APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/94-04

License: DPR-46

Licensee: Nebraska Public Power District
P.O. Box 98
Brownville, Nebraska 68321

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: March 28 through April 1, and April 11-15, 1994

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Elmo E. Collins, Team Leader, Division of Reactor Safety — Date

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EXECUTIVE SUMMARY

On July 18, 1989, the NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that provided a number of recommended actions for licensees to ensure the design requirements of cooling water systems would be met. The NRC initiated inspections of service water system performance and licensee implementation of the generic letter recommendations, using Temporary Instruction 2515/118, "Service Water System Operational Performance Inspection." This inspection addressed the Cooper Nuclear Station service water system and had three objectives: (1) to assess the licensee's actions in response to NRC Generic Letter 89-13; (2) to verify that the service water system would be capable of fulfilling thermal and hydraulic performance requirements and was operated consistently with the plant design basis; and (3) to assess the operational controls, maintenance, testing, and personnel training performed to ensure that the service water system was maintained and operated to perform its safety-related functions.

Overall, the team found that the material condition of the service water system was good and that the system was capable of performing its intended safety functions.

Design control measures were not always effectively implemented. The change of the service water system design maximum river water temperature from 85°F to 90°F was not reflected in some system calculations, in the heat exchanger performance testing procedures, in plant operating procedures, in the updated safety analysis report, and in some drawings. As a result, heat exchanger performance testing did not evaluate heat exchanger performance at the limiting design condition. In addition, the Seismic Class I design for the fire protection header in the service water system pump room was not translated into specifications and drawings. The licensee completed an analysis of the fire protection piping and concluded that the piping was operable.

The team found that the operations verification and validation of the service water system design criteria document were lacking. This was of particular concern since it indicated weak interaction between the design organization and the site and resulted in inaccurate design criteria documentation. For example, system pressure was not always maintained greater than residual heat removal system pressure in the shutdown cooling mode of operation and the updated safety analysis report and design criteria document did not reflect that this was the case. Another example involved the service water system design criteria document which stressed the importance of the service water pump discharge strainers. Approved operating procedures did not contain guidelines or limitations on operation with the strainers bypassed.

The licensee's testing demonstrated that sufficient service water system flow was available to meet accident requirements. Performance evaluations for the residual heat removal and for the diesel generator jacket water heat exchangers showed that they have sufficient heat removal capacity. The team was not able to conclude that the reactor equipment cooling heat exchanger performance testing produced results that demonstrated functionality in the limiting accident condition. In addition, heat exchanger performance test procedures contained several weaknesses. Actions taken to monitor the system for erosion, corrosion, biofouling, and silting appeared adequate; however, the licensee had not historically been aggressive in addressing microbiologically induced corrosion.

Control room operators were technically proficient in their knowledge and ability to operate the service water system. With minor exceptions, communications were closed loop and effective. The team observed that training was conducted professionally and that materials used were technically accurate and well presented. While the team found in general that procedures were adequate, multiple examples of operating procedure weaknesses were seen. Also, many procedures relied on operators' detailed system knowledge to accomplish the tasks.

A relatively low maintenance backlog existed on the service water system and recent maintenance activities had addressed significant equipment performance problems. The electrical, instrumentation, and controls equipment were, in general, being maintained in a condition to support the operation of the service water system. The licensee's resolution of a booster pump bearing failure demonstrated good capability to thoroughly resolve technical problems and was an example of improved problem resolution from what had been previously observed. The team found that some local instruments were not well maintained or reliable.

DETAILS

1 INSPECTION SCOPE AND OBJECTIVES

On July 18, 1989, the NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that provided a number of recommended actions for licensees to ensure the design requirements of cooling water systems would be met. A number of other generic communications related to service water system (SWS) problems and a supplement to the generic letter have been issued by the NRC. The NRC has initiated inspections of SWS performance and licensee implementation of the generic letter recommendations, using Temporary Instruction 2515/118, "Service Water System Operational Performance Inspection."

The NRC performed an announced safety inspection of the Cooper Nuclear Station (CNS) SWS in accordance with the temporary instruction. The inspection had three objectives: (1) to assess the licensee's actions in response to NRC Generic Letter 89-13; (2) to verify that the SWS would be capable of fulfilling thermal and hydraulic performance requirements and was operated consistently with the plant design basis; and (3) to assess the operational controls, maintenance, testing, and personnel training performed to ensure that the SWS was maintained and operated to perform its safety-related functions.

2 SERVICE WATER SYSTEM

The Missouri River was the ultimate heat sink and provided the service water for CNS. The SWS consisted of four vertical pumps located in the intake structure, and associated strainers, piping, valves, and instrumentation. The pumps take a suction on the service water intake bay (Bay E) and discharge to a common header from which piping supplies two Class I cooling water loops and one nonessential turbine building loop. Automatic shutoff to the turbine building loop in the event of a drop in header pressure was provided, thus assuring supply to the essential loops. Each essential loop feeds one diesel generator, two residual heat removal (RHR) SWS booster pumps, one control room basement fan coil unit, and one reactor equipment cooling (REC) heat exchanger.

The RHR service water booster system consisted of two independent loops, each with two pumps taking suction from the station SWS headers and providing coolant to the RHR heat exchangers. The RHR service water booster pumps maintained the service water side of the RHR heat exchangers at a higher pressure than the RHR system side to prevent out-leakage of radioactive water into the SWS. The discharge coolant from the RHR heat exchangers was monitored by a radiation detector which alarms on high radiation level of the coolant. Final discharge was returned to the SWS discharge headers and ultimately back to the Missouri River.

Piping was provided from the RHR service water booster pumps to the RHR system for emergency core flooding in the event the engineered safeguards systems were inoperative during a loss-of-coolant accident.

2.1 Design Review

The team reviewed the updated safety analysis report (USAR) and the SWS design criteria document (DCD) to identify the important functions of the SWS.

2.1.1 SWS Design River Temperature

The original design and licensing basis used a maximum Missouri River water temperature of 85°F. Operating experience had shown, however, that river water temperature can exceed 85°F. An analysis was performed in August 1989 to support plant operation with a SWS temperature up to 90°F. A 10 CFR 50.59 safety evaluation was completed and the station operations review committee approved a change to the CNS licensing basis for SWS temperature from 85°F to 90°F on June 6, 1990. The SWS design criteria document, Section 4.1.1.7, stated that the SWS shall supply cooling water to the required systems at a temperature no greater than 90°F.

The team found that some USAR analyses continued to use a SWS temperature of 85°F. USAR Section 5.3 discussed the maintenance of net positive suction head to the core spray cooling pumps during the long term transient following a design basis accident. This analysis assumed a maximum SWS temperature of 85°F and presented the peak suppression pool temperature as 192°F. The 1989 analysis calculated the maximum temperature to be 196°F. USAR Figure VI-5-15 presented the minimum containment pressure for operation of core spray cooling pumps, and this figure used the original design temperature of 85°F as the SWS temperature. During the inspection, the licensee additionally identified that USAR Drawings IV-8-1, VI-4-2, VI-4-3, and X-8-2 required updating. The USAR did reflect that additional evaluation had also shown that adequate net positive suction head existed with 90°F SWS temperature.

Licensee personnel stated that the August 1989 analysis considered only one accident scenario (Case E - the most degraded long term containment heat removal capability), and that the USAR revisions implemented in 1990 were limited to the sections addressing Case E. However, USAR Section 5.3, discussed above, addressed long term containment cooling with one RHR pump; one RHR heat exchanger; one SWS booster pump; one SWS pump; and, containment spray, which was Case E as described in USAR Section 6.3.3.3. The team concluded that the 1990 update to the USAR to reflect a SWS temperature of 90°F was not complete in that the USAR discussions, including Case E, continued to present results based on 85°F SWS temperature.

10 CFR 50.71(e) states that each licensee shall periodically update the final safety analysis report to assure that the information included in the final safety analysis report contains the latest material developed. The USAR shall be revised to include the effects of all changes made in the facility or procedures as described in the final safety analysis report and all safety evaluations performed by the licensee in support of conclusions that changes did not involve an unreviewed safety question.

The licensee did not update USAR Section 5.3 to include the effects of the safety evaluation performed on June 6, 1990 in support of conclusions that the change in the design basis temperature from 85°F to 90°F did not involve an unreviewed safety question. This is the first example of a Violation of 10 CFR 50.71(e) (298/9404-01).

The team found that Calculation 91-256, dated September 16, 1991, used a SWS temperature of 85°F and that Isometric Drawing 2852-3, Revision 5, referenced 85°F. Furthermore, the heat exchanger performance evaluation Procedures 13.15.1, "Reactor Equipment Cooling Heat Exchanger Performance Analysis," Revision 4; Procedure 13.17, "Residual Heat Removal Heat Exchanger Performance Evaluation," Revision 3; and Procedure 13.18, "DG Jacket Water and Lube Oil Heat Exchanger Performance Evaluation," Revision 2, continued to evaluate test data against the accident scenario based on a maximum SWS temperature of 85°F and did not evaluate heat exchanger performance at the design basis of 90°F.

Appendix B, Criterion III of 10 CFR 50 requires that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in Section 50.2, and as specified in the license application for those structures, systems, and components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions. Established measures did not assure that the 90°F SWS design temperature was translated into Calculation 91-256, dated September 16, 1991; Isometric Drawing 2852-3, Revision 5; and Procedure 13.15.1, "Reactor Equipment Cooling Heat Exchanger Performance Analysis"; Procedure 13.17, "Residual Heat Removal Heat Exchanger Performance Evaluation"; and Procedure 13.18, "DG Jacket Water and Lube Oil Heat Exchanger Performance Evaluation." This is the first example of a Violation of 10 CFR 50, Appendix B, Criterion III (298/9404-02).

2.1.2 Service Water Valve Classification

To assist the team in evaluating the scope of important SWS functions, the licensee color-coded the SWS process and instrumentation drawings to show the essential/non-essential portions of the system. In this effort, the licensee identified that Valves CW-468 and -469 were classified as non-essential when they should have been classified as essential. Nonconformance Report 94-059 documented the deficiency. The licensee performed an operability evaluation for the deficiency and concluded that the valves were operable. The licensee found that the valves were originally procured and installed as essential, but had mistakenly been reclassified as non-essential. The licensee stated that no maintenance had been performed on the valves that could have adversely affected the valve quality. The team observed the Station Operation Review Committee Meeting to review the operability evaluation and concluded that the committee was questioning and thorough in its review of this issue.

The licensee determined that the root cause for the misclassification was due to weakness in identifying interface components during the DCD process. Contributing to this was the fact that the valves were given circulating water designations. To address this weakness, as corrective action to

Nonconformance Report 94-059, the licensee planned to enhance review of interfacing components and systems during the DCD process.

2.1.3 Service Water Pump Room

The team reviewed the seismic calculations for the SWS pump/motor set and the automatic backwash strainer and piping and found that the SWS pump/motor seismic calculation used a 4.0g barge impact criteria, whereas the strainer used 3.0g barge impact criteria. USAR Section 8.1.6 stated that the service water pumps and service water piping and automatic strainers were designed, restrained and supported to both the Class IS earthquake criteria and 4.0g barge impact criteria. The licensee stated that the intake structure and its Class I equipment were designed to resist a horizontal acceleration of 3.0g. The 3.0g acceleration was used in the barge impact study. The team reviewed the barge impact study and confirmed that the acceleration was 3.0g. The SWS pump/motor set was conservatively analyzed to 4.0g, and this was incorrectly stated in the USAR for the SWS piping and strainers. The licensee planned to clarify the USAR statements in Section 8.1.6 to correctly specify the design loading of the automatic backwash strainer and piping.

The team questioned the seismic capability of non-essential SWS piping, which runs in the SWS pump room. The licensee stated that large bore (2" and larger) piping had been analyzed using Seismic I loads combined with the barge impact spectra, but without the ability to trace material certification.

The team questioned the seismic/barge impact capability of fire protection piping in the SWS pump room, the ventilation unit and ductwork in the SWS pump room, and the electric conduit/raceway to the SWS pump motors. The licensee stated that no seismic calculations could be found and that these issues were planned to be addressed as part of the USI-A46 response scheduled for the 1995 outage.

Subsequently, the team identified in General Design Criteria Document (GDCD-1), "Internal Flooding," that the licensee had committed during the licensing of the facility to make the fire protection header in the SWS pump room Seismic Class I. In response, the licensee completed an analysis of the fire protection header on April 25, 1994, and concluded that the fire protection header piping was operable. The licensee included consideration of deadweight, pressure, and design basis dynamic loading, and the effects of microbiologically induced corrosion (MIC) related degradation.

The team questioned the verification and validation of the information assembled in GDCD-1. The licensee stated that a verification and validation of the information assembled in general design criteria documents was not part of their program and was not performed for GDCD-1. The team also noted that the original safety evaluation report for Cooper included a discussion of potential common mode failures of the SWS. As discussed in Section 9.3.4, at licensing, the staff required the licensee to analyze the effect on plant safety of failure of the Class II (seismic) fire protection system. The intake structure was of particular concern because fire protection system piping was in close proximity to service water pumps and piping. The licensee committed to modify fire protection system piping to Class I (seismic) standard in all areas where it passed over or near the Class I (seismic) systems. This item was not identified in the SWS DCD.

Appendix B, Criterion III of 10 CFR 50 requires that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in Section 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions. Established measures did not assure that the design basis, as specified in the general design criteria document for internal flooding to qualify fire protection system piping in the service water system pump room to Class I (seismic) standards, was translated into specifications and drawings. This is the second example of a Violation of 10 CFR 50, Appendix B, Criterion III (298/9404-02).

In response to team questions, the licensee also conducted an evaluation of the cable conduit/raceway and the ventilation unit and ductwork for the design basis earthquake and barge impact loading. The conduit/raceway and ventilation unit and ductwork were evaluated as satisfactory. Nevertheless, during the walkdown phase of this evaluation, the licensee identified a potential concern for the two air handler units mounted on vibration isolator spring supports. A detailed review concluded that although no credible and significant interactions were expected with adjacent essential components, some form of lateral restraint was recommended. The licensee planned to reinforce the air handler units during the spring 1995 outage.

2.1.4 Instrumentation and Controls

The team reviewed the DCD, USAR, Technical Specifications, and lesson plans to identify what instrumentation and controls were necessary to ensure that the SWS operated in accordance with design. The team also reviewed piping and instrumentation diagrams and procedures to verify that the instruments and controls were present, as described in the design documents. The team found that the instrumentation and controls appeared adequate to operate the SWS in accordance with design.

The team found that the licensee had included the appropriate instrumentation and controls in the preventive maintenance and surveillance programs. The licensee's surveillance procedures were found to be technically accurate. The team concluded that the licensee could maintain the equipment in an operable condition if the procedures were properly implemented.

2.2 <u>Modifications</u>

The team reviewed Design Change 93-057 which established divisional electrical separation within and between the A and B loops of the SWS and REC system to eliminate a single failure vulnerability. The single failure vulnerability was identified by the licensee in February 1993 during development of the SWS DCD. Design Change 93-057 was developed as corrective action for the single failure vulnerability. The team concluded that the design change was technically adequate and that the concerns identified with respect to separation had been addressed. The team considered Design Change 93-057 to have been well engineered and thorough.

During plant walkdowns, the team identified that Drawing 2006 was incorrect in that it showed a restricting orifice in each of the RHR SWS Booster Pump minimum flow lines. The restricting orifices had been replaced with blind flanges with the installation of Design Change 76-107. The licensee initiated Drawing Change Notice 94-0361 to correct the drawing error. Minimum flow was provided by interlocking the SWS booster pumps with the RHR heat exchanger outlet valves so that the pumps would not start until the heat exchanger outlet valves were opened.

The team found that a safety evaluation had not been performed for the portion of Design Change 76-107 that installed the blind flanges and removed the use of the booster pump minimum flow line. The team reviewed the licensee's current design for providing minimum flow to the booster pumps and found that it appeared adequate. In addition, the team found that the method of providing minimum flow to the booster pumps was not described in the USAR.

The team questioned if there was a population of old design changes that did not receive a safety evaluation. The licensee sampled old design changes and did not find other similar examples where changes did not receive the proper safety review. The team independently sampled design changes and did not find any additional examples where a safety evaluation had not been performed. The team noted that the DCD process did not verify that safety evaluations had been performed for modifications.

3 GENERIC LETTER 89-13

The licensee's responses to Generic Letter 89-13 were documented in NPPD letters dated January 29, 1990, and October 15, 1990. The team assessed the licensee's actions in response to the generic letter.

3.1 Surveillance to Reduce the Incidence of Biofouling

In response to Generic Letter 89-13, the licensee stated that the intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms, sediment, and corrosion. Inspections should be performed, either by scuba divers, by dewatering the intake structure, or by other comparable methods. Any fouling accumulations should be removed. The team noted that the licensee's inspections of the intake structure were not complete, in that Service Water Bay E could not be isolated to permit diver inspection inside the travelling screen, nor dewatered to permit cleanup. All four SWS pumps take a suction from Bay E. The licensee planned a modification to provide a backup service water supply using the sparger/screen wash pumps to be implemented during the 1995 outage. This planned modification would allow diver inspection of Service Water Bay E.

Diver inspection of the wall area of intake Service Water Bay E outside of the travelling screen for biofouling was performed under Preventive Maintenance Item 06082 at the frequency of once per operating cycle. The team reviewed the results of the licensee's inspections and found that no indication of biofouling had been identified.

The licensee collected river bottom sediment samples and examined deployed artificial substrates (cinder blocks) at least once every twelve months for evidence of zebra mussels and asiatic clams. This sampling was conducted under Preventive Maintenance Item 06142 and the analyses of the samples were guided by the recommendations contained in a comprehensive study titled "Cooper Nuclear Station-Zebra Mussel and Asiatic Clam Monitoring Program," dated October 1992. The team reviewed the results of the inspections and found that the licensee had not identified evidence of Zebra mussels or Asiatic clams.

The team noted that Preventive Maintenance Items 06082 and 06142 were weak in that they did not provide direction or guidelines to the divers in terms of what to look for, where to inspect, and how to collect samples for analysis by others. The licensee had recognized the weaknesses and planned to include, by August 30, 1994, a chemistry analyses for the presence of zebra mussel larvae from the collected samples. The licensee also planned to proceduralize the inspection plans to permit consistency, to establish criteria on what items to inspect, and to allow trending. This enhancement was planned for September 30, 1994.

To confirm the validity of the results of the weak preventive maintenance items, the team reviewed the results of inspections conducted using Maintenance Procedure 7.2.42, of heat exchanger performance evaluations conducted using Procedures 13.15.1 for the REC heat exchanger, Procedure 13.17 for the RHR heat exchangers, Procedure 13.18 for the diesel generator jacket water and lube oil heat exchangers, and post-LOCA flow verification conducted using Surveillance Procedure 6.3.18.5. The team concluded that there was no evidence of performance degradation as a result of macroscopic biofouling or blockage.

3.2 <u>Verification of Heat Exchanger Capability</u>

The SWS directly cooled the RHR, the REC, the diesel generator Jacket water and lube oil, and the diesel generator turbocharger intercooler heat exchangers. The licensee used two approaches to assure heat transfer capability: periodic performance evaluation, and periodic cleaning and inspection.

3.2.1 Periodic Performance Evaluation

The procedures used to evaluate heat exchanger performance were: Procedure 13.15.1, "Reactor Equipment Cooling Heat Exchanger Performance Analysis," Revision 4; Procedure 13.17, "Residual Heat Removal Heat Exchanger Performance Evaluation," Revision 3; and Procedure 13.18, "DG Jacket Water and Lube Oil Heat Exchanger Performance Evaluation," Revision 2. Each performance evaluation procedure used two methods for heat transfer analysis.

3.2.1.1 Heat Exchanger Performance Evaluation

The heat exchanger performance evaluation consisted of using performance test data as input to a computer program to calculate an in-situ fouling factor. This fouling factor then became the input to a second calculation using parameters established for the accident scenario, thus demonstrating the heat transfer capability.

The computer software supplier provided a validation manual which discussed the various features of the computer program. The team reviewed this manual, and concluded that the program was applicable to the shell and tube design of the safety-related heat exchangers supplied by the SWS and adequately addressed the design conditions of the heat exchangers. The team observed that the tube side and shell side heat transfer film coefficients and heat transfer equations were based on turbulent flow correlations. The validation for the diesel generator lube oil heat exchanger was on-going in that the fluid and heat transfer properties of lube oil were difficult to define.

The team found that the flow conditions of the REC heat exchangers for the accident scenario were significantly different than those for the design or test conditions. This was illustrated by the following data which was from the heat exchanger data sheet and the January 24, 1994 REC Heat Exchanger A performance evaluation report:

	DESIGN	ACCIDENT
SWS Flow (gpm)	6,600	400
REC Flow (gpm)	3,800	195
Tube side velocity (ft/sec)	4.9	0.2994
Shell side velocity (ft/sec)	4.7	0.2472
Reynolds Number-tube side	34270	2052
Reynolds number-shell side	42191	2000
Heat transfer duty (MBtu/hr)	33	1.8

The computer program which calculated the tube side and shell side heat transfer film coefficients used turbulent flow correlations and heat transfer equations. Also, the ability to achieve uniform flow distribution on both tube side and shell side with the low fluid velocities was not evident. The accident conditions were laminar flow on both the shell and tube sides, and were outside the bounds of the computer program validation. Consequently, the team questioned if the REC heat exchanger performance evaluations properly considered the laminar flow conditions.

The licensee contacted the software supplier and was verbally advised that the program contained a correction factor for laminar flow. This information, however, was not evident in a follow-up letter from the software supplier, nor was such a correction factor discussed in the validation manual. The licensee was not able to explain why the correction factor, if used, was not discussed in the validation manual.

For the REC heat exchanger performance testing, the team found that the testing was done in a condition significantly different than that which the heat exchangers will experience in the accident scenario. Based on the information provided by the licensee, the team concluded that REC heat exchanger testing did not demonstrate that the REC heat exchangers would function as required in the limiting condition of 400 gpm and 90°F SWS temperature. The licensee planned to evaluate the technical basis for the heat exchanger testing. This is an unresolved item pending NRC review of adequate demonstration of REC heat exchanger performance at the limiting accident conditions (298/9404-03).

Performance evaluations reviewed by the team for RHR Heat Exchangers A and B, and for the diesel generator jacket water heat exchangers showed that they have sufficient heat removal capacity at the accident conditions with a SWS temperature of 85°F. Although the heat exchanger performance testing did not project heat exchanger performance at a SWS temperature of 90°F (see Section 2.1.1), the team assessed, based on the apparent margin, that the testing demonstrated adequate heat exchanger performance.

Performance evaluation for the diesel generator lube oil heat exchanger could not be confirmed because of the validation efforts. Nevertheless, the team did not anticipate any inability to meet the accident requirements since these heat exchangers have not experienced any degradation to date.

3.2.1.2 Performance Evaluation by Comparing U_o

Another measure of heat exchanger performance that the licensee used was comparison of a calculated overall heat transfer coefficient, U_o (Btu/hr-ft^2-°F) from heat exchanger performance test data to the manufacturer's design U_o. The team did not consider this method effective in validating heat exchanger performance at the accident conditions, since the flow rates, temperatures and heat transfer duty at accident conditions were different than test conditions and there was no analysis to link the test data to the accident scenario. Nevertheless, this comparison did provide some measure of the degree of degradation present in the heat exchanger performance.

3.2.1.3 Procedure Enhancements

The team found that heat exchanger performance test procedures did not specify test instrument calibration, test instrument accuracy, nor explicit acceptance criteria. Also, the diesel generator heat exchanger performance test procedure did not specify the load of the diesel generator to be used in testing. The licensee committed to implement procedure enhancements to address these items by August 31, 1994.

3.2.2 Periodic Cleaning and Inspection

The licensee conducted periodic cleaning and inspection of safety-related heat exchangers to maintain their heat transfer capability using Maintenance Procedure 7.2.42. The team reviewed Maintenance Procedure 7.2.42 and found that the licensee was in the process of developing several procedural enhancements. These included: to perform pre- and post-heat exchanger cleaning performance tests to determine the effectiveness of the cleaning procedure; to perform an assessment of the sediment accumulation in the heat exchanger; to photograph and maintain a record of the condition of the inlet and outlet channels before and after cleaning; and, to inspect for signs of

MIC. The licensee committed to complete these procedural enhancements to Maintenance Procedure 7.2.42 by April 30, 1994. The team concluded that Maintenance Procedure 7.2.42 was adequate and that these procedure enhancements were appropriate.

3.2.3 RHR Heat Exchanger Tube Plugging

Starting in 1988, because of a history of tube leaks and tube wall thinning, 100 percent of the RHR heat exchanger tubes were inspected by eddy current testing (ECT) each refueling outage. The tubes were also subjected to a shell side pressure test, and any tubes that were leaking were plugged. The licensee established a criterion to plug tubes with ≥ 60 percent wall thinning.

A consultant, who specialized in the analysis of ECT data and heat exchanger degradation, identified that the most probable root cause of tube failure was tube OD wear in the U-bend region resulting from flow induced vibration. The consultant concluded that since the design and the operating parameters could not be varied, tube degradation and plugging will continue. The number of tubes plugged were 3.7 percent and 3.2 percent for RHR Heat Exchangers A and B, respectively, with an upper limit of 4 percent. The consultant projected that one or both of the RHR heat exchangers would exceed the 4 percent limit by the 1995 inspection and that an analysis was needed to justify an increase in the tube plugging limit. The analysis that addressed the increase in the tube plugging limit was included as part of Design Change 91-144. The licensee planned to complete review of Design Change 91-144 by July 22, 1994.

The team concluded that the licensee's actions in response to RHR tube thinning and tube leaks were appropriate.

3.2.4 Eddy Current Testing of the REC Heat Exchanger

The REC heat exchangers were supplied by the same vendor that supplied the RHR heat exchangers. These heat exchangers were of a straight tube design. No tubes were plugged because neither units had experienced tube leaks. The licensee did not conduct ECT. The team questioned if ECT was necessary to determine tube condition. The licensee committed to initiate ECT for the REC heat exchanger tubes to identify and address any tube thinning during the Spring 1995 outage.

3.3 <u>Corrosion, Erosion, Silting, and Biofouling</u>

3.3.1 Erosion Corrosion Program

Ultrasonic testing (UT) of the SWS started during the 1988 and 1989 outages. The areas were selected on the basis where erosion could most likely occur. In May of 1991, the licensee implemented the Augmented Erosion Corrosion Program which specifically addressed the SWS and components that were subject to, or potentially subject to wall loss from the effects of erosion from entrained particulates, and corrosion due to system chemistry or configuration. The affected areas that required periodic UT inspection were identified based on maintenance history and operating experience of the SWS.

In February 1993, the scope of the augmented erosion/corrosion program was broadened to include additional areas for UT examination. These were five areas of the large bore SWS discharge piping in the SWS pump room, and six areas of the SWS booster pump discharge piping. The selection criteria were based on the location in the SWS lines and the fluid flow rates that these piping areas experienced during operation.

The team reviewed the augmented erosion/corrosion program, the broadened scope of February 1993, and the erosion/corrosion maintenance work requests (MWR), and concluded that the licensee's monitoring for corrosion appeared to be adequate to ensure structural integrity of the system.

3.3.2 Microbiologically Induced Corrosion

MIC was first identified in the SWS at CNS in 1991 when a diesel generator room cooler SWS supply line leak was attributed to MIC. In the 1993 refueling outage, through-wall leaks of the radiation monitor sample return lines were attributed to MIC. To address MIC concerns in the SWS, the licensee implemented the SWS Corrosion Action Plan to identify locations in the SWS that may be susceptible to MIC, and survey these locations.

In January 1994, during the inspection of REC Heat Exchangers A and B using Maintenance Procedure 7.2.42, extensive MIC pitting at the outlet channel surrounding the outlet nozzles was found. The channel wall thickness was 0.500 inch with a corrosion allowance of 0.125 inch. UT showed pitting as deep as 0.250 inch. The affected areas were repaired by weld buildup to 0.400-inch nominal. The team reviewed the maintenance work request documentation under which the repairs were conducted, and found them acceptable. To protect the heat exchanger channels against future MIC attack, a protective coating was evaluated and approved. The licensee planned to apply the coating during the next outage.

The licensee conducted a study to assess the potential for MIC in CNS systems. This study was issued in February 1994 and identified that MIC pitting was found in the fire protection storage tanks and that MIC attack of the fire protection piping was suspected. Based on this information, the licensee included potential MIC degradation in their evaluation of the seismic capability of the SWS pump room fire protection header (Section 2.1.3).

A revision to the SWS piping corrosion action plan was submitted to the NRC on February 18, 1994, which provided recommendations for future activities on the control and monitoring of MIC in the CNS SWS piping system. Eighteen sections of the SWS piping that were potentially susceptible to MIC were identified by using the following screening criteria: (1) fluid velocity less than 2-3 ft/sec, (2) intermittent or no-flow sections, and (3) safety-related sections. The licensee's inspection of the eighteen sections did not identify any additional areas of MIC attack.

The letter also outlined an additional six-step action plan to address the MIC issue at CNS. Of the six items only one, periodic system walkdowns to look for leaks, had been implemented. The remaining items included: (1) to augment, by September 1994, the CNS Erosion Corrosion Program to include SWS piping potentially susceptible to MIC; (2) to enhance, by April 1994, heat exchanger inspection procedures to provide for more detailed inspections; (3) to establish, by September 1994, controls to insure that any time a SWS component is opened for maintenance, that it is inspected for MIC related degradation; (4) to evaluate, by October 1994, the conversion of normally stagnant portions of the SWS to continuous flow; and, (5) to evaluate, by November 1994, the use of biocides.

The team concluded that the locations checked by the licensee for MIC in the SWS appeared to encompass the sections of SWS piping potentially susceptible to MIC, and that the licensee had taken adequate corrective actions to address areas where MIC attack had been identified. While the actions planned or taken by the licensee appeared adequate to address MIC in the SWS, the team concluded that, historically, the licensee had not been aggressive in identifying and taking actions to mitigate MIC in the SWS.

3.3.3 Protective Coating Failure and Biofouling

Only the SWS underground supply headers were coated with bitumastic primer and top coat. Maintenance Procedure 7.2.42 specifically directed examination of the sediments for bitumastic deposits whenever the heat exchangers were opened for cleaning. Maintenance Procedure 7.2.42 also requested examination for evidence of shells and shell fragments, which were examples of macroscopic biological fouling.

The team reviewed recent inspection reports and photographs, and concluded that there was no abnormal degradation of the bitumastic coating, nor evidence of macroscopic biological fouling. The team concluded that the inspection plans for protective coating failure and macrobiological fouling were adequate.

3.3.4 Silting

The licensee performed an assessment of the potential impact of silt on the essential portions of the SWS and concluded that no silting concerns existed that impacted the SWS critical loops' performance. The team reviewed the silting study and concluded that the licensee had adequately assessed the impact of silt on operation of the SWS. In addition, the team reviewed the post-LOCA flow verification tests and found that the tests consistently showed that there was more than adequate SWS flow to the safety-related heat exchangers.

3.4 Service Water System Functionality

3.4.1 Flow to meet the CNS Accident Analysis.

The team reviewed the SWS post-LOCA flow verification conducted under Surveillance Procedure 6.3.18.5 and concluded that sufficient SWS flow was available to meet the accident requirements throughout the range of river elevation.

3.4.2 Single Failure Criteria.

The team reviewed the results of the emergency core cooling system single failure analysis for the Cooper Station, which included the SWS review which was performed for Generic Letter 89-13, and found that there were no single active failures of active components of the SWS that impacted the safety function of the SWS. The team concluded that the emergency core cooling system single failure analysis was thorough.

4 SYSTEM OPERATION

The team evaluated the licensee's practices and controls to operate the SWS. This evaluation included control room observations of licensed operator activities, plant walk-through observations, review of operator training lesson materials, and review of procedures associated with the normal and emergency operation of the SWS. The team also reviewed the consistency of facility procedures with the system design basis as outlined in the USAR and the DCD.

4.1 Control Room and Plant Walk-Through Observations

The team observed licensed operators perform routine activities in the control room, including the conduct of SWS surveillances, a shift crew relief and turnover briefing, and entry into shutdown cooling and control of routine plant work. The team also observed simulated performance of several plant emergency procedures, including plant shutdown from the alternate shutdown panel due to a simulated control room evacuation. The team additionally made housekeeping and accessibility observations of installed plant equipment. In general, the team found that control room operators were technically proficient in their knowledge and ability to safely operate the SWS.

The team observed shift crew communications in the control room incident to plant walk-throughs and observations of other activities. With minor exceptions, communications were closed loop and effective, although informal in several instances. While in shutdown cooling, an operator was observed to acknowledge a cleared annunciator (RHR heat exchanger steam inlet drip leg level high) without verifying the expected automatic actions had occurred (drain valve MS-AO-791 automatically shut), nor did the operator report the cleared alarm to the control room supervisor. The team also observed a crew turnover meeting with the shift supervisor, and although somewhat informal, the expectations for the oncoming shift were communicated. The oncoming crew was attentive and questioning both during shift relief and the turnover briefing.

4.2 Procedures

The team reviewed the licensee's procedures for operation of the SWS in normal and emergency conditions. In general, the procedures were adequate to perform the required system operations, although some procedures relied on operators' detailed system knowledge to accomplish certain tasks, did not direct the operator to reference procedural guidance, or were inconsistent with other procedures, as discussed in this section. The team noted that operators were very familiar with facility procedures and were able to locate the appropriate procedural references, both in response to plant conditions, and when directed in a governing procedure where the specific procedure was not referenced.

The team identified the following procedure weaknesses.

- The SWS was operated inconsistently with its design basis as reflected in the USAR and the SWS DCD to maintain system pressure greater than RHR system pressure in the shutdown cooling mode of operation. Operating Procedure 2.2.70 "Service Water Booster Pump System," Sections 8.6 and 8.7, directed the operator to supply the SWS side of the RHR heat exchangers without running the RHR SWS Booster Pumps. Operating the RHR SWS Booster system in this mode was referred to as "windmilling" the booster pumps. Although operation in this mode was allowed by the operating procedure, this mode was not described in the DCD or the USAR as a normal operational mode. "Windmilling" the booster pumps appeared to be in conflict with system design Criterion 5 of the SWS DCD and the USAR description of SWS operation which stated that operation of the booster pumps maintains SWS pressure higher than RHR system pressure to ensure no leakage of potentially contaminated RHR water into the SWS, and, subsequently, into the environment.

  The team noted that "windmilling" the SWS Booster pumps was first done at the facility as a special procedure to show that 4000 gpm SWS flow could be provided to the RHR heat exchanger in the event that the SWS Booster Pumps were unavailable due to control building flooding (Facility response to Final Safety Analysis Report Question 10.20). USAR Section 8.2.8 discussed that the SWS lines to the RHR heat exchangers had been modified to permit 4000 gpm flow to each RHR heat exchanger without operating the SWS booster pumps in the unlikely event of flooding of the control building basement. The team reviewed the safety evaluation performed on April 7, 1984 for Special Procedure 84-002 and found that the licensee considered that the special procedure was not a change to what was described in the USAR. Consequently, the USAR was not updated to reflect this as a routine mode of operation.

  The team found that operating the SWS booster pumps during shutdown cooling was described in the USAR. USAR Appendix G Figure G-6-1 showed the RHR SWS as an essential safety system auxiliary to shutdown cooling. In addition, USAR Section 8.2.5 described the RHR SWS booster system as maintaining the service water side of the RHR heat exchangers at a higher pressure than the RHR system side to prevent out-leakage of radioactive water into the SWS. USAR Section 8.2.6 described that when the RHR system was in the shutdown cooling mode, that the SWS booster pumps were started.

  10 CFR 50.71(e) states that each licensee shall periodically update the final safety analysis report to assure that the information included in the final safety analysis report contains the latest material developed. The USAR shall be revised to include the effects of all changes made in

the facility or procedures as described in the final safety analysis report and all safety evaluations performed by the licensee in support of conclusions that changes did not involve an unreviewed safety question.

The licensee did not update the USAR, including Appendix G and Sections 8.2.5 and 8.2.6 to include the effects of the safety evaluation performed on April 7, 1984 in support of conclusions that the change to not operate the service water booster pumps in shutdown cooling, and consequently not maintain SWS pressure higher than RHR system pressure, did not involve an unreviewed safety question. This is the second example of a Violation of 10 CFR 50.71(e) (298/9404-01).

The team also found that while "windmilling," the RHR heat exchanger tube to shell differential pressure alarm would actuate. The alarm response procedure did not address "windmilling" the RHR SWS Booster Pumps, so operators were not responding to the annunciator. The licensee initiated a procedure change notice to the alarm response procedure to address the expected condition while "windmilling." The team considered this to be an example of "living" with a problem.

The team reviewed the emergency operating procedures and found that the procedures specified starting the SWS booster pumps in accident scenarios. The licensee stated that the booster pumps would be operated continuously in an accident scenario to maintain the SWS pressure higher than RHR system pressure. While the team did not identify any apparent safety concerns with this mode, the USAR and the SWS DCD did not reflect this mode as within design. This operations inconsistency with the design basis was an example of the lack of operations verification and validation in the DCD process.

- The importance of the SWS pump discharge strainers and their function was not reflected in system operating procedures, in that no guidelines nor operating limitations were specified for the amount of time the plant was operated with the strainers bypassed. Neither Procedure 2.2.71, "SWS Operation," nor Procedure 2.4.8.3.1, "SWS Casualty," addressed the actions required when the SWS pump discharge strainers were clogged or inoperable. Alarm Response Procedures 2.3.2.7, B-3/D-7, 2.3.2.4, and A-4/D-7 for high strainer differential pressure only stated to change to an alternate SWS pump lineup as required. Operators stated that system knowledge was used to bypass the strainer, keeping the associated train in operation. The USAR and DCD described the function of the strainers as important to reduce the loss of heat transfer capability through fouling of downstream heat exchangers. The team also noted the potential for fouling of downstream strainers. This lack of procedural guidance was another example of the lack of operations verification and validation in the DCD process.

  The team reviewed the 1993 maintenance records on the service water pump discharge strainers and found that the strainers had not been out of service an excessive amount of time. The licensee committed to evaluate the administrative out-of-service time for the strainers and to incorporate the guidelines into the appropriate procedure by June 1, 1994.

- No procedural guidance existed to direct the operators' actions when river water temperature approached the design basis maximum temperature of 90°F. Section 8.12.1 of 2.2.65.1, "REC Operation at Elevated River Temperature," addressed maintaining the outlet REC temperature below a specified maximum, but did not reference actions based on river temperature. The licensee identified the lack of procedural guidance during the inspection and initiated Deficiency Report 94-249 on March 14, 1994. The team considered this as another example of the lack of operations verification and validation in the DCD process.

- Operating procedures did not address automatic operation of SWS RHR heat exchanger outlet isolation and throttle Valves SW-MO-89A and -89B. In automatic, Valves SW-MO-89A and -89B respond to RHR heat exchanger tube to shell differential pressure and positions to maintain SWS pressure higher than RHR pressure. Operators stated that the automatic feature was available, but was never used.

  Additionally, the team found that Procedure 14.15.4, "RHR HX Tube to Shell Differential Pressure Instrument Calibration Test", Section 2.1, stated that the automatic mode select capability had been disabled per Temporary Design Change 86-012. The automatic mode feature; however, had been re-enabled on August 31, 1992, after the SW-DPT-91A and -91B instruments were environmentally qualified. The licensee planned to correct Procedure 14.15.4.

- Section 1.1.8 of Appendix B of the SWS DCD stated that the SWS pump discharge strainers, when operated in the intermittent mode, will backflush for 5 minutes automatically when strainer differential pressure reaches the setpoint, and backflush a minimum of daily due to the timing circuit. This was inconsistent with the training lesson plan and the SWS operating procedure which stated the timing circuit was set for every 4 hours. The team considered this another example of an inconsistency between the SWS DCD and operating procedures.

The team concluded that operators were knowledgeable of the SWS and aware of the safety aspects of its operation. The operators competently used station procedures as appropriate. The team noted that operators' skill-of-the-craft was used extensively in some procedures where guidance was non-specific or interpretive. The team was reasonably assured that the operators were sufficiently trained to implement procedures; however, the reliance on skill-of-the-craft was considered a potential vulnerability in the future safe operation of the system.

The team concluded that the operations verification and validation of the SWS DCD were lacking and considered this to be a significant weakness. This weakness resulted in inaccurate design criteria documentation. For verification and validation, the licensee stated that Design Basis Instruction DBI-7 was used to generate a cross-reference matrix to ensure that documents that referenced or established design criteria were consistent. The "procedures" column of the matrix initially presented to the team did not identify any operating procedures. Later, the licensee identified that some reviews were performed; however, it was not clear what, if anything, was done with the information gathered.

4.3 System Walkdown Observations

The team conducted detailed SWS walkdowns. The team focused on system housekeeping and cleanliness, consistency with plant process and instrumentation drawings, and habitability and accessibility for operators conducting local valve and other system related manipulations. The team noted that, with exceptions as described below, the SWS material condition was good and consistent with plant drawings.

- The team identified a through-wall pinhole leak in a 3/4-inch pipe stub between Fire Protection System Service Water Isolation SW-V-1336 and weldolet to Gland Water Pressure Control Valve 361A. The licensee responded with Deficiency Report 94-298 and replaced the leaking pipe section. The licensee preliminarily evaluated the cause of the leak as MIC.

- The team compared the actual plant configuration for the SWS to the piping and instrumentation drawings. The team identified a small number of minor discrepancies. These discrepancies included missing labels and piping being identified as a different size due to a reducer being shown in the wrong location. These items were brought to the attention of the licensee for resolution and were not a functional concern.

- The team identified poor painting practices in the SWS pump room. The licensee had painted such items as valve stem threads, packing gland followers, exposed bolt threads, and stainless steel piping. While the team was on site, the licensee initiated an MWR to clean the inappropriately painted areas and provided additional guidance to painters on what was expected.

- Additionally, the team identified numerous bolted connections which appeared to have inadequate thread engagement. The licensee provided the team with an engineering evaluation that indicated that only three full threads were needed to develop the full bolt strength. On the basis of this evaluation, the team concluded that the observed bolted connections met the licensee's acceptance criteria.

- The team observed on March 17 and April 13, 1994, that SW-DPI-359B, "RHR Heat Exchanger B Service Water DP," was pegged low (Section 5.2).

The team concluded, based on the above items identified, that there remains room to improve the thoroughness and questioning attitude of plant personnel.

4.4 Operator Training

The team observed training related to operation of the SWS in normal and abnormal/emergency modes of operation. The team observed one requalification classroom lecture and several dynamic simulator training sessions and scenarios. The team reviewed approved lesson plans and other training material used to support the classroom lectures and simulator sessions. The team observed that training was conducted professionally, that materials used were technically accurate and well presented, and that student participation was good.

5 MAINTENANCE AND TESTING

5.1 Mechanical Maintenance

5.1.1 Maintenance Backlog

The team reviewed the backlog of MWRs for the SWS. At the time of the inspection, the total number of open MWRs at CNS was 1350. Thirty-nine of these were essential work items for the SWS. The team reviewed the 39 items and concluded that the schedule for completing the work was appropriate since none of the items appeared to be safety significant.

The team questioned the scheduling of maintenance activities. The licensee stated the maintenance planner reviewed other MWRs and preventive maintenance activities for the same train to determine if they could be implemented at the same time. This was done to minimize the unavailability of a train. The licensee stated the requirement to review other MWRs and preventive maintenance items was not proceduralized but was practiced by the maintenance planners.

The team reviewed Maintenance Procedure 7.0.1.2, Revision 1, "Maintenance Work Request - MWR Generation and Review," which described the process for generating and reviewing MWRs. The procedure stated that MWRs were routed to the applicable system engineer during the MWR review cycle. In addition, essential and environmental qualification MWRs were routed to the maintenance supervisor and operations supervisor for any additional requirements. Maintenance Procedure 7.0.1.1, Revision 2, "Maintenance Work Request - Condition Report Processing," specified the process used to disposition a condition report and generate an MWR. This procedure described the priority system and the time limit for starting the MWR based on the priority of the MWR. The team reviewed a draft of Maintenance Procedure 7.0.4, Revision 1, "Conduct of Maintenance." This procedure described the responsibilities of the maintenance department at CNS and defined backlog for MWRs. MWR backlog was defined as MWRs 90 days old or older which were awaiting work. The team concluded that the licensee had adequate procedures for the planning and coordination of maintenance.

5.1.2 Maintenance Work History

The team reviewed the maintenance work histories for the past five years of the major components in the SWS including, the service water pumps and booster pumps, pump discharge check valves, backwash strainers, and a number of valves in the SWS. The review of the work histories indicated that there were not a significant number of repeat maintenance activities for most of the components. The team reviewed four areas where there had been repeat maintenance performed. These included the service water pumps with numerous lift adjustments, the service water strainers being out of service due to broken shear pins, service water booster pump bearing oil problems, and service water booster pump discharge check valve wear problems.

5.1.2.1 Service Water Pump Lift Adjustments

The four service water pumps were vertical circulator pumps manufactured by the Byron Jackson Pump Division of the Borg Warner Corporation. While reviewing the maintenance work histories of the pumps, the team noted that the lift of the pumps was adjusted numerous times during the five year period. The clearance between the impeller and the liner was defined as lift. The licensee had been setting the lift at 0.021 inch which had been recommended by the manufacturer. Approximately every 6 months, the lift was readjusted, which increased the differential pressure across the pump, thereby improving the pump performance. The licensee stated that the pump lift was reset due to wear of the impeller during pump operation.

The team reviewed Change Number 2, dated November 19, 1993, of the Byron Jackson "Installation, Operation and Maintenance Manual" and found that this change had revised the lift requirement for the pump. The impeller lift setting was changed from 0.021 inch to 0.056 inch. In addition, the team reviewed CNS Maintenance Procedure 7.2.45, Revision 4, dated February 10, 1994, "SW Pump Lift Adjustment." The team noted that the CNS procedure had not been revised to specify the new lift.

The team reviewed a November 12, 1993 letter from Byron Jackson to CNS concerning the service water pump lift settings. The pump manufacturer stated the lift setting of 0.056 inch was correct and compensated for the shaft elongation during operation. The letter stated that the elongation due to thrust was 0.030 inch based on a calculation. Therefore, setting the impeller at 0.021 inch caused rubbing of the impeller and liner on initial pump start which resulted in additional wear of the edges of the impeller.

The licensee prepared Deficiency Report Number 93-438 which recommended that a special test should be performed to determine if the service water pump flow and head requirements would be met with an impeller lift setting of 0.056 inch. The licensee planned to perform this special test in 1996. The licensee stated that the operability of the pumps was verified every three months during in-service testing (IST). In addition, the licensee was not concerned about the wear of the impeller since the impellers were replaced every 24 months. The team concluded that there was not an operability concern for the pumps. However, the team did not consider the licensee to be proactive in pursuing the testing of the recommended lift setting.

5.1.2.2 Service Water Strainers

The team noted that the shear pins of SWS Pump B discharge strainer had been replaced 9 times in a 5-year period. The team questioned the unavailability of the B SWS train due to the strainer being out for maintenance. The licensee stated when a strainer was out of service, the SWS train was considered operable. Instead, a 20-inch bypass line was opened which allowed flow to bypass the strainers.

The team determined that 3/8-inch mesh was present in the intake traveling screens and that 1/8-inch mesh was present in the strainers. In addition, the team determined that CNS operating procedures did not address system operation with the strainers bypassed, and, consequently, did not provide any guidelines or limitations on system operation with the strainers bypassed (also Section 4.2). The licensee stated that the function of the strainers was long term in nature to prevent long term fouling of the heat exchangers. The team expressed a concern with the 3/8-inch particles collecting in downstream components such as the service water booster pump suction strainers, diesel generator heat exchanger tubes and small lines. The licensee committed to evaluate the service water strainer administrative out of service time and incorporate guidelines into appropriate procedures.

5.1.2.3 Service Water Booster Pump Check Valves

The team noted that the four service water booster pump check valves had been replaced over a period of time. The team reviewed MWR 93-3489, dated September 19, 1993, which was written to troubleshoot a failure of Booster Pump A Discharge Check Valve SW-CV-19CV. The booster pump check valve had failed IST. The licensee found that the disc was stuck in the seat due to an alignment problem. The licensee initiated Nonconformance Report 93-208 to perform a root cause analysis and determine appropriate corrective actions. The team reviewed the nonconformance report which determined that the root cause of the valve failure was the hinge pin clearance of the valve. They determined that this was a valve design problem.

The corrective action for the failure was to replace the valve with an improved design valve. SW-CV-19CV was the last of the four booster pump check valves to be replaced with a newer design. The new design included closer tolerances on the hinge pin for alignment purposes and a stabilizer designed to prevent significant flutter, thereby minimizing hinge pin bearing wear. The team concluded that the licensee's corrective action was appropriate.

5.1.2.4 Service Water Booster Pump Motor Bearing Oil

The team noted a number of instances where the service water booster pump motor bearing oil level was low and the bearings were found running hot. In March 1994, the licensee formed a problem resolution team (PRT) to determine the cause of a high temperature condition observed on the inboard bearing of Booster Pump Motor C. The high temperature occurred during a pump run when the temperature reached 185°F. The motor bearing covers were removed and bearing material deposits were found on the upper half of the inboard bearing. Additional examination revealed other deposits with some plugging of the oil drain holes. In addition, the motor coupling had moved approximately 1/4 inch on the shaft. The axial movement forced the motor shaft inboard thrust face to come into contact with the bearing, causing damage.

The PRT determined that the root cause was inadequate procedural guidance for the coupling installation. The PRT determined that the procedures used provided instructions for installation of the coupling hub on the pump shaft and assembly of the coupling, but provided no guidance for the hub on the motor shaft. For corrective actions, the PRT recommended that the maintenance procedures be revised to include measuring the coupling hub to motor shaft fit. In addition, the PRT reviewed the generic implications and determined that the booster pump motor A should be removed and the proper interference fit verified. Finally, the PRT made additional recommendations in the areas of temperature monitoring and bearing temperature probe positioning.

The team reviewed the Problem Resolution Team Report, dated March 21, 1994, and concluded the licensee had done a very thorough review of the bearing failure. The team considered that the report demonstrated the capability to thoroughly resolve technical problems and was an example of improved problem resolution from what had been observed in previous NRC inspections.

5.1.3 Maintenance Work Requests

MWR No. 93-2212, dated May 22, 1993, was written to investigate and repair Service Water Booster Pump A. During testing, the licensee had found the inboard and outboard bearing vibration outside limits. During review of the MWR, the team noted that Maintenance Procedure 7.2.14, Revision 14, "RHR SWBP Overhaul and Replacement," had been revised. Originally the procedure had required the coupling hub to be preheated for 8 hours at 500°F in a heated oven due to the interference fit. The revision deleted the 8-hour preheat requirement and only required the hub to be preheated to 500°F in a heated oven.

The team asked the licensee how the station craft controlled the temperature without the preheat time requirement. The licensee stated that the maintenance shop used an induction heater to heat the hub for installation on the shaft and measured the temperature of the hub with a contact pyrometer. The team considered this to be another example of reliance on skill-of-the-craft.

5.2 Electrical Maintenance

The team reviewed the previous 5 years of electrical maintenance history for the SWS. The team did not identify any repetitive activities on electrical components. The team did notice numerous work items for clogged or malfunctioning instruments. In 1993, the licensee issued at least ten maintenance work requests for malfunctioning instruments, with at least one being a repeat failure. The licensee was required to backflush the instrument lines to correct the problems.

Although the licensee had Instrument and Control Procedure 14.4.4, "Instrument Sensing Line Backflush/Backfill," Revision 1, there was no preventive maintenance task that required this procedure to be implemented on a periodic basis. The team noted that some of the calibration and surveillance procedures did require backflushing of the sensing lines; however, many did not.

The team identified that SW-DPI-359B, "RHR Heat Exchanger B Service Water DP," was pegged low on March 17, 1994, during a plant tour. This instrument was used for local indication only and its malfunction did not operationally affect the system. Upon further review, the team found that this instrument had been "repaired" on March 8, 1994, per MWR 94-0985 and again on March 11, 1994, per MWR 94-1030. The team noted once more, on April 13, 1994, during an inspection of the SWS during torus cooling, that SW-DPI-359B was pegged low. The licensee then provided the team with information that indicated that the problem with this instrument dated back to November 1992.

During the observation of the licensee's performance of Surveillance Procedure 6.3.18.3, "Service Water Surveillance Operation," Revision 29, the team noted that SW-FI-385A, "Service Water Pumps Flow A and C," failed to respond when placed in service after backflushing the instrument lines in accordance with the procedure. This instrument malfunction presented a challenge to the technician's during performance of the test.

In response to the team's identification of problems with instrument malfunctions that the licensee attributed to a silting problem, the licensee issued a condition report to determine the cause of the instrument malfunctions. The licensee also initiated Deficiency Report 94-0223 to evaluate the need for flushing SWS instruments on a periodic basis.

The team concluded that the electrical, instrumentation, and controls equipment were, in general, being maintained in a condition to support the operation of the SWS. The team also considered the licensee's decision to evaluate the cause and determine a course of action for the periodic instrument malfunctions to be appropriate.

5.3 Pump and Valve Testing

The team witnessed IST performed in accordance with Procedure 6.3.18.3, Revision 29, "Service Water Surveillance Operation." The purpose of the test was to check each of the service water pump's flow rate, total head and to determine the operational readiness of the pumps. The procedure required that the river level was measured. This measurement was then used in the total developed head calculation. The team noted that the river level was measured with a tape measure which was blowing in the breeze. The tape measure would not stay vertical, which caused the measurement to be difficult to obtain and potentially inaccurate. The team observed that the CNS personnel performing the surveillance followed the steps in the procedure.

The team reviewed a list of SWS IST components on the increased testing frequency list for the past year. Per the list, there was only one component, Service Water Pump A, that remained on increased test frequency. There had been a total of 11 components on the list for the year. The components consisted of the service water pumps, service water booster pumps and one motor operated valve. Most of the equipment had been removed from the list by performing maintenance or adjusting the pump lift. The team noted that Service Water Booster Pump D had been removed from increased frequency testing by an engineering evaluation.

The team reviewed the licensee's Pump Discrepancies/Corrective Actions Log which was prepared and maintained by the IST coordinator. The team found that the Service Water Booster Pump D differential pressure and vibration had been rebaselined during the year and the pump removed from increased test frequency. The initial baseline value for the differential pressure across the pump had been 345 psi. In July 1993, the baseline value was changed to 308 psi. The decrease in differential pressure was an indication of pump wear. The system engineer justified rebaselining the differential pressure by stating that a decrease in the pump pressure was to be expected after maintenance since the booster pumps were very sensitive to increased or decreased impeller/casing clearances.

From the Pump Discrepancy Log, the team determined that the Service Water Booster Pump D had been on increased test frequency prior to November 1993. It had been on increased test frequency due to a vibration point being above the vibration alert level. Again, the pump was removed from increased frequency based on an engineering evaluation. Removing the pump from increased frequency was justified by an engineering evaluation which stated the vibration point was below the ASME Section XI alert level. The evaluation stated after reviewing other vibration data that the reference value appeared to be incorrect and artificially low. The engineering evaluation recommended rebaselining the pump which was done.

The team reviewed IST trend data for Booster Pump D and found that the differential pressure across the pump had degraded to 295 psi as of March 11, 1994. The licensee stated that they would not rebaseline the differential pressure below 300 psi as a rule of thumb. The licensee stated that this guideline was not proceduralized. The team determined that the pump had been rebuilt in September 1992 and was due to be rebuilt or replaced every 18 months so it was due in March 1994. The licensee planned to replace the pump in 30 to 60 days. The team found that the licensee's conclusions were acceptable.

5.4 System Testing

The team reviewed the surveillance procedures listed in Attachment 3 for SWS components. The team did not identify and discrepancies during its review of these procedures.

ATTACHMENT 1

1 PERSONS CONTACTED

Nebraska Public Power District

M. Armstrong, Secretary
M. Boyce, Design Basis Supervisor
L. Bray, Regulatory Compliance Specialist
R. Brungardt, Operations Manager
D. Dageforde, Lead Mechanical Engineer
M. Dean, Nuclear Licensing and Safety Supervisor
E. Erickson, Consultant
C. Estes, Corrective Action Program Overview Group
R. Foust, Assistant Engineering Manager
S. Freeborg, Plant Engineering Supervisor
M. Gillan, Nuclear Training Supervisor
H. Hitch, Site Services Manager
G. Horn, Vice President-Nuclear
J. Lynch, Plant Engineering Manager
E. Mace, Sr. Manager Site Support
E. Matzke, Station Licensing Engineer
M. McClure, Mechanical Coop Engineer
J. Meacham, Sr. Nuclear Division Manager of Safety Assessment
C. Moeller, Technical Staff Manager
B. Nitsch, Service Water System Engineer
D. Pavel, Engineering Configuration Management
D. Robinson, Quality Assessment Manager
R. Sanchez, Corrective Action Program Overview Group
J. Sayer, Acting Plant Manager
D. Shollenberger, Lead License Instructor
G. Smith, Quality Assurance Operations Manager
G. Smith, Nuclear Licensing and Safety Manager
M. Sparr, Engineer
W. Swantz, Project Manger
M. Unruh, Maintenance Manager
K. Walden, Manager Configuration Management
R. Wenzl, Nuclear Engineering Department Site Manager
A. Wiese, Lead Engineer
V. Wolstenholm, Division Manager, Quality Assurance

Others

R. Abernethy, Chief Engineer - Lincoln Electric
J. Parker, Senior Engineer - Midwest Power

NRC

L. Callan, Regional Administrator
G. Cha, Consultant
E. Collins, Team Leader
J. Gagliardo, Branch Chief
P. Goldberg, Reactor Inspector
T. Gwynn, Director, Division of Reactor Safety

R. Kopriva, Senior Resident Inspector
R. Lantz, Reactor Engineer
C. Paulk, Reactor Inspector
W. Walker, Resident Inspector

The above personnel attended the exit meeting. In addition to the personnel listed above, the team members contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on April 15, 1994. During this meeting, the team members summarized the scope and findings of the inspection. The licensee acknowledged the inspection findings presented at the exit meeting. The licensee made commitments to: (1) Upgrade Maintenance Procedure 7.2.42 as discussed in Section 3.2.2; (2) Upgrade heat exchanger performance testing procedures as discussed in Section 3.2.1.3; (3) Initiate eddy current testing on the REC heat exchangers as discussed in Section 3.2.4; and, (4) Evaluate the out-of-service time for service water pump discharge strainers as discussed in Sections 4.2 and 5.1.2.2. The licensee did not identify as proprietary any information provided to, or reviewed by, the team.

ATTACHMENT 2

INSPECTION FINDINGS INDEX

- Violation 298/9404-01 was opened (Sections 2.1.1 and 4.2).
- Violation 298/9404-02 was opened (Sections 2.1.1 and 2.1.3).
- Unresolved 298/9404-03 was opened (Section 3.2.1.1).

ATTACHMENT 3

PROCEDURES REVIEWED

OPERATIONS

SYSTEM OPERATING PROCEDURE 2.2.70 "SERVICE WATER BOOSTER PUMP SYSTEM," Revision 31

SYSTEM OPERATING PROCEDURE 2.2.71, "SERVICE WATER SYSTEM," Revision 34

SYSTEM OPERATING PROCEDURE 2.2.71A, "SERVICE WATER SYSTEM VALVE CHECKLIST," Revision 8

SURVEILLANCE

SURVEILLANCE PROCEDURE 6.3.7.4, "SW RADIATION MONITOR SOURCE CHECK AND FUNCTIONAL TEST," Revision 21

SURVEILLANCE PROCEDURE 6.3.7.4.1, "SW RADIATION MONITOR CALIBRATION CHECK AND INSTRUMENT CHANNEL TEST," Revision 8

SURVEILLANCE PROCEDURE 6.3.7.4.2, "SW RADIATION MONITOR KNOWN SOURCE CALIBRATION," Revision 4

SURVEILLANCE PROCEDURE 6.3.7.4.3, "SW RADIATION MONITOR SOURCE CHECK," Revision 0

SURVEILLANCE PROCEDURE 6.3.10.24, "POSITION INDICATOR INSERVICE TESTING," Revision 2

SURVEILLANCE PROCEDURE 6.3.12.1, "DIESEL GENERATOR MONTHLY OPERABILITY TEST," Revision 36

SURVEILLANCE PROCEDURE 6.3.16.1, "REC PUMP OPERABILITY TEST," Revision 8

SURVEILLANCE PROCEDURE 6.3.16.2, "REC MOTOR OPERATED VALVE OPERABILITY TEST," Revision 19

SURVEILLANCE PROCEDURE 6.3.18.1, "SERVICE WATER PUMP OPERABILITY TEST," Revision 8

SURVEILLANCE PROCEDURE 6.3.18.2, "SERVICE WATER MOTOR OPERATED VALVE OPERABILITY TEST," Revision 21

SURVEILLANCE PROCEDURE 6.3.18.3, "SERVICE WATER SURVEILLANCE OPERATION," Revision 29

SURVEILLANCE PROCEDURE 6.3.18.4, "SERVICE WATER TIME DELAY RELAY CALIBRATION/FUNCTIONAL TEST," Revision 4

SURVEILLANCE PROCEDURE 6.3.18.5, "SERVICE WATER SYSTEM POST-LOCA FLOW VERIFICATION," Revision 3

SURVEILLANCE PROCEDURE 6.3.18.6, "SERVICE WATER CHECK VALVE CLOSURE TEST," Revision 3

SURVEILLANCE PROCEDURE 6.3.18.7, "DIESEL GENERATOR SERVICE WATER SUPPLY CHECK VALVE IST OPENING TEST," Revision 1

SURVEILLANCE PROCEDURE 6.3.18.8, "SERVICE WATER GLAND WATER IST CHECK VALVE TESTING," Revision 3

SURVEILLANCE PROCEDURE 6.3.20.1, "RHR SERVICE WATER BOOSTER PUMP FLOW TEST AND VALVE OPERABILITY TEST," Revision 27

INSTRUMENT AND CONTROL PROCEDURE 14.4.4, "INSTRUMENT SENSING LINE BACKFLUSH/BACKFILL," Revision 1

INSTRUMENT AND CONTROL PROCEDURE 14.5.2, "TEMPERATURE ELEMENT CALIBRATION CHECK PROGRAM," Revision 2

INSTRUMENT AND CONTROL PROCEDURE 14.15.4, "RHR HEAT EXCHANGER TUBE TO SHELL DIFFERENTIAL PRESSURE INSTRUMENT CALIBRATION TEST," Revision 5

INSTRUMENT AND CONTROL PROCEDURE 14.27.5, "OPERABILITY CHECK OF INSTRUMENTS THAT NORMALLY INDICATE ZERO," Revision 1

INSTRUMENT AND CONTROL PROCEDURE 14.28.1, "SERVICE WATER SYSTEM INSTRUMENT CALIBRATION," Revision 8

INSTRUMENT AND CONTROL PROCEDURE 14.34.1, "REACTOR EQUIPMENT COOLING SYSTEM INSTRUMENT CALIBRATION," Revision 4

MAINTENANCE

MAINTENANCE PROCEDURE 7.2.14, "RHR SWBP OVERHAUL AND REPLACEMENT," Revision 15

MAINTENANCE PROCEDURE 7.2.15, "SERVICE WATER PUMP COLUMN MAINTENANCE AND BOWL ASSEMBLY REPLACEMENT," Revision 12

MAINTENANCE PROCEDURE 7.2.15.1, "SERVICE WATER PUMP BOWL ASSEMBLY OVERHAUL," Revision 2

MAINTENANCE PROCEDURE 7.2.26, "GENERAL VALVE MAINTENANCE," Revision 8

MAINTENANCE PROCEDURE 7.2.26.4, "SW-AOV-TCV451A AND SW-AOV-TCV451B REMOVAL AND INSTALLATION," Revision 0

MAINTENANCE PROCEDURE 7.3.7, "TIMING RELAYS SETTING AND TESTING," Revision 7

MAINTENANCE PROCEDURE 7.3.16, "LOW VOLTAGE RELAY REMOVAL AND INSTALLATION," Revision 3

HEAT EXCHANGER TESTING

PERFORMANCE EVALUATION PROCEDURE 13.16.1, "TURBINE EQUIPMENT COOLING HEAT EXCHANGER PERFORMANCE ANALYSIS, Revision 2

PERFORMANCE EVALUATION PROCEDURE 13.15.1, "REACTOR EQUIPMENT COOLING HEAT EXCHANGER PERFORMANCE ANALYSIS," Revision 4

PERFORMANCE EVALUATION PROCEDURE 13.17, "RESIDUAL HEAT REMOVAL HEAT EXCHANGER PERFORMANCE EVALUATION," Revision 3

PERFORMANCE EVALUATION PROCEDURE 13.18, "DG JACKET WATER AND LUBE OIL HEAT EXCHANGER PERFORMANCE EVALUATION," Revision 2