UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-369/83-48 and 50-370/83-55

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

Docket Nos.: 50-369 and 50-370

License Nos.: NPF-9 and NPF-17

Facility Name: McGuire Nuclear Station Units 1 and 2

Inspection at McGuire site near Charlotte, North Carolina

Inspectors: for A. J. Ignatonis — 2/27/84
W. T. Orders — Date Signed

for A. J. Ignatonis — 2/27/84
R. Pierson — Date Signed

Approved by: Virgil L. Brownlee — 2/28/84
V. L. Brownlee, Section Chief — Date Signed
Division of Project and Resident Programs

SUMMARY

Inspection on December 20, 1983 - January 20, 1984

Areas Inspected

This routine, unannounced inspection involved 148 resident inspector-hours on site in the areas of operations safety verification, surveillance testing, maintenance activities, independent verification, and shift manning.

Results

Of the five areas inspected, no violations or deviations were identified in four areas; two violations were found in one area (Violation - failure to abide by procedure concerning emergency plan implementation resulting in inadequate emergency kits (50-369/83-48-01, 50-370/83-55-02) - Paragraph 11; violation - failure to follow procedure concerning equipment control resulting in loss of decay heat removal (50-370/83-55-01) - paragraph 7).

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REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   G. Cage, Superintendent of Operations
   *J. Foster, Health Physics Coordinator
   *M. Glover, Emergency Preparedness Coordinator
   *W. H. McDowell, Technical Associate - Licensing
   *M. McIntosh, Station Manager
   *D. Mendezoff, Licensing Engineer
   *M. Pacetti, MSRG
   *D. Rains, Superintendent of Maintenance
   *M. Sample, Project Engineer
   *J. Silver, Operations Engineer
   *B. Travis, Operations Engineer

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

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on January 20, 1984, with those persons indicated in paragraph 1 above. The licensee acknowledged cognizance of and concern over the inspector's findings.

3. Licensee Action on Previous Enforcement Matters

   Not inspected.

4. Unresolved Items

   Unresolved items were not identified during this inspection.

5. LER Followup

   The inspector evaluated the action which has been taken by DPC as part of the corrective action taken for LERs RO-369/81-178 and RO-369/81-189.

   a. (Closed) In reference to LER 81-178 the inspector found the annunciator alarm setpoints for the upper head injection (UHI) surge tank Hi/Lo pressure have been changed from the Technical Specification limits of 1206 and 1264 psig to 1215 and 1255 psig. DPC has completed the installation of additional UHI pressure guages which allow the control room operators to more accurately determine the UHI surge tank pressure. A review of the operating procedure for annunciator panel 1AD8 indicated that the applicable procedure, OP/1/A/6100/10I, has been revised to specify the most recent UHI surge tank Hi/Lo pressure settings. Also, the analog computer has added a point fed by INIPT5700 and/or INIPT5710 (pressure transmitters for the UHI surge tank pressure) to allow a readout of the UHI surge tank at the main control room consoles.

This LER is closed.

b. (Open) LER 81-189 resulted from noticeable decreases in pressurizer pressure which was attributed to several breakers on the pressurizer heaters power panels tripping open, requiring resetting. DPC attributed the cause of the occurrence to be a design inadequacy. Extensive modifications of the pressurizer heater power supplying circuit were scheduled for completion in March 1982. A review of a DPC request for plant modification dated March 19, 1981, indicated that DPC was aware of electrical control problems which may have been the cause of the violation of Technical Specification requirements for the pressurizer pressure control, which is documented on LER 81-189 dated December 30, 1981, (approximately nine months after the modification request had been written).

In addition to reviewing documentation related to the above LER, the inspector toured various control sections of the plant, interviewed operations and technical personnel. As a result of the observations, reviews, and interviews the inspector noted that DPC modified the electrical controls for the pressurizer heaters. The modification changed the fundamental function of the 600 volt pressurizer heater switchgear from operating as an on/off switch to a primary feed for the pressurizer heater panels. Essentially, a contactor circuit was placed between the primary power supply and the heater panel. The circuit consists of a vacuum type breaker cycled by two M-coils.

Even though this modification was completed in early 1982, the modification has not gone without operating problems. On or about February 9, 1983, DPC wrote LER 83-02 to document failures of the modified pressurizer control circuits to correctly function. The fault was attributed to a design defect in the vacuum breaker contactor coil circuit, whereby the heat dissipating resistor for the controls "M"-coil was overheating and burning its connecting wires. The incident resulted in pressurizer heater group "B" power supply failing to stay continuously energized.

On June 23, 1983, the inspector observed that group "B" pressurizer heater control switch, located on Unit 1 main control console, displayed a tag indicating that heater group "B" has a ground fault; a work request numbered 113957 was also referred to by the tag.

LER 81-189 and LER 83-02 remain open pending satisfactory resolution of the afore reported design defects and NRC receipt of the followup report which was committed to by DPC in their letter to RII dated February 9, 1983.

6. Plant Operations

The inspector reviewed plant operations throughout the report period, December 20, 1983 - January 20, 1984, to verify conformance with regulatory requirements, Technical Specifications, and administrative controls. Control room logs, shift supervisors logs, shift turnover records, and equipment removal and restoration records were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel on day and night shifts.

Activities within the control rooms were monitored during all shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in Section 3.1 of the Station Directives. The complement of licensed personnel on each shift met or exceeded the minimum required by Technical Specifications. Operators were responsive to plant annunciator alarms and appeared to be cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a systematic basis. The areas toured include but are not limited to the following:

Turbine Buildings
Auxiliary Buildings
Units 1 and 2 Electrical Equipment Rooms
Units 1 and 2 Cable Spreading Rooms
Station Yard Zone Within the Protected Area

During the plant tours, ongoing activities, housekeeping, security, equipment status and radiation control practices were observed.

McGuire Unit 1 began the reporting period operating at 92% power, restricted to that power level due to an inoperable main turbine governor valve (discussed in previous reports). At 9:40 a.m. on December 21, 1983, the only operable nuclear coolant drain tank (NCDT) pump was lost. The NCDT pump is used to pump down the pressurizer relief tank (PRT). Since there is a leaking pressurizer code safety valve (previously reported), the PRT requires constant cooling and periodic pumping. Loss of the NCDT pump thus required unit shut down to facilitate repairs. At 10:40 a.m. operations began load decrease at 5MW/min. The unit was off line at 2:10 p.m. Subsequent to repairs the unit was returned to Mode 2 at 3:55 p.m. the following day and placed on line at 6:26 p.m. The unit was escalated to and maintained 92-94% power until 11:29 p.m. on December 27, 1983 when a reactor trip occurred, the result of an electro-hydraulic control (DEH) failure. The DEH control problem caused the main turbine governor valves to open fully increasing load to 1132 MWE.

An erroneuous overspeed protection speed channel then caused the governor valves to close which in turn shrank steam generator level and tripped the unit on lo lo level in the A steam generator.

Plant systems responded virtually as expected.

Subsequent investigation revealed that water leaking from a chiller had leaked into the DEH control cabinet shorting several components.

Following necessary repairs, the unit was taken into Mode 2 at 9:30 p.m. that evening and placed on line at 12:16 a.m. December 28. Power was escalated and maintained at 92-94% until 9:45 a.m. on January 16. It was necessary at that time to take the unit off line (unit maintained mode 2) to facilitate repair of a steam generator blowdown valve BB-142. The unit was returned to mode 1 at 7:30 p.m. and placed on line at 8:40 p.m. The unit operated virtually unencumbered throughout the remainder of the report period.

McGuire unit 2 began the report period operating at 89% power, restricted to 90% due to a reactor coolant (NC) flow inadequacy as previously reported. The unit operated virtually unencumbered until 9:00 a.m. on December 23 when the unit was shutdown in preparation for a planned maintenance outage. The outage transpired with few difficulties aside from three instances of lost decay heat removal which are discussed in paragraph 7. As the report period ended the unit was preparing for restart.

7. Loss of Decay Heat Removal

On three occasions between the dates of December 31, 1983 and January 15, 1984, McGuire unit 2 experienced the loss of decay heat removal capability. On December 31, 1983 at 4:50 p.m., control room indications revealed no flow from the operating decay heat removal (ND) pump. The pump was stopped, reactor coolant (NC) level was increased, the pump and lines were vented, and the pump restarted at 5:20 p.m. The loss of ND was attributed to a loss of ND pump suction, the result of a reduced level in the NC system.

On January 9, 1984 at 12:46 p.m. the control room received an ND low flow alarm. Control room indications revealed symptoms similar to the previously discussed incident. Once again the pump was stopped, level increased, lines vented and pump restarted by 1:53 p.m. The loss of ND was once again attributed to the loss of ND pump suction, due to a reduced level in the NC system.

On January 15, 1984 at 10:07 p.m. the ND suction valves off the NC system, ND-1 and ND-2 were inadvertently closed when power was returned to the valve operators with a close signal present from the solid state protection system which was deenergized for maintenance. In this case, the valves were reopened and the pump started by 10:55 p.m.

Licensee investigation into the first two incidents revealed that NC level is very critical in the maintenance of ND pump suction head in that a level decrease of as little as 1 inch at an ND flow rate of 2500-3000 gpm results in air entrainment in the ND suction flow due to vortexing in the area of the NC to ND piping interface. This air then collects in a high point in the ND suction line and eventually can result in the loss of pump suction. This is hypothetically what occured in those incidents. The licensee subsequently processed procedure changes which, a) maintains a higher level in the NC system and b) reduces ND flow rate to be commensurate with ND heat load. These changes should preclude recurrence of this type incident.

The incident of January 15, 1984, occurred due to what appears to be a failure to follow procedure. When the incident occured, an Instrumentation and Electronics (IAE) technician was in the process of performing procedure, IP-0-A-3010-06, Reactor Protection System Response Time Test. Prerequisite 4.6 of that procedure requires the technician to verify that power has been removed from valve motors for ND-1 and ND-2 to prevent their closing upon removal of fuses in Step 10.1.2 (of the procedure) and to place red tags on the breakers to prevent inadvertent actuation. Operations in the mean time was preparing to restart the unit, having virtually completed a planned maintenance outage. In an interview with the IAE technician, he stated that he did contact operations concerning having the valves red tagged. (That statement was corroborated).

Operations in turn told the technician that the valves were already red tagged but pursuant to other work in progress, no red tags were hung pursuant to the technicians work.

At 10:07 p.m., operations restored power to valves ND-1 and ND-2 having reached that point in the startup, and having no administrative hold (red tags) to prevent it. When the valves were re-energized, they closed in response to the aforementioned IAE test in progress.

Station Directive 3.1.19, Safety Tags, Lock-Outs and Delineation Tags, requires that when an employee becomes aware of a need for a safety tag, to initiate placement of the tag by notifying the person responsible for issue of the tag. The directive specifies that the Shift Supervisor, Assistant Shift Supervisor, or other supervisor having a clearly defined area of exclusive operational responsibility shall issue and recall Red Tags. In this case ND-1 and 2 are operation's responsibility. Further the directive dictates that where workers not under the same direct supervision are conducting independent work related to the same component, they shall arrange for placement of separate safety tags.

Clearly, the IAE technician should have contacted Opeations, which he did, and Operations should have placed the Red Tags, which they did not. The IAE technician should at that point have gone no further in the procedure.

The requirements of IP-0-A-3010-06, prerequisite 4.6, as well as the requirement of Station Directive 3.1.19 were violated.

Technical Specification 6.8.1 clearly requires that current, written approved procedures be established and followed concerning equipment control (e.g., locking and tagging).

The above described incident is a violation of those requirements (50-370/83-55-01).

8. Independent Verification

Pursuant to a commitment made during a meeting held on October 19, 1983, between representatives of Duke Power Company and NRC, Region II, Duke Power was to "implement an upgraded program for independent verification affecting safety-related systems and components by January 1, 1984." Detailed herein is a synopsis of the revised program.

Station Directive 4.2.2, Independent Verification Requirements, was issued on December 6, 1983 and is the parent document governing the implementation of the revised program.

Pursuant to the Station Directive, one of the following techniques is employed to accomplish independent verification:

1. Two qualified individuals independently reaching the conclusion that affected components are properly removed from service or returned to service by the direct observation of the component or the direct performance of the necessary actions.

2. One qualified individual uses direct observation of the component or directly performs the necessary actions followed by a second qualified individual observing a remote indication.

3. Two qualified individuals using a single remote indication.

The following are methods of ascertaining the status of systems or components:

1. Direct observation of the component, direct performance or observation of performance of the action required by the procedure step.

2. Observation of a remote indication which provides the status of the component affected by the applicable procedure step.

3. Comparison of equipment identification number on a work request or procedure with that on the equipment.

4. Testing that establishes acceptable system performance or demonstrates component is correctly aligned as defined in the Technical Specifications and procedures.

Independent Verification is required for removal and return to service of systems and components which affect the performance of safety-related systems and applies to equipment which, if improperly aligned, could result in the uncontrolled release of radioactive liquids or gases from the site in excess of Technical Specification limits.

Independent verification is required on components for the following station activities:

1. Initial valve lineup and electrical alignments performed to declare a system operable.

2. All removal and restoration actions performed on applicable equipment using the Removal and Restoration Procedures of station groups.

3. All removal and restoration performed as an integral part of any station procedure used by station groups.

4. All alignments for planned releases of radioactive gas or liquid from the station. On site transfers of liquid or gases that do not involve a release path outside of station are exluded.

5. Prior to beginning maintenance on any applicable component, independent verifiction that correct component has been identified is required.

6. Following completion of maintenance, independent verification that correct component has been returned to service is required.

The implementation of the requirements entailed in the station directive are effected through diverse means within the various sections at McGuire. Detailed below in outline format are the sections involved and the administrative mechanisms employed by those sections:

I. Operations

  A. Station Directive 4.2.2

    1. Operations Management Procedure 1-6, <u>Independent Verification</u>

      a. Operating Procedures

II. Instrument and Electrical (IAE) Section

  A. Station Directive 4.2.2

    1. IAE Guideline #8, <u>Independent Verification</u>

      a. <u>IP/0/A/3090/19, Implementation of Independent Verification and Temporary Modifications</u>

        i. Performance Test Procedures (PT)

        ii. Instrument Procedures (IP)

III. Performance

  A. Station Directive 4.2.2

1. Performance Manual section 4.5, Independent Verification

    a. Performance Tests

IV. Maintenance

A. Station Directive 4.2.2

1. Memorandum to File, Subject: Independent Verification Requirements for Safety Related Maintenance Procedures

    a. Maintenance Procedures

V. Chemistry

A. Station Directive 4.2.2

1. Chemistry Manual, section 3.4, Independent Verification

    a. Chemistry Procedures

VI. Health Physics (HP) Section

A. Station Directive 4.2.2

1. Health Physics Manual Section 8.6, The Repair and Restoration Logbook-Independent Verification.

    a. Health Physics (HP) Procedures

Having reviewed the programs and interviewed personnel in each section pertaining to the implementation of the respective programs, it appears the new programs more adequately incorporate the intent of NUREG 737 item I.C.6.

The inspectors will continue to monitor the effectiveness of the program and report same in subsequent reports.

9. Shift Manning

A change to 10 CFR 50.54, issued on July 11, 1983, requires that, effective January 1, 1984, a Senior Reactor Operator (SRO) be present at all times in the control room from which a nuclear power unit is being operated. The purpose is to assure the availability of at least one qualified SRO in the control room without affecting the freedom of the Shift Supervisor to move about the site as needed. The requirements for licensed operator staffing is established via the Technical Specifications for each plant and generally includes, for a single unit station, a Senior Reactor Operator who is the Shift Supervisor for the unit and two Reactor Operators (ROs).

The change to 10 CFR 50.54 codifies staff criteria published in NUREG-0737, "Clarification of TMI Action Plan Requirements," which stated a need for a second SRO, in addition to the Shift Supervisor, to be present in the control room. The criteria of NUREG-0737 have been applied to all plants licensed since the TMI-2 accident, and are being backfit to other operating plants in accordance with the rule change.

McGuire Technical Specification 6.2.2 requires that when either unit is in mode 4 or above that a licensed SRO other than the shift supervisor shall be in the control room.

Pending a decision on a Draft Policy Statement regarding use of a dually-qualified individual to satisfy the requirements for the second SRO and the Shift Technical Advisor (STA) on shift, there is concern over such practice. McGuire Technical Specifications Table 6.2-1, page 6-6 specifically allows on occasions when there is a need for both the Shift Supervisor and the SRO to be absent from the control room, the STA shall be allowed to assume the control room command function and serve as the SRO in the control room provided that: (1) the Shift Supervisor is available to return to the control room within 10 minutes, (2) the assumption of SRO duties by the STA be limited to periods not in excess of 15 minutes duration and a total time not be exceed 1 hour during any 8-hour shift, and (3) the STA has an SRO license on the unit.

The inspector will monitor the situation and verify appropriate changes are made if warranted should they become necessary subsequent to the Final Policy Statement.

10. Surveillance Testing

The surveillance tests categorized below were analyzed and/or witnessed by the inspector or ascertain procedural and performance adequacy.

The completed test procedures examined were anlayzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria, and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration completed and test results were adequate.

The selected procedures perused attested conformance with applicable Technical Specifications and procedural requirements, they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency specified.

Detailed in paragraph 11 are the details concerning an inadequately performed surveillance.

Procedure	Title
PT-2-A-4200-09A	ESF Actuation Periodic Test
PT-0-A-4600-14A	NIS Power Range Functional Test
PT-0-A-4601-07	Reactor Trip Breaker Response Time Test
PT-2-A-4252-02	CA Valve Stroke Time (Quarterly)
PT-0-A-4209-01C	Standby Makeup Pump Flow Periodic Test
PT-2-A-4403-01B	Nuclear Service Water Pump 2B Performance Test
PT-0-A-4201-02	Containment Pressure Control System Functional Test
PT-2-A-4209-01B	Centrifugal Charging Pump 2B Performance Test
PT-2-A-4204-01B	RHR Pump 2B Performance Test
PT-2-A-4200-26A	Turbine and MFWPT Trips for ESF
PT-2-A-4252-01	T/D CA Pump 2 Performance Test
PT-1-A-4601-01	Protective System Channel 1 Functional Test
PT-1-A-4252-01A	Motor Driven Auxiliary Feedwater Pump Performance Test
PT-1-A-4204-01B	RHR Pump 1B Performance Test
PT-0-A-4601-06	Containment Pressure Transmitter Monthly Exercise

11. Surveillance Inadequacies

On November 2, 1983 during a McGuire emergency exercise, the licensee detected certain inadequacies in the complement and condition of supplies contained in the emergency protective equipment kits. This prompted the licensee to interrogate the technician whose responsibility it was to inventory those kits on a monthly basis, as is required by procedure PT/0/A/4600/11, Function Check of Emergency Vehicle and Equipment.

The technician admitted instances of having completed those sections of the procedure indicating he had inventoried the kits when in fact he had not.

Based upon the fact that the technician falsified the procedure, compounded by another recent falsification of surveillance records, the licensee terminated the technician's employment. The licensee also performed PT/0/A/4600/11, replenishing and verifying the adequcy of the kits.

The resident inspector was informed of the above incident on January 3, 1984.

Technical Specification 6.8.1(d) requires that written procedures be established, implemented and maintained covering emergency plan implementation. Failure of the technician to accomplish the procedural requirements, yet complete the procedure constitutes a violation of those requirements.

Because the NRC wants to encourage and support licensee initiative for self-identification and correction of problems, NRC will not generally issue a Notice of Violation for a violation that meets all of the tests criteria specified in 10 CFR Part 2, Appendix C. In applying the test criteria, this incident has been determined to be almost identical in nature to a previous incident for which enforcement is pending; (Reference report 50-369/83-39, 50-370/83-46) and in more general terms is similar in nature to several previous examples of failure to follow procedure; 50-369/83-21-01, 50-370/83-29-01, 50-369/83-28-01, 50-369/83-30-01, 50-369/83-32-01, 50-369/83-33-01, and 50-369/83-36-01, the enforcement flexibility described above is disallowed. This is a Violation (50-369/83-48-01, 50-370/84-55-01).

12. Maintenance Observations

The maintenance activities categorized below are analyzed and/or witnessed by the resident inspection staff to ascertain procedural and performance adequacy.

The completed procedures examined were analyzed for embodiment of the necessary prerequisites, preparation, instruction, acceptance criteria and sufficiency of technical detail.

The selected activities witnessed were examined to ascertain that where applicable, current written approved procedures were available and in use, that prerequisites were met, equipment restoration completed and maintenance results were adequate.

The selected work requests/maintenance packages perused attested conformance with applicable Technical Specifications and procedural requirements and appeared to have received the required administrative review.

Work Request	Equipment
105020	Containment Sump Flow Monitor
85105	1SA-49
116465	1B VF Exhaust Fan
020482	A RF Pump
116565	VE Fan
117514	EFA-127
117421	CH III Pressurizer Level
027285	OTDT OPDT TAVE
116719	Annulus Ventilation Fan B