U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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| Docket Nos: | 50-369, 50-370 |
| License Nos: | NPF-9, NPF-17 |
| Report No: | 50-369/97-20, 50-370/97-20 |
| Licensee: | Duke Energy Corporation |
| Facility: | McGuire Nuclear Station, Units 1 and 2 |
| Location: | 12700 Hagers Ferry Road<br>Huntersville, NC 28078 |
| Dates: | December 14, 1997 - January 24, 1998 |
| Inspectors: | S. Shaeffer, Senior Resident Inspector<br>M. Sykes, Resident Inspector<br>M. Franovich, Resident Inspector<br>N. Economos, Regional Inspector (Section M2.1 through M2.3)<br>D. Forbes, Regional Inspector (Sections R1.1, R1.2, R5.1, R8.2)<br>W. Stansberry, Regional Inspector (Section S1.2, S2.2, S2.3, S2.4, S3.2, and S7.1) |
| Approved by: | C. Ogle, Chief, Projects Branch 1<br>Division of Reactor Projects |



Enclosure 2

# EXECUTIVE SUMMARY

## McGuire Nuclear Station, Units 1 and 2
## NRC Inspection Report 50-369/97-20, 50-370/97-20

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a six-week period of resident inspection and inspections of the Unit 2 steam generator replacement project. In addition, it included the results of three regional inspections reviewing radiological protection practices, plant material condition, and plant physical security.

### Operations

- The licensee made proper determinations regarding reportability of three events during the report period. Operator response to the event involving the loss of both trains of the control room ventilation system was appropriate. (Section O1.2)

- An Unresolved Item was identified for several design issues related to the refueling water storage tanks and whether stratification could have affected past operability of each unit's tank. (Section O2.1)

- The Unit 2 startup evolutions, including preparation for criticality and zero power physics testing were well controlled. Briefing packages for the evolutions were detailed, command and control were properly established, and operations and engineering management oversight of the evolutions was excellent. The startup evolution was appropriately delayed to resolve operator concerns regarding potential operator aid computer problems. (Section O4.1)

- The removal of the original Unit 2 steam generators and installation of replacement steam generators was well planned and executed. Testing to demonstrate the stability of the steam generators during transient conditions was well controlled. Replacement equipment functioned properly. (Section M4.1)

### Maintenance

- Routine surveillance activities observed were completed satisfactorily. (Section M1.1)

- Inspection of the auxiliary building areas, the turbine buildings and the Unit 1 doghouse confirmed that the licensee was proactive in maintaining housekeeping and material condition in a satisfactory condition. (Section M2.1)

- The Top Equipment Problem Resolution Program and its implementation were well organized and managed by qualified engineering personnel with a positive attitude. Results of actions taken to resolve long standing equipment problems indicated a proactive approach to resolution. (Section M2.2)

- A valve steam leak temporary repair was well planned, managed and executed with sufficient coverage by engineering and operations personnel who took a proactive role in the project. Personnel involved were well trained and worked in a safe manner to minimize the chance of personal injury. Procedures were complete and accurate. (Section M2.3)

- The licensee's initiative to measure improvement in the open problem investigation process program and work orders has provided a tool for licensee management to assess performance in this area. (Section M3.1)

- Removal of the original Unit 2 steam generators and installation of replacement steam generators was well planned and executed. Testing to demonstrate the stability of the steam generators during transient conditions was well controlled. Replacement equipment functioned properly. (Section M4.1)

- Implementation of the new dynamic rod worth testing method was excellent. Pre-job briefing of the testing was detailed and adequately prepared both operations and reactor engineering personnel for the evolution. Use of vendor oversight was considered beneficial. The overall incorporation of the rod worth testing technique was well controlled. (Section M4.2)

- The licensee's Quality Maintenance Feedback process was a good initiative to improve the overall quality of maintenance related performance at the site. (Section M7.1)

Engineering

- Immediate actions to isolate a pipe break in the abandoned condenser circulating water pipe that occurred on January 4, 1998, were adequate. Procedures were in place for coping with a potential loss of the low level intake structure. Long-term actions appeared appropriate. (Section E2.1)

- The licensee's efforts to test the component cooling water check valves in the reactor coolant pump thermal barrier inlet were a good response

to Information Notice 97-031. Engineering evaluation of the design differences between the McGuire thermal barrier and those noted in Information Notice 97-031 was adequate. An inspector followup item was open pending further NRC review of the adequacy of Emergency Procedure ECA 1.2, Loss of Coolant Accident Outside Containment, to allow diagnosis and isolation of a potential thermal barrier tube rupture. (Section E4.1)

Plant Support

- The licensee was effectively maintaining controls for personnel monitoring, control of radioactive material, radiological postings, and radiation area and high radiation area controls as required by 10 CFR Part 20. (Section R1.1)

- The licensee had continued to maintain exposures As Low As Reasonably Achievable (ALARA). The overall ALARA program was considered a strength. (Section R1.2)

- The radiation protection technicians had been provided an adequate level of training to perform routine activities involving radiation and/or control of radioactive material. (Section R5.1)

- Three violations were identified involving access controls for personnel that were contrary to the criteria in Section 6 of the Duke Power Company Nuclear Security and Contingency Plan, Security Procedure EXAO-02, and Nuclear Station Directive 218. (Section S1.2)

- Through observation, discussion with licensee representatives, and document review, the inspectors concluded that the licensee was complying with the alarm stations and communication criteria in Sections 8, 10, and 16 of the Duke Power Company Nuclear Security and Contingency Plan. (Section S2.2)

- Intrusion detection systems, site illumination and assessment aids were found functional, well maintained, and effective for both covert and overt penetration attempts. The licensee met the Duke Power Company Nuclear Security and Contingency Plan commitments and regulatory requirements. (Section S2.3)

- Maintenance and repair programs ensured the reliability of security related equipment and devices. This area was considered a strength in the security program. This was demonstrated by the responsiveness of

dedicated maintenance personnel who repaired inoperable security equipment. (Section S2.4)

- The random review of directives, plans, procedures, records, reports, and interviews with appropriate individuals verified that safeguards procedures and documentation complied with 10 CFR Part 50. Changes to sections reviewed in the Duke Power Company Nuclear Security and Contingency Plan did not decrease the effectiveness of the Plan. (Section S3.2)

- Safeguards audits were thorough, complete, and effective in uncovering weaknesses in the security system, procedures, and practices. The audit report concluded that the security program was adequately and effectively implemented, and recommended appropriate action to improve the effectiveness of the security program. The licensee analyzed the findings and acted appropriately in response to recommendations made in the audit report. (Section S7.1)

## Report Details

### Summary of Plant Status

#### Unit 1

Unit 1 operated at approximately 100 percent power from the beginning of the inspection period until January 3, 1998. On January 3, 1998, reactor power was reduced to 86 percent to perform a turbine valve movement test. Later that day, the unit was returned to approximately 100 percent power. The unit operated at approximately 100 percent power for the remainder of the inspection period.

#### Unit 2

Unit 2 began the inspection period in Mode 4, completing preparations to restart the unit after the refueling outage. The unit entered Mode 3 on December 14, 1997. After final walkdowns were accomplished to verify hot gap measurements, the unit was restarted on December 17, 1997. Load reduction testing associated with the replacement of the unit's steam generators during the outage was successfully accomplished at both 38 and 78 percent power. The unit reached 98 percent power on December 23, 1997. The unit remained at 98 percent power until concerns regarding over-temperature delta temperature (OTDT) channel spiking could be resolved. On December 31, 1997, reactor power was reduced to 90 percent for calibration of excore nuclear detectors. The unit achieved 100 percent power on January 2, 1998, and operated at approximately 100 percent power for the remainder of the inspection period.

### Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

## I. Operations

### O1 Conduct of Operations

#### O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was satisfactory. The inspectors noted good command and control during the final stages of the Unit 2 steam generator

replacement and refueling outage. The low number of equipment problems on Unit 2 facilitated a smooth transition from maintenance and modification status to operational readiness. The inspectors observed that the operators continued to maintain the proper operational focus for continued safe operation of Unit 1 during the Unit 2 outage. Specific events and noteworthy observations are detailed in the sections which follow.

01.2 10 CFR 50.72 Notifications

a. Inspection Scope

During the inspection period, the licensee made the following notifications to the NRC. The inspectors reviewed the events for impact on the operational status of the facility and equipment.

b. Observations and Findings

1. On January 2, 1998, the licensee made a notification pursuant to 10 CFR 50.72 regarding loss of the emergency notification system (ENS). Operators were temporarily unable to establish communication (daily plant status call) between the control room and the NRC emergency operations center. The operations center was able to contact the licensee via an alternate telephone line. The problem (loose connection) was immediately corrected by the licensee.

2. On January 9, 1998, the licensee made a notification pursuant to 10 CFR 50.72 regarding a potential failure of both trains of the Unit 1 digital rod position indication (DRPI) for fifteen seconds. During a planned power supply change for the train B DRPI, indication on both monitors for Unit 1 DRPI was lost in the control room. During the event, the rod demand position indication system was available as an alternate means of rod bank location. No evidence of rod movement occurred during the event. The problem did not affect the ability of the rods to move in automatic or trip into the core if required. No plant shutdown was initiated.

   Based on subsequent review of the reporting criteria and actual plant equipment availability, the licensee determined that the event was not reportable per the requirements of 10 CFR 50.72 or 10 CFR 50.73. This was based on the verification that during the

fifteen-second interval in question, the demand position indication system was available as an alternate means of rod bank location. In addition, data from the operator aid computer (OAC) indicated that the Unit 1 DRPI channel A was available when the DRPI channel B lost its normal power supply. With one train of DRPI available, along with the demand indication system, the licensee determined that the Technical Specification (TS) for rod control position indication was being met. On January 9, 1998, the licensee retracted the subject notification.

3. On January 14, 1998, the licensee made a notification per the requirements of 10 CFR 50.72 as a result of both trains of the control room ventilation system being declared inoperable. While at the ventilation control panel in the control room, a non-licensed operator dropped a procedure, which inadvertently repositioned the Train A engineered safety feature (ESF) selector switch. Each train has one selector switch which is either in the off or selected position. Prior to the event, the Train A was selected for operation and the Train B was in the off position. The selected position allows normal operation of one train of ventilation equipment and enables that train to be available for ESF or blackout operation. When the switch was inadvertently moved, the Train A chiller tripped as expected, and rendered both the A and B train chillers incapable of auto-starting upon a ESF actuation signal.

   The involved operators immediately identified the cause of the problem and evaluated existing ventilation system configuration to determine the best method to recover normal system operation Due to a 15-minute restart restriction timer on the Train A chiller, its operation could not immediately be resumed. Operators decided to start the normal operation of the Train B control room ventilation system prior to expiration of the Train A timer after about 8 minutes to limit any control room temperature increase due to the normal control room ventilation being off. The inspectors responded to the control room and reviewed the event and immediate licensee corrective actions. No problems were noted during this review. The inspectors determined that, the control room temperature never exceeded any equipment or administrative limits and the temperature increase was minimal. Operator actions following identification of the problem were considered acceptable.

The licensee subsequently reviewed the reportability of this event and determined that the event notification should be retracted for the following reasons. First, the design basis of the ventilation system allows operators 30 minutes to start control room ventilation for adequate temperature control. This action is prompted in the reactor trip response procedure E-0 to verify operation of at least one control room chiller. Second, the event did not affect the ability of the control room ventilation system to protect the operators from a radiological dose perspective. The system ventilation fans would have started as designed and provided pressurization and filtration to protect the operators from radiation dose. On January 20, 1998, the licensee retracted the subject notification.

c. Conclusions

The inspectors concurred with the licensee's conclusion on reportability of three issues during the report period. Operator response to the event involving loss of both trains of the control room ventilation system was appropriate.

## O2 Operational Status of Facilities and Equipment

### O2.1 Potential Operation With Elevated Refueling Water Storage Tank (RWST) Temperatures

a. Inspection Scope (71707)

The inspectors questioned previous operating practices involving RWST temperature near the upper limit of control room indications.

b. Observations and Findings

The inspectors reviewed past operating practices during periods of elevated ambient temperatures which raised the temperature of the RWST tanks to near the upper TS limit of 100 degrees Fahrenheit (F). This involved situations where the indicated RWST temperature approached 98 to 99 degrees F, requiring operators to provide forced recirculation cooling of the tank to maintain the tanks within TS temperature limits. The inspectors reviewed the design basis of the RWST tanks and noted that the temperature sensors are located near the bottom of the tank. Given this and the potential for stratification of the tank contents,

the inspectors were concerned that the average bulk temperature of the tank could exceed the TS temperature limit.

In addition, the inspectors reviewed Section 15.6 of the UFSAR and questioned the use therein of 95 degrees F as an input parameter and initial condition in the large break loss of coolant analysis. The inspectors were concerned that this value was below the actual temperature of the RWST tanks during short period of high summer temperatures. The UFSAR also stated that the 95 degree F value was derived from averaging the TS upper and lower limits of 70 and 100 degrees F, which needed further licensee clarification. This statement appeared inconsistent with the TS temperature limit.

Following the inspectors' observations, the licensee strengthened administrative controls to ensure cooling of the tanks would be initiated at the 95 degree F value. Based on the above concerns, this issue will be identified as an Inspector Followup Item (IFI) 50-369,370/97-20-01, Operation With Elevated Refueling Water Storage Tank Temperatures.

c. Conclusions

The inspectors questioned several design attributes of the RWSTs and whether stratification could have affected past operability of each unit's tank. An IFI was identified concerning the issue.

O2.2 Improperly Locked Valve in the Starting Air System for the Unit 2 B Emergency Diesel Engine

a. Inspection Scope (71707)

The inspectors reviewed the licensee's investigation and corrective actions for an improperly locked valve in the Unit 2 emergency diesel engine starting air system identified by the NRC.

b. Observations and Findings

On December 22, 1997, the inspectors identified that valve 2VG82 was not properly locked. However, the inspector did determine that the valve was in the proper position (open). During a walkdown, the inspectors identified that the chain and lock were not on the valve and were wrapped around the associated pipe approximately 1 foot from the valve body and handwheel. Valve 2VG82 is a manual valve that is in the flow

controlling air for the Unit 2 B emergency diesel generator (EDG) engine. Operations Procedure 2/A/6350/02, Revision 61, Diesel Generator, states that valve 2VG82 should be in the locked and open position.

This issue was documented in Problem Investigation Process (PIP) 0-M97-4848. As corrective action, the licensee verified that the valve was open and properly locked the valve. Inspectors verified that these actions were completed by the next operating shift.

Prior to the discovery, the OP/2/A/6350/02 checklist was last completed on November 23, 1997. Operators who completed this procedure confirmed that the valve was properly secured on November 23, 1997. No documented work or valve manipulations were identified for the period between November 23, 1997, and December 22, 1997. The licensee's Operations Management Procedures (OMP) 8-2, Separate and Double Verification, notes that locks on valves are for administrative control only and are not intended to maintain valve position. The procedure further states that reasonable attempt should be made to place the lock and chain on valves to prevent inadvertent movement of the valve. The corrective actions also included having each operations shift manager discuss OMP 8-2 with their personnel as it related to this issue.

The inspectors concluded that the license's failure to maintain valve 2VG82 properly locked in conformance with plant procedures was a violation of minor significance and is being treated as a non-cited violation (NCV) consistent with Section IV of the NRC Enforcement Policy. NCV 50-370/97-20-02: Improperly locked Starting Air Valve 2VG82 for the Unit 2B EDG.

c. Conclusions

An NCV was identified for an improperly locked valve in the diesel generator control air system.

## 04 Operator Knowledge and Performance

### 04.1 Overview of Unit 2 Criticality and Startup Activities

a. Inspection Scope

During the inspection period, the inspectors witnessed preparations for criticality and zero power physics testing (ZPPT) for the Unit 2 restart

from the scheduled refueling and steam generator replacement outage. The inspectors witnessed criticality preparations and shift briefings in the control room, reviewed startup controlling procedures, and observed coordination of the evolution between operations and the reactor engineering group.

b. Observations and Findings

On December 16 and 17, 1997, the inspectors witnessed the preparations for criticality and ZPPT of Unit 2. The inspectors observed that the overall control of the preparations, operator awareness of plant parameters, and interactions between operators involved in the restart and reactor engineering personnel were excellent. Good communications between operators and reactor engineering personnel discussing preparations for criticality were observed. Operators were well informed of anticipated changes in plant parameters during the approach to criticality. The startup process was slightly delayed by operators due to a potential for an inaccurate OAC point associated with the shutdown bank position indications. Operator aid computer technicians were consulted and determined that the indication discrepancy was limited in scope and would not affect any critical indications which could impact the criticality process.

The inspectors also reviewed the procedural pre-job briefing package for the approach to criticality and ZPPT evolutions. Nuclear Site Directive (NSD) 304, Reactivity Management, requires that reactor startups be treated as an infrequently performed evolution. The purpose of the briefing was to discuss with operators and other involved personnel how the approach to criticality and withdrawal of the control rods were going to be controlled and performed. During the briefing, emphasis was placed on plant parameters the operator at the controls should monitor, limits on reactivity additions, and the frequency for monitoring. Communication lines between reactor engineering personnel and operators were clearly delineated. Command and control functions were well established.

In addition to the above, plant personnel used conservative practices such as initially setting the power range reactor trip set points no higher than 5 percent full power (TSs requires they be set below 25 percent full power), and the nuclear engineering manager requiring that the qualified reactor engineer and a dedicated senior reactor operator independently calculate the estimated critical rod position.

c. Conclusions

The inspectors concluded that the startup evolutions, including Unit 2 preparation for criticality and ZPPT, were well controlled. Briefing packages for the evolutions were detailed, command and control were properly established, and operations and engineering management oversight of the evolutions was excellent.

## O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-369/96-04 and LER 50-369/96-04, Revision 1: Incorrectly Calibrated Reactor Coolant LOOP Loss of Flow

This LER is considered administratively closed based on previous inspections documented in Inspection Report 50-369,370/96-10. In that report, NCV 50-369/96-10-03 was identified for the root cause of the subject LER. Based on the previous reviews, both revisions of the subject LER are closed.

O8.2 (Closed) LER 50-369/96-01, Revision 1: Unit 1 Manual Reactor Trip Initiated as a Result of an Equipment Failure Caused by an Unknown

Revision 0 of the subject LER was previously closed in Inspection Report 50-369,370/96-10. On April 19, 1996, the licensee issued Revision 1 of the subject LER to document that the event was determined not to be reportable under the Nuclear Plant Reliability Data System. No other changes were made to the LER. This LER is closed.

O8.3 (Closed) LER 50-370/96-04: Lightening Strike Initiated a Fault Resulting In An Automatic Start of EDG 2A

On May 24, 1996, the 2A EDG automatically started due to a momentary undervoltage condition on the 4160 volt (V) Essential Bus 2ETA. The undervoltage occurred during an automatic slow bus transfer following a lightning strike that affected Unit 2 525 kilo-volt (kV) switchyard equipment. Because the voltage recovered, the 2A EDG was not required to carry the blackout loads.

The lightning surge was detected by switchyard protective relaying which initiated a switchyard breaker realignment and lockout of one of the 525kV buslines. Due to ongoing maintenance activities in the switchyard, a pathway was created that allowed the lightning strike to affect a breaker current transformer resulting in the protective relay

actuation. The lightning strike, coupled with improper breaker maintenance practices, led to the protective relaying sensing an overcurrent condition and actuating according to design. The 2A EDG operated as designed due to the undervoltage condition on 2ETA.

The inspectors verified that switchyard breaker maintenance practices involving installation of grounding devices had incorporated instructions to not allow grounding devices to remain installed for extended periods when work activities are delayed. This LER is closed.

O8.4 (Closed) LER 50-370/96-05: ESF Actuation of the 2B EDG After Blackout on Unit 2 Essential Bus

On November 9, 1996, with Unit 2 in Mode 4, the Unit 2 B EDG automatically started after power was lost to 2ETB 4160V Essential Bus. The power loss was caused by spurious protective relay actuation opening the normal 6900V feeder breaker from power transformer 2TD. The resulting automatic lockout of the normal and standby breakers prevented immediate restoration of the essential bus voltage prior to the diesel starting and loading. The EDG sequenced on the blackout loads and operated for approximately 3 hours until power could be restored through shared auxiliary transformer SATB. Because the licensee could not identify any indications of high current, the licensee checked the relay actuation and settings. Although no problems were identified, the relay was replaced and returned to the vendor where the functions were checked and calibrations verified within specifications. No problems were identified by the vendor. Based on the licensee's actions in response to the relay actuation and automatic EDG start, the inspectors determined that the licensee had appropriately attempted to identify and correct the root cause. Although no conclusive evidence was identified to confirm that an intermittent failure of the protective relay caused the event, the licensee's actions were considered adequate. This LER is closed.

## II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 and 62707)

The inspectors observed portions of the following work activities:

| Procedure/Work Order | Title |
|---|---|
| IP/0/A/4971/007 | ITE 27N and Time Delay Relay Calibration, Revision 3 |
| IP/0/A/4971/010 | Brown Boveri ITE27D Relay Calibration, Revision 1 |
| PT/2/A/4350/004 | 4kV Sequencer Loss/Undervoltage Detector Actuating Device Operational Test, Revision 4 |
| PT/1/A/4200/028A | Train A Slave Relay Test, Revision 47 |

b. Observations and Findings

The inspectors witnessed selected surveillance tests to verify that approved procedures were available and in use; test equipment in use 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.

c. Conclusion

The inspectors concluded that these routine surveillance activities were completed satisfactorily.

**M2 Maintenance and Material Condition of Facilities and Equipment**

M2.1 Material Condition and Housekeeping (Unit 1 and 2)

a. Inspection Scope (62700)

The inspector determined by observation and document review, the adequacy of the licensee's material condition and housekeeping activities. The licensee's governing procedure was NSD 104, Revison 12, Housekeeping, Material Condition and Foreign Material Exclusion.

b. Observations and Findings

The inspector reviewed the above-mentioned procedure and performed a walk-through inspection in selected areas of Units 1 and 2 to verify that procedural requirements were being enforced. The areas inspected included: turbine building Units 1 and 2; emergency diesels Units 1 and 2; doghouse Unit 1; auxiliary building elevations 695, 716 and 750. In addition, the rooms containing charging pump 2B, safety injection pump 1A, service water pump 1A and 2A, and spray pump 2B were inspected.

As a result of this effort, the inspector verified that mechanical and electrical (small motors) equipment was being properly maintained. The equipment showed no evidence of abuse or neglect. The small bore piping, instrument tubing and electrical trays also showed no evidence of being used for climbing. Equipment and certain rooms were painted and free of smudges, debris and oil leaks. Motors, pumps and valves had been clearly labeled. All leaks were tagged and fluid contained and directed to a drain as appropriate. Floors were painted and generally free of water, dirt and sundry debris. The licensee was tracking leaks and was reporting them on a monthly and yearly basis.

Records showed that the rolling average of 6.73 leaks per month was less than the target of 10-15 leaks per month. The list of oil pans in use was tracked in the same manner. Records showed the number of oil pans used in Unit 1 over a seven month period, which ended November 1997, was fairly constant and trending downward, for Unit 2.

c. Conclusion

Inspection of the auxiliary building, the turbine buildings and the Unit 2 doghouse confirmed that the licensee was proactive in maintaining housekeeping and material condition in a satisfactory condition.

M2.2 Equipment Reliability and Operator Workaround Programs

a. Inspection Scope (62700)

The inspector determined through discussion and document review the adequacy of the licensee's program associated with equipment reliability and operator workaround programs.

b. Observations and Findings

The inspector met with plant management to discuss measures which had been taken to address significant equipment problems that could have a negative impact on nuclear safety, plant availability and reliability, or generation capacity. These measures established goals to be achieved and included elements of prevention, detection and correction. These goals and objectives are delineated in the following documents:

- MSD-340, Revision 1 — Top Equipment Problem Resolution (TEPR) Process
- NSD-506, Revision 0 — Operator Workarounds
- Consistent Site Measures for Equipment Reliability.

The TEPR process draws from the Major Equipment Problem Resolution (MEPR) and Workaround Problem Resolution (WAPR) lists. The TEPR process is staffed by a team consisting of key engineering managers, and superintendents from operations, maintenance work control, as well as other work groups. The team is co-sponsored by the station manager and site engineering manager. The lead individual, assisted by management designated individuals, defined the details of the problem and took appropriate steps to assure that problems are resolved in a timely manner. The lead individual is also responsible for closure. Following is a list of TEPR items which were in progress at the end of this inspection.

| Item | Date Identified | Date Cleared |
|---|---|---|
| Containment Penetration Bellows Reliability | May 1995 | EOC-12 |
| Instrument Air System Reliability | April 1996 | October 1998 |
| Large Motor Reliability Reactor Coolant Pump Motors | June 1996 | January 1, 1998<br>2 EOC-12 |
| Source Range Detector Reliability | November 1996 | Partially complete<br>End Date to be Determined |

| | | |
|---|---|---|
| Main Feedwater Isolation Valve Reliability | October 1996 | EOC-12 |

Candidates for the subject list were selected by the TEPR review team with consideration given to impact of nuclear safety, plant availability and reliability and generation capacity. Top plant Workaround (WA) Problem Resolution (WAPR) items are generated in the same manner as described above. The WAPR list consisted of equipment with long standing or repetitive problems that prevented systems from operating as originally designed and intended. Items on this list were identified by operations or chemistry. A review of the workaround chart reflecting the monthly totals showed a running backlog ranging between 65-75 from December 1996, to September 19, 1997. Completed workarounds over the same time intervals ranged from zero and 10.

c. Conclusion

The TEPR program and its implementation were well organized and managed by qualified engineering personnel with a positive attitude. Results of actions taken to resolve long standing equipment problems indicated a proactive approach to resolutions.

M2.3 On-line Corrective Maintenance to Stop Steam Leak on Steam Dump Control Valve 1SBVA0018 (Unit 1)

a. Inspection Scope (62700)

The inspector determined by work observation, procedure and record review, the adequacy of work activities in regards to performing an on-line temporary repair of the subject valve. The piping system was non-safety and non-code Duke Class G classification. The applicable work order (WO) was 97098669-01. Applicable procedures were as follows:

| | |
|---|---|
| MP/O/A/7650/77 | On-line Leak Sealing Initial Injection |
| MP/O/A/7700/05 | On-line Leak Sealing Reinjection |
| MP/O/B/7600/92 | Fisher EWP Globe Valve Corrective Maintenance |
| USSI-NP-14, Revision 2 | Full Face Flange - Injection Washers |
| Drawing MCFD-1593-02.01 | Flow Diagram of Main Steam Bypass to Condenser System |

Maintenance Directive 3.22, Revision 0 — Guideline for Control of Leak Sealing Activities

b. Observations and Findings

The inspector confirmed by observation, document review and discussions with technical personnel that the steam leak was located on the body-to-bonnet connection of control valve 1-SB-VA-0018. The licensee evaluated the problem and determined that since the valve could not be isolated with the plant on-line, a temporary repair by seal injection would be appropriate. For the long-term repair, the licensee planned to disassemble and repair the valve during Unit 1 scheduled refueling outage EOC 12.

The work was performed by Utilities Support Specialists Incorporated (USSI) who were under contract with the licensee. The repair plan called for removing one nut and stud at a time and replacing it with a longer stud and as injection washer, and retorquing the nuts to the required torque level. All 12 studs and nuts were replaced and retorqued satisfactorily. The sealing material used for the injection was rated as nuclear grade, and the torque wrench used was appropriate for the work and records showed that it was in calibration. The inspector observed selected stages of the repair and determined that the work was well planned. Pre-job briefings were attended by maintenance and operations and were conducted in a professional manner. Areas covered included job site prep alternates to the proposed repair, job execution and personnel safety. At the close of this inspection, the inspector observed that although the subject valve had been seal injected, there was some evidence that the injection of sealant had not completely stopped the leak. Through discussions with technical licensee personnel, the inspector ascertained that the condition had been evaluated and the licensee decided to leave the valve as is and monitor the condition, and perform the appropriate corrective maintenance during the upcoming schedule refueling outage in May 1998. The inspector concurred in these actions.

c. Conclusion

The valve steam leak temporary repair was well planned, managed and executed with sufficient coverage by engineering and operations personnel who took a proactive role in the project. Personnel involved were well trained and worked in a safe manner to minimize the chance of

personal injury. Procedures were followed and records were complete and accurate.

## M3 Maintenance Procedures and Documentation

### M3.1 Timeliness of Corrective Actions

a. Inspection Scope (40500 and 62707)

The inspectors reviewed a licensee initiative designed to improve completion timeliness of corrective actions.

b. Observations and Findings

On January 21, 1998, the inspectors attended a meeting conducted by McGuire management identified as "The Oldest Open Ones Meeting" or TOOOM. The objectives of this initiative, which began formally in October 1997, was to measure improvement in the number of open problem investigation process (PIP) items and work orders (WO) which are outside of the licensee's predetermined guidelines. The inspectors reviewed the documentation presented at the meeting and found that the associated performance measure format provided a tool for licensee management to assess this area. Management was continuing to modify the format to further enhance their capability to improve monitoring, prioritization, and overall effectiveness of corrective action completions. One attribute the inspectors considered noteworthy was review, by the team members, of planned long term improvements for specific PIP issues. During this review, the established actions were either approved or disapproved as a second review of the establish corrective actions.

c. Conclusion

The licensee's initiative to measure improvement in the number of open PIPs and WOs has provided a tool for licensee management to assess performance in this area.

## M4 Maintenance Staff Knowledge and Performance

### M4.1 Unit 2 Steam Generator Replacement Project

a. Inspection Scope (50001 and 62707)

The inspectors observed portions of the Unit 2 steam generator removal and replacement activities as well as post-installation verification and testing. Additionally, evaluations of associated modifications were also performed to verify licensee conformance to applicable codes and standards, licensing commitments, and regulations.

b. Observations and Findings

Steam Generator Removal and Replacement

The inspectors observed removal of the Unit 2 B and D steam generators as well as the installation of the Unit 2 A and B steam generators. The inspectors noted that the licensee had placed appropriate emphasis on foreign material exclusion, doses As Low As Reasonably Achievable (ALARA), and personnel safety. The inspectors noted that the licensee's performance of the lifting, rigging, and transport of equipment were good. Appropriate licensee and contractor technical support was available during the removal and replacement evolutions. Crane and rigging inspections were performed by qualified personnel. The replacement project staffing was adequate and managed in accordance with NSD 105, Control of Non-Assigned Individuals and Organizations.

Post-Installation Verification

The inspectors conducted a number of post-installation inspections of the reactor building during installation on the support columns and prior to Unit 2 entry into Mode 3. The inspectors verified that major nuclear steam supply system restraints and supports, removed during replacement, were either reinstalled, replaced, relocated or deleted by approved station modifications. The original steam generator mirror and blanket insulation was replaced with all fiberglass mass insulation within a fiberglass cloth blanket. The fiberglass blanket was covered by a stainless steel jacket to minimize damage to the cloth during subsequent maintenance activities. The licensee received a license amendment to allow operation of Unit 2 containment purge while in Mode 4 and Mode 3 to remove thermal decomposition gases from the reactor building during the initial heat up of the blanket insulation. Prior to

entering Mode 2, the licensee secured containment purge and leak tested the previously open penetrations to verify containment integrity. The inspectors also examined steam generator enclosure installation to ensure excessive air flow would not bypass the ice condenser during postulated accidents invalidating UFSAR assumptions. No significant pathways were identified.

In accordance with 10 CFR 50.55a, the licensee performed full temperature and pressure leak inspections of the reactor coolant system as outlined in American Society of Mechanical Engineers (ASME) Section XI Code Case N-416-1 rather than performing hydrostatic testing. No system leakage was identified.

Operational Testing

The inspectors monitored functional testing of potentially affected control systems including pressurizer level control, steam generator level control, and rod control performed with Unit 2 in Mode 1. The testing was performed to verify operability of equipment affected by the steam generator replacement. The testing was performed to satisfy the post-modification testing requirements for NSM-MG-29815, Replacement Steam Generator Instrumentation and Control. At approximately 38 percent and 78 percent power reactor power, the licensee manually induced a step load change of approximately 10 percent of rated electrical output on the secondary system to verify automatic control system responses. Actual plant control system responses were compared to predicted design calculations. The inspectors noted that instrumentation and controls functioned properly to stabilize the systems at the reduced power level. The inspectors reviewed test results to ensure compliance with test acceptance criteria and the UFSAR. No discrepancies were identified.

c. Conclusions

The inspectors concluded that removal of the original Unit 2 steam generators and installation of replacement steam generators was well planned and executed. Testing to demonstrate the stability of the steam generators during transient conditions was well controlled. Replacement equipment functioned properly.

M4.2 Implementation of Dynamic Rod Worth Measurement (DRWM) Testing Changes

a. Inspection Scope (61726)

The inspectors reviewed the implementation of recent changes in the method of performing control rod bank worth measurements. The inspectors reviewed procedural controls for the changes in test methodologies, attended a Plant Operating Review Committee meeting on the subject, and witnessed control room preparations for the testing.

b. Observations and Findings

During the initial startup from the Unit 2 refueling outage, the licensee implemented a new DRWM technique with an advanced digital reactivity computer. In this process, the worth of each individual rod bank was measured by use of the DRWM technique, which has been approved by the NRC since January 1996. The technique has been successfully implemented at a number of other facilities and is accomplished via data collection during insertion of the control rod banks.

Prior to the evolution, the licensee conducted a detailed pre-job briefing. The briefing package highlighted the new DRWM technique and focused on specific differences in expected parameters which operators may experience during the test from previous rod worth measurement techniques.

Implementation of the new testing method was considered excellent. Operators and reactor engineering personnel were knowledgeable of their respective roles and responsibilities. The licensee appropriately utilized vendor expertise in both pre-job equipment setup and monitoring of the testing process. The quality of the controlling procedure was also good.

c. Conclusions

The inspectors concluded that the implementation of the new dynamic rod worth testing method was excellent. Pre-job briefing of the testing was detailed and adequately prepared both operators and reactor engineering personnel for the evolution. Use of vendor oversight was considered beneficial. The overall incorporation of the rod worth testing technique was well controlled.

## M7 Quality Assurance in Maintenance

### M7.1 Review of Maintenance Quality Feedback to Improve Maintenance Performance

a. Inspection Scope (62707)

The inspectors reviewed a licensee initiative designed to improve maintenance quality. The inspectors discussed the initiative with maintenance management and other site personnel, and reviewed documentation associated with the licensee's Quality Maintenance Feedback process.

b. Observations and Findings

One initiative which maintenance management performs to improve the overall quality of maintenance activities at the McGuire site is a direct feedback of lessons learned. The process is called Quality Maintenance Feedback and consists of a weekly written summation of examples of both strong and weak maintenance practices. As described by the licensee, the purpose is to effectively communicate human performance lessons learned throughout the maintenance organization on a timely basis by identifying work practice successes, work practice problems, and review of applicable operating experience issues. The inspectors reviewed several months worth of the most recent Quality Maintenance Feedback issues and considered that they were providing a structured process for incorporating lessons learned within the area of maintenance.

c. Conclusions

The inspectors concluded that the licensee's Quality Maintenance Feedback process was a good initiative to improve the overall quality of maintenance related performance at the site.

## III. Engineering

### E2 Status of Engineering Facilities and Equipment

#### E2.1 Condenser Circulating Water Pipe Break

a. Inspection Scope (35551)

The inspectors reviewed the circumstances associated with a pipe break in an abandoned condenser water pipe at the low level intake (LLI) structure. The inspectors examined the pipe break location and reviewed immediate licensee corrective actions and applicability of plant abnormal and emergency procedures.

b. Observations and Findings

On January 4, 1998, a pipe break occurred in an abandoned circulating water pipe located outside the protected area. The pipe is part of the LLI from Lake Norman and is one of three large pipes (approximately 48-inch diameter) that take suction adjacent to the Cowans Ford dam. A 180-degree crack developed at a stress point along a circumferential weld located in the underground portion of the pipe (approximately 100 feet from the dam spillway). Soil in the vicinity of the break was washed away exposing the ruptured pipe. The break was isolated by closing an upstream motor operated valve (MOV) 1RC65 located at the dam.

Prior to the pipe break, on December 28, 1997, the licensee had opened 1RC65 to keep the abandoned pipe filled. The licensee was concerned that pressure from the soil could deform voided portions of the pipe. However, licensee investigations concluded that unknown corrosion, pressure from an approximately 6,000 pound concrete manway block on top of the pipe, and static pressure from the lake,once 1RC65 was opened, all contributed to the pipe failure. The inspectors verified that service water was not interrupted (service water pipe connects upstream of 1RC65 and is located on higher ground than the abandoned pipe). Additionally, the assured service water source (emergency pond) is located on the opposite side of the plant, and therefore was not affected or threatened. The licensee's abnormal procedures incorporate realignment of service water in cases of a dam break or loss of the LLI structure. Through a control room board walkdown, inspectors confirmed that MOVs for isolation and realignment for service water were available.

Corrective actions were to repair the pipe and permanently remove the manhole near the pipe break. The licensee indicated that metallurgical tests will be performed and a determination will be made whether to perform an inspection of the joints in the other two circulating water pipelines.

c. Conclusions

The inspectors concluded that the immediate actions to isolate a pipe break in the abandoned condenser circulating water pipe were adequate. Procedures were in place for coping with a potential loss of the LLI. Long-term actions appeared appropriate.

## E4 Engineering Staff Knowledge and Performance

### E4.1 Potential Reactor Coolant Pump (RCP) Thermal Barrier Tube Rupture

a. Inspection Scope (35551)

The inspectors assessed the licensee's evaluation and corrective actions to industry operating experience presented in NRC Information Notices (IN) 89-054, Potential Overpressurization of the Component Cooling Water (CCW) System, and IN-97-031, Failures of RCP Thermal Barriers (TBs) and Check Valves in Foreign Plants. The inspectors interviewed cognizant engineering personnel, reviewed the system design and DBD, the UFSAR, CCW check valve test results, Emergency Procedures (EPs), and Abnormal Procedures (APs).

b. Observations and Findings

NRC IN 89-054 was issued in 1989 to notify utilities of a potential for an un-isolable reactor coolant system (RCS) leak outside containment resulting from a rupture in a CCW line. The scenario involved a tube rupture from the RCP thermal barrier heat exchanger into the low pressure CCW system (i.e., Interfacing System Loss of Coolant Accident (ISLOCA)). The resulting leak could potentially overpressurize the CCW system and result in reactor coolant being discharged outside containment if the leak could not be isolated. NRC IN 97-31 was issued in 1997 to relay operational experience information on failures of TBs and check valves in foreign and domestic plants.

At McGuire, the plant design allows isolation of a breach of the thermal barrier. Each RCP has a check valve and a MOV (automatic closure on

high CCW flow) on the CCW inlet and outlet of the TB, respectively. According to plant drawings, the CCW piping for the isolation portion to the TB is rated for full RCS pressure. During the previous Unit 2 refueling outage, inspectors walked down portions of the Unit 2 CCW supply and return piping (inside containment) that service each RCP. Material condition of the CCW piping generally appeared adequate.

In response to IN 89-054, the licensee added a larger relief valve in the CCW surge tank. In response to IN 97-031, the licensee evaluated the design differences between McGuire and the foreign PWRs that had experienced the thermal barrier failures. The principal difference was the material of the tubes and flanges where McGuire thermal barrier tubes comprise ASME Class 1 type 304 stainless steel. To address check valve reliability issues, the licensee tested all four isolation check valves. Test results showed excess leakage through two check valves (approximately 0.75 gallons per minute and 8 gallons per minute). These valves were disassembled, inspected, and refurbished. No metallic oxide buildup was identified as noted in IN-97-31. The licensee indicated that the associated Unit 1 CCW check valves are to be tested during the next Unit 1 refueling outage. The licensee was evaluating adding the checks valves to their ASME supplemental test program. The licensee does not currently test the TB outlet MOVs.

The inspectors reviewed the APs and EPs and operator systems training materials to confirm they contained sufficient detail to diagnose the break location and implement coping measures. ECA 1.2, LOCA (loss of coolant accident) Outside Containment, did not contain specific reference to an ISLOCA from a thermal barrier tube rupture or symptoms associated with a breach if it were not automatically isolated. However, AP/2/A/5500/10, RCS Leakage Within the Capacity of Both Charging Pumps, Revision 5, did contain specific information for a thermal barrier leak.

The inspectors were concerned that insufficient detail existed in the ECA 1.2 to allow timely operator actions for coping with the ISLOCA. Although AP/2/A/5500/10 did contain sufficient detail, there was no transition noted from ECA 1.2 to the AP. Given a scenario where a tube rupture occurs (in lieu of a leak) a reactor trip and subsequent operator entry into the EPs could occur before operators enter the AP. The inspectors identified an additional concern that the TB outlet isolation valves are not tested, and may have limited routine preventive maintenance on the MOVs. Operator action to isolate CCW through other

means would be important if the affected TB outlet valve did not function.

c. Conclusions

The inspectors concluded that the licensee's effort to test the CCW check valves in the TB inlet was a good response to IN 97-031. Engineering evaluation of the design differences between McGuire thermal barrier and those noted in IN 97-031 was adequate. Pending further NRC review of the adequacy of EP ECA 1.2, LOCA Outside Containment, to allow diagnosis and isolation of a potential thermal barrier tube rupture, this is identified as Inspector Followup Item (IFI) 50-369,370/97-20-03, Emergency Procedure Adequacy for Coping with a Tube Rupture in the RCP Thermal Barrier Heat Exchanger.

## E8 Miscellaneous Engineering Issues

E8.1 (Closed) VIO 50-369/96-11-05: Failure to Perform a 10 CFR 50.59 Review Prior To Performing a Test or Experiment Not Described in the UFSAR

The inspectors reviewed the licensee's response to a cited violation for failure to formally evaluate and provide a basis for the determination that testing performed between March and December 1996, not described in the UFSAR, did not involve an unreviewed safety question. The test included lowering secondary plant hydrazine levels to evaluate whether the levels currently specified in the McGuire Station Chemistry Manual were in excess of the necessary values for optimum corrosion protection during power operations.

The inspectors reviewed the licensee's actions which included revisions and clarifications to the Station Chemistry Manual and the McGuire UFSAR. The licensee also emphasized the potential impact of not evaluating parameter changes to chemistry group supervisors. The inspectors concluded that the licensee's actions to prevent recurrence were adequate. This item is closed.

## IV. Plant Support

### R1 Conduct of Radiological Protection and Chemistry

#### R1.1 Tour of Radiological Protected Areas

a. Inspection Scope (83750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program as required by 10 CFR Parts 20.1501, 1502, 1601, 1802, 1902, and 1904. The review included observation of radiological protection activities including personnel monitoring controls, control of radioactive material, radiological surveys and postings, and radiation area and high radiation area controls.

b. Observations and Findings

During tours of the auxiliary building and radioactive waste storage and handling facilities, the inspectors reviewed survey data and performed selected independent radiation and contamination surveys to verify area postings. Observations and survey results determined the licensee was effectively controlling and storing radioactive material. The inspectors also observed a radiation protection (RP) technician source check an instrument as required by procedure and noted instruments in use in the auxiliary building were currently source checked and calibrated as required.

During plant tours, the inspectors observed that extra high radiation areas (locked high radiation areas) were locked as required by licensee procedures and all other high radiation areas observed were appropriately controlled as required by licensee procedures. The inspectors also inventoried the licensee's extra high radiation area (EHRA) and very high radiation area (VHRA) key control boxes maintained by radiological control and determined that at the time of the inspection, all keys assigned to radiological control personnel for locked EHRAs and VHRAs were accounted for. Dosimetry controls for the EHRAs and VHRAs observed were established in radiation work permits (RWPs) and special radiation work permits (SRWPs) as required by licensee procedures. The inspectors observed workers complying with RWP and SRWP requirements during facility tours.

The inspectors reviewed personnel contamination event (PCE) reports prepared by the licensee to track, trend, determine root cause, and any necessary follow up action. The licensee had continued efforts in 1997 to reduce personnel contaminations. Approximately 313 PCEs occurred in 1997 which included 109 skin contaminations and 204 clothing contaminations. In June of 1997, the licensee established a Quality Improvement Team to identify methodology, process, and procedure enhancements to effectively lower the number of PCEs during refueling outages. Some of the recommendations by this team that were incorporated during the Unit 2 Cycle 11 outage included use of sticky pads at specific plant locations, replace maslin on mops used for decontamination with tact cloth, setting up hot particle zones for additional controls where particles are detected, implementing additional control requirements for the use of mop heads used in hot particle zones, identifying tools and contamination clothing used in hot particle zones, training and improved communications regarding contamination events, and a review of the PCE investigative process. The inspectors reviewed several PCEs that did occur during the Unit 2 Cycle 11 outage and discussed potential root causes and licensee followup actions to the events. The inspectors determined the licensee had effectively tracked the events, assigned doses received by the workers, and evaluated root causes for corrective actions.

All personnel exposures to the skin, eyes, extremities, and whole body in 1997 and to date in 1998 were below regulatory limits. The licensee issued 26 respirators in 1997. Of this number 14 were required and the other 12 were issued upon worker request. Documents reviewed determined no positive uptakes of radioactive material requiring dose assignment had occurred during 1997.

During the inspection, the licensee was maintaining approximately 755 square feet or 0.7 percent of the total radiologically controlled area (RCA) as recoverable contaminated area. Records reviewed also showed the licensee maintained a maximum of 3.3 percent of the RCA as recoverable contaminated area during outage periods in 1997. The inspectors also observed radiological housekeeping in the facilities to be good.

c. Conclusions

The licensee was effectively maintaining controls for personnel monitoring, control of radioactive material, radiological postings, and

radiation area and high radiation area controls as required by 10 CFR Part 20.

R1.2 As Low As Reasonably Achievable (ALARA)

a. Inspection Scope (83750)

The inspectors reviewed the licensee's implementation of 10 CFR 20.1101(b) which requires that the licensee shall use, to the extent practicable, procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses and doses to members of the public that are ALARA.

b. Observations and Findings

The inspectors interviewed licensee personnel and reviewed records of ALARA program results and activities. The 1997 site radiation exposure goal was 579.5 person-rem. The 1997 site exposure was approximately 461.7 person-rem and included refueling and steam generator replacement outages in both Units 1 and 2, non-outage periods for both units, and forced outage work. The replacement of four steam generators during the Unit 2 Cycle 11 outage resulted in approximately 83 person-rem. The Unit 2 Cycle 11 refueling portion of the outage was accomplished for approximately 110 person-rem. The total Unit 2 Cycle 11 outage was completed for approximately 194 person-rem versus a previously established goal of 233 person-rem. This was approximately 40 person-rem or 17 percent below the established goal. Records reviewed determined the licensee was effectively tracking and trending dose rate reduction efforts for outage and non-outage task. During tours of the facility, the inspectors observed RP technicians effectively controlling access to areas as a drum of highly radioactive material was being prepared for shipment to a waste processor. Exposures incurred during refueling outages and non-outage periods had continued to trend downward as a result of the licensee's ALARA initiatives. Some of these initiatives included sub-micron filtration, hot spot reduction efforts, improved planning for shielding installation and removal, and remote monitoring and communication systems. Based on observations and records reviewed, the inspectors determined the licensee had continued to maintain exposures ALARA and the inspectors viewed the overall ALARA program as a strength.

c. Conclusions

The licensee had continued to maintain exposures ALARA and the inspectors viewed the overall ALARA program as a strength.

## R5 Radiological Protection and Chemistry Staff Training and Qualification

### R5.1 Radiation Protection Technician Training

a. Inspection Scope (83750)

Training of radiation protection technicians was reviewed to determined whether the technicians had been provided adequate training in procedures to minimize radiation exposures and control radioactive material as required by 10 CFR Part 19.12.

b. Observations and Findings

The inspectors reviewed training requirements and records for the RP technicians. The inspectors also reviewed the continuing training curriculum for the period January 1, 1997, through December 10, 1997, which included topics to minimize radiation exposure and control radioactive material. During facility tours the inspectors interviewed RP personnel and observed work practices to determine the effectiveness of radiation protection training.

c. Conclusions

The radiation protection technicians had been provided an adequate level of training to perform routine activities involving radiation and control of radioactive material.

## R8 Miscellaneous Radiological Protection and Chemistry Issues

R8.1 (Closed) VIO 50-369,370/97-01-03, (EA 97-544): Violation of 10 CFR 70.24 Requirements.

The licensee responded to the subject violation on April 17, 1997, detailing their corrective actions taken for the violation. Subsequent to the licensee's response, the NRC exercised enforcement discretion and withdrew the cited violation per correspondence dated November 25, 1997.

R8.2 (Closed) Inspector Followup Item (IFI) 50-369,370/96-11-06: Followup on Licensee Closeout Actions on PIP Number 2-M96-3238

This issue involved start-up activities associated with the addition of hydrazine with the chemical and volume control system demineralizers bypassed. The preliminary results of the investigation indicated that the demineralizers were placed back in service before the hydrazine concentration had reached the planned level resulting in the solubilization and release of Cobalt-58 removed during the shutdown cleanup. The licensee estimated that between 300 and 400 Curies were released to the primary water system from the demineralizer beds. These estimates were based on remote teledosimetry measurements. A more in-depth licensee followup investigation determined the activity spike was from the crud burst which occurred when the RCPs were started in lieu of placing the demineralizers in service early. However, the licensee did revise the chemistry procedure to effectively communicate in written form the desired actions to be taken when hydrazine is being added to the chemical and volume control system. This item is closed.

## S1 Conduct of Security and Safeguards Issues

### S1.2 Access Control

a. Inspection Scope (81700)

The inspectors reviewed three security events involving a failure to notify security of an employee's termination, a security badge removed from the protected area, and the mis-issuance of a security access badge.

b. Observations and Findings

These three events were documented in PIPs 0-M97-4028, 3926, and 4030.

As identified in PIP 0-M97-4028, an employee quit on or about October 15, 1997. The employee's supervisor did not notify security to terminate the employee's badge. On October 26, 1997, it was identified that the employee quit and a group supervisor notified security to put the terminated individual's badge on administrative hold. The individual's badge was placed on administrative hold by security at 8:13 a.m. on October 26, 1997. On October 27, 1997, security was notified to terminate the former employee's badge. The badge was canceled at 4:55 p.m. on October 27, 1997.

Nuclear Station Directive 218 requires that management be responsible for verbally notifying site security or site staffing contacts to delete an individual's security badge. Security Procedure EXAO-02 requires that if termination is unfavorable, security shall be notified.

The failure to notify security and terminate an individual's badge as required by established procedures is identified as a violation. This violation is identified as violation (VIO) 50-369,370/97-20-04. This is a repeat of an example of failure to notify security and terminate an individual's badge identified in VIO A of our correspondence dated September 26, 1997, Failure to Deactivate And/or Deny Protected Area Access to Terminated Employees.

As identified in PIP O-M97-3926, on October 22, 1997, at approximately 6:30 p.m., an employee exited the protected area with his security badge. On October 23, the individual reported to security that the badge was inadvertently taken home. At the time of this event, a compensatory security officer was posted at the exit as a corrective action to a previous similar event.

Duke Power Company Nuclear Security and Contingency Plan, (PSP) Revision 6, Chapter 6, paragraph 6.3, requires that protected area badges shall remain within the protected area.

The failure to keep a security badge within the protected area is identified as a violation. This violation is identified as VIO 50-369,370/97-20-05: Failure to Control a Protected Area Access Badge. The failure to control a protected area badge is a repeat of an example in VIO C in our correspondence to you dated September 26, 1997.

As identified in PIP O-M97-4030, on October 28, 1997, at approximately 6:24 p.m., an employee requested badge number V-461 at the north Personnel Access Portal (PAP). Badge number V-561 was issued to the individual. The individual acknowledged that the badge was correct. The Personnel Access Door security officer failed to notice the incorrect badge when the individual handed the badge to the security officer and stated his name and badge number V-461. The officer read the badge number and name from the badge to the individual. The individual again acknowledged the badge as correct and proceeded into the protected area. The employee returned to the north PAP to return the incorrect badge (V-561) to security. At approximately 6:39 p.m., the correct badge, V-461, was issued to the correct employee. This non-repetitive, licensee-identified and corrected violation is being treated

as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This violation was identified as NCV 50-369,370/97-20-06: Issuance of the Wrong Badge to an Individual and Failure to Correct the Mis-issuance Before the Individual Entered the Protected Area.

c. Conclusion

Three violations were identified involving access controls for personnel that were contrary to the criteria in Section 6 of the PSP, Security Procedure EXAO-02, and Nuclear Station Directive 218.

**S2 Status of Security Facilities and Equipment**

S2.2 Alarm Stations and Communications

a. Inspection Scope (81700)

The inspectors evaluated the licensee's alarm stations and communication equipment to ensure that the criteria in Sections 8, 10, and 16 of the Duke Power Company Nuclear Security and Contingency Plan, Revision 6, dated May 19, 1997, and appropriate Security Plan Procedures (SPPs) were implemented.

b. Observations and Findings

The inspectors verified that annunciation of protected and vital area alarms occurred audibly and visually in the alarm stations. The licensee equipped both stations with closed circuit television (CCTV) assessment capabilities and communication equipment. These stations were continually manned by capable and knowledgeable security operators. The stations were independent yet redundant in operation. The following station security tests were conducted:

Daily Checks

Local law enforcement agencies (LLEA) communication radios, emergency and plant telephones, panel lights, annunciator lights, and power source status lights

Shift Checks

On and off site security radios, CCTV, and Shift Turn Over Checklists

The inspectors evaluated the provision, operation, and maintenance of internal and external security communication links. Each security force member could communicate with an individual in each of the continuously manned alarm stations. This individual (an alarm station operator) could call for assistance from other security force personnel and from LLEA. The alarm stations had the capability for continuous two-way voice communication with the LLEA. The Charlotte and Mecklenburg Police Department conducted radio checks to the Central Alarm Station (CAS) and Secondary Alarm Station (SAS). Communication checks of the Control Room, CAS, and SAS were made at the beginning of each day shift.

c. Conclusion

Through observation, discussion with licensee representatives and document review, the inspectors concluded that the licensee was complying with the alarm stations and communication criteria in Sections 8, 10, and 16 of the PSP.

S2.3 Protected Area Detection and Assessment Aids

a. Inspection Scope (81700)

Based on the commitments in Sections 4 and 8 of the PSP, the inspectors evaluated the licensee's intrusion detection systems and assessment aids to verify that they were functionally effective and met licensee commitments. This evaluation was made to ensure that no vulnerabilities could be exploited to avoid detection.

b. Observations and Findings

Intrusion detection systems had been installed that could detect attempted penetrations through the isolation zone, and attempts to gain unauthorized access to the protected area. The licensee segmented the intrusion detection systems into enough alarm zones to provide adequate coverage of the protected area perimeter barrier and isolation zones. Tests of the intrusion detection systems were accomplished by walking through the isolation zone. The inspectors found through observation,

that the licensee had installed detection and surveillance subsystems for the protected areas. They consisted of microwave and infra-red systems to discover unauthorized activities and conditions. These systems sent alarm conditions to response force personnel in the alarm stations, allowing for response force personnel to assess and correct the conditions.

The inspectors evaluated the licensee's program for provision and maintenance of assessment aids. The licensee provided means for monitoring and observing, by human eye or CCTV, persons and activities in the isolation zone and exterior areas within the protected area. These means provided for assessing intrusion alarms for possible threats occurring in the isolation zone and exterior areas within the protected area. The alarm stations could simultaneously monitor scenes viewed by CCTV cameras used for intrusion alarm assessment.

The inspectors evaluated programs for provision and maintenance of facility lighting. The isolation zone and exterior areas within the protected area observed were illuminated to at least 0.2 foot candles measured horizontally at ground level. The illumination of the isolation zone and exterior areas within the protected area was appropriate. It was sufficient to monitor and observe persons and activities within these areas by the unaided human eye or CCTV. Protected area access portals were appropriately illuminated for identification and search of packages, personnel, and vehicles.

c. Conclusion

Intrusion detection systems, site illumination and assessment aids were found functional, well maintained, and effective for both covert and overt penetration attempts. The licensee met the PSP commitments and regulatory requirements.

S2.4 Testing and Maintenance

a. Inspection Scope (81700)

The inspectors evaluated programs for testing and maintenance of security equipment. This ensured the reliability of physical protection-related equipment and security-related devices. The inspectors also verified compliance with the criteria in Sections 9 and 16 of the PSP.

b. Observations and Findings

Programs for testing and maintenance were established to ensure that physical protection-related equipment met general performance requirements. Designated onsite personnel tested and maintained security-related devices and equipment in an operable condition. Each intrusion alarm was tested for performance at the beginning and end of any period in which it was used and at least once every seven days during continuous use. Alarm station operators tested the communication equipment required for onsite communication for performance at least at the beginning of each security work shift. Communication equipment required for offsite communication was tested at least once a day.

Records documenting tests and maintenance on security-related equipment were on hand and properly maintained. The records included onsite alarm annunciation, location of each protected and vital area alarm, false alarms, alarm checks, alarm circuit, date, time and response to each alarm, and intrusion or other security incident. A review of repair data records indicated a range of 0 to 2.3 days for time of fail date to the date of repair for security equipment. The overall average fail date to repair date for all security equipment was 1.32 days. This low overall average was indicative of the superior maintenance and repair support security equipment was receiving and is considered a strength. A random review of the Day and Night Shift Check-off Sheets and the related supporting documentation revealed that the shift, daily, 7-day, monthly, quarterly, and annual inspection, inventory, and test commitments or requirements were being met.

The inspectors reviewed the technical training and qualification records of the two dedicated maintenance individuals and found that they were appropriately trained and annually qualified as required by the licensee.

c. Conclusion

Maintenance and repair programs ensured the reliability of security related equipment and devices. This area was considered a strength in the security program. This was demonstrated by the responsiveness of dedicated maintenance personnel who repaired inoperable security equipment.

## S3 Security and Safeguards Procedures and Documentation

### S3.2 Security Procedures

a. Inspection Scope (81700)

The inspectors reviewed appropriate sections of the PSP and related supporting security procedures to determined their adequacy and compliance with 10 CFR Part 50.

b. Observations and Findings

The inspectors reviewed six sections of the PSP, eight security procedures, and NSD 208, Problem Investigation Process (PIP), dated November 17, 1997. The inspectors discussed with the licensee that Appendix D to NSD No. 208 did not address the reportability criteria of 10 CFR 73.71, Reporting of Safeguards Events. A review of the Contingency Plan in the PSP revealed that it addressed sabotage as a security contingency; however, did not mention tampering or vandalism as a security contingency element. The glossary in the PSP did not provide a definition of sabotage, tampering, or vandalism and their different severity levels. The licensee indicated that these items will be reviewed.

c. Conclusion

The random review of directives, plans, procedures, records, reports, and interviews with appropriate individuals verified that Safeguards procedures documentation complied with 10 CFR Part 50. Changes to sections reviewed in the PSP did not decrease the effectiveness of the PSP.

## S7 Quality Assurance in Security and Safeguards Activities

### S7.1 Audits and Self-Assessment Program, Corrective, and Problem Analysis

a. Inspection Scope (81700)

Based on commitments in Sections 11 and 16 of the PSP and NSD No. 208, the inspectors evaluated the audit program, corrective action system, and problem analysis procedures. This review also ensured compliance with the requirement for an annual audit of the security and contingency

programs. Also, the qualifications and independence of the audit program auditors were evaluated.

b. Observations and Findings

The audit program commitments included auditing the security program, and the Security and Contingency Plan at least every twelve months. Persons conducting the audit were independent of both security management and security supervision. The audit included a review of routine and contingency security procedures and practices. The Regulatory Audit Group performed Departmental Audit SA-97-10(MN)(RA) Security Activities at McGuire Nuclear Site on July 21-24, 1997. One recommendation, two strengths, and two findings were identified. The recommendation and findings were not regulatory issues. The audit report concluded that overall, the security program at the McGuire Nuclear Site was adequately and effectively implemented.

The inspectors reviewed the problem analysis and corrective actions in PIF O-M97-3085, 3086, and 3087. The problem analysis, as outlined in NSD 208, was good and the corrective actions were appropriate.

c. Conclusion

Safeguards audits were thorough, complete, and effective in uncovering weaknesses in the security system, procedures, and practices. The audit report concluded that the security program was adequately and effectively implemented, and recommended appropriate action to improve the effectiveness of the security program. The licensee analyzed the findings and acted appropriately in response to recommendations made in the audit report.

## 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 27, 1998. The licensee acknowledged the findings presented. The NRC Branch Chief for the Duke Energy sites was in attendance.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

Barron, B., Vice President, McGuire Nuclear Station
Bhatnagar, A., Superintendent, Plant Operations
Boyle, J., Civil/Electrical/Nuclear Systems Engineering
Byrum, W., Manager, Radiation Protection
Cash, M., Manager, Regulatory Compliance
Dolan, B., Manager, Safety Assurance
Evans W., Security Manager
Geddie, E., Manager, McGuire Nuclear Station
Herran, P., 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 40500: | Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems |
| IP 50001: | Steam Generator Replacement Inspection |
| IP 61726: | Surveillance Observations |
| IP 62707: | Maintenance Observations |
| IP 71707: | Conduct of Operations |
| IP 71750: | Plant Support |
| IP 81700: | Physical Security Program |
| IP 83750: | Occupational Exposure |
| IP 84750: | Radioactive Waste Treatment, and Effluent and Environmental Monitoring |
| IP 92901: | Followup - Operations |
| IP 92903: | Followup - Engineering |

## ITEMS OPENED, CLOSED, AND DISCUSSED

OPENED

| | | |
|---|---|---|
| 50-369,370/97-20-01 | IFI | Operation With Elevated Refueling Water Storage Tank Temperatures (Section O2.1) - |
| 50-370/97-20-02 | NCV | Improperly Locked Starting Air Valve 2VG82 for the Unit 2B EDG (Section O2.2) |

| | | |
|---|---|---|
| 50-369,370/97-20-03 | IFI | Emergency Procedure Adequacy for Coping wi+' a Tube Rupture in the RCP Thermal Barrier Heat Exchanger (Section E4.1) |
| 50-369, 370/97-20-04 | VIO | Failure to Deactivate And/or Deny Protected Area Access to Terminated Employees (Section S1.2) |
| 50-369, 370/97-20-05 | VIO | Failure to Control a Protected Area Access Badge (Section S1.2) |
| 50-369, 370/97-20-06 | NCV | Issuance of the Wrong Badge to an Individual and Failure to Correct the Mis-issuance Before the Individual Entered the Protected Area (Section S1.2) |

CLOSED

| | | |
|---|---|---|
| 50-369/96-04 Revision 0 andl | LER | Incorrectly Calibrated Reactor Coolant LOOP Loss of Flow (Section O8.1) |
| 50-369/96-01 Revision 1 | LER | Unit 1 Manual Reactor Trip Initiated as a Result of an Equipment Failure Caused by an Unknown (Section O8.2) |
| 50-370/96-04 | LER | Lightening Strike Initiated a Fault Resulting In An Automatic Start of EDG 2A (Section O8.3) |
| 50-370/96-05 | LER | ESF Actuation of the 2B EDG After Blakcout on Unit 2 Esstial Bus (Section O8.4) |
| 50-369/96-11-05 | VIO | Failure to Perform a 10 CFR 50.59 Review Prior to Performing a Test or Experiment Not Described in the UFSAR (Section E8.1) |
| 50-369,370/97-01-03 | VIO | Violation of 10 CFR 70.24 Requirements (EA 97-544) (Section R8.1) |
| 50-369,370/96-11-06 | IFI | Followup on Licensee Closeout Actions on PIP Number 2-M96-3238 (Section R8.2) |

# LIST OF ACRONYMS USED

ALARA - As Low As Reasonably Achievable
AFW - Auxiliary Feedwater
AP - Abnormal Procedure
ASME - American Society of Mechanical Engineers
CAS - Central Alarm Station
CCTV - Closed Circuit Television
CCW - Component Cooling Water
CFR - Code of Federal Regulations
COLR - Core Operating Limits Report
CR - Control Room
DES - Duke Engineering Services
DRPI - Digital Rod Position Indication
DRWM - Dynamic Rod Worth Measurement
EDG - Emergency Diesel Generator
EHRA - Extra High Radiation Area
ENS - Emergency Notification System
EP - Emergency Procedure
ESF - Engineered Safety Feature
F - Fahrenheit
GL - Generic Letter
HRA - High Radiation Area
IFI - Inspector Followup Item
IN - Information Notice
IR - Inspection Report
ISLOCA - Interfacing System Loss of Coolant Accident
KV - Kilo-volt
LER - Licensee Event Report
LLEA - Local Law Enforcement Agencies
LLI - Low Level Intake
LOCA - Loss of Coolant Accident
MEPR - Major Equipment Problem Resolution
MOV - Motor-Operated Valve
MSSV - Main Steam Safety Valve
NCV - Non-Cited Violation
NRC - Nuclear Regulatory Commission
NRR - NRC Office of Nuclear Reactor Regulation
NSD - Nuclear Site Directive
OAC - Operator Aid Computer
OMP - Operations Management Procedures
PAP - Personnel Access Portal
PCE - Personnel Contamination Event

| | | |
|---|---|---|
| PDR | - | Public Document Room |
| PIP | - | Problem Investigation Process |
| PM | - | Preventive Maintenance |
| PSP | - | Duke Power Company Nuclear Security and Contingency Plan |
| PT | - | Periodic Testing |
| RCA | - | Radiogically Controlled Area |
| RCS | - | Reactor Coolant System |
| RCP | - | Reactor Coolant Pump |
| RP | - | Radiation Protection |
| RWP | - | Radiation Work Permit |
| RWST | - | Refueling Water Storage Tank |
| SAS | - | Secondary Alarm Station |
| SFP | - | Spent Fuel Pool |
| SPP | - | Security Plan Procedures |
| SRWP | - | Special Radiation Work Permit |
| TB | - | Thermal Barrier |
| TEDE | - | Total Effective Dose Equivalent |
| TEPR | - | Top Equipment Problem Resolution |
| TM | - | Temporary Modification |
| TOOOM | - | The Oldest Open Ones Meeting |
| TS | - | Technical Specifications |
| UFSAR | - | Updated Final Safety Analysis |
| URI | - | Unresolved Item |
| USSI | - | Utilities Support Specialists Incorporated |
| USQ | - | Unreviewed Safety Question |
| VHRA | - | Very High Radiation Area |
| V | - | Volt |
| VIO | - | Violation |
| WAPR | - | Workaround Problem Resolution |
| WO | - | Work Order |
| ZPPT | | Zero Power Physics Testing |