February 7, 2000

Duke Energy Corporation
ATTN: Mr. H. B. Barron
Vice President
McGuire Nuclear Station
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

SUBJECT: NRC INTEGRATED INSPECTION REPORT NOS. 50-369/99-09 AND 50-370/99-09

Dear Mr. Barron:

This refers to the inspection conducted between December 12, 1999, and January 15, 2000, at the McGuire Nuclear Station. The enclosed report presents the results of that inspection.

During the five-week period covered by this inspection, your conduct of activities at the McGuire facility was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls.

Based on the results of this inspection, the Nuclear Regulatory Commission (NRC) has determined that three violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1 of the Enforcement Policy. The NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region II, the Resident Inspector at the McGuire Nuclear Station, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790(a) of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and any response will be placed in the NRC Public Document Room.

Sincerely,

(Original signed by)
Charles R. Ogle, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos. 50-369, 50-370
License Nos. NPF-9, NPF-17

Enclosure: (See page 2)
Enclosure: NRC Inspection Report 50-369/99-09, 50-370/99-09

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-369, 50-370
License Nos:	NPF-9, NPF-17
Report No:	50-369/99-09, 50-370/99-09
Licensee:	Duke Energy Corporation
Facility:	McGuire Nuclear Station, Units 1 and 2
Location:	12700 Hagers Ferry Road Huntersville, NC 28078
Dates:	December 12, 1999 - January 15, 2000
Inspectors:	S. Shaeffer, Senior Resident Inspector M. Franovich, Resident Inspector G. Wiseman, Regional Inspector (Sections F2.1, F7.1, F8.1)
Approved by:	C. Ogle, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

McGuire Nuclear Station, Units 1 and 2
NRC Inspection Report 50-369/99-09, 50-370/99-09

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a five-week period of resident inspections and also included a regional inspection in the area of fire protection.

Operations

- Licensee monitoring and preparedness for potential Year 2000 problems were well implemented. (Section O2.1)

- Containment isolation valve 1NM22 failed to close during a quarterly test. Operators adequately responded and complied with Technical Specifications. Separately, control board open indication for containment isolation valve 1RV33 was lost. Evaluation of the condition by operations and engineering was timely and reasonable to justify continued operability of valve 1RV33. Overall, the inspectors determined that the licensee's corrective actions were adequate. (Section O2.2)

Maintenance

- Modified engineered safeguards features testing identified an incorrect permissive logic contact for one train of the Unit 1 hydrogen recombiner system. A non-cited violation was identified for inadequate corrective actions associated with previously identified incomplete circuit testing and updating the Updated Final Safety Analysis Report. A non-cited violation was also identified against 10 CFR Appendix B, Criterion V for failure to install the appropriate contact switch logic on hydrogen recombiner contact switch DD(1ESGAX3) - 8/8a as depicted on the applicable station drawings. (Section M2.1)

- Copper oxide fouling of the Unit 1 main generator stator cooling coils had occurred, in part, due to inadequacies in maintaining the dissolved oxygen content of the cooling water and outage system layup conditions. (Section M2.2)

- A first-time evolution for McGuire Nuclear Station involving on-line chemical cleaning of the stator coils fouled by copper oxide was adequately controlled to prevent a potential turbine trip/reactor trip. Control room operators were prepared for a potential turbine trip/reactor trip during the evolution. Manual turbine trip/reactor trip criteria were clearly established and incorporated into a temporary procedure for the chemical cleaning evolution. (Section M2.2)

Plant Support

- One non-cited violation was identified for failure to implement and maintain in effect the provisions of the fire protection program for inoperable fire barrier penetration seals between safety and non-safety plant areas. (Section F2.1)

- The 1999 Nuclear Performance Assessment Section assessment of the facility's fire protection program was comprehensive and effective in identifying fire protection program safe shutdown circuit analysis documentation issues to management. The most significant issues identified by the audit team involved the adequacy of fire protection safe shutdown circuit analysis documentation. Planned corrective actions in response to the audit issues were substantial and included the initiation of a Fire Protection Generic Issues Project. (Section F7.1)

Report Details

Summary of Plant Status

Unit 1

Unit 1 began the inspection period at approximately 85 percent power. The unit was at reduced power to facilitate chemical cleaning of the stator cooling water system. The unit was returned to 98 percent power on December 13, 1999, and 100 percent power on December 15, 1999. On December 31, 1999, power was reduced to 85 percent as a preplanned Year 2000 grid stability precaution. On January 1, 2000, the unit was returned to 100 percent power and operated at that power level for the remainder of the inspection period.

Unit 2

Unit 2 began the inspection period at 100 percent power. Between December 17, 1999, and January 2, 2000, the unit operated at approximately 65 percent power as part of a fuel conservation plan to support the next scheduled refueling outage. The unit was returned to 100 percent power on January 3, 2000, and operated at that power level for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. Other specific events and noteworthy observations are detailed in the sections which follow.

O2 Operational Status of Facilities and Equipment

O2.1 Monitoring Facilities for Potential Year 2000 (Y2K) Equipment Performance Issues (71707)

During the current inspection period, the inspectors monitored licensee activities associated with the Y2K transition which occurred December 31, 1999. Previous Y2K programmatic reviews were documented in NRC Inspection Report 50-369,370/99-04. The inspectors reviewed the licensee’s preparedness activities associated with procedures for recovery of offsite power supplies, switchyard protection and vulnerabilities, emergency diesel operability, required actions for degraded grid conditions, and plant staffing augmentation. The inspectors were in the control room for the transition to the new year. The inspectors monitored key system parameters and observed the implementation of preplanned unit power reductions for the transition period. Based on the inspectors’ observations and the licensee’s final review of plant equipment, no Y2K equipment problems were identified.

Licensee monitoring and preparedness for potential Year 2000 problems were well implemented.

O2.2 Emergent Issues with Unit 1 Containment Isolation Valves

a. Inspection Scope (71707)

The inspectors reviewed the facts and circumstances of problems with two Unit 1 containment isolation valves. The Technical Specifications (TS), design basis information, regulatory guidance documentation, and other plant information were reviewed. The degraded conditions were discussed with involved engineering and operations personnel.

b. Observation and Findings

On December 26, 1999, nuclear sampling (NM) system valve, 1NM22, failed to close during a quarterly inservice test (IST). Valve 1NM22 is the inboard isolation valve in the reactor coolant system (RCS) sampling line from the 1A hotleg. During the test, the valve traveled to the intermediate position as indicated on the control board and the operator aid computer (OAC). Inspectors independently verified that the outboard containment isolation valve 1NM26 was closed and deenergized within the time constraints of TS 3.6.3. The inspectors had observed failures of NM valves during previous operating cycles. Engineering personnel stated that an adverse trend existed regarding the reliability of NM valves and actuators. The licensee was working with the vendor to potentially upgrade the valves and actuators in the NM system.

On December 30, 1999, a control room operator observed that an open indication light for valve 1RV33 was extinguished. Valve 1RV33 is the inboard containment isolation valve to the lower containment coolers. The inspectors responded to the control room and discussed the issue with involved station personnel. The inspectors observed that the OAC indicated the valve was in the open position and the previous valve stroke test indicated satisfactory performance. The inspectors did not identify an increase in lower containment temperatures, which would indicate valve 1RV33 was partially shut. Engineering personnel supervising the troubleshooting indicated that the control circuit check did not reveal an abnormal condition; however, the valve position indication circuit (independent of the control circuit) revealed a degraded switch on the control board. The licensee considered the valve operable and wrote a work request to repair the switch.

Due to the identification of the inoperable indication light, the inspectors reviewed with operators how containment isolation valve closure verification would be achieved as directed by the emergency procedures (EP) and availability of the OAC alternate indication during a design basis accident. EP containment isolation verification would require closure of 1RV32 (outboard) valve should 1RV33 fail to close on a Phase A isolation signal. Should a loss of offsite power occur, the OAC would be available for approximately 4 hours from non-safety related batteries barring a fault between the battery and the OAC. The inspectors noted that the licensee promptly addressed the lack of control board indication in a manner that supported compliance with the 4-hour action limit of TS 3.6.3. No problems were identified with the licensee’s corrective actions for the identified containment isolation valve problems.

c. Conclusions

Containment isolation valve 1NM22 failed to close during a quarterly test. Operators adequately responded and complied with TS. Separately, control board open indication for containment isolation valve 1RV33 was lost. The evaluation of the condition by operations and engineering was timely and reasonable to justify continued operability of valve 1RV33. Overall, the inspectors determined that the licensee's corrective actions were adequate.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707)

The inspectors reviewed a variety of maintenance and/or surveillance activities during the inspection period, focusing on the following specific items:

- TO/1/A/9600/115, Revision 0, Chemical Cleaning of Main Generator Stator
- MP/0/A/7650/045, Revision 6, Freeze Sealing of Pipe
- PM 1EQBLP27A, D/G Load Sequencer Panel - preventive maintenance

b. Observations and Findings

The inspectors witnessed selected surveillance test activities to verify that approved procedures were available and in use; test equipment was calibrated; test prerequisites were met; system restoration was completed; and acceptance criteria were met. In addition, the inspectors reviewed or witnessed routine maintenance activities to verify, where applicable, that approved procedures were available and in use; prerequisites were met; equipment restoration was completed; and maintenance results were adequate. The maintenance and surveillance activities were properly approved by operations personnel and were included on the plan of the day. Work associated with risk significant structures, systems, or components was properly evaluated to determine its impact on the plant's risk profile. Appropriate TS action statements and selected licensee commitments were implemented. Applicable TS surveillance requirements (TSSR) and/or the core operating limits report limits were also satisfied.

c. Conclusions

The inspectors concluded that the reviewed routine maintenance and surveillance activities were adequately completed.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Deficiency Identified During Engineering Safeguards Features (ESF) Testing

a. Inspection Scope (61726, 62707)

The inspectors reviewed the licensee's corrective actions for PIP M99-4840 concerning an incorrect contact switch logic identified in the circuitry for the Unit 1 hydrogen recombiner 1A. Specifically reviewed were the status of the other similar circuits on both units, past operability considerations for the subject equipment, and method of discovery for the problem.

b. Observations and Findings

During Mode 6 ESF testing performed during the Unit 1 End-of-Cycle (EOC) 13 refueling outage, the licensee identified that contact DD(1ESGAX3)-8/8a was incorrectly installed as a normally closed contact. This contact was designed to permit manual starting of the hydrogen recombiner 1A following an event requiring a safety injection (SI). Upon discovery, the licensee verified that the similar contacts for the redundant train of Unit 1 and both trains of the Unit 2 hydrogen recombiner systems were correctly installed and tested. Minor modification MGMM-11337 was completed to rewire the miswired contact, which included a functional overlap test within PT/1/A/4200/09A, Engineered Safety Features Actuation Periodic Test. The inspectors verified the miswired contact was corrected prior to restart of the unit.

System Background and Operational Requirements:

The safety-related hydrogen recombiner system is designed to reduce the hydrogen content of the containment atmosphere following a postulated loss of coolant accident (LOCA). The recombiner units are placed in service manually by operators during the performance of emergency recovery procedures and are required to be placed in service within 24 hours of the event. The recombiners are provided with emergency diesel generator (EDG) power supply; however, they are not automatically started.

TS 3.6.7.1, 2, and 3 provide functional surveillance requirements for the recombiner units, verifying functional performance features including operating temperatures, resistance readings, and inspection for other physical problems which could affect recombiner operability.

Section 7.6.6.2.7 of the Updated Final Safety Analysis Report (UFSAR) indicates that there are no interlocks associated with the hydrogen recombiners operation. There is no description of surveillance testing for the hydrogen recombiner system in the UFSAR.

McGuire Design Bases Document (DBD) Section 31.3.1.3 indicates that operation of the recombiners is initially blocked upon receipt of an SI or loss of offsite power (LOOP) signal.

Operation is permitted following sequencing of load group 10 (at 12 minutes) if an SI signal is present.

Recombiner Circuit Testing

In 1996, the licensee performed a review per NRC Generic Letter (GL) 96-01 of testing performed for safety-related circuitry. During this review, the licensee identified that the diesel generator load sequencer included interlocks for the hydrogen recombiners within its circuitry that were not being fully tested. Corrective actions were documented for this problem in PIP M96-3507 and included revisions to ESF test procedure PT/1/A/4200/09A to fully verify the hydrogen recombiner's ability to be manually started per emergency procedures after load group 10 has been sequenced. Group 10 permits the recombiners to be started, but does not start them. The revised ESF test was completed during the 1EOC12 refueling outage; however, the subject contact problem was not identified. Prior to the 1EOC13 ESF test, the licensee performed an additional modification to improve the test method. This included adding a power available light within the control circuit such that it could be directly used for verifying recombiner power available. During the Unit 1 EOC13 outage ESF testing, the licensee determined that the Unit 1 EOC12 testing failed to detect the wiring discrepancy. The root causes for not identifying the issue during the Unit 1 EOC12 outage included confusing depiction of the interlocks on the available vendor drawing and a cumbersome test method.

The inspectors reviewed mitigating circumstances for the identified deficiency. Although the recombiner would not have been able to be immediately energized following a postulated SI event, applicable emergency procedures would have directed the operators to reset the SI signal prior to instructing operators to energize the recombiner. The resetting of the SI signal would allow the recombiner to be placed in service. In addition, the opposite train was not affected by this problem. Therefore, the inspectors determined that the hydrogen recombiner remained functional despite this deficiency in the wiring of the contact.

Based on the above, the inspectors concluded that the corrective actions taken for the problem identified in PIP M96-3507 and PIP M96-3001 were inadequate, in that, conditions adverse to quality were not promptly identified and corrected as required by 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. Three examples were identified as follows:

- Corrective actions for the identified incomplete testing of hydrogen recombiner circuitry were ineffective in developing an adequate test for the subject circuitry. Consequently, the wiring problem went undetected an additional three years since the lack of testing of the hydrogen recombiner interlock circuitry was first identified.

- The licensee identified that the resolution of PIP M96-3507 failed to revise Section 7.6.6.2.7 of the UFSAR, which incorrectly indicated that there were no interlocks associated with the hydrogen recombiners operation.

- Coincident in 1996 with the identification of the hydrogen recombiner test deficiencies, the licensee also identified via PIP M96-3001 that the subject interlock circuitry affected the hydrogen mitigation system (hydrogen igniters). The inspectors identified during this inspection period that Section 7.6.18.1.4 of the UFSAR incorrectly indicates that there are no interlocks associated with the hydrogen mitigation system operation; however, no corrective actions were taken to resolve the UFSAR discrepancy within PIP M96-3001. The licensee revised the corrective action for PIP M99-4840 to resolve this problem.

The above examples of a Severity Level IV violation are being treated as an Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP M99-4840 and will be identified as NCV 50-369/99-09-01: Inadequate Corrective Actions for Previously Identified Lack of Logic Circuit Testing and Inaccuracies in the UFSAR.

In addition to the above, the inspectors also reviewed the circumstances regarding the mis-wired recombiner contact. The licensee determined through a work history review that the device had been installed incorrectly since initial startup of the unit (date code was 5-75-6908 indicating 1975 vintage). Elementary electrical drawing MCEE 114-00.03-01 depicts contact DD(1ESGAX3)-8/8a designed and installed as a normally open contact; however, the contact was installed as a normally closed contact. 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to this requirement, hydrogen recombiner contact switch DD(1ESGAX3)-8/8a was not correctly installed as depicted on the applicable station drawings. This constituted a violation of 10 CFR Appendix B, Criterion V, Instructions, Procedures, and Drawings. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP M99-4840 and will be identified as NCV 50-369/99-09-02: Incorrect Wiring Associated with the Train A Hydrogen Recombiner.

c. <u>Conclusions</u>

Modified engineered safeguards features testing identified an incorrect permissive logic contact for one train of the Unit 1 hydrogen recombiner system. A non-cited violation was identified for inadequate corrective actions associated with previously identified incomplete circuit testing and updating the UFSAR. A non-cited violation was also identified against 10 CFR Appendix B, Criterion V for failure to install the appropriate contact switch logic on hydrogen recombiner contact switch DD(1ESGAX3)-8/8a as depicted on the applicable station drawings. The significance of the miswiring problem was minimized due to operator actions established in emergency response procedures, which would bypass the circuit deficiency prior to the affected recombiner being required to be placed in service.

M2.2 Chemical Cleaning of Unit 1 Main Generator Stator

a. Inspection Scope (62707, 71750, 71707)

The inspectors reviewed a first time for McGuire Nuclear Station on-line chemical cleaning of the Unit 1 main generator stator cooling coils. A temporary operating procedure, temporary modifications, and evolution controls were observed and evaluated. Operator preparedness for a potential phase-to-ground fault that could result in a turbine trip/reactor trip was evaluated and discussed with on-shift operators. Electrical protective relaying scheme, plant parameters, and operating data were also independently reviewed by the inspectors. Cross-departmental meetings regarding this issue were also observed.

b. Observation and Findings

Shortly following the Unit 1 restart from the Unit 1 EOC 13 refueling outage, control room operators received OAC alarms on high stator coil differential temperature from the main generator stator cooling water (KG) system. Troubleshooting and engineering investigation revealed that copper oxide fouling had occurred, in part, due to inadequacies in maintaining the dissolved oxygen content of the cooling water and outage system layup conditions. The copper oxide fouling in the stator bar's water channels restricted flow through the stator cooling coils. On several occasions, in accordance with plant procedures, operators reduced power levels between 85 and 95 percent of full power to maintain stator temperatures below coil limits.

With Unit 1 at 85 percent reactor power, the chemical flush was initiated on December 11, 1999. A vendor and chemistry personnel performed the chemical flush. Prior to and during the cleaning, the inspectors independently verified plant conditions, work activities, temporary station modifications, and KG system and generator core instrumentation. The inspectors observed and determined the following:

- Operators were prepared to cope with a potential phase-to-ground fault on the main generator and were frequently monitoring associated generator instrumentation. Operator knowledge and associated training materials for the generator system and protective relaying were comprehensive.

- Engineering and chemistry personnel were thorough and meticulous in the development of a chemical cleaning procedure to perform the first-time evolution. Emphasis, in part, was placed on control of the KG water conductivity to prevent a phase-to-ground fault during the chemical additions since copper oxide would be released from the stator coils. Redundant conductivity monitoring was performed and continuously monitored by chemistry personnel.

- The chemical cleaning procedure, including unit manual trip criteria, was clear and conservative. Use of industry operating experience and lessons learned from other nuclear plants that had performed the on-line chemical cleaning was reflected in working meetings and in the procedure.

- Unexpected high conductivity readings observed during the chemical tracer additions were appropriately discussed and resolved prior to the chemical flush.

- Strong management involvement and oversight was evident during preparation and implementation of the chemical cleaning activities. Inter-department involvement was well represented in internal discussions of the proposed cleaning activity.

On December 15, 1999, the unit was returned to 100 percent power because sufficient copper oxide had been removed by the KG system demineralizers to permit the power increase. Chemical cleaning was terminated on December 22, 1999; however, dissolved oxygen began trending upward. Engineering personnel identified a leaking flange as the source of the air in-leakage into the KG system and subsequently sealed the flange. The air in-leakage was masked during the chemical flush due to the reaction of the chemicals with the dissolved oxygen and the copper oxide. All KG system alarms were cleared and system performance restored to normal conditions following chemical cleaning and sealing of the leaking flange. Engineering personnel indicated that the leaking flange may have been disassembled during a previous outage and not adequately sealed. Maintenance rule implications were under evaluation at the conclusion of the inspection period.

c. Conclusions

Copper oxide fouling of the Unit 1 main generator stator cooling coils had occurred, in part, due to inadequacies in maintaining the dissolved oxygen content of the cooling water and outage system layup conditions. A first-time evolution for McGuire Nuclear Station involving on-line chemical cleaning of the stator coils was adequately controlled to prevent a potential turbine trip/reactor trip. Control room operators were prepared for a potential turbine trip/reactor trip during the evolution. Manual turbine trip/reactor trip criteria were clearly established and incorporated into a temporary procedure for the chemical cleaning evolution.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

The inspectors made frequent tours of the controlled access area and reviewed radiological postings. The inspectors observed that workers were adhering to the requirements for wearing protective clothing. The inspectors also determined that locked high radiation doors were properly controlled, high radiation and contamination areas were properly posted, and radiological survey maps were updated to accurately reflect radiological conditions in the respective areas.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Inoperable Fire Barrier Penetration Seals

a. Inspection Scope (64704)

The inspectors reviewed an issue involving the failure to fully implement Selected Licensee Commitment 16.9-5, “Fire Rated Assemblies” to maintain fire barrier penetration seals operable in committed fire barriers separating areas containing redundant safe shutdown equipment.

The inspectors reviewed Special Report Number 99-03, dated December 15, 1999; the Facility Operating License Conditions 2.C(4) (Unit 1), and 2.C.(7) (Unit 2); UFSAR Selected License Commitments (SLC) Section 16.9-5, Auxiliary Systems - Fire Protection Systems, “Fire Rated Assemblies;” PIP M-99-05256; drawings MC-1315-01.06-002 and -105, “Fire Boundary Walls,” Revision 0; fire protection calculation DPC 1435.00-00-0006, Revision 1, Appendix D.22, “Test Report 2293.2;” and, work order tasks associated with Work Request No. 98104626. The inspectors walked down and observed the repairs made to five penetration seals and discussed with the site fire protection engineers the installation and repair history of the seals.

b. Observations and Findings

On November 15, 1999, during the performance of penetration seal configuration inspections the licensee determined that seven penetration seals were not installed in the required three-hour rated seal configurations. Six of the deficient seals were located on elevation 767 feet (within 30 feet of each other) in an auxiliary building fire barrier wall that separated the auxiliary building common area and the auxiliary service building. The other deficient seal was located in the floor of the Unit 2 electrical penetration room that separated the room from the auxiliary feedwater pump room below. Two of the six auxiliary building fire barrier penetration seals were found to have no seals installed and the remaining four seals had improperly installed seal configurations. The one electrical penetration room seal was found to have had an inadequate seal configuration installed within the concrete floor slab. The fire barriers were declared inoperable and fire watches were established for the affected fire zones in accordance with the fire protection program requirements.

On November 16, 1999, the licensee notified the NRC of these deficient conditions (Event Number 36440). The inspectors verified that the licensee made a written special report to the NRC on December 15, 1999, describing the failure to implement and maintain in effect the provisions of the fire protection program concerning the fire barrier penetrations seals.

The inspectors verified that plant personnel documented these problems in PIP M-99-0526, which included an evaluation of the causes of the penetration seal problems and proposed corrective actions to repair the penetration seals. The inspectors’ review of the PIPs, the fire boundary seal drawings, work order tasks, procedural guidance for fire penetration seal repairs, and observation of the upgraded seals, found that these penetration seals had been properly repaired or replaced to required design configurations that had satisfactorily passed fire resistance testing.

McGuire Facility Operating License Conditions 2.C(4) (Unit 1), and 2.C.(7)(Unit 2) require that Duke Energy Corporation implement and maintain in effect all provisions of the approved fire protection program, as described in the Final Safety Analysis Report, as updated. UFSAR commitments contained in SLC, Section 16.9-5, “Fire Rated Assemblies,” requires that all sealing devices in fire rated assembly penetrations be operable.

The inspectors verified that the licensee’s penetration seal configuration inspections identified that a number of penetration seals in the auxiliary building that separated safety and non-safety plant areas were not installed as required and were not operable as evidenced by the absence of a sealing device in the penetrations and inadequate seal configurations installed in the barrier walls and floors. These conditions had affected the fire barriers since their installation during construction of the plant. The failure to implement and maintain in effect the provisions of SLC 16.9-5 to maintain fire barrier penetration seals operable in committed fire barriers separating safety and non-safety plant areas is a violation of the plant operating license condition for fire protection. This Severity Level IV violation is being treated as a non-cited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy, and is identified as NCV 50-369,370/99-09-03: Failure to Properly Implement and Maintain the Plant Fire Protection Program Requirements for Fire Barrier Penetration Seals. Licensee management had appropriately addressed the factors that caused the above non-compliance in its corrective actions as described in PIP M-99-0526.

c. Conclusions

One non-cited violation was identified for failure to implement and maintain in effect the provisions of the fire protection program for inoperable fire barrier penetration seals between safety and non-safety plant areas.

F7 Quality Assurance in Fire Protection Activities

F7.1 Fire Protection Audits (64704)

a. Inspection Scope

The following fire protection audit report, Special Report, and the plant response to the issues were reviewed:

- Nuclear Performance Assessment Section Report SA-99-04(MC)(RA)(FPFA), “McGuire Fire Protection Functional Audit,” dated April 9, 1999.
- McGuire Nuclear Plant Special Report No. 99-02, dated March 25, 1999.
- McGuire Nuclear Plant Response on Licensing Position on Fire Protection Audit Items in Audit Report SA-99-04(MC)(RA)(FPFA), dated October 20, 1999.

b. Observations and Findings

The licensee's Nuclear Performance Assessment Section performed an assessment of the fire protection program during the period of February 5, 1999, through March 4, 1999. The audit as performed in accordance with the guidance from NRC's Draft Inspection Procedure "Fire Protection Functional Inspections." The report for this assessment was Report No. SA-99-04(MC)(RA)(FPFA). The assessment team determined that the fire protection program was effectively implemented in preventing, detecting , and controlling fires. The most significant issues identified involved documentation issues involving the licensee's safe shutdown circuit analysis for fire induced circuit failure modes. The assessment report identified 23 findings.

On March 12, 1999, the licensee notified the NRC of three of the safe shutdown circuit analysis audit findings that represented potential deviations from the approved fire protection program (Event Number 35463). The inspectors verified that the licensee made a written special report to the NRC on March 25, 1999, describing three of the audit's significant findings and planned corrective actions. The licensee's evaluation of these issues did not identify any adverse conditions that would affect the ability of the plants to mitigate a design bases fire event. The licensee determined that the safe shutdown circuit analysis issues were generic to all of the licensee's nuclear facilities and the subject of current NRC and industry initiatives. As a result, the licensee initiated a Generic Issues Project under the management of the Duke Nuclear Generation Department to further evaluate and direct resolution of the circuit analysis issues.

The inspectors verified that the fire protection program audit issues were documented through the corrective action program PIP process. The inspectors reviewed the final audit report, the licensee's response to the identified issues, and the planned corrective actions identified in the associated PIPs. The inspectors determined that the issues identified by the audit team were similar to those types of safe shutdown circuit analysis items identified during the NRC Fire Protection Functional Inspection pilot program. These items involve NRC technical concerns of the licencee's safe shutdown circuit analysis to adequately identify and evaluate fire induced circuit failures. These concerns are addressed in NRC Information Notices (IN) 92-18 and 99-17 and are the subject of current NRC and industry initiatives described in a letter from the NRC to the Nuclear Energy Institute, dated July 21, 1999.

c. Conclusions

The 1999 Nuclear Performance Assessment Section assessment of the facility's fire protection program was comprehensive and effective in identifying fire protection program safe shutdown circuit analysis documentation issues to management. The most significant issues identified by the audit team involved the adequacy of fire protection safe shutdown circuit analysis documentation. These were similar to those issues identified during the NRC Fire Protection Functional Inspection pilot program and are the subject of ongoing NRC and industry initiatives. Planned corrective actions in response to the audit issues were substantial and included the initiation of a Fire Protection Generic Issues Project.

F8 Miscellaneous Fire Protection Issues (92904)

F8.1 (Closed) Inspection Followup Item (IFI) 50-369,370/98-07-10: Review of Licensee's Revalidation of Fire Barrier Penetration Seals

This issue related to the lack of available documentation to verify that fire barrier penetration seals were installed in accordance with design specifications and bounded by configurations that had satisfactorily passed 3-hour fire resistance testing.

The inspectors reviewed the Duke Energy Corporation letter to the NRC dated August 4, 1998, “Fire Barrier Penetration Seals,” that described the licensee’s three-site plan and schedule to update penetration seal design-basis documentation and configuration information. This plan included the performance of inspections to document as-built penetration seals configurations and the development of design-basis documents to describe bounding tested configurations and engineering analysis.

The inspectors also reviewed the scope and completion status of the penetration seal plan implementation. The inspectors verified that the plan implementation was on schedule. The licensee’s Phase I configuration walk downs and inspection data gathering was completed on December 16, 1999, for approximately 1700 penetrations. The inspectors verified that the licensee’s penetration seal design and installation parameter inspection criteria (being verified during licensee walk downs) satisfied the guidance described in Sections 3.1 and 3.2 of NRC Generic Letter (GL) 86-10. The licensee’s ongoing Phase II engineering activities include the development of a design database of configuration records and performing design-basis engineering evaluations. These activities are scheduled to be completed in 2000. The inspectors determined that the scope of the fire barrier penetration seal plan was reasonable and complied with the guidance provided by NRC's Generic Letter 86-10. The inspectors concluded that the scope of the fire barrier penetration seal plan for

McGuire was sufficiently documented in the licensee’s PIP corrective action program to assure that the corrective actions identified in the IFI would be completed.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 26, 2000. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Barron, B., Vice President, McGuire Nuclear Station
Bradshaw, S., Superintendent, Plant Operations
Byrum, W., Manager, Radiation Protection
Cash, M., Manager, Regulatory Compliance
Dolan, B., Manager, Safety Assurance
Evans W., Security Manager
Geer, T., Manager, Civil/Electrical/Nuclear Systems Engineering
Jamil, D., Station Manager, McGuire Nuclear Station
Patrick, M., Superintendent, Maintenance

Peele, J., Manager, Engineering
Loucks, L., Chemistry Manager
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical Systems Engineering

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 64704:	Fire Protection Program
IP 71707:	Conduct of Operations
IP 71750:	Plant Support
IP 90712:	In-Office Review of Written Reports of Nonroutine Events
IP 92903:	Followup - Engineering
IP 92904:	Follow up- Plant Support

ITEMS OPENED AND CLOSED

Opened

50-369,370/99-09-01	NCV	Inadequate Corrective Actions for Previously Identified Lack of Logic Circuit Testing and Uncorrected Inaccuracies in the UFSAR (Section M2.1)
50-369,370/99-09-02	NCV	Incorrect Wiring Associated with the Train A Hydrogen Recombiner (Section M2.1)
50-369,370/99-09-03	NCV	Failure to Properly Implement and Maintain the Plant Fire Protection Program Requirements for Fire Barrier Penetration Seals (Section F2.1)

Closed

50-369, 370/98-07-10	IFI	Revalidation of Fire Barrier Seals (Section F8.1)

LIST OF ACRONYMS USED

DBD	-	Design Bases Document
EDG	-	Emergency Diesel Generator
EOC	-	End of Cycle
EP	-	Emergency Procedure
ESF	-	Engineering Safeguard Features
FSAR	-	Final Safety Analysis Report
GL	-	Generic Letter
IFI	-	Inspector Followup Item
IN	-	Information Notice
IR	-	Inspection Report

ISI	-	Inservice Inspection
IST	-	Inservice Test
KG	-	Stator Cooling Water
LCO	-	Limiting Condition for Operation
LOCA	-	Loss Of Coolant Accident
LOOP	-	Loss Of Offsite Power
NCV	-	Non-Cited Violation
NM	-	Nuclear Sampling
NRC	-	Nuclear Regulatory Commission
NRR	-	NRC Office of Nuclear Reactor Regulation
OAC	-	Operator Aid Computer
PIP	-	Problem Investigation Process
RCS	-	Reactor Coolant System
SI	-	Safety Injection
SLC	-	Selected License Commitment
TS	-	Technical Specifications
TSB	-	Technical Specifications Branch
TSSR	-	Technical Specifications Surveillance Requirements
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
Y2K	-	Year 2000