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

Report Nos.: 50-413/86-09 and 50-414/86-06

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

Docket Nos.: 50-413 and 50-414 License Nos.: NPF-35 and CPPR-117

Facility Name: Catawba 1 and 2

Inspection Conducted: January 13-17 and 23-31, 1986

Inspectors: McKenzie Thomas 2-25-86
M. Thomas Date Signed

for McKenzie Thomas 2-25-86
J. B. MacDonald Date Signed

Accompanying Personnel: F. Jape

Approved by: Frank Jape 2/25/86
F. Jape, Chief, Test Programs Section Date Signed
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope: This routine, announced inspection involved 163 inspector-hours on site in the areas of preoperational test witnessing, preoperational test results review, NRC Information Notice followup, review of Safety Evaluation Report (SER) open item and review of previously identified inspector followup items.

Results: No violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *#J. W. Hampton, Station Manager
   #L. Adams, Operations, QA
   #H. B. Barron, Operations Superintendent
   *#W. F. Beaver, Performance Engineer
   #E. M. Couch, Division Manager, Construction
   #J. W. Cox, Technical Services, Superintendent
   C. L. Hartzell, Compliance Engineer
   *#R. A. Jones, Performance Test Engineer
   J. A. Kammer, ESF Test Cooridnator
   *#P. G. LeRoy, Licensing Engineer
   D. R. Rogers, IAE Engineer
   #F. P. Schiffley, II, Licensing Engineer
   #G. Smith, Maintenance Superintendent

   Other licensee employees contacted included test coordinators, engineers, technicians, operators and office personnel.

   NRC Resident Inspectors

   #*P. H. Skinner, Senior Resident Inspector - Operations
   #*P. K. VanDoorn, Senior Resident Inspector - Construction

   *Attended exit interview January 17, 1986
   #Attended exit interview January 31, 1986

2. Exit Interview

   The inspection scope and findings were summarized on January 17 and 31, 1986, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed the inspection findings. No dissenting comments were received from the licensee. One new item identified during this inspection is listed below.

   - Inspector Followup Item 414/86-06-01, Improper setting of Train B sequencer timing relay - paragraph 6.b.

   The licensee did not identify as proprietary any of the material provided to or reviewed by the inspector during this inspection.

3. Licensee Action on Previous Enforcement Matters

   This subject was not addressed in the inspection.

4. Unresolved Items

Unresolved items were not identified during the inspection.

5. Followup on PORV Upgrade and IEN 85-98

a. PORV Upgrade

The inspectors reviewed the status of SER Open Item 9 concerning upgrading the pressurizer and steam generator power operated relief valves (PORVs) to safety related valves. The licensee has committed to upgrade the PORVs prior to startup following the first refueling outage for Unit 1 (License Condition 18) and prior to fuel load for Unit 2. In discussing the status for Unit 2, licensee personnel stated that the modifications for the pressurizer PORVs have been completed. The valves were tested to verify proper operation during preoperational (preop) test TP/2/A/1600/08, Pressurizer Dynamic Response Functional Test. The completed data package for this preop test was reviewed by the inspector during this inspection. Instrument air system check valves VI367 and VI368 have not been tested and the licensee is reviewing emergency operating procedures to determine if any procedures need to be revised to establish the conditions for alignment of the cold leg accumulator nitrogen to the PORVs.

The steam generator PORVs modifications have been completed. However, testing to verify that the valves operate properly will be performed by preop test TP/2/A/1600/06B, Steam Generator Steam Line Pressure Control Functional Test after fuel load. The licensee has identified that testing of the steam generator PORVs will not be completed at the time of fuel loading in their Status for Fuel Loading letter which was sent to the NRC in Region II on January 24, 1986.

b. IEN 85-98 Followup

The inspectors reviewed the licensee action on IE Information Notice 85-98: Missing Jumpers from Westinghouse Reactor Protection System Cards for the Overpower Delta Temperature (OPDT) Trip Function.

Following reactor trips at McGuire Unit 2 and V. C. Summer, it was discovered that the low-limiting (JA) jumper was missing from several of the OPDT trip cards. The purpose of this jumper is to limit the lead circuit response so that it will not raise the trip setpoint under conditions of decreasing average temperature (T-ave). The jumpers were apparently removed for preoperational testing and were not reinstalled. The preoperational and subsequent surveillance testing at both plants failed to detect the missing jumper because none of the tests included test signals that simulate conditions of decrease T-ave.

The inspectors reviewed Catawba Station Procedures IP/1/A/3222/76 (Unit 1), and IP/2/A/3222/76 (Unit 2) which provides for visual identification of the low-limiting (JA) jumper as well as tests it to ensure a zero output under conditions of decrease T-ave. IEN 85-98 is closed for Units 1 and 2.

6. Preoperational Test Witnessing (70312, 70315, 70316, 70441) - Unit 2

The inspectors witnessed the conduct of portions of the preop tests discussed below. This included attendance at coordination meetings, discussions with the performance test engineer and test coordinators, general observations of testing and operations in the control room. The tests were witnessed to verify that:

- Appropriate revisions of the procedure were available and in use by test personnel.
- Test prerequisites were met.
- Personnel involved in the tests were briefed prior to beginning the test.
- Proper plant systems were in service.
- The tests were performed in accordance with requirements.
- Adequate coordination among the personnel involved in the tests.
- Test data were collected and recorded in the proper manner.
- Problems encountered during testing were properly identified and documented for evaluation.

Portions of the following tests were observed:

a. TP/2/A/1100/06, Diesel Generator 2B Post Inspection Run, Sections 13.3 and 13.4. Section 13.3 verifies proper operation of engine trip devices during emergency operation. Section 13.4 verifies the 24-hour capability. Other functions verified during the 24-hour run included filter and strainer change-over during diesel generator (DG) operation; DG fuel oil consumption rate at 5750 KW; and main fuel oil storage supply to the fuel oil day tank.

b. TP/2/A/1200/03A, Engineered Safeguards Features Functional Test, Section 12.3. This section demonstrated proper response of Train B components to a sustained undervoltage condition (blackout) simultaneous with a simulated loss of coolant accident (LOCA) using the committed loading sequence. Train A was disabled throughout the actuation and absence of bus voltage was verified on the disabled train. The blackout was simulated by tripping breaker 2ETB-3 which is the normal incoming feeder from transformer 2ATD and the LOCA was a simulated containment Hi Hi pressure.

   During the initial testing of Section 12.3 on January 25, 1986, when the blackout and LOCA were actuated, proper sequencing of the Class 1E loads onto the essential bus did not occur as required by the test procedure. The licensee determined from reviewing the test data that the first three load groups had been sequenced onto the essential bus before the bus was re-energized by the emergency diesel generator. Subsequent troubleshooting by the licensee determined that the problem was one of the timing relays in the sequencer's committed load sequencing logic was set at zero seconds instead of 9.7±0.3 seconds (as required by the Catawba Technical Specifications). When a blackout is initiated, the DGs start and two timing relays are actuated simultaneously. The first timing relay is to be set at approximately eight seconds. If the undervoltage condition still exists after the timing relay has timed out, then load shedding of the essential bus is initiated (approximately 0.5 seconds) and the DG breaker closes approximately one second later, aligning the DG to the essential bus. The second timing relay is to be set at 9.7±0.3 seconds but was found set at zero seconds. After the second timing relay times out, automatic load sequencing begins. With the second timing relay setting of 9.7±0.3 seconds, it is assumed that the initiating undervoltage condition did not clear prior to eight seconds. Thus, after the blackout and LOCA were initiated for the test, loads were automatically being sequenced onto the essential bus since the second timing relay was set at zero seconds. After the first timing relay timed out, the essential bus was load shed. This included the first three load groups which had already been sequenced onto the bus. After the bus load shedded, the DG breaker closed aligning the DG to the essential bus and the automatic load sequencing continued with load group four. The test was subsequently terminated (load group eight had been sequenced) due to the possibility of problems developing with various components as a result of load group one being load shed. The timing relay was replaced and the licensee initiated an investigation to determine why the timing relay was set at zero seconds instead of 9.7 seconds. The preop test had already been performed on the Train B sequencer and the load sequencing times had been verified. The inspector informed the licensee that this item will be identified for future review as inspector followup item 414/86-06-01, Improper setting of Train B sequencer timing relay.

Section 12.3 was attempted again on January 28, 1986. The test was terminated after DG 2B tripped during the loading sequence. Subsequent troubleshooting by the licensee determined that the problem was a improperly sized orifice in the air line pressurizing the low low lube oil pressure trip. This limited the supply of control air (which is supplied by the DG starting air system) necessary to pressurize the low low lube oil pressure circuit within the time required (approximately 1-2 minutes) to prevent the DG from shutting down. The vendor drawings specified an orifice size of 0.028 inches. Licensee personnel stated that the orifice, which had been installed by the vendor, was only 0.014 inches. Licensee personnel stated that the air supply necessary was marginal which possibly contributed to the problem not being detected during previous testing of DG 2B. The problem had only been encountered during the post inspection testing and ESF testing. The licensee replaced the orifice in DG 2B and inspected the control panel for DG 2A and found that the correct sized orifice was installed.

Section 12.3 of the test was repeated on January 30, 1986. The Train B sequencer and DG 2B both operated properly.

c. TP/2/A/1350/25A, DG 2A Blackout and Load Rejection Preoperational Test. The inspectors witnessed the successful completion of the DG 2A Blackout and Load Rejection test performed on January 13, 1986. The test was originally initiated on January 9, 1986, but was terminated after breaker 2FTA1 failed to close. It was determined that the trip coil had malfunctioned and was subsequently replaced. The purposes of the test was to:

Verify proper operation of the degraded bus voltage protection on 2ETA switchgear. Proper operations includes the following functions:

DG 2A can start automatically and energize the emergency bus with permanently connected loads within acceptable time limits.

The load shed feature operates properly.

DG 2A can accept the blackout design loads in committed sequence and maintain voltage and frequency within acceptable limits.

DG 2A blackout auto-connected loads do not exceed the two hour rating.

DG 2A operates for greater than or equal to five minutes while loaded with blackout loads.

Verify that the DG can accept the blackout design loads under an accelerated sequence and maintain voltage and frequency within acceptable limits.

Verify that DG 2A can synchronize with offsite power while connected to emergency loads, transfer these loads to the offsite power source and proceed through a shutdown sequence returning the DG to standby.

Verify that a hot bus transfer on the blackout switchgear can be performed once synchronized with normal offsite power.

Verify that DG 2A can reject a load of $\geq$834 KW without exceeding the acceptable voltage and frequency limits.

Verify that during blackout actuation, the essential and blackout trains are independent and isolated from each other.

In the areas inspected, no violations or deviations were identified.

7. Preoperational Test Results Review (70322, 70329, 70400) - Unit 2

The inspectors reviewed the completed test data packages for the following preop tests:

TP/2/A/1200/03B, Upper Head Injection System Functional Test

TP/2/A/1200/03E, Safety Injection System Check Valve Functional Test

TP/2/A/1350/16A, 4160 Volt Essential Auxiliary Power System Preoperational Test

TP/2/A/1350/16B, 4160 Volt Essential Auxiliary Power System Preoperational Test

TP/2/A/1400/15, Auxiliary Shutdown Panel Cooldown Functional Test

TP/2/A/1600/08, Pressurizer Dynamic Response Functional Test

The test data packages were reviewed to verify that:

- Test changes were approved in accordance with administrative procedures.
- Test changes did not change the basic objectives of the test.
- Actions required by test changes had been completed.
- Test deficiencies had been resolved, including retesting where required.
- Individual test steps and data sheets were completed properly.
- Test data were within the acceptance criteria specified.
- Evaluation and approval of the test results had been completed by appropriate engineering and management personnel.

No violations or deviations were identified in the areas inspected.

8. Inspector Followup Item Review (92701) - Units 1 and 2

The inspectors reviewed the inspector followup items (IFIs) discussed below:

a. (Closed) IFI 414/85-42-02, concerning resolution of the discrepancies identified during performance of preop test TP/2/A/1400/15, Auxiliary Shutdown Panel Cooldown Functional Test. The inspector reviewed the completed data package and verified that actions taken to resolve all the test discrepancies were satisfactory.

b. (Closed) IFI 414/85-42-03, concerning location of controls on the auxiliary feedwater pump turbine control panel. The modifications will be made under exempt changes CE-0397 for Unit 1 and CE-0398 for Unit 2.

c. (Closed) IFI 413/85-51-01 and 414/85-59-01, concerning daily checks of the DG governor oil level. Operations Management Procedure 2-19, Round Sheets, has been revised to include checking the governor oil level during the daily rounds.

d. (Closed) IFI 413/85-51-02 and 414/85-59-02, concerning whether a valid governor oil level can be obtained without the engine running. Periodic test procedures PT/1/A/4350/10 and PT/2/A/4350/10, Diesel Generator Operating Parameters, have been revised to include checking the governor oil level while the DG is running.

e. (Closed) IFI 414/85-67-02, concerning the response times specified in the ESF test procedures for certain nuclear service water (RN) system valves being different from the Technical Specifications (TS) response times. Design drawings indicate that the valves in question, 1RN003A and 1RN004B, receive a containment pressure Hi Hi safety signal. Per TS Table 3.3-5, the response time for RN system operation is not applicable when the initiating signal is containment pressure Hi Hi. The inspector also noted during review of the data that the response times of the valves were less than those specified in the ESF test procedure and TS.

9. Dedicated Shutdown Capabilities

The inspectors reviewed shift staffing, training and the licensee's use of operating and abnormal procedures as these activities relate to the dedicated shutdown capabilities. These areas were reviewed to determine if the requirements of Standard Review Plan (SRP) Section 9.5.1, Position C.5.c for "hot standby" conditions and subsequent cold shutdown conditions are being met.

a. Shift Staffing and Training

The licensee's normal shift staffing was reviewed to verify that sufficient personnel are available to operate equipment and systems described in Operating Procedure OP/0/B/6100/13, Standby Shutdown Facility Operations. The review indicated that adequate shift staffing is being provided to man the necessary stations to support plant operations. The shift operating personnel provided to support OP/0/B/6100/13 are separate from the operating personnel assisting the fire brigade. The inspector had recently conducted a review of licensee training program during inspections of Unit 1 dedicated shutdown capability. The training provided to licensed and non-licensed operator is a continuing program and is part of the license operator requalification training.

b. Abnormal and Operating Procedures

The inspectors reviewed the licensee's abnormal operating procedure (AOP) and operating procedures (OP) to verify that SRP, Section 9.5.1, Position C.5.c requirements as given below have been incorporated into applicable procedures.

- Achieve and maintain hot standby conditions
- Achieve and maintain subcritical reactivity conditions in the reactor
- Provide decay heat removal capabilities
- Maintain reactor coolant inventory and steam generator inventory
- Achieve and maintain cold shutdown conditions
- Provide direct readings of process variables necessary to control the above conditions

The following procedures were reviewed:

- AP/2/A/5500/17, Retype 1, Loss of Control Room
- OP/2/A/6100/04, Retype 0, Shutdown Outside the Control Room from Hot Standby to Cold Shutdown
- OP/0/B/6100/13, Retype 5, Standby Shutdown Facility Operations
- OP/2/A/6100/20, Retype 0, Operational Guidelines for Achieving Cold Shutdown Following a Fire in the Plant

c. (Open) IFI (414/85-50-05) Completion of Alternative/Dedicated Shutdown Capability. This item identified three areas which were incomplete during that inspection. These areas are: procedures not completed for Unit 2 shutdown using standby shutdown system, the associated circuit analysis and the damage/repair procedures required to bring the plant to cold shutdown due to fire. This report identifies the operating procedures and abnormal operating procedures necessary to operate the standby shutdown system and were found to be adequate to accomplish shutdown operations due to fire in certain areas of the plant. IFI 414/85-50-05 is considered closed regarding procedures, training and shift staffing.

Within the areas inspected, no violations or deviations were identified.