U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
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Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/97-11, 50-414/97-11

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection, as well as the results of announced and reactive inspections by regional reactor safety inspectors.

Operations

- A good questioning attitude and operating crew safety sensitivity were observed during routine shift turnovers and operations in the control room. (Section O1.1)

- A non-cited violation was identified for failure to follow the control rod movement testing procedure. The licensee's reactivity management evaluation process following the occurrence was effective. (Section O1.2).

- Two manual Unit 2 reactor trips were initiated in response to Digital Optical Isolator (DOI) failures that caused the D Steam Generator (SG) Main Steam Isolation Valve (MSIV) to close. The failure to correctly develop a DOI replacement plan and to perform DOI replacement activities in accordance with controlling procedure was identified as a violation. (Section O1.3)

- Following the second manual trip, the decision by the Operator at the Controls to control the D SG level within 1 percent of the lo-lo level setpoint for auxiliary feedwater system auto-start contributed to an unnecessary Engineered Safety Feature actuation and associated minor post-trip complications. The inspector raised concerns regarding the Plant Operations Review Committee's initial recommendation that Unit 2 was prepared for restart contingent upon successful DOI test results. However, the subsequent decision to delay restart to replace potentially implicated components that had the same date stamp as the failed components was appropriate. Efforts to obtain additional information on the DOI failures and develop a strategy and procedures for online testing of the MSIV DOIs until a root cause could be determined, were also considered appropriate. (Section O1.3)

- During plant tours, operating and standby equipment appeared to be in generally good material condition. However, observed material condition of some balance of plant equipment indicated a need for additional maintenance attention. (Section O2.1)

Maintenance

- Testing of the 1B emergency diesel generator was conducted in a good manner. The procedure provided clear instructions and operations personnel conducting the test performed the evolutions in a thorough and professional manner. (Section M1.1)

- Evaluation of the emergency diesel generator output breaker trip problem and troubleshooting was conducted as required by licensee procedures and processes. In addition the Failure Investigation Process provided a methodical method for cause determination. However, only an apparent cause was identified. (Section M1.2)

- An unresolved item was identified, pending the licensee's completion of a metallurgical analysis and root cause determination of an emergency diesel generator turbocharger mounting bolt failure, to determine if the root cause and corrective actions for previous failures should have prevented recurrence. (Section M1.3)

- The licensee's evaluation to determine the root cause of condensation in the B and 2B pump motor breaker cubicles was thorough, and corrective actions to prevent recurrence were appropriate. (Section M2.1)

- A violation was identified for failure to identify conditions adverse to quality and take corrective actions during reviews in accordance with Generic Letter 96-01. (Section M7.1)

Engineering

- The licensee's planned and completed actions to determine the root cause for the failure of the E-max digital optical isolation devices were adequate. The licensee took conservative steps by replacing five Unit 2 MSIV DOIs that had the same manufacturers date code as the two that previously failed. (Section E2.1)

- Communications between McGuire Nuclear Station (MNS) and Catawba Nuclear Station (CNS) regarding the degraded condition of the ice condenser floor at MNS was prompt. Based on the licensee's inspection of Unit 2 and review thus far, this issue does not appear to be a problem at Catawba. Inspection of the Unit 1 ice condenser has been placed on the licensee's forced outage list. (Section E2.2)

- An issue involving excess aluminum in containment, which was identified at MNS, was communicated to CNS engineering personnel in a timely manner, and engineering support from the corporate office to determine the impact was responsive. An unresolved item was identified pending the completion of a root cause evaluation to determine why inappropriate filters were used inside containment. (Section E2.3)

Plant Support

- The licensee's efforts to monitor ammonia concentrations in closed cooling water systems were proactive in minimizing the risk of stress-corrosion cracking of copper-alloy heat exchanger tubes. Appropriate actions were taken to reduce elevated levels ammonia in these systems. (Section R1.1)

- The licensee's response to the temporary loss of access to the Unit 2 auxiliary feedwater pump room and auxiliary shutdown panels was timely and appropriate. The root cause evaluation was adequate, and the conclusion that tampering was not involved in the incident was well-reasoned. Actions taken to prevent recurrence were appropriate. (Section S1.1)

Report Details

Summary of Plant Status

Unit 1 operated at or near 100% power during the inspection period.

Unit 2 operated at or near 100% power until July 26, when a manual reactor trip was initiated in response to the closure of the D Steam Generator (SG) Main Steam Isolation Valve (MSIV). The immediate cause was attributed to a failed Digital Optical Isolator (DOI) in the seal-in circuit associated with the D SG MSIV "Open" pushbutton. The DOI was replaced, and the unit restarted on July 28. The unit reached 100% power on July 29 and operated at that power level until August 17, when a manual reactor trip was initiated following the closure of the D SG MSIV due to the failure of a second DOI. Like the first, this second DOI was also located in the MSIV seal-in circuitry for the "Open" pushbutton. The unit restarted on August 18 following testing of other DOIs in the Unit 2 MSIV control circuits and replacement of 6 DOIs (including the one that had failed). The unit returned to 100% reactor power on August 19 and operated at or near that power level for the remainder of the inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspector observed several operations shift turnover meetings in the control room. The inspector also observed that the turnover meetings involved discussion on unit status and upcoming evolutions by each oncoming crew member. The inspector noted the briefings of shift personnel were generally formal and followed a process which allowed for crew interaction to assure all items were discussed. During one of the briefs, an abnormal condition annunciated on Unit 2. Briefing activities were stopped and operator attention was focused on the understanding of the condition annunciated. The briefing did not recommence until this issue was appropriately addressed by the operators. The inspector considered these operations crew actions demonstrated a good questioning attitude of an abnormal condition.

The inspector conducted several control room tours and observed each unit's operators performing evolutions. The inspector noted that few annunciators were lit and when operators were questioned about lit annunciators, they fully understood reasons why annunciators were in alarm. The inspector specifically noted good sensitivity by the

Operations Shift Manager. The inspector considered the operations crews demonstrated a good operating safety sensitivity.

O1.2 Error During Unit 1 Control Rod Movement Surveillance

a. Inspection Scope (71707,61726)

On July 30, during the performance of the Unit 1 monthly control rod movement surveillance (PT/1/A/4600/01, Section 12.11.5), the reactor operator performing the test erroneously withdrew control bank C control rods during a portion of the test requiring the bank be inserted. The inspector reviewed procedure guidance for performing the test and the effect this error had on the reactor core and rod control system. The inspector also reviewed the licensee's assessment of this error as a potential reactivity management event.

b. Observations and Findings

The control rod movement test is a surveillance required by Technical Specifications (TS) that verifies proper operation of the control rods and rod position indication system. During the test, each individual bank of control rods is inserted a total of 10 steps (in 5 step increments) and subsequently withdrawn (in five step increments) to its initial location. When control bank C was selected for testing, the reactor operator verified all prerequisites, but inadvertently withdrew the bank from its initial position of 229 steps to 231 steps. The reactor operator recognized the error and stopped rod movement. Concurrently, the control room Senior Reactor Operator (SRO) recognized the error and verbally instructed the reactor operator to stop. The control room staff determined that control bank C was in a safe position at 231 steps. After consultation with engineering, the bank was returned to its initial position and the test was completed.

At 229 steps, control bank C was essentially fully withdrawn from the core and outside of the active fuel region. Moving to 231 steps had little or no reactivity effect. The 231 step position is the last valid control rod position. Moving control bank C to this position did not impact operation of the rod control system, which would occur if outward rod movement is demanded beyond 231 steps.

The licensee initiated Problem Investigation Process (PIP) report 1-C97-2484 and a root cause evaluation to investigate the problem. The inspector attended a reactivity management meeting where this problem was discussed. The meeting was well supported by Operations, Maintenance, Chemistry and Engineering personnel. Discussions involving the assessment and characterization of this and other reactivity related PIPs were in depth.

Failure to insert the control bank C control rods is a violation of TS 6.8.1, Procedures and Programs, for failing to follow procedure.

However, based on the immediate corrective actions and the safety significance of the circumstances, this non-repetitive, licensee-identified, and corrected violation is being treated as a Non-Cited Violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. NCV 50-413/97-11-01: Failure to Follow Control Rod Movement Testing Procedure.

c. Conclusions

A non-cited violation was identified for failure to follow the control rod movement testing procedure. The licensee's reactivity management evaluation process following the occurrence was effective.

O1.3 Manual Reactor Trip Following Closure of the 2D Steam Generator Main Steam Isolation Valve

a. Inspection Scope (71707, 37551)

On July 26 and August 17, the Unit 2 Operator at the Controls (OATC) responded to control room indications that the D Steam Generator (SG) Main Steam Isolation Valve (MSIV) had closed. The OATC manually tripped the reactor, and the Failure Investigation Process (FIP) was initiated to determine the root cause. The first MSIV failure was attributed to a failed Digital Optical Isolator (DOI), whereas the second MSIV failure was attributed to a degraded DOI. The inspector responded to both unit trips, inspected the electrical cabinet that housed the failed DOIs, discussed the FIP team's progress with Engineering personnel, and reviewed the associated PIPs and Licensee Event Report (LER) 50-414/97-06.

b. Observations and Findings

First Manual Trip

On July 26, the D SG MSIV failed closed for no apparent reason. A control room annunciator alarmed, and the OATC referred to the valve position indications to verify that the valve was closed. The OATC then manually tripped the reactor, and a FIP team was organized to investigate the cause of the MSIV failure. The licensee reported the manual actuation of the Reactor Protection System (RPS) in accordance with 10 CFR 50.72.

The FIP team identified a failure of one of two DOIs that separate the nonsafety-related control circuitry from the safety-related control circuitry in the seal-in circuit associated with the MSIV's "Open" pushbutton. The voltage across the DOI did not meet acceptance criteria during a simple test using a Fluke multimeter. The DOI was replaced on July 27, and work requests were generated to similarly test the DOIs associated with the control circuits of the other Unit 2 MSIVs. The

testing did not reveal any other failed DOIs.

During replacement of the failed DOI, technicians incorrectly isolated the component and caused the MSIVs for the other three SGs to close. Control room operators manually cycled SG Power Operated Relief Valves (PORVs) to relieve the resulting pressure increase. The technician had jumpered around the input of the failed DOI, which was in series with three DOIs associated with the other SG's MSIVs. Instead of jumpering around the output, the technician isolated it, which disrupted the circuit and caused the other three MSIVs to close.

The controlling procedure for the DOI replacement was IP/0/A/3840/003, "Calibration, Checkout, and Replacement of Optical Isolators," Revision 11. Prerequisite 4.1 of the procedure directs the technician to review drawings, details, manuals, procedures, and other reference material as necessary. Implicit in the prerequisite is that these activities be performed correctly. The inspector interviewed the technician performing the replacement activities, who indicated that he had misread a connection diagram when developing the DOI replacement plan.

The error was self-revealing, affected the safety-related control circuits of three MSIVs, caused the MSIVs to close, and induced a SG pressure transient that required manual mitigation by control room operators. Therefore, this failure to correctly develop a DOI replacement plan and to perform DOI replacement activities in accordance with the controlling procedure is identified as a violation of TS 6.8.1. Violation 50-414/97-11-02: Failure to Correctly Develop a DOI Replacement Plan and to Perform DOI Replacement Activities in Accordance With the Controlling Procedure.

The licensee sent the failed DOI to the Qualification and Testing Facility at the McGuire Nuclear Station to determine which subcomponent caused the failure. Unit restart commenced on July 28.

Second Manual Trip

On August 17, the D SG MSIV failed closed. The OATC manually tripped the reactor in response to indications that the MSIV had closed, and a FIP team was organized to investigate the cause of the MSIV failure. The licensee reported the manual actuation of the RPS in accordance with 10 CFR 50.72.

An Auxiliary Feedwater (AFW) system auto-start signal was generated when the OATC was manually cycling the SG PORV to relieve pressure and controlling D SG level to avoid overcooling of the loop. The Unit 2 SG lo-lo level setpoint for AFW auto-start, which is an Engineered Safety Features (ESF) actuation, is 37 percent. The controlling procedure, EP/2/A/5000/ES-0.1, "Reactor Trip Response Procedure," Retype Number 11, does not provide specific guidance for controlling SG level above the lo-lo level setpoint for AFW actuation. The OATC decided to control the

D SG level at 38 percent.

Although manual cycling of the PORV was proactive, executed in anticipation of an automatic action and performed in accordance with applicable procedures and management expectations, the resulting change in SG inventory caused SG level to drop to the AFW autostart setpoint. Controlling SG level so close to the setpoint contributed to an unnecessary ESF actuation and associated minor post-trip complications. The ESF actuation generated an auto-start signal to the AFW pumps (which were running at the time) and caused the AFW flow control valves to fully open. The OATC throttled the flow control valves back, and no appreciable Reactor Coolant System (RCS) cooldown resulted. The licensee included the ESF actuation in the 10 CFR 50.72 report for the manual RPS actuation.

The inspector questioned the appropriateness of controlling SG level so close to the lo-lo level setpoint and discussed the question with Operations management. Operations management asserted that the OATC was operating the plant in accordance with procedures. When questioned about expectations for preventing unnecessary ESF actuations, Operations management expressed an expectation that ESF actuations should be avoided. Operations management indicated that some procedural enhancements and augmented training would be considered and addressed accordingly in station PIP 2-C97-2684.

The FIP team investigating the MSIV closure determined that the other DOI in the seal-in circuitry associated with the MSIV's "Open" pushbutton had degraded. The voltage across the DOI met the acceptance criteria during the test using a Fluke multimeter. However, over time, spikes in the output voltage were detected by the Fluke multimeter. An oscilloscope was used to perform an extended test to confirm this behavior. Engineering personnel speculated that a spike in voltage had caused resistance to increase and a downstream, normally energized relay to de-energize; thereby opening the seal-in circuit associated with the "Open" pushbutton.

The licensee replaced the degraded DOI and successfully tested its replacement. In light of the earlier DOI failure in the MSIV circuit on July 26, the licensee also planned to conduct an extended test of the DOIs associated with the other Unit 2 SG MSIVs.

A restart Plant Operations Review Committee (PORC) meeting was conducted via teleconference on the evening of August 17; the inspector was present via telephone. Potential causes of the DOI failure, including environmental conditions, degraded power supplies, and defective components or manufacturing processes, were discussed. Engineering personnel indicated to the PORC that a root cause of the DOI failures had not been determined and that the vendor was not available for assistance. Engineering personnel recommended extended testing of the Unit 1 MSIV DOIs and subsequent weekly testing of all MSIV DOIs until a

root cause of the DOI failures could be determined.

The PORC recommended that the remaining Unit 2 MSIV DOIs be tested and that unit restart commence contingent upon successful test results; the station manager approved the recommendation. The inspector raised concerns about restarting the unit when: (1) the root cause of the DOI failures had not been determined; (2) common cause failure had not been ruled out; and (3) the licensee had not involved the vendor in its investigation of the second MSIV DOI failure. The licensee delayed restart to replace five DOIs in the other Unit 2 MSIV control circuits that had the same dates stamped into the components as those that had failed.

A second restart PORC was conducted on August 18. Since the first restart PORC, the licensee had: (1) ruled out certain potential root causes; (2) developed a testing plan with formal testing procedures and test acceptance criteria for online testing of the MSIV circuits; (3) begun to address generic implications for similar DOIs in critical control applications other than MSIV circuits; (4) determined that a failed resistor had caused the MSIV DOI to fail; and (5) contacted Performance Improvement International to arrange for a component failure analysis. The PORC recommended unit restart, and the recommendation was approved. Unit restart commenced on August 18. Both manual reactor trips and the ESF actuation associated with the second manual trip were documented in LER 50-414/97-06, which was submitted to the NRC on August 25, 1997. (Details of the failure history of DOIs and the licensee's root cause investigation are discussed in Section E2.1. of this Inspection Report.)

c. Conclusions

Two manual Unit 2 reactor trips were initiated in response to DOI failures that caused the D SG MSIV to close. The failure to correctly develop a DOI replacement plan and to perform DOI replacement activities in accordance with the controlling procedure was identified as a violation. Following the second manual reactor trip, the OATC's decision to control the D SG level within 1 percent of the lo-lo level setpoint for AFW auto-start contributed to an unnecessary ESF actuation and associated minor post-trip complications. The inspector raised concerns regarding the PORC's initial recommendation that Unit 2 was prepared for restart contingent upon successful DOI test results. However, the subsequent decision to delay restart to replace potentially implicated components that had the same date stamp as the failed components was appropriate. Efforts to obtain additional information on the DOI failures and develop a strategy and procedures for online testing of the MSIV DOIs until a root cause could be determined, were also considered appropriate.

O2.1 Observed Plant Operational Conditions

a. Inspection Scope (71707)

The inspector conducted several tours of selected areas of the plant. Areas or components observed included:

- Unit 1 and Unit 2 Main Turbine Decks
- Unit 1 and Unit 2 Main Feed Pumps
- Unit 2 Condensate Booster Pumps
- Unit 1 and Unit 2 Hotwell Pumps
- Instrument Air Compressors
- Unit 1 and Unit 2 Condenser Waterbox Areas
- Unit 2 Heater Drain Pumps
- Unit 1 Emergency Diesel Generators
- Unit 1 and Unit 2 Vital Inverters
- Unit 1 Emergency Shutdown Boards

b. Observations and Findings

The inspector observed that housekeeping in most plant areas toured was good. In addition, most of the operating and standby equipment appeared to be in good material condition. However, oil leaks were noted on the Unit 1 and 2 hotwell pumps and the Unit 2 condensate booster pumps. Also, minor water leakage was noted for both the Unit 1 and Unit 2 condenser waterboxes where the waterboxes attach to the condenser. The inspector noted a body to bonnet leak on Valve 2-HW-65 (2C1 Heater Drain Tank Pump Recirculation Line Control Valve). Operators had identified this leak as a packing leak. After questioning by the inspector, operators reclassified the leak as body to bonnet.

c. Conclusions

During plant tours, operating and standby equipment appeared to be in generally good material condition. However, observed material condition of some balance of plant equipment indicated a need for additional maintenance attention.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation (VIO) 50-413/95-16-01: Inadequate Operating Procedure for Reestablishing Normal Letdown Resulting in a Water Hammer

The violation cited an example where a procedure failed to maintain proper system configuration and led to a challenge of the letdown system. The inspector reviewed the licensee's violation response dated August 31, 1995, which addressed the procedural inadequacy, control of troubleshooting activities, and management and engineering review needed to implement troubleshooting activities. Through review of the corrective action documentation (PIP 1-C95-058), the inspector verified that the licensee revised procedures for establishing letdown, required management approval prior to opening the most risk significant valves in the letdown system, and communicated expectations to Operations Shift Managers for including engineering for independent review and obtaining station management concurrence for troubleshooting plans.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspector observed and reviewed complete test documentation for all or portions of the following work activities:

- PT/1/A/4350/02B — DIESEL GENERATOR 1B OPERABILITY TEST, performed on August 26, 1997
- PT/1/A/4350/02B — DIESEL GENERATOR 1B OPERABILITY TEST, performed on August 27, 1997

b. Observations and Findings

The inspector reviewed the surveillance packages and discussed the test activities with operations personnel. The inspector noted the work instructions were appropriately filled out and functional testing accomplished as required. The procedure provided clear instructions to accomplish the work activity. On August 26, after the 1B EDG was loaded to approximately 5700KW, the output breaker from the EDG tripped open due to a high current condition. This issue is further discussed in section M1.2 of this report. After corrective actions were accomplished for PIP 1-C97-2796, the 1B EDG was tested in accordance with PT/1/A/4350/02B on August 27, 1997. No deficiencies were noted.

c. Conclusions

The inspector concluded the testing of the 1B EDG was conducted in a good manner. The procedure provided clear instructions and operations personnel conducting the test performed the evolutions in a thorough and professional manner.

M1.2 Unit 1 B Emergency Diesel Generator (EDG) Output Breaker Trip During Testing

a. Inspection Scope (62700)

The inspector monitored licensee activities associated with emergent work order generation, EDG troubleshooting, and subsequent corrective maintenance associated with the subject problem.

b. Observations and Findings

The inspector was observing testing of the 1B EDG when the output breaker tripped open. The initial indication of the cause of the trip was an overcurrent condition (Instantaneous Overcurrent Trip Relay 50DTG) caused by loss of control of the machine load (drift). Operators exited the test and shut down the machine. A work order (W/O 97074038) and PIP 1-C97-2796 was written to commence troubleshooting of the problem.

During the next 24 hours, the licensee conducted troubleshooting activities to determine the cause of the overcurrent condition. A Failure Investigation Process (FIP) team was established to perform a root cause evaluation. Troubleshooting testing was performed using procedure OP/1/A/6350/02, "DIESEL GENERATOR OPERATION" during the afternoon of August 26, and again during the morning of August 27, 1997. Maintenance activities were conducted between the troubleshooting tests. Maintenance activities included:

- W/O 97074038-06 TEST 50 DGT RELAY
- W/O 97074038-07 CHANGE OIL IN GOVERNOR

The inspector monitored troubleshooting activities including EDG troubleshooting test runs and reviewed completed documentation for the maintenance activities.

The FIP team used a list of possible failure modes (causes) for both the drift and overcurrent conditions experienced during testing. These possible causes were documented along with a discussion of each. Although the problem could not be repeated and no root cause could be found, the FIP team determined the apparent cause of the event was an intermittent bad connection on the motor operated potentiometer (MOP) which was used to control EDG speed during testing. The FIP team

concluded the MOP problem would not affect EDG operation because the MOP returned to the 60 hertz position after each test run and/or initiation of an emergency start. The FIP team review process and apparent cause was presented at a Plant Operations Review Committee (PORC) meeting on August 28, 1997. The PORC agreed that EDG 1B could be returned to an Operable status.

The inspector discussed the findings with FIP team members and attended the PORC meeting on August 28, 1997. In addition, the inspector reviewed the FIP team notes, the PIP evaluation, and the PORC minutes. The inspector also reviewed applicable licensee Elementary Generator Control Panel Electrical Schematic Diagrams and independently verified from the diagrams that the POT would return to the 60 hertz position after each test run and/or initiation of an emergency start. During discussions with the licensee, the inspector questioned whether disassembly of the POT would have provided any additional information which could support their apparent cause. The licensee did not consider this action was necessary at this time.

c. Conclusions

The inspector concluded the evaluation of the EDG output breaker trip problem and troubleshooting was conducted as required by licensee procedures and processes. In addition, the FIP provided a methodical method for cause determination. However, only an apparent cause was identified.

M1.3 Emergency Diesel Generator (EDG) Turbocharger Bolt Failure

a. Inspection Scope (61726)

On August 19, during performance of semi-annual Preventative Maintenance (PM) to check the torque on the 2B EDG turbocharger mounting bolts, the licensee identified a broken bolt from the EDG turbocharger mounting bracket. A similar failure of three mounting bolts for the same turbocharger had occurred in September 1995, resulting in Violation 50-413,414/95-20-01: Inadequate Incorporation of Vendor Information Into Diesel Generator Maintenance Instructions. The inspector reviewed the previous violation, PIPs 2-C95-1495 and 2-C97-2713, the metallurgical analysis report associated with the previous failures, and turbocharger mounting drawings and specifications. The inspector also discussed this issue with engineering personnel.

b. Observations and Finding

The inspector reviewed the September 1995 event to understand the mounting bolt failure mechanism and the corrective actions that were implemented to prevent recurrence. The metallurgical examination of the three bolts that had failed revealed that the bolt failures were caused by vibration-induced fatigue cracking resulting from loosening of the

bolts. The bolts loosened because no locking device had been installed. Lock washers were specified to be used as shown on the vendor's mounting diagrams. As a corrective action, the licensee generated Minor Modification CNCE-7308 and procedure changes to provided for installation of flat washers and lock washers in accordance with vendor recommendations, and the use of a support plate. The support plate was installed to accommodate elongated mounting bracket holes. Support plates were not required, but could be used as deemed necessary by maintenance personnel performing maintenance on the turbochargers . Support plates had not been installed on the turbocharger bank that had the bolt failures, but had been installed on all the other EDG turbochargers.

After the failed bolt was identified during a torque pass PM on the 2B EDG right-bank turbocharger on August 19, all four mounting bolts were removed and replaced with new bolts. The failed bolt and the other three mounting bolts were sent for metallurgical analysis. The resident visually verified that support plates were not installed on the 2B EDG right-bank, unlike the other seven inservice turbochargers. Licensee evaluation determined that the failure of a single mounting bolt did not affect the operability of the 2B EDG. Subsequent to the review of PIP 2-C95-1495 (which documents the original bolt failures) and of listed possible causes, the inspector questioned engineering personnel about the loading of the mounting bolts and the adequacy of bolt thread engagement. The bolt torque had been increased as a corrective action for the 1995 failures from 60 ft-lbs to 75 ft-lbs. However, adequate bolt loading may not exist if the mounting bolt is bottomed out in the turbocharger casing. If this condition is present, it could cause the bolt to loosen. Engineering personnel indicated that no calculations had been performed to determine the adequacy of actual bolt loading or thread engagement.

c. Conclusions

Once completed, the metallurgical analysis should reveal if this repeat failure occurred from high-cycle vibrational fatigue cracking, which was the previous failure mechanism. The inspector will review the completed metallurgical analysis and the licensee's root cause determination to determine if the root cause and corrective actions for the previous failures should have prevented recurrence. Pending the completion of the licensee's root cause analysis, this item is identified as Unresolved Item 50-414/97-11-03: Failure of 2B EDG Turbocharger Mounting Bolt.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Moisture-Induced Corrosion of Nuclear Service Water Pump Motor Breaker

a. Inspection Scope (62707)

On July 22, the licensee identified moisture in the switchgear cubicle associated with the 2B Nuclear Service Water (NSW) pump motor. The licensee determined that the moisture originated from condensation that had developed on the inner surface of the cable conduit housing the pump motor leads. The inspector discussed the condition of the breaker with engineering personnel, inspected the motor breaker cubicle, traced the conduit line from the breaker cubicle to the adjacent room, and reviewed station PIP 0-C97-2368. The inspector also discussed the generic implications of the condensation dynamics with engineering personnel.

b. Observation and Findings

During preventive maintenance activities on the 2B NSW Pump Motor, the licensee identified condensation in the pump motor breaker cubicle. Maintenance personnel determined that water had been entering the breaker cubicle from the cable conduit at the top of the cubicle over a period of time. A high potential (Hi Pot) test was performed to determine if the cable had degraded. The initial test was unsuccessful. The motor leads were disconnected, and the connections were cleaned. The Hi Pot test was performed again, and the results were good.

The licensee determined that condensation had been forming inside the cable conduit for the NSW pump motor leads. The conduit exits the breaker cubicle, runs the length of the switchgear room ceiling, and enters a pullbox in the 2B EDG Sequencer hallway. Engineering personnel speculated that warm, humid air had migrated through the conduit from the EDG Sequencer hallway into the cool, air-conditioned essential switchgear room. A ventilation duct vent located above the breaker cubicle was blowing cool air onto the conduit just above the cubicle, exacerbating the condensation of moisture in the air.

The other three NSW pump motor breakers were inspected for condensation, and moisture was also discovered inside the 1B NSW pump motor breaker cubicle. Immediate corrective actions were taken to clean and dry the 1B and 2B NSW pump motor breaker cubicles and block air flow from the ventilation duct that was blowing directly onto the conduit. Water samples were take for chemical analysis to verify that the water was condensation and not from another source. Past and present operability evaluations, documented in PIP 0C97-2368, determined that the 2B and 1B NSW pump motor breakers were and had been operable. Corrective actions to seal the conduit to prevent the migration of warm, moist air through the conduit and into the switchgear room were implemented via work orders (WO) 97063728-05 (for Unit 1) and 97062900-01 (for Unit 2). The inspector verified that the tasks associated with the work were completed.

The inspector asked engineering personnel if the electrical breaker cabinets associated with other vital equipment were susceptible to a similar condensation dynamic. The response was that armored cabling was used to house the motor leads of the other vital components in the switchgear rooms, and that the use of conduit was specific to the NSW pump motor breakers. Since armored cabling is insulated and no air space exists between the cabling and the armored conduit, the potential for condensation is very low.

c. Conclusions

The licensee's evaluation to determine the root cause of condensation in the 1B and 2B NSW pump motor breaker cubicles was thorough, and corrective actions to prevent recurrence were appropriate.

M7 Quality Assurance in Maintenance Activities

M7.1 Missed Technical Specification Surveillance Requirements

a. Inspection Scope (61700)

The inspector reviewed licensee identified issues associated with inadequate testing of both units solid state protection system (SSPS) P-11 function and the Unit 2 SSPS P-13 function.

b. Observations and Findings

The licensee identified, during a review of operating experience reports, that some plants were not adequately testing, on a quarterly basis, the SSPS P-11 function. This issue was identified at another plant as part of the other plant's Generic Letter 96-01 (GL), "TESTING OF SAFETY-RELATED LOGIC CIRCUITS" dated January 10, 1996, review. The Catawba Instrumentation and Controls (I&C) surveillance procedures, (Analog Channel Operational Tests, ACOTs) were reviewed and found to be inadequate in that they were not testing the SSPS P- function as required by Technical Specification 3.3.2. The licensee wrote PIP 0-C97-2554 to resolve the issue. Further review of other circuits determined that Unit 2 SSPS P-13 testing had not been conducted in a condition that adequately tested this function as required by TS 3.3.1 due to the testing being moved to an operational (innage) window instead of testing being accomplished during an outage window. PIP report 0-C97-2646 was written to address this potentially generic problem.

The inspector reviewed corrective actions documented in PIPs 0-C97-2554 and 0-C97-2646. He also reviewed procedure IP/2/A/3222/000B, "ANALOG CHANNEL OPERATIONAL TEST CHANNEL II 7300," Revision 52 which was performed on August 26, 1997, and verified the P-11 interlock was appropriately tested based on corrective actions for PIP 0-C97-2554. The inspector discussed the corrective actions for these issues and the process used to conduct the GL 96-01 review at Catawba with licensee

engineering and management personnel on August 28, 1997. The licensee noted that several enhancements to procedures were identified during the reviews and considered the review process was thorough and detailed. However, the problems discussed above were not identified as part of the GL 96-01 review process.

The inspector reviewed a portion of GL 96-01 which requested, in part, that licensee's "Compare electrical schematic drawings and logic diagrams for the reactor protection system, EDG load shedding and sequencing, and actuation logic for the engineered safety features systems against plant surveillance test procedures to ensure that all portions of the logic circuitry, including the parallel logic, interlocks, bypasses and inhibit circuits, are adequately covered in the surveillance procedures to fulfill the TS requirements." The inspector reviewed the licensee's responses to the NRC for GL 96-01 dated April 17, and May 20, 1997. The April 17, 1997, response stated, in part, that "Duke Power will initiate a program that implements the requested actions of GL 96-01. This program will include a comprehensive review of each station's logic diagrams and surveillance test procedures to ensure that all portions of the logic circuitry are tested such that the Technical Specifications requirements are fulfilled." The May 20, 1997, response stated, in part, "the purpose of this letter is to confirm the completion of the requested actions of GL 96-01 on Catawba Units 1 and 2. The review program that was recently completed on Catawba Units 1 and 2 confirmed that all portions of the effected logic circuitry were being tested such that the existing station Technical Specifications were fulfilled."

Although the inspector considered the licensee's review of electrical schematic drawings was methodical, the review process did not identify the P-11 problem, or at that time, the potential problem associated with P-13. Code of Federal Regulations 10 CFR 50, Appendix B, Criterion XVI requires, in part, measures shall be established to assure that conditions adverse to quality, such as deficiencies, deviations, and nonconformances are promptly identified and corrected.

The inspector considered that licensee actions for GL 96-01 which were completed May 20, 1997, did not identify the P-11 problem. This problem was identified after the licensee's review of an operating experience report from another plant which was documented in PIP 0-C97-2554 on August 4, 1997. Also, the GL 96-01 review did not identify the P-13 problem which was documented in PIP 0-C97-2646 on August 13, 1997. This is identified as a Violation 50-413,414/97-11-05: Failure to Identify Conditions Adverse to Quality and Take Corrective Actions During Reviews in Accordance With GL 96-01.

The inspector noted the licensee took required corrective actions for each TS violation identified.

c. Conclusions

A violation was identified for failure to identify conditions adverse to quality and take corrective actions during reviews in accordance with GL 96-01.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) VIO 50-413,414/95-20-01: Inadequate Incorporation of Vendor Information Into Diesel Generator Maintenance Instructions

The violation was issued because of a failure to incorporate vendor information into maintenance instructions (procedures), which allowed the introduction of a common mode failure (i.e., broken turbo charger mounting bolts) to the Unit 1 and 2 EDGs. As indicated in Inspection Report 50-413,414/95-20, maintenance procedures were revised to include a lockwasher configuration for mounting the turbochargers to the diesel engines. In addition, a modification was implemented to allow for an alternate mounting configuration. The inspector reviewed the licensee's initial response, dated December 4, 1995, and a supplemental response, dated December 21, 1995, which addressed broader corrective actions to ensure continued reliability of the Catawba EDGs. The inspector verified these actions were performed. As addressed in Section M1.3, another failure of an EDG turbocharger mounting bolt was identified subsequent to the licensee's corrective actions. This subsequent failure and its reflection on previous corrective action adequacy will be followed up under URI 50-414/97-11-03. Accordingly, Violation 50-413,414/95-20-01 is closed.

M8.2 (Closed) URI 50-413,414/94-17-04: Overpressure Protection for Service Water (RN) Pumps

The issue involved additional review of the licensee's administrative controls for precluding the addition of heat to RN pump motor and upper bearing coolers when the cooling system was isolated for maintenance. The ASME Code section discussing overpressure protection allows for positive controls and interlocks. The inspector reviewed applicable sections of the following licensee processes to verify appropriate positive controls were in place:

- NUCLEAR SERVICE WATER SYSTEM OP/0/A/6400/06C, "VALVE CHECKLIST OUTSIDE CONTAINMENT," Units 1 and 2
- NUCLEAR SERVICE WATER PREPLANNED TAGOUT LISTINGS
- ANNUNCIATOR RESPONSE PROCEDURES FOR RN MOTOR OPERATION
- NUCLEAR SERVICE WATER SYSTEM DESIGN BASIS SPECIFICATION SPEC. CNS-1754.RN-00-0001, Revision 11

- FLOW DIAGRAMS FOR RN SYSTEM
- PIP 0-C94-1084

The inspector determined the licensee used appropriate positive controls and/or interlocks to ensure overpressure protection for the motor and upper bearing coolers for the RN pumps. This issue is considered closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Engineering Activities to Determine Root Cause For Digital Optical Isolator (DOI) Failures that Resulted In Two Reactor Trips

a. Inspection Scope (37550)

A regional based inspector was dispatched to the Catawba site on August 19, 1997, to inspect the facility's plans for determining the root cause for two DOI failures that occurred in Unit 2 on July 26 and August 17, 1997, which resulted in Main Steam Isolation Valve (MSIV) closure events and subsequent manual reactor trips.

b. Observations and Findings

Background

The Unit 2 MSIV closure events that occurred on July 26, and August 17, 1997, involved failure of one of two safety related "QA Condition 1" DOIs in the control circuitry for the 2SM-1 MSIV associated with steam generator 2D. The licensee had documented the two events on Problem Investigation Process (PIP) reports 2-C97-27681 and 2-C97-2422, respectively. Both events involved failures of E-max Model number 175C156 DOIs with ac input and dc output, and a manufacturer's date code of 8/95. The inspector found that the Failure Investigation Process (FIP) team was being directed by Instrumentation and Control (I&C) Engineering. The preliminary results of the Engineering investigation had concluded that the failures resulted from failure of a 20,000 ohm (5 percent), 2 watt, metal film resistor that was mounted in the Model 175C156 DOI circuit board. This resistor was identified as R1 on the DOI schematic drawings.

The DOI that failed on July 26, 1997 had undergone evaluation and failure analysis testing at the Duke Qualification and Testing Facility just prior to the occurrence of the second DOI failure on August 17, 1997. The failed DOI circuit board components were inspected and the R1 resistor was discovered to have a brownish discoloration on the component body and visible cracks in the ceramic coating. Subsequently, the R1 resistor was removed from the DOI circuit board and its resistive

measurements were taken. The measurements showed the resistance was either infinite or an open circuit condition existed. The R1 resistor was replaced with a new resistor, and the DOI tested satisfactorily in accordance with design. The Duke Qualification and Testing facility issued an evaluation report on the test results (documented in Memo To File No. EV-190 dated July 30, 1997), that indicated the failure of resistor R1 was a random component failure caused by aging from heat dissipation and mechanical stresses, and should not be classified as a manufacturing defect.

The R1 resistor on the second DOI failure also was found to be discolored. The licensee observed that both failed DOIs had the same manufacturer's date code of 8/95. Accordingly, the licensee replaced five other critical DOIs installed in the Unit 2 MSIV circuitry that had the same 8/95 date code. The R1 resistors in these other five DOIs with 8/95 date codes also showed signs of discoloration.

The licensee shipped the two failed isolators and one "good" isolator with the 8/95 date code to an outside testing facility to conduct further failure analysis. The licensee had also scheduled an audit of the vendor (E-Max) to be performed on August 25, 1997. The licensee was informed by the vendor that the supplier and the design of resistor R1 had changed in the new replacement isolators installed in 1995. Visual examination by the licensee and also by the inspector of an older E-Max Model 175C156 DOI revealed that the new replacement resistor R1 was physically much smaller in size than in the older models. The inspector noted that other internal components were also different in both size and color. However, the significance of these differences was not known by the licensee.

Review of Procurement Documentation

The procurement documentation (i.e., purchase orders, packing slip, Duke supplier verification release, Receiving Inspection Report, and vendor certificate of compliance) was reviewed for the subject DOIs and was acceptable. The inspector found that the E-Max DOIs were procured as safety-related components in accordance with Duke's "QA Condition 1" procurement classification and purchase Specification No. CNS-1338.00-00-0001, "Optical Isolation Device," Revision 10, dated January 24, 1995. The vendor provided a certificate of compliance that certified the devices were manufactured and tested in accordance with the referenced specification.

The inspector found that the vendor was on the approved vendor list; however, the licensee informed the inspector that, at the time the failed DOIs were being manufactured, restrictions had been placed on the vendor as a result of a Quality Assurance (QA) audit finding regarding a failure to follow procedures in processing Engineering Change Orders and their failure to implement timely corrective action for the audit finding. A subsequent audit and surveillance verified that the vendor

had corrected the problem, and the restriction was removed.

Review of Design Specifications for DOIs

The inspector reviewed the electrical, environmental, and mechanical specifications discussed in the DOI vendor manual and found them to be consistent with the performance requirements outlined in Duke's Specification No. CNS-1338.00-00-0001. However, the inspector questioned whether the DOIs were designed to operate continuously at the maximum abnormal temperature limit of 140 degrees Fahrenheit as described in the manual, or were they designed to operate for only 8 hours as discussed in the specification? The specification required the units to be designed to satisfactorily operate at an abnormal temperature of 140 degrees Fahrenheit for 8 hours. The technical manual indicated the DOIs could operate in a temperature band of 32 degrees Fahrenheit to 140 degrees Fahrenheit with no limits being placed on DOI operation at the maximum abnormal temperature of 140 degrees Fahrenheit. Engineering was not aware of the discrepancy and did not know if the temperature band described in the technical manual was for continuous operation of the DOIs at 140 degrees Fahrenheit. The inspector noted that newly manufactured units received a 100 hour burn-in test by the vendor at 60 degrees Celsius (140 degrees Fahrenheit) as part of the factory acceptance test. Later the licensee learned from the vendor that the DOIs were qualified only to operate for 8 hours at 140 degrees Fahrenheit and that the vendor manual would need to be clarified to indicate that this was not a continuous rating.

Walkdown of MSIV DOIs

The inspector, accompanied by engineering personnel, inspected both Unit 1 and 2 MSIV DOIs. Both the Unit 1 and 2 MSIV DOIs are located in a common room in the auxiliary building that was ventilated with outside air, but was not air conditioned. The Unit 1 DOIs were mounted in Panel 1SMTC1, and the Unit 2 MSIV DOIs were mounted in Panel 2SMTC1. Both panels were several feet apart. The inspector touched the housing of some of the energized DOI modules on both units and found them to be warm from self-heating effects as expected. The licensee had evaluated the internal heat rise in the DOIs and determined that it should be no more than 10 degrees Fahrenheit above ambient temperature inside the panel. The electrical grounding of the panels was observed, and no noticeable concerns were identified. The internal wiring and general housekeeping inside the panels looked good. The licensee indicated to the inspector that the Unit 2 MSIV DOI circuitry had been checked for power quality and ground problems; no problems were identified.

Failure History Trends of E-Max Digital Optical Isolators

The inspector found that there have been a total of three DOI failures in the Unit 2 MSIV control circuitry. These failures caused MSIV closure events on two different MSIVs. The first E-Max DOI failure

occurred in February 1995. The licensee, in conjunction with the vendor, determined that the root cause was a failure of capacitor C4, which had reached the end of its service life. The corrective actions taken at that time were to upgrade the C4 capacitor with a more reliable capacitor; replace the DOIs with old capacitors in MSIV circuitry and other identified critical control circuits; and implement a PM program to replace those DOIs every 12 years based on the manufacturer's date code. The Unit 2 MSIV DOI failures that occurred on July 26 and August 17, 1997, involved the new replacement DOIs with the new capacitors. Overall, the inspector found that there had been 5 failures of the DOIs with new capacitors. The other three failures involved different model numbers (two failures of Model 175C180 and one failure of Model 175C157). The root cause for one of the two failures of Model 175C180 was a failure of resistor R3. The remaining two failures were considered random, and a root cause investigation had not been performed by the licensee.

The inspector was informed that there were approximately 5700 DOIs included in the Catawba design. Approximately 4800 were in indication circuits, and 900 were in control circuits. This breakdown between control and indication was considered significant from the standpoint of which isolators were included in the PM program. The DOIs in indication circuits were not included in the PM program for replacement and were identified by the licensee as "run to failure." Approximately 432 of the 900 DOIs in control circuits were in the PM program; the remaining 483 DOIs were also considered as "run to failure."

The licensee indicated that the failure thresholds or goals for DOI failures were 0.128 percent per quarter for control failures and 0.521 percent per quarter for indication failures. The licensee also indicated that if the failure goals were exceeded, a corrective action plan or root cause analysis would be developed. The Failure Analysis and Trending System Reports for 1997 were reviewed for DOI control and indication failures. The trend report for the second quarter of 1997 provided the average failure rate for the past six quarters for the population of both control and indication DOIs. The average quarterly failure rate for the DOIs was 0.06 percent in control applications and 0.29 percent for DOIs in indication applications. As these failure rates were below the established goal rates, Engineering assessed them as being acceptable.

Corrective Actions

The short-term corrective actions taken and or planned by the licensee included testing the Unit 1 MSIV DOIs; developing a test procedure and conducting weekly testing of the Unit 1 and 2 MSIV DOIs (32 total); and performing one-time testing of 57 other DOIs that were in critical control circuits for a total of 89 isolators to be tested. The licensee indicated that the testing would be completed within 3 to 4 weeks.

c. Conclusions

The licensee's planned and completed actions to determine the root cause for the failure of the E-max digital optical isolation devices were adequate. The licensee took conservative steps by replacing five additional Unit 2 MSIV DOIs that had the same manufacturer's date code as the two that previously failed.

E2.2 Ice Condenser Door Operability

a. Inspection Scope (37551)

On July 18, the McGuire Nuclear Station (MNS) made a 4-hour 50.72 notification to the NRC when they determined that 10 of 48 ice condenser lower inlet doors in Unit 2 would not open within the allowable TS torque limit. The apparent cause of the door failures was attributed to heaving of the ice condenser floor and subsequent binding of the doors. Engineering personnel at the Catawba Nuclear Station (CNS) evaluated the potential for a similar problem at CNS. The inspector reviewed drawings of the ice condenser, discussed the issue with licensee personnel and NRC inspectors at MNS, and reviewed work orders and ice condenser refrigeration system diagrams.

b. Observations and Findings

Several operational events were identified at MNS during which ice may have melted and the resulting water seeped into the foam concrete layer of the ice condenser floor, froze, and caused the floor to expand and heave. In addition to the operational events, the licensee also discovered that undetected floor cooling system degradation occurred as a result of instrument drift. (See Inspection Report 50-369,370/97-16 for more details.)

In response to the adverse condition of the Unit 2 ice condenser at MNS, Catawba Engineering personnel evaluated the potential for conditions that have caused or would have caused water to seep into the foam concrete layer of the ice condenser floor. A Loss Of Offsite Power (LOOP) event occurred on Unit 2 in February 1996. A Safety Injection during the event caused the pressurizer PORVs to lift, and the rupture disk on the pressurizer relief tank (PRT) eventually ruptured, releasing steam into containment. The ice condenser system engineer indicated that he had obtained temperatures of the ice condenser floor after the PRT had ruptured during the LOOP event, and that floor temperature had not increased above freezing. To the licensee's knowledge, no other operational events have occurred that could have caused the damage incurred at MNS.

The system engineer indicated that non-licensed operators verify flow through the floor cooling loop on a weekly basis during containment building rounds. The inspector verified that this was true. A flow

gauge indicates flow rate from the floor cooling coil discharge header of the ice condenser refrigeration system. The licensee also initiated work orders (WOs) to provide for visual inspection of the Unit 1 and Unit 2 ice condenser floors at the next available opportunity. A visual inspection of the Unit 2 floor was performed during the forced outage following the MSIV failure and manual reactor trip on August 17. Licensee personnel inspected the concrete floor under the lower inlet door hinges and around the clevis located at the ends of the turning veins. No cracks were found. The inspection included verification that a gap existed between the lower inlet doors and the flashing just above the floor. No discrepancies were identified other than a need to replace caulking around some concrete joints. The inspection results were documented in the task completion comments for WO 97064768-01. Inspection of the Unit 1 ice condenser floor is on the forced outage list to be performed under WO 97064769-01.

c. Conclusions

The inspector concluded that communication between MNS and CNS regarding the degraded condition of the ice condenser floor was prompt. Based on the licensee's inspection of Unit 2 and review thus far, this issue does not appear to be a problem at Catawba. Inspection of the Unit 1 ice condenser has been placed on the licensee's forced outage list.

E2.3 Identification of Aluminum in Containment in Excess of Assumed Volume

a. Inspection Scope

A concern was identified at McGuire Nuclear Station (MNS) when the licensee discovered that the square footage surface area of aluminum inside containment was higher than assumed in the UFSAR. Engineering personnel in the licensee's General Office evaluated the applicability of the concern to Catawba Nuclear Station and documented the results of the evaluation in PIP Q-C97-2602. The inspector discussed the issue with Engineering personnel and reviewed their UFSAR, Design Basis Documentation, and PIP.

b. Observations and Findings

During a review of the Containment Purge Ventilation (VP) System, which is a non-nuclear safety related system at MNS, engineering personnel discovered that the High-Efficiency Particulate Air (HEPA) filters and prefilters used in the lower containment filtration units contained aluminum separators, which provide structural support to the filters. The engineers calculated the total surface area of aluminum associated with these units (13,186 square feet) and determined that it exceeded the surface area assumed in the UFSAR (1,500 square feet). During certain design basis accidents, the aluminum is assumed to interact with the acidic reactor coolant system water, which can cause corrosion of aluminum and generate hydrogen, a combustible gas. In sufficient

concentrations, hydrogen can deflagrate (a challenge to equipment) or detonate (a challenge to containment integrity). The MNS finding was immediately shared with CNS engineering personnel, who evaluated the potential for applicability to CNS and initiated PIP 0-C97-2602 to document their assessment.

Catawba's Containment Ventilation (VV) System has two Containment Auxiliary Carbon Filter Units (CACFUs). Each CACFU has six HEPA filters with aluminum separators, comprising 8,240 square feet of aluminum surface area. The FSAR limit for aluminum was 2,000 square feet of surface area. An engineering group at the licensee's corporate office re-evaluated the original calculation used to determine the allowable amount of aluminum in containment and the associated generation of hydrogen, and identified assumptions that were overly conservative. The licensee performed a calculation based on more reasonable assumptions and determined that the allowable aluminum in containment had increased from 2,000 to 10,000 square feet. The CACFUs contributed 8,240 square feet of aluminum, and other sources contributed approximately 800 square feet of aluminum. The licensee concluded that present levels of aluminum were within the revised allowable limits.

The inspector questioned the licensee why the aluminum in the CACFUs had not been recognized until the MNS finding was identified. Procurement Engineering personnel indicated that the original HEPA filters on the CACFUs did not contain aluminum separators. The original filter met the requirements of Specification CNS-1211.00-00-0003, Paragraph 5.5, which reads "Separators, if used, shall be 304 stainless steel." Since 1989, a different HEPA filter (Stock Code 85212) with aluminum separators has been used in accordance with Specification CNS-1211.00-00-0011, which applies to nuclear safety-related filters outside of containment. The 85212 filter had not been evaluated for the VV System CACFUs. The inspector inquired how a filter that is not intended nor appropriate for the CACFUs could be installed; thereby raising the concern that controls for ensuring appropriate materials are used in containment applications may not be effective or adhered to. To address the inspector's concern, the licensee initiated action to determine the root cause of the inappropriate material usage. Pending the completion of the licensee's evaluation, this issue is characterized as Unresolved Item 413,414/97-11-04: Use of Aluminum HEPA Filter Separators Inside Containment. The inspector will review the hydrogen generation calculations during followup inspection of this item.

c. Conclusions

The inspector concluded that the issue, which was identified at MNS, was communicated to CNS engineering personnel in a timely manner, and engineering support from the corporate office to determine the impact was responsive. A root cause evaluation to determine why inappropriate filters were used in the CACFUs was initiated. Pending the completion of a root cause evaluation, this issue is characterized as an unresolved item.

E8 **Miscellaneous Engineering Issues** (92903)

E8.1 (Closed) Unresolved Item (URI) 50-413,414/97-05-01: Non-Conservative SG PORV Technical Specification

This item was opened pending NRC approval of a license amendment to: (1) require four SG PORVs operable per unit; and (2) allow for the use of manual operator action to mitigate a SG tube rupture. On April 29, 1997, the NRC issued amendments 159 and 151 for Units 1 and 2, respectively, to require four (instead of three) SG PORVs to be operable. The use of local operation was credited in the event that remote operation is unavailable.

IV. Plant Support

R1 **Radiological Protection and Chemistry (RP&C) Controls**

R1.1 Ammonia Concentration Levels In Closed Cooling Water Systems

a. Inspection Scope (71750)

On July 21, station chemistry personnel determined that ammonia concentration levels for the several closed cooling water systems with copper-alloy heat exchanger tubes were in excess of the recommended limit of 0.5 parts per million (ppm). Corrective actions were taken to decrease the concentration of ammonia in the systems and determine the cause of the increase. The inspector discussed the issue with chemistry personnel, attended a management update on the issue, and reviewed associated PIP 0-C97-2527.

b. Observations and Findings

On July 21, station chemistry personnel determined that ammonia concentration levels for the Component Cooling Water (KC) System, the Control Area Chilled Water (YC) System, and the Emergency Diesel Generator Engine Cooling Water System (KD), were in excess of 0.5 ppm, the station limit.

Industry experience has indicated that stress-corrosion cracking of copper alloys is exacerbated by high concentrations of ammonia and dissolved oxygen. In 1995, the Institute for Nuclear Power Operations (INPO) provided information to the Nuclear Industry via a document titled "Good Practice CY-708, Treating and Monitoring Closed Cooling Water Systems." The phenomenon also is discussed in an EPRI document, currently in draft form, titled "EPRI Closed Cooling Water Guidelines." To minimize the potential for piping degradation, the Licensee's General Office imposed a 0.5 ppm limit for ammonia concentration in closed cooling water systems with copper alloy piping. The limit was based on information in "INPO Guideline for Chemistry at Nuclear Power Stations, 88-021," Revision 1, 1991. On July 21, the licensee determined that the ammonia concentrations in the YC and KD systems were 1.3 ppm and 0.7 ppm, respectively; ammonia concentration in the KC system was 0.96 ppm. Corrective actions were taken to feed and bleed the systems on a

periodic basis in an effort to decrease the ammonia concentrations. The sampling frequency was increased from quarterly to weekly to monitor the trend and verify that feed and bleed evolutions were effective in reducing ammonia concentrations. The licensee generated PIP 0-C97-2527 to document the issue and is pursuing six potential root causes of the ammonia level increase. Long-term corrective actions will be determined once the root cause has been identified.

c. Conclusions

The inspector concluded that the licensee's efforts to monitor ammonia concentrations in closed cooling water systems were proactive in minimizing the risk of stress-corrosion cracking of copper-alloy heat exchanger tubes. Appropriate actions were taken to reduce elevated levels of ammonia in these systems.

P8 Miscellaneous EP Issues (92904)

P8.1 (Closed) Deviation (DEV) 50-413,414/95-18-02: Control Room Habitability Discrepancies

The deviation cited several instances where the licensee did not comply with UFSAR commitments of Regulatory Guide 1.95, Protection of Nuclear Plant Operators Against an Accidental Chlorine Release (Revision 1, 1/77). The inspector reviewed the licensee's response dated September 28, 1995, which addressed corrective actions to reperform the analysis of the maximum credible onsite chlorine release based on existing quantities of chlorine stored onsite. Based on the result, the licensee determined that the control room breathing air apparatus was no longer required to meet Regulatory Guide 1.95 requirements and revised the UFSAR accordingly (refer to November 30, 1995 update). The licensee continues to maintain the breathing apparatus operational and has provided additional masks in various sizes in the main control room. The licensee has also added additional breathing air tanks and masks adjacent to the control room. The inspector considered the licensee's actions appropriate.

S1 Conduct of Security and Safeguards Activities (71750)

S1.1 Loss of Access to the Unit 2 Auxiliary Feedwater Pump Room and Auxiliary Shutdown Panels

a. Inspection Scope

On August 11, operations personnel were notified that the door to the Unit 2 auxiliary feedwater (AFW) pump room, which also contains the A and B train auxiliary shutdown panels, was inaccessible. Catawba Nuclear Site Directive (NSD) 3.1.4, Operational Response to Acts Directed Against Plant Equipment, Revision 0, was implemented to determine if tampering of the door locks was involved. The inspector discussed the issue with compliance and security personnel and reviewed NSD 3.1.4 and associated PIP 2-C97-2624.

b. Observations and Findings

On August 11, operations personnel were notified that the door to the Unit 2 AFW pump room, which also contains the auxiliary shutdown panels, was inaccessible. Security and Maintenance personnel immediately responded to the door to attempt to access the room. They were unable to unlock the door using a key and removed the key core to open the door. Within 25 minutes the door was opened successfully.

Maintenance personnel determined that the door had been locked using the push-buttons on the door edge. Catawba NSD 3.1.4 was implemented to determine if tampering of the door locks was involved and to ensure that no other doors were adversely affected. Operations personnel did not identify problems with any other Unit 1 or Unit 2 vital area doors.

The licensee determined that the last person to card out of the AFW pump room was a maintenance technician. The technician was located and interviewed to determine what may have caused the door to lock. According to the technician, he was carrying large loads out of the AFW pump room as he was exiting the area. Security personnel speculated that the door lock push-button was impacted by the load and inadvertently displaced into the locked position. Tampering was ruled out as a cause of the locked access.

The inspector questioned the impact of fettered access to the AFW pumps and the auxiliary shutdown panels to determine if timeliness requirements for manual actions were adversely affected. To determine if assumptions regarding time requirements for responding to these areas were compromised, the licensee conducted a computer search through the UFSAR, contacted probabilistic risk assessment experts in the licensees's Corporate Office, and queried emergency and abnormal operating procedures. A requirement to access the rooms within a specified period of time could not be identified. The licensee also indicated that, had there been an urgent need to access the room in response to an event, security and maintenance personnel would have been able to remove the lock core within 10 to 15 minutes. The inspector considered this reasonable, and could not identify, independent of the licensee's review, a time requirement for responding to the room during event response.

Because the AFW pump room door was susceptible to inadvertent locking, the licensee proposed a corrective action in PIP 2-C97-2624 to prevent recurrence. Security personnel evaluated the use of other types of locking mechanisms that do not feature push-buttons and are less susceptible to inadvertent locking. Doors to vital areas were evaluated to determine which ones had locking mechanisms featuring push-buttons. Work orders (WOs) were generated to replace the locks featuring push-buttons with those requiring key access. The inspector reviewed work orders 97033503 and 97035509 to verify that locks had been changed to key-controlled locking mechanisms for doors associated with the EDGs, AFW pump rooms, containment, the containment annulus, and doghouses (containing secondary isolation and relief valves). The inspector visually inspected a sample of doors identified for lock replacement to

verify that key locks had been installed; no discrepancies were identified.

c. Conclusions

The inspector concluded that the licensee's implementation of NSD 3.1.4 was a timely and appropriate response to address the potential threat of tampering. The root cause evaluation was adequate, and the conclusion that tampering was not involved in the incident was well-reasoned. Actions taken to prevent recurrence were appropriate.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 4, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Birch, M., Safety Assurance Manager
Boyle, M, Radiation Protection Manager
Glover, R., Operations Superintendent
Forbes, J., Engineering Manager
Jones, R., Station Manager
Nicholson, L., Compliance Specialist
Kitlan, M., Regulatory Compliance Manager
Peterson, G., Catawba Site Vice-President
Propst, K., Chemistry Manager

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 62700:	Maintenance Implementation
IP 61726:	Surveillance
IP 61700:	Surveillance Procedures and Records
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413/97-11-01	NCV	Failure to Follow Control Rod Movement Testing Procedure (Section O1.2)
50-414/97-11-02	VIO	Failure to Correctly Develop a DOI Replacement Plan and Perform DOI Replacement Activities in Accordance With the Controlling Procedure (Section O1.3)
50-414/97-11-03	URI	Failure of 2B EDG Turbocharger Mounting Bolt (Section M1.3)
50-413,414/97-11-04	URI	Use of Aluminum HEPA Filter Separators Inside Containment (Section E2.3)
50-413,414/97-11-05	VIO	Failure to Identify Conditions Adverse to Quality and Take Corrective Actions During Review in Accordance with GL 96-01 (Section M7.1)

Closed

50-413,414/95-18-02	DEV	Control Room Habitability Discrepancies (Section P8.1)
50-413,414/97-05-01	URI	Non-Conservative SG PORV Technical Specification (Section E8.1)
50-413,414/95-20-01	VIO	Inadequate Incorporation of Vendor Information Into Diesel Generator Maintenance Instructions (Section M8.1)

50-413/95-16-01	VIO	Inadequate Operating Procedure for Re-establishing Normal Letdown Resulting in a Water Hammer (Section O8.1)
50-413,414/94-17-04	URI	Overpressure Protection for RN Pumps (Section M8.2)

LIST OF ACRONYMS USED

AFW - Auxiliary Feedwater
CACFU - Containment Auxiliary Carbon Filter Unit
CFR - Code of Federal Regulations
DEV - Deviation
DOI - Digital Optical Isolator
DPC - Duke Power Company
EDG - Emergency Diesel Generator
EP - Environmental Protection
EPRI - Electric Power Research Institute
ESF - Engineered Safety Feature
FIP - Failure Investigation Process
FSAR - Final Safety Analysis Report
HEPA - High-Efficiency Particulate Air
IAE - Instrument and Electrical
IFI - Inspector Followup Item
INPO - Institute for Nuclear Power Operations
IR - Inspection Report
KC - Component Cooling Water
KD - Emergency Diesel Generator Engine Cooling Water System
LER - Licensee Event Report
MNS - McGuire Nuclear Station
MSIV - Main Steam Isolation Valve
NCV - Non Cited Violation
NSD - Nuclear Site Directive
NSW - Nuclear Service Water
OATC - Operator at the Controls
PIP - Problem Investigation Process
PORC - Plant Oversight Review Committee
PORV - Power Operated Relief Valve
ppm - parts per million
PRT - Pressurizer Relief Tank
QA - Quality Assurance
RCS - Reactor Coolant System
RG - Regulatory Guide
RP&C - Radiological Protection and Chemistry
RPS - Reactor Protection System
SG - Steam Generator
SRO - Senior Reactor Operator
TS - Technical Specifications
UFSAR - Updated Final Safety Analysis Report
URI - Unresolved Item
VIO - Violation
VV - Containment Ventilation

WO - Work Order
YC - Control Area Chilled Water