented and running properly, (2) supplemental heating was available and functioning, and (3) continuous fire watches had been stationed to observe bay levels and watch for icing and monitor diesel-fired heaters. At the NRC's request, the operators maintained continuous manning of the emergency notification system through the night.
1758	The shift supervisor terminated the Notification of Unusual Event. The basis for the termination was the declared operability of Train "A" essential service water system pump. The action was discussed with the operations manager, the vice president-plant operations, and the system engineer.
1911	The oncoming shift supervisor assumed the shift.
1915	The operators began a shift turnover.
1923	The operators stopped the Train "A" essential service water system pump due to oscillations in flow and pressure, and re-entered Technical Specifications 3.8.1.1 and 3.7.1.2.
1931	The operators notified the NRC resident inspector and the emergency notification system of the loss of the Train "A" essential service water system pump.
1934	The site watch reported that the Train "A" essential service water system suction bay level was 10 feet below normal.
1936	The shift supervisor reviewed the emergency action level charts, but did not make an emergency declaration because the Train "B" essential service water system pump was operating properly and the turbine-driven auxiliary feedwater pump was not required for Mode 4 (Hot Shutdown).

Time	Event
2002	The operators noted that the Train "B" essential service water system suction bay level decreased slowly about to about 15 feet below normal, which was about 4 feet above the minimum net positive suction head requirement for the essential service water system pumps. The operators again reviewed the emergency action level charts and decided not to make an emergency declaration.
2019	The operators placed heat loads on Train "B" of the essential service water system to direct warmer water to the essential service water warming line.
2021	The Train "B" essential service water system suction bay level recovered.
2058	The operators again noted level oscillations in Train "B" of the essential service water system bay.
2100	The shift supervisor again reviewed the emergency action level chart due to the level fluctuations. The shift supervisor decided that if the Train "B" essential service water system suction bay level dropped below 1070 feet or if the pump could not be run, he would declare a Site Area Emergency in accordance with Block 7 of the safety system failure or malfunction emergency action level chart or the administrative emergency action level chart. (The licensee selected the level of 1070 feet based on the minimum reservoir level allowed in the Technical Specifications emergency action level charts. Although this level was not directly related to the low levels previously observed, the Augmented Inspection Team observed that 1070 feet corresponded to about 15 feet below normal water level.)
2214	The operators completed venting and started the Train "A" essential service water system pump.
2227	The operators stopped the Train "A" essential service water system pump due to continued oscillations in flow and pressure. In discussions with NRC Region IV, the operators discussed their plans to declare a Site Area Emergency if the Train "B" essential service water system pump was lost or declared inoperable. Although mitigation actions were discussed, the licensee did not staff the technical support center.
2230	The site watch reported that the Train "A" essential service water system bay was 12 feet below normal.

Time	Event
January 31, 1996	
0047	The relief shift supervisor was directed by the operations manager to leave the control room and staff the technical support center. The outage support center staff relocated to the technical support center.
0238	The shift supervisor authorized divers to inspect the Train "A" essential service water system suction bay.
0400	Technical support center staff notified the state and county agencies of the center's staffing. However, the agencies were not informed of the possibility that a Site Area Emergency would be declared upon the loss of the Train "B" essential service water system pump.
0600	The technical support center staffing was completed.
0602	The operators completed fill and venting of the Train "A" essential service water system.
0800	At approximately 0800, the technical support staff notified the state and county emergency preparedness coordinators of the center's staffing. The state and county were not informed of the potential for declaration of a Site Area Emergency.
1000	The operators declared a Notification of Unusual Event based on the diver's report of ice buildup and complete blockage of the Train "A" essential service water system trash racks.
1000	The state emergency preparedness coordinator called the licensee to inquire about the potential for the licensee to declare a Site Area Emergency after receiving a call from the NRC state liaison officer.
1315	Senior licensee managers discussed the licensee's protective action recommendations with the State of Kansas, Coffey County, NRC, and Federal Emergency Management Administration. This discussion concluded that the John Redmond Reservoir would not need to be evacuated in the event of the licensee's declaration of a Site Area Emergency for this one-time event.
1435	Sparging air was introduced into the Train "A" essential service water system warming line from a temporary air compressor.
1610	The technical support center informed the shift supervisor that the use of sparging air outside the essential service water system trash racks had moved the ice block 2 feet back from the trash racks.
1650	The operators commenced cooling down to Mode 5 (Cold Shutdown).
1821	Maintenance personnel commenced injecting air to the Train "A" essential service water system vent line.
1900	Divers again entered the water to inspect the Train "A" essential service water system bay.

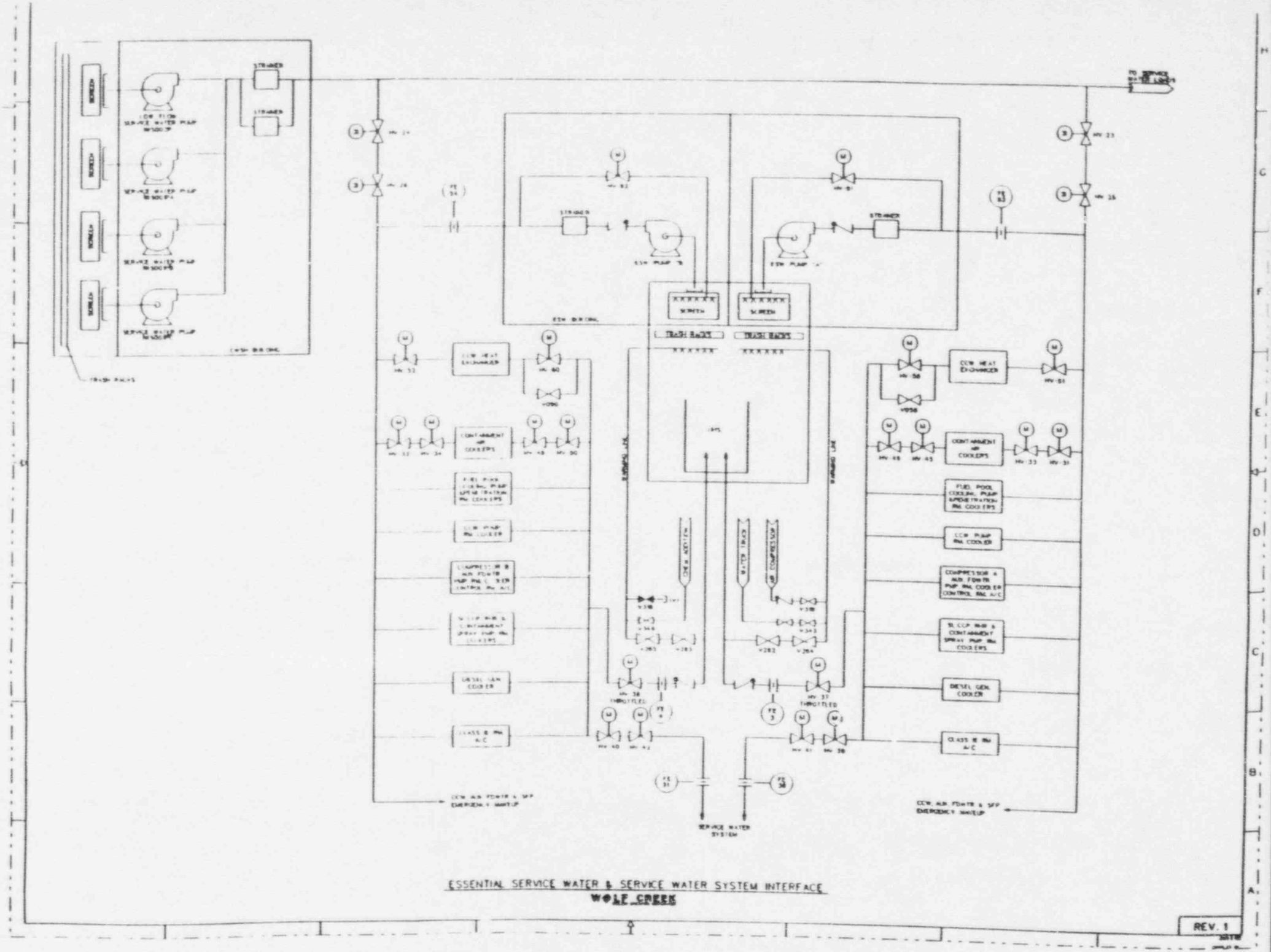
Time	Event
2045	The divers reported that the Train "A" essential service water system trash racks were clear of ice.
2100	The operators established service water system flow to the Train "A" essential service water system in accordance with Temporary Modification TMP 96-006.
2248	The plant entered Mode 5 (Cold Shutdown). The operators exited Technical Specifications 3.7.4 and 3.8.1.1.

February 1, 1996

1005	The Notification of Unusual Event was terminated.
1648	The operators placed the Train "B" circulating water system pump in service.
1700	The circulating water system warming line was placed in service.
2300	Maintenance personnel lowered the sparging heater in Train "A" essential service water system bay from 15 feet below normal water level to the bottom of the bay.
2310	The sparging heater was returned to 15 feet below normal water level.
2330	A temporary procedure was completed to gather data on Train "A" essential service water system.

ATTACHMENT 4

SIMPLIFIED FLOW DIAGRAM OF THE ESSENTIAL SERVICE WATER SYSTEM



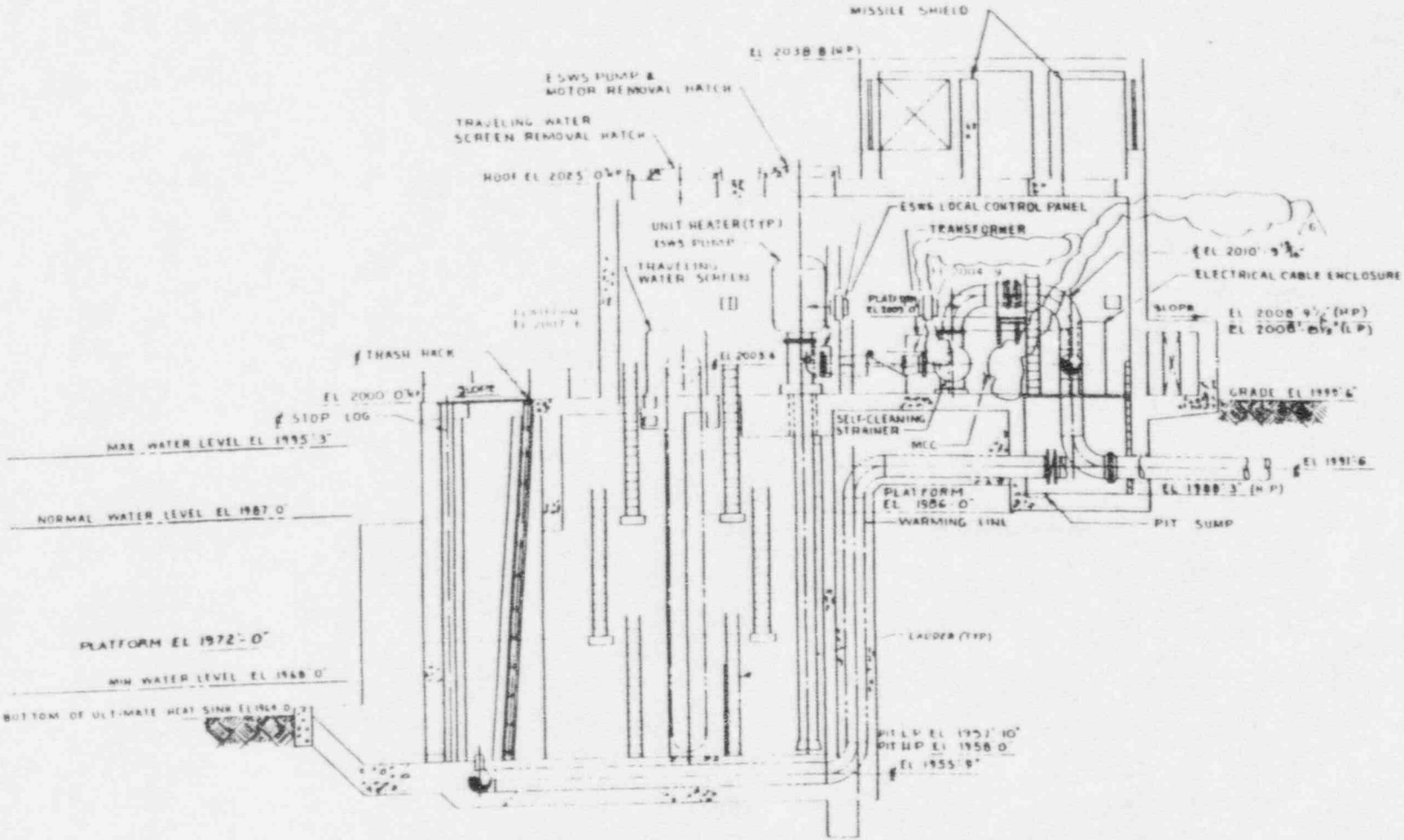
ESSENTIAL SERVICE WATER & SERVICE WATER SYSTEM INTERFACE

WOLF CREEK

REV. 1

ATTACHMENT 5

DIAGRAM OF THE ESSENTIAL SERVICE WATER PUMPHOUSE

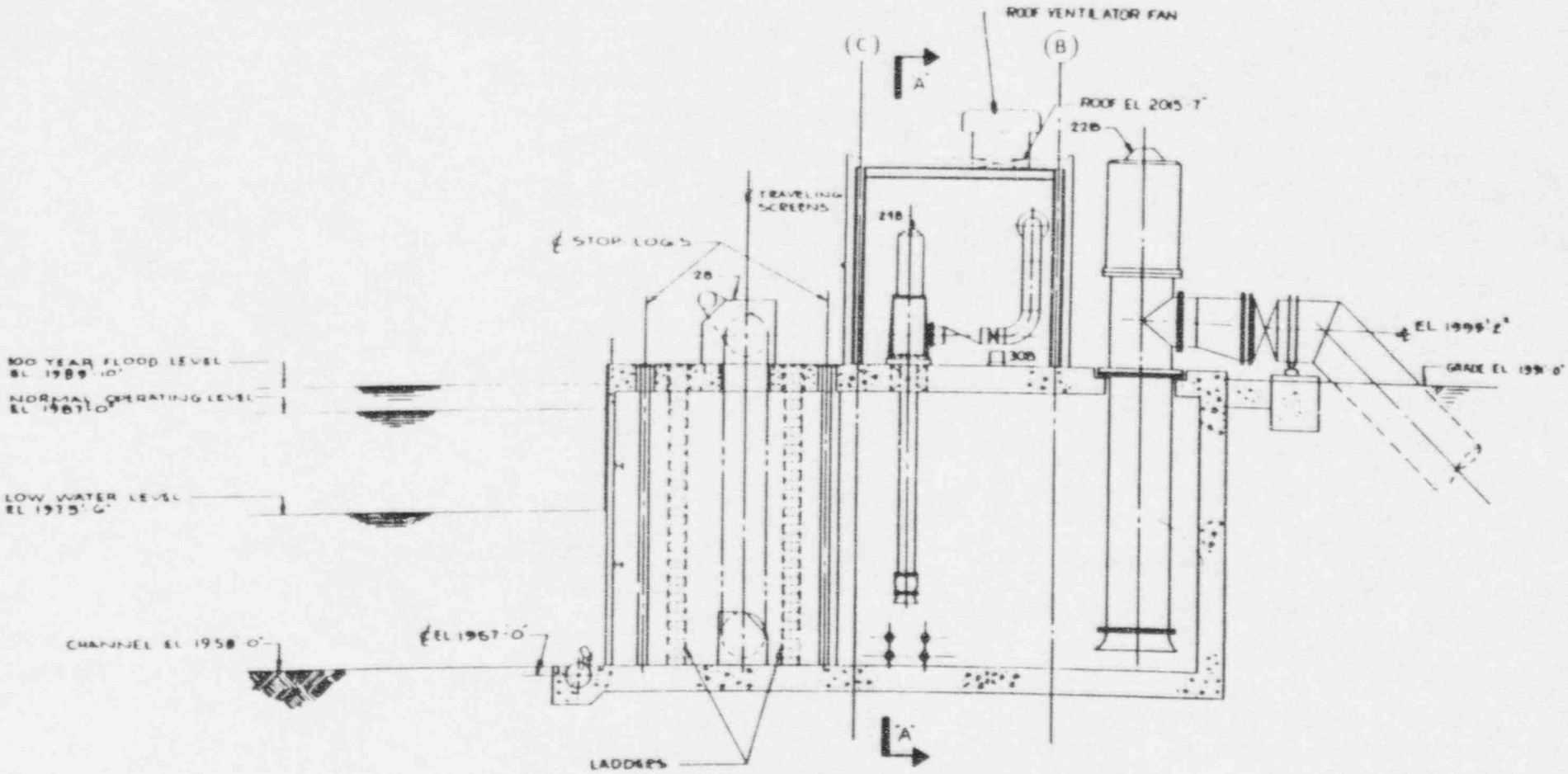


SECTION (A) M-KG081

SEE DWG M-KG080

ATTACHMENT 6

DIAGRAM OF THE CIRCULATING AND SERVICE WATER PUMPHOUSE


ROOF VENTILATOR FAN
(C)
(B)
A
ROOF EL 2015'-7"
22B
TRAVELING SCREENS
21B
℄ STOP LOGS
28
30B
℄ EL 1995'-2"
GRADE EL 1991'-0"
100 YEAR FLOOD LEVEL EL 1989'-10"
NORMAL OPERATING LEVEL EL 1987'-0"
LOW WATER LEVEL EL 1975'-6"
CHANNEL EL 1958'-0"
℄ EL 1967'-0"
LADDERS
A

SECTION "B-B"

ATTACHMENT 7

LIST OF DOCUMENTS REVIEWED DURING AUGMENTED INSPECTION

Licensee Procedures

AI 28B-003, "Incident Investigation Team," Revision 4

AP 30-110, "Forced Outage Planning and Implementation," Revision 0

ALR 00-008C, "Service Water STR 1A Delta P HIHI," Revision 6

ALR 00-005B, CWSH Screen Trouble," Revision 4

ALR 00-006A, "CWSH Bay 2 Emergency," Revision 5

ALR 00-008B, "Service Water Pressure HI LO," Revision 9

ALR 00-007A, CWSH Bay 3 Emergency," Revision 7

ALR 00-006C, "CWSH Fast Wash," Revision 5

ALR 00-006B, CWSH Screen Bloc," Revision 4

ALR 00-005A, CWSH Bay 1 Emergency, Revision 7

EMG E-0, "Reactor Trip or Safety Injection," Revision 8

EMG ES-02, "Reactor Trip Response," Revision 7

EPP 01-1.0, "Control Room Organization," Revision 12

EPP 01-2.1, "Emergency Classification," Revision 15

EPP 01-3.1, "Immediate Notifications," Revision 17

EPP 01-3.2, "Followup Notifications," Revision 14

GEN 00-006, "Hot Standby to Cold Shutdown," Revision 32

GEN 00-005, "Minimum Load to Hot Standby,," Revision 27

OTSC 96-0050, GEN 00-006, Revision 32

SYS EA-120, "Service Water System Startup," Revision 16

STS RE-004, "Shutdown Margin Determination," Revision 16

STS AL-103, "TDAFFW Pump Inservice Pump Test," Revision 20, page 21 of 21

STS BB-011, "Reactor Coolant System and Pressurizer Heatup/Cooldown Surveillance," Revision 14, dated 1/30/96 1740 hours

STS BB-011, "Reactor Coolant System and Pressurizer Heatup/Cooldown Surveillance," Revision 14, dated 1/30/96 1024 hours

STS GP-001, "Plant Winterization," Revisions 16 and 17

SYS EF-200, "Operation of the essential service water System, Revision 19

Technical Specification Interpretation Request Form No. 003-88

TMP 96-006-KC, Revision 0, 2/7/96

TMP 96-006, "Service Water to Train "A" essential service water," Revision 0

Training Records Courses: 1r0035600 001

Lesson Plan NO 12 089 00, "Essential Service Water System," Revision 9

Lesson Plan NO 16 089 04, "Essential Service Water System," Revision 2

Lesson Plan NO 12 075 00, "Circulating Water System," Revision 6

Lesson Plan TIN LR 00 356 00, "Emergency Classification," Revision 1

Licensee Drawings

Essential Service Water System Pumphouse Equipment Location-Sections, Revision 6

Essential Service Water & Service Water System Interface Drawing

Incident Investigation Team Internal Documentation

Incident Investigation Team 96-002 - Assignment Log

Incident Investigation Team 96-002 - Circ Water and essential service water Intake Icing

Incident Investigation Team 96-002 - Circ Water and essential service water Intake Icing, Revision 1

Incident Investigation Team 96-002 - Work Order 96-0024

Letter WM 96-0014 to L. J. Callan, Region IV Regional Administrator, "Wolf Creek Icing Event Shutdown," dated February 2, 1996

Root Cause of A essential service water Pump Becoming Inoperable Due To Frazil Ice Blocking Its Trash Screens

How Close Were We To Losing B essential service water Pump?

CIRC Water essential service water Icing Incident Investigation Team Interview of Glenn Neises

Hydraulic Analyses of Essential Service Water System

Turbine-Driven Auxiliary Feedwater Pump, Summary of Inboard Packing Failure on January 30, 1996

Probabilistic Safety Analysis Review of the January 30, 1996, Plant Shutdown

Answers To: What Were the Time Frames When Frazil Ice Could Have Been Forming In the Lake In the Vicinity of the Intake Structures From 1/30/96 to 2/1/96?

Description of How EF LIT-0027 Operates and Some Of the Thought As To Why It Responded As It Did On 1/30/96

Evaluation of Essential Service Water Piping Gradient Diagram

Incorrect Valve Line-up for essential service water System

Team Comments on "Loss of essential service water" SEN

Lake Ice Cover by Don Eccles, dated 2/5/96

Event Notification Worksheet of 1/30/96

Communication With Offsite Officials During the Icing Event- 1/31/96

Review of Immediate and Followup Forms From 1/31/96

Post/Compensatory Orders, dated 1/30/96, 1630 hours

Summary of Ice Problems at the Wolf Creek Power Plant, dated 2/8/96

Incident Investigation Team Interview Logs

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Steve Ernst, dated 2/4/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bob Kopecky/Pat Guevel, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Frank Caryl, dated 2/5/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bob Kopecky/Pat Guevel, dated 1/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Mark Jenkins/Mona Guyer, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Joe LaRue, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of L. Gorman, dated 2/5/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of B. Kopecky and others of Question 2, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bob Kopecky and others of Question 8, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of William Ketchum, 1000 hours, dated 2/6/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Jeanne Dagenette, 1325 hours, dated 2/5/96, interview with Britt McKinney

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Dale Berry, dated 2/4/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Jeanne Dagenette, dated 2/6/96, Interview with Dave Dees

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Jeanne Dagenette, dated 2/5/96 (Preston Lawson, Mike Mitchell, R. Hubbard)

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bill Wiseman, dated 2/5/96 (William Ketchum, Bert Halfman)

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets Bob Kopecky and others of Question 9, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bob Kopecky/Pat Guevel, dated 1/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of William Ketchum at 1400 hours, dated 2/3/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Bob Kopecky, dated 2/5/96, 1600 hours

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of William Ketchum, (Britt McKinney) 1300 hours

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Randy Carlson (Jeff Schaefer) 1015 hours

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Troy Lazarowski (site watch), dated 2/8/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Mark Schreiber dated 2/7/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Duane Smith, dated 2/7/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Len Parmenter, dated 2/6/96, 1730 hours

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Mark Schreiber, dated 2/7/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Steve Yunk and others, dated 2/6/96, 1600 hours

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Don Eccles, dated 2/14/96

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Jeanne Dagenette, dated 2/9/96 (Otto Maynard Interview and others)

Incident Investigation Team CW/ESW Icing Event 96-002 Log Sheets of Wayne Drogemueller, dated 2/13/96

Incident Investigation Team Meeting Notes

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/7/96, 0730 hours

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/6/96, 1500 hours

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/6/96, 0800 hours

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/5/96, 0730 hours

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/3/96, letter WO 96-0024

Incident Investigation Team 96-002 Operations Sub-Team Meeting Notes, dated 2/3/96, Initial Team Meeting

Calculations

Shutdown Margin Calculation Worksheet, SDM-1 Packages, dated January 30-31, 1996

Calculation No. AL-12

Calculation No. EF-13

Calculation No. C-K-20-01-F

Other Documents

Instruction Manual For Power Operated Relief Valve, Crosby Valve and Gage Co., M-724-00561-W07

Telephone Memorandum by Akhil Prakash, WC, to Garry Bakke, Ingersoll-Rand, 96-00174, dated 1/30/96

Cold Regions Technical Digest No. 91-1, March 1991, Frazil Ice Blockage of Intake trash Racks, Steven F. Daly

Telephone Call Record by Don Eccles, Wc to Nolan Packard, Midwest Marine Contracting, Inc., dated 2/6/96

Environment Design of Mechanical & Electrical Equipment (3.11(B)) Qualification Tests and Analysis (3.11.B.2) Wolf Creek Updated Safety Analysis Report

IM For Reactor Coolant Pump, M-712-00068

M-021-00061-W13, Instruction Manual for Auxiliary Feedwater Pumps, Revision W13

NUMARC/NESP-007, "Methodology for Development of Emergency Actions Levels," Revision 2

NRC Regulatory Guide 1.101, "Emergency Planning and Preparedness For Nuclear Power Reactors," Revision 3

ATTACHMENT 8

PERSONS CONTACTED AND ENTRANCE MEETING

1 PRINCIPAL PERSONS CONTACTED

1.1 Licensee Personnel

G. Boyer, Training Manager
B. Brooks, ITIP Coordinator, Nuclear Safety Engineering
N. Carns, President and Chief Executive Officer
J. Dagenette, Engineer Specialist III, Emergency Planning
T. Damashek, Supervisor, Regulatory Compliance
K. Davison, Operations, Support Supervisor
D. Dullum, Supervisor, Plant Trending and Evaluation
D. Eccles, Environmental Specialist
S. Ferguson, Nuclear Engineering
R. Flannigan, Manager, Nuclear Engineering
R. Gerdes, Maintenance Planner
R. Guyer, Supervisor Initial Training
N. Hoadley, Manager, Support Engineering
D. Jacobs, Assistant Maintenance Manager
R. Johannes, Chief Administrative Officer
J. Johnson, Superintendent, Security
W. Ketchum, Nuclear Engineering
W. Lindsay, Manager, Performance Assessment
J. Lutz, Reactor Engineer
O. Maynard, Vice President-Plant Operations
B. McKinney, Manager, Operations
R. Meister, Senior Engineering Specialist
G. Miller, Quality Specialist, Quality Evaluations
K. Moles, Manager, Information Services
D. Moore, Manager, Maintenance
T. Morrill, Manager, Plant Support
G. Neises, Supervisor, Reactor Engineering/Nuclear Engineering
W. Norton, Vice President-Engineering
K. Parmenter, Operations, Support Supervisor
C. Reekie, Regulatory Compliance
R. Sims, Supervisor, Operations Support
C. Stone, Auditor, Quality Evaluations
S. Wahlmeier, Engineer III, Systems Engineering
J. Weeks, Manager, Emergency Planning
C. Younie, Superintendent, Operations

1.2 Other Personnel

S. Daly, US Army Corps of Engineers
C. Dumsday, Westinghouse Electric Company
L. James, Consultant
G. Komanduri, Sargent & Lundy
F. Rhodes, Consultant

1.3 NRC Personnel

S. Allen, Office Assistant, Wolf Creek Resident's Office
M. Chatterton, Reactor Systems Branch, Office of Nuclear Reactor Regulation
G. Johnston, Senior Project Engineer
D. Marksberry, Operations Center, AEOD
J. Ringwald, Senior Resident Inspector, Wolf Creek Resident's Office
J. Stone, Project Director, Office of Nuclear Reactor Regulation
J. Tatum, Senior Reactor Engineer, Plant Systems Branch, Office of Nuclear Reactor Regulation
C. VanDenburgh, Chief, Engineering Branch

The personnel listed above attended the entrance meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection.

2 ENTRANCE MEETING

An entrance meeting with the licensee was conducted on February 6, 1996. During the meeting, the inspectors reviewed the scope and purpose of the inspection. The licensee indicated that they understood the inspection scope and committed to supporting the information needs of the inspectors.

ATTACHMENT 9

PERSONS CONTACTED AND EXIT MEETING

1 PRINCIPAL PERSONS CONTACTED

1.1 Licensee Personnel

G. Boyer, Manager, Training
N. Carns, President and Chief Executive Officer
J. Dagenette, Engineer Specialist III, Emergency Planning
T. Damashek, Supervisor, Regulatory Compliance
K. Davison, Superintendent, Operations Support
D. Fehr, Superintendent, Operations Training
R. Flannigan, Manager, Nuclear Engineering
M. Gayoso, Chief Business Officer
S. Hatch, Regulatory Compliance
N. Hoadley, Manager, Support Engineering
R. Johannes, Chief Administrative Officer
K. Kline, Operations Specialist
B. Kopecky, shift supervisor
W. Lindsay, Manager, Performance Assessment
O. Maynard, Vice President-Plant Operations
B. McKinney, Manager, Operations
K. Moles, Manager, Information Services
D. Moore, Manager, Maintenance
T. Morrill, Manager, Plant Support
W. Norton, Vice President-Engineering
L. Parmenter, Operations, Support Supervisor
E. Peterson, Supervisor, Quality Evaluation
C. Redding, Engineering Specialist, Regulatory Compliance
C. Reekie, Regulatory Compliance
G. Reeves, Licensing Supervisor Instructor, Simulator Maintenance
M. Schreiber, Manager, Community and Government Affairs
R. Sims, Supervisor, Operations Support
K. Thrall, Emergency Planning
T. Weatherford, Manager, Administrative Services
M. Westman, License Instructor II
J. Yunk, Engineering Specialist, Regulatory Compliance

1.2 Other Personnel

S. Breman, Topeka Capital Journal
C. Dumsday, Westinghouse
C. Farra, Emporia Gazette
R. Fraass, Kansas Department of Health & Environment
H. Haun, KEPCO
M. Hicks, Union Electric Company
R. Jewett, Coffey County Emergency Planning
K. Mazacher, Western Resources, Internal Audit
G. Mills, Coffey County Emergency Planning

B. Moore, Kansas Gas & Electric
M. Peterson, Coffey County Today
F. Rhodes, Consultant
G. Smith, Topeka Capital Journal

1.3 NRC Personnel

S. Allen, Office Assistant, Wolf Creek Resident's Office
L. Callan, Regional Administrator
J. Dixon-Herrity, Resident Inspector, Wolf Creek Resident's Office
B. Henderson, Public Affairs Officer
G. Johnston, Senior Project Engineer, Division of Reactor Projects
D. Marksberry, Operations Center, Office for Analysis and Evaluation of Operational Data
J. Ringwald, Senior Resident Inspector, Wolf Creek Resident's Office
J. Tatum, Senior Reactor Engineer, Plant Systems Branch, Office of Nuclear Reactor Regulation
C. VanDenburgh, Chief, Engineering Branch, Division of Reactor Safety

2 EXIT MEETING

A public exit meeting was conducted on February 15, 1996. During the meeting, the inspectors reviewed the scope and preliminary findings of the inspection. The licensee indicated that they understood the inspection findings. The licensee did not identify as proprietary any information provided to or reviewed by the inspectors. Proprietary information is not included in this inspection report.