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

Report Nos.: 50-413/95-22 and 50-414/95-22

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: October 8, 1995 - November 18, 1995

Inspectors: R L Carroll for Pertelcon 12/14/95
R. J. Freudenberger, Senior Resident Inspector Date Signed

P. A. Balmain, Resident Inspector
N. Economos, Reactor Inspector
R. L. Watkins, Resident Inspector

Approved by: R. V. Crlenjak 12/14/95
R. V. Crlenjak, Chief Date Signed
Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope: This inspection was conducted in the areas of plant operations, maintenance, engineering and plant support. As part of this effort, backshift inspections were conducted.

Results: In the plant operations area, administrative controls for system and component availability were effective at minimizing plant risk during shutdown operations. Nonetheless, the licensee has not been fully successful in ensuring activities which may complicate operation or initiate events while in reduced reactor coolant inventory operation are understood and receive priority attention by licensee personnel. Non-Cited Violation 50-413,414/95-22-01 was identified for failing to minimize the potential for disturbing reactor coolant system level during reduced inventory operation (paragraph 3.a). Weak work coordination within operations in support of the realignment of the Unit 2 letdown penetration was a contributor to an inadvertent reactor coolant system pressure fluctuation (paragraph 3.c). Expanded Plant Operations Review Committee involvement and influence in current operational issues and preparations for infrequently performed evolutions was evident. The two Significant Event Investigation Teams discussed in this report were initiated at a low safety

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significance threshold which enabled timely assessment of the programmatic implications of these events (paragraph 3.d).

In the maintenance area, minor procedural discrepancies noted in the secondary manway installation procedures and discrepancies observed on the installed manway covers indicated a lack of attention to detail in workmanship (paragraph 4.a). Non-Cited Violation 50-413,414/96-22-02 was identified regarding a reactor coolant pump seal maintenance procedure which specified the use of a restricted lubricant (paragraph 4.b). The occurrence of foreign material intrusion events and a "Management Attention Item" identified by the Nuclear Safety Review Board regarding inconsistent implementation of foreign material exclusion controls, indicate that continued management attention to this area is warranted (paragraph 4.c).

In the engineering area, the inservice inspection program was meeting minimum applicable requirements, non-destructive examination technicians were knowledgeable of procedural requirements and were performing the examinations in a conservative manner. The ten year reactor vessel examination was adequately planned and was being executed by well trained personnel with adequate technical expertise to analyze and evaluate identified indications (paragraph 5.a). The program to inspect the derailed steam generator for damage was well coordinated. The licensee's participation in this work effort was noteworthy in that engineering, licensing, and quality assurance were well represented and took an active role in the evolution (paragraph 5.b). The spent fuel pool cooling system analysis bounded operating practice and no concerns with the spent fuel pool cooling system capability were identified (paragraph 5.c). Licensee actions to address the potential for pressure locking of the containment sump recirculation valves were appropriate (paragraph 5.e). Indication of the status of auctioneered power supplies to the reactor coolant pump seal injection backpressure valves was not monitored or alarmed (paragraph 5.f).

In the plant support area, a vendor escorted into the Radiological Control Area without appropriate dosimetry and authorization was the subject of Non-Cited Violation 50-413,414/95-22-03 (paragraph 6.a). Contingency plans for resolving potential removal of security badges from the protected area were appropriate (paragraph 6.b).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

B. Addis, Training Manager
* A. Bhatnagar, OPS Superintendent
D. Cabe, Electrical System Support/NDE Technical Support
K. Connell, Procurement and Licensing Manager, SGRP
S. Coy, Radiation Protection Manager
J. Forbes, Engineering Manager
W. Funderburk, Work Control Superintendent
R. Giles, ISI Coordinator
T. Harrall, IAE Superintendent
M. Keck, Design Engineer, SGRP
D. Kimball, Safety Review Group Manager
D. Mayes, Nuclear Services Division
* W. McCollum, Catawba Site Vice-President
W. Miller, Operations Superintendent
* K. Nicholson, Compliance Specialist
* M. Patrick, Safety Assurance Manager
* G. Peterson, Station Manager
R. Propst, Chemistry Manager
G. Robinson, Maintenance Execution Support Supervisor
* D. Rogers, Mechanical Superintendent
R. Sharpe, Licensing/QA, SGRP
* Z. Taylor, Regulatory Compliance Manager
D. Tower, Regulatory Compliance Engineer

Other Organizations:

Babcock & Wilcox Nuclear Technologies
D. Fairbrother, Manager NDE Services
A. Richmond, Site Manager

Babcock & Wilcox International Division
P. Salter, Manager Quality Engineering

* Attended exit interview.

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

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

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2. **PLANT STATUS**

   a. Unit 1 Summary

   Unit 1 operated at or near 100 percent power throughout the inspection report period.

   b. Unit 2 Summary

   Unit 2 began the report period in the EOC7 refueling outage and remained in the outage through the end of the inspection report period.

   c. Inspections and Activities of Interest

   During the week of November 13, a specialist inspection of security access authorization was conducted. The inspection, which was performed by inspectors from the NRC Region II Office, assessed licensee activities in the Duke Power Company's General Office and all three nuclear sites. The results of the inspection are documented in NRC Inspection Report 50-413,414/95-23.

3. **PLANT OPERATIONS** (NRC Inspection Procedures 40500 and 71707)

Throughout the inspection period, control room observations and facility tours were conducted to observe operations activities in progress. During these inspections, discussions were held with operators, supervisors, and plant management. Some operations activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections evaluated whether the facility was being operated safely and in conformance with license and regulatory requirements. In addition, the inspection assessed the effectiveness of licensee controls and self-assessment programs in achieving continued safe operation of the facility.

The following items were reviewed in detail:

   a. Reduced Reactor Coolant System Inventory Operation

   In preparation for the Catawba Unit 2 EOC7 Refueling Outage, the resident inspectors reviewed the licensee's administrative controls for operating the RCS in reduced inventory and midloop conditions. The outage included one period of operation in reduced inventory and midloop. The unit entered reduced inventory from November 6 through November 9 for steam generator nozzle dam removal and miscellaneous valve work. The unit remained in midloop until the reactor head was set and RCS vacuum refill was in progress.

The inspector reviewed the following items before the RCS entered reduced inventory/midloop conditions:

- Generic Letter 88-17, Loss of Decay Heat Removal
- NRC Information Notice 95-35, Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation (Issued 9/28/95)
- Site Directive 3.1.30, Unit Shutdown Configuration Control Licensee Pre-Evolution Presentation: Draining the RCS in a Low Decay Heat Condition
- OP/2/A/6150/01, Filling and Venting the Reactor Coolant System
- OP/2/A/6150/01, Enclosure 4.2, Reactor Coolant System Vacuum Refill
- OP/2/A/6150/06, Draining the Reactor Coolant System
- OP/2/A/6150/06, Enclosure 4.2, Decreasing the NC System Level
- OP/2/A/6150/06, Enclosure 4.10, Requirements for Operation with NC System Below 16%

The inspector also verified that the licensee reviewed their controls and administrative procedures governing mid-loop operation. The licensee had revised and reissued Site Directive 3.1.30, which defines the requirements and plant conditions necessary to maintain safe unit shutdown configuration control with fuel in the core or in the spent fuel pool. It includes administrative requirements for reduced inventory and mid-loop operations in both high and low decay heat conditions.

The licensee conducted pre-evolution briefings with the operations shifts that operated the unit in reduced RCS inventory conditions. The inspector observed one of the four briefings to verify that controls specified in Site Directive 3.1.30 and the potential use of relevant abnormal operating procedures (i.e., response to a loss of RHR, a leak in the RHR system, or gravity refill of the RCS) were reviewed. The inspector was present in the control room during the drain down to reduced inventory to verify implementation of these controls.

The following are issues associated with reduced reactor coolant system inventory operation that the inspector reviewed:

(1) Monitoring of Core Exit Thermocouples

On October 11, with Unit 2 in Mode 6 and the RCS level at 23%, just below the reactor vessel flange, operations personnel noticed that the core exit thermocouple temperature was indicating 160°F, while the RHR heat exchanger inlet temperature indication was 108°F. Operators investigated the discrepancy and determined that the Operator Aid Computer data points for the five core exit thermocouples that were intended to be monitored were not in service.

In accordance with the recommendations in GL 88-17, the licensee's procedure for draining the RCS involves leaving at least two core exit thermocouples connected until two hours before the head is lifted. Routinely, the licensee jumpers five thermocouples, and all other thermocouples are disconnected in preparation for head removal. The operators monitor core exit temperature using these instruments, which provide indication to the Operator Aid Computer. Because the technician jumpered the wrong set of five thermocouples, operators were provided erroneous temperature readings.

Since RCS level was at the flange with loops filled when the discrepancy was identified, operators had not been required by procedure to monitor and record RCS temperature. Nonetheless, the inspector concluded that had operators been utilizing and comparing the indications available to monitor the parameter, identification of the discrepancy could have been more timely. The safety impact of the discrepancy was low since it was corrected prior to reduced RCS inventory operations.

The licensee initiated a root cause investigation of the error and determined that misorientation on the part of the technician installing the jumpers, in conjunction with an error in reading an electrical drawing, led to the error in jumpering the wrong thermocouple cables. In addition, the subsequent functional test was not appropriate for revealing the type of error that occurred. The proposed corrective actions identified in the root cause analysis included revising the procedure (specifically, changing the functional test and enhancing tables for cross-referencing core location, thermocouple numbers, port designations and computer points) and labeling the instrumentation ports.

The inspector concluded that the licensee's root cause analysis was thorough, and the proposed corrective actions were appropriate.

(2) Reactor Coolant System Level Indication

On October 12, while performing a Unit 2 Containment Purge Ventilation System walkdown, a system engineer manipulated two backdraft dampers slightly to assess freedom of movement. This resulted in an increase in containment pressure. Control room operators noted that concurrent with the increase in containment pressure, a 1% decrease in indicated RCS level occurred. The RCS was at 22% level, below the reactor vessel flange, with the head detensioned and the steam generator "U" tubes filled with nitrogen when the level change occurred. The licensee initiated PIP 2-C95-1749 to document the occurrence.

The reference of the differential pressure indication for RCS level is the containment atmosphere; therefore, it was not evident whether the change in indicated level was an indicated or actual change in level. In preparation for entry into reduced RCS inventory operations, the inspector reviewed the status of the PIP resolution in order to ensure that the interaction between containment pressure and level indication was understood. The inspector noted that evaluation due dates listed in the PIP for completion of the evaluation were after entry into reduced RCS inventory and questioned if the licensee planned to complete the evaluation before the unit entered reduced RCS inventory, when accurate level indication is crucial.

Engineering evaluated the interaction between containment pressure and RCS level indication with the plant conditions at the time of occurrence. They determined that manipulating the backdraft damper caused containment pressure to increase, depressing the reactor coolant level in the vessel and displacing the volume into the steam generator "U" tubes by compressing the nitrogen bubble in the tubes. The unit was at 22 percent RCS level with the head detensioned when the level change occurred, and similar effects would not occur with the unit in midloop operation; therefore, the safety impact was low.

Although the licensee performed an evaluation that provided sufficient understanding of the issue to verify that no impact on the accuracy of the RCS level indication existed before the unit entered reduced inventory operation, inspector questioning prompted the evaluation. Had the inspector not questioned the timeliness of PIP resolution, the licensee might have allowed operation in reduced inventory without fully understanding the interaction between containment pressure and RCS level.

(3) Unplanned Reactor Coolant System Inventory Loss

On November 7, 1995, after refueling the Unit 2 core, the RCS was being maintained in reduced inventory at 8.5% level (approximately 5 inches above the top of the hot leg) for steam generator nozzle dam removal and reactor coolant pump seal work. In addition, two check valves in the alternate charging line to the "D" steam generator cold leg were scheduled for repair of bonnet leaks identified during the current refueling outage inspections.

The check valves are unisolable from the RCS. A high point vent exists in the line between the check valves and the RCS penetration into the top of the "D" cold leg. To prevent a siphoning from the RCS, the high point vent valve (2NC-261) was opened, and its associated pipe cap was removed. Then the bonnet of the check valve adjacent to the RCS (2NV-40) was opened with four bolts remaining in place to control expected drainage. The high point vent did not break the siphon as expected because sealant material from previous pipe cap leak repair was blocking the vent path. As a result, the RCS began to drain at approximately 1 to 2 gpm.

Control room operators recognized the unplanned loss of inventory, controlled level by inventory additions, and initiated actions to restore the integrity of valve 2NV-40. The licensee estimated that approximately 500 gallons of reactor coolant was drained.

This event did not challenge continued decay heat removal. Had the operators not made inventory additions, the drain path would have terminated itself when the level in the RCS had dropped below the top of the loop piping, allowing air into the line and breaking the siphon. During the period that the siphoning occurred, RCS level was maintained above the top of the hot leg opening.

Recognizing the importance of inventory control during reduced RCS operations, licensee management initiated a Significant Event Investigation Team. Preliminary recommendations of areas for improvement included the following: emergent work control process; shutdown risk programs for activities that can incur risk in ways other than system unavailability; management expectations to foster a culture that supports a questioning attitude; operations ownership and control (including awareness of leak repaired components); and discussion of this event in operations' continuing training program.

Because the control room operators recognized the drop in RCS level in a timely manner, took prompt action to maintain level, and the siphon path would have terminated itself before RHR system operation would have been challenged, the safety impact was minimal.

Site Directive 3.1.30, Unit Shutdown Configuration Control, specifies that RCS level disturbances during reduced inventory and midloop operations should be minimized. Insufficient precautions were incorporated into the work plan to minimize the potential for disturbing reactor coolant system level. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. NCV 50-413,414/95-22-01: Failure to minimize potential for disturbing RCS level during reduced inventory operation.

(4) Conclusion - Reduced RCS Inventory Operation

Licensee administrative controls for system and component availability are effective at minimizing plant risk during shutdown operations. Nonetheless, for reduced reactor coolant inventory operation, the issues described above indicate that the licensee has not been fully successful in ensuring activities which may complicate operation or initiate events are understood and receive priority attention by licensee personnel.

b. Diesel Generator Room 1A Cardox Actuation

On November 6, the carbon dioxide fire suppression system for the 1A diesel generator room inadvertently actuated. Warning alarms (flashing lights and sirens) present for personnel safety and intended to alarm for sixty seconds prior to carbon dioxide discharge did not function. The licensee initially declared the 1A diesel generator and the fire suppression systems for both Unit 1 diesel generators inoperable. The diesel generator was inoperable due to battery charger alarms which occurred simultaneously with the fire suppression system actuation. Following the actuation, the fire suppression system was inoperable due to low level in the carbon dioxide storage tank. The inspector verified that continuous fire watches were established. The licensee initiated the Failure Investigation Process to assess the failure and documented the occurrence in PIP 1-C95-2065. This included the fire suppression systems for the diesel generator rooms and the auxiliary feedwater pump rooms on both units since they are similar.

The licensee's investigation considered various failure modes, ruled out a mechanical failure, and began to focus on a control system failure. Testing and vendor involvement in the investigation was not successful in identifying the cause of the system actuation by the end of the report period. In the interim, the licensee refilled the Unit 1 carbon dioxide storage tank, tagged and isolated valves in the system to prevent the personnel hazard from inadvertent actuation, and implemented fire watches for the affected areas on both units.

The inspector concluded that the licensee's actions to address this issue to date were appropriate and in compliance with the applicable Selected Licensee Commitments.

c. Unit 2 Pressure Transient while in Solid Plant Operations

On November 14, the Unit 2 reactor coolant system was at approximately 350 psig with one reactor coolant pump operating and the pressurizer solid. The letdown penetration had been out of service and drained for containment leak rate testing. While operators realigned the letdown penetration, a portion of the piping that had been drained was connected to the letdown in service from the RHR system. This initiated a reactor coolant system pressure decrease of sufficient magnitude to cause low reactor coolant pump seal differential pressure on the operating pump. The pump was appropriately secured by the control board operator.

The licensee initiated PIP 2-C95-2240 to document the event and corrective actions. As part of the PIP resolution the licensee initiated a root cause evaluation of the event. At the end of the report period, the root cause evaluation was not complete. The inspector reviewed the circumstances of the event and preliminary information from the root cause evaluation. Based on this review, the inspector concluded that the realignment of the letdown penetration was scheduled with minimal consideration of limitations on plant configuration and was authorized under a weak evaluation of the potential impact considering the plant conditions that existed. In summary, the inspector concluded that weak coordination within the operations department contributed to the event.

d. Self-Assessment

Nuclear Safety Review Board Meeting

On October 24 and 25 the Nuclear Safety Review Board met on site. The inspector attended portions of the meeting and reviewed the associated meeting minutes dated November 7, 1995. Four "Management Attention Items" were identified by the board:

(1) continued improvements in operational focus are needed at Catawba; (2) inconsistent controls to prevent foreign material entry into open systems were noted; (3) an assessment of the operational impact of the loss of control room cooling for an extended period of time was requested to be performed; and (4) some aspects of the steam generator replacement project appeared to need attention to ensure readiness and preparation for the upcoming steam generator replacement outage.

The inspector concluded that the Nuclear Safety Review Board was providing a solid oversight function, with a wide range of industry perspectives represented by the board members.

Plant Operations Review Committee

Throughout the report period, the inspectors attended licensee Plant Operation Review Committee meetings. Meetings observed or monitored included regularly scheduled, unplanned, and some meetings conducted by tele-conference during off normal hours.

The inspectors observed a special Plant Operations Review Committee meeting conducted on November 15. The meeting addressed several equipment deficiencies which impacted systems on Unit 2 that could cause operational complications. At the time, Unit 2 was in solid RCS operation. The complications were discussed individually and collectively to assess their impact on plant safety. Additionally, an informal probablistic assessment based on current plant conditions, assuming further complications was performed and discussed. Based on the discussion, the Plant Operations Review Committee clarified optimum sequencing of activities to address the equipment issues and confirmed that no significant increase in risk existed due to the combination of deficiencies.

Several regularly scheduled meetings were attended by the inspectors to assess the Plant Operations Review Committee review of preparations and controls for infrequently performed evolutions. These discussions were detailed and usually generated comments which strengthened controls and improved the quality of the briefing packages.

In summary, the inspectors noted expanded Plant Operations Review Committee involvement and influence in current operational issues and preparations for infrequently performed evolutions.

Significant Event Investigation Teams

During the report period, two Significant Event Investigation Team investigations were conducted by the licensee. The events which precipitated the investigations are discussed individually in paragraphs 3.a.(3) and 4.c. In each case, initial inspector review of the circumstances of the events concluded that the significance of the event itself may not have warranted team investigations; however, potential programmatic issues existed which could benefit from a structured, timely, in-depth assessment. The inspector noted that the two Significant Event Investigation Teams discussed in this report were initiated at a low safety significance threshold which enabled timely, detailed assessment of the programmatic implications of these events.

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

Throughout the inspection period, maintenance and surveillance testing activities were observed and reviewed. During these inspections, discussions were held with operators, maintenance technicians, supervisors, engineers and plant management. Some maintenance and surveillance observations were conducted during backshifts. The inspections evaluated whether maintenance and surveillance testing activities were conducted in a manner which resulted in reliable, safe operation of the facility and in conformance with license and regulatory requirements.

The following items were reviewed in detail:

a. Unit 2 Steam Generator Secondary Manway Installation

On October 27, the inspector observed the removal and replacement of the steam generator 2B1 secondary manway cover. The licensee experienced numerous SG secondary manway cover leaks during the previous operating cycle which resulted in complicating the operation of Unit 2. The licensee implemented several corrective actions and enhancements to the secondary manway installation process during the Unit 2 EOC7 refueling outage in an effort to improve the integrity of the manway cover joints and to eliminate future manway cover leakage.

The inspector reviewed the licensee's enhancements to the secondary manway installation process. The enhancements included: extensive measurement of the manway cover to manway pad gap and "as found" gasket thickness of the removed gaskets on all secondary manways; replacement of all secondary manway gaskets; use of guide pins to ensure the manways were not cocked during mounting; and measurement of gasket compression from initial torque to final torque values. In addition to the installation process improvements, the licensee planned to implement torque checks on all the secondary manways following mid cycle plant shutdowns if the unit is taken to mode 4. The licensee also plans to remove and inspect each secondary manway and replace all gaskets during every refueling outage.

The inspector witnessed the second removal and replacement of the 2B1 secondary manway (WO 95020380-01). The gasket for this cover was replaced twice during this outage due to data from the first installation which indicated that the first gasket may not have reached full compression at final torque. The inspector found the reinstallation of the cover acceptable. Nonetheless, several minor discrepancies associated with workmanship on the cover that was removed and adjacent covers on the B and C steam generators were identified by the inspector. These discrepancies included a thick application of Deacon 600 sealant material evident on the removed cover gasket, as well as inconsistent stud engagement and apparent torquing pattern discrepancies on adjacent covers. The inspector considered these discrepancies as having minimal safety significance, but were examples of a lack of attention to detail in workmanship. Following the completion of all of the secondary manway gasket replacements, the inspector reviewed the licensee's gasket compression measurements and verified that all of the gaskets achieved a nominal compression.

Based on this review the inspector determined that the licensee's enhancements to the maintenance installation process for steam generator secondary manway covers were effective in improving and retaining the integrity of the manway gasketed joints. The inspector observed minor procedural discrepancies in the installation procedures and several examples observed on the installed manway covers that indicated a lack of attention to detail in workmanship.

b. Unit 2 Reactor Coolant Pump Seal Maintenance Activities

During this inspection period, the inspector reviewed maintenance activities associated with Unit 2 RCP seal removal and installation. During the most recent operating cycle, high number one seal leakoff flow from the 2B RCP occurred which resulted in complicating operation of Unit 2.

The licensee performed seal replacements on the 2B and 2C RCPs during the current Unit 2 refueling outage (EOC7). The inspector reviewed maintenance work order documentation for the 2B and 2C seal maintenance activities (95069443-01 and 95076734-01) and witnessed portions of the seal removal and replacement for the 2C RCP.

The inspector observed the licensee's inspection of the 2B RCP number one seal and runner following its removal. The inspector noted that the licensee obtained vendor personnel with extensive experience in RCP seal operation to evaluate the possible causes of its poor performance. Vendor personnel determined, based on the appearance of the seal and runner faces, that the seal and runner had experienced rubbing of the sealing faces at some point in the previous operating cycle. The licensee suspected that this contact may have occurred during startup from the last refueling outage. The inspector also observed the licensee's inspection of three small pieces of debris that were removed from an area beneath the 2B RCP number 1 seal housing. The licensee identified the debris during the 2B seal removal and determined that the debris had remained in the seal housing from previous maintenance activities (PIP 2-C95-1304). No debris was identified during removal of the 2C RCP seal assembly.

The inspector witnessed portions of the removal and replacement of the 2C RCP number one seal assembly. During the installation of the number one seal runner per procedure MP/0/A/7150/039, Reactor Coolant Pump Seal Removal and Replacement, the inspector identified that Dow Corning No. 4 silicone lubricant (used on the O-ring seals) was not available at the work location inside containment. Following this observation, the licensee obtained the required lubricant from the warehouse. The inspector observed that a similar silicone lubricant (Dow Corning No. 111) was located with the RCP tools at the work site. Dow Corning No. 111 is a general purpose seal and gasket lubricant, but it is not the specified O-ring lubricant for use in the RCP seal maintenance.

Following observation of the 2B RCP seal replacement activities, the inspector questioned the use and suitability of the silicone lubricants for RCP seal maintenance. Dow Corning No. 4 is required to be used by MP/0/A/7150/039 and the inspector verified by interviewing maintenance technicians and reviewing completed procedure documentation that Dow Corning No. 4 was used as required. The inspector questioned the impact of inadvertently using Dow. Corning No. 111 since it had been available with the RCP tools.

From discussions with system engineering personnel, the inspector learned that although the Dow Corning No. 4 was required for use by procedure and recommended by the RCP seal vendor, it had been classified as a Category II material in the Power Chemistry Materials Guide. Category II material is prohibited from use in contact with reactor coolant system water due to chemical impurities. After the inspector questioned the use of a restricted lubricant for RCP seal maintenance, the licensee performed a technical evaluation of the specific application of Dow Corning No. 4 and determined that it could be used and an exception to the Power Chemistry Materials Guide was processed for this application. The inspector reviewed procedure documentation and determined that Dow Corning No. 4 had been used since August 1986, without approval for use in the RCS.

Based on this review, the inspector found that overall RCP seal maintenance activities were acceptable. During the review the inspector identified an example where the RCP seal maintenance procedure was not adequate in allowing the use of a lubricant for an extended period of time that had been previously prohibited from use in this application. This example is considered a violation of the requirements of TS 6.8.1 since the procedure specified the use of a restricted lubricant without a technical evaluation. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. NCV 50-413,414/95-22-02: Inadequate Maintenance Procedure specified use of a restricted lubricant.

c. Unit 2 Diesel Generator Foreign Material Intrusion Events

On October 18, with outage related maintenance in progress on the 2B diesel generator, maintenance technicians identified a folded pile of oil absorbent pads inside the 2B lube oil sump tank. The technicians recognized this as an unexpected condition, contacted their supervision, and the manway was replaced leaving the pads undisturbed. Because of the potential consequences and unknown source of the pads, site management initiated a Significant Event Investigation Team.

On October 29, with outage related maintenance in progress on the 2A diesel generator, maintenance technicians identified a single oil absorbent pad inside the 2A lube oil sump tank. Site management requested that the SEIT be reconvened to assess the additional occurrence.

The inspector reviewed the licensee's actions regarding operability assessment of the Unit 1 diesel generators, attended the team exit meetings, and discussed the Significant Event Investigation Team results with team members. The operability of the diesel generators was not affected by the oil absorbent pads in the lube oil sump tanks. This conclusion was based on the following: the location of the pads in the tank and the tanks' configuration with an integral strainer which prevented the possibly of the pads migrating to the lube oil pump suction; the pads were made from an inert material; and the lube oil pump discharge pressure and filter differential pressure trends showed no unexplained changes.

The Significant Event Investigation Team concluded that the most likely source of the oil absorbent pads was unintentional entry during maintenance activities last performed in February and March of 1993. Team recommendations focused on improved implementation of the Foreign Material Exclusion Program, particularly regarding quality control closeout inspection of tanks.

In summary, although the activities which caused the introduction of the pads into the diesel generator lube oil sump tanks occurred over two years ago, the Significant Event Investigation Team identified areas for improving the current program and its implementation.

In view of the observations characterized as a "Management Attention Item" by the Nuclear Safety Review Board regarding inconsistent implementation of foreign material exclusion controls (paragraph 3.d), as well as the foreign material intrusion events discussed in this and the previous paragraph, continued management attention in this area is warranted.

d. Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies

NRC Inspection Report 50-413,414/95-10, paragraph 5.b, describes an inspection of long-term licensee actions in response to Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies. A modification of the Rod Control System Current Order Timing was to be installed on both units. During the previous inspection, the inspector reviewed the minor modification, its associated 50.59 evaluation, completed work order documentation and the results of post implementation testing for the modification installed on Unit 1. During this report period, the inspector verified that minor modification CE-4744 was installed on Unit 2 during the current refueling outage. The inspector discussed the post implementation test results with licensee engineering personnel and reviewed a sample of the current order traces which indicated proper timing. Rod Control System Current Order Timing Modifications have now been completed on both units.

e. (Closed) Inspector Followup Item 50-413,414/94-31-01: Standby Makeup Pump System Testing

NRC Inspection Report 50-413,414/95-10, paragraph 5.c, described licensee actions to address testing of the reactor coolant pump seal injection flow path from the standby makeup pump. This flow path had never been tested. A test procedure was developed and implemented on Unit 1, during the unit's spring outage. The test demonstrated that the seal injection lines were not obstructed.

During the current Unit 2 outage, procedure PT/2/A/4200/07D, Standby Makeup Pump Flow Verification, was implemented. This procedure demonstrated that the flow paths were not obstructed and grossly quantified the flow to each seal. The inspector reviewed the completed procedure and discussed the test results with licensee engineering personnel. This item is closed.

5. **ENGINEERING** (NRC Inspection Procedures 37551, 73753, and 50001)

Throughout the inspection period, the inspectors reviewed engineering evaluations, root cause determinations, and modifications. During these inspections, discussions were held with operators, engineers, and plant management. The inspection evaluated the effectiveness of licensee controls in identifying and appropriately documenting problems, as well as implementing corrective actions.

The following items were reviewed in detail:

a. Inservice Inspection

The inspector reviewed documents and observed activities as indicated below, to determine whether ISI was being conducted in accordance with applicable procedures, regulatory requirements, and licensee commitments. The applicable ISI code for Catawba Unit 2 is the ASME B&PV Code, Section XI, 1980 Edition with Addenda through Winter 1981(80W81). Unit 2 was in the seventh and last outage, in the third 40-month period, of the first ten-year ISI interval. The licensee's nondestructive examination personnel were performing the liquid penetrant, magnetic particle and ultrasonic examinations. The ten year ultrasonic examination of the Reactor Pressure Vessel was being performed by BWNT.

<u>Review of Non-Destructive Examination Procedures</u>

The inspector reviewed the procedures listed below to determine whether they were consistent with regulatory requirements and licensee commitments. The procedures were also reviewed for technical content.

Procedure	Revision	Title
NDE-25	(16)	Magnetic Particle Examination Procedure and Techniques
NDE-35	(15)	Liquid Penetrant Examination
NDE-600	(6)	Ultrasonic Examination of Similar Metal Piping Welds in Wrought Ferritic and Austenitic Material
NDE-640	(1)	Straight Beam Ultrasonic Examination of Weld and Base Material in Pressure Vessels and Piping

BWNT Administrative Procedures

ISI-1	(8)	Administrative Procedure for Control of Inservice Inspection Procedures and Procedure Qualifications
ISI-2	(8)	Administrative Procedure for Records

		Management
ISI-21	(18)	Administrative Procedure of Personnel Qualification in UT Examinations
ISI-106	(3)	Procedure for the Remote UT Examination of Reactor Vessel and Associated Piping Welds Using the URSULA Manipulator and the Accusonex Acquisition and Analysis System
PQ-106-1		Qualification of UT Procedure ISI-106
PQ-106-3		Qualification to Address Changing Procedure ISI-106 Rev.3 for Near Surface Examination
BWNT-1087A-1	(0)	Ten Year Reactor Vessel Examination Calibration Matrix

The above procedures contained the necessary elements for performing the required examinations and were consistent with the requirements of the applicable code.

Observation of Work Activities

The inspector observed work activities, reviewed certification records of NDE equipment and materials, and reviewed NDE personnel qualifications for individuals utilized for ISI examinations observed. The observation and reviews conducted by the inspector are documented below.

(1) Ultrasonic Examination

Item no.	Weld	Dimensions	Comments
C05.021.051	2CF38-01	18"x.938"	Valve-to-Pipe, Intermittent root configuration verified with RT film review. Acceptable.
C05.021.052	2CF-10-C	18"x.938"	Pipe-to-Elbow, no reportable indications
C05.021.247	2NI-93-14	8"x.906"	Pipe-to-Elbow, root geometry, verified with RT film review. Acceptable.
C05.021.248	2NI-93-16	7"x.906"	Pipe-to-Elbow, root geometry, verified with RT film review. Acceptable.

(2) Liquid Penetrant Examination

Item No.	Weld	Dimensions	Comments
C05.021.247	2NI-93-14	8"x.906"	Acceptable
C05.021.248	2NI.92-16	"	"
C05.021.251A	2NI144-02	6"x.719"	"

C05.021.252A	2NI144-04	"	"
C05.021.253A	2NI144-05	"	"

(3) Magnetic Particle Examination

Item No.	Weld	Dimensions	Comments
C05.021.051A	2CF38-01	18"x.938"	Acceptable
C05.021.052A	2CF-10-C	"	"

For these examinations, the inspector verified that the activity was being performed in accordance with applicable code and procedural requirements including: calibration of equipment and system; use of qualified personnel; appropriate methodology of inspection and coverage of the area of interest; adequate analysis evaluation and documentation of identified indications; and review of previous examination results, as appropriate.

Ten Year Examination of Reactor Pressure Vessel Welds

Background: In addition to requirements of the above mentioned procedures and the applicable code, the licensee was utilizing requirements of later editions of ASME Section XI, to examine certain welds in the Reactor Pressure Vessel.

Through Relief Request No. 93-02, authorized by the NRC, on July 3, 1995, the licensee was to examine certain Reactor Pressure Vessel welds to the requirements of both the 1989 and 1992 editions of the code with exception to Appendix VIII. The subject welds included: the outlet nozzle to vessel welds; outlet nozzle inside radius sections; outlet nozzle to safe end welds; and outlet nozzle safe end to reactor coolant system piping welds. These welds were examined from the Reactor Pressure Vessel Inside Diameter. Credit for these examinations will be applied to the second inspection interval, first period requirements for the nozzle to vessel welds and nozzle inside radius sections. These examinations will also be applied to meet the second inspection interval percentage requirements. The reactor vessel outlet nozzle to vessel welds and outlet nozzle inside radius sections, will therefore not be examined during the second inspection interval.

The examinations were performed by BWNT utilizing a new underwater remote examination tool identified as "URSULA." Except for the aforementioned code case, examinations were governed by ASME Code Sections V and XI, (80W81) and 1983 Edition through the Summer 83, Addenda. The NRC Regulatory Guide 1.150, was applicable by reference.

System calibrations were performed by personnel qualified as Level

II UT examiners. Data analysis would be performed by Level II UT Limited or higher. Evaluation of recordable indications exceeding acceptable limits were the responsibility of Level III UT examiners. Data acquisition as done with BWNT's automated data acquisition "ACCUSONEX" system which is capable of collecting and digitizing ultrasonic data and transducer location.

Weld Scanning: Areas of interest, welds and all base metal through which angle beams will pass, were scanned with a 0 angle, straight beam transducer to the extent possible. Also, areas of interest will be examined with 45, 60, and 70 degree angle beam transducers from each side of the weld.

Work Observation: The inspector observed system calibration performed with calibration blocks NO.50304 and 50378, using 0 L wave and 45 shear wave transducers. ASME distance amplitude correction curves were developed which were consistent with code requirements. Results were reviewed and documented in the computer for use during weld examination. Through these observations and discussions with technicians, the inspector determined that the calibration was being performed in a satisfactory manner, procedures were adequately written and demonstrated to the code inspector, and results were being documented in a satisfactory manner.

Examination of Reactor Vessel Welds: Scanning commenced early on October 20, 1995. The first weld to be examined was identified on the inspection plan as item No. B01.011.002. This was horizontal weld No. W-12, in the Vessel Beltline region. The examination was being performed using two "URSULA" units working simultaneously and opposite each other. At the closing of inspector observations, the weld segment between 270 and 0 degrees was completed, while the segment between 0 and 90 degrees was still in process. A confirmatory calibration indicated that the 0 transducer was degrading. After several attempts to identify and correct the problem proved unsuccessful, BWNT removed the head with the bad transducer from the unit for repairs. The examination proceeded with one "URSULA" unit because of

Personnel Qualifications

The inspector reviewed personnel qualification documentation as indicated below for examiners who performed the examinations detailed in the paragraphs above. These qualifications were reviewed in the following areas: employer's name, person certified, activity qualified to perform, current period of certification, basis used for certification, signature of employer's designated representative, annual visual acuity and color vision examination, and periodic recertification.

EXAMINER RECORDS REVIEWED

Method	Level	Number
Ultrasonic	III	3
	II	10
	I	1
Liquid Penetrant	II	5
Magnetic Particle	II	2

Equipment Certification Records

Equipment/materials certification used in the inspections described in the paragraphs above were reviewed to ensure compliance with applicable code requirements.

Equipment Type	Equipment Identification
Spotcheck, Cleaner	Batch 94J01K
" Penetrant	" 95E05K
" Developer	" 95D07K
MT Powder	" 800,Type M28B25
Temperature Gage	S/N CNNDE-00002
MT Yoke	S/N CNO-31, Y6
Computer, HP-75000	DB-2088 and -2089
Signal Processor	DB-22001, -22004, and -22009
Power Supply (ACCUSONEX)	DB-20135 and -20138
Oscilloscope	
Tektronix	VH-298 and -5322
Stavely	VH-074 and 0749
UT Transducers	DB-34098 1 MHz 0 L
	-34081 2.25MHz 40 L
	-34381 W.Band 70 L
	-5508-93001 1 MHz 45S-L
	-5604-94002 1MHz 60S-L
	-5008-95001 1MHz 0-L
	-5008-91003 1MHz 0-L
	-9731-94001 W.Band 70-L
	-9731-95002 W.Band 70-L

Conclusion

Through reviews of administrative controls, procedures and records from work observation, the inspector ascertained that the licensee's program was meeting minimum applicable requirements, NDE examiners were knowledgeable of procedural requirements and were performing the examinations in a conservative manner. The ten (10) year ISI vessel examination was adequately planned and was being executed by well trained personnel with adequate technical expertise to analyze and evaluate identified indications.

b. Derailed Replacement Steam Generator Inspection

On October 2, 1995, the inspector was notified that the specially designed railroad car (shnabel) used to transport the first replacement steam generator to Catawba from the vendor's plant in Cambridge, Ontario, Canada, had derailed in Lima, Ohio. Through discussions with cognizant licensee personnel and document review, the inspector ascertained the following information. The accident occurred in the railyard, on a straight section of track between two gradual curves. The schnabel car carrying the SG apparently derailed because of load shift and other factors, as the train was being walked past the aforementioned track section. Upon derailment, it skidded down a two foot grade, rolled over on to its left side on the left hand side of the track and came to rest at approximately 90 degrees from its normal on-car position. When the schnabel car assembly came to rest, the SG was still held securely in the schnabel car by retaining bands and saddles. The only exception was that it had pulled away slightly from the support by about 1/2" and had settled outward and slightly downward.

The licensee's initial qualitative assessment of loading during the event indicated that the SG and center portion of tne schnabel car traveled downward through a vertical height of about six feet before coming to rest on its side parallel to the track. During the event, the beam on the side of the car in contact with the ground, carved a furrow about four feet deep into the rail bed and perpendicular to the track; thus suggesting that the schnabel car and the SG were not moving forward at the time of the mishap. Also, the qualitative assessment indicated that there was no evidence of axial deceleration at the location and concluded that the SG had a relative soft landing. The SG was removed from the site of the derailment and was transported to a warehouse nearby for storage, detailed damage assessment, and inspection.

B&W issued Nonconformance Report No. 14054 dated October 17, 1995, which was the controlling document and was used to describe the occurrence, damage assessment, structural and design analysis and inspection requirements. Design analysis and shipping stress calculations were used as the basis to determine which internal components would be more likely to see relatively high stresses resulting from the derailment.

Internal components identified for detail stress evaluation included: Flat bar U-bend restraint system, including the fan-bar assembly, tie-bars, arch-bars, and tie-tubes; Shipping supports; Lower shell internal components at the top lattice elevation; and

Steam drum internal components including the main and auxiliary feedwater header systems, primary separator assembly, and supporting components.

Following evaluation and analysis of the aforementioned components, B&W developed a Site Inspection and Operating Criteria plan to carry out and document the inspections. B&W's Nuclear Engineering prepared inspection requirements detailing the areas to be inspected and the methods to be used. B&W's Nuclear Services prepared a step by step Inspection Test Plan, based on engineering requirements with provisions for B&W and DPC signoffs.

Specific items designated for inspection were as follows:

- Approximately 30% or 1990 out of 6633 tubes in this SG were to be eddy current inspected over their full length with bobbin coil. This population sample consisted of all peripheral tubes in contact with J-tabs and two additional rows in the same general location for a total of four rows. In addition, crossover tubes adjacent to the tube lane and an additional sample consisting of 26 clusters of five tubes, distributed symmetrically throughout the bundle. An additional 30 tubes were inspected with an MRPC probe.

- From the secondary side, visual inspections included: approximately 25% or 200 of the U-tube/J-tab contact points for surface indication; Archbars, Clamping bars, J-tabs; Tie tubes, platform/archbar lugs and shipping restraint lugs on tie tubes; Shipping restraint components; Fan bars - short length between tube bundle and point engagement with clamping bars; Lattice grids; Steam drum internals; and Main feedwater header, including J-tubes, shroud cone extension, and support brackets.

- Pressure Boundary visual inspections included: Outer shell, nozzles, upper and lower heads, manways, holders and inspection ports.

At the time of this inspection, eddy current examination of SG tubes designated for examination was complete. Through discussions with cognizant B&W and DPC personnel the following information was ascertained. The examination was performed with bobbin and MRPC probes using Zetech's MIZ-18A eddy current analysis system. The applicable code was ASME Code Sections V and XI, 1992 Edition. The examination was performed by B&W personnel using B&W procedures. Data was analyzed and evaluated by B&W Level II or higher, ET examiners who performed independent primary and secondary analysis. The licensee's Level III ET examiner reviewed procedures for technique and adequacy. Bobbin and MRPC results were compared with data from ET examinations performed at

Cambridge. This effort showed that both sets of data were relatively similar, indicating that the derailment had no measurable adverse effects on the SG tubes.

The inspector performed an independent review of selected tubes and verified that the difference between the baseline data and the post accident data was essentially not measurable. The records showed that tube C119-R134 had a dent indication located in the middle of the U-bend. The indication was observed with MRPC probe and measured approximately 4.5 volts. Also, tube C96-R121 was plugged in the shop.

Liquid Penetrant Examination:

Nozzles with inconel buttering were PT tested for evidence of indications resulting from the derailment. A total of seven such nozzles were tested and no indications were identified. The examination was performed using B&W's PT procedure 2555548 Rev. B with Attachment 12-3-PT/C300 Rev.5, written to meet ASME Code Sections III and V Article 6, 1986 Edition. The inspector reviewed inspection records, personnel qualifications, material certifications and procedure qualification dated January 19, 1995. The records reviewed were in order.

Magnetic Particle Examination:

Nozzles with carbon steel welds were magnetic particle tested for evidence of indications resulting from the derailment. A total of twelve such nozzles were tested and no indications were identified. As stated above, this procedure was also written to meet the aforementioned code. The inspector reviewed examination records, personnel qualifications and material certifications and determined that they were in order.

Visual Examination of Internals, Secondary Side:

Part of the inspection test plan, devised to verify that the derailment did not compromise the integrity of the SG, was to perform a close visual examination of components and associated surfaces on the secondary side. This effort was performed by B&W in accordance with ITP No N5015 Rev 0, Secondary Side Internal Inspections and External Inspections. The inspector reviewed visual inspection reports describing the conditions observed relative to U-bend support systems, J-tabs, platforms, pins, washers, lugs, shipping spokes, U-brackets, fan blades, lattice grid, steam drum internals, main feedwater header and auxiliary feedwater header. In addition to reviewing inspection results, the inspector performed an independent visual inspection of secondary side internal components and contact surfaces to verify the aforementioned inspection results. As stated in the subject reports, the inspector observed no evidence of deformed parts, disturbed metal, loose bolts, abnormal gaps between J-tabs and SG tubes. Steam drum internals, the main feed water header, auxiliary feed water header, tie-tubes, arch-bars, top of the bundle, J-tabs and J-tubes all looked undisturbed. A small gouge was observed on the OD surface of the main feedwater nozzle. This was removed with light grinding and blending, leaving a small impression approximately 0.020" deep which will be dispositioned by engineering. Also, one of the water level nozzles was slightly bent by the impact, leaving a deflection of about 0.040" from dead center, near the tip of the nozzle. This too, will be dispositioned by engineering. A PT revealed no evidence of rejectable indications.

In conclusion, the licensee's visual inspection of secondary side internals disclosed that a significant number of fan bars, between 20 and 60, did not extend one tube diameter beyond the edge of the tube as required for support. At the time of this inspection the root cause for this condition was not clear. However, discussions were underway to determine how to disposition this problem. One of the options under consideration was to plug the tubes in contact with the suspect fan tabs.

At the closing of this inspection, preparations were underway to perform a loose parts inspection within the SG's secondary side spaces. Also, plans called for the SG to remain at the Lima, Ohio temporary storage location until arrangements for further shipping were finalized.

The inspector found that the program to inspect the primary and secondary sides of the SG were adequate. Inspections were being performed by personnel who were well qualified to perform their task. The licensee's participation in this work effort was noteworthy in that engineering, licensing and quality assurance were well represented and took an active role in this evolution.

c. Spent Fuel Pool Heat Load Design Assumptions

During this inspection period the inspector reviewed the licensee's design heat load assumptions for the spent fuel pool relative to refueling offload practices. Concerns have been identified at another nuclear power facility where the normal operating practice of offloading the entire core during refueling outages may have exceeded the heat removal design of the spent fuel pool cooling system.

The inspector reviewed FSAR Section 9.1.3.1.1, Spent Fuel Pool Cooling, and observed that the licensee's spent fuel pool cooling design assumes two heat load cases, a nominal heat load and a maximum heat load case. The inspector verified that the maximum heat load case described in the FSAR assumes more heat load than a full core offload. The inspector also observed that the spent fuel pool temperature would be maintained less than 150°F with the maximum heat load case assuming that two cooling trains are operating.

The inspector also reviewed TS amendments No. 134 (Unit 1) and No. 128 (Unit 2) dated August 31, 1995, which revised the TSs to increase the enrichment limits for fuel stored in the fuel pools. The NRC safety evaluation related to this amendment considered spent fuel pool cooling and heat transfer aspects (section 3.0). The safety evaluation concluded that the licensee's calculation of decay heat generation for both the normal and maximum cases and the analyzed values of spent fuel pool coolant temperatures for both cases were acceptable. The inspector reviewed operating data for the Unit 2 spent fuel pool cooling systems and verified the Unit 2 spent fuel pool temperature remained below 150°F following a full core offload. Both cooling trains were required to maintain the temperature for approximately 24 hours immediately following the core offload and only one cooling train was necessary subsequently.

Based on this review the inspector concluded that the spent fuel pool cooling system analysis bounded operating practice and no concerns with the spent fuel pool cooling system capability were identified.

d. 10 CFR Part 21 Notification Affecting Safety Injection Pumps

During this inspection report period, the inspector reviewed Unit 2 modifications associated with a 10 CFR Part 21 notification that was submitted by Westinghouse Corporation on October 26, 1994, and an update to that notification that was submitted on February 20, 1995. The subject of the original report involved a potentially defective part installed on JHF model safety injection pumps supplied by Ingersoll-Dresser Company through Westinghouse. The defect involved axial cracks in the pumps' rotating element pressure reducing sleeve locknut. These locknuts were made of 416 stainless steel with a specified Rockwell hardness of 27-32 and an actual hardness of 47, which is known to be susceptible to intergranular stress-corrosion cracking in fluid environments. In the update to the original report, two additional suspect pump parts, the pump suction impeller locknut and spacer sleeves, were identified as potentially defective as well. Westinghouse recommended that the affected pump parts be replaced with current parts manufactured from 410 stainless steel with a hardness rating of 27-32. The licensee's initial responses to the original report and the update are documented in NRC Inspection Report 50-413,414/94-31, and NRC Inspection Report 50-413,414/95-16, respectively. PIP 1-C92-0635 documents the licensee's actions in response to the issue.

The inspector reviewed the modification work orders (95059543 and 95018949 for safety injection pumps 2A and 2B, respectively) to verify that the subject parts were replaced with current parts manufactured from 410 stainless steel with a hardness rating of 27-32. The 2A safety injection pump rotating element was replaced during the current outage with a spare element that had been refurbished by Pacific Pump Company (a division of Dresser Industries). According to the licensee's repair reports associated with the modification, the refurbishment involved replacement of 416 stainless steel parts (including split rings) with 410 stainless steel parts (per purchase order U-06429-C5). The 2B safety injection pump rotating element was replaced with the element that had been removed from the 2A safety injection pump, disassembled, inspected and rebuilt with 410 stainless steel material replacing all 416 stainless steel material (per purchase order CN 5116). These modifications were appropriate to correct the original defect. Once spacer sleeves have been replaced on the 1B safety injection pump, corrective actions to address the 10 CFR Part 21 notification will be complete.

e. Containment Sump Recirculation Valve Pressure Locking Modification

During this inspection period the inspector reviewed a modification that was implemented in response to an industry issue that involved the potential for the containment sump recirculation valves to fail to open, because of pressure locking, during the recirculation phase of a postulated loss of coolant accident. The pressure locking phenomenon is described in NRC Information Notice 95-14, and the licensee's actions in response to the information notice have been documented previously in NRC Inspection Reports 50-413,414/95-07 and 50-413,414/95-12.

Each unit at Catawba has two containment sump recirculation valves. They are 18-inch Westinghouse reduced port flexible wedge stainless steel gate valves, a design that the licensee had determined might be susceptible to pressure locking. To determine if the bonnets of these valves could fill with fluid from the decay heat removal system (the first phase of the phenomenon), the licensee performed ultrasonic tests on the bonnets early in the outage, soon after "B" train of the decay heat removal system was placed in service. The tests indicated that the valve bonnet was less than half filled with water and its condition remained unchanged. "A" train testing had similar results.

Assuming the recirculation sump valve bonnets could become water solid and pressurize to the RHR system operating pressure when the unit was in Mode 5, the licensee concluded that the sump valves might not open for bonnet pressures higher than 310 psig. Therefore, modifications were planned to prevent pressure locking of these valves as a long-term corrective action. The modification involved the installation of a 1/2-inch bonnet vent valve on the RHR side of each sump recirculation valve; the vent valves were planned to be administratively controlled in the open position. The inspector reviewed the modification packages associated with the installation of the vent valves and inspected the sump recirculation valves affected by the modification to verify that it had been implemented. The inspector also discussed the modification with the Region II inspector who coordinated the inspection findings of this issue when it initially emerged. No concerns were identified.

Following installation of the modification, as reactor coolant system pressure was increased during mode 5 operation, operators detected leakage into the containment sump. They determined that leakage was migrating from the RHR system through "A" train pump suction piping. The seating surface of the sump-side valve wedge was apparently damaged, and since the bonnet vent valve was open, the leakage continued through the vent valve and into the sump. The vent valve was closed and leakage stopped. The licensee drafted an operability determination to address operating with the "A" train vent valve (2NI488) closed. The document asserts that any small bonnet leakage will prevent pressure locking, and that the leakage past the sump-side wedge provides that bonnet leakage path. Therefore, the risk of pressure locking is minimal. The inspector reviewed the operability determination and concluded that it was plausible. Licensee actions to address the potential for pressure locking of the containment sump recirculation valves were appropriate.

f. Reactor Coolant Pump Seal Injection Flow Control Valve Failure

At around 3:30 a.m., on October 18, 1995, operations deenergized 600 volt load center 2ELXB in preparation for tagout of essential switchgear 2ETB. Shortly thereafter, control room operators noticed that 1NV-309, a seal water injection flow control valve, had lost control button indication on its selector station. The flow valve controls back pressure on the charging header to ensure that adequate seal water is provided to the reactor coolant pump number 1 seals. As flow gradually increased, operators attempted to control valve position in manual; however, the controller did not respond. Using an abnormal operating procedure, operators then isolated 1NV-309 to allow for troubleshooting; seal injection flow was maintained at 36 gpm.

The Failure Investigation Process was initiated to determine the cause of the failure. The FIP team determined that the valve was not controlling in either manual or automatic. They also identified the same symptoms on 2NV-309. The licensee's investigation revealed that control power for both 1NV-309 and 2NV-309 utilize a unique power supply scheme.

Two low-voltage power supplies feed both the 1NV-309 and 2NV-309 circuits. The primary power supply (for both valves) of 26 volts DC is fed from Unit 1 (1KPW), and the backup power supply of 24 volts DC is fed from Unit 2 (2KPW). An automatic auctioneering mechanism ensures that the valves receive power from the power supply with the highest output. Apparently, the primary power supply had degraded prior to the event, and feed had switched to the backup power supply. When bus 2ELXB was deenergized for maintenance, feed switched back to the degraded primary supply, causing the loss of valve control.

As an interim measure, the backup power supply, which functioned acceptably, was inserted in the primary position so that it would be fed from Unit 1 and work on 2ELXB could continue; 1NV-309 was returned to normal control. Replacements for both power supplies were obtained and installed under minor modification CNCE-7395.

One of the more salient FIP findings was that if either ETA or ETB were lost from either unit, one power supply would be available to the control circuits of both valves. The licensee evaluated the reliability of this configuration and has determined that, because seal injection flow is not a safety-related function, redundant power supplies were not necessary. Nonetheless, reliable functioning of RCP seal injection is important to plant safety by minimizing seal failures. Indication of the status of the auctioneered power supply was not monitored; therefore, the primary power supply degradation and the associated loss of redundancy was not recognized.

The inspector reviewed the minor modification package associated with the power supply replacement, discussed the issue with a member of the FIP team, and questioned the existence of other similar power supply configurations in the facility. A licensee evaluation determined that this was a unique power supply configuration. As a result of the unrecognized power supply degradation, the licensee is considering periodic monitoring of the power supplies.

6. **PLANT SUPPORT** (NRC Inspection Procedures 71750)

Throughout the inspection period, facility tours were conducted to observe activities in progress. Some tours were conducted during backshifts. The tours included entries into the protected areas and the radiologically controlled areas of the plant, including emergency response facilities. Observations included assessments of radiological postings and work practices. During these inspections, discussions were held with radiation protection and security personnel. The inspections evaluated the effectiveness of the programs to assess whether activities were performed safely and in conformance with license and regulatory requirements.

The following items were reviewed in detail:

a. Radiological Control Area Entry Without Dosimetry

On October 11, licensee personnel identified that a vendor had been escorted into the Radiological Control Area without dosimetry, body burden analysis, training, or appropriate documentation.

The vendor was escorted by an engineer into areas of the Radiation Control Area containing Control Room Ventilation System components, low dose rate areas. The escort received no measurable dose during the entry. Upon identification, the licensee initiated PIP 0-C95-1744. Corrective actions documented in the PIP included: counselling of the escort, a site wide communication, and temporary signs were placed at Radiological Control Area access points to remind workers that dosimetry is required prior to entry. Since this entry appeared to be an isolated case, the inspector concluded that these corrective actions were appropriate.

The safety significance of this issue was minimal due to the low dose rates in the areas entered. Nonetheless, the entry in the Radiological Control Area without dosimetry, body burden analysis, training, or appropriate documentation did not comply with the licensee's Radiation Protection Manual and constituted a violation of NRC requirements. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. NCV 50-413,414/95-22-03: Radiological Control Area Entry Without Dosimetry.

b. Security Badge Control

On October 12, a vendor exited the plant without returning his security badge at the exit turnstile. An alarm should have alerted security personnel to the passing of the badge through the turnstile; however, the alarm did not actuate. The inspector questioned the possibility that a badged worker could remove a security badge from the plant and alter it for future unacknowledged access to plant protected areas. The inspector discussed this concern with site security personnel.

The licensee periodically tests the alarm, and failures are rare.

The licensee also performs an inventory check at the end of each day to account for all badges. The inventory would provide for the identification of badges not returned by people who are not in the plant. Once identified as "missing," these badges would be terminated and inspected for tampering if returned to the security organization. A person who either inadvertently or intentionally removes their badge from the protected area will be issued a new badge to replace the terminated, unaccounted for badge. The licensee also tests all badges on a quarterly basis to ensure that the alarming mechanism functions. The inspector concluded that the contingency plans for resolving potential removal of security badges from the protected area was appropriate.

7. EXIT INTERVIEW

The inspection scope and findings were summarized on November 21, 1995, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings addressed in the Summary and listed below. 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.

Item Number	Status	Description and Reference
NCV 50-413,414/ 95-22-01	Closed	Failure to minimize potential for disturbing RCS level during reduced inventory operation (paragraph 3.a)
NCV 50-413,414/ 95-22-02	Closed	Inadequate Maintenance Procedure specified use of a restricted lubricant (paragraph 4.b)
NCV 50-413,414/ 95-22-03	Closed	Radiological Control Area Entry Without Dosimetry (paragraph 6.a)
IFI 50-413,414/ 94-31-01	Closed	Standby Makeup Pump System Testing (paragraph 4.e)

8. ACRONYMS AND ABBREVIATIONS

ASME - American Society of Mechanical Engineers
B&PV - Boiler and Pressure Vessel
B&W - Babcock & Wilcox
BWNT - Babcock & Wilcox Nuclear Technology
CFR - Code of Federal Regulations
DPC - Duke Power Company
ECCS - Emergency Core Cooling System
EOC - End of Cycle
ESF - Engineered Safety Features

ET	-	Eddy-Current Test
FIP	-	Failure Investigation Process
FSAR	-	Final Safety Analysis Report
GL	-	Generic Letter
gpm	-	gallons per minute
IAE	-	Instrument and Electrical
IFI	-	Inspector Followup Item
ISI	-	In-Service Inspection
ITP	-	Inspection Test Plan
LER	-	Licensee Event Report
MT	-	Magnetic Particle
NC	-	Reactor Coolant
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NRC	-	Nuclear Regulatory Commission
MRPC	-	Motorized Rotating Pancake Coil
PIP	-	Problem Investigation Process
psig	-	pounds per square inch gauge
PT	-	Liquid Penetrant Test
R&R	-	Removal and Restoration (Tagging Order)
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RT	-	Radiographic Test
SEIT	-	Significant Event Investigation Team
SG	-	Steam Generator
SGRP	-	Steam Generator Replacement Project
TS	-	Technical Specifications
URI	-	Unresolved Item
UT	-	Ultrasonic Test
WO	-	Work Order