U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report No: 50-369/97-01, 50-370/97-01

Licensee: Duke Power Company

Facility: McGuire Generating Station, Units 1 & 2

Location: 12700 Hagers Ferry Rd.
Huntersville, NC 28078

Dates: January 12, 1997 - February 22, 1997

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Enclosure 2

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 & 2
NRC Inspection Report 50-369/97-01, 50-370/97-01

This integrated inspection includes aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection and region based inspection.

Operations

- Operator actions to reduce unit power and realign main feedwater flow through the auxiliary feedwater nozzle following identification of a hydraulic fluid leak at main feedwater containment isolation valve 1CF26 was good (paragraph O2.1).

- Operator diagnosis of and response to the loss of Unit 2 isophase bus cooling and coincident rod control system malfunctions was good (paragraph O2.2).

- Operator response to the main generator voltage control problem was adequate. Improved guidance to operators regarding the degraded condition was provided by engineering in a timely manner (paragraph O2.3).

- Control of Unit 1 shutdown for refueling was adequate. Shutdown activities were conducted with minimal impact on the operating unit (paragraph O2.4).

- An URI was identified to continue inspection of an RCS leak through a letdown filter casing. Operator response to the event was good (paragraph O3.1).

- The station's monitoring of control room indication problems, as defined by the licensee's CRIP process, was considered to be adequately implemented. The inspectors also concluded that the process may be challenged during the upcoming Unit 1 OAC replacement project. The use of Control Room information tags was generally well implemented. The inspectors expressed a concern to Operations Management regarding potential overlapping of problem tracking processes, including the operator work around process, which could present confusion regarding problem monitoring and resolution (paragraph O4.1).

- A significant weakness was identified concerning inconsistencies between the critical action times modeled in the simulator and the actual plant response times during plant transients. The example noted could have adversely impacted operator response capabilities by training on the incorrect critical action times. Once identified, licensee immediate corrective actions and response to the concerns were considered adequate (paragraph O5.1).

- Control of overtime for plant personnel and postings to workers during this period was adequate. Licensee assessments performed on the control of overtime were detailed and provided good oversight (paragraphs O6.1 and O6.2).

- The results of the INPO evaluation completed in late 1996 were generally consistent with the results of similar evaluations conducted by the NRC. No additional NRC follow-up of any specific issue was identified (paragraph O7.1).

Maintenance

- Corrective maintenance activities associated with malfunctions of isophase phase bus cooling fans were thorough (paragraph M2.1).

- Control of non-tagout work activities was not sufficient to provide adequate controls to ensure proper tracking to prevent occurrences that may potentially result in personnel injuries and equipment damage (paragraph M3.1).

- The licensee's restructuring of the Maintenance and Work Control organizations to provide better distribution of responsibilities without disrupting the current Work Control process was adequate. The inspectors also noted that the restructuring should also enhance QA/QC independence (paragraph M6.1).

- The licensee was actively involved in evaluation and resolution of motor problems. The Root Cause Failure Analysis Report was thorough and identified several focus areas for improving motor performance. Even though some motor problems continued, the licensee's Quality Improvement Team initiative at McGuire had produced some positive results, and should improve motor performance if the initiative is continued (paragraph M7.1).

Engineering

- The inspector concluded that engineering personnel were performing in-depth reviews of the Refueling Water system design basis to ensure compliance in that area and to identify any potential problems. An IFI was identified regarding ongoing reviews of previous FWST design changes and the FWST current design basis (paragraph E2.1).

- Reviews of engineering activities which support operations by observations of engineering and operations personnel interfaces and review of active engineering material in the control rooms concluded that engineering was providing effective support to operations. The number of open evaluations/determinations was not abnormal. The quality of the determinations was good and the results were well documented (paragraph E2.2).

- The review of the 50.59 annual summary of changes, tests, and experiments concluded that the licensee has complied with the regulations (paragraph E3.1).

- The licensee's use of the trippable worth strategy in Mode 4 was considered conservative based on available information. The licensee's detailed evaluation of the practice confirmed that the issue was not a safety concern. The inspectors recognized the licensee's efforts and good questioning attitude (paragraph E4.1).

- The final root cause analysis and corrective actions for the Emergency Diesel Generator lubricating oil pressure sensing line issue appropriately addressed the problem (paragraph E8.1).

Plant Support

- A Violation of 10 CFR 70.24 (a)(3) was identified for failing to have established emergency procedures to address a potential criticality event. In addition, requirements to perform evacuation drills of the affected areas were also not met (paragraph R1.1).

Report Details

Summary of Plant Status

Unit 1 began the inspection period at approximately 100 percent power. On January 23, a power reduction to approximately 20 percent was made to allow for repairs to the main feedwater isolation valve 1CF26. The valve actuator had developed a fluid leak. After repairs were completed, the unit returned to 100 percent power. On February 11, Unit 1 began a coastdown power reduction leading to the U1EOC11 outage. The unit was shutdown on February 14, for the beginning of the planned 90 day outage. After an extended RCS crud burst to facilitate lower outage dose, the unit was cooled for defueling operations. At the end of the inspection period, Unit 1 was in progress of core offload.

Unit 2 began the inspection period at approximately 100 percent power. On January 21, a power reduction to approximately 70 percent was necessary due to the failure of one of the unit's isophase bus cooling fans and the inability to immediately start the backup fan. After adjustment of a limit switch, the backup fan was started and the unit was returned to 100 percent power the following day. The unit operated at approximately 100 percent power for the remainder of the inspection period.

Review of 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/or 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 professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below. The shutdown of Unit 1 for the planned 90 day refueling/steam generator replacement outage was well controlled and executed. In addition to the issues discussed in this report, other steam generator specific inspections are detailed in NRC Inspection Report 369/97-03.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Main Feedwater/Containment Isolation Valve 1CF26 Actuator Hydraulic Fluid Leak

On January 23, control room operators performed a rapid downpower of Unit 1 in accordance with Abnormal Procedure AP/1/A/5500/04 Rapid Downpower. The unit power was reduced to approximately 20 percent in response to a hydraulic fluid leak at valve 1CF26, Main Feedwater/Containment Isolation Valve to the "D" Steam Generator. Operators realigned main feedwater flow through the auxiliary feedwater nozzle to minimize the probability of a loss of feedwater to the generator due to the uncontrolled closure of 1CF26. The valve is located in the Feedwater System flowpath to the D steam generator main nozzle in the main steam vault. Valve 1CF26 is a safety related hydraulic isolation valve. The valve receives a signal to close on a Safety Injection, Low Tavg coincident with Reactor Trip, HI-Hi doghouse Water Level, or HI-HI steam generator level.

The inspectors noted that control room operator recognition of and response to the indications of the hydraulic fluid leak were good. The unit remained at reduced power until the leak could be repaired. Following the repair, testing was completed and the valve returned to service. The normal main feedwater flowpath was re-established and power escalated to approximately 100 percent with no additional operational challenges.

O2.2 Isolated Phase Bus Cooling Fan

a. Inspection Scope

The inspectors reviewed the licensee's response to the failure of the Unit 2 Isolated Phase Bus Cooling System and coincident malfunction of the Unit 2 Rod Control System.

b. Observations and Findings

On January 20, the Unit 2 IPB cooling fan 2A tripped. Operators were dispatched to start the standby 2B fan but attempts to start the standby fan were unsuccessful. As a result, control room operators began a rapid downpower in accordance with Abnormal Procedure AP/2/A/5500/04. While reducing generator load, operators recognized that the rod control system was not responding as expected to the Tavg-Tref mismatch. The operators took manual control of the rod control system and generator load control and stabilized generator output at approximately 70 percent and busline current less than 20,000 amperes. The reduction of busline current to less than 20,000 amperes was recommended to reduce the overheating electrical components. The standby 2B cooling fan was subsequently started when the suction damper limit switch was manually adjusted. The suction damper limit switch position must be established

prior to fan operation. Unit 2 returned to 100 percent power on January 21.

Work requests were generated to investigate and troubleshoot the IPB cooling system and rod control system malfunctions. See paragraph M2.1 for further discussion of these items.

c. Conclusions

The inspectors concluded that operator diagnosis of and response to the loss of IPB cooling and the coincident rod control system malfunctions was good. The inspectors also concluded that the load reduction, although not mandated by TS, was conservative.

O2.3 Unit 1 Voltage Regulator Perturbations

a. Inspection Scope

The inspectors reviewed operator response to a Unit 1 generator voltage fluctuation and its potential impact to the unit.

b. Observations and Findings

On February 11, 1997, operators responded to indications that the Unit 1 generator voltage was increasing for unknown reasons. Attempts were made to lower the voltage using the voltage adjust pushbutton with little effect. CR operators dispatched NLOs to locally investigate the problem. Within a short time, operators stopped the continued voltage increase; however, voltage swings were occurring. Transmission group personnel were called to assist in the troubleshooting effort. The maximum voltage seen during the transient was 25.45 kv and 713 MVAR. The swings lasted approximately one hour. The operators were eventually able to return the voltage to the normal range. The voltage swings were determined to not have adversely affected any major plant equipment.

The licensee installed a recorder on the control cabinet to attempt to determine what caused the voltage swings. During the shutdown of Unit 1 for the outage several days later, no additional problems were identified with the operation of the voltage regulator. The licensee determined that operator guidance could be improved regarding this type of anomaly and its potential impact on the plant. Procedural guidance was developed to place operating limits on the voltage swings to protect plant equipment. The licensee plans to continue troubleshooting of the problem during the Unit 1 outage and will perform a root cause investigation of the occurrence. Management focused the investigation on determining the problem due to a potential recurrence during unit restart from the outage.

c. Conclusions

The inspectors concluded that initial operator response to the main generator voltage control problem was adequate. Improved guidance to operators regarding the degraded condition was provided by engineering in a timely manner.

O2.4 Unit 1 Shutdown for Unit 1EOC11 Outage

a. Inspection Scope

The inspectors witnessed portions of the Unit 1 shutdown to Mode 4 focusing on special activities in progress that could impact safety system performance or reliability to verify that licensee controls were sufficient.

b. Observations and Findings

The inspectors witnessed portions of the Unit 1 shutdown for 1EOC11 on February 14. The unit entered Mode 3 on at 0412 and Mode 4 at 1438. The shutdown was controlled in accordance with Operating Procedure OP/1/A/6100/02, Controlling Procedure for Unit Shutdown. During the shutdown, the inspectors noted that on shift control room operators were attentive and responsive to plant parameter changes and communicated the changes to the appropriate shift personnel. Control room staffing met TS requirements and distractions were kept to a minimum in the horseshoe area. Operating conditions of plant equipment were adequately monitored and appropriate actions were initiated when necessary. Known steam generator 1B leakage remained below TS leakage limits with no unexpected increases. At the time of the unit shutdown, the leakage was approximately 60 gpd. Adequate core monitoring equipment was available and operable for the operational mode.

During the unit shutdown, the inspectors witnessed portions of ongoing surveillance activities including B Train EDG 24 hour surveillance run, 4160V essential power system realignment to support offsite and emergency power supply maintenance, and RCCA drop time testing to meet Generic Letter 96-01 commitments.

The licensee encountered some unexpected difficulties during the shutdown to Mode 5. The Source range channel N31 detector failed. Because the licensee had installed additional source range monitoring equipment, no significant safety concerns were identified. The rod drop time testing could not be completed in its entirety due to rod control malfunctions. The inspectors determined that no deviation from the Generic Letter 96-01 commitment existed. A primary system leak occurred on a letdown filter casing (see paragraph O3.1). At the close of the inspection reporting period, no enforcement actions were identified.

c. Conclusions

The inspectors noted that licensee response to unexpected occurrences was good and control of plant shutdown was adequate. Shutdown activities were conducted with minimal impact on the operating unit.

O2.5 50.72 Notifications

a. Inspection Scope

During the inspection period, the licensee made the following notifications to the NRC as required or for information purposes.

b. Observations and Findings

On February 15, 1997, operators made a 50.72 notification regarding excessive leakage from an isolable leak on the Unit 1 RCS letdown filter housing. The report was made under guidance provided by 10 CFR 50.72 (b)(1)(vi), where the leakage potentially could have hampered the performance of station personnel due to the localized requirement for anti-contamination clothing. Based on subsequent review, the licensee later retracted the notification based on their determination that the leak did not pose a threat to the safety of the plant or hamper station personnel.

c. Conclusions

The inspectors concluded that the notification was prudent and that the retraction was adequate for the circumstances. The inspectors also reviewed the occurrence for potential Notification of Unusual Event (NOUE) and concluded the criteria for NOUE was not established. Details of the event are discussed below.

O3 Operations Procedures and Documentation

O3.1 RCS Leakage in Excess of TS Limit During Letdown Filter Changeout

a. Inspection Scope

The inspectors reviewed events regarding an RCS leak which developed during changeout of the Unit 1 "A" RCS letdown filter. The unit was in MODE 4 and in process of being taken to MODE 5 for refueling preparations.

b. Observations and Findings

At approximately 2350 hours on February 14 a leak developed at the filter access plate on the 1A RCS letdown lter housing when operators detensioned the housing cover. Filter changeout was in progress due to an approximate 19 psi differential pressure reading which prompted the

activity (not uncommon during unit shutdown). The unit was in MODE 4 at the time of the leak and at an RCS pressure of approximately 300 psig. All four RCPs were in operation. The operators entered the appropriate abnormal response procedures and took actions (sampled) to identify the leak as either RCS or RMWST (RMWST is demineralized flush water which is utilized during filter changeout). The leakage was confirmed to be RCS and operators then isolated letdown, which stopped the leakage. Prior to repair of the leak area, operators raised a concern whether excess letdown could be adequately established given the low RCS pressure and whether pressurizer level should be reduced to increase the margin to solid RCS operations. After discussing the available options, Operations Management allowed letdown to be briefly reinitiated to allow for reduction of pressurizer level from approximately 80 to 40 percent. This and the placement of excess letdown in service allowed adequate repair time without challenging solid operaticns.

The leak was estimated at approximately 14 gpm. TS 3.4.6.2 requires that RCS identified leakage be limited to 10 gpm or reduce the leakage within 4 hours or be in Hot Standby within 6 hours and cold shutdown with in the following 30 hours. As stated, the unit was in MODE 4 at the time of the event and the leakage was secured within the allowable TS ACTION requirements. Cleanup of the leak was completed in a timely manner and the event did not result in any personnel contamination incidents. Initial licensee review of the event identified leakage through the letdown filter isolation valve, procedural weaknesses, and configuration problems with the installed letdown filter housing vent. The licensee is planning on performing a complete root cause investigation of the event. This issue will be identified as URI 50-369/97-01-01, Root Cause of RCS Letdown Filter leak.

c. Conclusions

The inspectors concluded that the operators were challenged by the RCS leak and reacted to the event in an appropriate manner. Root cause evaluations will be performed to address the identified URI.

O4 Operator Knowledge and Performance (71707)

O4.1 Tracking of Control Room Problems

a. Inspection Scope

During the inspection period, the inspectors reviewed a process by which the licensee monitors and trends control room indication problems and information tags on the control boards.

b. Observations and Findings

One method that the licen:e utilized to monitor CR problems is the Control Room Indicator Problem (CRIP) process. CRIPs are routinely

tracked by operations and reported to site management as a performance measure to assess the impact of the equipment concerns on plant operations. The program is defined by MSD 590. A CRIP is defined as a control room instrument or control that cannot perform its intended function, including any equipment problem which prevents a dark annunciator condition when required. In general, these devices provide information to CR operators on the status of plant equipment, provides input to control process parameters, controls equipment operated from the CR, and provides integrated information retrieval and display capabilities.

WRs are reviewed for applicability to the CRIP criteria as part of the work planning process. Per MSD 590, higher priority is given to those work requests identified as a CRIP. Innage CRIP work orders are expected to be planned to allow resolution of the problem within two weeks of origination. The status of CRIPs are monitored by maintenance management, operations, and work control.

The inspector discussed the CRIP process with involved plant personnel, performed CR walkdowns to determine if all relative issues were identified as CRIPs, and reviewed the historical completion of CRIP WRs. As of the end of 1996, the total number of innage CRIP's was eight with a YTD average of six. The oldest innage CRIP was less than two weeks, indicating that the work off was within the program guidance. The total number of outage CRIP work orders was approximately 40, with the expectation that all items would be resolved post outage. All equipment problems reviewed for CRIP applicability were found to be appropriately identified as such.

The inspectors also reviewed the CR information tagging process. This utilizes yellow information tags on a variety of CR equipment which allows operators to be informed about special equipment concerns, problems, or expected responses. The inspectors compared the current information tags to the CR information tag log and did not identify any major discrepancies. Some minor inconsistencies were found regarding tag issue information such as lead contacts or initiation dates. In general, operator awareness of the content of the information tags was considered adequate. All operators questioned were knowledgeable as to where to find additional information if necessary.

c. Conclusions

Based on the inspector's review, the station's monitoring of control room indication problems, as defined by the licensee's CRIP process was effectively implemented. The inspectors also concluded that the process may be challenged during the upcoming Unit 1 OAC replacement project. The use of CR information tags was generally well implemented. The inspectors expressed a concern to Operations Management concerning potential overlapping of problem tracking processes, including the operator work around process, which could present confusion regarding

problem monitoring and resolution. The licensee was receptive to the comments and was reviewing the issue for potential impacts.

O5 Operator Training and Qualification

O5.1 Differences in Assumed Simulator Response Times for Operator Actions

a. Inspection Scope

During the inspection period, the inspectors reviewed a licensee identified problem concerning discrepancies between actual plant equipment response times versus simulator modeling of certain operator time critical actions.

b. Observations and Findings

During an effort to verify that FSAR response times matched actual operator performance in transferring to RCS cold leg recirculation, the licensee identified several critical times which needed to be evaluated. Operators did not have problems completing the necessary steps prior to FWST depletion; however, critical times assumed in the simulator response were based on design assumptions that differed from actual plant performance. Specifically, the most significant example was identified where the simulator was modeled with the containment spray pump flow rate of approximately 3,400 gpm whereas actual plant flow rates were closer to 4,000 gpm. This incorrect modeling of the simulator could have potentially impacted operator response to a plant event by decreasing the time for critical operator action prior to FWST depletion. The inspector was specifically concerned that the incorrect simulator modeling had gone undetected for a long period of time and could have conditioned operators to expecting a certain amount of time to complete key actions during event response.

Upon recognition of the concern, operations reviewed the applicable procedures and identified numerous areas were enhancements could be made to increase the time allowed for critical action response. After the procedure enhancements were made, the procedures were re-validated with crew performance, indicating that the critical functions could be performed. In addition, operator training emphasized that since the FWST could deplete faster than the simulator model during a design base LOCA, operators may have been accustomed to exaggerated critical action time requirements in the past. The licensee also provided additional guidance which emphasized that key critical tasks should be performed "without delay". At the end of the inspection period, the licensee was continuing to evaluate other potential areas where operator critical time monitoring could be enhanced.

c. Conclusions

The inspectors concluded that the inconsistency between the critical action times modeled in the simulator and the actual plant response times during plant transients was indicative of a significant weakness. The example noted could have adversely impacted operator response capabilities by training on the incorrect critical action times. Once identified, licensee immediate corrective actions and response to the concerns were considered adequate.

O6 Operations Organization and Administration (71707)

O6.1 Overtime Controls

a. Inspection Scope

The inspector performed a review of approved overtime for the most recent months for the plant operations and maintenance groups. The inspector also overviewed licensee records of all personnel overtime exemptions for hours in excess of established limits. Control of overtime for plant personnel is required by Technical Specification 6.2.2.e and NSD 200, Overtime Control. These documents require the licensee to document and properly authorize work hour extensions.

b. Observations and Findings

The inspector reviewed work hour extension documentation for the subject groups and determined that the forms, in general, were properly filled out and reasons for the work hour extensions were appropriate for the circumstances. The inspector verified that the station manager was reviewing a monthly site overtime report to determine that the use of overtime was warranted and not being abused.

The inspector noted that in an overtime control report dated November 20, 1996, the licensee's evaluation of the data identified several discrepancies regarding the completeness of the required forms. The problems were documented in PIP 0-M-96-3399 for corrective action.

c. Conclusions

The inspector concluded that control of overtime for plant personnel during this period was adequate. In addition, the licensee assessments performed on the control of overtime were detailed and provided good oversight.

O6.2 Posting of Notices to Workers

During the inspection period, the inspector reviewed the licensee's compliance with the requirements of 10 CFR 50 Part 19.11, Posting of Notices to Workers. The licensee implements these requirements via NSD

205, Posting Requirements. This procedure identifies three locations where required postings are to be maintained. The inspector verified that the licensee conspicuously posted current copies of NRC Form-3 and other required materials such as escalated enforcement and radiological violations in the areas. No problems were observed by the inspectors during this review.

O7 Quality Assurance in Operations (40500)

O7.1 Review of Institute of Nuclear Power Operations (INPO) report

During the inspection period, the SRI and the NRC DRP Branch Chief, reviewed the most recent Institute of Nuclear Power Operations (INPO) report. The review concluded that the results of the INPO evaluation completed in late 1996 were generally consistent with the results of similar evaluations conducted by the NRC. No additional NRC follow-up of any specific issue was identified.

O8 Miscellaneous Operations Issues (92700)

O8.1 (CLOSED) LER 50-369/96-03: Inoperability of Both Unit 2 EDGs. This LER is closed based on reviews performed during the closure of Violation 369,370/96-07-07, Failure to Take Adequate Corrective Action for EDG Fuel Line Failure which is discussed in paragraph E8.3.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62707)

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, resident inspectors reviewed and/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.

a. Inspection Scope

The inspectors observed all or portions of the following work activities:

PROCEDURE/WO#	TITLE
• PT/0/A/4600/78	RCCA Drop Timing Using Rod Position Grey Code

- PT/1/A/4350/36B Emergency Diesel Generator 1B 24 Hour Run
- PT/1/A/4350/06 4160V Essential Power System Test
- PT/0/A/4601/08A SSPS Train A Periodic Test with NC System Pressure > 1955 Psig

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Malfunctions of Isophase Phase Bus Cooling Fans and Rod Control System

a. Inspection Scope

The inspectors conducted inspections to verify that activities to correct the isolated phase bus cooling system and rod control system malfunctions were conducted in manner to ensure safe and reliable equipment operation.

b. Observations and Findings

Maintenance technicians were contacted to identify and correct the cause for the 2A isophase bus cooling fan trip and subsequent 2B isophase cooling fan failure to start. Technicians investigated the cause for the 2A fan trip and determined that the 2A IPB fan tripped on thermal overload due to higher than anticipated area temperatures. The area ventilation had been secured resulting in elevated temperatures. The licensee determined that the thermal overload trip setpoint was overly conservative providing very little margin between normal operating ranges and the overload relay trip setpoints. The licensee developed and implemented modifications to replace the 2A and 2B thermal overloads to provide additional margin. The relay was replaced and functionally verified.

The licensee investigated the failure of the backup supply fan to start and determined that a limit switch at the fan outlet damper failed to provide the necessary interlock for the manual start of the standby fan.

A Work Request was written to investigate the rod control system failure to operate in automatic when the operators began reducing power. The licensee's investigations identified a comparator circuit card which controls the rods in-rods out function. The card was replaced. The licensee concluded that the rods would have operated properly following a manual or automatic reactor trip signal. The comparator circuit card was replaced and functionally tested. Rod control was returned to automatic. No other rod control malfunctions occurred prior to unit shutdown for refueling outage 1EOC11.

c. Conclusions

The inspectors concluded that the licensee's corrective maintenance was effective. Rod control system repairs were adequate. Isophase cooling relaying modifications and damper switch replacement should provide improved cooling system reliability.

M3 Maintenance Procedures and Documentation

M3.1 Work Control Process

a. Inspection Scope

The inspectors performed inspection of activities related to the unanticipated automatic trip of the "A" auxiliary electric boiler (AEB).

b. Observations and Findings

On January 10, the "A" AEB was started to support functional verification following completion of mechanical maintenance activities. The boiler was started and operated. Monitored parameters were normal with the exception of slow steam pressure response. The boiler tripped and station personnel observing boiler operation promptly exited the area. The licensee determined that the boiler tripped due to overcurrent conditions related to boiler ph levels. No station personnel were injured due to the boiler operation.

Prior to the boiler operation and subsequent trip, other maintenance on the 'A' AEB on the steam pressure control loop had begun and had not been completed prior to boiler operation. The steam pressure control valve, CB70 was closed with air removed. Completion of the maintenance activity was scheduled. No tags had been issued to perform this work. Technicians had provided information describing the maintenance effort on the boiler and had received authorization to perform the activity. The maintenance activity was not completed prior to shift turnover. During shift turnover, the information was not communicated to the oncoming operations shift and no tag clearance was necessary to operate the AEB. The inspectors noted that the work control for the particular work activity was not managed adequately to minimize the potential for personnel injury and/or equipment damage. The operation of the "A" AEB while IAE maintenance was ongoing was due to poor communications between operating shifts. The inspectors discussed the occurrence and determined that no information was readily available to inform the on-shift operations staff of the ongoing maintenance activity prior to boiler operation.

c. Conclusion

The inspectors reviewed the events and determined that control of no tagout work activities was not sufficient to provide adequate controls. Similar occurrences may potentially result in personnel injuries or equipment damage.

M6 Maintenance Organization and Administration

M6.1 Maintenance and Work Control Restructuring

The licensee made organizational changes in Maintenance and Work Control to re-establish consistency between the three Duke Power licensed facilities. The official restructuring was scheduled to be completed no later that June 1, 1997.

Under the new organization, Quality Assurance/Quality Control, Procedures, Planning, Clerical Support, Welding, and Modification Execution teams, previously under Maintenance will report to Work Control. This licensee concluded that this restructuring should better distribute responsibilities between Maintenance and Work Control and does not require changes to the current work control process. The restructuring should also enhance QA/QC independence.

M7 Quality Assurance in Maintenance Activities

M7.1 Review of Motor Reliability Problems/Improvement Initiative

a. Inspection Scope (62700 and 40500)

In June 1995, Duke Power Company identified that motor performance at nuclear power stations did not meet industry standards. McGuire, Unit 1 performance, based on Nuclear Plant Reliability Data System data, showed the highest failure rate for large motors of all nuclear sites in the country over a three year period. McGuire Nuclear Station established a Quality Improvement Team initiative to improve reliability of all motors at the station in September 1995. The licensee initiated PIP 0-M96-0204 to document the problem and corrective actions at McGuire. The inspectors reviewed corrective actions for PIP 0-M96-0204 including the Motor Reliability Improvement Initiative Report, specific motor problems and corrective actions, and conducted plant walkdowns and discussions with engineering personnel responsible for implementing corrective actions to improve motor performance.

b. Observations and Findings

A review of PIP 0-M96-0204 identified several motor problems and corrective actions taken to date. Motors identified with high failure rates included Condensate Booster Pump motors, "C" Heater drain Pump motors, Steam Generator Blowdown motors, Lower Containment Ventilation

motors, Control Rod Drive Mechanism Ventilation motors, Fuel Pool Cooling motors, Reactor Coolant Pump motors, Turbine Building Ventilation motors, Instrument Air Compressor motors, and motor/Generator Sets. The licensee identified specific causes of the failures for each motor type and instituted corrective actions in most cases. For example, the Fuel Pool Cooling motor problem was determined to be improper ventilation configuration resulting in lower than required lubrication levels for bearings. The ventilation was reconfigured to resolve the problem. The Reactor Coolant Pump Motor problem required refurbishment of each motor. This process has not been completed due to operational requirements and availability of only one spare motor for both McGuire and Catawba. However, the causes of past failures were understood, and corrective actions were scheduled.

The inspectors noted the licensee matrixed the causes of the motor failures in the Root Cause Failure Analysis Report in a Motor Fault Tree format. The report identified several problems associated with motor failures. Specific failure causes were identified as inadequate maintenance, lack of vendor quality control, and improper motor application. The licensee identified the root cause of the motor problems as a motor program management deficiency. The inspectors considered the licensee's failure analysis was properly focusing on problem areas.

The inspectors discussed the motor problems with engineering personnel and performed plant walkdowns to evaluate motor material conditions. In addition, preventive maintenance work orders and procedures were reviewed to evaluate adequacy of the licensee maintenance in this area. The reviews determined the licensee was focusing resources on preventive maintenance for motors which was based on causes of past failures and vendor recommendations. Observed conditions of motors in the plant were generally good. However, some items were identified which required additional disposition. One issue involved internal inspection of RHR (ND) and Containment Spray (NS) Pump motors. When questioned by the inspectors, the licensee could not provide documentation of motor internal inspections. The licensee initiated PIP 0-M97-0177 on January 16, 1997, to review and disposition this issue.

The inspectors also noted that the "C" Heater Drain Pump motors continued to exhibit some problems. During plant walkdown, the inspectors noted oil leakage from four of the six "C" Heater Drain Pump motors. In addition, the air filters on the side panels for the Unit 1 pump motors were dirty. These items were discussed with engineering personnel who stated they would be addressed as part of PIP 0-M96-0204 corrective actions. The licensee identified the root cause of these motor problems to be inadequate repair/refurbishment information available to motor repair shops. The licensee was working with

Westinghouse to provide appropriate repair information during future motor refurbishment. The inspectors concluded that this area requires continued licensee attention to assure appropriate corrective actions are implemented.

During this period, the inspectors noted several observations relating to plant processes and housekeeping. Positive observations included: low threshold for identification of issues in the problem investigation process, good housekeeping in the charging pump rooms, examples of good predictive maintenance/monitoring, good engineering response to issues, and a thorough Operations shift turnover in the control room on January 16, 1997. Other observations included staging located in RHR pump room 2A and Containment Spray pump room 1B. The inspectors discussed the staging observations with the operations shift on January 16, 1997. Operators stated they did not brief status of activities requiring staging in operable safety-related pump rooms at shift turnovers. Although the staging was appropriately tagged, the inspectors considered that activities involving staging in operational safety-related pump rooms should be minimized with appropriate operational focus being maintained.

c. Conclusions

The inspectors concluded the licensee was actively involved in evaluation and resolution of motor problems. The Root Cause Failure Analysis Report was thorough and identified several focus areas for improving motor performance. Even though some motor problems continued, the licensee's Quality Improvement Team initiative at McGuire had produced some positive results, and should improve motor performance if the initiative is continued.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Design Basis for the FWST and Surrounding Missile Wall

a. Inspection Scope (37551)

Review of design basis for the FWST and surrounding missile wall.

b. Observations and Findings

During the inspection period, the inspectors questioned the design basis for the FWST swapover function during post LOCA operator actions. Specifically, the inspector noted that the licensee's design did not incorporate an interlock between the automatic post LOCA injection realignment and actual containment sump levels. An interlock feature has been incorporated at other facilities, including Catawba, to ensure that appropriate containment sump levels exist after FWST depletion in order to ensure adequate suction supply to the ECCS pumps.

The licensee reviewed the inspector's concern and also other in-progress reviews that were being performed at other Duke facilities regarding the overall design basis of the FWST. It was determined that a discrepancy existed in the wall height of the FWST missile shield wall. Specifically, the height of the McGuire FWST missle wall was 2 inches below the height of the FWST to containment sump ECCS suction swapover level setpoint. The FWST missle wall was designed to protect the tank during a tornado event, assuring sufficient volume to make up for the RCS system shrinkage during a postulated steam line break. In this event, the centrifugal charging pumps would inject to offset the volume contraction and to provide a source of negative reactivity for criticality considerations.

The licensee performed extensive analysis of the concern which was documented in PIP 0-M97-0180. The licensee identified that a change was made in the mid 1980's which raised the automatic swap-over level set point from 100 inches to 150 inches. This change (NSM-MG-1-1790) made the swapover level relative to the bottom of the tank to be 170 inches. However, the missle wall was built to be 168 inches relative to the bottom of the tank. Therefore, a rupture of the tank at the missle wall height could potentially deplete the tank's volume below the auto swap level without the required containment sump inventory for cold leg recirculation. The licensee reviewed this scenario and concluded that since auto swapover aligns the low head ECCS pumps to the sump, the Low head (RHR) pumps would not be injecting due to the primary system pressure not falling below the pump's shutoff head. The review concluded that the RHR pumps would have sufficient volume in their mini-flow recirculation volume to not experience cavitation for the duration of the event. In addition, the high and intermediate head pumps would still have adequate suction supply from the FWST. The licensee concluded the FWST was both past and currently operable.

In addition to the above, the licensee identified several other questions regarding FWST design and operator actions associated with FWST depletion scenarios. At the end of the inspection period, the inspector was continuing to evaluate the licensee's engineering reviews of the FWST design and operability basis. The reviews will be identified as IFI 369, 370/97-01-02, FWST Design Basis.

c. Conclusions

The inspector concluded that engineering personnel were performing in-depth reviews of the FWST design basis to ensure compliance in that area and to identify any potential problems.

E2.2 Engineering Support of Operations

a. Inspection Scope (37550)

The inspector reviewed engineering activities which support operations by observations of engineering and operations personnel interfaces and review of active engineering material in the control rooms.

b. Observations and Findings

The inspector reviewed the open operability evaluations, the degraded but operable determinations and the ongoing evaluations. The evaluations and determinations were reviewed to ensure that they did not involve an unreviewed safety question and that the margin to safety was not decreased by the existing degraded condition. Reviewed were 13 operability evaluations, two ongoing evaluations, and three degraded but operable determinations.

c. Conclusions

The inspector concluded that Engineering was providing effective support to Operations. The number of open evaluations/determinations was not abnormal. The quality of the determinations was good and the results were well documented.

E3 Engineering Procedures and Documentation

E3.1 Changes, Tests and Experiments Performed In Accordance With 10 CFR 50.59 (April 1, 1995, to April 1, 1996)

a. Inspection Scope

By letter dated October 18, 1996, the licensee submitted its annual summary of all changes, tests, and experiments that were completed under the provisions of 10 CFR 50.59 for the period April 1, 1995, to April 1, 1996. The licensee's October 18, 1996, summary includes 82 changes made during the subject period. The inspector reviewed a number of these changes against the provisions of the regulation.

b. Observations and Findings

1. Background

10 CFR 50.59 provides that a licensee may (1) make changes in the facility as described in the safety analysis report, (2) make changes in the procedures as described in the safety analysis report, (3) conduct tests or experiments not described in the safety analysis report, without prior Commission approval, unless the change involves a change in the technical specifications or an unreviewed safety question (USQ). The regulation defines a USQ as a proposed action that (a) may increase

the probability of occurrence or consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report, (b) may create a possibility for an accident or malfunction of a different type than any previously evaluated in the safety analysis report, (c) may reduce the margin of safety as defined in the basis for any technical specification.

2. Procedures

The inspector reviewed the licensee's current (dated March 21, 1996) version of Nuclear System Directive (NSD) 209, "10 CFR 50 59 Evaluations," which is a procedure that describes how Duke Power Company (DPC) meets the requirements of 10 CFR 50.50. NSD 209 requires that changes be evaluated against appropriate Final Safety Analysis Report (FSAR), Technical Specifications, and NRC Safety Evaluation Report sections to determine if there is need for revision. Specifically, the procedure in NSD 209 has the criteria specified by 10 CFR 50.59 broken down into seven (7) questions. For a change to be qualified for 10 CFR 50.59, the answers to all seven questions must be "no".

3. Training

The licensee has a required training program for personnel that perform reviews of 50.59 screenings and evaluations. These personnel are known as Qualified Reviewers (QRs). A QR is defined by the licensee as an individual qualified by education, training and experience to perform the reviews for procedures, procedure changes and nuclear station modifications. Often preparers of procedures, procedure changes and nuclear station modifications are also qualified as QRs. A review of the training program determined that the program covered all the essential aspects of the 50.59 screenings and USQ evaluations.

4. Implementation

The implementation of the licensee's 50.59 program was evaluated by reviewing a sample of completed 50.59 screenings and USQ evaluations and interviewing personnel involved in the preparation or review of 50.59 screenings and USQ evaluations. The sample was taken from a total of 82 changes made between April 1995 and April 1996, that were reported in the licensee's annual summary of changes. Also, a review was done of a sample of "screened out" (determined not to require USQ evaluation) items that were randomly chosen from the licensee's files.

The inspector performed an in-office review of the licensee's summary to determine the nature and safety significance of each change. Through this review, the inspector selected the following changes for more detailed review onsite:

Procedure changes -

OP/ 1/A/6400/05, 1/A/6100/10K, 0/B/6200/109, 1/A/6200/04A,
2/A/6200/04A
EP/ 1/A/5000/FR-P.1, 1/A/5000/FR-I.1, 1/A/5000/ES-1.1,
1/A/5000/ECA-2.1, 1/A/5000/ECA-0.2, 1/A/5000/ECA-0.1,
1/A/5000/E-3, 1/A/5000/G-1
AP/ 1/A/5000/35
MP/ 2/A/7150/57, 0/B/7150/121
PT/ 1/A/4150/044

Modifications -

NSM 12096, 12279/P6, 12441, 22096, 22441, 22445, 22454,
22455,22457,22473, 29040/P22
MM 3409, 3416, 3860, 3866, 3919, 4039, 4040, 4045, 4097, 5451,
5452, 6164, 6165, 7067,7068, 7096, 7125, 7757

Revision to NRC commitments -

Monitoring eight break locations

Licensee "screened out" items -
OP/ 2/A/6100/23
EP/ 2/A/5000/ECA-2.1
EP/ 1/A/5000/FR-P.2
PT/ 1/A/4206/03A (CHANGE 13)
IPOA 3207007

During the in-office and onsite reviews, the inspector made a number of observations as noted below and has communicated them to licensee personnel:

- A good self-assessment was recently performed on the 50.59 process at Catawba. McGuire has utilized the results of this self-assessment by incorporating the lessons learned into their 50.59 process.

- NSD 209 represents a solid foundation for the 50.59 process and should serve the three stations well, provided the licensee is diligent in getting personnel to correctly implement the Directive's requirements.

- Minor administrative problems, which were similar to those identified by the licensee in the above mentioned self-assessment, were found in the McGuire 50.59 packages. These included:

  - Blocks on some of the 50.59 forms were not checked as required by NSD 209.

- Illegible preparer and QR signatures were noted on some forms.

- The justification write-ups for some 50.59 packages did not clearly address the questions asked on the 50.59 form.

c. Conclusion

Based on the review of the licensee's October 18, 1996, annual summary on 10 CFR 50.59 changes, and audit of the licensee's procedures and evaluations, the inspector concludes that the licensee has complied with the provisions of this regulation for the changes reported in the annual summary.

E4 Engineering Staff Knowledge and Performance

E4.1 Shutdown Bank Trippable Worth Strategy

a. Inspection Scope (37551)

The inspectors reviewed the licensee evaluation of withdrawing shutdown banks while in Mode 4 to provide additional shutdown reactivity.

b. Observations and Findings

The licensee held PORC meetings to review and evaluate the practice and determined that a no potential existed for a noncompliance with assumptioNs used in UFSAR accident analyses. Some questions were raised about the assumptions used in the uncontrolled bank withdrawal from zero power analysis. The PORC concluded that the assumptions of the current UFSAR uncontrolled rod withdrawal analysis bound any credible unexpected rod withdrawal power transient.

The current UFSAR analysis assumes that the reactor is critical such that the first available trip is the 25 percent low power trip. This assumption allows for an extremely fast reactivity addition, allowing the reactor to reach a prompt critical condition. This results in a severe power, temperature and pressure transient by withdrawal of shutdown banks. With the unit subcritical, in MODE 4, operators would receive the high flux at shutdown alarm at one half decade above background counts and the reactor would also encounter the source range trip at 10E5 cps. Therefore, a real rod withdrawal event from subcritical conditions could be terminated by operator action or automatically with the reactor significantly subcritical. There would not be a resulting reactor coolant system temperature or pressure transient. Therefore, the consequences of such an event were determined to be bounded by the current analysis.

Following the PORC, the licensee concluded that the withdrawal of shutdown banks A and B would not place the plant in a degraded condition with regards to an uncontrolled bank withdrawal event. As a result, the

licensee revised the existing shutdown and startup procedures to allow control room operators to close the reactor trip breakers and withdraw pre-selected shutdown rod banks during Modes 3 and 4.

c. Conclusions

The inspectors concluded that the licensee's use of the trippable worth strategy was conservative based on available information. The inspectors identified no TS noncompliances or UFSAR deviations. The inspectors reviewed the results of the licensee's evaluation and concluded that the practice of early withdrawal of a shutdown bank to provide a means for immediate negative reactivity addition during a dilution was conservative.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Violation 50-369, 370/96-02-02: Failure to Correct Long Term Deficiencies Resulting in Valid Failures of EDGs.

The issue involved emergency diesel generator failures due to inadequate design of the lines for lubrication oil pressure sensing instrumentation and control. The licensee responded to the Violation in a letter dated June 6, 1996. In that letter, the licensee stated they took corrective actions including conducting a root cause failure analysis and identifying corrective actions. The corrective actions included periodic maintenance to vent the lubrication oil pressure loops, periodic testing of the lubrication oil impulse lines, and implementation of a modification on the Unit 2 emergency diesel generator lubrication oil instrumentation lines to shorten the lines.

The inspectors reviewed the licensee's root cause analysis report (PIP 2-M-96-0331), verified other corrective actions were implemented as stated, and observed routine testing of the 1B EDG on January 14, 1997. All equipment performed as required. Implementation of the modification to shorten the Unit 1 lubrication oil instrumentation sensing lines was scheduled for the next refueling outage commencing in February 1997. The inspectors determined that corrective action without the modification in place for Unit 1 was adequate; however, based on Unit 2 test results, the modification provided additional margin to prevent recurrence of the problem. The inspectors concluded the root cause analysis and corrective actions for the EDG lubricating oil pressure sensing line issue appropriately addressed the problem.

E8.2 (CLOSED) DEV 50-369,370/96-07-04: Failure to Comply with Commitments in Response to Generic Letter 88-03 Steam Binding of Auxiliary Feedwater Pumps

This deviation involved the failure of the licensee to provide continuous monitoring to detect steam voiding that was not accomplished due to the installation of an incorrect type of resistance thermal detector (RTD). These RTDs provide indication of auxiliary feedwater piping temperature and activation of control room alarms when temperatures exceeded established administrative limits. In addition, inadequate compensatory measures were taken once the problem was identified. The inspector noted that the licensee had installed RTDs of the correct type to provide continuous indication of CA piping surface temperatures and alarms. This deviation is closed.

E8.3 (CLOSED) Violation 50-369,370/96-07-07: Failure to take Adequate Corrective Action for EDG Fuel Line Failure and LER 50-369/96-03 Rev 1.

On June 19, 1996, the licensee experienced a failure of the 4R cylinder fuel line on the 1B EDG. The licensee issued a root cause evaluation report of the 1B EDG fuel line failure on the 4R cylinder. The failure was attributed to tube pullout of the 4R cylinder fuel injection line to fuel pump connection. Specifically, the report concluded the line had ejected from the ferrule connection due to inadequate crimping of the ferrule to the tube. All the fuel lines on the Unit 1 EDGs had been upgraded to a new double-walled tube design in December 1995 to prevent through wall crack propagation. The Unit 2 EDGs fuel lines were previously replaced (all but four were upgraded double-wall) during earlier unit refueling cycles and had not experienced any failures. Corrective actions were developed to re-crimp all applicable EDG fuel lines on Unit 1 and the four selected fuel lines for the Unit 2 EDGs. These actions were scheduled to occur concurrent with the routinely scheduled EDG outage days (i.e., one EDG per month) to minimize unavailability. On July 30, 1996, the licensee experienced an additional failure of the 1B EDG 4R cylinder, prior to performing the re-crimping as discussed above. Based on the second failure at the same location, the licensee expanded their original root cause investigation process and obtained the services of two separate vendors to act as oversight for the failure analysis and to provide technical expertise. The second revision to the root cause analysis concluded that the most likely cause of the second failure was improper crimping of the sleeve onto the fuel line, possibly aggravated by some pressure increase at the fuel pump outlet. The licensee also concluded that the monitoring of cylinder exhaust temperatures was not as good of a failure indicator as previously expected.

Based on the revised root cause, the licensee significantly expanded their corrective actions. These PORC reviewed actions included:

- For the 1B EDG, fuel lines were re-crimped, fuel line ends were machined for proper ferrule positioning, and a 16 hour run performed to verify the re-crimping process.

- Replaced both injector and fuel pump on the 4R cylinder and inspected the two additional injectors for contamination. No contamination was identified.

- Ferrule connections and the crimping process was reviewed by an industry expert.

- Removed, re-crimped, machined tube ends, and reinstalled all fuel injection lines for the 1A, 2A, and 2B EDGs in an expedited manner.

The inspector reviewed the licensee's response to a Notice of Violation dated, October 24, 1996, and the corrective actions included in that response. The inspector reviewed Revision 4 to MCS-1301.00-000007, dated January 16, 1997, the EDG spare parts specification. This specification had been revised to address the new fuel line crimping and dimensional requirements. Procedures MP/0/A/7400/009, Nordberg Diesel Engine Cylinder Head Removal and Installation, Rev 13, and MP/0/A/7400/01, Nordberg Diesel Engine Fuel Oil Injection Pump Removal, Installation and Lift to Port Closure Check, Rev 5, were reviewed to ensure the new crimping and dimensional checks had been included. The inspector reviewed the Nordberg Diesel Owners Group Recommended Maintenance Program, undated, to verify that it contained a six-year recommendation to clean the injector spray tips. The inspector observed the spare fuel lines in the warehouse for proper crimping. This had been accomplished under WO 96087369. The engineering training package discussing the fuel line failures and lessons learned was reviewed. Based upon the above reviews and observations, this item and LER 50-369/96-03, Revision 1 is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Review of Criticality Monitoring Requirements

a. Inspection Scope

Review of the licensee's compliance with criticality monitoring and associated requirements contained in 10 CFR 70.24 (a).

b. Observations and Findings

During the inspection period, the inspector reviewed the licensee's actions to comply with the requirements of 10 CFR 70.24 (a). The purpose of 70.24 (a) was to require monitoring, procedural guidance, and emergency drills, unless a specific exemption was granted to the requirements. The licensee's monitoring capability in the area of the new fuel receipt/ spent fuel pool areas consisted of two detectors in the new fuel vault and one detector on the refueling bridge. 70.24(a), in general, requires that a monitoring system be capable of detecting a criticality within a required time frame. The coverage of the monitoring system in all areas shall be

provided by two detectors. In addition, appropriate drills and procedures shall be established as part of the requirements.

The licensee had previously received an exemption from the applicable 70.24 monitoring requirements as part of their special nuclear material (SNM) license during construction; however, the licensee did not request an additional exemption once the construction license terminated. The inspectors discussed the status of their current compliance with 70.24 (a) and determined the following:

- No emergency procedures were in place for evacuation of the applicable areas nor were evacuation drills performed as required by 70.24 (a)(3). At the end of the inspection period, the licensee had developed emergency procedures and were planning the performance of evacuation drills prior to the receipt or movement of any new fuel. The inspector verified that the new fuel inspection and storage procedures were on hold status such that new fuel would not be received prior to procedure training and drill completion.

- Once identified to the licensee, prompt actions were taken to submit an exemption request to the Commission (dated February 4, 1997) on behalf of the McGuire, Catawba, and Oconee sites. On February 13, 1997, the NRC requested additional information regarding the licensee's compliance with 70.24 requirements. As of the end of the inspection period, NRR review of the exemption request was still in progress.

c. Conclusions

The inspector discussed the above findings with NRC management and reviewed the regulatory significance. Based on the review, a Violation of 10 CFR 70.24 (a)(3) was identified for failing to have established emergency procedures to address a potential criticality event. In addition, requirements to perform evacuation drills of the affected areas were also not met. This will be identified as Violation 50-369, 370/97-01-03, Violation of 10 CFR 70.24 Requirements.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 24, 1997. The licensee acknowledged the findings presented.

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
Boyle, J., Civil/Electrical Systems Engineering
Byrum, W., Manager, Radiation Protection
Cline, T., Senior Technical Specialist, General Office Support
Cross, R., Regulatory Compliance
Davison, Valve Supervisor
Dolan, B., Manager, Safety Assurance
Geddie, E., Manager, McGuire Nuclear Station
Harley, M., Engineering Supervisor
Herran, P., Manager, Engineering
Jones, R., Superintendent, Operations
Karriker, S., Valve Engineer (Site GL 89-10 Program Lead)
Kunkel, N., Senior Engineer
Lamb, J., Valve Engineer
Michael, R., Chemistry Manager
Nazar, M., Superintendent, Maintenance
Painter, D., Valve Engineer
Sample, M., Manager, Steam Generator Maintenance Group
Setzer, F., Valve Engineer
Snyder, J., Manager, Regulatory Compliance
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical/Nuclear Systems Engineering
Tuckman, M., Senior Vice President, Nuclear Duke Power Company
Welch, T., Engineering Supervisor

NRC

S. Shaeffer, Senior Resident Inspector, McGuire
M. Sykes, Resident Inspector, McGuire
P. Kellogg, Regional Inspector
W. Holland, Regional Inspector

INSPECTION PROCEDURES USED

IP 71707: Conduct of Operations
IP 40500: Self Assessment
IP 92700: Miscellaneious Operations Issues
IP 62703: Maintenance Observations
IP 61726: Surveillance Observations
IP 37550: Engineering
IP 37551: Onsite Engineering
IP 92902: Miscellaneous Engineering Issues
IP 71750: Plant Support
IP 37550: Engineering Staff Knowledge and Performance

ITEMS OPENED, CLOSED, AND DISCUSSED

OPENED	TITLE
URI 50-369/97-01-01	Root Cause of RCS Letdown Filter leak (paragraph O3.1)
IFI 50-369,370/97-01-02	FWST design basis (paragraph E2.1)
VIO 50-369,370/97-01-03	Violation of 10 CFR 70.24 Requirements (paragraph R1.1)

CLOSED	TITLE
VIO 50-369,370/96-02-02	Failure to Correct Long Term Deficiencies Resulting in Valid Failures of EDGs (paragraph E8.1)
LER 50-369/96-03	Inoperability of Both Unit 2 EDGs (paragraph O8.1)
DEV 50-369,370/96-07-04	Failure to Comply with Commitments in Response to Generic Letter 88-03 Steam Binding of Auxiliary Feedwater Pumps (paragraph E8.2)
VIO 50-369,370/96-07-07	Failure to take Adequate Corrective Action for EDG Fuel Line Failure and LER 50-369/96-03 Rev 1 (paragraph E8.3)

LIST OF ACRONYMS USED

AEB - Auxiliary Electric Boiler
CA - Auxiliary Feedwater System
CR - Control Room
CRIP - Control Room Indicator Problem
DRP - Division of Reactor Projects
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
FWST - Refueling Water Storage Tank
IFI - Inspector Followup Item
IPB - Isolated Phase Bus
LER - Licensee Event Report
LOCA - Loss of Coolant
MVAR - Mega Volts Amperes Reactive
NCV - Non-Cited Violation
NLO - Non-licensed Operator
NRC - Nuclear Regulatory Commission
NRR - NRC Office of Nuclear Reactor Regulation
PDR - Public Document Room
PIP - Problem Investigation Process
PMT - Post Maintenance Test
PORC - Plant Operations Review Committee
RCCA - Rod Cluster Control Assembly
RCS - Reactor Coolant System
RHR - Residual Heat Removal
RTD - Resistance Temperature Detector
SNM - Special Nuclear Material
SRI - Senior Resident Inspector
TI - Temporary Instruction
TS - Technical Specification
UFSAR - Updated Final Safety Analysis Report
URI - Unresolved Item
VIO - Violation
WO - Work Order
WR - Work Request