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REGION II

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Licensee: Duke Power Company

Facility: McGuire Generating Station, Units 1 & 2

Location: 12700 Hagers Ferry Rd.
Huntersville, NC 28078

Dates: June 15 - July 27, 1996

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Enclosure 2

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 & 2
NRC Inspection Report 50-369/96-06, 50-370/96-06

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by regional specialists and inspectors.

Operations

- Unit 2 reduced inventory conditions were well controlled to facilitate coupling of the repaired RCP motors (O1.2).
- Operators took appropriate actions to initiate a Unit 1 TS required shutdown in response to the inoperability of both EDGs (O1.3).
- A review of existing programmatic controls for monitoring and controlling switchyard activities concluded good controls have been established (O2.1).
- The inspectors identified a second example of NCV 369,370/96-04-03 regarding a failure to make a required 10 CFR 50.72 report. The licensee modified governing procedures to correct this NRC identified problem (O4.2).
- A good station self-assessment on procedure reviews was followed by weak corrective actions (O7).

Maintenance

- Examples of inattention to detail were identified by inspectors during material condition walkdowns of the Unit 2 lower containment (M1.2).
- An example of poor test planning and implementation was identified regarding ampacity testing on one of the stations vital batteries (M1.3).
- Overall review of corrective maintenance activities was adequate; however, specific review of activities regarding the WZ sump pump concluded that the process for identifying potential root causes could have been improved (M2.1).
- A negative trend was identified regarding overall site motor performance (M4.1).
- A weakness was identified concerning the handling of Rx trip and bypass breakers during maintenance (E7.1).

Engineering

- An Unresolved Item was identified concerning the failure of the 1B EDG fuel line coupling. The inspectors also concluded that followup on the 1A EDG voltage regulator problems did not occur as planned due to inadequate communications of expectations to vendor personnel (E1).

- An Unresolved Item was identified regarding refueling practices involving full core off load into the SFP as described by the FSAR (E3.1).

- An example of poor communications between engineering and operations was identified regarding the status of Unit 2 rod bank annunciation. Operators were not made aware of known problems with rod control annunciation, resulting in stopping the reactor startup to resolve the concern (E4.1).

- A Violation was identified regarding a failure to incorporate vendor data into reactor trip breaker maintenance procedures (E7.1).

- An Unresolved Item was identified regarding design of equipment used to implement TS required containment air lock surveillances (E7.2).

- Implementation of control room ventilation (VC) system modification was postponed indefinitely based on NRC questioning operability impact on both trains. The inspectors concluded that further licensee reviews were warranted to incorporate actual TS operability impact of the proposed modification to the VC system (E7.3).

- Temporary Modifications were adequately monitored and controlled (paragraph E2). System engineering knowledge and familiarity with assigned systems was adequate (paragraph E4). Examples were noted of good problem identification by System Engineering (paragraph E4). Adequate training was provided for Engineering performance of 10 CFR 50.59 Safety Reviews (E5).

Plant Support

- Reviews in the area of radiological controls concluded that the licensee had effectively implemented a program for shipping radioactive materials required by NRC and DOT regulations; had adequately maintained effluent and environmental monitoring equipment to support plant activities; and effectively controlled radiation doses to members of the public well below regulatory limits (R1.1, R2, and R3).

- Good personnel safety and ALARA practices were noted for a decision to place Unit 2 in cold shutdown for replacement of a failed IR detector (R4.1).

- The self assessments program continued to be adequate in identifying items of substance for corrective action relating to the radiation protection program. However, additional examples of licensee recommended changes to the FSAR will be added to URI 96-04-02 (R.8).

- Licensee review of the impact of a new stadium near downtown Charlotte concluded it did not adversely impact existing emergency preparedness plans (P2.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On June 19 a TS required reactor shutdown was initiated due to the inoperability of both of the Unit 1 EDGs. The shutdown was secured at approximately 38 percent power when the 1B EDG was returned to operable status. The unit then returned to 100 percent power. On July 3 the unit was manually reduced to 86 percent power to allow for repair of a leak identified on the turbine EHC system. The unit was returned to rated power and operated at rated for the remainder of the inspection period.

Unit 2 began the inspection period in cold shutdown (MODE 5) completing repairs to the RCP motors. The motors were repaired and returned to service without incident. On July 29 the unit entered startup (MODE 2); however, the startup was secured due to erratic operation of one of the intermediate range detectors. Following investigation, the unit was returned to MODE 5 (cold shutdown) to replace the failed IR detector. On July 3 the unit was restarted and subsequently operated at or near 99 percent power, limited at that power level due to reduced steam pressure from excessive S/G tube plugging and constraints on turbine governor valve positions. On July 26 the licensee implemented a change to the normal secondary heater string operation which allowed the unit to achieve 100 percent power for the remainder of the inspection period.

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.

O1.2 Unit 2 Reduced Inventory Operations

a. Inspection Scope (71707)

Unit 2 entered reduced reactor coolant system inventory conditions in order to recouple and align reactor coolant pump motors after repairs. The draindown to the reactor coolant pump flange level was necessary to reinstall three of the Unit 2 reactor coolant pump motors. The licensee did not enter midloop operation and nozzle dams were not installed. Prior to entering reduced inventory operations, the inspectors reviewed the operations and maintenance schedules to identify any potential periods of high risk. The inspectors focused on activities that may result in reactor coolant system level perturbations and/or loss of shutdown cooling. None were identified. The inspectors also confirmed that the licensee had procedures in place to provide control during reduced inventory conditions.

b. Observations and Findings

Briefings were conducted by licensee management prior to entering reduced inventory to prepare the operating shifts for the infrequently performed evolution. Management expectations and safety concerns were emphasized during the briefing. Plant status was reviewed with particular interest on reactivity management, decay heat removal capability, containment integrity, reactor coolant system inventory, power availability, and spent fuel pool cooling. This information was reviewed and discussed routinely during the licensee's plan of the day meetings. The inspectors verified the accuracy of the information during daily control room visits.

Offsite and emergency power sources were confirmed to be available. The reactor coolant system temperature was monitored by using core exit thermocouples and residual heat removal system inlet temperature. Independent indications of reactor coolant system level were operable. Reactor coolant system makeup methods were available including the residual heat removal system and high head safety injection system with the necessary flow path from the refueling water storage tank to the reactor. The inspectors verified that controls were in place for reactor coolant system venting during reduced inventory conditions. A containment closure coordinator was also assigned to Unit 2 to monitor the status of any closure exceptions to ensure that they could be promptly closed, if required.

c. Conclusion

The inspectors determined that the licensee exhibited adequate safety focus in preparing for the reduced inventory operation. The evolution was well coordinated and executed. Maintenance completed the recoupling and alignment of the reactor coolant pump motors and reinstallation of the supports and auxiliary systems in accordance with procedures with little or no rework. The inspectors considered licensee controls of plant conditions to be appropriate and shutdown risk awareness was adequate.

O1.3 Notification of Unusual Event - Two EDG'S Inoperable

a. Inspection Scope (93702)

On June 19, 1996, at 6:30 a.m. EST, with Unit 1 at 100 percent power, a Notification of Unusual Event (NOUE) was declared based on the two Unit 1 EDGs being incapable of powering the 4160 Volt essential busses for greater than 2 hours. The 1A EDG was originally declared inoperable at 9:22 a.m. EST on June 18, 1996, due to the identification of erratic voltage regulator operation during post maintenance testing. Following replacement of a voltage regulator circuit card and potentiometer, the 1A EDG was retested and subsequently failed to reach required voltage. Due to the 1A EDG being inoperable, the licensee performed testing of the 1B EDG as required by TS within 24 hours. During this testing, the 1B EDG developed a fuel oil leak on a coupling at an injector pump to injector line. The 1B EDG was shut down and declared inoperable at 4:30 a.m EST on June 19, 1996.

b. Observations and Findings

The inspectors were made aware of the EDG problems and responded to the site prior to the declaration of NOUE. Repair activities were immediately initiated on the 1B EDG fuel leak. Due to the loss of onsite emergency power supplies, the licensee entered ACTION b. of TS 3.7.1.2, which requires that with two motor-driven AFW pumps incapable of being powered from separate emergency busses, place the unit in at least HOT STANDBY within 6 hours. The licensee initiated a unit shutdown at 5:30 a.m. EST.

Per the licensee's Emergency Plan, with both EDG's being inoperable for greater than two hours, a Notification of Unusual Event was made at 6:30 a.m. EST. The licensee completed expeditious repairs to the 1B EDG fuel coupling, successfully tested, and declared the 1B EDG operable at 9:32 a.m. EST. The licensee subsequently exited the NOUE at 9:32 a.m. EST and secured the unit shutdown at approximately 38% power. The unit was returned to 100 percent power and technicians continued troubleshooting the 1A EDG voltage regulator problem and developing a root cause failure mechanism for the failed 1B EDG fuel line coupling.

On July 20 technicians completed additional troubleshooting and repair to the 1A EDG including replacement of a voltage regulator control board and motor operated controlled potentiometer. Required testing was performed and the 1A EDG was declared operable. Further review of the 1A and 1B EDG problems are discussed in section E1 of this report.

c. Conclusions

The inspectors concluded that operators took appropriate actions to initiate a Unit 1 TS required shutdown in response to the inoperability of both EDGs. The power reduction was well controlled and the Emergency Classification was made in a timely manner.

O1.4 Unit 2 ESF Actuation (71707)

On July 22 during the performance of PT/2/A/4350/26E, Auxiliary Shutdown Panel Control Verification for B Train Components, an ESF actuation occurred because of an inadvertent swap from the normal suction to the assured nuclear service water supply for CA pumps. The test was being performed to verify the operability of the pushbuttons, switches and controllers located in the Auxiliary Shutdown Panel, the B CA Pump

Panel, and on the CA Pump Turbine Control Panel. The swapover to the assured service water supply normally occurs on low CA pump suction pressure. The licensee is currently evaluating the event to determine a root cause. The licensee reported the event to the NRC under 10 CFR 50.72 requirements. However, the report was later retracted, on August 1, based on subsequent analysis concluding that movement of the subject valves in and of itself did not meet the criteria for ESF Actuation (i.e. the AFW pump did not start and the valve movement alone would not affect the consequences of an accident.

O2 Operational Status of Facilities and Equipment

O2.1 Switchyard Controls

a. Inspection Scope (93702)

During the inspection period, the inspectors reviewed the licensee's process for controlling work activities in the high voltage switchyard. The inspectors performed this review based on the PRA analysis revealing the increased potential for a loss of switchyard event due to the location of the yard in relation to the site.

b. Observations and Findings

The overall governing procedure for access to the McGuire switchyard is NSD 502. Enhancements have been incorporated to improve access controls, increase the reliability of the offsite power sources, and to minimize the risk to plant operation. The procedure established the presence of a Switchyard Coordinator stationed at the McGuire switchyard. The Switchyard Coordinator acts as the single point of contact for the McGuire switchyard and serves as the primary interface between the power delivery operating groups and the McGuire control room. The Switchyard Coordinator is responsible for controlling access in and out of the switchyard. This includes maintaining the switchyard gate in a secured position, controlling access of all individuals into the yard, communicating with the McGuire control room SRO, and maintaining a log of individuals accessing the switchyard.

The inspector reviewed the controls established by NSD 502. The inspector confirmed that all current switchyard work was governed by a job sponsor and coordinated through the control room SRO and the Transmission Control Center (TCC). The inspector noted that all switchyard work maintenance activities are controlled by a WMS work order and the switchyard is included in the McGuire PRA matrix. A pre-job briefing is conducted prior to work beginning in the switchyard and the Switchyard Coordinator ensures that the control room SRO is in agreement with the work activity. The inspector observed examples where McGuire operations informed the coordinator when there was scheduled plant work or degraded plant conditions that could impact work/operations within the switchyard. Both the control room SRO and the switchyard coordinator were empowered to halt work in the switchyard if the need arises.

c. Conclusions

The inspector concluded that the licensee had established good controls over work activities in the high voltage switchyard. The inspectors also concluded that the establishment of a Switchyard Coordinator greatly enhanced the licensee's ability to maintain adequate oversight for this PRA significant system.

03 Operations Procedures and Documentation

03.1 Bypass of High Pressure Feedwater Heaters

a. Inspection Scope (71707)

On July 19, 1996, the licensee implemented measures to increase Unit 2 power generation from 99 to 100 percent following the recent outage. Since returning to power, Unit 2 has operated at less than 100 percent due to the large number of steam generator tubes that have been plugged. The licensee developed a method to increase power by by-passing some feedwater flow around the high pressure feedwater heaters via throttling High Pressure Heater Bypass valve, 2CF-75. Throttling this valve reduces the high pressure heater extraction flow resulting in lowering final feedwater temperature. The lower feedwater temperature increases the enthalpy rise across the steam generators. The net effect is an increase in generator output.

b. Observations and Findings

The inspector observed the licensee attempt to increase power by slowly throttling open the High Pressure Heater Bypass valve, 2CF75. The evolution was performed using enclosure 4.4. of OP/2/A/6100/03, Controlling procedure for Unit Operation, High Pressure Heater Bypass. The inspector reviewed the procedure and noted no discrepancies. The inspector also noted that the licensee conducted a detailed pre-job brief prior to implementing the procedure. The inspector noted evidence of good planning. For example, communications were established between the control room and personnel required to manipulate the valve. Good command and control by shift operations supervisory personnel was also evident. The inspectors noted that licensee engineering management oversight was provided throughout the entire initial evolution. The licensee was cognizant of the impact of this evolution on the plant including reactivity management caused by bypassing the high pressure feedwater heaters.

The inspectors noted that some unanticipated minor failures complicated the initial attempts to increase power. These failures included the valve's manual clutch and an OAC computer card. On July 26 the licensee successfully increased the unit to 100 percent power.

The inspectors questioned the licensee concerning the lack of an erosion evaluation of the associated feedwater piping prior to repositioning the bypass valve. The inspectors were informed that currently, reviews to determine what the effects are, if any, on secondary piping (for erosion) are performed on a post-modification basis or after changes to system configurations. The inspectors discussed with the licensee a potential for this review process not allowing erosion problems to be detected in a timely manner. The inspectors recognized that most erosion problems occur after extended periods of operation; however, the inspectors also concluded that the erosion review process may warrant further evaluation. The licensee is currently evaluating the inspectors comments.

c. Conclusion

The inspector concluded that the licensee's implementation of measures to increase plant generation output was good.

O4 Operator Knowledge and Performance

O4.1 10 CFR 50.72 Reportability

a. Observations and Findings

During the inspection period, the inspectors reviewed licensee activities in the area of required NRC reports. Specifically, the inspectors reviewed a recent event regarding inoperability of two trains of the KC system. The February 18, 1996, event occurred when the 2B2 component cooling water (KC) pump bearing problem caused B train KC to be declared inoperable. This placed Unit 2 into TS 3.0.3 due to previously scheduled work activities already being performed on the A train nuclear service water (RN) header (which affected A train KC operability). The inspectors determined that, although operators appropriately entered 3.0.3 for the specific condition (two trains of KC considered inoperable), operators did not report the condition to the NRC as required by 50.72. The inspectors informed the licensee of the problem and the licensee took corrective actions to improve guidance to operators in this area. The inspectors concluded that this problem was an additional example of NCV 369, 370/96-04-03 regarding a failure to make a required 10 CFR 50.72 report as required.

c. Conclusion

The inspectors concluded that increased management attention was warranted concerning operator training and/or guidance on making required NRC reports.

06 Operations Organization and Administration

06.1 Overtime Controls

a. Inspection Scope (71707)

The inspector performed a review of approved overtime for the past three month period for plant operations and maintenance groups. Control of overtime for plant personnel is required by Technical Specification 6.2.2.e and NSD 200, Overtime Control. These documents required the licensee to document and properly authorize work hour extensions.

b. Observations and Findings

The inspectors reviewed work hour extension forms for the maintenance and operations groups. The inspectors found that most explanations for overtime approval were reasonable. However, isolated documentation discrepancies included; a lack of an explanation why a specific individual was required to performed a given task, and an estimated range of hours to be worked. No evidence of excessive or routine use of overtime was noted.

c. Conclusion

The licensee control of overtime for plant personnel during this period was adequate.

06.2 Posting of Notices to Workers

During the inspection period, the inspector reviewed the licensee's compliance with the requirements of 10 CFR 50, Section 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 these areas. The inspector also noted; however, that several other bulletin board/site information areas on the site had outdated Form 3's posted. These areas were brought to the attention of the licensee and were taken down. The licensee initiated a PIP 0-M96-1844 to document the concern and develop corrective action.

O7 Quality Assurance in Operations

O7.1 Licensee Self Assessments

a. Inspection Scope (40500)

The inspector reviewed the licensee's self-assessment of procedures to determine if adequate measures were implemented to assure the quality of station procedures.

b. Observations and Findings

The licensee performed an assessment of identified procedure errors in 1994 which determined that ineffective procedure review by Quality Reviewers (QRs) was the primary cause for procedure errors. The audit and finding was applicable to all plant organizations. The assessment was documented in SA-95-12, Nuclear Station Procedure Review/Cross Disciplinary Review Process, dated March 28, 1995. Corrective actions included the development and distribution of an audit review package to all QRs, and the development and implementation of a QR training program. The inspector noted that the existing QRs were not required to complete the new training program until 1997. Review of the available documentation indicated that 50 of approximately 230 QRs had not reviewed the audit review package over one year after the audit finding. The potential exists that the staff performing the ineffective reviews identified by the audit had not been retrained or completed review of the audit review package. These personnel could still be performing ineffective reviews. The largest group that had not received the benefit of this information was the operations group, although the 50 QRs referenced above were in all station groups.

The inspector noted a recent PIP, 0-M96-1354, which identified an operations start-up procedure (OP/2/A/6100/01) with an error in the valve line-up check list. The revised start up procedure omitted a valve closure verification which resulted in a decreasing CLA nitrogen pressure during start up. Discussions with operations indicated that an ineffective procedure review contributed to this procedure error. The example above was not a safety significant event; however, it indicated that ineffective procedure review continued to be an issue.

c. Conclusion

Assessment SA-95-12 was a good self-assessment of procedure performance but the follow-up of corrective actions was weak. An enhanced attention to detail in procedure reviews which would have been communicated by the corrective actions was not achieved.

II. Maintenance

M1 Conduct of Maintenance

ME.1 General Comments (61726 and 62703)

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.

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

M1.2 Unit 2 Containment Walkdown

a. Inspection Scope (62703)

Near the completion of the Unit 2 forced outage for RCP motor replacement, the inspectors performed a containment inspection of the reactor building. The walkdowns included inspections of the lower containment, containment sump areas, pipe chase, and fan/accumulator rooms.

b. Observations and Findings

During the tour, the inspectors identified the following concerns:

- Two steel construction wedges were found installed under SI piping at the polar crane wall penetration. The wedges were in plain view, approximately 8 feet off the floor adjacent to an RCS cross-over loop.
- Several deviations from established instrumentation line slope criteria were identified.
- Loose bolts on an incore detector hatch cover (lock was installed).
- One missing and one loose electrical conduit cover.

In addition to the above, no fibrous material was identified that could have potentially prevented adequate residual heat removal performance during the recirculation phase of emergency core cooling system injection phase. Insulating material had been adequately secured and tools and other temporary outage equipment had been removed. However, the inspectors noted the use of sealant (Sealastic 720, manufactured by Dow Chemical) in between joints of mirror insulation on crossover piping. At the conclusion of this inspection the licensee was evaluating whether this application was appropriate.

c. Conclusions

The licensee addressed issues raised by the inspectors by making necessary repairs and/or justifying any discrepancies. The inspectors concluded that licensee performance during containment walkdowns may warrant increased management overview emphasizing attention to detail.

M1.3 Capacity Test on Vital Battery EVCA

a. Inspection Scope (61726)

The inspectors reviewed T.S. 4.8.2.1.2, FSAR Section 8.3.2.1.4.2 and Surveillance Test Procedure PT/0/A/4350/40C, as they related to the site vital batteries. The review included verification that the surveillance test procedure was adequate and consistent with both the FSAR and applicable section of the Technical Specification. The inspectors noted that the licensee had replaced each of the vital plant batteries (EVCA, EVCB, EVCC, and EVCD) in 1991 with cells that were manufactured and supplied by AT&T. The cells of these AT&T 2000 Series batteries were found to be cylindrical in shape measuring about 18" in diameter and about 30" in height. The cells' positive and negative plates were circular and were installed horizontally inside their opaque containers. This configuration was atypical of the battery cells installed at the majority of nuclear stations that are located in Region II. That is, most station battery cells are rectangular in shape and have their electrical plates installed vertically.

b. Observations and Findings

The inspectors found that the procedure; PT/0/A/4350/40C, 125VDC Vital I&C Battery Modified Performance Test using BCT-2000, was to be used as guidance for battery bank EVCA during its first 60-month capacity test as required by T.S. 4.8.2.1.2.d. The inspectors reviewed NRC Information Notice 95-21, Unexpected Degradation of Lead Storage Batteries, that identified problems concerning AT&T round cell batteries. The notice described a situation where another utility was conducting a capacity test on their batteries and experienced an unexpected test failure. The failure apparently resulted from manufacturing defects and involved only a limited number of cells. The inspectors were informed by station management that the McGuire AT&T battery cells were not included in the lot containing the defects.

- Capacity Test Prerequisites

  On July 9, 1996, the capacity test was conducted on vital battery EVCA. The inspectors verified that test personnel first obtained approval from the SRO/RO and properly clearance tagged the electrical circuits. Also, the technicians obtained the specific gravities, temperature and level readings prior to installing the required test equipment. The prerequisite portions of the Controlling Procedure PT/0/A/4350/40C, were completed by approximately 1:00 p.m. on July 9.

- Battery Discharge

  The battery discharge test equipment included: two Alber Model 5 D.C. load units, one Alber BCT-2000 capacity test system, sensing leads, associated test meters, and hardware. The test method required the battery (EVCA) to be connected to the Alber BCT-2000 system and the system be programmed to discharge at a rate of 758 AMPs until battery terminal voltage reached 105 VDC. The battery was expected to maintain voltage above 105 VDC for at least 60 minutes. After the prerequisites were completed and the discharge equipment and hardware were in place, the test began. However, several problems were experienced with both test equipment and hardware. These unexpected problems resulted in the discharge test being started and stopped several times. For example, prior to starting the final discharge rate (758 AMPs) the test program system caused the battery to discharge at a rate of about 1300 AMPs for greater than 4 minutes. The inspectors noted that this was almost 300 AMPs greater than the 1014 AMPs that was recommended for the first minute of the discharge test. After the discharge test was stopped, the inspectors noted that the battery voltage had dropped to 105 VDC after about 45 minutes. The initial (approximately 1300 AMPs) discharge rate had dropped to the suggested final rate (758 AMPs).

- Battery Re-Charge and Return to Normal

  After the battery discharge was secured (in the late afternoon of July 9) test personnel disconnected and removed the battery DC load units and associated cables and hardware. The battery was then prepared for re-charging, the battery charger was energized, and an equalizer battery charge was activated. The controlling procedure IP/0/A/3061/12, Charging Station Lead Acid Batteries, was used for guidance by operations personnel. Step 10.2 of this procedure identified an equalizer charge as being a method of constant voltage. Step 10.2.3 specified that AT&T batteries utilize a voltage of 2.5 VDC per cell. The 2.5 volts per cell multiplied by the total number of cells (59) revealed that the overall constant voltage should have been 147.5 VDC.

Initially, the operators placed the battery on equalize charge and increased the voltage to a value of about 130 VDC. Attempts were made to increase this value, however the voltage began to oscillate. After about two hours, operators were able to increase the applied voltage to the desired value (147.5 VDC) and allowed it to remain at that value until the current stabilized and decreased, as expected. The inspectors were informed by the licensee electrical engineering personnel that the unexpected oscillations were indications that the battery charger was possibly not performing as expected. After the charge was completed, the charger was evaluated for possible repairs and/or modifications.

c. Conclusions

The licensee determined, and the inspectors agreed, that the capacity test was invalid and was not conclusive enough to verify whether or not the requirements of TS Section 4.8.2.1.2.e. were satisfied. The major cause of the test becoming invalid was the apparent "first use" of the Controlling Test Procedure, PT/0/A/4350/40C, by the test personnel. Also, the lack of a designated "test coordinator" and the overall lack of good communications between site engineering and test personnel contributed to the faltered test. The inspectors concluded that a weakness exists in the area of test execution for the AT&T station batteries. On July 10 the inspectors and visiting representatives from NRR conducted a brief meeting with the licensee. During that meeting, the inspectors informed the licensee of their observations, findings, and conclusions.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Recurring Problems with the Chemical and Volume Control Charging Pumps and Turbine Building Ground Water Sump Pumps

a. Inspection Scope (62700 & 62703)

The inspector reviewed all completed corrective maintenance work orders issued for pumps during the past 3 years to determine which pumps had histories of recurring problems. As a result of this review the inspector selected the chemical and volume control charging pumps and the turbine building ground water sump pumps to perform an in-depth review of the failures in order to determine whether the licensee had properly identified the cause of the failures and taken appropriate corrective action.

Once the above components were selected for inspection, applicable problem evaluation reports, preventive maintenance documentation, maintenance procedures, vendor technical manuals, failure and trending summary's, failure analysis reports, engineering evaluations, and portions of the following in-process maintenance activities were examined.

- Work Order No. 96040318-01, Charging Pump 2A Mechanical Seal Inspection
- Work Order No. 96017787-01, Charging Pump 2A Bolt Hole Alignment Measurement
- Work Order No. 96047188-03, Trouble Shoot and Repair Ground Water Drain C Sump Pump B (MCOWZ PU0006)

b. Observations and Findings

Failures experienced on the chemical and volume control charging pumps consisted of seal leakage, bearing misalignment, and high cycle fatigue leading to bending of the shaft. An industry survey was conducted by the licensee to determine if other utilities had experienced similar problems with their charging pumps. The survey revealed that 10 of the 14 plants surveyed had experienced chronic seal leakage and, within the nuclear industry, eight centrifugal charging pumps had suffered shaft failures. At the time of this inspection, there were no seal upgrades available and neither the pump or seal manufacturer had plans to fund an upgrade for the seal. The Westinghouse Owners Group (WOG) is considering funding a study of the seal. In addition, the WOG plans to recommend a superior pump shaft material to the vendor, Ingersoll-Dresser. Corrective measures taken by the licensee were based on discussions with other licensee's, the seal and pump manufacturer's, the WOG, and Duke's maintenance practices. They included upgrading the charging pump maintenance procedures and providing additional training on element replacement, centering, alignment, and seal maintenance. On July 9, 1996, the inspector observed maintenance activities on the Unit-2 "A" Charging Pump delineated above. These activities included inspecting and cleaning the pump seals. No seal degradation was observed.

On June 9, 1996 the licensee issued Problem Investigation Report No. 96-1664 to document the short term unreliability of the ground water drain pumps in the "C" ground water sump. The "A" pump was experiencing very high vibrations and was completely rebuilt and returned to service under Work Order No. 96044949. The determined cause of the "A" pump's high vibrations were attributed to normal wear of the bearings. The "B" pump was rebuilt under Work Order No. 96047188. The cause of the "B" pump's failure was attributed to the impeller nut coming loose, which allowed the impeller to drop down and contact the suction head. On July 5, 1996, upon running the "B" pump for functional verification after reinstallation, smoke started coming from the areas of the bearings and the motor tripped approximately 10 seconds into the run. On July 10, 1996, the inspector observed maintenance personnel remove the pump and motor and trouble shoot the pump for the apparent cause. There was evidence of rubbing of the impeller against the housing. This could indicate that the clearances were set wrong the first time the pump was rebuilt. The clearances were reset and the pump reinstalled in the sump. However, the inspector was concerned that other causes were not considered during the trouble shooting process. The shaft material differing from the previously replaced shaft was not reviewed. The failed pump was found smoking, but the trouble shooting inspection did not include the shaft and the intermediate bearings. The inspector also pointed out to engineering a weakness noted by the inspector when reviewing the Problem Investigation Report (96-1664) for the previous pump failure. The cause of the "B" pump failure was determined by the licensee to be that the impeller nut came loose and was evaluated to be an isolated instance. The licensee did not conduct a root cause failure analysis to determine the condition which caused or allowed the nut to come loose, and no corrective action was taken to prevent this failure mechanism from recurring. As a result of the inspector's concern, engineering re-opened Problem Investigation Report No. 96-1664 and proposed corrective action that would require engineering to develop a method of securing the impeller nut which will prevent the nut from coming loose. Engineering also verified that the replacement shaft material was the same as the original material. On Monday July 15, 1996, the pump was tested and found to function correctly.

During the pump documentation review process, the inspector found that documentation, evaluations, and corrective actions taken by the licensee on previous pump failures were satisfactory. In addition, all work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspector frequently observed supervision, technical support engineers, and component engineers monitoring job progress and noted that quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

c. Conclusion

Maintenance activities were generally completed thoroughly and professionally. Only one minor weakness was identified which dealt with the identification of root cause and appropriate corrective action for a pump failure. Documentation reviewed was appropriate in each area examined and personnel audited were knowledgeable.

III. Engineering

E1 Conduct of Engineering

Based on the NOUE which occurred on June 19, 1996, and as discussed in section O1.3 of this report, the inspectors reviewed the suspected root causes for the failures as of the end of the inspection period.

E1.1 1A EDG Voltage Regulator Failure

Troubleshooting and repair of the 1A EDG regulator included replacement of a voltage regulator control board and a motor operated potentiometer. Attempts to recreate a similar failure during subsequent testing were not successful; therefore, the exact failure mechanism could not be identified by the licensee. Procedure PT/1/A/4350/19A, EDG 1A Governor and Voltage Regulator Benchmark Comparison Test, was performed satisfactorily on June 19, 1996, which verified that the EDG would respond as anticipated to an ESF type loading transient. In addition, PT/1/A/4350/02A, EDG 1A Operability Test, was completed (1 hour run) prior to the 1A EDG being declared operable.

Based on the inconclusive root cause evaluations, the licensee returned the control board and motor operated potentiometer to the manufacturer for failure analysis. However, due to a communication error, the control board and the potentiometer were repaired and returned without a full failure analysis being performed. Subsequent review did reveal that a small deadband in the potentiometer had been identified; however, the licensee could not definitively determine that this was the root cause of the voltage regulator problem. The inspectors concluded that followup on the 1A EDG voltage regulator problems did not occur as planned due to inadequate communications of expectations to vendor personnel.

E1.2 1B EDG Fuel Line Failure

Immediate corrective actions for the fuel line coupling failure at the fuel pump connection was to replace the entire fuel line between the fuel injector and the fuel pump. Operability testing was satisfactorily completed and the EDG was declared operable on June 19, 1996. The failed line was evaluated by the licensee through their root cause investigation process. On July 18, 1996, 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 line had ejected from the ferrule connection due to inadequate crimping of the ferrule to the tube. The fuel line and ferrule involved was supplied by NAK Engineering Inc. The licensee postulated that an inconsistent ferrule crimping process led to the failure of the 4R cylinder fuel line. 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 fuels lines were previously replaced (all but four were upgraded to double-wall) during two earlier unit refueling cycles and had not experienced any failures.

Based on the results of the root cause evaluation, the inspectors discussed with licensee management the schedule for inspecting and/or re-crimping the existing double-walled fuel lines. The inspectors were concerned that other fuel lines may be susceptible to similar failures based on the inadequate crimping found on the 4R line. The inspectors were informed that the remaining fuel lines would be inspected and re-crimped as necessary during planned EDG outages (i.e. one EDG per month). The inspectors expressed additional concerns whether this action was timely considering the failure mechanism. The licensee informed the inspector that the re-crimping schedule was adequate based on several reasons. First, an ability to predict a failure of the lines via analysis of cylinder exhaust temperature. Specifically, a review of historical exhaust temperature data indicated that the 4R cylinder had been experiencing a slow decrease in temperature which was an indication of a small, undetectable fuel leak. Second, the licensee had previously performed a torsional analysis evaluation on the McGuire Nordberg EDG crankshafts which concluded that operation of the EDG could continue with the failure of a cylinder fuel line. The study indicated that the fuel supply to a failed cylinder could be shut off and with the exception of the number 1 cylinder (furthest from the flywheel) the EDG would perform adequately under full load. Additionally, the licensee informed the inspectors that a visual inspection of all the fuel lines had been performed with no evidence of pullout or misalignment observed.

At the end of the report period, the inspectors were continuing to evaluate the 1B EDG fuel line failure pending inspection of the other potentially affected fuel lines. The inspectors also had questions concerning the process used by the manufacturer of the fuel lines to consistently crimp the ferrule to tube connection. These issues will be identified as an Unresolved Item URI 370/96-06-01, Root Cause Evaluation of 1B EDG Fuel Line Coupling, pending completion of further NRC review and evaluation.

E2 Engineering Support of Facilities and Equipment

E2.1 Temporary Design Modifications

a. Scope (37550 & 37551)

The inspector reviewed the design change activity associated with Temporary Modifications (TMs) to determine if this activity was consistent with regulatory guidance, ANSI N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, and licensee procedures.

b. Observations and Findings

There were 20 active TMs which exceeded the station goal of 15 TMs. The inspector reviewed the TMs and field verified the one safety related TM which was associated with a connection for a temporary air driven Auxiliary Building sump pump. All TMs had been installed for less than one year. The applicable station procedure, Nuclear Site Directive 301.7, Administration of Temporary Modifications, dated June 27, 1996, required quarterly TM audits. The audits were performed monthly. The inspector determined that the existing TMs provided no apparent challenge to plant safety or equipment/system function.

c. Conclusion

Temporary Modifications were adequately monitored and controlled. TM activity was consistent with regulatory guidance and station procedures.

E2.2 McGuire Station Motor Reliability

a. Inspection Scope (37551)

During the period, the inspectors noted a concern with station motor reliability. The inspectors communicated the concern to the licensee. The licensee had recognized the adverse trend and had confirmed that station motor performance was below industry standards based on the previous three years data. Motor failures had resulted in significant primary and secondary system transients and reactor trips.

b. Observations and Findings

The licensee had established a working group to actively address the reliability concern. The group was charged with developing recommendations to prevent future problems and redirect the adverse trend by developing goals for improved performance and enhanced monitoring of selected motor reliability. The working group had performed preliminary reviews of certain motor failures and determined that deficiencies in the current predictive/preventive maintenance program, vendor repair quality, and motor/pump design were apparent root causes for the decreased reliability.

Working group members were assigned to each set of problem motors. The members were expected to review the motor failures and identify root causes and solutions and develop and implement an action plan to achieve improved motor performance.

c. Conclusions

The inspectors reviewed current and past motor reliability data comparing McGuire motor performance to industry standards and the current plan developed by the working group. The inspectors noted that the current plan included aggressive refurbishment and repair schedules for the chronic motor problems and reevaluation of previous preventive/predictive maintenance schedules to improve motor reliability. However, the inspectors concluded that a weakness was evident in station motor reliability and continued engineering and maintenance attention was necessary to reverse the current adverse motor reliability trend.

E3 Engineering Procedures and Documentation

Subsequent to the February 1996 Regional inspection (IR 96-01) pertaining to the Spent Fuel Pool, the NRR staff performed an additional evaluation of McGuire spent fuel pool decay heat removal and refueling practices. This involved a review of the licensing basis documents for McGuire, including the FSAR and documents related to Amendments 159 and 141 issued November 9, 1995. Specifically, a review was performed of the licensing basis regarding spent fuel pool decay heat removal and refueling outage core off-load practices.

In a revision of the FSAR (Section 9.1.3) dated January 12, 1995, the licensee described the heat loads assumed for analyzing the spent fuel pool cooling section. The FSAR states:

<u>Normal Heat Load</u>: Assumes one-third core has been placed in the pool seven (7) days after shutdown. The remainder of the pool, less 193 spaces, is filled with previous McGuire discharges from normal refueling operations and Oconee spent fuel which has decayed at least five (5) years. The 193 empty spaces are reserved for a full core discharge.

<u>Abnormal Heat Load</u>: Assumes one full core discharge consisting of three batches. The batches are irradiated 23.5 days, one-year, and two years respectively. In addition, one refueling batch has decayed 36 days. The remainder of the pool is filled with previous McGuire discharges from normal refueling operations and Oconee spent fuel which has decayed at least five (5) years.

Further, FSAR Table 9-5 describes the calculated bulk spent fuel temperature for these two cases (identified in the Table as the normal maximum and abnormal maximum heat loads) with two spent fuel pool cooling system configurations (one and two trains operating) analyzed for each case. An assumed heat load, [spent fuel pool] design basis temperature and calculated spent fuel pool temperature were provided for each case. The normal maximum heat load case, analyzed with one cooling train operating, results in a calculated spent fuel pool temperature of 133F. The abnormal maximum heat load case, analyzed with one cooling train operating, results in a calculated spent fuel pool temperature of 178F. In a footnote to Table 9-5, the licensee stated, regarding design basis for spent fuel pool temperature, that 140F was used as a maximum for [spent fuel pool] structural calculations.

The licensee routinely performs a full core off-load during each refueling outage. As noted above, this is defined in the FSAR as an

Abnormal Heat Load. The inspectors considered that partial off-loads, as defined in the FSAR for the Normal Heat Load, would be the normal practice for refueling outages. The inspectors noted that the licensee had performed a full core off-load, which may have been inconsistent with the FSAR (licensing basis), with heat loads in excess of the defined normal case, each refueling outage.

The practice of routinely performing full core off-loads and introducing a greater than normal heat load into the spent fuel pool, without an analysis of the spent fuel pool structure that demonstrates the acceptability of exceeding 140F in the event of a failure of one single fuel pool cooling train, may be considered to be a change to the normal case described in the McGuire FSAR (licensing basis). If such a change occurred to the operation of the facility, the change should have been reviewed pursuant to 10 CFR 50.59 prior to instituting the practice of routinely off-loading the full core.

It is noted that the above findings pertain to refueling outages up to and including Unit 1, cycle 10. Before removing fuel for the Unit 2, cycle 10 outage that started April 5, 1996, the licensee performed a change to the McGuire FSAR that stated that the spent fuel pool structures, systems and components had been analyzed for a complete loss of spent fuel pool cooling for up to 72 hours. The licensee stated that 72 hours provides adequate time for restoration of pool cooling should a train be lost during maximum heat conditions. This analysis pursuant to 10 CFR 50.59 demonstrated the acceptability of the change to the normal case as described in the FSAR.

The issue of the licensee's past practice of performing full core off-loads on a routine basis, and evaluating the change to the licensing basis regarding appropriate analysis for normal refueling practices, is an Unresolved Item URI 369, 370/96-06-02, Spent Fuel Pool Offloading, pending further NRC evaluation.

E4 Engineering Staff Knowledge and Performance

E4.1 Unexpected CR Annunciation (71707 and 37551))

a. Observations and Findings

On June 29 the inspector reviewed the operator response to a CR annunciator that unexpectedly remained lit. During the Unit 2 startup, operators noted that the CR digital rod position indication (DRPI) annunciator for rod bottom did not go dark, as expected, upon withdrawal of control bank A being withdrawn greater than six steps. The operators secured the startup sequence to investigate the concern. Review determined that in a previous investigation (WO 95099071) engineering personnel identified an electrical problem inside the containment that causes the Unit 2 DRPI annunciator to go dark when the rods are lifted from control bank C rather than A. The inspectors concluded that operations personnel should have been made aware of the identified problem, by engineering, prior to the startup. An information tag was initiated for the problem and operations amended the annunciator information note to specify that the annunciator was not functioning properly. The licensee initiated a PIP to address the problem.

b. Conclusions

The inspector concluded that this was an example of poor communications between engineering and operations regarding the status of Unit 2 rod bank annunciation. Operators were not made aware of known problems with rod control annunciation, resulting in the securing of reactor startup to resolve the concern and determine the significance of the issue.

E4.2 Engineering Staff Knowledge and Performance

a. Inspection Scope (37550 & 37551)

The inspector reviewed System Engineering activities to assess their knowledge and familiarity with the assigned systems. The inspector selected for review the engineers assigned to the Safety Injection (NI) and Component Cooling (KC) systems.

b. Observations and Findings

Engineering had established Position Specific Guidelines (PSGs) which included training on general engineering functions and activities specific to an individual engineer's functions and responsibilities. The general PSG portion included engineering procedures, processes, and programs. Most engineers had completed this portion. The individualized portion was in the development stage for most system engineers. The schedule goals did not require this portion to be completed at this time.

Discussions and system walkdowns with the selected system engineers indicated a good knowledge of the assigned systems' status. Both System Engineers had been assigned to their respective systems less than one year; however, the previously assigned System Engineers provided adequate transition support. The inspector noted two examples which demonstrated good problem identification by the system engineers. In one example, a short term condition related to Cold Leg Accumulator (CLA) in-leakage was identified and monitored. In the second example, a potential LOCA injection flow diversion was identified during CLA fill activity. Appropriate corrective actions were initiated to address these issues.

c. Conclusion

The System Engineers interviewed during the inspection demonstrated an appropriate knowledge and familiarity with their assigned systems.

Examples of good problem identification by systems engineers was noted.

E5 Engineering Staff Training and Qualification

a. Inspection Scope (37550 & 37551)

The inspector reviewed the Engineering training program for the performance of 10 CFR 50.59 safety reviews to determine if adequate training was provided for this activity.

b. Observations and Findings

A plant wide program was established to train Qualified Reviewers (QR) to perform review activities which included procedure reviews and 50.59 safety reviews. With respect to 50.59 reviews, the training program included applicable regulatory guidance, station procedures, and an overview of the Final Safety Analysis Report (FSAR) Chapter 15 accident analysis. The QR program was upgraded in 1995 to address weaknesses identified in procedure review performance. Engineering had completed the retraining in December 1995. The inspector reviewed the training documentation for engineering and determined that the designated QRs had been trained. Discussions with several Engineering QRs indicated that the individuals were knowledgeable of the 50.59 review process.

c. Conclusion

The designated Engineering QRs were adequately trained to perform 50.59 safety reviews. The training program was well structured and of good content.

E7 Quality Assurance in Engineering Activities

E7.1 Reactor Trip Breaker Secondary Contact Failure

a. Inspection Scope (37551 and 62703)

On June 12, 1996, during reactor trip breaker (RTB) testing at McGuire Unit 2, the licensee identified that one of the bypass RTBs failed to open electrically when the local shunt trip push button was depressed. The breaker was later verified to open mechanically. The McGuire Unit 1 and Unit 2 RTBs and bypass RTBs are Westinghouse Model DS-416 breakers equipped with four secondary contact disconnect assemblies, each containing eight spring loaded contacts, mounted on the upper rear portion of the breaker. The shunt trip, undervoltage trip and open/closed monitoring circuits for the breakers are wired through these assemblies.

During subsequent inspection of the failed RTB, a small piece of the assembly was found. The licensee postulated that the fragment may have lodged in the secondary contact disconnect assembly preventing good electrical connection for the local shunt trip pushbutton circuit. The assemblies, made of a molded cellulose-filled phenolic material, appear to have low impact strength and may be highly susceptible to chipping or cracking. McGuire Unit 2 was in cold shutdown (MODE 5) at the time of discovery.

The postulated root cause of the chipped assembly was determined to be mechanical damage during maintenance or contact installation.

On July 1, 1996, while performing extent of condition inspections of the remaining Unit 1 and Unit 2 RTBs, the licensee discovered that an entire secondary contact disconnect assembly on a Unit 1 RTB was broken in half and one of the spring loaded finger contacts had fallen out in the breaker cubicle during the breaker inspection. Unit 1 was operating at rated power at the time of discovery. Consequently, the licensee inspected the internals of the breaker cubical for damage. No damage to the cubicle was identified. The licensee replaced the failed breaker with an available bypass RTB. Required retesting of the replacement breaker was completed and the RTB was placed in service. The root cause of the cracked assembly was determined to be stress induced from over-torquing of the assembly during replacement in September 1994.

b. Observations and Findings

The inspectors reviewed the maintenance practices and procedures for removing and reinstalling the breakers for scheduled refurbishment. The current maintenance procedure for corrective maintenance adequately referenced the vendor recommended torquing requirements. The maintenance procedure had been revised in 1995.

In June 1993 the vendor issued a technical manual revision for a variety of breakers including the DS-416 breakers. The vendor incorporated torquing requirements to address known concerns with overtorquing of the secondary contact disconnect assembly mounting bolts. The licensee received this information in February 1994; however, the licensee failed to promptly incorporate the technical manual revision into the McGuire document control program until January of 1995 following a vendor manual technical audit. The audit was performed as a corrective action item following a similar failure to incorporate vendor information which resulted in a failure of an MSIV during the 1993 LOOP event at the station. After incorporation of the breaker manual revision into the document control program, the applicable procedures were revised to reference the new manual which identified specific torquing requirements for the secondary contact disconnect assembly. However, the licensee did not immediately recognize the addition of secondary contact assembly torquing requirements.

The inspectors also noted that the licensee frequently lifted the breakers by hand during removal and re-installation from the cubicles to allow corrective and preventive maintenance instead of the vendor recommended lifting device. The licensee did not consistently use good breaker handling practices.

The installed RTB and bypass RTB secondary contact assemblies for both McGuire units, along with the breaker cubicles were inspected. The secondary contact assemblies were removed during the inspections and reinstalled using the vendor specified torquing requirements. Spare breaker secondary contact assembly blocks were also inspected for chips and deformation. All damaged assemblies were replaced. Additional cracking problems on the secondary contact block were also identified at the Catawba Station.

c. Conclusions

Following a thorough review, the inspectors concluded that mishandling of the breakers during removal and reinstallation as well as failure to promptly incorporate vendor information were the apparent causes for the damaged secondary assemblies. The latter resulted in overtorquing of the of the Unit 1B RTB secondary contact assembly during corrective maintenance. The inspectors reviewed the circumstances surrounding the breaker failure and subsequent investigation findings and determined that a weakness existed in maintenance execution because of insufficient handling of the RTBs during corrective and preventive maintenance. The inspectors also concluded that the failure to promptly incorporate and implement available vendor information was a Violation of NRC requirements and will be identified as Violation 50-369, 370/96-06-03; Failure to Promptly Incorporate Vendor RTB Information.

d. RTB Reportability

The licensee initially notified the NRC Headquarters Operations Officer on June 26, 1996, per McGuire Unit 2 Operating License Condition 2.C(12). The condition stated that the licensee notify the Commission on failure of any reactor trip breaker or reactor trip bypass breaker, either in service or during testing (on either undervoltage or shunt coils). The licensee later determined that the condition statement was not applicable and retracted the notification. The inspectors discussed the retraction with the licensee and NRC management to evaluate justification for the retraction. The licensee stated that since the license condition 2.c(12) specifically referred to failures of the undervoltage or shunt coils that NRC notification was not required. The inspectors determined that the licensee's decision to retract the notification did not violate the Operating License Condition. However, the inspectors concluded that the original reporting of this event was prudent. The event was significant enough to warrant a NRC (Information Notice) and industry notifications. The licensee later recognized the importance of the incident and decided to submit a written Special Report to the Commission.

E7.2 Containment Personnel Air Lock (PAL) Door Leakage Detection System Operability

a. Inspection Scope (37551)

During troubleshooting of the station PAL leakage detection device, the licensee identified defects in the automatic leakage detection system circuitry. The licensee determined that the Volumetrics Automatic Airlock Leakage Detection Device provided non-conservative airlock door annulus seal leakage indication when leakage values exceeded the calibrated range. The unit was calibrated to operate in the range of 0-1000 sccm. The Volumetrics system would read normally up to the maximum flow range; however, it would start to count back down when subjected to leakage flows in excess of 1000 sccm. This wraparound characteristic was not initially recognized by the licensee during the original installation and testing. This false indication may potentially mask equipment degradation and equipment malfunction. PAL leakage detection monitoring is required by TS 3.6.1.3.

b. Observations and Findings

After identification of this equipment characteristic, the licensee initiated manual airlock door testing to ensure operability of both units upper and lower PALs. The manual airlock operability surveillances were performed. Because the manual test requires entry into the airlock, the licensee must repeat the TS required manual airlock operability test on a 72 hour frequency to ensure operability of the airlock. The licensee reviewed previous data to evaluate past operability of the airlock and determined that since actual leakage values obtained during manual testing were well below the overranged conditions that the airlock was past operable. The licensee also issued a nuclear network message to alert other licensees of the finding.

The licensee contacted the equipment manufacturer to pursue replacement components that would allow an increase in the system operating range. The replacement parts were scheduled to be delivered to the site during the next inspection report period.

c. Conclusions

The inspectors witnessed portions of the manual operability testing of the personnel airlock and concluded that the manual test was adequate to ensure airlock operability. The test was completed in accordance with the controlling procedure and test technicians were skilled in performing this test. No discrepancies were noted.

At the close of the inspection period, the inspectors evaluated the situation and determined that the initial design review and testing of the leakage detection system prior to installation may have been deficient. The inspectors also noted that corrective actions had not been fully developed prior to the end of the inspection period. This item will be identified as Unresolved Item 50-369,370/96-06-04, Design of Equipment Used to Implement TS Required Containment Air Lock Surveillances, pending completion of the root cause analysis and development of corrective actions.

E7.3 <u>Implementation of VC modification postponed based on NRC questioning operability impact on both trains.</u>

On June 24 the inspectors reviewed proposed modification MGMM-7484 which was planned to install duct access portals for flow elements within the VC system duct work. The modification involved cutting the duct work to install permanent access ports. Based on the review, the inspectors questioned the licensee's reason for breaching the system integrity for the modification of the VC system. The purpose of the proposed modification was to install two access ports, one on each train, to allow access to flow elements within the duct work for periodic cleaning. The design of the McGuire VC system involves two independent trains of VC; however, the trains share common duct work by design. The inspectors were concerned that (if the modification was performed as written) both trains of the VC system would become inoperable due to the breach. However, the licensee had not intended to declare both of the trains of VC inoperable.

The inspectors raised the concern to the licensee and the modification was postponed indefinitely. The licensee documented the concern in PIP 0-M96-1804. The licensee's proposed modification justified the two train VC system breach based on use of a "3 minute rule." Through engineering review, this rule allowed for the VC system to be breached as long as contingency measures were in place that assures the system could be sealed up within 3 minutes of an ESF actuation. The source of the 3 minute rule was MCC-1227-00-00-0048, Dose Consequence Impact of Mark BW Fuel Reload for Accident Analyzed in Chapter 15 of McGuire FSAR. The 3 minute criteria was based on the amount of time it would take to seal a given VC system breach and allow the CR pressurization fans to pressurize the CR to ensure radiological doses to operators would not be exceeded.

Licensee review of the issue concluded that the use of the "3 minute rule" for this modification application would be inappropriate without further in-depth review under the 10 CFR 50.59 process. The inspectors concluded that further licensee reviews were warranted to incorporate actual TS operability impact of the proposed modification to the VC system.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (CLOSED) VIO 50-369,370/95-13-01: Failure to Consider the Effects of the Increased Service Water Flow on Control Room Ventilation/Chiller System Reliability When the Service Water System Valves Were in a Fully Open Position as a Result of an ESF Actuation

The licensee performed engineering tests and calculations to characterize chiller performance as a function of nuclear service water (RN) system flow and temperature and initiated manual throttling of RN flow control valve to maintain chiller operability. In addition, the licensee revised retest requirements and conducted training on the need to consider the effects of design changes on safety functions. The inspectors reviewed the licensee's technical evaluations, procedure changes, and training records and confirmed that they had been properly conducted and implemented. The inspectors concluded that the licensee's corrective action had been appropriate. This item is closed.

E8.2 (CLOSED) DEV 369, 370/95-14-02: Failure to Meet GL 88-14 Commitments Concerning the Instrument Air System

This item addressed the licensee's failure to implement commitments related to installation of end-use filters on designated safety related air operated valves and dampeners. Additionally, preventive maintenance (PM) frequency for the installed end-use filters was not consistent with the GL 88-14 commitments. The licensee's corrective actions specified in their August 31, 1995, response to the deviation included enhancements to the commitment tracking program, installation of the designated end-use filters, and a supplemental response to GL 88-14 which justified the PM frequency for filter replacement.

The inspector reviewed the maintenance work documentation and administrative correspondence which documented the completion of the corrective actions specified in the response. The final end-use filter was installed on May 3, 1996. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Transportation of Radioactive Materials

a. Inspection Scope (86750, TI 2515/133)

The inspectors evaluated the licensee's transportation of radioactive materials programs for implementing the revised Department of

Transportation (DOT) and Nuclear Regulatory Commission (NRC) transportation regulations for shipment of radioactive materials as required by 10 CFR 71.5 and 49 CFR Parts 170 through 179.

b. Observations and Findings

The inspectors reviewed procedures and determined that they adequately addressed the following: assuring that the receiver has a license to receive the material being shipped; assigning the form, quantity type, and proper shipping name of the material to be shipped; classifying waste destined for burial; selecting the type of package required; labeling and marking the package; placarding the vehicle; assuring that the radiation and contamination limits are met; and preparing shipping papers.

Licensee's records for 6 recent shipments of radioactive material were reviewed and the inspectors determined the shipping papers contained the required information. The inspectors also determined the licensee had maintained records of shipments of licensed material for a period of three years after shipment as required by 10 CFR 71.91(a). Based on a review of the licensee's A1/A2 Tables, the inspectors determined the licensee had revised the tables to incorporate recent changes to 10 CFR 71 and 49 CFR 173.433. The licensee's emergency response telephone number provided to drivers for radioactive shipments was verified by the inspectors to be operable and an adequate response for incoming calls was demonstrated.

The inspectors also verified that the licensee possessed a current certificate of approval (NRC Form 311) for their "Quality Assurance Program Description for Radioactive Material Shipping Packages Licensed Under 10 CFR 71."

c. Conclusions

Based on the above reviews, the inspectors determined that the licensee had effectively implemented a program for shipping radioactive materials required by NRC and DOT regulations.

R2 Status of Radiation Protection (RP) Facilities and Equipment

a. Inspection Scope (84750)

The inspection scope was to determine if process and effluent radiation monitors and radiological environmental monitors were being maintained in an operational condition.

b. Observations and Findings

During tours of the Auxiliary Building and Radwaste Building, the inspectors observed process radiation effluent monitors in service and reviewed operability performance of the monitors with cognizant licensee personnel for the previous 12 month rolling period. Documentation reviewed by the inspectors indicated monitors required by TSs had been operable an average of 98.24 percent of the time and monitors not required by Technical Specifications (TSs) had been operable 97.95 percent. The lowest operability percentage for a specific TS required monitor was 79 percent due to filter paper problems. The licensee had increased frequencies for inspecting the filter paper to increase operability.

The inspectors also toured the onsite environmental laboratory and observed that radiological postings, contamination controls, and general housekeeping in these areas was good. The inspectors observed equipment use and discussed sampling and counting procedures with laboratory personnel. The inspectors observed environmental sampling equipment including environmental air samplers and liquid surface water samplers. The NRC identified in Inspection Report 50-369/95-21 and 50-370/95-21 that 31 deviations from the specified sampling plan occurred in 1994, most of which were due to air and sampling equipment malfunctions. During that inspection, the inspectors reviewed an ongoing licensee project, MG-95-0449, Environmental Sampling Deviation Reduction Plan. The plan initiated actions to reduce equipment malfunctions which included: surge protection installation; heat tracing lines for freeze protection; movement, water proofing, and grounding of electrical outlets; air sampler housing physical modifications to increase air flow; and the addition of two backup portable water backup samplers and eight additional air samplers. Based on corrective actions, the licensee had reduced the number of equipment malfunctions in 1995 to 15.

c. Conclusions

The inspectors concluded effluent and environmental monitors were being maintained adequately to support plant activities.

R3 Radiation Protection and Chemistry Procedures and Documentation

a. Inspection Scope (84750)

The inspectors determined if the licensee had implemented procedures to maintain an effective program to monitor and control liquid and gaseous radioactive effluents as required by TSs.

b. Observations and Findings

The inspectors reviewed annual effluent data for 1995 and compared the data to previous annual reports back to 1991. Annual Radioactive Effluent Release Reports were required to be submitted to the NRC prior to May 1 of each year. Summaries of the quantities of radioactive materials in liquid and gaseous effluents released from the facility and an assessment of the radiation doses due to those releases were required to be included in the reports. The inspectors reviewed the supporting data for the effluent release report covering the year 1995. The amount of activity released during 1995 as dissolved gases in liquid effluents and fission gases, and iodines and particulates in gaseous effluents all decreased. These results were attributed to minimizing in-plant pipe leakage and good fuel integrity. The amount of tritium increased slightly for liquid effluents and gaseous effluents in 1995 compared to 1994. However, the quantity was less than the 3 years reviewed prior to 1994. The annual average per unit radiation doses for an individual from the liquids and gaseous effluents were all less than one tenth of a millirem (mrem) and only a small percentage of their respective annual limits.

c. Conclusions

Based on the above reviews, it was concluded that the licensee had properly implemented procedures to maintain an effective program to monitor and control liquid and gaseous radioactive effluents to limit doses to members of the public. The projected offsite doses resulting from those effluents were well within the limits specified in the TSs, Offsite Dose Calculation Manual (ODCM), and 40 CFR 190.

R4 Staff Knowledge and Performance in RP&C

During the inspection period, the inspectors reviewed judgements made by the RP&C staff with regard to personnel safety and ALARA. Specifically, the inspectors noted that personnel safety and ALARA concerns highly influenced the decision to place Unit 2 in cold shutdown for replacement of a failed IR detector.

R5 Staff Training and Qualification in Radiation Protection and Chemistry

a. Inspection Scope (86750, TI 2515/133)

The inspectors reviewed training for personnel and supervisors involved in transportation of radioactive material.

b. Observations and Findings

The inspectors verified that personnel involved with radioactive material shipping were maintaining current hazardous material training qualifications.

c. Conclusions

The inspectors concluded that personnel involved with radioactive material shipping were maintaining current training qualifications.

R7 Quality Assurance in Radiation Protection and Chemistry Activities

a. Inspection Scope (84750, 86750, TI 2515/133)

The inspectors reviewed self assessments performed since the last inspection in the areas of radiation protection, chemistry, and transportation of radioactive material to determine if the licensee periodically reviewed the RP program content and implementation at least annually as required by 10 CFR 20.1101(c). Licensee activities, audits, and appraisals were also reviewed by the inspector to determine the adequacy of identification and corrective action programs for deficiencies or weaknesses related to the control of radiation or radioactive material.

b. Observations and Findings

The licensee's independent audits and appraisals in the radiation control area consisted of formal audits per TS requirements, documented observations, and specific surveillances. Qualified personnel with health physics and chemistry experience were assigned to the station to assist with the licensee's assessment activities.

Observations by the inspector and discussions with cognizant licensee personnel indicated that these efforts were accomplished by reviewing procedures, observing work, reviewing industry documentation, and performing plant walkdowns to include surveillance of work areas by supervisors and technicians during normal work coverage. Documentation of problems by licensee representatives was included in Quality Assurance Audits. The findings of self assessment, SA-96-71, Radiation Protection Program, conducted March 1996, were reviewed by the inspectors. The self assessment identified findings and recommendations to improve the overall RP program. The inspectors also reviewed a recent self assessment of the RP/Chemistry area conducted by the Duke Power General Office in May of 1996. The purpose of the assessment was to review regulatory compliance. In the assessment report, several potential items for improvement were identified and recommended actions addressed.

Another method used by the licensee to identify potential problems and corrective actions was the Problem Investigation Process (PIP). The inspectors reviewed 10 PIPs in the area of RP/Chemistry. The inspectors noted the licensee had written PIPS for licensee recommended Final Safety Analysis Report (FSAR) changes identified during a recent RP review of the FSAR in the area of RP/Chemistry. The licensee recommended approximately 100 changes to the FSAR in this area. Many of the changes noted were editorial in nature. The inspectors informed the licensee that these licensee identified FSAR recommended changes were additional examples of recommended FSAR changes previously identified as an Unresolved Item (URI) in NRC Inspection Report 96-04-02.

c. Conclusions

Based on the above reviews and observations, it was concluded that the self assessment program continued to be adequate in identifying items of substance for corrective actions relating to the radiation protection program. However, additional examples of licensee recommended changes to the FSAR will be added to URI 96-04-02.

P2 Status of EP Facilities, Equipment, and Resources

a. Observations and Findings

Based on the construction of a new stadium near downtown Charlotte, a review was performed by the licensee to assess any impact on the site EP Plan. The review concluded that due to the stadium being outside the 10 mile EPZ, the existing EP Plan is adequate. However, the Licensee did express a concern to local law enforcement about the potential of having problems in promptly manning the Corporate EOF Center in downtown Charlotte, NC during football weekends. The local county/city police informed the Licensee that there is less expected traffic during football weekends than there is during normal weekday rush hours. A contingency Traffic Plan has been established to assist the Licensee in promptly manning the DPC Corporate Office.

b. Conclusions

The inspector discussed with the licensee their evaluation of the new stadium facility and the potential impact on their ability to properly staff required emergency response facilities. The licensee's impact review of new stadium near downtown Charlotte concluded it did not adversely impact existing emergency preparedness plans. The inspectors concluded that the licensee's review of the potential impact to the emergency plan implementation was appropriate, due o the potential impact of the new facility.

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 July 30, 1996. 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.

X2 NRC Chairman Jackson Site Visit

On July 26, 1996, NRC Chairman Jackson visited the McGuire site. The Chairman met with licensee Senior Management, discussed current issues with the NRC Resident Inspector staff, and toured portions of the facility. The Chairman was accompanied by S. Ebneter, Regional Administrator for Region II, J. Crienjak, Branch Chief, and Technical Assistants J. Johnson and C. Miller.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Boyle, J., Manager, Safety Assurance (Acting)
Byrum, W., Manager, Radiation Protection
Curtis, T., Manager, Mechanical/Nuclear Systems Engineering
Geddie, E., Manager, McGuire Nuclear Station
Herran, P., Manager, Engineering
Jones, R., Superintendent, Operations
Loucks L., Radiation Protection Manager (Acting)
McMeekin, T., Vice President, McGuire Nuclear Station
Michael R., Chemistry Manager
Nazar, M., Superintendent, Maintenance
Sample, M., Manager, Steam Generator Maintenance Group
Snyder, J., Manager, Regulatory Compliance
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical/Civil Equipment Engineering
Tuckman, M., Senior Vice President, Duke Power Company

NRC

G. Maxwell, Senior Resident Inspector, McGuire
S. Shaeffer, Senior Resident Inspector, McGuire
M. Sykes, Resident Inspector, McGuire
G. Harris, Resident Inspector, McGuire
S. Rudisail, Project Engineer, RII

INSPECTION PROCEDURES USED

IP 71707:	Plant Operations
IP 61726:	Surveillance
IP 62703:	Maintenance
IP 71750:	Plant Support
IP 37551:	Onsite Engineering
IP 40500:	Self-Assessment
IP 92903:	Engineering Followup
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP 93801:	Regional Initiative
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management and Transportation Of Radioactive Materials
TI 2515/133:	Implementation of Revised 49 CFR Parts 100-179 AND 10 CFR Part 71

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

URI 50-369,370/96-06-01	Failure Analysis for 1B EDG Fuel Line Failure (E1.2)
URI 50-369,370/96-06-02	Refueling Practices Involving Full Core Off Load Into SFP (E.3)
VIO 50-369,370/96-06-03	Failure to Incorporate Vendor RTB Information Into Plant Procedures (E7.1)
URI 50-369,370/96-06-04	Design of Equipment Used to Implement TS Required Containment Air Lock Surveillances (E7.2)

Closed

VIO 50-369,370/95-13-01	Failure to Consider the Effects of the Increased Service Water Flow on Control Room Ventilation/Chiller System Reliability When the Service Water System Valves Were in a Fully Open Position as a Result of an ESF Actuation (E8.1)
DEV 50-369,370/95-14-02	Failure to Meet GL 88-14 Commitments Concerning the Instrument Air System (E8.2)

<u>Discussed</u>

URI 50-369,370/96-04-02 FSAR inconsistencies (R7)

NCV 96-04-01, Additional Example of Previous NCV

LIST OF ACRONYMS USED

ALARA	As Low As Reasonably Achievable
AFW	Auxiliary Feedwater
CLA	Cold Leg Accumulator
DEV	Deviation
DRPI	Digital Rod Position Indication
EDG	Emergency Diesel Generator
EHC	Electro Hydraulic Control System
EOF	Emergency Operations Facility
EP	Emergency Plan
EPZ	Emergency Plan Zone
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
IFI	Inspector Followup Item
IR	Inspection Report
KC	Component Cooling (system)
LOCA	Loss of Coolant Accident
LER	Licensee Event Report
LOOP	Loss Of Offsite Power
NCP	Reactor Coolant Pump
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSD	Nuclear System Directive
PIP	Problem Investigation Process
PM	Preventive Maintenance
PRA	Probabilistic Risk Assessment
PSG	Position Specific Guideline
PT	Liquid Penetrant Test
QR	Quality Reviewer
RCP	Reactor Coolant Pump
RN	Nuclear Service Water System
RO	Reactor Operator
RTB	Reactor Trip Breaker
SRO	Senior Reactor Operator
SSF	Standby Shutdown Facility
TCC	Transmission Control Center
TMs	Temporary Modifications
TS	Technical Specifications
URI	Unresolved Item
VC/YC	Control Room Ventilation System
VI	Instrument Air System
VIO	Violation
WMS	Work Management System
WO	Work Order