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REGION II
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Report Nos.: 50-413/94-31 and 50-414/94-31

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: December 4, 1994 - January 7, 1995

Inspectors: R. V. Crlenjak for 2/1/95
R. J. Freudenberger, Senior Resident Inspector Date Signed

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Approved by: R. V. Crlenjak 2/1/95
R. V. Crlenjak, Chief Date Signed
Projects Branch 3
Division of Reactor Projects

SUMMARY

Scope: This resident inspection was conducted in the areas of plant operations, maintenance, engineering, plant support, and evaluation of on-line maintenance (Temporary Instruction 2515/126). As part of this effort, backshift inspections were conducted.

Results: In the plant operations area, the licensee's evaluation of a degraded Component Cooling Water valve was thorough and detailed. Compensatory measures to allow continued operation with the degraded condition were properly implemented. Detailed operator training was conducted on the impact of the valve degradation, the compensatory measures implemented, and operating and emergency procedures affected (paragraph 3.a).

In the maintenance area, scheduling practices for on-line safety-related maintenance activities were found to be adequate; however, several scheduling program deficiencies were identified which reduced the effectiveness of the licensee's ability to evaluate proposed schedules for conflicts and risk significant impact to the plant (paragraph 4.a).

In the engineering area, an Inspector Followup Item was identified

ENCLOSURE

involving review of the licensee's testing of components in the standby makeup pump seal injection flow path (paragraph 5.b). An Unresolved Item was opened for further NRC review of a licensee identified design deficiency in the Auxiliary Building Ventilation Filtered Exhaust System that could adversely impact the licensee's control room and offsite dose assumptions (paragraph 5.c).

In the plant support area, the licensee's corrective actions for a missed Selected Licensee Commitment surveillance due to the deletion of the Model Work Order prescribing the surveillance was determined to be adequate. A Surveillance Coordinator was assigned to review all changes to Model Work Orders to prevent recurrence (paragraph 6).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

B. Addis, Training Manager
W. Byers, Security Manager
S. Coy, Radiation Protection Manager
* J. Forbes, Engineering Manager
W. Funderburk, Work Control Superintendent
T. Harrall, IAE Superintendent
D. Kimball, Safety Review Group Manager
* 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
D. Rogers, Mechanical Superintendent
* Z. Taylor, Regulatory Compliance Manager
D. Tower, Regulatory Compliance Engineer

* 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.

2. **PLANT STATUS**

Units 1 and 2 Summary

Both units operated at essentially full power for the entire report period with no major problems.

3. **PLANT OPERATIONS** (NRC Inspection Procedure 71707)

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 technicians, 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.

The following items were reviewed in detail:

a. Failure of Unit 1 Component Cooling Water (KC) Valve

On December 12, 1994, the licensee was conducting post-maintenance flow balance testing on portions of KC train 1B using procedure PT/1/A/4400/03D, Component Cooling System Flow Balance for Engineered Safeguards. This flow balance was being performed to verify adequate flow to the KC train 1B essential header after re-routing a section of the KC piping which provides essential cooling to the Residual Heat Removal pump 1B mechanical seal heat exchanger. The flow balance test alignment required that the KC train 1B reactor building non-essential header be isolated from the KC train 1B essential header. This was to be accomplished by closing valve 1KC-228B, the Reactor Building Non-Essential Header Isolation. When this was attempted, 1KC-228B could not be closed from the control room. Subsequent investigations determined that the valve was mechanically bound and could not close any more than 2 inches off its backseat.

The KC system consists of two redundant trains in each unit, with two pumps, and one heat exchanger and surge tank per train. During normal operation, only one KC train is in service. The eight KC cross-over valves (4 per train) are open allowing one train to provide cooling flow to its essential header, as well as to the opposite train essential header and to the common reactor building and auxiliary building non-essential headers. 1KC-228B is one of the four KC train cross-over isolation valves related to KC train B. During certain design basis events, 1KC-228B, along with the other cross-over isolation valves, automatically closes on the following signals: (1) low-low KC surge tank level; (2) low Refueling Water Storage Tank level following a Safety Injection signal, and 3) Phase B Isolation signal. These functions provide KC train separation, as well as isolation from cooling loads in the reactor building and auxiliary building non-essential headers that are not required to mitigate the consequences of design basis events.

The licensee evaluated the design function of 1KC-228B and how operability of the KC system was affected with the valve maintained fully open. The licensee determined that all safety functions of the KC system could be maintained with the valve open by implementing the following compensatory measures to the Unit 1 KC system:

- 1KC-228B was verified to be fully open and power was removed from the valve to ensure that it did not change position.

- The automatic isolation on low-low KC surge tank 1B level was transferred from valve 1KC-228B to 1KC-338B. 1KC-338B is the reactor building non-essential KC header containment isolation valve located downstream of 1KC-228B. The purpose of the low-low surge tank level isolation is to protect the KC system from leakage associated with potential KC piping failures. During design basis LOCA events, postulated KC piping failures can result from the interaction with breaks from other piping systems such as the reactor coolant system and residual heat removal system. By transferring the low-low surge tank level isolation to 1KC-338B, the protection from KC piping breaks would be maintained.

- All four KC train A crossover isolation valves (1KC-1A, 1KC-3A, 1KC-50A, and 1KC-230A) were closed and administratively maintained in this position. This ensured KC train separation by placing the train A cross-over valves in their safety-related position.

- The normal operating KC configuration was modified to allow operation of only one KC pump in each train. In this alignment, KC train B would supply cooling to the reactor building and auxiliary building non-essential headers, as well as its associated essential train components, and KC train A would be supplying its essential train components only.

- Management was to be notified prior to any work affecting the operability of other safety-related systems in order to ensure that the effects of the equipment out of service was properly evaluated until 1KC-228B was repaired. The licensee planned to replace this valve during the next refueling outage.

The inspector reviewed the licensee's safety evaluation for continued operation with 1KC-228B degraded. The inspector determined that the licensee had thoroughly evaluated the capability of the KC system to perform all of its safety functions with 1KC-228B maintained open with the above mentioned compensatory measures implemented.

The inspector attended several licensee briefings that were conducted with the operators to inform them of the valve problem, the compensatory measures implemented, the effect on the KC system alignments and operation, and the procedures that were revised as a result of the configuration changes. The inspector noted that the briefings and the material provided were detailed and thorough. The inspector also verified that all procedures impacted by the compensatory measures and configuration changes were properly revised and were in-place prior to returning KC train B to service on December 15.

The inspector reviewed the Temporary Station Modification (TSM) which transferred the KC surge tank 1B low-low level isolation function from 1KC-228B to 1KC-338B. The inspector did not identify any discrepancies with the licensee's 50.59 evaluation associated with the TSM. The inspector walked down the installation of the TSM in the field and verified that jumpers and sliding links were installed or repositioned as required by the TSM. The inspector also verified that temporary jumpers used for post installation testing were removed. The inspector verified from maintenance work order documentation (WO 94094070-01) that functional testing of the modification was completed successfully. Based on this review the inspector did not identify any discrepancies with the TSM and determined the TSM was properly installed.

The inspector reviewed corrective actions for several historical issues involving 1KC-228, including licensee actions taken following a previous similar failure of this valve and response to industry issues concerning mechanical binding of valves installed in similar orientations as 1KC-228. In 1992, the valve mechanically bound during operation with no flow or differential pressure. The inspector reviewed work order documentation of the subsequent repair and observed that the licensee replaced the gate valve disc and machined the valve guides to repair mechanical damage caused by the failure. Since this failure, the valve had operated adequately and Generic Letter 89-10 differential testing was successfully completed.

In 1981, prior to initial operation, a Part 21 report was issued by the valve vendor that informed licensees that this valve type was subject to binding if it was oriented from 22.5 - 157.5 degrees from vertical. The inspector verified from vendor documentation that the licensee returned the affected valves to the vendor for a modification to round all sharp edges on the valve gate and guides. NRC Information Notice 92-59, Horizontally-Installed Motor Operated Gate Valves, informed licensees that MOVs installed in horizontal positions may be especially susceptible to performance problems, including friction or binding of the valve disc. In addition to the issues discussed in NRC Information Notice 92-59, industry MOV test program results are provided in EPRI TR-1032, MOV Performance Prediction Program - Gate Valve Design Effects Testing Results. The EPRI tests concluded that appropriately machined edges on the disc and seat of gate valves can reduce friction dramatically. The inspector reviewed the licensee's corrective actions documented in PIP 0-C93-0391 and verified that the licensee was taking adequate actions in response to NRC Information Notice 92-59 and EPRI testing results.

The inspectors will continue to followup the results of the licensee's evaluation of the cause of 1KC-228 failing to close when this valve is disassembled during the upcoming refueling outage.

b. Unit 1 Annunciator Failure

On December 7, Unit 1 experienced a failure of a portion of the annunciator system which resulted in the loss of power and alarm function for two annunciator panels and a portion of a third annunciator panel. Alarms on these panels account for approximately 28 percent of the total Unit 1 annunciators. This failure resulted in the degradation of the annunciator system for approximately 1 hour and 20 minutes until these panels inexplicably reenergized without any corrective work or troubleshooting being performed.

The licensee made a determination that the inoperability of this portion of the annunciator system did not result in a condition which met emergency action levels, requiring the declaration of an emergency classification or a 10 CFR 50.72 notification to the NRC. The inspector reviewed emergency action levels provided in RP/0/A/5000/01, Classification Of An Emergency, and verified that the percentage of annunciators lost on December 7, was less than the 50 percent limit which would constitute an Alert emergency classification. The inspector also verified that the licensee's evaluation of this failure to determine the impact on emergency assessment capability and reportability was adequate.

Subsequent to the self-restoration of the annunciators, the licensee initiated 15 minute surveillance testing of the affected annunciator panels to verify proper operation and to detect additional failures. This surveillance interval was extended to 2 hours on December 9, based on an engineering review of the system design which determined a loss of power to these panels would be evident by the receipt of the same 11 alarms on panel 1AD07 that were received following the initial failure.

The licensee's investigation determined that a failure in the inverter which energizes the field contact power supplies for annunciator panels 1AD06, 1AD08, and a portion of 1AD07 was the only possible source of the annunciator failure. The licensee developed an action plan to replace the inverter. The inspector observed portions of the replacement evolution, including the premaintenance briefing of the control room operators, and initial portions of the actual replacement. The inspector verified that the licensee developed appropriate operations surveillance contingencies for monitoring plant parameters during the replacement evolution when annunciator panels 1AD06, 1AD07, and 1AD08 would be deenergized.

Prior to the removal of the inverter assembly from the annunciator system, the inspector observed the licensee performing voltage measurements of the inverter assembly to aid in the failure analysis. During this activity the inverter output deenergized and resulted in the same loss of annunciator problem which occurred originally. It was also evident that a relay mounted on the inverter assembly was arcing internally and intermittently changing states that resulted in an intermittent loss of inverter power output. The relay that had apparently failed, was the inverter assembly K1 relay. This relay is a normally energized relay in circuitry that functions to swap the normal input power supply to the inverter to a backup power supply upon the loss of the normal inverter power supply. The licensee determined that a failure of the K1 relay would result in a loss of inverter output that caused the annunciator failure in panels 1AD06, 1AD07 and 1AD08. The licensee completed replacement of the inverter assembly and restored the annunciator system. The failed inverter assembly is also being sent to the vendor for a complete failure analysis.

Based on this review the inspector considered the licensee's actions to increase annunciator testing frequency while the system was potentially degraded and contingencies for monitoring plant parameters during an inverter replacement to be appropriate. The inspector also considered the development of the inverter troubleshooting and replacement action plan to be effective.

4. **MAINTENANCE** (NRC Inspection Procedures 62703, 61726 and TI 2515/126)

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 were 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. Evaluation of On-Line Maintenance (TI 2515/126)

This inspection effort was performed to determine whether licensee processes appropriately consider the significance and risk to plant safety when scheduling on-line maintenance. The inspection focused primarily on the licensee's procedures and practices regarding the scheduling and removal of equipment from service to perform on-line scheduled maintenance and the licensee's effectiveness in evaluating the overall safety impact of these activities on the plant.

The inspector reviewed the applicable work control process procedures for planning and scheduling on-line maintenance. This included a review of the following procedures:

- WPM 600, Scheduling Work on the Master Schedule,

- WPM 601, Innage Management/Innage Work Window Manager Rotation Schedule,
- WPM 104, Catawba Nuclear Station Site Specific Transition Plan
- Site Directive 3.0.8, Scheduling Philosophy for TSAIL Items, EMFs, CRIPS, and other Priority Work.

The licensee's maintenance schedule is built around a 12 week equipment/component train rotation cycle. This 12 week cycle is divided into two week intervals such that two "A" train work weeks are followed by two "B" train work weeks. The Work Control Scheduling group utilizes a computerized Master Schedule to tentatively schedule all work task items (WOs) within a given week. Fully planned WOs are downloaded from the Work Management System database into the Artimis Prestige scheduling tool database. The majority of these WOs consist of TS required periodic testing and routine pre-defined maintenance items; the rest include primarily corrective maintenance WOs. Using Artimis, the schedulers place the WOs into the appropriate date and time slots of the proposed Master Schedule based on the following scheduling philosophy/criteria provided in SD 3.0.8 and WPM 104:

- Train Related Work Week: "A" train equipment WOs are scheduled during "A train work weeks and "B" train equipment WOs are scheduled during "B" train work weeks. Recently, management approval was added as a requirement if any "cross-train" work is to be performed.

- Priority: Significant work items based on plant safety and criticality to plant operations are scheduled before less significant items. In November 1994 more specific scheduling evaluation criteria was provided to the schedulers via WPM 104 and SD 3.0.8. The revised procedures emphasized those components/systems that were considered to be important and provided specific guidance on how to schedule work affecting them. For example, corrective work items that involve equipment/systems with TS action statements less than or equal to 72 hours, should be scheduled as soon as possible. Less significant items are scheduled within 5 days, 10 days, next available train related week, or later.

- Maximization of Equipment Availability: Work items are grouped together when possible (e.g., upcoming pre-defined WOs might be scheduled with corrective WOs that affect the same equipment in order to minimize the amount of equipment unavailability).

- Resources: Availability of qualified work crew personnel is taken into consideration when scheduling work items.

A Work Window Manager, who is responsible for a given work execution week, analyzes the proposed schedule 4 weeks in advance of the work execution week and interfaces with the schedulers to resolve any scheduling conflicts. Two weeks prior to the work execution week, the Work Window Manager distributes the proposed schedule to the execution groups for review. Meetings are then held between the scheduling group, planning group, and execution groups to discuss the proposed schedule in order to obtain a commitment to the schedule. Representatives from the execution groups are expected to attend this meeting, address schedule conflicts, and make commitments for their group. For example, operations support representatives are expected to attend this meeting and be cognizant of important outstanding degraded equipment and its impact on the proposed schedule. A committed master schedule is generated after all groups involved agree that the schedule can be supported.

The inspector determined that the licensee's process for evaluating the safety impact on the plant when scheduling on-line maintenance was adequate. The scheduling philosophy used was determined to be conservative with regard to minimizing both safety system unavailability and diverse equipment within the same train removed from service at the same time. The inspector noted, however, that formal risk assessment evaluations are not routinely conducted to identify risk significant activities or to determine the overall/cumulative safety impact on the plant when scheduling on-line maintenance. Based on discussions with schedulers and Work Window Managers, systems engineering personnel were being consulted routinely when questions arose regarding potential conflicts. In addition, systems engineering personnel are expected to review the proposed schedules to identify potential conflicts. The inspector noted that this policy was not being adhered to consistently among the engineers. This was discussed with engineering management who indicated that greater emphasis would be placed on these reviews and guidance would be developed to reflect management expectations of the quality of such reviews.

The inspector determined that in lieu of a formal program or guidance, consideration for the overall safety impact in the scheduling process relies heavily on the experience and plant systems knowledge level of the individuals involved in the scheduling and scheduling review process (i.e., the work control schedulers, Work Window Managers, and work execution groups). The inspector noted, however, that with the exception of the scheduling criteria/philosophy discussed above, the schedulers and reviewers had not been provided with guidance or training on how to effectively evaluate the cumulative risk impact on the plant when scheduling on-line maintenance. While the majority of the Work Window Managers have held Senior Reactor Operator licenses which afforded them some PRA insight training, the schedulers and work execution groups have not. Based on discussions with selected schedulers, as well as Work Window Managers, the individuals were not familiar with insights gained from the

Catawba Individual Plant Examination dated September 1992 or other plant PRA studies that could aid in assessing the relative risks associated with having combinations of equipment inoperable simultaneously. The inspector concluded that lack of adequate training and guidance reduced the licensee's effectiveness in evaluating the proposed schedules for conflicts and risk significant impact to the plant.

The inspector reviewed the licensee's proposed master schedules of on-line maintenance planned for the weeks beginning January 2 and 9. The purpose of this review was to determine if the licensee had adequately evaluated the potential risk associated with performing the scheduled activities and to verify that the work control process was being implemented in accordance with procedures. As a result of this review, no potentially risk significant activities were identified that had not been adequately evaluated by the license. However, the inspector noted the following scheduling program deficiencies that reduced the effectiveness of the process for evaluating the proposed schedules for conflicts and risk significant impact to the plant.

- The proposed master schedules were not being developed, distributed, nor reviewed within the timeframes established by the work process guidelines. For example, one of the goals of the scheduling group is to develop and distribute a planned master schedule for the Work Window Managers to review within 4 weeks from the start of the execution work week. However, the schedule for the weeks reviewed were not released until approximately two weeks before the start of the execution dates. As a result of this and other scheduling problems, the Work Window Managers have not been consistently able to review and distribute a proposed schedule to the execution groups for review within two weeks of the execution week. The inspector considered that reducing the allotted review times due to these delays could reduce the effectiveness of identifying potential risk significant conflicts.

- The proposed master schedules distributed by the schedulers were not complete. For example, the January 9 proposed schedule that was distributed for review did not include activities associated with the tube cleaning of KC Heat Exchanger 2B. In addition, the schedules did not contain routine periodic TS related surveillance test items that the operations group is responsible for completing. The inspector determined that the operations group was adequately tracking these items separately via their own scheduling system; however, there was no formal process to relay changes in the operations schedule to the schedulers to assure that there were no potential conflicts. The inspector considered it important that the schedules be complete during the review process.

The inspector determined that the above scheduling problems were primarily the result of difficulties the licensee was having with the proper operation of the new computer scheduling program "Artimis." This scheduling tool was implemented in October 1994, but had not worked properly since that time. The inspector determined that the licensee was pursuing resolution of these scheduling problems and expected to complete upgrades to Artimis within the upcoming months. The inspector plans to continue to monitor the licensee's actions to resolve these scheduling problems.

b. Static-O-Ring Pressure Switch Setpoint Drift

On December 12, the licensee identified an issue regarding the setpoint drift of pressure switches installed in the Reactor Protection System, loss of feedwater channel at the Oconee Nuclear Station. The switches were Static-O-Ring model 9N6-W5-U8-C1A-JJTTNQ. PIP 1-094-1761 was written to address this issue at Oconee.

During the week of December 19, the licensee identified that similar pressure switches were installed in a similar (high pressure) application at Catawba. In the Catawba application, the switches monitor main turbine hydraulic oil pressure associated with each of four turbine stop valve actuators as an indication of turbine trip status which is an input to the reactor protection system. Low hydraulic oil pressure on two of the four valves indicates the stop valves are closed and the turbine is tripped. The trip setpoint of the pressure switches is 550 psig and the Technical Specification minimum allowable value was 500 psig. With reactor power greater than 69% power, a main turbine trip will cause a reactor trip. Diverse main turbine trip status is also provided to the reactor protection system by limit switch position indication of the turbine stop valves.

Calibration of the main turbine stop valve hydraulic oil pressure switches is normally performed with the unit shutdown. The licensee considered the need to shutdown the units or reduce power to below 69% power to perform the calibrations. A method was identified for performing the calibrations at power with minimal risk of an inadvertent reactor trip. On January 4, after revision to the calibration procedures and walkthroughs of the evolution involving operations and IAE personnel, the pressure switches were calibrated. The inspector observed portions of the activity and reviewed calibration data. Of the eight pressure switches in this application on both units, "as found" data of all switches was greater than the Technical Specification minimum allowable value. Two switches were within tolerance of the setpoint, one was slightly out of tolerance low (non-conservative) and five were slightly out of tolerance high (conservative). Based on these results, the licensee did not plan on increasing the frequency of calibration. At the end of the report period, the licensee was continuing to evaluate the scope of the applicability of the setpoint drift of Static-O-Ring pressure switches based on "as found" calibration data of switches in various applications.

The licensee's actions to identify potential applicability of this instrument setpoint drift issue to similar safety-related installations and verify operability were appropriate.

c. (Closed) LER 413/93-11: Technical Specification Surveillance Interval Exceeded

On December 20, 1993, the licensee identified that the TS 3/4.7.8 Surveillance Interval for Snubber Visual Inspections was exceeded for 128 accessible snubbers. The licensee subsequently completed the required inspections and determined that the root cause of missing this TS surveillance was due to document use practices following the issuance of a TS Amendment which changed the surveillance. The licensee's review showed that the work orders that implemented the surveillances were not revised to incorporate a TS change.

The inspector reviewed the licensee's corrective actions and verified that the two model work orders which implement the snubber inspections (91003414 and 91004921) were revised to include a surveillance interval that is within current TS limits. The inspector verified that Catawba Site Directive 2.1.7, Technical Specification Amendments, was revised to provide additional guidance to incorporate TS changes into implementation level documents. The inspector also reviewed the licensee's review of TS changes and related documentation, and verified that the review encompassed the two year period prior to this missed snubber surveillance event. The inspector did not observe additional instances of similar events which were not identified by the licensee at the time that this LER was submitted.

Based on this review, this item is considered closed.

d. Review of Part 21 Affecting Safety Injection Pumps

During this inspection period, the inspector reviewed the licensee's actions in response to a 10 CFR 21 report that was submitted by Westinghouse Corporation via Nuclear Safety Advisory Letter 94-023, dated October 26, 1994. The subject of this Part 21 report involved a potentially defective part installed on JHF model safety injection pumps supplied by Ingersoll-Dresser Company through Westinghouse. The pumps affected at Catawba were the four original safety injection pumps supplied by the manufacturer in 1976.

The defect involved the potential for axial cracks of the pressure reducing sleeve locknut associated with the pump internal rotating element. In 1992, Duke Power Company first discovered the existence of axial cracks in the locknuts during maintenance on the Catawba 1B safety injection pump. Failure analysis performed by Duke Power Company determined that the cracks were the result of stress corrosion cracking. The locknut was manufactured from 416 stainless steel with a presumed Rockwell Hardness of 27-32. The actual hardness of the material was determined to be 47. It is known that 400 series stainless steel with a hardness in excess of 40 is susceptible to intergranular stress corrosion cracking.

Ingersoll-Dresser determined that the hardness of all locknuts manufactured in the same heat treatment as that at Catawba was potentially out of specification. It was determined that the locknuts of 29 pumps had been manufactured with this heat treatment. The Part 21 report recommended that these locknuts be replaced with current locknuts that are manufactured from 410 stainless steel with a hardness of 27-32.

The licensee initiated PIP 1-C92-0635 to address the failure of the locknut associated with the 1A Safety Injection Pump and the generic implications for the remaining three pumps. The inspector verified that the licensee had received the part 21 report and was aware of the recommendations. The inspector verified by reviewing maintenance WOs 85011750-01, 91059754-01, and 93065400-01 that the licensee had already replaced the locknuts associated with three of the four safety injection pumps. These WOs documented the replacement of either the pump rotating element (which included the new locknut) or the new locknut itself. Replacement of the locknut associated with the original 2A Safety Injection Pump is currently scheduled for the upcoming Unit 2 refueling outage in December 1995. The licensee attempted to replace the original locknut in the 2A pump during the previous outage, but was unsuccessful due to difficulty experienced when trying to remove it. A dye penetrant test was performed on the exposed surface of the locknut and no crack indications were identified. Based on these results, the licensee decided it would be acceptable to replace the locknut during the next outage. The inspector determined that, to date, the licensee's actions associated with this Part 21 were appropriate.

5. **ENGINEERING** (NRC Inspection Procedures 37551 and 92903)

a. Pressurizer Power Operated Relief Valve Operability Evaluation

On December 27, the inspector was performing a review of an operability evaluation which was performed to support closure of PIP 2-C94-1134. The PIP documented the failure of a power supply in process cabinet 8, which resulted in an unrecognized entry into Technical Specification 3.4.4, Reactor Coolant System Relief Valves, Action b. The power supply failure generated two simultaneous alarms in the Control Room. Based on the alarms, the operators called in Instrument and Electrical personnel to aid in determining operability of pressurizer power operated relief valve

2NC-34 and perform necessary repairs. The technician diagnosed the failure and replaced a failed process card within six hours of the failure. Shortly thereafter, it was determined that the card failure rendered pressurizer power operated relief valve 2NC-34 inoperable. Action b of Technical Specification 3.4.4, allows 72 hours to return the power operated relief valve to an operable status prior to the initiation of a shutdown. The PIP was written to document the unplanned entry into Technical Specifications and request a past operability evaluation from engineering.

Inspector review of the past operability evaluation noted that the process card failure blocked the automatic actuation of the power operated relief valve to relieve a reactor coolant system overpressure condition. The evaluation concluded that although the automatic function was blocked, the valve was operable because it could be operated from a switch on the main control board. The inspector questioned the reliance on manual actions and found this to be inconsistent with the Technical Specification basis, which stated that automatic operation of the power operated relief valves was a function required for operability to reduce challenges to the code safety valves during overpressurization events. This inconsistency was communicated to the licensee. Upon reassessment of the operability evaluation, the PIP operability determination was revised to indicate that valve 2NC-34 was inoperable without automatic control.

Licensee evaluation of the cause of the erroneous operability evaluation determined that the individual who had performed the operability evaluation had relied on the information contained in the Design Basis Document for the basis of his determination. The Design Basis Document and the Technical Specification basis were inconsistent regarding functions required for operability of the power operated relief valves. A new PIP, 0-C95-0028, was written to address this inconsistency.

Although the past operability evaluation was in error, the inspector considered that there was no impact on plant safety because appropriate actions to repair the failed power supply were performed in a timely fashion. Nonetheless, the erroneous operability evaluation had been reviewed and approved by an engineering supervisor and a member of the Safety Review Group. The inspector questioned the effectiveness of this review and whether review of operability determinations by licensed operators would be appropriate. The licensee included this observation for consideration by the Systems Engineering Business Excellence Steering Team which has responsibility for the operability evaluation process.

b. Standby Shutdown System Testing

The inspector conducted an evaluation of the performance testing on Standby Shutdown System dedicated components. These components included the Standby Shutdown System diesel generator, the standby makeup pump, and the turbine driven auxiliary feedwater pump. Additionally, the applicability of findings regarding the testing of Oconee's Standby Shutdown System as documented in NRC Inspection Report 50-269,270,287/93-25, was considered with respect to Catawba.

The Standby Shutdown System provides a means to achieve and maintain hot standby conditions for 3.5 days on both units following a fire incident or a plant security emergency in which the control room and auxiliary shutdown panel are unavailable. The dedicated portions of the Standby Shutdown System were not designed to meet the consequences of design basis accidents. The Standby Shutdown Facility and the dedicated portions of the Standby Shutdown Systems were not designed to seismic Category I or safety-related criteria except where the dedicated systems interfaced with safety-related systems. The Standby Shutdown Facility, which is physically separated from other plant buildings, houses the dedicated diesel generator and its supporting equipment, batteries, switchgear, and control room. The standby makeup pumps, one per unit, are located in the annulus below the fuel pool in the reactor building. They supply reactor coolant pump seal injection and reactor coolant system makeup during Standby Shutdown System operation using the fuel pool as a suction source. Unlike Oconee's Standby Shutdown System, the existing turbine driven auxiliary feedwater pump is considered part of the Standby Shutdown System and is used to feed the steam generators during Standby Shutdown System operation. Since this pump is used during abnormal operations other than a fire or security emergency, Oconee's Standby Shutdown Facility findings were not directly applicable. The inspector did not evaluate the Standby Shutdown System design calculations.

Testing requirements for the turbine driven auxiliary feedwater pumps and the Standby Shutdown System components are included in Technical Specifications 4.7.1.2, Auxiliary Feedwater System, and 4.7.13, Standby Shutdown System. The Standby Shutdown System requirements include testing of the diesel generator, the diesel generator starting battery, the standby makeup pump and its water source, and the 250/125-Volt battery system. The inspector reviewed applicable operations and performance test procedures, temporary test procedures, and preoperational test procedures to determine the adequacy of the Standby Shutdown System testing.

The standby makeup pumps are tested quarterly in recirculation to demonstrate that the pump develops flow greater than or equal to 26 gpm at greater than or equal to 2488 psig. This testing meets Technical Specification requirements. Review of preoperational testing identified that the pumps had been tested in recirculation at that time as well. Other than initial flushing, flow through portions of the system was not tested. Flow from the suction source to the seals was not tested.

The licensee's Individual Plant Examination Submittal Report recognized the importance of the Standby Shutdown System as a means of providing totally independent reactor coolant pump seal cooling, and thus an additional level of reactor coolant pump seal loss of coolant accident protection. This additional level of protection is important in mitigating sequences that result in total failure of major support systems. Some of the major sequences affected are those initiated by loss of offsite power, loss of nuclear service water, loss of component cooling water and turbine building floods. Overall, the Individual Plant Examination concluded that the core melt frequency would be significantly higher without the Standby Shutdown System.

The Individual Plant Examination also recognized that the standby makeup pump seal injection flow path from the suction source to the seals was not tested. The performance of this type of test was considered as part of the Individual Plant Examination effort. It was determined that the proposed test could possibly result in long-term reactor coolant pump seal integrity problems because the quality of the water provided by the standby makeup pump is not the same as the normal seal injection source. Additionally, since the flow components in the path are considered reliable and are subject to individual testing, it was concluded that an integrated test would provide only marginal additional confidence in the reliability of the system.

The inspector reviewed the testing of the individual components in the flow path and questioned whether some components, particularly check valves, had been demonstrated to pass flow. At the end of the report period, the licensee was investigating current testing or inspections of components in the flow path, including passive components such as check valves.

Additionally, the inspector questioned the basis of the evaluation that was performed as part of the Individual Plant Examination which concluded that an integrated test would provide only marginal additional confidence in the reliability of the system considering the fact that it had not been flow tested in the past and flow distribution to the reactor coolant pump seals had not been verified. At the end of the report period, the licensee planned to develop a flow test which would include flow through the system into the normal seal injection lines, but not into the reactor coolant pump seals. This test would be developed based on information gathered during walkdowns of the system during the upcoming Unit 1 refueling outage in February 1995, and initially implemented during the next Unit 2 refueling outage currently scheduled for the fall of 1995.

The inspector will review: (1) the results of the licensee's evaluation of current testing and any planned actions based on this review, and (2) the licensee plans for flow testing of the system in future outages. This issue is identified as Inspector

Followup Item 50-413,414/94-31-01: Standby Makeup Pump System Testing.

c. Auxiliary Building Ventilation Filtered Exhaust System Single Failure Issue

On January 4, the licensee identified a potential design deficiency that affected both units' VA Filtered Exhaust Systems. The deficiency involved the discovery of single failures that could prevent the system from aligning to its filter mode on a LOCA signal. If the system does not properly align to its filter mode, the offsite dose analysis could be impacted. PIP 0-C95-0007 was initiated by the licensee to address this issue.

During normal operation, the VA Filter Exhaust System operates in the "bypass" mode. In this mode, all filtered exhaust fans are in operation, but the filter units are bypassed so that air from the auxiliary building is not filtered before being discharged from the unit stack. Upon receipt of a Safety Injection signal, the system aligns to its "filter" mode. In this mode, radioactive iodine that could be present in the ECCS rooms following a LOCA, are filtered through carbon units before being discharged to the outside environment.

When each VA Filter Exhaust train automatically aligns to filter mode, a bypass damper around the filter unit must close and the inlet and outlet dampers to the filters must open. The licensee identified that single failures could occur (e.g., failure of the bypass damper to close) that alone, would prevent the system from aligning to the filter mode. These failures were not assumed in the original dose analysis; therefore, the licensee initiated an evaluation of the increase in dose consequence should the VA Exhaust System fail to align to its filter mode.

On January 4, the licensee implemented interim measures to place the VA system in its filter mode until the dose evaluations were completed. To ensure that the system remained in its accident alignment, TSMs were installed to isolate air to the pneumatic dampers in the filter system to prevent these dampers from changing position.

The inspector reviewed the completed maintenance work packages that implemented the TSM on each of the four filtered exhaust trains. This included a review of TSM 95001648-01, 95001649-01, 95001650-01, and 95001651-01. The inspector also performed a walkdown to ensure that the TSMs were installed correctly. During these walkdowns the inspector verified the following: (1) the VA filtered exhaust system dampers were in their filter mode positions, and (2) the instrument air valves to the dampers were properly isolated, tagged, disconnected from the damper, and the openings taped to prevent the intrusion of foreign material. No discrepancies were identified.

At the end of the inspection period, the licensee was still evaluating the impact of the VA design deficiency on the current dose analysis assumptions. The inspectors plan to review the results of this evaluation upon completion. This issue is identified as Unresolved Item (URI) 50-413,414/94-31-02: Review VA Design Deficiency Evaluation Results.

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

Visual Inspection of Fire Rated Assemblies

On December 20, 1994, the licensee submitted a special report titled "Selected Licensee Commitment Surveillance for Visual Inspection of Fire Rated Assemblies Exceeded." This report was generated as the result of a failure to perform a portion of the visual inspections of fire rated barriers within the surveillance interval. In 1992, a review of the Model Work Orders which implemented the Selected Licensee Commitment incorrectly concluded that one of the Model Work Orders could be deleted. The inspector reviewed the report and discussed the issue with licensee personnel.

On November 29, the Station Fire Protection Engineer identified that the visual inspection of the exposed surfaces of fire rated assemblies had not been performed within their surveillance interval. Fire rated assemblies referred to by the Selected Licensee Commitment includes passive fire barriers such as walls, floor/ceilings, cable tray enclosures and other passive structures of fire barriers. The fire rated assemblies were declared inoperable and the visual inspections were initiated. The inspections were completed later the same day with no discrepancies identified. Visual inspections of fire dampers and sealed penetrations had been performed in accordance with sections a.ii and a.iii of Selected Licensee Commitment 16.9-5.

As a result of a previously identified issue regarding missed Technical Specification surveillances, a Surveillance Coordinator had been assigned in the Work Control Group. Changes to the surveillance program, including Selected Licensee Commitment surveillances are now reviewed by the Surveillance Coordinator.

The inspector concluded that the licensee's response to this issue was appropriate and previously implemented corrective actions appeared sufficient to prevent recurrence.

7. **EXIT INTERVIEW**

The inspection scope and findings were summarized on January 11, 1995, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings 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
TI 2515/126	Closed	TI 2515/126: Evaluation of On-Line Maintenance (Paragraph 4.a)
LER 413/93-11	Closed	Technical Specification Surveillance Interval Exceeded (Paragraph 4.c)
IFI 413,414/ 94-31-01	Open	Standby Makeup Pump System Testing (Paragraph 5.b)
URI 413,414/ 94-31-02	Open	Review VA Design Deficiency Evaluation Results (Paragraph 5.c)

9. **ACRONYMS AND ABBREVIATIONS**

CFR - Code of Federal Regulations
CRIPS - Control Room Indication Problem Status
EPRI - Electric Power Research Institute
IAE - Instrument and Electrical
IFI - Inspector Followup Item
KC - Component Cooling Water
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
MOV - Motor Operated Valve
NPF - Nuclear Power Facility
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
PIP - Problem Investigation Process
PRA - Probabilistic Risk Assessment
psig - Pounds per square inch gauge
R&R - Removal and Restoration (Tagging Order)
SD - Catawba Site Directive
TI - Temporary Instruction
TS - Technical Specifications
TSAIL - Technical Specification Action Item Log
TSM - Temporary Station Modification
URI - Unresolved Item
VA - Auxiliary Building Ventilation System
WO - Work Order
WPM - Work Process Manual