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REGION II

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Licensee:	Duke Energy Corporation (DEC)
Facility:	Catawba Nuclear Station, Units 1 and 2
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ENCLOSURE

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/98-09, 50-414/98-09

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by regional reactor safety inspectors, and an onsite 10 CFR 50.59 review by a Nuclear Reactor Regulation (NRR) senior project manager. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- Two examples of an apparent violation were identified concerning the failure to follow clearance procedures. Both were caused by human error and involved improper implementation of station tagout procedures associated with the nuclear service water system and the emergency diesel generator. One event resulted in a total loss of nuclear service water flow to both units for three minutes. The other resulted in a blackout of essential bus 2ETB for about 30 minutes. This apparent violation will remain open for a reasonable time to allow the licensee to develop corrective actions. (Sections O1.2 and O1.3; [EEI-1A, 3A])

- An unresolved item was opened concerning potentially inadequate procedures which may not have ensured the operability of the standby shutdown facility during certain events. (Section O3.1; [URI-1C])

Maintenance

- In general, maintenance and surveillance activities observed and reviewed during the inspection period were performed well, with proper adherence to procedural compliance, equipment calibration, and radiation protection requirements. (Section M1.1; [POS-2B, 3A])

- Inservice examination activities observed were performed in a skillful manner. Discontinuities were properly recorded and evaluated by knowledgeable examiners using approved procedures. No findings adverse to quality were identified during the examinations observed. (Section M1.3; [STREN-2B, 3B])

- Erosion/corrosion examination and engineering activities were conducted in an excellent manner during the Unit 2 end-of-cycle 9 refueling outage. Lay-out of grids on components were proper, the non-destructive examination examiners were skillful in conducting the ultrasonic examinations, and engineering evaluated the data in an effective manner. (Section M1.4; [STREN-2B,3B])

- The licensee's program for maintenance and testing of reactor coolant system pressure boundary valves was acceptable. Review of leakage testing data and machinery history indicated good material condition of these isolation boundaries. (Section M2.1; [POS-2A, 2B])

- No problems were identified during the inspector's review of the licensee's program for testing of American Society of Mechanical Engineers Section XI Class 2 and 3 relief valves. The licensee's initiative of an increased testing frequency for relief valves demonstrated a commitment to safety. (Section M2.2; [POS-2A, 2B])

- A non-cited violation was identified involving the inoperability of one channel of the overtemperature delta temperature reactor protection function for Unit 2. (Section M8.3; [NCV-5A, 5C , NEG-2B, 4B])

Engineering

- The licensee has complied with the provisions of 10 CFR 50.59 for the changes listed in the annual summary report submitted to the NRC on April 1, 1998. The inspectors also found the licensee's summary report for 1997 changes to be concise, informative, and accurate. (Section E3.1; [POS-4B])

- An unresolved item was closed which addressed the installation of portable air sampling equipment at various Unit 1 and 2 radiation monitor skids. Various weaknesses were identified by the inspectors, however, no violations of NRC requirements were identified. (Section E8.1; [URI-4A, 4B])

Plant Support

- Radioactive material was labeled appropriately, and areas were properly posted. (Section R1.1; [STREN-1C])

- Personnel dosimetry devices were appropriately worn. (Section R1.1; [STREN-1C, 3B])

- Radiation work activities were planned; radiation worker doses were being maintained well below regulatory limits; and the licensee was continuing to maintain exposures as low as reasonably achievable. (Section R1.1; [STREN-1C])

- The licensee's emergency preparedness program was being maintained in a high state of operational readiness. (Section P2; [POS-1C])

Report Details

Summary of Plant Status

Unit 1 began the period in Mode 5 due to ice condenser inspection and repairs. Following completion of the ice condenser work, the unit returned to Mode 1 and reached 87 percent power on September 2, 1998, when a deviation between demand and actual position associated with steam generator C feedwater control valve 1CF-46 was identified. Power was reduced to approximately 27 percent for valve repair. The licensee determined that the cause of the deviation was an air leak in the tubing going to the valve positioner. A similar air leak was also identified on steam generator B feedwater control valve 1CF-37. Both valves were repaired and power escalation to 100 percent was completed on September 3, 1998. The unit operated at or near 100 percent power for the remainder of the inspection period.

Unit 2 began the period at or near 100 percent power until coasting down for the end-of-cycle (EOC) 9 outage, which began on August 24, 1998. A power reduction was initiated on September 4, 1998, and the unit entered Mode 3 on September 5, 1998. Plant cooldown to Mode 4 and Mode 5 was accomplished on September 5, 1998. The unit entered Mode 6 on September 11, 1998, and core off-load (No Mode) was completed on September 16, 1998. The unit remained in No Mode the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness and communications, and adherence to approved procedures. The inspectors attended operations' shift turnovers and site direction meetings to maintain awareness of overall plant status and operations. Operator logs were reviewed to verify operational safety and compliance with Technical Specifications (TS). Instrumentation, computer indications, and safety system lineups were periodically reviewed, along with equipment removal and restoration tagouts, to assess system availability. The TS Action Item Log (TSAIL) books for both units were reviewed daily for potential entries into limiting conditions for operation (LCO) action statements. The inspectors conducted plant tours to observe material condition and housekeeping. Problem Identification Process reports (PIP) were routinely reviewed to ensure that potential safety concerns and equipment problems were resolved. Two notable human performance errors occurred during the period while operators implemented clearance procedures. They are discussed in Sections O1.2 and O1.3 below. Otherwise, no major problems were identified by the inspectors.

O1.2 Inadvertent Loss of Nuclear Service Water Flow Due to Operator Error

a. Inspection Scope (71707, 40500)

The inspectors reviewed circumstances surrounding the inadvertent operation of the 1A nuclear service water (RN) pump under zero flow conditions for several minutes on September 2, 1998. The pump operated at shutoff head for two to three minutes when operators accidentally closed its discharge isolation valve while attempting to implement a clearance for the idle 2A RN pump. The inspectors reviewed procedures and alarm printouts, and interviewed operators to determine the root cause of the event and assess plant response. The inspectors also reviewed pump test data and an engineering evaluation of RN pump 1A to determine whether the licensee adequately addressed its operability concerns before returning the pump back to service.

b. Observations and Findings

On September 2, 1998, while implementing clearance tagout procedure R&R 28-1258 to isolate RN pump 2A, operators inadvertently closed valve 1RN-29, the discharge isolation RN valve for RN pump 1A. Since RN pump 1A was the only RN pump operating at the time, all RN flow was lost for both units, resulting in several control room alarms and the automatic shutdown of control room ventilation chiller B. Operators entered abnormal operating procedure AP/0/A/5500/20, Case 1, Loss of RN Train, Revision 16, and restored service water flow within three minutes by starting the 2B RN pump. The inspectors verified that system flow was re-established within that short time frame by reviewing control room alarm logs generated by the plant computer. Operators quickly restarted the control room ventilation system chiller. No adverse consequences were noted. Both units were in Mode 1 at the time.

Discussions with plant personnel indicated that the operators intended to close valve 2RN-29 (RN pump 2A discharge isolation valve), as directed by the clearance tagout procedure. There were two operators involved, with one serving as an independent verifier that the correct valve was manipulated. The lead operator incorrectly identified valve 1RN-29 as valve 2RN-29, and the independent verifier concurred. Discussions with one of the operators after the event indicated that they detected no unusually high noise while closing valve 1RN-29 with the 1A RN pump operating, nor did they note any unusual difficulty with closing the valve under increasing pump discharge pressure. Both valves are located in a pit below the Unit 1 and 2 A train pumps at the RN pump house. Both valves were appropriately labeled with unit-specific color coded tags. However, operators indicated that the 1RN-29 valve tag had a rust-like residue on it, slightly obscuring the "1." The valves are offset at an angle from their associated pumps at the elevation above; thereby contributing to the mistake, according to operations personnel. Discussions with operations management indicated that, despite these factors, the mistake was clearly a human performance issue. This was the first of two human performance events involving improper clearance tagout implementation in a four-day period. The second event is discussed in Section O1.3 below.

The inspectors reviewed pump performance test data, obtained after the event using procedure PT/0/A/4400/022A, Nuclear Service Water Pump Train A Performance Test, Revision 60. All pump performance and vibration data were within specified acceptance ranges. The licensee also conducted an engineering evaluation of several potentially adverse factors associated with operating the pump at shutoff head, including heat generation and pump fluid vaporization, pump down-thrust as compared to motor thrust bearing rating, upper guide bearing temperature increase, and pump discharge pressure increase to determine if pressure transmitters were over-ranged. The licensee determined that neither the pump nor the motor had been degraded. The inspectors found no evidence to the contrary. The evaluation was documented in PIP 0-C98-3149.

Although this event resulted in no adverse consequences to the plant or the public, the inspectors considered the human performance aspects to be of concern, especially the failure of the independent verification process. Licensee management shared this concern and initiated a human performance time-out with plant personnel to reemphasize the importance of having a proper questioning attitude and using proper verification techniques.

As discussed above, this event was caused by human error and failure to follow clearance tagout procedure 28-1258. The failure to follow the clearance tagout procedure was contrary to requirements in TS 6.8.1.a and Regulatory Guide 1.33, Revision 2, Appendix A, Section 3.m, which state that written procedures shall be established and implemented covering the operation of the service water system. This is identified as Example 1 of Apparent Violation (EEI) 50-414/98-09-01: Failure to Follow Procedural Guidance While Implementing Clearances - Two Examples. This item will remain open for a reasonable time to allow the licensee to develop corrective actions.

c. Conclusions

An apparent violation was opened concerning the failure of two operators to properly implement a clearance for the 2A nuclear service water pump. The error resulted in the loss of nuclear service water flow to both units and the operation of nuclear service water pump 1A at shutoff head for two to three minutes.

O1.3 Inadvertant Blackout of Essential 4160 Volt (V) Bus 2ETB

a. Inspection Scope (93702, 40500)

The inspectors responded to the site and reviewed the circumstances surrounding the inadvertent blackout of the Unit 2 Train B essential 4160 volt bus (2ETB) , and the effects this transient had on the plant on September 6, 1998. The inspectors assessed plant response to the event, operator performance, and the root cause of the transient.

b. Observations and Findings

Description of Events

On September 6, 1998, at approximately 2:05 p.m., operators were performing OP/2/A/6800/010, Revision 5, 2B D/G Block Tagout Procedure, Enclosure 4.1, Isolation and Draining, to support outage maintenance on the 2B emergency diesel generator (EDG). The plant was in Mode 5, Cold Shutdown, with the reactor coolant system (RCS) temperature and pressure at approximately 182 degrees Fahrenheit (F) and 292 pounds per square inch gauge (psig), respectively. Low temperature overpressure protection (LTOP) for the RCS was operable, as required per TS 3.4.9.3, while in Mode 5 with the reactor vessel head on. Non-licensed operators in the 2ETB Essential Class 1 4160 V alternating current (AC) switchgear room were performing step 2.3.4 of the enclosure which required the operators to tag Diesel Gen 2B PT (potential transformer) (EDG 2B Fuse Drawer), located in the diesel generator 2B control panel, in the open position. Instead, operators opened the 2ETB Bus PT fuse drawer in the 2ETB essential switchgear room. This caused the relaying on 2ETB essential bus to actuate as though an actual undervoltage condition had occurred. The B train sequencer actuated and tripped the incoming bus feeder breaker and bus load-shedding occurred as designed. The B train of the control room area ventilation system, which was powered from Unit 1, automatically started. The 2B EDG did not start because it was already tagged in the "Maintenance Mode"; therefore, essential bus 2ETB blacked out and no B train components were loaded onto the bus. Control room operators entered AP/2/A/5500/07, Revision 24, Loss of Power To An Essential Bus.

As a result of the loss of power on 2ETB, centrifugal charging pump discharge flow control valve 2NV-294 failed to the full open position. This caused charging flow into the RCS to go to maximum. RCS pressurizer level and pressure increased rapidly due to the increased charging flow, and temperature dropped as a result of the increased flow of colder water. The pressurizer cooldown that occurred, as measured by pressurizer surge line instrumentation, was from 418 degrees to 188 degrees in approximately 13 minutes. In an effort to reduce the ongoing pressure increase in the pressurizer, which was at 90 percent level with a steam bubble established prior to the event, the control room operators initiated pressurizer spray. With the increased charging flow into the RCS and the spray flow into the pressurizer, the pressurizer went solid and power-operated relief valve (PORV) 2NC-32B lifted as expected at 385 psig to provide low temperature overpressure protection for the RCS. The PORV cycled approximately 85 times. Eventually, the suction supply to the centrifugal charging pumps automatically swapped over to the refueling water storage tank on low volume control tank level.

The pressurizer surge line temperature began increasing during a subsequent outsurge as stratified layers of water in the pressurizer were broken down from the spray flow. The resulting surge line heatup was from 188 degrees to 391 degrees F and occurred in about 5 minutes. Both the cooldown and heatup in the pressurizer surge line exceeded Technical Specification limits.

The discharge from PORV 2NC-32B increased the level in the pressure relief tank (PRT) from approximately 68 to 85 percent and increased the pressure in the tank to 94.5 psig (approximately 5 psig below the PRT rupture disc relief pressure). The rupture discs were not breached.

Voltage was restored to 2ETB at 2:35 p.m., and at approximately 3:01 p.m., operators manually throttled charging flow to the RCS; thereby terminating the event. Plant conditions were stabilized. This event was reported per 10 CFR 50.72, item (b)(2)(ii). The licensee documented the event and all subsequent planned and completed corrective actions in PIP 2-C98-3219.

Plant Response and Equipment Concerns

The Unit 2 B 4160 essential switchgear sequencer actuated as expected during this event. The sequencer, due to an undervoltage condition on bus ETB, initiated bus shedding; but was not able to start sequencing on essential 4160 volt bus loads because EDG 2B was tagged out for maintenance. The undervoltage condition on bus 2 ETB caused the B train of the control room emergency ventilation system to auto-start as designed. The B train was aligned to be powered from Unit 1 at the time of the event. The auxiliary feedwater system functioned as designed. Both the A and B motor driven auxiliary feedwater pumps were operating before the event to aid in RCS cooldown. When the undervoltage signal occurred on 2ETB, the B motor driven pump was load shed from the bus; the A pump remained running.

During the event, RCS pressure decreased rapidly during each PORV cycle while reactor coolant pump (RCP) seal return pressure remained relatively high. As a result, the licensee calculated that RCP number 1 seal differential pressure dropped below 200 psid (pounds per square inch differential) for 61 seconds on the A and B RCPs. RCPs C and D were not operating during the event. The consequences of the drop in RCP seal differential pressure to below 200 psid is that insufficient differential pressure could cause a faceplate rub on the number 1 seal. A faceplate rub can cause poor seal performance, which could mandate a unit shutdown based on seal leakoff in excess of established limits for RCP operation. Accordingly, the licensee replaced the number 1 seal on the A and B RCPs.

The inspectors were concerned about the condition of PORV 2NC-32B after cycling 85 times. Discussions with engineering personnel involved in evaluating the condition of 2NC-32B revealed that since no seat leakage was observed from the valve following this event, stroke time testing of the valve was all that was necessary to determine the condition of the valve for continued operation. The licensee's conclusion was discussed with Control Components Incorporated, the valve manufacturer, who concurred with this determination. The stroke time testing was completed satisfactorily. The inspectors identified no discrepancies associated with the licensee's determination that no degradation in the valve's seat and disc occurred.

The inspectors performed a walkdown in lower containment to inspect the PRT, the PRT inlet piping, and associated piping supports. No evidence of any damage was observed.

When charging flow went to maximum after centrifugal charging pump discharge flow control valve 2NV-294 failed to the full open position, the regenerative heat exchanger experienced excessive flow rates. The regenerative heat exchanger is a Safety Class 2 component. Engineering personnel determined by calculation that the maximum flow through the heat exchanger was approximately 375 gallons per minute (gpm). With flow rates this high, the divider plate in the heat exchanger was susceptible to damage due to the high differential pressure across it. The inspector's verified that the licensee evaluated the vulnerability of the divider plate prior to unit restart.

Operator Performance and Regulatory Significance

The inspectors interviewed plant personnel and determined that this event was caused by failure to follow procedures. The operator intended to pull the 2B EDG PT fuse drawer, but pulled the 2ETB Bus PT drawer instead. Human error was the root cause of the event. The failure to follow procedure OP/2/A/6800/010, 2B D/G Block Tagout Procedure, was contrary to requirements in TS 6.8.1.a and Regulatory Guide 1.33, Revision 2, Appendix A, Section 3.s.(2)(a), which states that written procedures shall be established and implemented covering operation of emergency power sources. This is identified as Example 2 of Apparent Violation (EEI) 50-414/98-09-01: Failure to Follow Procedural Guidance While Implementing Clearances - Two Examples. This item will remain open for a reasonable time to allow the licensee to develop corrective actions.

Since the pressurizer surge line cooldown and subsequent heatup exceeded TS 3.4.9.2 limits (maximum heatup of 100 degrees in any 1-hour period, and a maximum cooldown of 200 degrees in any 1-hour period), the licensee is required to perform an engineering evaluation. This evaluation was underway at the end of the inspection period.

Technical Specification 3.4.9.3, Action d requires that, in the event either the PORVs or the reactor coolant system vent(s) are used to mitigate a reactor coolant system pressure transient, a special report shall be prepared and submitted to the Commission within 30 days. This report shall describe the circumstances initiating the transient, the effect of the PORVs or reactor coolant system vent(s) on the transient, and any corrective action necessary to prevent recurrence. The licensee confirmed that this report will be submitted to the NRC and documented in PIP 2-C98-3219.

c. Conclusions

An apparent violation was identified associated with operator performance errors while implementing a station clearance procedure. The errors caused the 2ETB essential 4160 bus to be inadvertently deenergized. This event ultimately resulted in TS limits for pressurizer cooldown and heatup being exceeded, and caused multiple cycles of a pressurizer PORV.

O3 Operations Procedures and Documentation

O3.1 Abnormal Operating Procedures Potentially Affecting Standby Shutdown Facility Operability

General Comments (71707)

While reviewing abnormal operating procedure AP/1(2)/A/5500/06, Loss of S/G Feedwater, Revision 20 (16), the inspectors noted in Case II, Step 21, that operators were directed to defeat the automatic swapover logic of auxiliary feedwater (CA) pump suction to the condenser circulating water assured makeup source by dispatching an operator to open circuit breakers associated with normally open valve CA-178 and two normally closed valves (CA-174 and 175) designed to open on low turbine-driven CA pump suction pressure. The inspectors reviewed TS 3.7.13, Standby Shutdown System, TS surveillance requirement 4.7.13.5, and Updated Final Safety Analysis Report, Section 10.4.9.2, to determine if this action were performed, would it affect Standby Shutdown System (SSS) or Standby Shutdown Facility (SSF) operability.

Based on a review of the above documents, and licensee test procedure PT/1/A/4350/022, Revision 11, CA Control From SSF Operability Test, which demonstrated the operability of the SSS by cycling valves CA-174, 175, and 178 from the SSF, the inspectors concluded that the actions prescribed in the abnormal operating procedure did adversely impact the SSF operability. This observation was brought to the licensee's attention, who later found that another abnormal operating procedure, AP/1(2)/A/5500/17, Revision 36 (30), Loss of Control Room, contained similar directions for operators. The inspectors toured the SSF and verified that current configuration control was properly maintained with the breakers for these valves racked in and closed.

The inspectors concluded that the abnormal operating procedures were potentially inadequate in that they did not ensure the operability of the SSF. The licensee was still evaluating possible changes to these procedures at the end of the inspection period. This item is identified as Unresolved Item (URI) 50-413,414/98-09-02: Potentially Inadequate Procedures Not Ensuring the Operability of the SSF. This item will remain open pending further NRC review of the licensee's design basis, the likelihood that the procedures would be performed in operational modes requiring the SSS/SSF to be operable, and whether any previous performances of either procedure resulted in the SSF being inoperable.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on the Conduct of Maintenance and Surveillance Activities (62707, 61726)

The inspectors observed portions and/or reviewed completed documentation of the following maintenance and surveillance activities:

- IP/O/A/3240/004A, Source Range Channel Calibration, Revision 17
- PT/1/A/4200/005B, Safety Injection Pump 1B Performance Test, Revision 52
- MP/0/A/7150/072, Main Steam Safety Valve Setpoint Test, Revision 6
- PT/1/A/4600/002E, Mode 5 Periodic Surveillance Items for Unit 1, Revision 49
- PT/0/A/4150/019, 1/M Approach to Criticality
- PT/2/A/4350/015B, Diesel Generator Periodic Test, Revision 17
- PT/0/A/4400/022A, Nuclear Service Water Train A Performance Test, Revision 60
- PT/1/A/4350/022, CA Control From SSF Operability Test, Revision 11

In general, the referenced maintenance and surveillance activities were performed well, with proper adherence to procedural compliance, equipment calibration, and radiation protection requirements. During the performance of main steam safety valve testing, the inspectors noted that one of the crews performing the test increased the pressure on the safety valves at a faster rate than the other crew. As a result, the lift setpoints were detected to the nearest 5 psig and documented accordingly. The inspectors discussed this observation with a test technician, who indicated that the pressurization rate would be decreased to improve the resolution of the data. The inspectors also discussed the observation with engineering personnel, who initiated PIP 0-C98-3199 and proposed corrective action to re-emphasize, in training, the need to conduct the testing in a slow, deliberate manner. The inspectors noted that this practice was ongoing despite the presence of the licensee's quality control inspectors.

M1.2 Additional Review of Completed Surveillance Test Packages

a. Inspection Scope (61726)

The inspector reviewed selected completed periodic test packages to verify that the documentation satisfied the referenced Technical Specification (TS) surveillance requirements (SRs).

b. Observations and Findings

The inspector reviewed test package documentation for the two most recent performances of the following periodic tests (PTs):

- PT/1/A/4200/13H, NI and NV Check Valve Test (Unit 1)
- PT/2/A/4200/13H, NI and NV Check Valve Test (Unit 2)
- PT/1/A/4200/01N, Reactor Coolant System Pressure Boundary Valve Leak Rate Test (Unit 1)
- PT/2/A/4200/01N, Reactor Coolant System Pressure Boundary Valve Leak Rate Test (Unit 2)
- PT/1/A/4400/01 ECCS Flow Balance (Unit 1)
- PT/2/A/4400/01 ECCS Flow Balance (Unit 2)

No problems were identified with the completed periodic test packages reviewed. For each of the above PT packages reviewed, the TS SRs referenced by the licensee's PT had been satisfied. Completed periodic test packages reflected acceptable test results.

c. Conclusions

Completed periodic test packages reflected acceptable test results; thereby satisfying the referenced TS SRs.

M1.3 Inservice Inspection

a. Inspection Scope (Unit 2) (73753)

The inspector observed four methods of nondestructive examinations, including snubber functional testing activities to evaluate the effectiveness of licensee inspection and testing procedures; examiners' skill in using the specific examination equipment; and the examiners' ability and knowledge to correctly perform the examination methods and interpret the test results. Equipment calibrations; component examinations; and interpretation, evaluation, and acceptance of test results were verified.

b. Observations and Findings

One manual ultrasonic examination, one liquid penetrant examination, eight snubber functional tests, and portions of steam generator "A" eddy current examinations (consisting of initial system calibrations, acquisition of data, and the 4-hour in-process calibration) were observed. The inspector verified that the approved procedures were in accordance with the Section XI of the American Society of Mechanical Engineers (ASME) Code, Technical Specifications, and/or enhanced qualification efforts approved by the NRC. Procedures were being followed and examination personnel were properly certified and knowledgeable of the examination method and operation of the test equipment. Calibrations, examinations, evaluations, recording of appropriate data and acceptance of test results were performed as required by the specific procedure. In addition, the inspector verified that previous examination data was reviewed to determine any change in the recorded data.

c. Conclusions

Inservice examination activities observed were performed in a skillful manner. Discontinuities were properly recorded and evaluated by knowledgeable examiners using approved procedures. No findings adverse to quality were identified during the examinations observed.

M1.4 Inspection of Erosion/Corrosion Monitoring Activities

a. Inspection Scope (49001)

The Catawba erosion/corrosion plan for the Unit 2 EOC 9 outage was reviewed and the examination of feedwater component E2CF59A was selected by the inspector to verify the effectiveness of non-destructive examination and to determine whether subsequent actions taken by the licensee, when wall thinning was detected, met procedural and ASME Code Case N-480 requirements. This component was selected because it was one of two components whose wear rate indicated that it may not meet minimum design wall thickness this inspection.

b. Observations and Findings

The inspector verified that the grid patterns for component E2CF59A were in accordance with the layout instructions, non-destructive examination personnel were certified, test equipment was properly calibrated, and readings were recorded on each grid intersection. The examination of component E2CF59A revealed that this 18-inch diameter pipe was experiencing wear on the upstream portion of the pipe between 5:00 and 7:00 o'clock, with the lowest readings recorded at the 6:00 o'clock pipe position. Readings taken on several grid intersections at this location revealed minimum remaining wall thicknesses of 0.800 inches. The design minimum for this main feedwater line was 0.801 inches. Approval of ASME Code Case N-480 had been obtained by the licensee in NRC Approval Letter dated September 9, 1996, and was used to conduct the analytical evaluation of this component. This was a quality assurance (QA) Condition 1 calculation because it served as the basis for qualification of a QA Condition 1 system, structure, or component. The inspector reviewed the completed analytical evaluation in order to perform independent verification of this calculation. The evaluation revealed that the localized thinning in this component was acceptable for continued service, the calculated minimum allowable wall thickness was 0.731 inches, and based on the wear rate, the minimum projected thickness at the end of cycle 10 for Unit 2 would be 0.780 inches. The erosion/corrosion engineer also stated that the component was planned to be replaced next refueling outage with a piping material that would be more resistant to erosion/corrosion.

c. Conclusions

Erosion/corrosion examination and engineering activities were conducted in an excellent manner during the Unit 2 end-of-cycle 9 refueling outage. Lay-out of grids on components were proper, the non-destructive examination examiners were skillful in conducting the ultrasonic examinations, and engineering evaluated the data in an effective manner.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance/Material Condition of Reactor Coolant System (RCS) Pressure Boundary Valves

a. Inspection Scope (62700)

The inspector reviewed the licensee's program for maintenance and testing of selected RCS pressure boundary valves (PBVs) to determine the adequacy of that program for maintaining the integrity of those RCS isolation boundaries. The inspector also verified that the licensee's program for testing of those isolation valves satisfied TS SRs from SR 4.4.6.2.2 for verification of RCS PBV leakage. The inspector reviewed available documentation associated with previously known problems in this area. Additionally, the inspector reviewed maintenance work packages and post-maintenance test documentation for completed work on selected isolation valves.

b. Observations and Findings

The inspector reviewed machinery history and leak testing data for selected RCS PBVs to evaluate the adequacy of the licensee's program for maintaining the integrity of those RCS isolation boundaries and to verify that TS 4.4.6.2.2 had been satisfied by testing. Valves selected for review consisted of important isolation valves, including check valves, which, if failed, could result in an interfacing system loss of coolant accident (IS-LOCA). The inspector reviewed the licensee's surveillance procedures for periodic leak rate testing of PBVs along with as-found leakage test data for selected valves from testing performed by the licensee during the 1EOC9, 1EOC10, 2EOC7, and 2EOC8 refueling outages. Specific leakage test packages reviewed are listed in Section M1.2. The inspector also reviewed selected valve leakage data for testing performed during unplanned outages on Unit 2 during February 1996, August 1996, and December 1996. The inspector also reviewed selected maintenance procedures used by the licensee for disassembly and inspections of check valves as required by the licensee's Inservice Testing (IST) Program. Additionally, the inspector reviewed maintenance work packages and post-maintenance test documentation for completed work on selected valves.

The inspector noted that each of the licensee's leakage testing procedures required that valve leakage be normalized for an RCS pressure of 2235 psig. This normalized leakage value was required to be used rather than the actual observed leakage values anytime testing involved a lower test pressure.

The inspector determined that very few problems or failures had occurred in this area. Only one RCS PBV had failed leak rate testing at Catawba. That check valve, 2NI-169, had been installed under a design change and the failure occurred during post-modification testing. The inspector reviewed maintenance work orders 95-025112 and 95-090037, which documented the replacement and satisfactory retest of that check valve prior to startup from the outage. No problems were identified during the review. No other RCS PBVs had failed leak rate testing.

Catawba has a history of intermittent periods of minor leakage past some RCS pressure boundary check valves and secondary safety injection (NI) system check valves during normal plant operations. This has required more frequent refilling of affected RCS cold leg accumulators and venting of the residual heat removal (ND) and NI piping to relieve pressure and remove trapped nitrogen. The problem appeared to be related to changes in differential pressure across the valve discs, which occurred during operation or testing of emergency core cooling systems (ECCS). There has been no evidence of problems with material condition of the check valves. No problems were identified during any subsequent disassembly or inspections of suspected check valves. The inspector determined that the licensee had performed increased monitoring of the affected systems and was evaluating additional possible corrective actions. The licensee had evaluated the leakage and determined that the leakage from the RCS PBVs has been minimal, estimated to be less than 0.1 gallons per minute (gpm) maximum extrapolated to system pressure. The inspector determined that this problem had resulted in some operator burden. Further inspection of related system venting concerns will continue under Inspector Followup Item (IFI) 50-413,414/98-07-02.

The inspector verified that the licensee's program for maintenance and testing of PBVs was acceptable and that leakage testing had satisfied the TS requirements. No problems were identified during the inspector's review in this area.

c. Conclusions

The licensee's program for maintenance and testing of RCS PBVs was acceptable. No examples of inadequate maintenance were identified during this review. No adverse trends or degradation of the material condition for RCS for PBVs were identified during review of machinery history. Review of leakage testing data indicated good material condition of those RCS isolation boundaries.

M2.2 Testing of ASME Section XI Class 2 and 3 Relief Valves

a. Inspection Scope (62700)

The inspector reviewed the licensee's program for testing of ASME Section XI Class 2 and 3 relief valves to verify that the program satisfied requirements of ASME/American National Standards Institute (ANSI) OM-1987, Operation and Maintenance of Nuclear Power Plants. Verification of correct lift setpoints for these relief valves was necessary to ensure proper operation of ECCS systems and because of the potential impact of improper lift setpoints on a postulated IS-LOCA event.

b. Observations and Findings

ASME Section XI Class 2 and 3 relief valves at Catawba included a large number of smaller relief valves in various systems such as NI, ND, and other systems. The inspector reviewed documentation for all ASME Class 2 and 3 relief valves in the NI and ND systems that had been tested during the 1EOC10 and 2EOC8 refueling outages. Specific relief valves tested were documented in Maintenance Procedure SM/0/A/8030/001, Relief Valve Set Pressure Testing and Adjustment. The inspector determined that the licensee's program required relief valve lift setpoints be readjusted whenever the as-found setpoint exceeded +/- 3% of nominal as required by ASME/ANSI OM-1987. The inspector reviewed documentation for resetting of lift setpoints for selected relief valves which had as-found lift setpoint failures. No problems were identified during this review. The inspector determined that the licensee had checked a sufficient number of relief valves to satisfy sampling requirements from ASME/ANSI OM-1987, Part 1, Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices. The inspector also noted that the licensee's program for testing of relief valves involved more frequent testing than required by the Code. ASME/ANSI OM-1987 requires testing of these relief valves such that at least 20% of each group (by vendor, valve model, and application) are tested during a 48-month period and all are tested within 10 years. The licensee's program required testing all ASME Class 2 and 3 relief valves within a 3-year period.

c. Conclusions

No problems were identified during the inspector's review of the licensee's program for testing of ASME Section XI Class 2 and 3 relief valves. The licensee's initiative of an increased testing frequency for relief valves demonstrated a commitment to safety.

M8 Miscellaneous Maintenance Issues (IP 92902, 90712)

M8.1 (Closed) VIO 50-413,414/97-11-05: Failure to Identify Condition Adverse to Quality and Take Corrective Actions During Reviews in Accordance with Generic Letter 96-01

(Closed) LER 50-413/97-06: Missed Technical Specification Surveillance on P-11 and P-13 Permissive Interlocks Due to Inadequate Procedures

These items identified the inadequate testing of the P-11 and P-13 permissive functions as required by TS 3.3.1 and 3.3.2. The P-11 pressurizer pressure permissive allows a safety injection actuation to be blocked below 1955 psig and the P-13 turbine impulse chamber pressure permissive automatically enables certain reactor trips on increasing power above 10%. Functional testing of the P-11 permissive was required every 92 days and functional testing of the P-13 permissive was required every 18 months. Existing test procedures had not fully satisfied the TS since the procedures had not specifically verified an actual change in state of the respective solid state protection system (SSPS) input relays whenever pressurizer pressure was equal to or above 1955 psig or power equal to or above 10 percent. These problems were identified as the result of a licensee review of industry experience information. However, the licensee had failed to identify those problems during a previous review of protective logic test procedures in response to Generic Letter 96-01.

The inspector reviewed the licensee's response to the violation, dated October 23, 1997, along with LER 50-413/97-06 dated September 19, 1997. The licensee's response attributed the problem to inadequate procedures, which failed to test the permissives under all potential plant operating modes. Calibration procedures had been developed with the implicit assumption that they would be performed during outages and analog channel operational test (ACOT) procedures had been developed with the implicit assumption they would be performed at power. The licensee's response further stated that applicable procedures would be reviewed to ensure that these implicit assumptions would not result in any significant problems when the procedures were performed at other than the assumed conditions.

Proposed corrective actions were documented in PIPs 0-C97-2726, 0-C97-2646, and 0-C98-0056. The inspector reviewed these PIPs and ACOTs IP/1/A/3222/00A, IP/1/A/3222/00B, IP/1/A/3222/00C, IP/1/A/3222/00D, IP/2/A/3222/00A, IP/2/A/3222/00B, IP/1/A/3222/00C, and IP/2/A/3222/00D. The inspector verified that the necessary revisions were made for these ACOTs, which were used for the quarterly verification of operability of the P-11 permissive with RCS pressure equal to or greater than 1955 psig. The inspector determined that the required revisions to the 18-month P-13 ACOTs and to the 18-month channel calibration procedures for P-11 permissive had not yet occurred. Those procedures were on administrative hold pending completion of the revisions as required by PIP 0-C97-2646 and were scheduled to be completed prior to the next planned outage. The inspector concluded these items were adequately resolved.

M8.2 (Closed) IFI 50-413,414/97-12-01: Assess Licensee Actions to Resolve Nuclear Service Water (NSW) Component Leaking Problems

The NSW system had experienced numerous problems with system leakage. The licensee had attributed the leakage to various causes such that the system's performance warranted further review. This item was opened to assess licensee activities to resolve leaks in the NSW system.

The inspector met with members of licensee management to evaluate the adequacy of corrective actions in this area. The inspector also reviewed PIPs 0-C97-2649 and 0-C97-3663 along with the most recent status report of the licensee's small bore piping replacement project. The inspector noted that piping reliability concerns affected systems other than NSW and had been identified as a Catawba Site Focus Item (MEPR 96-20). Corrective actions have been identified by the licensee to address piping reliability concerns such as corrosion and fouling. These included replacement of small bore carbon steel piping with stainless steel piping, increased monitoring of material condition of piping, periodic ultrasonic examination of strategic locations of piping, and evaluation of a trial chemical dispersant treatment skid. The inspector determined that a significant portion of the licensee's small bore replacement project had been completed. The inspector concluded that most of the remaining corrective actions in this area were long-term activities and that the licensee had adequately addressed the inspector's original concern. This item is closed.

M8.3 (Closed) LER 50-414/98-03: Overtemperature Delta T Setpoint Exceeded Allowable Value Due to Procedure Error Which Resulted in Violating Technical Specification 2.2.1

The inspectors verified that corrective actions (addressed previously in Inspection Report 98-08) were completed or incorporated into the licensee's corrective action program via PIP 2-C98-2463. The inspectors also verified that the single failure criteria was met with one channel inoperable; therefore, the overtemperature delta T reactor trip function would have been provided by the remaining channels. This non-repetitive, licensee identified and corrected violation is characterized as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-414/98-09-03: Unit Operation with an Inoperable and Non-Tripped Channel of the Reactor Protection System. This item is closed.

M8.4 (Closed) VIO 50-413/96-12-02: Failure to Adequately Train Welders to Perform Their Assigned Tasks

During the replacement of the Unit 1 steam generators, the licensee took exception to the regulatory position that welders be tested for proficiency under simulated access conditions such as those that would be encountered when fabricating production/field welds. The licensee's approach was to only use highly skilled personnel as a means of assuring acceptable welds. Therefore, applicable welders received little or no formal training or indoctrination on the requirements of the welding program and were given no mock-up training to achieve proficiency in the production of radiographic quality welds under field conditions. This failure to provide adequate training on the welding program requirements and performance training was a major contributor to the poor welding performance demonstrated on specific welds during this replacement activity.

The licensee's response for this violation dated October 29, 1996, was reviewed and accepted by NRC letter, dated November 13, 1996. During this inspection, the inspector verified the licensee's corrective actions by conducting discussions with cognizant site and corporate welding engineers and by reviewing both corporate and site specific revised procedures, which implemented a new welding technical support group for each site. These new welding support groups conducted weldability and constructability reviews, developed mock-up training and inspection requirements, and reviewed rejected welds and repair strategy. In addition, other applicable documentation such as records of personnel assigned to manage the dedicated welding groups for each site and mockup training records for outage EOC9 were reviewed. The licensee's corrective actions were effective in strengthening the welding program manual and site procedure requirements, establishing a dedicated support group for each site, instituting a limited access testing requirement to ensure applicable process piping welder proficiency levels are verified, and requiring annual Jaegar eye exams for all process piping welders.

III. Engineering

E3 Engineering Procedures and Documentation

E3.1 Changes, Tests, and Experiments Performed In Accordance With 10 CFR 50.59 (for 1997)

a. Inspection Scope (37551)

By letter dated April 1, 1998, DEC submitted its annual summary report of all changes, tests, and experiments, which were completed under the provisions of 10 CFR 50.59 during 1997. The licensee's summary report includes approximately 270 changes made during the subject period. The inspector evaluated these changes against the provisions of the regulation.

b. Observations and Findings

The inspector reviewed the licensee's current (dated March 31, 1998) version of Nuclear System Directive 209, "10 CFR 50.59 Evaluations," which is patterned after Nuclear Energy Institute 96-07, "Guidelines for 10 CFR 50.59 Safety Evaluations." This document requires that changes be evaluated against the appropriate Updated Final

Safety Analysis Report (UFSAR), Technical Specifications, and NRC Safety Evaluation Report sections to determine if there is need for revision. Specifically, the criteria specified by 10 CFR 50.59 are broken down into seven (7) questions. For a change to be qualified for 10 CFR 50.59, the answers to all seven questions must be "no." Based on review of this document, and the review of the licensee's 10 CFR 50.59 evaluations, the inspector concluded that the licensee's Nuclear System Directive 209 appropriately reflects the criteria of this regulation and that, if followed accordingly, would ensure that a change be correctly evaluated under this regulation.

In the previous 10 CFR 50.59 inspection (Inspection Report 50-413,414/97-09), the inspector noted a number of the evaluations in the previous summary report lacked sufficient information for a reader to even determine what system was involved, or what change was made. The licensee has incorporated appropriate changes in Nuclear System Directive 209 to enhance the readability of the summary report. The licensee's summary report for 1997 10 CFR 50.59 changes was concise, informative, and accurate.

The inspector performed an in-office review of the licensee's summary to determine the nature and safety significance of each change. Through this review, the inspector selected the following changes (about 10 percent of the changes in the summary report) for more detailed onsite review:

- CE-3489, Add Vent to Spent Fuel Cooling System Piping
- CE-5009, Incorporate Revised Westinghouse Ice Basket Information into Controlled Drawings
- CE-60278, Upgrade Conventional Low Pressure Service Water System Pump A Flow Capacity
- CE-8390, 2.5-inch Penetration in Steam Generator 2A for Foreign Object Retrieval
- CE-8592, Cut and Cap the Nuclear Service Water System Return Line from the Diesel Generator Engine Cooling Water System Heat Exchanger
- CE-8652, Revise the Setpoints of Reactor Coolant Pumps 2A and 2D
- CE-8710, Revise RHR Pump Miniflow Valve Pressure Setpoints
- CE-9241, Modify Support Mechanism for the CRDM and Incore Instrumentation System Backdraft Damper
- CE-7954 and CE-7956, Removal of Straightening Section from Fuel Pool Ventilation System Air Flow Monitors
- CN-21329, Operator Aid Computer Replacement
- CN-11373, Modify Main Steam Isolation Valve Control Circuit

- CN-50431, Instrument Air System Dryer Automatic Operation, Flow Instrumentation, Emergency Lighting, and Relief Valve Replacement

- CNC-1223.03-00-0030, Engineering Evaluation to Support Natural Circulation Following Reactor Coolant System Vacuum Fill

- Removal of Forward Flow Test Requirement from Inservice Test Program for Valve 1(2)NI48, the Cold Leg Accumulator Nitrogen Supply Check Valve

- The Compensatory Actions for Excavation in Area of Buried Nuclear Service Water System Piping

- Revision of Core Operating Limits Report to Increase the Limit on Boron Concentration

- Revision to Core Operating Limits Report Mode 4 Reactor Makeup Water Pump Flowrate Limit

- Revision to the Core Operating Limits Report to Reflect Changes in the Loss-of- Coolant Accident (LOCA) Power Peaking Limits
- Specification Change to Coatings Specification DPC-1167.01-00-0001

- (Change 144) Revision 1a to Topical Report DPC-NE-1003-A, Rod Swap Methodology for Startup Physics Testing
- (Change 145) Revision 2a to Topical Report DPC-NE-3002, UFSAR Chapter 15 System Transient Analysis Methodology

- (Change 157) Creation of Procedure MP/2/A/7150/115, Core Exit Thermocouple Nozzle Disassembly and Reassembly

- Procedure TT/2/A/9300/023, Test for Valve NV-1(2)813, Check Valve Between Train A of the Residual Heat Removal System and the Centrifugal Charging Pumps

- Procedure PT/0/A/4150/012A, Isothermal Temperature Coefficient of Reactivity Measurement

- Revision to Procedure MP/0/A/7150/042, Reactor Vessel Head Removal and Replacement

- Revision to Procedure PT/s/A/4200/01C, Containment Isolation Valve Leak Rate Test, to Allow Testing of the Standby Makeup Containment Header Check Valve 2NV-874

The inspector found that these changes were correctly evaluated by the licensee under the provisions of 10 CFR 50.59.

The licensee's corresponding revision of the Updated FSAR (UFSAR), per 10 CFR 50.71, lags behind 10 CFR 50.59 evaluations, since there is no requirement that these be performed concurrently. However, the licensee has listed the UFSAR sections that will be revised to reflect the changes. Such listing would help to ensure that the next UFSAR revision, to be submitted later in 1998, would capture all the 50.59 changes made in 1997 and within the scope of the UFSAR.

c. Conclusions

Based on in-office review of the licensee's April 1, 1998, annual summary on 10 CFR 50.59 changes, onsite review of the licensee's 10 CFR 50.59 evaluations, and audit of the licensee's procedures, the inspector concluded that the licensee has complied with the provisions of this regulation for the changes listed in the annual summary report submitted on April 1, 1998. The inspector also found the licensee's summary report for 1997 changes concise, informative, and accurate.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) URI 50-413,414/98-08-03: Inadequate Design Documentation For Portable Radiation Monitors (EMF)

This URI addressed the installation of portable air sampling equipment at various Unit 1 and 2 EMF skids. The EMF skid of particular concern was the Unit 1 and 2 unit vent skids because they were continuously in service. The inspectors previously identified that no documentation was available regarding the installation of portable equipment; the portable equipment was not described in the UFSAR; procedures used to control the use of the portable sampling equipment were not adequate; and no evaluation had been performed to analyze the effects on the EMF skid if the tygon tubing (used as the supply and return lines to the portable equipment) ruptured.

Catawba UFSAR Selected Licensee Commitments, Section 16.11 Radiological Effluents Controls, Table 16.11-5, Item 3, Vent System, requires that samples are continuously collected with auxiliary sampling equipment whenever EMF 35 and EMF 37 (particulate and iodine samplers) are inoperable. This justifies the existence of the portable air sampling equipment. Despite the inspector-identified weaknesses, this nonsafety-related equipment is not subject to 10 CFR 50, Appendix B criteria. Hence, no violations of NRC requirements were identified.

The licensee has completed a 10 CFR 50.59 evaluation, which concluded that the current plant configuration is acceptable, and has initiated corrective actions to modify existing instrument detail drawings and enhance the controlling procedures to be in accordance with current station requirements. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiological Protection

a. Inspection Scope (71750,83750)

The inspectors reviewed personnel monitoring radiological postings, high radiation area controls, posted radiation dose rates, contamination controls within the radiologically controlled area (RCA), and container labeling. In addition, As Low As Reasonably Achievable (ALARA) work planning, pre-job worker briefings, and job execution observations were performed. The inspectors also reviewed licensee records of personnel radiation exposure and discussed ALARA program details, implementation and goals. Requirements for these areas were specified in 10 CFR 20 and TS.

b. Observations and Findings

The inspectors toured the health physics facilities, the auxiliary building, outside radioactive waste storage building and upper containment.

Records reviewed showed that the licensee was tracking and trending personnel contamination events (PCEs). The licensee had tracked approximately 72 PCEs for the 1998 calender year to date which included skin and clothing contaminations. There were 46 clean area PCEs. The inspector reviewed the licensee's contamination investigation of PCE 98-65 and independently verified the licensee's calculations. The investigation resulted in an evaluated dose of approximately 15 mrem. No discrepancies were identified.

Radiologically controlled areas including radioactive material storage areas (RMSAs), high radiation areas, and locked high radiation areas were appropriately posted and radioactive material was appropriately stored and labeled.

The inspectors reviewed operational and administrative controls for entering the RCA and performing work. These controls included the use of radiation work permits (RWPs) to be reviewed and understood by workers prior to entering the RCA. The inspectors reviewed selected RWPs for adequacy of the radiation protection requirements based on work scope, location, and conditions. For the RWPs reviewed, the inspectors noted that appropriate protective clothing, and dosimetry were required. During tours of the plant, the inspectors observed the adherence of plant workers to the RWP requirements. The inspectors observed personal dosimetry was being worn in the appropriate location. The inspectors observed workers properly using friskers at the exit locations from controlled areas and properly exiting the protected area through the exit portal monitors.

The inspectors reviewed in detail two RWPs for work on Unit 2 steam generations. The inspectors attended pre-job briefings for the RWPs reviewed and observed the work activities in progress via closed circuit television. Appropriate dose control and acceptable work practices were observed.

The inspectors discussed ALARA goals and annual exposures with licensee management and determined the organizational structure and responsibilities for the ALARA staff were clearly defined in organizational charts. The inspectors reviewed the 1st, 2nd, and 3rd quarter ALARA Committee Meeting Minutes and found the Agenda Topics comprehensive and the meetings well attended by the committee members, including the Site Manager (Chairman) and the Site Vice President.

The Calender Year 1998 site exposure goal was set at 142 person-rem. At the time of the inspection (September 17, 1998), the site person-rem was about 92.100 person-rem. Approximately 49.100 estimated person-rem had been accumulated as a result of Unit 2 refueling activities.

The inspectors reviewed the Contaminated Square Footage Data and observed that the licensee was tracking approximately 11,373 square feet or 7.3 percent of the controllable 155,878 square feet. The contaminated square footage had increased from approximately 2150 square feet the week before. The increase was attributable to the outage activities.

c. Conclusions

Radiological facility conditions in radioactive material storage areas, health physics facilities, upper containment and waste storage building were found appropriate and the areas were properly posted and radioactive material appropriately labeled. Personnel dosimetry devices were appropriately worn. Radiation work activities were appropriately planned. Radiation worker doses were being maintained well below regulatory limits and the licensee was maintaining exposures ALARA.

R8 Miscellaneous RP&C Issues (92904)

R8.1 (Closed) Violation 50-413,414/97-14-05: Failure to Label Radioactive Material Required by 10 CFR 20.1904

The inspectors reviewed the licensee's Reply to Notice of Violation dated January 15, 1998. The inspectors selectively observed the corrective actions and independently verified selected training and postings during the inspection. For the items verified and reviewed the inspectors found them as stated. This item is closed.

R8.2 (Closed) VIO 50-413/97-15-06: Failure to Revise RWPs to Reflect Change in Dress Requirements as a Result of Changing Plant Conditions

The inspectors reviewed the licensee's Reply to Notice of Violation dated March 9, 1998. The inspectors selectively observed the corrective actions and independently verified selective training as stated in the closure package. The training attendance for the RWP revision requirements were spot checked and verified by health physics technician interview. The inspectors found the closure package complete and independent verification did not identify any discrepancies. This item is closed.

P2 Status of EP Facilities Equipment and Resources

P2.1 Operational Status of the EP Program

a. Inspection Scope (71750,82701)

Inspection objectives were to determine whether the licensee's emergency preparedness program was maintained in a state of operational readiness, and to determine whether changes to the program since the last inspection meet commitments, NRC requirements, and affect the licensee's overall state of emergency preparedness.

b. Observations and Findings

The inspector reviewed Revisions 97-2, 97-3, 98-1, and 98-2 to the Catawba Nuclear Plant Emergency Plan. The changes to the Plan were submitted in accordance with regulatory requirements and did not adversely affect the licensee's overall state of emergency preparedness.

One Emergency Plan implementation for a Notification of Unusual Event occurred on December 30, 1997, based on the judgement of the Operations Shift Manager/Emergency Coordinator that increased awareness of local authorities was warranted. The inspector's review of documentation indicated the classification and notifications were correct and timely.

Emergency facilities, equipment, instrumentation, and supplies were being well maintained. Improvements since the last inspection were the installation of 18 site assembly card readers and the addition of 800 megahertz radios for the field monitoring teams.

The only change to the organizational and management control to the emergency organization was the new Safety Assurance Manager assigned in August 1998. The manager had been fully trained and integrated into the emergency organization.

The inspector observed formal emergency preparedness training and reviewed the emergency response organization (ERO) training program and exercise/drill schedule. The training was excellent as were the visual aids in support of the training. The training program was maintained and organized with a computer generated listing that was reviewed monthly to verify the qualifications of ERO members. The ERO drill schedule provided for annual participation by each of the five control room shifts and all personnel assigned to the ERO.

The inspector's review of Safety Audit Reports 97-46 and 98-11 concluded the audits were comprehensive and met NRC requirements. Corrective actions taken in response to issues identified during drills and exercises were thorough and timely.

c. Conclusion

The licensee's emergency program was being maintained in a high state of operational readiness.

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 30, 1998. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Boyle, Radiation Protection Manager
S. Bradshaw, Safety Assurance Manager
S. Christopher, Emergency Preparedness Manager

R. Glover, Operations Superintendent
P. Herran, Engineering Manager
R. Jones, Station Manager
M. Kitlan, Regulatory Compliance Manager
G. Peterson, Catawba Site Vice-President
R. Propst, Chemistry Manager
D. Rogers, Maintenance Manager
M. Standridge, Acting Safety Review Group Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Controls in Identifying, Resolving, and Preventing Problems
IP 49001:	Erosion/Corrosion Monitoring Program
IP 61726:	Surveillance
IP 62700:	Maintenance Implementation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection
IP 82701:	Operational Status of Emergency Preparedness Program
IP 83750:	Occupational Exposure
IP 90712:	In Office Review of Written Reports
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Event Response

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-414/98-09-01	EEI	Failure to Follow Procedural Guidance While Implementing Clearances - Two Examples (Sections O1.2 and O1.3)
50-413,414/98-09-02	URI	Potentially Inadequate Procedures Not Ensuring the Operability of the SSF (Section O3.1)
50-414/98-09-03	NCV	Unit Operation with an Inoperable and Non-Tripped Channel of the Reactor Protection System (Section M8.3)

Closed

50-413,414/97-11-05	VIO	Failure to Identify Condition Adverse to Quality and Take Corrective Actions During Reviews In Accordance with Generic Letter 96-01 (Section M8.1)

50-413/97-06-00	LER	Missed Technical Specification Surveillance on P-11 and P-13 Permissive Interlocks Due to Inadequate Procedures (Section M8.1)
50-413,414/97-12-01	IFI	Assess Licensee Actions to Resolve NSW Component Leaking Problems (Section M8.2)
50-414/98-03	LER	Overtemperature Delta T Setpoint Exceeded Allowable Value Due to Procedure Error Which Resulted in Violating Technical Specification 2.2.1 (Section M8.3)
50-413/96-12-02	VIO	Failure to Adequately Train Welders to Perform Their Assigned Tasks (Section M8.4)
50-413,414/98-08-03	URI	Inadequate Design Documentation For Portable Radiation Monitors (Section E8.1)
50-413,414/97-14-05	VIO	Failure to Label Radioactive Material Required by 10 CFR 20.1904 (Section R8.1)
50-413/97-15-06	VIO	Failure to Revise RWPs to Reflect Change in Dress Requirements as a Result of Changing Plant Conditions (Section R8.2)

Discussed

50-413,414/98-07-02	IFI	ECCS High Point Vent Procedure/Gas Vented from RHR Discharge Piping (Section M2.1)

LIST OF ACRONYMS USED

ACOT - Analog Channel Operations Test
AFW - Auxiliary Feedwater
ALARA - As Low As Reasonably Achievable
ASME - American Society of Mechanical Engineers
CA - Auxiliary Feedwater
CFR - Code of Federal Regulations
CRDM - Control Rod Drive Mechanism
DEC - Duke Energy Corporation
EDG - Emergency Diesel Generator
EMF - Radiation Monitor
ERO - Emergency Response Organization
FSAR - Final Safety Analysis Report
IFI - Inspector Followup Item
ISLOCA - Interfacing System Loss of Coolant Accident
IST - Inservice Testing
LCO - Limiting Condition for Operation
LER - Licensee Event Report

LOCA	-	Loss of Coolant Accident
LTOP	-	Low Temperature Overpressure Protection
ND	-	Residual Heat Removal
NI	-	Safety Injection
NRR	-	Nuclear Reactor Regulation
NSW	-	Nuclear Service Water
PBV	-	Pressure Boundary Valves
PCE	-	Personnel Contamination Event
PIP	-	Problem Investigation Program
PORV	-	Power Operated Relief Valve
PRT	-	Pressure Relief Tank
PSIG	-	Per Square Inch Gauge
PT	-	Periodic Test
PT	-	Potential Transformer
RCA	-	Radiologically Controlled Area
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RMSA	-	Radioactive Material Storage Area
RN	-	Nuclear Service Water
RP&C	-	Radiological Protection and Chemistry
R&R	-	Clearance Tagout Procedure
RWP	-	Radiation Work Permit
SR	-	Surveillance Requirements
SSPS	-	Solid State Protection System
TS	-	Technical Specification
TSAIL	-	Technical Specification Action Item Log
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
USQ	-	Unreviewed Safety Question
VIO	-	Violation
WO	-	Work Order