UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-413/94-09 and 50-414/94-09

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

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

Facility Name: Catawba Nuclear Station Units 1 and 2

Inspection Conducted: February 6, 1994 - March 5, 1994

Inspectors: W. H. Miller Jr. 3/17/94
for R. J. Freudenberger, Senior Resident Inspector Date Signed

P. C. Hopkins, Resident Inspector
J. Zeiler, Resident Inspector
C. Yates, Intern
J. Bartley, Inspector, Region II

Approved by: M Lesser 3/21/94
Mark S. Lesser, Chief Date Signed
Projects Section 3A
Division of Reactor Projects

SUMMARY

Scope: This resident inspection was conducted in the areas of review of plant operations, maintenance, engineering, plant support and followup of previously identified items and Licensee Event Reports. Backshift inspections were conducted on February 7, 8, 9, 10, 11, 14, 15, 18, 22, 23, 24, 25, and March 1, 2, 3, 4, and 5.

Results: In the operations area, good performance was noted with regard to operator response to a Unit 2 condenser vacuum transient during a power reduction. Good plant management involvement and direction was noted in the licensee's investigation of the transient (paragraph 3.b).

In the maintenance area, good preplanning and consideration for potential safety concerns was noted for the Unit 2 Upper Containment Ventilation System pipe replacement. However, NRC inspection of the activity identified a weakness in the implementation of actions to control loose material inside containment (paragraph 4.a). NRC inspection of differential

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pressure testing of valve 1KC-C37A noted a weakness in the control of plant systems necessary to support the testing (paragraph 4.b).

In the engineering area, licensee identification and assessment of an operability concern which arose due to inaccurate determination of control rod reference position was timely and thorough (paragraph 5).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

B. Addis, Training Manager
S. Coy, Radiation Protection Manager
*J. Forbes, Engineering Manager
W. Funderburk, Work Control Superintendent
T. Harrall, IAE Superintendent
*W. McCollum, Station Manager
W. Miller, Operations Superintendent
*K. Nicholson, Compliance Specialist
*M. Patrick, Safety Assurance Manager
R. Propst, Chemistry Manager
D. Rehn, Catawba Site Vice-President
J. Roach, Security Manager
D. Rodgers, Mechanical Superintendent
*Z. Taylor, Compliance Manager

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

NRC Resident Inspectors

R. Freudenberger, Senior Resident Inspector
P. Hopkins, Resident Inspector
*J. Zeiler, Resident Inspector
*C. Yates, Intern

* Attended exit interview.

Acronyms and abbreviations used throughout this report are listed in the last paragraph.

2. **PLANT STATUS**

a. Unit 1 Summary

Unit 1 operated at essentially 97 percent power for the entire report period. Power was restricted to less than 98 percent on January 10 due to total reactor coolant flow being measured less than the required Technical Specification value for 100 percent power operation.

b. Unit 2 Summary

Unit 2 began the report period at full power. On February 21, a power reduction to 15 percent power was initiated in order to add oil to the lower bearing reservoir of the "B" Reactor Coolant Pump motor. On February 23, following the completion of this activity, power increase commenced. The unit reached full power on February 25 and operated at essentially full power for the remainder of the report period.

c. Inspections and Activities of Interest

During the week of February 7, a specialist inspection of the licensee's Emergency Operating Procedures program was conducted. Results of this inspection are documented in NRC Inspection Report 50-413, 414/94-02.

During the week of February 7, a specialist inspection of the licensee's security area was conducted. Results of this inspection are documented in NRC Inspection Report 50-413, 414/94-06.

During the week of February 28, a specialist inspection of the licensee's annual Emergency Preparedness exercise was conducted. The annual exercise was conducted on March 1. Results of this inspection are documented in NRC Inspection Report 50-413, 414/94-08.

In addition, on February 9, A. Herdt, the NRC Region II Branch Chief, Division of Reactor Projects, was on site for a management visit.

3. **OPERATIONS** (NRC Inspection Procedures 30702, 71707, 93702)

Throughout the inspection period, facility tours were conducted to observe operations and maintenance activities in progress. The tours included entries into the protected areas and the radiologically controlled areas of the plant. During these inspections, discussions were held with operators, radiation protection, and instrument and electrical technicians, mechanics, security personnel, engineers, supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections confirmed Duke Power's compliance with 10 CFR, Technical Specifications, License Conditions, and Administrative Procedures.

a. Unit 2 Reactor Coolant Pump Motor Oil Level Problem

Several times between February 9 and 21, the low level annunciator for the Unit 2 "B" reactor coolant pump motor lower bearing oil reservoir alarmed indicating that the level in the reservoir had reached the low level setpoint. Each time the alarm annunciated, the operators observed no change in any of the pump operating parameters. This 25 gallon reservoir contains oil that is used to lubricate the motor's lower guide bearing.

On February 21, licensee management decided to reduce power to 15 percent in order to send personnel inside lower containment to investigate the potential oil loss and to refill the oil reservoir if necessary. At 9:45 p.m., the power reduction was initiated at a rate of 2.5 percent per hour. On February 23, 15 percent power was reached and maintenance personnel entered containment to investigate the oil loss. There was no oil accumulation discovered in the vicinity of the pump and only approximately 1 gallon of oil had to be added to the lower reservoir. Based on the small amount of oil added, the licensee determined that the low oil level setpoint was out-of-calibration and the alarm had annunciated prior to reaching the true low level setpoint. The licensee plans to calibrate this instrumentation during the upcoming refueling outage. The unit returned to full power on February 25. The inspector monitored the licensee's activities with regard to the oil problem and concluded that their actions were appropriate.

b. Unit 2 Vacuum Decrease Transient

On February 22, while decreasing reactor power to 15 percent in order to add oil to the Unit 2 "B" reactor coolant pump motor, an unexpected decrease in condenser vacuum occurred. The unit was at approximately 55 percent power when vacuum began slowly decreasing. The operators recognized the decrease and entered the applicable abnormal operating procedure for a loss of condenser vacuum. While implementing this procedure, the RO noticed that the turbine steam seal header pressure was fluctuating slightly. In response to this indication, the RO opened valve 2TL-4, the steam seal header feed bypass valve, which increased seal header pressure. Condenser vacuum immediately began to return to normal. Within 30 minutes from the start of the transient, vacuum had recovered to its normal value. The power reduction to 15 percent continued with no further vacuum problems. The inspector was present in the control room during the event and noted timely operator response in identifying the vacuum decrease and entering the appropriate abnormal procedure. In addition, the RO's action in opening valve 2TL-4 indicated a good knowledge of the steam seal system.

The turbine steam seal system prevents the leakage of air into, and the leakage of steam out of the turbine. Above 50 percent power, steam seal header pressure is maintained by packing leakoff from the high pressure turbine and steam from the low pressure turbine 9th stage extraction ("E" Bleed). At lower loads, steam seal header pressure is maintained at approximately 4 psig by the steam seal supply control valve, 2TL-3, which throttles main steam or auxiliary steam to the header. At any load, if steam seal header pressure exceeds approximately 5 psig, the surplus steam is discharged to the condenser through the steam unloading valve, 2TL-9.

The licensee conducted an investigation of the vacuum loss and performed troubleshooting of the steam seal system. The licensee concluded that two valve problems in the steam seal system caused a loss of seal steam resulting in the vacuum decrease. First, the licensee believed that check valve 2TL-11 in the "E" Bleed flow path failed to properly close allowing the loss of seal steam back to the turbine as load was decreased. When the RO opened 2TL-4 which provided additional steam to the steam seal header, it was believed that 2TL-11 reseated, resulting in the vacuum recovery. Second, the licensee discovered that the steam unloading valve, 2TL-9, had been improperly setup during the previous refueling outage. This setup problem caused the valve to continuously discharge steam to the condenser, contributing to the loss of seal steam.

Since corrective maintenance on 2TL-11 could not be performed unless the turbine was taken offline, the licensee isolated the "E" Bleed supply source to prevent the improper operation of 2TL-11 from causing a similar vacuum problem if a down power became necessary. The licensee determined that the isolation of "E" Bleed steam would not adversely impact the operation of the unit while at full power. The setup problem on 2TL-9 was corrected and the valve was verified to operate properly. The licensee initiated a Problem Investigation Process to address the setup problem.

The inspector monitored the licensee's investigation into the cause of the vacuum decrease. The licensee conducted numerous management meetings to discuss the details of the investigation and to assess the findings. The inspector attended these meetings and noted good involvement and direction by plant management. The licensee briefed the operators on each shift with details of the transient. In addition, the operators were provided instructions describing the event and contingency actions if a similar vacuum problem occurred. The inspector concluded that appropriate action was taken.

No violations or deviations were identified.

4. **MAINTENANCE** (NRC Inspection Procedures 62703, 61726)

Surveillance tests were observed to verify that approved procedures were being used; qualified personnel were conducting the tests; tests were adequate to verify equipment operability; calibrated equipment was utilized; and TS requirements appropriately implemented.

In addition, the inspector observed maintenance activities to verify that correct equipment clearances were in effect; work requests and fire prevention work permits, as required, were issued and being followed; quality control personnel performed inspection activities as required; and TS requirements were being followed.

The following items were reviewed in detail.

a. Unit 2 Upper Containment Ventilation Unit Pipe Replacement

During this report period, the licensee replaced essentially all of the upper containment SW system supply and return piping to the Unit 2 upper containment ventilation unit coolers. The Upper Containment Ventilation Unit system contains four coolers designed to cool the air in upper containment during power operation. No credit for this system is taken during design-basis accident conditions. Cooling water to the Upper Containment Ventilation Unit coolers is supplied by the SW system. This SW piping had been found to have significant internal corrosion and needed to be replaced.

The licensee conducted an evaluation (10 CFR 50.59) of the SW pipe replacement work in upper containment and determined that it could be conducted without impacting plant operation with the unit at power operation. The inspector reviewed the licensee's safety evaluation. The inspector determined that the licensee had adequately evaluated the safety concerns of the activity. The inspector noted that considerable pre-planning of the work was performed. Detailed guidelines were developed, as well as training provided, in the following areas:

- Monitoring upper containment temperature,
- Protecting upper containment equipment, i.e, instrument air lines and hydrogen analyzer piping,
- Control of material brought into containment and housekeeping,
- Radiation control,
- Control of containment access,
- Control of Polar Crane movements, and,
- Personnel safety and containment evacuation.

The SW pipe replacement activity was conducted between February 21 and March 2, without incident. The inspector visited the work location periodically during this period, and with one exception, noted that the activity was performed in accordance with the guidance developed. On February 24, the inspector observed that proper control of loose material, i.e., paper, rags, plastic, and used radiation protection clothing, was not being maintained. Proper control of such material was necessary to prevent the obstruction of the refueling canal water drains during a design-basis accident. The 50.59 evaluation and work guidance document had indicated that this loose material would be stored in a closed and latched container when the material was not in use. The inspector found that there had been no provisions made for providing such a container inside containment. This discrepancy was communicated to the work supervisor at the time of the inspection. The inspector noted improvement in the control of loose material during subsequent inspections. On March 4, following the licensee's completion of all work activities, the inspector toured the Unit 2 upper containment area. The inspector noted that all material related to the job had been properly removed.

b. Differential Pressure Testing of Valve 1KC-C37A

On March 2, the inspector witnessed portions of the static and differential pressure testing of Unit 1 "A" train CCW system miniflow control valve, 1KC-C37A. This MOV is part of the licensee's Generic Letter 89-10 MOV testing and surveillance program. The purpose of this testing was to verify that the MOV would perform its function under design-basis differential pressure conditions.

Procedure PT/1/A/4200/21A, CCW Valve Inservice Test, was used by the licensee to control the alignment of the CCW system for the test conditions. Since testing would render the miniflow valve inoperable, the procedure prescribed the alignment of an alternated miniflow path in order to maintain availability of the "A" train CCW system. The inspector verified portions of the alignment, both from the control room and locally, to ensure that it was in accordance with the procedure.

Testing of 1KC-C37A was performed under Work Request No. 93036187-01. Prior to testing, the inspector reviewed the Work Request package and noted that there was no information regarding PT/1/A/4200/21A for controlling the alignment of the CCW System to support the testing. In addition, the Work Request had been signed by operations personnel on the previous night shift giving maintenance clearance to begin work and was provided to the maintenance crew prior to ensuring that the alternate miniflow path was established. Signing the "Clearance to Begin Work on Equipment" normally signifies that the equipment is ready for maintenance to start work and gives maintenance permission to do the work. In this case, actual work on the valve did not begin until after the alternate alignment was configured. This was due primarily to a good understanding on the part of the day shift Senior Reactor Operator for the need to change the CCW alignment before valve work was allowed to proceed. The inspector considered it an undesireable work practice for operations to sign on work and provide the work group with the work request package prior to equipment being ready for work to begin.

The licensee completed testing on 1KC-C37A with no major problems and the CCW System was returned to its normal alignment. The inspector reviewed the completed work request package and data collected. The diagnostic test results indicated that the torque switch, torque switch bypass, and thermal overload settings were correctly set for the MOV.

c. Unit 2 Main Turbine Valve Movement Testing

On March 1, the inspector witnessed portions of required TS testing of the four main turbine stop valves and the six low pressure turbine intermediate stop and intercept valves. These valves are designed to close automatically on a turbine trip to prevent turbine overspeed. This weekly test verifies proper valve operation by movement of each valve through one complete cycle. During the test, the intermediate stop and intercept valves that makeup CIV No. 4 failed to re-open after being closed. The licensee appropriately declared CIV No. 4 inoperable and entered the TS Action Requirement (TS 3.3.4.b), which allowed six hours to return the valve to an operable status or isolate the turbine from the steam supply. Isolation of the steam supply requires the turbine to be taken off-line.

The licensee expedited troubleshooting of the valve failure. It was determined that the problem was the failure of a solenoid-operated valve in the hydraulic test flow path. The licensee believed that particulates in the hydraulic fluid may have interfered with the normal movement of the pilot valve assembly in the test solenoid, preventing the CIV from re-opening. A jumper was installed to maintain CIV No. 4 closed and the test solenoid valve was electrically cycled to flush any particulates out of the flow path. The jumper was removed and CIV No. 4 opened properly. When CIV No. 5 was then tested, it also failed to re-open. The test solenoid valve was electrically cycled similar to CIV No. 4 and it re-opened. After successfully retesting all of the CIVs, the licensee considered the valves operable and the TS Action was exited without having to initiate actions to take the turbine offline. The inspector reviewed the troubleshooting and witnessed the re-testing of the CIVs. The activity was well organized and performed by experienced personnel. The inspector noted good support from engineering personnel, who were closely involved in the planning and execution of the troubleshooting action plan.

In order to determine the cause of the particulate contamination, the licensee sampled the hydraulic oil. At the conclusion of this inspection report period, the licensee had not received the results of the oil sample analysis. However, the licensee believed that small fibrous material from filters installed in the oil cleanup loop were responsible for the binding of the two test solenoid valves associated with CIVs 4 and 5. This problem had occurred in the past and was thought to have been resolved by the filter vendor. As a precaution, the licensee removed the filters from operation on both units. In order to cleanup any potential particulate in the Unit 2 oil, a temporary filter unit was placed in service. Later that night, the turbine emergency trip functions were tested to verify continued operability. No discrepancies were identified.

The inspector reviewed the licensee's corrective actions. While the licensee's short term actions were determined to be acceptable, the inspector noted that problems with this system have continued to occur. Long term resolution of problems associated with the performance of the turbine hydraulic oil system remained on the licensee's top ten site issues list and continued to receive management attention. The inspector plans to monitor this problem during subsequent inspections.

d. Unit 1 ESFAS Testing

On March 3, the inspector witnessed portions of the Unit 1 ESFAS automatic logic and relay testing. The purpose of this quarterly testing is to verify that the ESFAS slave relays actuate and the associated final output devices, i.e, breakers and status lights, operate as required. The licensee used procedure PT/1/A/4200/09A, Auxiliary Safeguards Test Cabinet Periodic Test, dated September 27, 1988, to perform the test. The inspector witnessed the performance of Section 13.48 of the procedure that tested portions of the "A" train Component Cooling Water system valves and several Containment Penetration Seal Water Injection system valves. The inspector monitored testing from the control room, reviewed the pre-test briefing package provided to the operators, and verified valve lineups from the control board. Testing was accomplished satisfactory and without incident. The inspector noted that testing was well coordinated between operations and test personnel and there was good communication between the two groups.

e. Performance Procedures and Tests

The inspector observed the performance of the following Performance tests.

PT/1/A/4250/06A	Auxiliary Feedwater 1A Head and Valve Verification
OP/1/A/6250/02	Auxiliary Feedwater Systems
PT/0/A/4200/17	Standby Shutdown Facility Diesel Test
PT/1/A/4350/02A	Diesel Generator 1A Operability Test
OP/1/A/6350/02	Diesel Generator Operation
PT/1/A/4350/15B	Diesel Generator 1B Periodic Test

The inspectors observed the entire process of preparation, procedure verification, and operational job briefings to maintenance and operations personnel.

The Standby Shutdown System Diesel Generator Test was performed by an operations test crew. The test crew reviewed the reference and test procedures along with TS surveillance item 4.7.13.1.A.1 & 2. Part of this verification was to insure that the Standby Shutdown System Diesel Generator was not in emergency mode and not in fuel oil recirculation mode. Diesel parameters were verified as the Standby Shutdown System Diesel Generator was loaded and unloaded. The system was operated for 30 minutes loaded, then the engine was cooled down five minutes unloaded before it was shutdown and returned to its original alignment.

After the engine had been warmed up, the step was initiated to place the diesel generator on line. When the diesel generator was synchronized to the line, the protective relay annunciator alarmed. The generator voltage was approximately 40 volts lower than the line voltage, causing the over-current protective relay to alarm. The synchronizing of the generator was accomplished and the test was completed satisfactorily. Accuracy of the instrumentation used to properly synchronize the diesel generator appeared to contribute to the difficulty. Similar difficulties in synchronizing the emergency diesel generators were noted in NRC Inspection Report 50-413, 414/93-31. An Inspector Follow Up item was opened to address the issue. Resolution of difficulties synchronizing the Standby Shutdown System Diesel Generator will be included in the review and closure of IFI 50-413/93-31-01 Resolution of Emergency Diesel Generator Outage Issues.

All other performance and operational tests that were observed were completed without incident. The following comments further identify the observations and conclusions of the inspectors.

The Central Work Control coordination of operations and maintenance activities and scheduling of surveillance and operational tests functioned well. The surveillance and operational functional tests were scheduled with minimum impact on operations and with sufficient time allowance to minimize the probability of missing a test.

Personnel who were assigned to the test crews, such as test technicians and systems engineers were generally knowledgeable and followed the test procedures properly.

Surveillance and operational test procedures reviewed by the inspectors showed that they had been properly reviewed by appropriate management within required time frames. The procedures were revised when required, clarified test requirements, clearly delineated acceptance criteria and, in general, were presented in a standardized format to reduce the potential of personnel error.

An adequate number of personnel were assigned to each test to monitor and document the required parameters to verify that test requirements were met.

Based upon direct observation, records review and personnel interview, the inspectors determined that the licensee had accomplished the Performance and Operational testing in a satisfactory manner.

f. Relay KC615 in Solid State Protection System Failed to Latch

On March 2, at 5:00 a.m., with Unit 1 at 97%, the latch coil for relay KC615 failed to latch during surveillance testing.

During testing of Relay KC615 by PT/1/A/4200/09A, Auxiliary Safeguards Test Cabinet Periodic Test, the test crew observed that the latch coil for Relay KC615 did not latch on demand. The relay latch for KC615 was declared inoperable and actions taken in accordance with Technical Specification 3.6.3.

The relay provides a signal to a series of valves for Phase A containment isolation or Safety Injection. The latching mechanism locks the signal in until it is reset by plant operators. Accordingly, the components which received a signal from the relay were also declared inoperable. The affected components were valves 1VG-2A, 1VQ-16A, and the train A Containment Purge System containment isolation valves. Valves 1VQ-3B and 1VQ-15B were tagged closed to comply with Technical Specification 3.6.3.

The licensee initiated compensatory action so that operations could perform a containment release in order to avoid a shutdown of Unit 1 due to high containment pressure. This action instructed operations personnel to ensure that valve 1VQ-2A in the release path would close upon receipt of a Phase A containment isolation signal or Safety Injection Signal then to remove power for the valve to ensure that it would remain closed. This action guarded against the inadvertent opening of 1VQ-2A following an accident, replacing the function of the relay latching mechanism.

A safety evaluation to satisfy 10 CFR 50.59 was accomplished by the licensee which determined no safety significance for the temporary compensatory actions.

Following use of the compensatory actions described above for containment releases while the work was planned, the latching coil and relay KC615 were replaced with like equipment.

The inspector noted that the replacement procedures were well prepared, functional testing was completed without incident, and resolution of this issue involved good support to maintenance from the engineering organization.

No violations or deviations were identified.

5. **ENGINEERING** (NRC Inspection Procedures 71707 & 40500)

Control Rod Cladding Wear

On February 9, the licensee identified an operability issue with Control Rod R30 due to calculated cladding wear in excess of established wall thickness criteria. The issue was identified during a review of PIP 1-C94-0133 which addressed a discrepancy in the assumed hard stop location for the control rods noted during Control Rod Drop Timing Tests conducted in December 1993.

As described in NRC Information Notice 87-19, Perforation and Cracking of Rod Cluster Control Assemblies, a mechanism for flow induced fretting wear of the Control Rod stainless steel cladding exists where it interfaces with the stainless steel guide cards. The guide cards are located in the reactor vessel upper internals and serve to restrict lateral movement of the control rods when they are withdrawn from the core.

In order to manage control rod wear at Catawba, the full out position was varied such that the wear on the cladding was distributed. Beginning in operating Cycle 7, the repositioning plan called for more frequent, single step repositioning and the elimination of potential inaccuracy of the location of the fully withdrawn control rod due to misstepping of the control rod drive mechanism. The control rods were positioned by withdrawing the control rod banks past the hard stops, resetting the step counters, and stepping the control rods in to their programmed position. Cladding wall thickness was tracked and projected by periodic measurement campaigns and computer tracking of wear rates by rod locations. Control rods were replaced when the cladding wall thickness decreased to a minimum limit of 7.5 mils. The nominal wall thickness of the cladding was 38 mils.

Unit 1 Control Rod Drop Timing Tests were conducted in December 1993, with the reactor coolant system at normal operating temperature and pressure. During the testing, the licensee monitored the number of steps from fully inserted to the withdrawal hard stop on one control rod from each rod group, for a total of 15 rods monitored. The data indicated that the hard stops were located at 231 steps withdrawn verses 230 steps as previously assumed, based on data taken with the reactor coolant system at approximately 350°F. As a result, during Unit 1, operating Cycle 7, the control rods were positioned one step further withdrawn than planned.

The licensee reevaluated calculated wear since the last measurement campaign on Unit 1, which was performed prior to operating Cycle 6. The reevaluation identified two control rods which had rodlets with calculated cladding wear greater than acceptance criteria. Rodlet 9 of control rods R30 and R24 were the affected rodlets. The licensee performed operability evaluations for each control rod, considering loss of shutdown margin due to leaching of the boron carbide from the affected rodlets and ability of the affected control rods to trip. The licensee did not identify a similar operability concern with Unit 2 control rods primarily due to the fewer operating cycles on the unit. The inspector reviewed the licensee's operability evaluations and found them acceptable.

During the reevaluation of cladding calculated wear, the licensee also identified that Control Rod R24 was removed from service following the 1EOC5 measurement campaign. Due to an administrative error during the development of the operating Cycle 8 core map, control rod R24 was placed back in service. The inspector reviewed administrative controls for more rigorous control of the revisions to cycle dependent core maps which had been implemented prior to the discovery of this problem. These controls should prevent the occurrence of similar errors in the future. The inspector considered the licensee's actions to address this issue to be appropriately thorough and timely.

No violations or deviations were identified.

6. **PLANT SUPPORT** (NRC Inspection Procedures 82301)

Annual Emergency Preparedness Exercise

The licensee conducted their annual emergency preparedness exercise on March 1. The scenario involved the rupture of one of the main steam lines due to a bomb detonation. The rapid depressurization of the steam line resulted in a simulated steam generator tube rupture. The inspector participated in the exercise and observed the activation, staffing, and operation of the emergency organization in the simulator control room, Technical Support Center, and the Operations Support Center. The scenario was challenging and the licensee generally exhibited good mitigation strategies. NRC Region II conducted a full evaluation of the exercise which is described in NRC Inspection Report Nos. 50-413, 414/94-08.

No violations or deviations were identified.

7. **PREVIOUS INSPECTION FINDINGS AND LICENSEE EVENT REPORTS** (NRC Inspection Procedures 92700 and 92702)

a. (Closed) IFI 413/92-26-02: For incore detector C, the normal path length decreased significantly, but the calibrate path length did not.

PT/0/A/4600/06B, "Incore Detector Setpoint Determination," was performed on October 20, 1992, to verify the top-of-core and bottom-of-core limits for the incore detectors. The end-of-thimble limit for Drive C was found outside the tolerance of less than one inch difference between the previous value and the as-found value. Drive C Path 1 end-of-thimble was found to have decreased by 22.5 inches. New limits were calculated in Enclosure 13.2 of the procedure. The inspectors noted the limits for Drive C calibrate path were not changed. The licensee had no explanation for why the calibrate path length had not changed as had the normal path length.

The licensee initiated a PIP on October 20, 1992. Immediate corrective action consisted of reestablishing NORMAL Mode setpoints per PT/0/A/4600/05B. Further corrective action had to wait for the next outage. Work Request 92050112 was performed to inspect the tubing runs between the five path and ten path transfer devices for detector C. The inspection revealed that the "Y" connections at detector C's ten path Transfer Device were improperly reassembled. Per the assembly drawing, detector C's normal "Y" coupling should have been installed at the top of the stack. The licensee found that it was actually installed at the bottom of the stack creating the 22.5 inch deviation.

The licensee's corrective action consisted of reassembling detector C's ten path Transfer Device per the assembly drawing and adjusting the setpoints of the detector. The inspectors reviewed Corrective Work Order Task 93006772 01 and verified that the licensee's corrective actions were completed. The inspectors noted that the licensee's corrective action for this issue did not specifically address the poor work practices which resulted in the incorrect assembly. The inspectors reviewed IP/0/A/3230/07, "Procedure for Movable Incore Detector Thimble Retraction and Insertion," to determine if it contained adequate guidance. Step 10.2.1 stated: "Verify tubing runs are clearly identified between 5-path and 10-Path Transfer Devices with individual numbers. Mark tubing as necessary to facilitate reinstallation." The inspectors concluded that this was adequate guidance to ensure correct reassembly of the transfer devices and that the incorrect assembly was due to poor work practices.

b. (Closed) LER 413/93-03: Technical Specification Required Surveillance not Performed.

On February 16, 1993, the licensee was alerted to a problem that was identified at another utility involving a portion of the ESFAS logic instrumentation for the containment spray system that was not being tested properly. TS 4.3.2.1 requires that the ESFAS instrumentation be demonstrated operable by the performance of a channel calibration every 18 months. During this testing, the input relay contacts for the containment spray channels are opened and following the completion of testing, the contacts are closed. This testing, however, did not verify that these relay contacts actually closed and there was circuit continuity. Since the circuitry is normally de-energized, and energizes to actuate, observation of the channel bistable lights could not be used to make this continuity check, as in the case with testing the rest of the ESFAS instrumentation.

Following identification of the problem, the licensee initiated circuitry continuity checks of the containment spray channels for both units. Based on the results of this testing, it was determined that the containment spray channels were operable.

This issue was the subject of Non-Cited Violation 413, 414/93-09-03, which was documented in NRC Inspection Report 50-413, 414/93-09.

The licensee's corrective actions included revising the four 18-month containment spray channel calibration procedures, IP/1(2)/A/3222/047A, B, C, and D, and the monthly Solid State Protection Functional Test procedures, IP/1(2)/3200/02A and 02B, to include this continuity check. The inspector verified that the procedures had been properly revised and considered that adequate licensee corrective action had been implemented.

c. (Closed) LER 413/93-04: Missed Technical Specification Surveillance of Offsite Sources

This LER was submitted when operating crews failed to initiate the proper Technical Specification surveillance of offsite power sources in a timely manner after an emergency diesel generator was declared inoperable. The licensee's long term action required that procedures OP/0/A/6400/06G, Nuclear Service Water and OP/1(2)/A/6350/02, Diesel Generator Operation, be revised to include steps to insure the proper surveillance has been complied with. These actions have been verified by the inspector and were considered adequate.

d. (Open) IFI 413/93-31-01: Resolution of Emergency Diesel Generator Outage Issues

Refer to paragraph 4.e for information on this item.

No violations or deviations were identified.

8. **EXIT INTERVIEW**

The inspection scope and findings were summarized on March 8, 1994, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed the inspection findings. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

10. ACRONYMS AND ABBREVIATIONS

CCW	-	Component Cooling Water
CFR	-	Code of Federal Regulations
CIV	-	Combined Intercept Valve
ESFAS	-	Engineered Safety Features Actuation System
IAE	-	Instrument and Electrical
LER	-	Licensee Event Report
MOV	-	Motor-Operated Valve
NRC	-	Nuclear Regulatory Commission
PIP	-	Problem Investigation Process
psig	-	pounds per square inch gauge
PT	-	Periodic Test
RO	-	Reactor Operator
SW	-	Nuclear Service Water
TS	-	Technical Specifications