ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Hwy. 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	April 23 through June 10, 1997
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Attachment:	Supplemental Information

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EXECUTIVE SUMMARY

Fort Calhoun Station
NRC Inspection Report 97-09

This team inspection investigated the causes, circumstances, and corrective actions associated with the April 21, 1997, extraction steam rupture at the Fort Calhoun Station. The inspection team evaluated the operators' performance, procedural controls, plant and equipment performance, maintenance, and engineering aspects of the event. The inspection covered a 4-week period, with 2 of these weeks conducted onsite.

Operations

- The team identified a strength in the overall operator response to the event. The licensed operators acted in a timely and decisive manner to trip the unit and to isolate the steam rupture. The subsequent decisions to implement emergency boration were conservative, and the plant was quickly stabilized.

- The inspectors noted a weakness in use of fire protection procedures. The plant operators displayed a lack of familiarity with the operating procedures used in isolating selected portions of the fire protection system. This lack of familiarity resulted in an unnecessary isolation of the entire fire protection system.

Maintenance

- It was determined that the licensee had missed a potential opportunity to detect the degraded elbow by not considering the implications of an upstream pipe replacement of a similar large radius elbow that had occurred in 1985 and had not adequately considered industry operating experience in the selection process to determine inspection locations to identify pipe wall thinning. Additionally, the inspectors noted that the licensee's analytical model for predicting the relative wear rate of components (CHECWORKS) had not accurately predicted the actual observed wear rates associated with large radius elbows in the fourth stage extraction steam system. These factors contributed significantly to the licensee's failure to identify the wall thinning in the fourth stage extraction steam elbows.

Engineering

- The inspectors determined that the overall plant and equipment response to the event were normal and no anomalies were noted. All equipment functioned as designed and no safety systems were actuated.

Report Details

Summary of Plant Status

The unit was manually tripped by the operators on April 21, 1997, as a result of the extraction steam rupture event. The unit was placed in cold shutdown for repairs and was subsequently returned to 100 percent power.

I. Operations

O1 Conduct of Operations (93702)

O1.1 Main Steam Extraction Line Rupture Event

On April 21, 1997, at approximately 8:20 p.m., the plant operators heard a loud noise coming from the turbine building at the Fort Calhoun Station. The plant was operating at 100 percent power and no unusual operational activities were in progress at that time. The plant operators opened the control room access to the turbine building and noted steam emanating from the grating, which separates the main turbine deck from the areas below. The plant operators determined that a steam rupture was in progress and manually tripped the reactor. The reactor trip resulted in a turbine trip.

The following is the sequence of events for the main steam extraction line rupture that occurred on April 21, 1997.

2020 The plant was operating at 100 percent power with normal surveillance activities in progress.

2022 A loud noise was heard in the control room, presumably emanating from the turbine building. The shift supervisor opened the control room door and observed a large amount of steam in the north end of the turbine building. The shift supervisor returned to the control room and ordered the reactor to be manually tripped.

2023 The reactor was manually tripped and Emergency Operating Procedure-00, "Standard Post Trip Actions," was entered.

2024 Emergency boration was initiated as a precautionary measure. (The operators determined that the potential existed for an uncontrolled heat extraction.)

2045 A notification of unusual event was declared based on the need for increased plant awareness.

2050 Emergency Operating Procedure-00, "Standard Post Trip Actions," was completed. Emergency Operating Procedure-01, "Reactor Trip Recovery," and Abnormal Operating Procedure-26, "Turbine Malfunctions," were entered due to lowering vacuum on the condenser and loss of the turning gear on the turbine. The plant operators also entered Abnormal Operating Procedure-32, "Loss of 4160 volt or 480 volt Bus Power," due to the loss of Motor-Control Center 4C3 and the degradation of Motor-Control Center 4C5. Both motor-control centers were in the direct path of the steam rupture.

2052 The plant emergency response organization was activated to assist in assessing the damage from the steam leak and restoring power to the secondary equipment.

2100 The turbine building fire protection system was isolated by placing the diesel fire pump and the electric fire pump in pull to lock. This was done to stop the spraying down of the turbine building by the fire sprinkler system that had actuated as a result of the event.

2114 Plant operators verified that the shutdown margin was adequate. Emergency boration was secured.

2336 All continuous fire watches were established.

2345 The notification of unusual event was terminated and the emergency response organization was secured. These decisions were based on the determinations that plant conditions were stable and that the damaged equipment had no adverse effect on maintaining a safe shutdown.

0220 The operators exited Emergency Operating Procedure-01, "Reactor Trip Recovery" and entered Operating Procedure-3A, "Plant Shutdown."

O1.1.1 Plant Performance Issues Associated with the Event

a. Inspection Scope (93702)

The inspectors reviewed the plant and equipment response to the event. Both primary and secondary side plant indications and responses were evaluated. The performance and reliability of important equipment were assessed, as well as, the potential for steam and moisture interaction with other plant equipment that was not directly affected by the rupture.

b. Observations and Findings

The inspectors performed a review of the recorded critical plant data for primary plant parameters associated with the event and no anomalies were noted. It was also determined that no primary side alarms or abnormal indications were received following the event. However, several alarms were received on extraction steam pressure. It was determined that these alarms were to be expected based on the location of the pipe rupture. No automatic safety-system actuations occurred during the event. However, portions of the fire protection system were actuated throughout the turbine building due to the heat and temperature rise associated with the steam rupture. The steam from the rupture caused seven wet pipe sprinkler heads to actuate in the basement level of the turbine building. These heads were in the immediate vicinity of the steam leak and were designed to actuate at 160 degrees fahrenheit. The team noted that the steam in the vicinity of these sprinkler heads exceeded the actuation temperature of the sprinkler heads.

The deluge system for the turbine lube oil reservoir also actuated at the time of the event. This system contains 15 deluge nozzles that sprayed water in the area of the reservoir and on the main lube oil pumps. The system was actuated by a rate of temperature rise probe. (This device will cause a deluge actuation if a 15 degrees fahrenheit per minute temperature increase occurs.) The team noted that the rate of temperature increase in the area of the steam rupture probably exceeded that required to actuate the detector. Due to the sprinkler and deluge system actuations, fire water system pressure decreased and caused the fire suppression water pumps to start automatically.

Following activation of the fire suppression system, intermittent electrical grounds were received on Vital DC Bus 1 and 480V Bus 1B4C, both of which are safety related. These grounds on the safety-related buses were determined to be most likely due to grounds on the turbine building motor-control centers in the vicinity of the pipe rupture. These motor-control centers are fed by the safety-related buses and can be isolated by the tripping of the critical quality equipment feeder breakers which isolate the nonsafety-related loads from their safety-related source. The inspectors reviewed the material history of selected critical quality equipment breakers on the 480V (1B4C-1) and vital dc buses. This review indicated no operational issues in the past 3 years.

However, the inspectors noted that problems with spurious tripping of safety-related loads, as a result of grounds on nonsafety-related equipment, had occurred both in the commercial nuclear industry, as well as, at Fort Calhoun Station. License Event Report 50-285/95-007-01 documented the licensee's problems with General Electric RMS-9 trip units. The licensee indicated that 13 RMS-9 trip units had been replaced on safety-related breakers as of August 22, 1996. The basis for the replacement of these particular RMS-9 trip units was the possibility of a common mode failure as the result of receiving multiple grounds resulting from a design basis accident. However, during the inspection, the inspectors noted that an additional 44 RMS-9 trip units existed on safety-related loads and load centers which had not been previously replaced. The licensee's rationale for not replacing these breakers was that sufficient redundancy could be demonstrated during design basis scenarios with the worst-case postulated RMS-9 trip unit failures. However, it was determined that the licensee's approach may not have been conservative in all cases. In particular, during some maintenance configurations, the SI-2C high pressure safety injection pump may have been susceptible to postulated RMS-9 trip unit failures during certain design basis scenarios. The licensee is in the process of reanalyzing the basis for RMS-9 trip unit replacements and currently plans to replace all of the RMS-9 trip units, which carry safety-related loads. In addition the licensee is reviewing all plant loads associated with RMS-9 trip units and is developing criteria for replacing some of the nonsafety-related units. This item will remain open pending further review regarding the licensee's criteria for not replacing some safety-related RMS-9 trip units in the original modification (50-285/9709-01).

The inspectors evaluated the potential for steam to intrude from the turbine building into the auxiliary building. In particular, the inspection focused on the 125 volt dc battery rooms, the electrical switchgear rooms, and the cable spreading rooms. The inspectors noted that the only method of communication between the turbine building and these areas was via four fire doors and a damper over the cable spreading room door. No fire alarms were received from any of these areas of the auxiliary building and inspection of these areas did not indicate any moisture intrusion. (It is expected that steam intrusion would have resulted in fire alarms in these areas because they are equipped with ionization detectors.) Also, a review of the ventilation systems was conducted and discussions were held with the ventilation system engineer concerning the potential for steam intrusion from the turbine building into the safety-related areas of the auxiliary building. It was determined that separate ventilation systems exist for the safety-related areas and that no potential existed for steam intrusion via the ventilation systems.

c. Conclusions

The team concluded that the plant and equipment response were normal. All plant systems operated as designed and no equipment failures or abnormal indications were noted. Further, the inspectors concluded there was no steam intrusion from the turbine building into the safety-related electrical switchgear rooms. However, the rupture resulted in significant challenge to the plant operators and led to a reduction in the station fire protection capabilities.

O4 Operator Knowledge and Performance

O4.1 Operator Performance and Procedural Issues

a. Inspection Scope

The team reviewed the operators' response and procedural issues associated with the event. Interviews were conducted with plant operators, and control room log reviews were performed. An overall evaluation of operator performance and procedural adequacy was performed with respect to the specific operator actions associated with the event.

b. Observations and Findings

The inspectors noted that the operator's actions to respond to the event were timely, decisive, and conservative. The operators acted quickly by tripping the reactor within 19 seconds of the initiation of the event. Additionally, the team determined that the operators took conservative measures by initiating emergency boration to ensure that an adequate shutdown margin was maintained in consideration of the potential for an uncontrolled heat extraction during the event. It was determined that the correct emergency operating and abnormal operating procedures were implemented during the event. The inspectors responded to the site in the early recovery stages of the event and noted that the control room was orderly and that good command and control were demonstrated by the licensed senior operator and the shift supervisor.

However, the inspectors did note a weakness during the response to the event with the operators' knowledge of fire protection procedures. Operating Instruction OI-FP-1, "Fire Protection System Water System," Revision 25, contains detailed steps on the isolation of the fire protection system. Specifically, this procedure contained details on isolating fire protection water to the turbine building basement, the turbine lube oil deluge and the turbine building mezzanine sprinkler systems. During the event the operators attempted to isolate the fire protection system using only the piping and instrument drawings and without referring to the proper procedure. The inspectors conducted selected interviews with auxiliary operators, who were attempting to isolate the fire protection system the night of the event, and each individual interviewed indicated that Operating Instruction OI-FP-1 should have been used. This would have made isolation of the fire protection system more timely and would not have resulted in an isolation of the entire turbine building fire protection capability. The operators attempted to isolate the fire protection system for approximately 40 minutes before a decision was made by the shift supervisor to secure the fire pumps. This terminated the spraying down of equipment in the turbine building and rendered the fire protection system inoperable without operator action to restart the fire pumps. The operators placed the fire protection system pumps in pull to lock in accordance with Standing Order SO-G-103, "Fire Protection Operability Criteria and Surveillance Requirements," Revision 5. The NRC is reviewing the adequacy of this procedure and the results of this review will be dispositioned in NRC Inspection Report 50-285/97-06. The inspectors determined that the lack of familiarity with the fire protection procedures resulted in an unnecessary reduction in station fire protection capabilities.

During the followup to the event, the licensee identified the failure to establish a continuous fire watch in the required time after securing the fire pumps. This was documented in Condition Report 199700499, which indicated that the sprinkler system for the diesel rooms was out-of-service for approximately 2 hours. Standing Order SO-G-103, "Fire Protection Operability Criteria and

Surveillance Requirements," Revision 5, Attachment 3, Step 2, requires that a continuous fire watch be established within 1 hour if the sprinkler system is inoperable. Failing to establish a continuous fire watch within 1 hour is a violation of Technical Specification 5.8.1. The licensee conducted training and issued an operations memorandum to address this deficiency. Additionally, refresher training on the usage of plant fire protection procedures was scheduled for the licensee's requalification program. This nonrepetitive licensee-identified and corrected violation, is being treated as a noncited violation consistent with Section V11.B1 of the NRC Enforcement Policy (50-285/9709-02).

c. Conclusions

The team concluded that licensed operator actions were accomplished in an expeditious manner. The operators' decisions were both rational and conservative. An overall strength was noted in the area of licensed operator response. A weakness was noted in the area of the use of the procedures to manually isolate selected fire protection headers.

II. Maintenance

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Erosion/Corrosion Issues

a. Inspection Scope (49001, 62706)

The team reviewed those aspects of the licensee's maintenance rule and erosion/corrosion control programs as they pertained to the circumstances surrounding the April 21, 1997, pipe rupture event.

b. Observations and Findings

The licensee determined, and the team agreed, that the failure of the piping in the fourth stage extraction steam system was most likely due to flow accelerated corrosion. The design conditions of the fourth stage extraction system were 300 psig/425°F and the system was composed of primarily 12-inch diameter piping fabricated from A-106B carbon steel with a nominal wall thickness of .375 inches. The "fishmouth" break, which occurred, was approximately 4 feet long by 1 foot wide, and it was postulated that an approximately 2-4 inch wide by 4 foot long section of pipe was below minimum wall thickness before the rupture. The failure location occurred on what is known as a "large radius elbow." The as-found readings on the failed pipe revealed a minimum wall thickness of the rupture seam of .054 inches, whereas the minimum allowable pipe thickness was .126 inches.

The failure location was modeled in the licensee's erosion/corrosion program (i.e., Location S-25) but the actual wall thickness had never been measured by nondestructive examination techniques. The licensee had relied on a predictive methodology (CHECWORKS) to monitor the condition of the large radius elbows in the extraction steam system. The CHECWORKS methodology had predicted a lower wear rate on the large radius elbows relative to other potential wear locations within the fourth stage extraction steam system.

The team determined that a prior opportunity to detect and prevent the failure had existed. It was discovered that Field Change 85-94 had been implemented in 1985 to replace the piping immediately upstream of the failure location. This modification included the replacement of the next upstream large radius elbow due to excessive wear caused by erosion/corrosion. The licensee indicated that the first elbow in the system (a short radius elbow) had developed a pinhole leak due to flow accelerated corrosion. During replacement of the short radius elbow, it was discovered that the next downstream elbow (a large radius elbow located immediately upstream of the site of the April 21, 1997, pipe rupture) was also significantly degraded due to erosion/corrosion and required replacement. The licensee could not produce documentation to indicate that any inspections were conducted at that time on Location S-25, (the failure location), or any other large radius elbows in the extraction steam system. Thus, the team determined that this information would have been sufficient to indicate that high wear rates were occurring in the large radius elbows despite the predictions made by the analytical methodology. Additionally, the team determined that the licensee had not adequately incorporated industry operating experience into the erosion/corrosion program. Various NRC information notices and industry notifications were available. They provided insights into significant operating failures in extraction steam and other similar systems. Additionally, several other sources of industry information, which contained an extensive amount of information related to similar problems in the extraction steam systems at other plants, were available to the licensee. These sources of industry information had not been adequately factored into to the licensee's erosion/corrosion program with respect to choosing suitable piping inspection locations.

As a result of the rupture, the licensee inspected all other large radius elbows at the facility, which had not been previously inspected. It was determined that the furthest downstream large Radius Elbow S-32 in the fourth stage extraction piping was also significantly below minimum wall thickness and had to be replaced. (The minimum wall reading was .044 inches.) Inspection Location S-27, another large radius elbow in the fourth stage extraction piping, was also found to have exhibited excessive wear, although this particular elbow had not exceeded the minimum allowable thickness. (This location exhibited a minimum wall reading of .155 inches and was replaced by the licensee.) The large radius elbow at Location S-27 was in the licensee's analytical model for the erosion/corrosion program and had never been inspected due to the lower relative wear rate predictions for large radius elbows which were supplied by the model. The licensee also inspected the large radius elbows in the second stage extraction steam system and these elbows were found to have acceptable wall thickness readings.

The licensee's staff acknowledged the deficiencies associated with incorporating plant and industry operating experience into the erosion/corrosion program. In response to this issue, the licensee implemented a panel of industry experts from other utilities and industry groups whose charter was to review the Fort Calhoun Station erosion/corrosion program with respect to the incorporation of industry insights. The erosion/corrosion program susceptibility evaluation was upgraded to conform to industry standards. The entire steam seal system, steam generator blowdown suction/discharge of the blowdown transfer pumps, condensate recirculation and steam traps and drains were added to the program. Additionally, this review group identified a number of additional inspection locations which were not being actively inspected in the licensee's program. The licensee conducted ultrasonic testing inspections of these locations and determined that several other locations in a different plant system had degraded to the point whereby the walls had exceeded minimum wall thickness standards. It was found that three separate parallel lines in the heater drains system (Location D-95) had very localized areas, which were below the minimum allowable wall thickness and required replacement (i.e., the minimum readings were .08 inches). Additionally, the licensee identified that Location S-54 in the sixth stage extraction steamline exhibited unacceptable wall thickness reading and required replacement. This particular piece of piping was known as a "pup" piece and was located immediately downstream of piping that had been replaced in 1985 with an alloy of chromium-molybdenum material. This location had a minimum wall thickness reading of .107 inches. In summary, the net result of these programmatic reviews of the licensee's erosion/corrosion program was the identification of five additional pipe locations (not including the rupture location) whose wall thicknesses had degraded below the minimum allowable.

The fourth and sixth stage extraction steam system and the heater drains system had been included within the scope of the licensee's program to implement 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These systems were included as subsystems of the main feedwater system and had been classified as being of low risk significance and were being monitored under Section (a)(2) of the Rule. The system performance criteria had been identified at the plant level and required that no forced shutdowns, power reductions, or trips be caused by maintenance preventable functional failures of the system. The licensee's program plan for implementation of the Maintenance Rule (Section 4, paragraph 3) specified that the plant operating experience review program would provide the responsible organizations the industry operating experience necessary for incorporating the required information into the maintenance rule program. Additionally, paragraph 4 of the program plan specified that the special services engineering department would maintain specialized programs to respond to component-specific concerns. The erosion/corrosion program was considered to be one such specialized program under the umbrella of maintenance rule implementation. Finally, the Maintenance Rule Implementing Instruction MRII-2, Section 5.3.4, "Condition Monitoring," stated that no specific condition monitoring was required by the Fort Calhoun Station Maintenance Rule

Project. The Fort Calhoun Station Maintenance Rule Project made maximum use of existing programs, such as erosion/corrosion control, to provide the necessary condition monitoring functions as required by the rule.

The Maintenance Rule, 10 CFR 50.65(a)(1), requires, in part, that each holder of an operating license shall monitor the performance of structures, systems, or components against licensee established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. 10 CFR 50.65(a)(2) states, in part, that monitoring as specified in paragraph (a)(1) is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance such that the structure, system, or component remains capable of performing its intended function.

The inspectors determined that the licensee had not established appropriate goals for those components in the fourth and sixth stage extraction steam system, and the heater drains system whose pipe walls had degraded to the extent that minimum wall thickness criterion had been exceeded. Additionally, it was determined that the licensee had not adequately incorporated industry-wide operating experience in the establishment of goals and performance monitoring activities, as required by the maintenance rule. As a result, a pipe rupture occurred on April 21, 1997, due to inadequate monitoring of the condition of the fourth stage extraction steam system. This pipe rupture resulted in a significant plant transient and personnel hazard. The pipe rupture required the plant operators to trip the unit and enter the emergency operating procedures in order to stabilize the plant. Additionally, damage occurred to certain balance-of-plant equipment, and a significant asbestos hazard was created due to damaged piping insulation in the vicinity of the rupture. The event also actuated portions of the fire protection system, which had to be disabled, thus, decreasing the station's fire protection capabilities. This is considered to be an apparent violation of 10 CFR 50.65 (50-285/9709-03).

In addition to the apparent violation described above, the inspectors noted the following deficiencies associated with the predictions generated by the CHECWORKS analytical model:

- Large radius elbows were monitored on the basis of predictive wear analysis only. There had been no erosion/corrosion examinations performed of large radius elbows.

- Engineering judgement was not adequately incorporated into the sample of components selected for erosion/corrosion examination (i.e., only those components with the highest predicted wear were inspected).

- The erosion/corrosion engineer had not routinely evaluated the accuracy of the analytical results. Therefore, the relatively poor predictive capability of the program with respect to this comparison of predicted wear to measured wear was not detected for the fourth stage extraction steam system at Fort Calhoun Station.

- Actual component measured wall thickness inspection data from the 1995 and 1996 erosion/corrosion examinations had not been incorporated into the analytical model.

- Minor modeling input errors related to incorrect component geometry codes were identified by the team. The modeling input errors appeared to be the result of incorrect component identification on as-built drawings used to generate input data. A similar deficiency of this type had been identified by the NRC in a routine erosion/corrosion inspection conducted in 1994.

- Only one train of multiple train systems had been modeled in the analysis.

Of particular significance was the fact that the CHECWORKS predictions for the fourth stage extraction steam system were not consistent with the actual observed wear rates as measured by the licensee following the event. In particular, those inspection locations whose relative wear rates were predicted to be the highest for this specific application (i.e., short radius elbows and tees) did not exhibit significant actual measured wear. Conversely, the larger radius elbows (which had been predicted to exhibit a lower relative wear rate) were wearing at rates higher than predicted for this specific application.

As of the end date of the inspection, the licensee had not determined the specific reasons for the discrepancies between the predictions and the actual observed wear rates for those components in the fourth stage extraction steam system. However, the licensee did identify several other issues associated with the implementation of the CHECWORKS methodology during a self-assessment associated with the steamline rupture event. These self-assessment findings are discussed in Section M7.1 of this report. As a result of these discrepancies, the licensee issued an industry notification, which reported the details of the issues associated with respect to the analytical methodology and its impact on this event.

c. Conclusions

The team concluded that significant weaknesses existed in the licensee's erosion/corrosion program. Specifically, the team concluded that the licensee had not adequately incorporated industry experience into the program, particularly in the area of the selection of inspection site locations. Additionally, the licensee had not properly incorporated prior plant operating inexperience into the program for the selection of inspection site locations. Finally, it was determined that the licensee's analytical model for predicting wear rates on the affected system components had not accurately predicted the actual wear rates and that an over-reliance existed with respect to the model's predictions for the extraction steam system. The result of these deficiencies led to significant degradation (i.e., exceeded minimum wall thickness requirements) in six separate piping locations in three separate plant systems. One of these areas of degradation resulted in a catastrophic failure of the piping, which caused an unnecessary plant transient and significant personnel hazard and contributed to a reduction in the station's fire protection capabilities.

However, at the exit meeting on June 10, 1997, the licensee indicated that several of these locations which were found to be below minimum wall thickness were not significant failures. The licensee stated that the piping replacements associated with these locations were implemented a precautionary measure.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Root Cause Investigation, Followup Activities and Corrective Actions

a. Inspection Scope (93702)

The team reviewed the licensee's self-assessment efforts, root-cause analysis, and corrective actions associated with the steam rupture event.

b. Observations and Findings

The licensee performed a formal root-cause analysis of the extraction steam line rupture event. The analysis was performed in two phases: Phase 1 was a preliminary root-cause analysis to identify apparent causes and to identify the root cause of the reason for not detecting the imminent failure of the piping. Phase 2 of the root-cause analysis would provide a final root cause, which would include a failure analysis (including a metallurgical examination) of the failed piping conducted by two separate and independent laboratories.

The Phase 1 root-cause analysis results determined that the piping failure was most likely the result of flow-accelerated corrosion, which had occurred over a relatively long period of time. The licensee determined, and the team agreed, that the degradation in the piping could have been detected well before the event. It was determined that an over-reliance was placed on one predictive factor, the relationship between elbow radius and predicted wear rate, in determining the specific locations for ultrasonic testing inspection site locations. Additionally, it was determined that there had been insufficient consideration of both industry and plant-specific operating experience in the selection of inspection site locations. The licensee also determined that the erosion/corrosion program lacked a detailed methodology to choose ultrasonic testing inspection locations and that inadequate management oversight existed with respect to the implementation of the program.

The licensee chartered a formal self-assessment team to review the erosion/corrosion program at the facility. The team was composed of plant personnel and management, as well as, industry representatives from other utilities, Electric Power Research Institute, and contract engineering firms. The self-assessment team conducted a broad-based review of the erosion/corrosion program and identified various program weaknesses and some strengths. The self-assessment findings were formulated into issues which were to be addressed in three phases: (1) prior to plant startup, (2) prior to start-up from the 1998 outage, and (3) those which were considered to be long-term corrective actions.

The most significant findings of the self-assessment effort identified specific factors which contributed to the failure to identify the eroded piping in the extraction steam system. In particular, the opportunity to identify excessive wear was missed due to failure to inspect the S-25 elbow during replacement of the next upstream large radius elbow in 1985. Additionally, the licensee's team noted that the plant had consistently missed the opportunity to identify high wear systems by not adequately incorporating industry operating experience into the erosion/corrosion program. The over-reliance on the predictive results of the CHECWORKS methodology (which had not accurately predicted the failure) was also a significant contributing factor.

Additional findings of the licensee's team included observations of various program weaknesses in the erosion/corrosion program. The licensee's team noted the following weaknesses in the program:

- The licensee had not aggressively pursued the change out of carbon-steel with more resistant material.

- The erosion/corrosion program did not provide a thorough description of susceptibility criteria or documentation of system susceptibility determinations.

- No detailed procedures existed for how inspection locations should be selected.

- The measured wear process, which was used, was not consistent with industry standards. The licensee had not been conducting point-to-point comparisons of all the ultrasonic test readings associated with a given component/location to determine the maximum wear rates. The licensee had been using the data from the ten lowest thickness locations to determine the wear rates.

- A considerable amount of susceptible piping that was suitable for modeling was not included in the analytical models.

- No documentation existed that indicated that the analytical models were kept current.

- The analytical models had not been verified.

- The erosion/corrosion program had not been maintained current with industry standards.

- Some data packages could not be located for several inspection point locations from the 1996 outage.

As a result of the root-cause analysis and self-assessment team efforts, the licensee identified specific actions to be accomplished prior to restarting the unit. The following activities were completed prior to the plant's restart on May 12, 1997:

- Reviews were conducted for all systems within the scope of the erosion/corrosion control program. The remaining large radius elbows, which had been predicted to exhibit lower relative wear rates, were inspected. Two additional elbows in the fourth stage extraction steam piping were replaced due to excessive wear.

- All pipes downstream of previously replaced piping or components were evaluated as to whether or not previous inspections had been conducted. One location was found to have not been previously inspected. An inspection was conducted on this location and it was found to have an acceptable wall thickness.

- The erosion/corrosion program susceptibility evaluation was upgraded to conform to industry standards. The entire steam seal system, steam generator blowdown suction/discharge of the blowdown transfer pumps, condensate recirculation and steam traps and drains were added to the program. Several additional required inspections were identified during this review and all of the additional inspection locations were found to exhibit acceptable wall thicknesses.

- A reinforcing pad was installed on Component S-56 (a branch location on the sixth stage extraction steam line feeding the low pressure heaters).

- All 1996 outage inspection packages, which had not been independently reviewed, were reviewed and found to be acceptable.

- All missing 1996 outage inspection packages were located. It was determined that three of the missing packages had not undergone any reviews to determine whether the readings for the affected components were below minimum allowable wall thickness. Additionally, several of the missing packages had not undergone the required independent review. All of the affected packages were reviewed, and all wall thickness readings were determined to be acceptable.

- Thirty components, which showed significant wear or whose wear rate could potentially lead to exceeding minimum wall thickness, were reevaluated using an industry standard analysis methodology. One of these components required re-inspection and the subsequent readings were found to be acceptable.

- A review of industry operating experience was conducted. This review resulted in the addition of several inspection locations. Subsequent inspections of these additional locations resulted in the replacement of three parallel pipes in the heater drain system.

Additionally, the licensee identified the following short-term corrective actions to be completed prior to the restart from the next refueling outage:

- Upgrade the erosion/corrosion control procedures to include more specific guidance on choosing inspection locations.

- Upgrade the measured wear determination process and the sample expansion process to conform to industry standards.

- Revise the erosion/corrosion control program to include a document that controls the identification of system susceptibility criteria.

- Incorporate past outage data into the current CHECWORKS model and perform a verification of the model. Additionally, formal controls will be established to ensure that model changes are properly documented.

Finally, the licensee identified a long-term corrective action related to the need for a followup assessment of the erosion/corrosion program. The followup assessment was intended to be verification that the interim improvements in the program were providing satisfactory results.

c. <u>Conclusions</u>

The team concluded that the licensee's self assessment and preliminary determination of apparent causes were adequate. The root cause associated with the failure to identify the degraded elbow appeared reasonable. The inspectors determined that the corrective actions completed prior to restart and the proposed short- and long-term corrective actions were acceptable. However, the team determined that additional actions to properly evaluate the predictive validity of the model would be necessary in order to maintain an awareness of the model's ability to reliably predict wear rates. The final determination regarding the Phase II root-cause analysis and the effectiveness of the short- and long-term actions will be reviewed in future inspections and are characterized as an NRC inspection followup item (50-285/9709-04). Additionally, further review of the licensee's overall program for incorporating industry-wide operating experience into applicable plant programs is planned and was characterized as an NRC inspection followup item (50-285/9709-05).

III.Engineering

E8 Plant Damage Assessment

a. Inspection Scope (93702)

The team conducted an assessment of the damaged areas of the turbine building. Additionally, the team reviewed the licensee's plan and scope of activities for conducting a plant damage assessment and the associated recovery activities.

b. Observations and Findings

The licensee's damage assessment team developed criteria in determining the area to be inspected for damage due to the rupture. The area defined for extensive assessment included the area of obvious physical damage, as well as, an area defined by a qualitative assessment of the thermal-hydraulic conditions associated with the rupture. The licensee defined the "break-affected" zone as that area extending outward from the break location in a roughly cone-shaped configuration that terminated at the turbine building wall. This assumption was based on visual examinations of the steam impingement effects, as well as, assumptions regarding the temperature and pressure of the steam and the duration of the event.

The scope of the damage assessment included a disposition of every plant system and whether or not the system could have been affected by the rupture. For those systems that had the potential for damage, damage assessment teams were formed and walkdowns were conducted. The results of the walkdowns were collated in "damage assessment reports," which were submitted to the overall damage assessment effort leaders for tracking purposes. The damage assessment teams, which were formed, consisted primarily of the cognizant system, design, and maintenance engineers, as well as, selected craft personnel. The following paragraphs provide a summary of the significant findings associated with the damage assessment effort.

The component in the "break-affected" zone with the most extensive damage was the Motor-Control Center 4C5. The inspectors observed that the motor-control center was approximately 8 inches out-of-plumb from the top to bottom. The back panels were bent open and deformed by the effects of steam impingement. Motor-Control Center 4C3, which was immediately adjacent to 4C5 did not display any structural damage. However, this particular motor-control center lost power during the event. (The motor-control center was subsequently re-energized during the recovery efforts.) There were two other motor-control centers in this area which did not suffer any obvious physical damage, but had been significantly "sprayed" with asbestos insulation that had been displaced during the event. The licensee consulted with the vendor of the motor-control centers and conducted the necessary repairs to the damaged equipment. A small portion of the bus insulation in the vertical section of the motor-control center was repaired and extensive clean up was required to remove all of the powdered pipe insulation. The breaker for the turbine seal oil pump required replacement due to physical damage.

Several cable trays were also located in the "break-affected" zone. The cable trays directly in the steam impingement zone were twisted and the unistrut cable tray support was significantly damaged. Several cable tray dividers and covers were displaced. The licensee performed a 100 percent visual inspection of all 36 instrumentation and control cables which were associated with the turbine control valves and stop valves. In addition, tests were performed prior to the unit's restart to ensure that the valves retained their ability to perform their design function. Additionally, visual inspections were conducted on all 480 volt ac power cables. The licensee implemented a sampling methodology to determine the electrical condition of the remaining cables in the affected cable trays. Approximately 33 percent of the remaining cables were meggared with the primary focus being that of the pump and fan motor loads. There were 56 cables in this area, and no problems were identified. The licensee indicated that while these cables were not safety related, they had been purchased to identical specifications as that of other safety-related cables in the plant.

The licensee stated that all of the electrical junction boxes in the "break-affected" zone had been inspected for signs of moisture. A total of six junction boxes were identified to have exhibited signs of moisture intrusion. (Five of these junction boxes were in the "break-affected" zone.) The one affected junction box, which was not in the damaged area, was immediately outside the control room. The licensee postulated that this particular junction box had most likely been sprayed down during the asbestos clean up of the turbine building. In addition, junction boxes were spot checked throughout other areas of the turbine building (outside of the break-affected zone) to ensure that moisture from the steam had not impacted other areas. No additional electrical junction boxes were identified as having been impacted by moisture intrusion.

Pipe supports and equipment supports in the general area of the pipe rupture were inspected and three supports were noted to have been damaged. All three of the affected supports were on the fourth stage extraction steam line near the site of the pipe rupture. All of the damaged supports were either repaired or replaced.

Additionally, it was noted that some damage had occurred to the turbine stop and control valves. Specifically the drain lines for Stop Valve 1 and 2 were bent. Stop Valves 1 and 2 and Control Valves 1 and 3 were in the direct path of the steam impingement. These drain lines were heated and straightened, no replacement was necessary. The solenoid valves and linear variable differential transformers were inspected on these valves and no obvious damage was noted. However, these components were replaced as a precautionary measure. Also, the servo valves on Control Valves 1 and 3 were replaced and the limit switches on Stop Valves 1 and 2 were cleaned and inspected. The inspectors noted that the turbine stop valve limit switches supply a turbine trip signal to the reactor protection system.

c. Conclusions

The team determined that the scope of the licensee's damage assessment was reasonable and adequate. The observed damage was of a localized nature in the immediate vicinity of the pipe rupture. No safety-related equipment or equipment required for safe shutdown was damaged. The licensee indicated that future additional followup inspections of certain important electrical components would be conducted periodically following startup to ensure that corrosion due to potentially undetected moisture would not affect the reliable operation of those components.

V. Management Meetings

X1 Public Meeting and Exit Meeting Summary

The licensee and NRC conducted a public meeting at the site on May 2, 1997, to discuss the licensee's root-cause analysis, damage assessment, self assessment, and corrective action efforts. The team presented the inspection results to members of licensee management at the conclusion of the inspection on June 10, 1997. The licensee acknowledged the findings which were presented. The inspectors asked the licensee whether any of the materials examined during the inspection should be considered proprietary. The licensee indicated that the details associated with the CHECWORKS predictive methodology should be considered proprietary. None of these details are contained in this report.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Andrews, Manager-Nuclear Assessments
C. Brunnert, Manager-Quality Assurance
J. Chase, Plant Manager
M. Core, Manager-System Engineering
S. Gambhir, Manager-Engineering and Operations Support
J. Gasper, Manager-Nuclear Projects
W. Gates, Vice-President of Nuclear Operations
B. Lisowyj, Station Engineering
E. Matzke, Station Licensing
R. Phelps, Manager-Station Engineering
R. Short, Manager-Operations
H. Sufick, Manager-Security
J. Tills, Manager-Nuclear Licensing

NRC

E. Merschoff, Regional Administrator
A. Howell, Director, Division of Reactor Safety
K. Brockman, Deputy Director, Division of Reactor Projects
D. Chamberlain, Deputy Director, Division of Reactor Safety
D. Graves, Project Engineer, Projects Branch B
R. Wharton, Project Manager, Office of Nuclear Reactor Regulation

INSPECTION PROCEDURES USED

49001	Inspection of Erosion/Corrosion Monitoring Programs
62706	Maintenance Rule
93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

50-285/9709-01	IFI	Replacement of RMS-9 trip units (Section O1.1.1)
50-285/9709-02	NCV	Establishing required fire watches (Section O4.1)

50-285/9709-03	APV	Failure to monitor the condition of plant piping systems and incorporate industry-wide operating experience in accordance with 10 CFR 50.65 (Section M2.1)
50-285/9709-04	IFI	Adequacy of short- and long-term corrective actions associated with the erosion/corrosion control program (Section M7.1)
50-285/9709-05	IFI	Incorporation of industry-wide operating experience into plant programs (Section M7.1)

Closed

50-285/9709-02	NCV	Establishing required fire watches (Section 04.1)

LIST OF DOCUMENTS REVIEWED

Procedures	Revision	Title
NOD-QP-21	6	"Operating Experience Review Program"
PED-GEI-56	5	"Configuration Change Closeout"
QCP-200	11	"Certification Requirements For Quality Control Inspectors"
QCP-331	6	"Ultrasonic Thickness Measurement for Erosion/Corrosion"
QCP-332	8	"Gridding Procedure for Erosion/Corrosion"
SO-G-21	62	"Modification Control"
SS-PM-MX-0800	0	"Ultrasonic Inspection of Station Pipe"

Modification Requests	Title
FC-85-94	"Extraction Steam Elbows"
FC-80-102	"6th Stage Extraction Erosion"

Other Documents

"Erosion/Corrosion Program Basic Document," Revision 7, dated February 1997

"Erosion/Corrosion Control Program Technical Reference Manual," Volumes 1 and 2

"Omaha Public Power District CHECWORKS Database," Analysis Date: January 4, 1995

"Maintenance Rule Program Plan," dated November 6, 1996

Assessments

Root Cause and Generic Implications Report, Revision 0, dated May 7, 1997

Damage Assessment Report for the Break in the Extraction Steam Line, Revision 0, dated May 3, 1997

Fort Calhoun Station-Erosion/Corrosion Assessment Report, Revision 0, dated May 2, 1997

Equipment/Examiner Certification

Omaha Public Power District, Fort Calhoun Station - For Erosion/Corrosion Examinations

Condition Reports	Creation Date
199700529	May 05, 1997
199700445	April 22, 1997
199700129	January 31, 1997
199601650	December 31, 1996
199601649	December 31, 1996
199601313	October 25, 1996