UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos. 50-369/96-03 and 50-370/96-03

Licensee: Duke Power Company
422 South Church Street

Docket Nos.: 50-369 and 50-370

License Nos.: NPF-9 and NPF-17

Facility Name: McGuire Nuclear Station 1 and 2

Inspection Conducted: March 12, 1996 - April 25, 1996

Inspectors: S. B. Rudisail for G. Maxwell, Sr. Resident Inspector per telcon — 5/17/96 Date Signed
M. Sykes, Resident Inspector
N. Economos, Region II Inspector
P. Steiner, Region II Inspector
S. Shaeffer, Project Engineer

Approved by: R. V. Crlenjak — 5/17/96 Date Signed
R. V. Crlenjak, Chief, Branch 1
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by the resident and/or regional inspectors in the areas of plant operations, maintenance, engineering and plant support. Some of the inspections were conducted during backshift hours. Backshift inspections were conducted on March 19, 22, and 28, 1996 and April 5, 16, 19, and 23, 1996.

Results:

Plant Operations The licensee provided adequate safety focus in preparing for the reduced inventory/midloop operation (paragraph 2.2). Actions have been implemented to address programmatic weaknesses in the licensees freeze protection program (paragraph 2.3).

ENCLOSURE

Maintenance

A non-cited violation was identified for an inadequate procedure for charging pump maintenance after water was found in the inboard bearing oil reservoir (paragraph 3.1). The licensee's plan to reduce power to add oil to the 1B reactor coolant pump lower oil pot was appropriate (paragraph 3.2). Replacement of the 1KC-1A valve was given adequate engineering support and the licensee dedicated adequate resources to carry out the replacement in a satisfactory manner. Replacement parts and field fabrication of tie-ins were consistent with applicable code requirements (paragraph 3.3). On-line surveillance of the 2A Diesel and the Containment Hydrogen Analyzer were observed. Procedures were adequate and personnel were adequately trained to perform their tasks. The procedure used to perform the calibration on the analyzer requires enhancement to minimize a potential problem with the acceptance criteria of the hydrogen reagent flow rate (paragraph 3.4). The licensee's Maintenance Self-assessment program appears to be well organized and well implemented. The number of components with poor performance has improved and a program has been implemented to provide further improvement in this area (paragraph 3.5). Licensee communication, coordination, procedural adherence, and safety focus was good during core offload and reload activities (paragraph 3.6). Steam generator maintenance was suitable to reduce shutdown risk and was considered a good maintenance practice (paragraph 3.7). Licensee efforts to improve reactor coolant pump motor preventive maintenance activities should enhance equipment reliability (paragraph 3.8).

Engineering

The Unit 2 RCCA performance during drop/drag testing was consistent with procedural acceptance criteria and no unexpected anomalies were identified (paragraph 4.1). An adverse trend was identified following recent component cooling water system butterfly valve failures (paragraph 4.2).

Plant Support

Licensee modifications have eliminated the need for ThermoLag fire barrier material (paragraph 5.2).

ENCLOSURE

REPORT DETAILS

Acronyms used in this report are defined in paragraph 8.

1.0 Persons Contacted

Licensee Employees

*Boyle, J., Superintendent, Work Control
*Charles, L., Nuclear Maintenance
*Cross, R., Regulatory Compliance
*Curtis, T., Manager, Nuclear Systems Engineering
Dixon, R., Valve Engineer
*#Geddie, E., Station Manager
Hatley, M., Supervisor, Maintenance Rotating Equipment
*Herran, P., Manager, Engineering
*Jones, R., Superintendent, Operations
Kinley, J., Supervisor, Nuclear Maintenance
#Manoocheer, N., Superintendent, Maintenance
*McMeekin, T., Vice President, McGuire Nuclear Station
*Snyder, J., Manager, Regulatory Compliance
*Thrasher, J., Manager, Modifications Engineering

Other licensee employees contacted included operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC Resident Inspectors

*Maxwell, G., Senior Resident Inspector
*Sykes, M., Resident Inspector

*Attended Exit Interview on April 23, 1996
#Attended Exit Interview on March 21, 1996

2.0 OPERATIONS (NRC Inspection Procedure 71707, 40500, 71714, and 60710)

Throughout the inspection period, inspectors conducted facility tours to observe operations and maintenance activities in progress. The tours included entries into the protected area and radiologically controlled areas of the plant. During these inspections, discussions were held with operators, radiation protection technicians, instrument and electrical technicians, mechanics, security personnel, engineers, supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshift inspections. The inspectors attended licensee meetings to observe planning and management activities. The inspections confirmed Duke Power Company's compliance with 10 CFR, Technical Specifications (TS), License Conditions, and Administrative Procedures. No cited violations were identified.

2.1 PLANT STATUS

Unit 1 operated essentially at 100 percent power throughout the reporting period.

Unit 2 operated essentially at 100 percent power until April 5 when the unit was shutdown for the scheduled Unit 2 End Of Cycle 10 refueling outage.

2.2 Unit 2 Reduced Inventory/Midloop Operations

Unit 2 entered reduced reactor coolant system inventory conditions in order to install steam generator loop nozzle dams and remove access manway covers. Prior to these operations and during reduced inventory conditions, the inspectors reviewed the schedule for entering reduced inventory conditions. The inspectors reassessed the planned work scheduled for the period of reduced/midloop conditions to identify any activity that might cause reactor coolant system level disturbances. The inspectors discussed the established controls and procedures used during these conditions with work managers, operations shift supervisors, and reactor operators.

Briefings were conducted by licensee management prior to entering reduced inventory to prepare the shift for the infrequently performed evolution. Management expectations and safety concerns were emphasized during the briefing. "Defense in Depth" sheets, which assess plant status based on reactivity, decay heat removal capability, containment integrity, reactor coolant system inventory, power availability, and spent fuel pool cooling were reviewed and updated, if necessary, during each shift by the Shift Work Manager. This information was reviewed and discussed during the daily outage team and station management meetings. The inspectors routinely verified the accuracy of the information during daily control room visits.

During the reduced inventory/midloop operations, a power source was available through the auxiliary transformers and two emergency diesel generators were 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 intermediate and high head safety injection. The necessary flow path was verified from the refueling water storage tank to the reactor. The inspectors verified that controls were in place for an adequate reactor coolant system vent during reduced inventory/midloop conditions. These controls were provided in procedure OP/2/A/6100/02, Controlling Procedure for Unit Shutdown. A containment closure coordinator was assigned to Unit 2 to

monitor the status of all closure exceptions and ensure that they could be promptly closed, if required.

The licensee also reduced the operating shift rotations from five shifts to four. The reduction in shifts generated additional licensed and non-licensed personnel to provide outage support to the operating shifts. The additional personnel were available to expedite the review and evaluation of planned outage activities to improve maintenance scheduling and execution without impacting plant safety.

The inspectors determined that the licensee provided adequate safety focus in preparing for the reduced inventory/midloop operation. The evolution was adequately coordinated and executed. The inspectors considered licensee controls of plant conditions to be comprehensive and appropriately implemented. The inspectors concluded that the licensee's shutdown risk awareness was adequate.

2.3 Cold Weather Preparation (NRC Inspection Procedure 71714)

Scope:

During the week of March 11 the inspectors evaluated the licensee's cold weather protection procedures in response to recent events related to the freezing of a Unit 2 refueling water storage tank level transmitter. Also, the inspectors continued the cold weather preparation inspection efforts that were documented in Inspection Report 50-369,370/95-29. The inspectors compared the licensee's freeze protection program to the commitments made in response to IE Bulletin 79-24, "Frozen Lines." The inspection included a walkdown of the freeze protection procedures with maintenance personnel, a drawing review with engineering personnel, and a procedure review with operations, maintenance, and engineering personnel.

Discussion:

The inspectors reviewed the two licensee procedures regarding freeze protection, PT/0/B/4700/38, Verification of Freeze Protection Equipment and Systems and IP/0/B/3250/59, Preventative Maintenance and Operational Check of Freeze Protection.

Concerning procedure PT/0/B/4700/38, Verification of Freeze Protection Equipment and Systems, the following observations were noted:

- The procedure did not have defined initiation criteria. The procedure was performed when a control room supervisor determined that freezing was an imminent potential hazard. This was inadequate because the secondary procedure it initiates, IP/0/B/3250/59, Preventative Maintenance and Operational Check of Freeze Protection, took months to complete. The secondary procedure involved checking the operability of some 300 control

circuits for heat tracing. The freeze protection circuitry evaluation was started on October 11, 1995, and was completed on January 31, 1996. This did not ensure that the system was operational prior to the plant being subjected to freezing temperatures.

- Procedure PT/0/B/4700/38 did not have guidance for the removal of the freeze protection. For example, step 12.4 in the procedure required that the exterior main steam stop valve enclosure (doghouse) vent curtains be lowered to retain heat inside the enclosure. The procedure did not contain guidance to assure that the curtains were maintained in place or properly removed.

Concerning procedure IP/0/B/3250/59, Preventative Maintenance and Operational Check of Freeze Protection, the inspectors reviewed the records of completion, walked down the procedure in the field, and discussed expectations with supervisory personnel. The following were noted:

- The procedure did not identify which electrical freeze protection controllers were required to be operationally checked. Instead the procedure relied on the performer to identify which controllers were to be checked by searching through some 75 drawings (which contain approximately 300 controllers). Apparently, the performer did not identify that the enclosure boxes for the RWST level transmitters contained strip heaters that should have also been checked for operability and adjusted.

- The procedure was written to perform maintenance on Nelson Electric Controllers. It was also used on Rochester controllers. The Rochester controllers were added to the freeze protection system circuitry in 1986. Engineering did not ensure the existing procedure was modified to identify the Rochester controllers.

- The procedure did not identify what settings the controller thermostats were to be adjusted to.

- The procedure did not identify the required electrical current values for energized heat trace or for the strip heaters located inside enclosure boxes that contained instrumentation. It required the performer to search through the applicable drawings to obtain those values.

Concerning maintenance and supervisory personnel assigned to perform procedure IP/0/B/3250/59, the following points were observed:

- A single individual was used to perform and identify all of the operational checks required. This introduced a potential common mode failure.

- The single individual performing the work was allowed to mark steps as Not Applicable (N/A).

- The individual performing the work marked the steps requiring the identification of calibrated equipment as N/A.

- Step 10.3.1 directed the performer to use a temperature source (ice bath or equivalent), to verify that the controller energized at low temperatures. The performer marked this step N/A for every heat trace controller. The performer instead dialed up the thermostat to obtain a controller response. The reason the performer deviated from the procedure guidance was stated that it would be too difficult, requiring the removal and reinstallation of the piping insulation and the sensing bulb.

  In the next step, the performer then dialed the thermostat down to a setting of approximately 40 on the controller. Neither the performer or the engineering staff were able to produce documentation verifying that 40 was the correct setting for all applications. Based on the lack of an explanation for the values of the settings, the inspectors determined that the procedure did not provide the necessary guidance to allow for a meaningful and practical method of adjusting the controller thermostats.

Engineering of the Enclosure Boxes:

The enclosure boxes, which in some cases contain safety grade instrumentation, do not allow easy access for preventative maintenance. For example, the inspectors observed two maintenance personnel removing the cover for an enclosure box that housed the Reactor Water Makeup Level Instrument. The enclosure lid was secured with eight bolts and a silicone sealant. After removing the bolts, the two individuals spent 10 minutes prying the lid off. With both individuals pulling on the lid, the box bowed at the top about 4 inches. It appeared that it would take several hours to reattach the enclosure lid to a water tight configuration. The inspectors noted that this type instrumentation enclosure did not offer ease of access for routine inspection or maintenance.

Conclusion:

The inspectors found the program for freeze protection to be ineffective. The Licensee's commitments to IE Bulletin 79-24 were not met by the licensee due to the following:

- Inadequate engineering of the heat trace/freeze protection system and the procedures which maintained the system. The procedures did not cover verifying operability and proper adjustment of the strip heaters for enclosure boxes that contain sensitive instrumentation.

- Poor maintenance practices.
- Inadequate supervision of maintenance personnel.
- Complacency with regard to the use of procedures.

Discussions were conducted between the licensee and NRC management concerning corrective actions and the level of attention that the site has recently placed on improving and maintaining freeze protection equipment. The licensee's discussions with NRC management provided assurance that the freeze protection program issues that were documented in 50-369,370/96-02 had been reviewed and a team developed to verify program adequacy. The inspectors noted that the short term corrective actions had been implemented and that long term actions should reduce the likelihood of any further freeze protection issues at the site.

This review was a follow up on cold weather preparation issues which were the subject of escalated enforcement as documented in inspection report 50-369,370/96-02.

3.0 MAINTENANCE (NRC Inspection Procedures 62703 and 61726)

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 selected tests and maintenance activities included:

Procedure/Work Order	Equipment/Test
PT/0/A/4600/77	Full Length Rod Control Cluster Assembly Drop Timing
MP/0/A/7150/73	Rod Control Cluster Assembly Heavy Drive Rod Unlatching and Latching
PT/2/A/4206/15B	2B Safety Injection Pump Head Curve Performance Test and Acceptance Criteria and acceptance testing of Various NI Check valves

The inspectors concluded that the above tests were conducted in accordance with the procedures. No cited violations or deviations were identified.

3.1 Water in Unit 1 B Charging Pump Motor Inboard Bearing Oil

On February 25 water was identified in the inboard bearing oil sightglass of the 1B NV pump motor. The licensee initiated activities to identify the source of the water. Since the bearing oil is not water cooled, water intrusion was thought to be from condensation or a result of decontamination activities previously performed. Oil samples were collected for analysis and 36 ounces of new oil was flushed through the reservoir with the component in service. The pump was later taken out of service and the oil was completely drained. The oil fill tube was wiped clean of condensation and new oil was added. Also, the oil fill sight glass was removed to help vent moisture out of the oil reservoir. The component was returned to service. The licensee continued to take oil samples to confirm that no moisture was present. However, samples indicated that the water intrusion continued.

The charging pump motor cooler cover was removed to reveal the inboard bearing housing. After removing the cover, the licensee discovered that the motor cooler condensation catch pan had four bolts missing allowing condensation within the motor cooler to migrate through the bolt holes and drip onto the motor shaft and bearing housing. The bolts in question were located under the inboard cooler. The licensee replaced the bolts and reinstalled the motor cooler cover. To ensure that other motors were not vulnerable to water intrusion, the licensee inspected similar motors to ensure that all motor cooler condensation catch pan bolts were installed. None were identified to be missing.

The licensee also evaluated the consequences of moisture intrusion. The results of the evaluation indicated that because of the small amount of water present in the oil (approximately 1.5 ounces) and the emulsification properties of Exxon Teresstic lubricants, the oil would maintain its lubrication properties. Since the charging pump motor bearing reservoirs hold approximately 38 ounces of oil, the small amount of water would not have prevented the oil slinger ring from providing sufficient motor bearing lubrication. Vibration data and bearing temperature information also reinforced the conclusion that the component was operable and could perform its intended safety function.

The inspectors reviewed the circumstances surrounding the licensee's findings and determined that the original procedure used to perform motor bearing maintenance failed to prevent omission of the bolts and therefore was not adequate to prevent water intrusion into motor bearing oil. Current procedures used for motor corrective maintenance provided adequate guidance to prevent a similar occurrence. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement

Policy. The item will be identified as NCV 96-03-01; Inadequate Procedure for Charging Pump Maintenance.

3.2 Unit 1 On-Line Maintenance

Due to a steady decrease in the Unit 1 B reactor coolant pump motor lower oil pot level, the licensee has scheduled to reduce reactor power to approximately 15 percent on May 25, 1996, to makeup to the lower oil pot. The licensee will also make an attempt to identify the source of the leak. The loss of oil was identified following the unit restart from 1EOC10. The licensee used online level monitoring equipment to identify a 0.03 inches per week decrease in lower oil pot inventory. The oil level has decreased approximately 0.25 inches below normal oil level. Because each of the unit reactor coolant pumps is equipped with an oil capture and drainage system, the licensee concluded that no immediate operability or fire safety concerns had been created. The licensee has predicted that the oil level will reach the low level alarm setpoint on or near May 25 (approximately 4 months after the Unit 1 EOC10 restart).

The oil addition was scheduled to be performed under WO 96015615. Due to the design and location of the oil reservoir, the licensee has not planned to repair the leak unless the pump is secured.

During the unit downpower to add oil to the 1 B motor lower oil pot, the licensee has also proposed to change taps on the 1A and 1B main stepup transformers to support Duke Power Transmission needs. The tap change requires each of the Unit 1 offsite power sources to be taken out of service. The unit will continue to operate between 15 and 50 percent generator output. This maintenance activity has previously been performed during unit outages when two buslines are not required by station TS. The proposed change involves voluntary entry into the 72 hour action statement of TS 3.8.1.1.a. for each transformer tap change. The evolution will include a hot bus transfer of 6.9 kV loads from the normal supply to the unit 1 auxiliary transformers 1ATA and 1ATB. The hot bus transfer and the removal of an offsite power source from service during power operation has not been previously performed at McGuire. The licensee has also planned to perform a similar evolution at another licensed facility.

The inspectors reviewed the potential cumulative impact of the maintenance activity on overall plant safety. The inspectors reviewed the licensee's plans to perform the maintenance activities and related contingencies. The inspectors concluded that the licensee had adequately planned for the proposed on-line maintenance activities. However, the inspectors noted that the performance of the transformer tap change may potentially result in an insignificant increase in plant risk.

3.3 Valve 1KC1A Replacement

Background:

Following completion of component cooling (KC) system flow balancing on Unit 1 "A" train on January 19, 1996, the 1KC1A valve failed to reach its full open position. The licensee performed an investigation and determined that the valve actuator was not the source of the problem. Additional attempts at cycling the valve remotely to its open and closed positions were also unsuccessful. This inability to cycle the valve to its safety-closed position from the control room resulted in the valve being inoperable. The 72 hour LCO per TS 3.7.3 was entered. The 1KC1A valve was subsequently closed by a combination of electrical and manual manipulations. When the 1KC-1A valve was returned to its safety position, Unit 1 "A" train was declared operable. The licensee calculated the total time the "A" train of the KC System was inoperable and determined that it was approximately one hour and eight minutes.

Valve 1KC1A is the "A" train auxiliary building non-essential return header isolation valve and it is a motor-operated safety-related valve. It is controlled from the control room with valve position indicated on the main control board. For "A" train operation, this valve is open, but it can be either open or closed for "B" train operation. Normally for "B" train operation this valve is closed. Upon safety injection actuation, valve 1KC1A will receive a signal to close automatically to provide isolation of the associated non-essential equipment and provide separation between the two KC trains.

Once the 1KC1A valve was secured in the safe-closed position and declared inoperable, the licensee made plans to replace it with a new equivalent valve. This work was being performed under a temporary modification (TM) which was being implemented under work order No. 96011835. The inspectors ascertained that temporary equipment including pumps, valves, and associated piping will be installed to provide temporary cooling flow capacity to the KF1A heat exchanger and the chemical volume control (NV) seal water heat exchanger. Specifically, the components and associated piping installed included two centrifugal pumps, PVC piping of 6 and 3 inches in diameter, a 2 inch diameter rubber hose, 6 inch manual valves, one 2 inch manual valve, one 3 inch manual valve, three 1/2 inch manual valves and one pressure gauge at the discharge header for the pumps. The electrical power requirements were for the two pumps and was provided by a non-safety-related shared motor control center.

The system connections for this TM were installed by Minor Modifications MGMM-8028 and MGMM-8076, which installed permanent piping and manual isolation valves so that the temporary KC cooling loop can be tied into the KC system. The four places where the temporary KC cooling loop connected into the KC system were:

1) the 6 inch connection between valve 1KC1A heat exchanger
2) the 6 inch connection downstream of the KF1A heat exchanger (KC piping)
3) the 2 inch connection on the KC surge tank drain line
4) the 3 inch connection downstream of the seal water heat exchanger (KC piping)

MGMM-8028: This MM was the controlling document for the installation of three permanent connections to the Unit 1 "A" KC train which were as follows:

1) A six inch pipe with a flanged connection was installed downstream of the KF1A heat exchanger between valve 1KC0150 and pressure transmitter 1KCPX5150. The pipe and flanged end are classified ASME Class C and the material was made from mild carbon steel.

2) A two inch connection was installed on the KC surge tank drain line between valves 1KC0118 and 1KC0119. The classification of this connection was Class E, and was made of stainless steel material. It included a manually operated ITT ball valve and a capped end. The added ball valve was identified as 1KC0984.

3) A three inch connection was installed downstream of the seal water heat exchanger between valves 1KC0141 and 1KC0142. The classification of this connection was Class C and the material was also made with mild carbon steel. Components included a manually operated ball valve and a flanged end. The added ball valve was identified as 1KC0982.

MGMM-9028: This MM was the controlling document for the installation of a two inch drain line connection between valve 1KC1A and 1KC2B to allow draining of any leakage past the two aforementioned valves when they are closed to facilitate the replacement of 1KC1A. The two-inch connection, which is a Class C classification has a manually operated two-inch stainless steel ball valve attached. When not in use, this valve was to be closed with the pipe capped.

MGMM-8016: This MM was the controlling document for the installation of a six inch connection with an isolation valve (1KC0983) on the Unit 1 KC, "A" train between valve 1KC31 and the KC1A heat exchanger. This tie-in will be upstream of the above mentioned heat exchanger and will provide an alternate path of supplying coolant to the 1KF1A heat exchanger and the seal water heat exchanger. The classification of this connection was Class C. The piping was made from mild carbon steel material.

Codes and Standards: Installation of the connections, discussed under the above mentioned MMs, was accomplished under ASME Code, Section III, 1971 Edition, Winter 1971 Addenda, Class C requirements.

Temporary procedure TO/1/A/9600/084, Temporary Component Cooling Water system, was issued to provide necessary instructions for operating the Temporary Component Cooling (TKC) system and to provide appropriate contingencies if cooling capacity was lost. At the time of this inspection, installation/ welding on the above mentioned connections were completed. The inspectors observed the completed welds for appearance, workmanship quality, and identification of piece and weld number. Following this field inspection, the inspectors reviewed quality records of replacement valve 1KC1A, identified as 20 inch NNMKII, which was manufactured by Henry Peatt Company in accordance with Duke Specification MCS-1205.02-00-0002 Rev. 14 and ASME Code, Section III (71W72) Edition.

Within these areas, the inspectors reviewed Code Data Report Form NPV-1 to verify design conditions, hydrostatic test results, certificate of conformance, and inspection and identification of valve components. In addition, the inspectors reviewed material certification fabrication and nondestructive examination results associated with this valve. The licensee's receipt inspection report dated February 15, 1996, was reviewed for completeness and accuracy. This report described the subject valve as a butterfly wafer 20 inch, 150 pounds at 160°F, electric motor-operated, flanged type. The valve was procured under Duke's purchase order No. MN10931 and was assigned QA number MC 43621.

Quality records of welding consumables used to install the above mentioned connections were reviewed for completeness, accuracy, and compliance to applicable code requirements. Consumables selected for this review were as follows:

Type	Dimens.	Heat	QA #	MSCH
ER 308	1/8 x 36	703435	MC40584	Arcalloy
ER 309	3/32 x 36	18167C	MC10351	Arcalloy
ER 70 S-2	3/32	L02015	MC35378	Techalloy
ER 309	1/8 wire x 36	PG773	MC38626	Arcalloy
ER 308	3/32	PG770	MC39122	National

Welders

Qualification of welders utilized for fabrication of tie-in welds were reviewed to verify whether they were qualified to the welding process,

type material, and thickness. Documents reviewed in this work effort were in order.

The inspectors observed portions of the valve replacement. The inspectors noted that the "A" train of KC was removed from service and Unit 1 voluntarily entered the 72-hour Action Statement for TS 3.7.3. Valve replacement was executed and when this was accomplished, the KC system was returned to service. Following the replacement and testing, the temporary system was disassembled and removed per the aforementioned temporary procedure.

3.4 Surveillance Observation (61726)

3.4.1 Diesel 2A Lube Oil analysis WO-95093507-1

This WO was issued to perform a lube oil analysis on 2A diesel generator under procedures MP/0/A/7300/036 Diesel Engine Lubrication and Oil Sampling and MP/0/A/7300/047 Diesel Turbocharger Oil Sampling and Replenishment.

The inspectors observed that the requirements of MP/0/A/7300/036 were met. The technician verified and documented the type of oil in various areas of the diesel engine was consistent with the Station Lubrication Manual; checked oil levels; lubricated the fuel pump and starting air distributor; and withdrew the proper amount of oil (3 oz) from the post filter sample valve (2LD-9001) and an equal amount from the crankcase as required by the subject procedure. In a similar manner a 3 oz oil sample was removed from the turbocharger following MP/0/A/7300/46, Step 11.3 Turbocharger oil sampling and replenishment. In this case, the amount removed was replaced by an equal amount. Equal amounts were retrieved following a diesel run of about an hour; however, this activity was not observed by the inspectors. The oil samples were subsequently sent to the laboratory for an analysis. Results of this analysis were forwarded to the inspectors for review following the close of this inspection. A review of these results showed no evidence of abnormalities.

3.4.2 Containment Hydrogen Analyzer Monthly/Quarterly Calibration, IP/0/A/3250/39

WO 96016811-01: This WO was issued to perform calibration checks on the Unit 2 hydrogen analyzer per procedure IP/0/A/3250/39. As such, the inspectors reviewed the procedure and verified that it conformed to applicable TS requirements and that proper licensee reviews and approvals had been completed. Also, the inspectors verified that instrumentation was within calibration. During the testing, the inspectors verified that procedural requirements were being met and critical instrument readings and operating ranges were within acceptance criteria or otherwise noted and communicated to supervision for resolution. Within these areas, the inspectors noted that the test had

to be interrupted to replace a hydrogen gas cylinder which showed a pressure indication that was below procedural requirements. When testing was resumed, the inspector noted that at the local panel, the as-found reagent gas flow rate of 33 cc/min. exceeded the acceptable range identified in the procedure as approximately 10 to 25 cc/min. Through discussions with the cognizant engineer, the inspectors ascertained that the acceptance range was not a setting established through calculations but rather an engineering estimate obtained through discussion with the equipment manufacturer. Therefore, the licensee considers any flow rate which was relatively close to this range as satisfactory. In response, the inspector stated that since the procedure has an acceptance criteria of 10 to 25 cc/min., even though it was qualified as approximate, flow rates would be expected to fall within this range. Also, the inspectors stated that if previous test data shows that these conditions cannot be met with constancy, then an evaluation should be performed to determine a more realistic range that would be achievable during operations and/or testing. In response to this concern the licensee issued PIP No. 0-M96-0757 for the purpose of evaluating this problem further and taking appropriate corrective action.

3.5 Maintenance Self-Assessment

The inspectors met with the licensee's maintenance superintendent and discussed the self-assessment program at McGuire including: component failure analysis reports, the failure analysis and trending program, maintenance self-assessment results, corrective actions taken during 1995, and the foreign material exclusion assessments. During 1995 the maintenance self-assessment group conducted a total of 51 assessments on various maintenance activities including electrical, I&E, valves, rotating equipment, mechanical, and ESS services. Of these, there were four areas which were identified as requiring improvements. These areas included written communications, work practices, training/qualifications, and work organization/planning. The report provided an assessment of the problem and specific recommendations for improvements.

Component failure rates are trending downward (improving) although there is still a number of components whose failure rates continue to rank below industry standards. For example, the number of components in this category was reduced from 39 in June 1994 to 21 in June 1995. Some of these components included, blowers (fans/ventilators), inverters, computation modules, power supplies, valves, pneumatic/diaphragm/cylinders, and reactor coolant temperature T-average channels. Poor performance of certain motors continues to be a problem. Components where problem motors have been identified include pumps, ventilation equipment, and S/G blowdown equipment motors. To address this problem the licensee has established a Rotating Equipment Group whose goals are: correct the problems, prevent their recurrence, and improve McGuire's motor performance reliability such that the motor

failure ratio for nuclear plant reliability systems will be equal to or less than the top 50% of the industry by 1998. In addition to the above effort, the inspector reviewed Work Order Backlog trending data beginning with December 1995 to the present. This data showed that the total inventory ranged between 500 to 600 while those greater than 90 days averaged around 200. The backlog of work orders greater than 180 days was in the range of 80 to 100.

3.6 Core Offload - Unit 2

Based on observations, discussions with cognizant licensee personnel, and reviews of documentation, the inspectors determined that operations and engineering personnel adequately coordinated activities in the fuel handling building, reactor building, and control room. Core unloading operations were conducted in accordance with procedures PT/0/A/4150/37, Total Core Unload. Spent Fuel and Reactor Building fuel handling and manipulator bridge performance improved; however, minor delays were encountered because of communication problems between the reactor building and the control room. These problems did not significantly impact the licensee's core offloading activities.

The licensee performed a full core offload to the Unit 2 spent fuel pool. Since the current McGuire Safety Analysis Report states that a full core offload is not a routine refuel activity, the licensee performed a safety evaluation to verify that this activity did not involve an unreviewed safety question. The evaluation was completed prior to fuel offload. No changes to plant systems or components were necessary. The licensee evaluation concluded that no unreviewed safety question existed. The inspectors reviewed the licensee's evaluation and concluded that the evaluation was adequate.

Due to rod control cluster assembly (RCCA) wear concerns, the licensee replaced all 53 RCCAs. The replacement RCCAs were manufactured by Framatome using boron carbide as the absorber in a stainless steel cladding. During visual inspections of the replacement RCCAs, the licensee observed a yellow residue forming on the cladding of the RCCAs. The licensee sampled the material and contacted the manufacturer to obtain additional information on the manufacturing process. It was determined that the material was a metal oxide that resulted from the nitriding process utilized by the manufacturer. The environmental conditions (low temperature, high oxygen) in the spent fuel pool accelerated the oxidation process.

The inspectors concluded that licensee communication, coordination, procedural adherence, and safety focus was good during core offload activities.

3.7 Unit 2 Steam Generator Tube Plugging

Based on preliminary tube plugging results, the inspectors observed that steam generator tube plugging was significantly lower than the licensee pre-outage projections anticipated. Currently, approximately 180 tubes have been plugged instead of the anticipated 400 plugs. The licensee attributed the low number of plugs to improved water chemistry. The licensee has planned to replace the Unit 1 and Unit 2 steam generators during the upcoming scheduled refueling outage. The reduction in the number of plugs installed helped to avoid a second draindown to midloop for nozzle dam removal. The inspectors noted the licensee performance in completing the steam generator maintenance was suitable to reduce shutdown risk and was considered a good maintenance practice.

3.8 Unit 2 A Reactor Coolant Pump Motor Inspection

During the Unit 2 EOC10 refueling outage, the licensee performed replacement of the 2A reactor coolant pump stator. The inspectors witnessed portions of the maintenance activity. Following disassembly of the pump motor, the licensee identified insulation breakdown as a result of stator end winding vibration. Additional investigation by the licensee revealed that the windings were not as structurally sound as assumed. Each of the windings was not secured to the structural support ring, allowing vibration to occur. This vibration accelerated stator winding insulation degradation. The licensee recognized this as a design concern and has planned to conduct similar inspections during upcoming refueling outages and to perform stator rewind and reinsulation for the remaining coolant pump motors as part of the normal motor rebuild rotation. The inspectors concluded that the licensees action to replace the 2A motor stator and future plans to rebuild the remaining pump motor stators was conservative and should improve equipment reliability.

3.9 Close Out Issues

3.9.1 (CLOSED) IFI 50-369,370/95-29-01, MSSV Testing in Mode 1. This item was identified because the 50.59 evaluation written to address the change to testing the MSSVs in Mode 1 rather than Mode 3 had not adequately addressed the potential impact to nuclear safety posed by this change. See Report 50-369,370/95-29 for details.

During this inspection the licensee provided memorandum MMNE96-003, dated February 16, 1996, Review of 50.59 Questions for PIP O-M95-2202, Use of PT/0/A/4250/01 in Mode 1; File No. MC 1503.13-00. This document addressed the inspector's concerns including the probability of FSAR unreviewed safety questions dealing with the increased probability of an accident, consequences of an accident, possibility of a different type accident than those evaluated, the increased probability of a malfunction of equipment, the increased consequences of a malfunction of

equipment, and the possibility of reducing the margin of safety as defined in the TS.

The inspectors agreed with the conclusion that changing of the Mode for testing of the MSSVs posed no new unreviewed safety questions and that this evaluation helped to clarify the original evaluation. This item is closed.

4.0 ENGINEERING (NRC Inspection Procedures 37551)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying, and resolving safety issues.

4.1 Response to Bulletin 96-01: CONTROL ROD INSERTION PROBLEMS

On April 4, 1996, the licensee submitted their response to NRC Bulletin 96-01 for review by the NRC staff. The licensee's response indicated that the plant's operators were promptly advised of the industry events described in the subject Bulletin. Review of operator simulator training programs were also reviewed and determined to have adequately covered the scenarios associated with the Bulletin events, (ie. stuck rod). In addition, review of Reactor Trip Response Procedure EP/1/A/500/ES-0.1 indicated that the procedure contained the required actions for plant operators to take in the event that all control rods were not fully inserted (i.e., boration).

The licensee also performed an operability evaluation utilizing the NSD 208, Problem Identification Process (PIP), and NSD 203, Operability. Beginning of cycle rod drop times and drag tests were reviewed for the last five years of operation. All acceptance criteria were met for the testing and no adverse trends were noted. All control rods reviewed had exhibited the rod recoil effect on the rod timing traces. The licensee also reviewed the results of reactor trip evaluations for the past five years. There were no cases of slow or sticking rod control cluster assemblies (RCCA) identified. In addition, preview of periodic rod movement (freedom) testing, performed every 31 days, identified no anomalies. It should be noted that, currently, both operating cores are composed of all Framatome Cogema Fuel (FCF) Mark BW fuel.

Review of RCCA data beyond five years identified that at the end of McGuire Cycle 6, it was observed that an RCCA would not insert into the final 8 inches of assembly S18. This assembly was a Westinghouse Optimized Fuel Assembly which had operated two fuel cycles (burnup of 24,500 MWD/MTU). Inspection revealed a fuel assembly bow of approximately 1/4 inch, which was considered normal. All guide tubes were inspected and none were found to be blocked. The RCCA was moved to another location and a different RCCA was inserted in S18. The different RCCA would not insert completely into assembly S18 either. The licensee redesigned the core to allow placement of the bowed S18

assembly into a non-rodded location for the final cycle. No other problems were identified.

As part of their response to the subject Bulletin, the licensee performed testing on Unit 2 RCCAs to identify potential problems regarding recent industry events with control rods failing to fully insert. Specifically, the testing was performed to identify failures associated with rod drop timing, rods failing to bottom, and rods exhibiting high drag forces. Review of the Unit 2 testing activities is discussed below.

The inspectors evaluated and witnessed the rod control cluster assembly (RCCA) drop time testing performed on Unit 2 during the 2EOC10 refueling outage shutdown. The testing was performed per PT/0/A/4600/77, Full Length Rod Control Cluster Assembly Drop Timing. The results of the testing indicated that all 53 RCCA locations met the TS required drop time criteria (2.2 seconds) and exhibited normal recoil. The average drop time was 1.47 seconds with the highest indicated time being 1.61 seconds. The licensee did identify that four RCCAs showed slight increases in drop times (100 to 200 milliseconds) from test data obtained in January 1995. Three of the four locations had achieved burnup rates greater that 45,000 MWD/MTU. At the end of the inspection period, the licensee was continuing to evaluate the testing results for abnormalities. The inspectors noted that all 53 Unit 2 RCCAs are being replaced during the current refueling outage to mitigate other RCCA concerns not related to the subject Bulletin. The other concerns involve cladding wear at the guide plate and additional concerns with rod tip swelling which have been associated with B_4C material RCCAs.

The licensee also performed RCCA drag testing prior to off-loading the core. The procedure, Rod Control Cluster Assembly Heavy Drive Rod Unlatching and Latching, MP/0/A/7150/73, was revised to include drag testing during drive rod unlatching. Based on licensee data, all control rods were determined to be within Westinghouse F-Spec No. 7.1 tolerances.

Based on review of the licensee's response to Bulletin 96-01 and review of Unit 2 RCCA testing activities, the inspectors concluded that Unit 2 RCCA performance was consistent with procedural acceptance criteria and no unexpected anomalies were identified. Additional testing is scheduled to be performed on the units during the next refueling outage or during any non-scheduled outage duration (return to MODE 2) of greater than 72 hours. The licensee does not plan to repeat the testing if it has been previously performed on the same unit within the last 62 effective full power days.

4.2 Adverse Component Cooling Water System Valve Performance

Following the initial failure of component cooling water system non-essential header return isolation valve, 1KC1A, to close during testing, other similar valve performance issues were discovered within the component cooling water system. During the repair of 1KC1A, valves 1KC2B and 1KC53B which are the B Train supply and return isolation valves to the non-essential KC header failed. The failure of these valves has the potential to render the B train of the component cooling water system inoperable. The valves were evaluated and tested by maintenance personnel. Currently, it appears that the failures were not of a generic nature. The licensee has identified changes to the applicable procedures to correct the identified deficiencies. The licensee will also complete operability evaluations and root cause evaluations for the valve failures.

On March 28 during realignment following planned maintenance on 1KC1A, 1KC2B could not be closed either manually or electrically. The failure of 1KC2B occurred while repairs were being performed to repair 1KC1A and resulted in the licensee entering TS 3.0.3 due to both trains of component cooling water being inoperable. After corrective maintenance to the gearbox clutching mechanism was completed the valve was manually placed in the safe position (CLOSED) and the 'B' train operability was re-established prior to expiration of the LCO Action Statement. The unit remained at 100 percent power. Valve 1KC2B is required to close on a safety injection signal to isolate the B train of component cooling water from the auxiliary building non-essential header to ensure an adequate flow of water to the essential header loads during accident conditions. This valve closure also provides train separation to mitigate a leak or rupture of one train.

The B Train supply valve to the non-essential header, 1KC53B, also failed to close during the realignment process following the repairs to 1KC1A. The valve operator limit switches were determined to be set non-conservatively. The valve would close approximately four handwheel turns from full close. Valve operator technicians adjusted the valve limit switches and verified adequate valve operation. The licensee completed an operability evaluation following the repair of the valve; however, a past operability has not been completed to determine if the event is reportable under 10 CFR 50 requirements.

Since each of the recent component cooling water system valve failures have occurred on ESF isolation valves, the inspectors communicated a concern to licensee management regarding the condition of these valves and similar valves in safety related applications. The licensee is currently reviewing the failure mechanisms and procedural guidance to identify any changes that may be necessary. Additional inspections in this area will be performed to better assess the adequacy of the licensee's actions.

4.3 Closeout Issues

4.3.1 (CLOSED) LER 50-369/93-10; Potential Exists for the Loss of The Residual Heat Removal System As A Part of the Emergency Core Cooling System Because of a Design Deficiency

This LER was written by the licensee in response to a Westinghouse Nuclear Safety Advisory Letter dated April 20, 1993, that involved the operation of the residual heat removal system. The specific points of concern included the potential degradation of the system pump performance due to potential vapor binding should an accident condition occur with the unit in a normal startup configuration. If the pump suction piping was not cooled prior to the system being removed from service, voids may be present when it was aligned for standby readiness. The licensee determined that this condition could have occurred while the unit was in Hot Standby or Hot Shutdown and the plant was being returned to power operations.

Prior to receipt of the advisory letter, the licensee did not have any procedural controls in place that would have prevented the potential vapor binding from occurring during plant startups at McGuire. Subsequently, the licensee has revised the applicable mode change procedures to ensure that cooling of the RHR pump suction piping has been completed prior to RHR system realignment.

The inspectors noted that Westinghouse, in resolution of this concern, issued WCAP-12476 which concluded the relative risk and safety significance was small. Also, the McGuire station would have been susceptible to this potential issue for only a very few occasions. Under normal startups following refueling outages, the RHR system pressure boundary isolation valves were leak tested using the check valve test header which would cool the suction piping and eliminate the potential for pump suction voiding. This would have reduced the potential inoperability of the RHR system for the few hours necessary to cool the pump suction piping following heatups during unit forced outages when leak testing of the system discharge leg check valves was not required. The inspectors verified that the licensee has revised the appropriate procedures, OP/1 & 2/A/6200/04, Residual Heat Removal System, to require cooling of the RHR system suction piping prior to realignment to standby readiness as a part of the ECCS when entering Mode 3. The changes were considered satisfactory to prevent creation of voids and should preclude the possibility of the RHR system becoming inoperable during mode changes as discussed above. Therefore, this item is closed.

5.0 PLANT SUPPORT (NRC Inspection Procedures 71750, 81070 and 83750)

Plant support activities were observed and reviewed to ensure that programs were implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. Activities

reviewed included radiological controls, physical security, emergency preparedness, and fire protection.

5.1 Unit 2 Thermolag Removal

During 2EOC10, the licensee completed removal of Thermolag fire barrier material from site applications. The licensee completed station modifications to alleviate the need for the material. The modifications included installation of check valves in the auxiliary feedwater piping to prevent the loss of condensate grade water to the service water system after opening valves CA161 and CA162 in accordance with operating procedures during a fire event. Disable/Enable switches were installed at the Safe Shutdown Facility Control Panel to allow operators to isolate the 250 VDC feeder power to valves CA161 and CA162 to prevent inadvertent closure subsequent to their opening during a fire event. This modification was completed for Unit 1 during the 1EOC10 outage and has been installed and tested on Unit 2 during the 2EOC10 outage. Operational Appendix R Safe Shutdown procedure revisions which incorporate the use of the check valves and the Safe Shutdown Panel control switches were implemented for Unit 1 operations. The changes have not been completed for Unit 2.

The licensee also removed the Thermolag from A train equipment cables that passed through a B train switchgear room and replaced the cabling with Whittaker Electronics Appendix R fire resistant cables. The Whittaker cables were developed for fire protection applications and harsh environments. The cables utilized a stainless steel sheath around silicon dioxide insulation using eight #12 AWG nickel coated copper wire conductors. The cables were tested in accordance with ASTM E119 (UL 263, NFPA No. 251) by Underwriters Laboratory Inc. in 1986.

The inspectors reviewed the licensee test results and determined that conductor resistance, insulation resistance, and dielectric strength measurements were acceptable. Since the cabling was used as control power cable, ampacity derating did not apply. The inspectors concluded that the licensee's actions to remove the Thermolag fire barrier material from the site was conservative and should not adversely impact plant safety.

6.0 Other NRC Personnel on Site

Paul Steiner, Region II Inspector, was on site March 11 through 15 to assist the Resident Inspectors.

Scott Schaeffer was on site April 8 through 12 acting for the Senior Resident Inspector.

7.0 FSAR Review

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the area inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

8.0 EXIT

The inspection scope and findings were summarized on April 23, 1996, with those persons indicated by an asterisk in paragraph 1. An interim exit was conducted on March 21, 1996. The inspectors described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
IFI	50-369,370/95-29-01	CLOSED	MSSV Testing in Mode 1 (paragraph 3.4)
NCV	50-369/96-03-01	CLOSED	Inadequate Maintenance Procedure (paragraph 3.1)
LER	50-369/93-10	CLOSED	Potential for Loss of RHR Because of a Design Deficiency (paragraph 4.3.1)

9.0 ACRONYMS

ASME	American Society for Mechanical Engineers
ECCS	Emergency Core Cooling System
ESS	Electrical Systems Support
FCF	Framatome Cogema Fuel
IE	Inspection and Enforcement
IFI	Inspector Followup Item
FSAR	Final Safety Analysis Report
KC	Component Cooling Water System
LCO	Limiting conditions for operation
MM	Minor Modification

ENCLOSURE

MSSV	Main Steam Safety Valve
N/A	Not Applicable
NCV	Non-Cited Violation
NSD	Nuclear Station Directive
NV	Chemical and Volume Control
PIP	Problem Identification Process
QA	Quality Assurance
RCCA	rod control cluster assembly
RHR	Residual Heat Removal System
RWST	Refueling Water Storage Tank
TKC	Temporary Component Cooling System
TM	Temporary Modification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	Work Order