UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 19, 2001

Duke Energy Corporation
ATTN: Mr. G. R. Peterson
Site Vice President
Catawba Nuclear Station
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 50-413/00-06, 50-414/00-06

Dear Mr. Peterson:

On March 24, 2001, the NRC completed an inspection at your Catawba Nuclear Station. The enclosed report documents the inspection findings which were discussed on March 26, 2001, with you and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified three issues of very low safety significance (Green and No Color). One of these issues was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a non-cited violation, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny this non-cited violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Catawba facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system

(ADAMS). ADAMS is accessible from the NRC Web site at
http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,
/RA/

Robert C. Haag, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-413, 50-414
License Nos.: NPF-35, NPF-52

Enclosure: Inspection Report 50-413/00-06, 50-414/00-06
w/ Attached NRC's Revised Reactor Oversight Process

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REGION II

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|---|---|
| Docket Nos: | 50-413, 50-414 |
| License Nos: | NPF-35, NPF-52 |
| Report No: | 50-413/00-06, 50-414/00-06 |
| Licensee: | Duke Energy Corporation |
| Facility: | Catawba Nuclear Station, Units 1 and 2 |
| Location: | 4800 Concord Road<br>York, SC 29745 |
| Dates: | December 24, 2000 - March 24, 2001 |
| Inspectors: | D. Roberts, Senior Resident Inspector<br>R. Franovich, Resident Inspector<br>M. Giles, Resident Inspector<br>R. Carrion, Radiation Specialist (Sections 2OS1, 4OA1.2, and 4OA1.3)<br>J. Kreh, Emergency Preparedness Specialist (Section 1EP4) |
| Approved by: | R. Haag, Chief<br>Reactor Projects Branch 1<br>Division of Reactor Projects |

Enclosure

## SUMMARY OF FINDINGS

IR 05000413-00-06, IR 05000414-00-06, on 12/24/2000 - 03/24/2001, Duke Energy Corporation, Catawba Nuclear Station, Units 1 & 2 - Maintenance Rule Implementation and Surveillance Testing.

The inspection was conducted by resident inspectors, a regional health physics inspector and regional emergency preparedness inspector. The inspection identified one No-Color finding and two Green findings, one of which involved a non-cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using the Significance Determination Process (SDP) found in Inspection Manual Chapter 0609. Findings to which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html

### A. **Inspector Identified Findings**

**Cornerstone: Mitigating Systems**

- No Color. The inspectors identified a failure to identify two maintenance preventable functional failures (MPFFs) affecting the Unit 2 auxiliary feedwater system, one involving the turbine-driven auxiliary feedwater pump, the other involving the A motor-driven pump. Both of these occurred on October 5, 2000, following an inadvertent transfer of pump control to a local control panel. Although the finding did not involve a violation of the maintenance rule, it represented a recurring performance problem in this area as the latest of several missed maintenance preventable functional failure determinations involving different safety systems over the last year and a half.

  This finding was of very low safety significance because the failure to identify these MPFFs did not directly affect the ability of the auxiliary feedwater system to perform its safety function (Section 1R12.1).

- Green. The licensee failed to demonstrate that the performance or condition of the station drinking water system, a risk-important system that provides backup cooling water to the Unit 1 and 2 A train charging pump motors and bearing oil coolers, was being effectively controlled through the performance of appropriate preventive maintenance (including surveillance activities). This resulted in a failure to recognize and correct a degraded system pressure condition, until it was identified by the inspectors.

  The degraded pressure condition was determined to be of very low safety significance because an analysis performed by the licensee demonstrated that the backup function to cool the charging pumps and motors would have been provided at the degraded pressure (Section 1R12.2).

- Green. A non-cited violation was identified regarding the licensees failure to properly perform Technical Specification Surveillance Requirement 3.4.9.3, which verifies that pressurizer heaters can be automatically transferred from their normal power supplies to their emergency power supplies. Once identified, the portion of the automatic circuit that had been omitted from the test was properly tested on February 5, 2001, and was verified to be functional.  This finding had a credible impact on safety because the licensee had never demonstrated the full automatic capability of the power supply transfer circuitry for the pressurizer heaters, which are important for maintaining pressurizer pressure control during a loss of offsite power event.  The finding was also the latest in a number of missed surveillance requirements identified at Catawba over the last two to three years.

This finding was of very low safety significance because the circuit was functional when tested and because of provisions in the licensee's emergency procedures for manually aligning the heaters to their emergency power source had the automatic transfer failed during a loss of normal power event (Section 1R22).

**B.** **Licensee Identified Violations**

No violations of significance were identified.

# Report Details

Summary of Plant Status: Unit 1 began the inspection period at 61 percent power following a main turbine runback, which had occurred as the result of a 1A main feedwater pump trip on December 23, 2000. Unit 1 returned to 100 percent power on December 24, 2000. The unit operated at full power until January 17, 2001, when a turbine trip/reactor trip occurred while plant personnel were troubleshooting a previous weekly turbine test failure. The turbine tripped due to a combination of equipment problems and errors committed during the troubleshooting effort. Once the equipment was repaired, the turbine was returned to service and a reactor startup was commenced on January 18, 2001. Unit 1 power escalation was halted at 69 percent on January 19, 2001, while technicians attempted to resolve problems with placing the 1A main feedwater pump in service. Power was returned to 100 percent on January 21, 2001. The unit operated at full power until February 8, 2001, when another main turbine runback (to 61 percent) occurred following a repeat 1A main feedwater pump trip. The licensee initiated a root cause investigation for the recurring problems with the 1A pump, and discovered a common-mode failure susceptibility (undersized thrust bearing wear trip pressure switch instrument tubing) that potentially affected each of the main feedwater pumps on both units. As a result, following repairs to the 1A pump, the licensee reduced power to 51 percent on February 11, 2001, to restore the 1A pump and remove the 1B pump from service. Following repairs to the 1B pump, the unit reached 100 percent power on February 14, 2001. The unit operated at full power for the remainder of the inspection period.

Unit 2 operated at 100 percent power throughout the inspection period, except for a brief period from February 23 to February 27, 2001, when reactor power was reduced to 50 percent to perform repairs on both main feedwater pumps following the identification of undersized thrust bearing wear trip pressure switch instrument tubing.

## 1. REACTOR SAFETY
**Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity**

### 1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed partial walkdowns of the following equipment: (1) the 1A emergency diesel generator (EDG) and its support systems following a trip of the 1B EDG due to low lube oil pressure; (2) the Unit 1 charging (NV) system, including the A train pump's main and backup cooling water supplies, while the Unit 1 standby makeup pump was inoperable for planned maintenance; and (3) the remaining three channels of 125 Volt DC (Vdc) vital equipment (batteries, battery chargers, and inverters) on Unit 1 while the C vital battery was inoperable for maintenance. These partial walkdowns were conducted to verify the availability of redundant or diverse systems and components during time periods when safety equipment was inoperable. The walkdowns were performed to ensure that proper levels of defense-in-depth were maintained.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors toured six areas of the plant important to reactor safety to verify that combustibles and fire ignition sources were properly controlled, and that fire detection and suppression capabilities were intact. For areas where fire detection equipment was out of service, the inspectors verified that compensatory measures (i.e., fire watch tours) were properly implemented. For dry-pipe suppression systems, the inspectors verified that pre-fire plans specified proper steps for fire brigade personnel to activate the systems when needed. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis, probabilistic risk assessment (PRA)-based sensitivity studies for fire-related core damage accident sequences, and summary statements related to the licensee's 1992 Initial Plant Examination for External Events submittal to the NRC. Areas toured this quarter included the standby shutdown facility, the Unit 2 turbine building (specifically in the area of the 6.9 kilovolt power transformer), the Unit 1 vital battery/125 Vdc load center area, the Unit 1 auxiliary building around the 1B auxiliary building filtered exhaust fan (which had a failed fire detector in its charcoal filtration system), the Unit 2 train A 4160 Volt alternating current (Vac) switchgear area, and the 1B EDG (associated with welding activities in the area).

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors observed testing activities associated with the Unit 1 and Unit 2 B train component cooling water (KC) heat exchangers (HXs). The testing involved a differential pressure (dp) measurement across the HX tubes, which was performed to measure as-found resistance factors. The resistance factors were compared to acceptance criteria to determine system operability. The testing was performed using procedures PT/1(2)/A/4400/009, Cooling Water Flow Monitoring for Asiatic Clams and Mussels Quarterly Test, Revision (Rev) 48 (Unit 1) and Rev. 28 (Unit 2). The dp tests supplemented HX heat capacity testing (done per procedures PT/1/A/4400/06D, Rev. 2, KC Heat Exchanger 1B Heat Capacity Test; and PT/2/A/4400/006D, Rev. 6, KC Heat Exchanger 2B Heat Capacity Test), along with periodic cleaning of the HXs' tubes and tube sheets (model work orders 91007127 and 91007128 for Units 1 and 2, respectively). The inspectors reviewed the results of the latest completed heat capacity testing and tube cleaning activities for the two HXs. All of the above activities were observed or reviewed to verify that potential HX deficiencies, which could mask degraded performance, were identified and that the licensee had resolved potential heat sink performance problems.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed a control room simulator training scenario on February 16, 2001, to assess licensed operator and crew performance. The training scenario involved a series of equipment failures, including a pressurizer spray valve that spuriously opened, a loss of A train normal (offsite) power, a failure of the turbine-driven auxiliary feedwater (CA) pump, a trip of the A train EDG, and a rapid loss of condenser vacuum. Following the simulator scenario, the inspector observed the exercise critique to assess the licensee's effectiveness at recognizing and addressing operator or simulator performance problems.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

.1 Review of Various Equipment Performance Issues

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule (10 CFR 50.65) to determine whether responsible personnel were properly evaluating the effectiveness of maintenance on equipment important to safety. To this end, the inspectors verified that the licensee was properly classifying maintenance preventable functional failures (MPFFs). Systems, structures, and components (SSCs) were also reviewed for proper scoping and risk categorization within the licensee's tracking system. The inspectors conducted this inspection with respect to the six equipment issues/SSCs identified in the following Problem Investigation Process reports (PIPs):

| PIP | Equipment Problem |
|---|---|
| C-00-04766 | Inadvertent transfer of CA pumps to local control |
| C-01-00057 | Station drinking water (YD) system header pressure reading less than the 60 pounds per square inch gauge (psig) required by Selected Licensee Commitment (SLC) 16.9-24 |
| C-01-00552 | 1B EDG tripped on low and low-low lube oil pressure |
| C-00-05715 | Containment purge system valves failed Type C leak rate tests |
| C-00-06162 | Control room ventilation system chiller tripped due to compressor high bearing oil temperature |
| C-01-00276 | Unit 1 Turbine Trip Caused Reactor Trip |

b. Findings

No findings were identified for four of the six items above; however, two findings of very low safety significance (Green and No Color) were identified as described in this section and in Section 1R12.2 below.

A No Color finding was identified for failing to identify two maintenance preventable functional failures associated with PIP C-00-04766, which addressed a problem with the Unit 2 turbine-driven CA pump and the A train motor CA driven pump. The PIP identified that the turbine-driven CA pump was briefly rendered inoperable on October 5, 2000, when plant personnel inadvertently transferred control of the pump from the main control room to the local control panel located in the auxiliary building. Operators declared the pump inoperable upon receiving main control room alarms associated with the transfer. They immediately responded to the local panel and found technicians working in the area on an unrelated item. Operators found the A train local transfer switch in the mid position, which had caused the inadvertent transfer. They immediately returned the switch to the correct position, which restored the pump to operable status.

The licensee attributed the cause of the transfer to someone inadvertently repositioning the switch during maintenance activities. The PIP included a corrective action to evaluate the need for providing controls to prevent future inadvertent transfers. However, no maintenance rule evaluation was conducted for this incident. An oversight during the PIP screening process resulted in the maintenance rule evaluation not being performed. The inspectors reviewed the closed PIP during this inspection period and questioned the lack of an MPFF determination. The licensee reopened the PIP evaluation and determined that this transfer of control resulted in both the turbine-driven pump and the A train motor-driven pump being incapable of automatically starting on a CA autostart signal, and the transfer would have prevented associated valves from automatically realigning the pumps' suction piping to the dedicated nuclear service water (RN) system if called upon. Because the motor-driven pumps and the turbine-driven pump are scoped separately in the CA system maintenance rule scoping document, this human performance incident resulted in two MPFFs that were not previously identified by the licensee.

The inspectors reviewed the total number of MPFFs associated with the CA system for the last two years and determined that these two would not have caused the system to exceed the licensee's criteria for having to monitor the system against performance goals and establish corrective actions as would be required by 10 CFR 50.65 (a)(1). Therefore, no maintenance rule violation was identified. However, these were the latest in a number of examples of missed MPFF determinations that the inspectors have identified over the past 18 months. Other missed MPFFs have involved the containment valve injection water system, the residual heat removal and containment spray pump area sump level interlock function, and a steam generator power-operated relief valve (PORV). An additional maintenance rule program implementation issue is discussed in Section 1R12.2 of this report. Using guidance contained in Manual Chapter 0610*, Appendix B, and in the NRC Enforcement Manual (NUREG/BR-0195, Rev. 3, Appendix A), the inspectors determined that the recurring nature of this performance issue made it more than minor. However, the licensee's failure to classify the CA pump problems as MPFFs did not directly result in equipment unavailability; therefore, this issue was determined to have very low safety significance. Since this performance issue (failure to classify MPFFs) did not directly impact a cornerstone, this finding has a No Color classification.

.2 Maintenance Rule Activities Associated with Backup Cooling for the A Train Charging (NV) Pumps

a. Inspection Scope

The inspectors reviewed the licensee's maintenance rule activities for the YD system, which had been modified to serve as a backup cooling source for the 1A and 2A NV pumps (which are also the high head safety injection pumps) and their motors. The modifications were implemented to reduce the station's overall core damage frequency (CDF) by 45 percent for both units. The modification was intended to mitigate the large contribution to CDF from postulated accident sequences involving losses of the KC system (the primary NV pump cooling source). A loss of cooling to the NV pumps could cause them to fail, which could result in a loss of seal injection water to the reactor coolant (NC) pumps. This could ultimately result in a NC pump seal failure and a loss of coolant accident. The inspectors conducted this review to verify that the YD system had been incorporated into the scope of the maintenance rule and effective controls were in place for maintaining the system.

b. Findings

A Green finding was identified for the licensee's failure to demonstrate that the performance or condition of the YD system had been effectively controlled through appropriate preventive maintenance or surveillance testing.

The YD system was modified in May 1999 (Unit 1) and March 2000 (Unit 2) to provide backup cooling to the 1A and 2A NV pumps and motors. Calculations performed in support of the modifications used a YD system header pressure of 60 psig to demonstrate that resulting flow rates and heat transfer would be adequate to cool the NV pump motors and bearings.

The licensee appropriately included the YD system function of providing backup cooling to the 1A and 2A NV pumps and motors into the scope of the maintenance rule. The system function description, as stated on the licensee's YD system scoping summary sheet, was to provide cooling to the NV pumps when the KC system is unavailable. A performance criterion note on the licensee's SSC Summary Sheet indicated that YD system reliability would be tracked by the performance of a flow test every outage. Similarly, system availability would be tracked by SLC 16.9-24, which required that the system be capable of supplying 60 psig at the station supply header. In station PIP C-99-03255, the licensee indicated that the surveillance required to meet the intent of the SLC should consist of a weekly check to verify an acceptable system header pressure of 60 psig.

On December 28, 2000, the inspectors identified low pressure indications on the system header (45 psig and 50 psig) that affected both Units. The licensee determined that the degraded pressure condition was caused by improperly set pressure control regulators, which had not been adjusted since before the modifications were implemented. The licensee initiated PIP C-01-00057 to document the degraded pressure condition and performed a calculation to determine if the YD system's backup cooling function was affected. The calculation indicated that a system header pressure as low as 40 psig would provide adequate flow rates for effective heat transfer. After the degraded condition was identified by the inspectors, the licensee conservatively included the YD system's unavailability in their daily evaluation of online risk impact to the plant [per 10 CFR 50.65 (a)(4)] until corrective maintenance was performed on January 4, 2001, to increase system header pressure to the 60 psig SLC requirement.

In reviewing the SLC document, the inspectors determined that a testing requirement to verify adequate YD system flow through the NV pump at least once per 18 months was specified for monitoring system reliability. However, no periodic surveillance test to verify acceptable system header pressure (and hence system availability) was performed, and no preventive maintenance provisions were established for the YD system to ensure that its backup cooling function would be provided when needed. The inspectors concluded that the licensee failed to demonstrate that the performance or condition of the YD system was being effectively controlled through the performance of appropriate preventive maintenance. Specifically, the licensee failed to set up a surveillance program for monitoring system availability and, as a result, did not detect a degraded pressure condition that had existed since May 1999 (Unit 1) and March 2000 (Unit 2).

The inspectors also noted that the YD system's maintenance rule function description (in the SSC summary sheet) was not sufficiently independent in that a functional failure of the YD system would be predicated by the unavailability of the very system (KC) it was designed to backup. As such, the YD system's maintenance rule function description was not adequate to ensure that actual failures of the system would be tracked, and corrective action would be taken, to improve system reliability before a concurrent loss of KC event would occur.

The YD system's availability as a backup cooling source for the NV pumps is assumed in the licensee's online risk monitoring program. The failure to adequately monitor the YD system's condition or performance, or to establish periodic maintenance to ensure the system was capable of performing its intended function had a credible impact to the plant. This was because degraded pressure conditions could go undetected and the consequential loss of the system's function would not be accounted for in determining the risk associated with removing other equipment (with redundant functions to cool NC pump seals and prevent seal failure) from service for maintenance. If not corrected, a degraded condition and system unavailability could exist for an entire cycle without being detected and result in increased risk of core damage (as a result of the unavailability of redundant equipment) to both units. Therefore, the inspectors concluded that this issue was more than minor. Because the degraded YD system pressure condition did not result in an actual loss of the backup cooling function, the inspectors concluded that the item did not constitute a violation of 10 CFR Part 50.65 and was of very low safety significance (Green).

## 1R13 Maintenance Risk Assessments and Emergent Work Evaluation

### a. Inspection Scope

The inspectors reviewed the licensee's assessments of the risk impact of removing from service those components associated with the six emergent and planned work items listed below, focusing primarily on activities determined to be risk-significant within the maintenance rule. These six plant configurations were reviewed to verify that the licensee was taking actions to minimize the probability of initiating events, maintain the functional capability of mitigating systems, and maintain barrier integrity. In addition to the items below, the inspectors reviewed PIP C-01-00488 which the licensee generated in response to an inspector-identified discrepancy involving the methodology by which different operators access data for ORAM-Sentinel "what-if" scenarios, which yielded inconsistent results for the calculated online plant risk. The inspectors performed a problem identification and resolution evaluation to verify that the licensee had identified and implemented appropriate corrective actions for this item.

| Component or System | Reason for Removal from Service |
|---|---|
| 1B motor-driven CA pump | Planned surveillance testing |
| Containment valve injection water (NW) train B | Delays in corrective maintenance on 1NW-68B caused its unavailability to be extended by several days |
| YD system (backup cooling for A train charging pumps) | Potential unavailability due to degraded pressure condition |
| NW train B | A non-PRA coded maintenance activity that rendered the B train inoperable |
| Unit 1 standby makeup pump | Planned work while turbine-driven CA pump was unavailable |
| E instrument air compressor | Air compressor failed due to human error while D compressor was inoperable for maintenance |

### b. Findings

No findings of significance were identified.

## 1R14 Personnel Performance During Nonroutine Plant Evolutions

### a. Inspection Scope

The inspectors observed or reviewed licensee performance during and following off-normal plant evolutions and transients, including a Unit 1 reactor trip on January 17, 2001; a Unit 1 turbine runback to 61 percent power on February 8, 2001; and operator response to equipment malfunctions resulting from elevated control room temperatures following a malfunction of the control room ventilation system on

March 23, 2001. These reviews were conducted to determine if operator actions were appropriate and in accordance with plant procedures and training. The inspectors also reviewed the procedures for adequacy.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability determinations (or justifications for continued operation) to verify that the operability of systems important to safety was properly established, that the affected component or system remained available to perform its intended safety function, and that no unrecognized increase in plant or public risk occurred. Operability evaluations were reviewed for the six issues listed below:

| PIP Number | Issue |
|---|---|
| C-01-00035 | 2SV-7, Steam Generator C PORV, nitrogen leak |
| C-01-00057 | Operability of the YD system at less than 60 psig system header pressure |
| C-00-06016 | Degraded condition involving apparent gas accumulation in A train residual heat removal HX |
| C-00-06127 | 1A cold leg accumulator leakage into safety injection discharge header |
| C-00-06360 | Justification for continued operation following an NRC-identified discrepancy with pressurizer heater surveillance testing |
| Not Applicable | Operability of the 1B RN pump with control room annunciator 1AD12-A/4 (RN Pump B Flow Hi/Low) inoperable |

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the post-modification tests associated with the May 1999 (Unit 1) and March 2000 (Unit 2) design changes to the YD system (backup cooling to NV pumps and motors) to determine if acceptance criteria were met. Acceptable flow rates were obtained by throttling valves in the flow path to balance coolant flow to the NV pump motor and oil coolers. The inspectors also reviewed abnormal procedure AP/1/A/5500/21, Loss of Component Cooling, Rev. 24, to verify that it provided similar guidance for adjusting valves and obtaining desired flow rates to support the YD system's backup cooling function. The modifications were governed by the following station documents:

| Nuclear Station Modification Number | Description |
|---|---|
| NSM CN-11389 | Unit 1 modification to YD system to provide backup cooling to A train NV pump |
| NSM CN-21389 | Unit 2 modification to YD system to provide backup cooling to A train NV pump |

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors observed or reviewed post-maintenance tests associated with the following six work activities to verify that equipment was properly returned to service and that proper testing was specified and conducted to ensure that the equipment could perform its intended safety function following maintenance.

| Test Procedure/Work Order (WO) Number | Maintenance/Test Activity |
|---|---|
| PT/2/A/4200/007B, Rev. 31 | 2B NV pump test following oil leak repair |
| PT/2/A/4450/003C, Rev. 24 | 2B containment annulus ventilation system maintenance (pressure controller replacement, pressure transmitter removal and reinstallation, and power supply replacement) to correct a pressure loop calibration problem following preventive maintenance |
| PT/1/A/4350/002B, Rev. 97 | Corrective maintenance following 1B EDG trip on low and low-low lube oil pressure during a monthly one-hour surveillance test |
| PT/1/A/4200/13, Rev. 23 | 1RN-63A valve inservice test following valve actuator preventive maintenance |
| PT/1/A/4200/010A, Rev. 65 | Residual heat removal pump 1A performance test following pressure instrument calibration |

| Test Procedure/Work Order (WO) Number | Maintenance/Test Activity |
|---|---|
| WO 98285557 | Testing of D instrument air compressor following overhaul activities |

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the six test procedures listed below to verify that Technical Specification (TS) surveillance requirements (SR) and/or SLC requirements were properly incorporated and that test acceptance criteria were properly specified. The inspectors observed actual performance of some of the tests and reviewed completed procedures to verify that acceptance criteria had been met. The inspectors also verified that proper test conditions were established in the procedures and that no equipment preconditioning activities were being conducted.

| Procedure Number | Title |
|---|---|
| PT/1/A/4250/003B, Rev. 40 | Auxiliary Feedwater Motor Driven Pump 1B Performance Test |
| PT/1/A/4200/004B, Rev. 51 | Containment Spray Pump 1A Performance Test |
| PT/2/4250/003C, Rev. 62 | Turbine Driven Auxiliary Pump #2 Performance Test |
| IP/2/A/3200/008B, Rev. 24 | Unit 2, Train B, Reactor Trip Breaker Testing |
| PT/1/A/4200/09, Rev. 167 | Engineered Safety Features (ESF) Actuation Periodic Test (reviewed for implementation of TS SR 3.4.9.3) |
| IP/1/B/3112/004, Rev. 51 | Calibration Procedure of Non-Safety Related RN Intake Structure Instrumentation |

b. Findings

A Green finding that was dispositioned as a non-cited violation (NCV) was identified for failure to properly implement TS SR 3.4.9.3, which directs the licensee to demonstrate that “required pressurizer heaters are capable of being powered from an emergency power supply” every 18 months. The TS Basis for this SR states, “this Surveillance demonstrates that the heaters can be automatically transferred from the normal to the emergency power supply.”

The A and B banks of pressurizer heaters for both units are covered by the TS SR, and the normal and emergency power schemes for the heaters are identical for both banks in each unit. The heaters' normal power supply is provided via a 4160 Vac non-safety related "blackout switchgear" designated as 1(2)FTA(B). Emergency power is provided by the EDG via 4160 Vac essential switchgear 1(2)ETA(B). (For clarity, future component references in this writeup will use the non-unit specific A train designation, i.e., FTA, GTA, or ETA.)

Blackout switchgear FTA is normally energized from offsite power through 4160 Vac breaker GTA1 and a 6900/4160 Vac unit auxiliary transformer. During a postulated loss of offsite power event, bus FTA is disconnected from the offsite power grid by a protective undervoltage relay, which automatically trips open the normal supply breaker GTA1. This defeats an interlock between GTA1 and tie breakers ETA2 and FTA1, which allows the tie breakers to close and connect blackout bus FTA to essential switchgear ETA. The interlock is intended to prevent the undesirable cross-tying of the normal and emergency power supplies, which in the presence of a fault could potentially damage the switchgear or the EDG and result in a loss of power to other safety related loads. The licensee designed the entire sequence described above to happen automatically upon a loss of offsite power.

Periodic test procedure PT/1/A/4200/009 was intended to implement SR 3.4.9.3. During a review of this procedure, the inspectors identified that it directed plant personnel to *manually* open breaker GTA1 such that the cross-tie interlock would essentially be set up prior to initiating automatic actuations. Later in the test, the procedure directed technicians to generate a degraded voltage signal on essential switchgear ETA, which would ultimately result in the actuation of the EDG and its load sequencer. The EDG would subsequently re-energize essential bus ETA and the sequencer would close the two tie breakers connecting the pressurizer heaters to their emergency power source. However, the test procedure did not provide for the *automatic* opening of breaker GTA1 by the undervoltage relay. The successful closure of the two emergency supply tie breakers is dependent upon the opening of breaker GTA1, and the inspectors questioned if a portion of the automatic GTA1 trip logic circuitry was not being tested as a result of the licensee's manual opening of the breaker during the test sequence. The inspectors' reviews of station electrical drawings and undervoltage relay calibration procedure IP/1/B/4971/025A, Rev. 002, 1FTA 4160 Volt Blackout Switchgear Protective Relays, confirmed that the automatic and manual trip logic circuit paths were parallel to each other and that a portion of the GTA1 breaker automatic trip circuitry was not being tested.

When notified of this deficiency, the licensee initially attempted to resolve it by crediting the undervoltage relay calibration procedure as satisfying the TS SR. They stated that proper overlap existed between the calibration procedure and the ESF test procedure, PT/1/A/4200/009, to test the entire automatic actuation circuitry. This evaluation was documented in PIP C-00-06360. However, the inspectors later identified that, even considering the calibration procedure, the licensee had not completely tested the automatic function (which also included a separate latching relay that had not been accounted for). Furthermore, both the Unit 1 and Unit 2 A train calibration procedures were last performed in December 1998, placing both units beyond the 18-month surveillance frequency specified by TS SR 3.4.9.3. On February 5, 2001, the licensee concluded that the surveillance requirement had not been fulfilled for either unit and entered TS SR 3.0.3, which allowed them 24 hours to properly test the function. The inspectors reviewed the testing performed on February 5, 2001, and determined it to be adequate.

The pressurizer heaters are important for maintaining control of reactor coolant system pressure and maintaining natural circulation of reactor coolant following a loss of offsite power event. The failure to properly test the automatic function had a credible impact on safety in that, had the automatic circuitry not operated during an event, operators would have had to defer to emergency procedures containing multiple steps for manually aligning the heaters to their emergency power source. The inspectors determined that this missed surveillance was more than minor in that it represented the latest in a number of documented test deficiencies in the licensee's surveillance program over the last two years. Additionally, in May 1998, the licensee had identified a problem with the implementation of this test requirement as documented in Licensee Event Report (LER) 50-413/98-006. The inspectors considered the 1998 problem to be a previous opportunity for the licensee to identify the test deficiency discussed in this report. However, because the automatic logic circuitry performed as expected when tested in February 2001, and because the heaters, by design, are not sequenced onto the emergency bus for at least 12 minutes following a loss of offsite power, the failure to properly test the automatic transfer capability was of very low safety significance (Green).

The failure to properly test the automatic transfer capability was considered a violation of TS SR 3.4.9.3. This violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-413,414/00-06-01: Failure to Adequately Perform TS SR 3.4.9.3 for Pressurizer Heaters. This violation has been captured in the licensee's corrective action program as PIP C-00-06360.

1R23 <u>Temporary Plant Modifications</u>

a. <u>Inspection Scope</u>

The inspectors reviewed a temporary modification this quarter to verify that important safety system functions were not affected. The modification, CNTM-0007, essentially disabled the reactor coolant pump (RCP) 1A input to a control room annunciator for lower bearing high temperature alarm (a possible indication of a loss of RCP seal injection water). The modification was developed to eliminate nuisance alarms associated with 1A RCP lower bearing temperature until the root cause of a "noise spike" could be identified and corrected. The modification included provisions for slightly increasing an operator aid computer alarm setpoint, which remained functional to compensate for the defeated annunciator input from the 1A RCP. The inspectors verified that an alarm function was available for Number 1 seal outlet high temperature as an alternative indication of loss of seal injection water and an associated lower bearing high temperature condition.

b. <u>Findings</u>

No findings of significance were identified.

**Cornerstone: Emergency Preparedness**

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes

a. Inspection Scope

The inspectors conducted an in-office review of changes to the Emergency Plan, as contained in Revisions 00-1 and 00-2, against the requirements of 10 CFR 50.54(q) to determine whether any of those changes decreased Plan effectiveness. Revision 00-1 included major changes to the EALs (namely, incorporation of an EAL methodology based on NUMARC/NESP-007, Revision 2) that had been submitted to the NRC for approval prior to implementation. The inspectors reviewed whether the EAL modifications in Revision 00-1 were discussed with, and agreed upon by, State and local officials prior to implementation, as required by Section IV.B of Appendix E to 10 CFR Part 50.

b. Findings

No findings of significance were identified.

**2. RADIATION SAFETY**
**Cornerstone: Occupational Radiation Safety**

2OS1 Access Control to Radiologically-Significant Areas

a. Inspection Scope

The inspectors reviewed licensee procedure SH/0/B/2000/012, Revision 001, Access Controls for High, Extra High, and Very High Radiation Areas, and observed work conducted in a posted extra high radiation area, including the support by health physics personnel who monitored the dose received by the workers. Associated with that work, the inspectors observed a job planning session, which reviewed the work to be performed, and the pre-job briefing, which reviewed radiological conditions of the work area and Radiation Work Permit (RWP) 4028, General Entry into Room 315, Extra High Radiation Area, Revision 1, with the personnel who were scheduled to perform the tasks. Training records for the workers assigned to work in the extra high radiation area were also reviewed by the inspectors. In addition, the inspectors reviewed the licensee's program with respect to control of keys to locked high radiation and very high radiation areas, including the key sign out log, against the requirements of 10 CFR 20.1601 and 20.1602.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

### 4OA1 Performance Indicator (PI) Verification

.1 Reactor Safety PIs

a. Inspection Scope

The inspectors conducted annual reviews of the following two Reactor Safety PIs, as submitted to the NRC by the licensee, for accuracy:

| Cornerstone | PI |
|---|---|
| Barrier Integrity | Reactor Coolant System Identified Leak Rate |
| Mitigating Systems | Safety System Functional Failures (SSFFs) |

This review was conducted for fourth quarter 2000 PI data submitted to the NRC on or about January 21, 2001. To verify the PI data, the inspectors reviewed control room logs, results of completed daily surveillance tests for reactor coolant system leakage calculations, and LERs for the year 2000. The inspectors verified samples of data for the entire period covered by the PI under review (e.g., for PIs covering four quarters, the inspectors reviewed samples of data for the three quarters immediately prior to fourth quarter 2000 in addition to that quarter's data).

b. Findings

There were no findings of significance associated with the inspectors' review. However, the inspectors identified a potential discrepancy with the licensee's determination that the Unit 2 hydrogen ignition system (HIS) did not incur a functional failure when both trains were determined to be inoperable between April 8 and April 26, 2000. A performance indicator interpretation feedback form was submitted of the Office of Nuclear Reactor Regulation (NRR) to resolve the discrepancy. Because this potentially reportable SSFF would not result in increased agency attention (i.e. correction would not result in the indicator crossing a threshold), this potential discrepancy is considered minor.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed licensee PIPs for the previous 12 quarters (first quarter 1998 through fourth quarter 2000) for high radiation area, very high radiation area, and unplanned exposure occurrences to assess whether non-conformances were properly classified as PIs. The licensee's database, which contains radiologically-controlled area (RCA) exit transactions with exposures greater than 100 milli-roentgen equivalent man (mrem), was reviewed by the inspectors to determine whether the exposures were within radiation work permit (RWP) limits and whether any met this criteria for a PI.

b. Findings

No findings of significance were identified.

.3 Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual (RETS/ODCM)-Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed PIP reports for liquid and gaseous effluent releases that were reported to the NRC. In addition, the inspectors reviewed the effluent release information for the past four quarters (CY 2000) which was being assembled for the 2000 Annual Radioactive Effluent Release Report to assess whether all radiological effluent release occurrences in excess of limits were counted as PIs.

b. Findings

No findings of significance were identified.

.4 (Closed) URI 50-414/00-04-03: Minor PI Discrepancy Associated with the "Scram with Loss of Normal Heat Removal" indicator (June 5, 2000, Unit 2 reactor trip). This item was opened to determine whether the subject reactor trip event should have been characterized as one involving a loss of normal heat removal. After the inspectors consulted with the NRC Office of Nuclear Reactor Regulation (NRR), and after the licensee independently consulted with NEI, the inspectors determined that, because there was conflicting guidance governing the reportability of this event, the licensee's decision to report it as an "Unplanned Scram per 7000 Critical Hours" instead of one involving a loss of normal heat removal was acceptable.

.5 (Closed) URI 50-414/00-04-04: Potential Discrepancy with the "Safety System Unavailability - Auxiliary Feedwater System" PI (2CA-15A valve failure). This item was opened to determine whether or not the licensee could credit mitigative operator actions in their decision not to report fault exposure hours associated with the subject valve failure in their second quarter 2000 PI data. Two questions were answered: (1) can control room operator actions, in general, be considered legitimate mitigative actions to credit when determining not to report fault exposure hours associated with equipment failures; and (2) could operator actions at Catawba following the subject valve failure prevent the A train motor-driven CA pump from becoming unrecoverable.

After consulting with NRR, the inspectors determined that, in this case, the licensee could take credit for control room operator actions (provided they occur within 10 minutes or before (which ever time period is shorter) the affected function is lost due to pump damage). The licensee concurrently performed an extensive engineering evaluation and determined, primarily with engineering judgement, that operator actions would occur within 10 minutes to open 2CA-15A and restore the function of the 2A motor-driven CA pump before it failed. This evaluation was documented in the licensee's corrective action program in PIP C-00-01692. The inspectors verified that emergency procedures described in the licensee's evaluation were in place and concluded that it was likely that operators would properly respond to the valve failure. Therefore, the inspectors concluded that the licensee's decision to not report fault exposure hours associated with the March 31, 2000, valve 2CA-15 failure was acceptable.

4OA3 Event Follow-up

.1 Unit 1 Reactor Trip on January 17, 2001

a. Inspection Scope

The inspectors responded to the control room and toured the turbine building following an uncomplicated Unit 1 turbine/reactor trip on January 17, 2001. The trip was reported to the NRC in LER 50-413/01-001. This LER is discussed in paragraph 40A3.3 below. The inspectors also inspected portions of this event and the licensee's performance under IP 71111.14 (see Section 1R14). This inspection was performed to verify that safety equipment responded as designed and to provide input to regional management for determining the need for additional NRC response.

b. Findings

No findings of significance were identified.

.2 (Closed) LER 50-413/00-006: Invalid Engineered Safety Features Actuation Occurred During Calibration of Pressurizer Pressure Instrumentation Channels as a Result of a Defective Procedure.

This event occurred on November 10, 2000, while Unit 1 was in Mode 6 during the end-of-cycle 12 refueling outage. The licensee documented the root cause of this event to be an inadequate procedure. The licensee determined that IP/1/A/3222/059C, Pressurizer Pressure, Protection Channel 3, Loop 1NCPT5170 (PT-457) Calibration, contained inadequate instructions for existing plant conditions, in that it did not verify the status of the remaining pressurizer pressure channels prior to removing channel 3 from service for calibration. Pressurizer pressure channel 2 was already in a tripped condition when channel 3 was removed from service, satisfying the 2-out-of-4 pressurizer low pressure actuation logic, which generated a safety injection signal, causing sequencer actuation and the operation of ESF equipment. This event was documented as PIP C-00-05709 in the licensee's corrective action program. Failure to provide an adequate procedure for controlling the ESF system while performing calibration of pressurizer pressure channel 2 was contrary to TS 5.4.1 and Regulatory Guide 1.33 [Item 8.b(1)(l)]. The inspectors concluded that this non-compliance had no actual or credible impact on plant safety based on system configuration at the time of the event. Affected systems had been procedurally removed from service (placed in recirculation mode) and the solid state protection system was not required to be operable at the time. The inspectors also determined that had this procedure been used in a plant operating mode other than cold shutdown, sufficient administrative controls were in place to prevent a similar event from occurring. This noncompliance, therefore, constitutes a violation of minor significance and is not subject to formal enforcement action. The inspectors' review of this LER identified no additional findings of significance. This LER is closed.

.3 (Closed) LER 50-413/01-001: Reactor Trip Caused by a Turbine Trip Due to Incomplete Troubleshooting Analysis.

This event, which occurred on January 17, 2001, when Unit 1 was operating in Mode 1, was captured in the licensee's corrective action program as PIP C-01-00276. The inspectors reviewed the LER and no findings of significance were identified. Performance problems associated with the troubleshooting effort did not constitute a violation of NRC requirements. This LER is closed.

4OA5 Other

Institute of Nuclear Power Operations (INPO) Report Review

The inspectors reviewed the final report issued by INPO for the evaluation that was conducted at the Catawba facility during the weeks of July 10 and 17, 2000. The inspectors did not note any safety issues in the INPO report that either warranted further NRC followup or that had not already been addressed by the NRC.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Gary Peterson, Site Vice President, and other members of licensee management at the conclusion of the inspection on March 26, 2001. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

E. Beadle, Emergency Preparedness Manager
R. Beagles, Safety Review Group Manager
M. Boyle, Radiation Protection Manager
G. Gilbert, Regulatory Compliance Manager
R. Glover, Operations Superintendent
W. Green, Work Control Superintendent
P. Grobusky, Human Resources Manager
P. Herran, Engineering Manager
R. Jones, Station Manager
R. Parker, Maintenance Superintendent
G. Peterson, Catawba Site Vice President
F. Smith, Chemistry Manager
R. Sweigart, Safety Assurance Manager

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed During this Inspection

| | | |
|---|---|---|
| 50-413,414/00-06-01 | NCV | Failure to Adequately Perform TS SR 3.4.9.3 for Pressurizer Heaters (Section 1R22) |

Previous Items Closed

| | | |
|---|---|---|
| 50-414/00-04-03 | URI | Minor PI Discrepancy Associated with the “Scram with Loss of Normal Heat Removal” indicator (June 5, 2000, Unit 2 reactor trip) (Section 40A1.4) |
| 50-414/00-04-04 | URI | Potential Discrepancy with the “Safety System Unavailability - Auxiliary Feedwater System” PI (2CA-15A valve failure) (Section 40A1.5) |
| 50-413/00-006 | LER | Invalid Engineered Safety Features Actuation Occurred During Calibration of Pressurizer Pressure Instrumentation Channels as a Result of a Defective Procedure (Section 40A3.2) |
| 50-413/01-001 | LER | Reactor Trip Caused by a Turbine Trip Due to Incomplete Troubleshooting Analysis (Section 40A3.3) |

Discussed

None

# NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

**Reactor Safety**

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

**Radiation Safety**

- Occupational
- Public

**Safeguards**

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

Attachment