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Licensee: Duke Energy Corporation

Facility: McGuire Nuclear Station, Units 1 and 2

Location: 12700 Hagers Ferry Road  
Huntersville, NC 28078

Dates: May 9, 1999 - June 19, 1999

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Enclosure

## EXECUTIVE SUMMARY

### McGuire Nuclear Station, Units 1 and 2 NRC Inspection Report 50-369/99-04, 50-370/99-04

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a six-week period of resident inspections, as well as the results of announced inspections performed by a regional inspector and a visiting resident inspector.

#### Operations

- The licensee's efforts to identify and eliminate a reactor coolant system leak within the Unit 2 pressurizer cubicle were well planned and executed. (Section O2.2)
- A non-cited violation was identified concerning a failure to totally remove a vent ring from a pressurizer vent valve. (Section O2.2)
- A non-cited violation was identified for failure to provide adequate corrective actions to prevent the recurrence of a Unit 2 steam generator power operated relief valve shaft key problem. The inadequate corrective actions for replacement of a missing key on valve 2SV-1 in 1996 contributed to two similar failures in 1999. (Section O4.1)
- A negative observation was made for an NRC identified configuration control problem involving an inappropriately capped air vent for steam generator power operated relief valve 2SV-13. (Section O4.1)
- Housekeeping in the doghouses and the material condition of the steam generator power operated relief valve were adequate. Licensee implemented recommendations from a 1997 self-assessment on steam generator power operated relief valves' accessibility improved operators' ability to successfully complete time critical actions. (Section O4.1)

#### Maintenance

- Maintenance and engineering efforts to troubleshoot and repair the 2A emergency diesel generator were focused and well controlled. This focus allowed the licensee to promptly resolve the identified problem and restore the diesel to an operable configuration. As a result of the apparent root cause, the licensee was reviewing the established breaker preventative maintenance program for enhancements to preclude future problems in this area. (Section M2.1)
- The June 11, 1999, control room area ventilation system air handling unit bearing corrective maintenance was performed in accordance with the work order, procedures, and the associated Technical Specification. Compensatory measures were conservative with thorough Plant Operations Review Committee and Nuclear Safety Review Board review and comment. A detailed and complete pre-job briefing included discussion regarding contingency actions if the running train of control room ventilation became inoperable during the planned maintenance. Strong maintenance supervisory oversight and engineering support were provided. (Section M4.1)

- A non-cited violation was identified for previous failures to enter and/or comply with the associated action statements for Technical Specification 3.7.7 for a number of periods when electrically deenergizing auxiliary building filtered exhaust system fans. (Section M8.1)

#### Engineering

- Documentation of the required safety reviews to support the leak search evolutions within the pressurizer cubicle while generally adequate, was less than thorough in documenting one alternate heavy load scenario. (Section O2.2)
- The Year 2000 checklist, per Temporary Instruction 2515/141, was completed. Overall, the Year 2000 project is about 90 percent complete and the contingency plan is about 90 percent complete. (Section E2.1)
- System engineering's use of an independent bearing expert was appropriate in addressing a failed control room area ventilation system air handling unit bearing. Corrective actions for the June 1999 repair were adequate. (Section M4.1)
- A non-cited violation was identified for inadequate corrective actions following a failed safety-related air handling unit bearing in March 1999. A repetitive bearing failure was experienced in June 1999. (Section M2.1)

## Report Details

### Summary of Plant Status

#### Unit 1

Unit 1 operated at approximately 100 percent of licensed thermal power throughout the inspection period.

#### Unit 2

Unit 2 operated at approximately 100 percent of licensed thermal power throughout the inspection period with the exception of a brief reduction in power to 91 percent on June 8, 1999, for anticipated solid state protection system response time testing. The testing was later determined not to be required at that time and the unit was restored to 100 percent power.

## 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 following sections.

### **O2 Operational Status of Facilities and Equipment**

#### **O2.1 10 CFR 50.72 and Other Required Notifications**

##### **a. Inspection Scope (71707)**

During the inspection period, the licensee made the following notifications to the NRC as required by 10 CFR 50.72 or for other information purposes. The inspectors reviewed the events for impact on the operational status of the facility and equipment.

##### **b. Observations and Findings**

1. On May 19, 1999, the licensee notified the NRC that a particular penetration design was believed to not have been installed in conformance with design and as required by Conditions C.(4) (Unit 1) and C.(7) (Unit 2) of the McGuire Facility Operating License. Selected Licensee Commitment 16.9-5 requires that all fire rated assemblies and sealing devices separating 1) safety from non-safety related areas, 2) redundant analyzed post-fire safe shutdown equipment, 3) the control complex (control room, cable rooms, and battery rooms) from the remainder of the plant, or 4)

containment from non-containment areas shall be operable. The licensee determined that numerous fire barrier penetrations of a particular type designed to satisfy the above separation criteria for certain containment to non-containment penetrations were inoperable. Immediate corrective actions were to identify the affected penetration types and initiate the required fire watch. This discovery was made as part of routine surveillance testing.

On May 20, 1999, the licensee retracted the notification based on further evaluation which determined that the penetrations were qualified to perform their intended function based on previous licensee qualification reviews and supporting documentation. The inspectors agreed that this retraction was appropriate.

2. On June 16, 1999, the licensee made a four-hour non-emergency NRC notification in accordance with 10 CFR 50.72 (b)(2)(ii) (engineered safety features actuation) when the Unit 2 turbine driven auxiliary feedwater (TDAFW) pump was inadvertently started with Unit 2 at 100 percent power. The automatic pump start occurred when motor control center SMXG was deenergized for standby shutdown facility (SSF) maintenance work. Deenergizing SMXG resulted in SSF steam generator (SG) wide range (WR) level instrumentation failing low. By design, an automatic start of the TDAFW pump will occur when SSF SG WR level is below approximately 45 percent. The Unit 1 TDAFW pump did not start since it was isolated for maintenance work and hence no notification was required for Unit 1. Unit 2 was quickly stabilized and the TDAFW pump was secured. Also, due to the TDAFW pump automatic start, relatively cold feedwater was injected into the SGs. The secondary system transient resulted in a primary system cooldown and subsequent positive reactivity addition. Reactor power momentarily went just above 100 percent. Operators reduced turbine load and power returned to 100 percent. The inspectors considered this action was taken in a timely manner. The event lasted approximately 10 minutes before power was restored to the affected panel board and the TDAFW pump was secured. At the end of the inspection period, the licensee was performing a root cause analysis of the event and preparing Licensee Event Report (LER) 50-370/99-003-00 regarding the event. NRC followup reviews will occur during review of the LER.

c. Conclusions

The inspector concluded that the licensee appropriately reported/retracted the events in accordance with the requirements of 10 CFR 50.72 (b)(2)(ii) and Facility Operating License Conditions C.(4) and C.(7) for Units 1 and 2, respectively. Immediate corrective actions were appropriate for the identified problems. Operator actions to limit the effects of a positive reactivity addition during an inadvertent auxiliary feedwater pump actuation were timely.

## O2.2 Unit 2 Reactor Coolant System (RCS) Leak Search and Isolation

### a. Inspection Scope (71707, 37551)

The inspectors monitored the licensee's troubleshooting activities associated with identifying the source of an increase in unidentified RCS leakage observed on Unit 2. The inspectors attended Plant Operations Review Committee (PORC) meetings on the subject, reviewed engineering documentation regarding the search activities, and evaluated the effectiveness of the licensee's root cause investigation of the issue.

### b. Observations and Findings

During the inspection period, the licensee identified an increased trend in the Unit 2 unidentified leakage rate, which was measured as high as 0.25 gallons per minute (gpm). This was below the Technical Specification (TS) limit for unidentified leakage of 1.0 gpm. Through evaluation of additional plant parameters, the licensee determined that there was a high probability that the leakage source was in the pressurizer cavity. Personnel entry into the top of the pressurizer enclosure was restricted in Modes 1 and 2 due to previous licensee commitments to limit heavy load lifts during those modes of operation. On the top of the pressurizer enclosure are three access plugs, one large and two small. Each rectangular plug consists of concrete with steel reinforcements along with embedded steel angle plates on the plug edges and corners. The licensee performed a 10 CFR 50.59 review to justify changing the established commitment to enable the hatch plugs to be lifted in Modes 1 and 2 to facilitate a leak search. Subsequent investigations involved inspections through hatch plug bolt holes to verify the potential for the leakage to be within the pressurizer cavity and ultimate removal of one of the hatch plugs to allow entry to the area. The inspectors considered that the licensee's preparations for these on-line activities were well planned and controlled, compensatory measures were established for potential problems, and management oversight of the activities was strong. These effort resulted in the activity being accomplished within the established one-hour limiting condition for operation (LCO) without incident. The overall planning and control of the evolution was considered a strength.

The licensee's inspections revealed that the source of the unidentified leakage was a leak out of the installed pipe cap for pressurizer vent valve 2NC-243 (loops A and B spray supply high point vent). Immediate corrective actions to tighten the valve resulted in stopping the leak. Further investigation identified that part of a temporary pressurizer vent rig, installed during the recent outage, had inappropriately remained installed on the end of the subject vent valve. The galvanized steel vent rig normally consists of a threaded 90 degree elbow and approximately 12 inches of straight pipe, to which a filter is attached. The as found configuration consisted of the vent rig with a stainless steel cap at the end. Discussions with plant operators revealed that during restoration of the vent assembly during the previous Unit 2 outage, operators could not remove the temporary vent rig as required and decided to remove only the filter and cap the vent rig. This was performed after the RCS pressure was above 300 pounds per square inch gauge (psig). The licensee postulated that during subsequent unit heatup, vent valve 2NC-243 developed a slight seat leak which the vent rig could not contain. It should be noted that the RCS pressure boundary for the system ends

at 2NC-243 and does not include any of the pipe cap and vent configuration. The normally installed pipe cap provides an additional means of minor leak prevention. The licensee performed an evaluation to determine if continued operation with the vent rig installed would affect system operation. Based on the evaluation, the licensee concluded that operating with the vent rig installed would not adversely affect system structural integrity. Therefore, the unit would continue to operate with the vent rig installed during the current operating cycle.

The inspectors reviewed Unit 2 startup procedure OP/2/A/6100/SU-5, Filling the RCS, Revision 13, and determined that the procedure required the removal of the filter vent rig and capping of the line after acceptable seat leakage is observed. Contrary to this procedural requirement, the vent rig was left partially installed on 2NC-243. This is a violation of TS 5.4.1 for failure to follow procedure OP/2/A/6100/SU-5. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP 2-M99-2141, 2-M99-2428, 2-M99-2435, and 2-M99-2447 and is identified as NCV 50-370/99-04-01, Failure to Follow Pressurizer Vent Restoration Procedure.

In addition to the above, the inspectors reviewed the 50.59 evaluation to allow the lifting of the hatch plug during Modes 1 and 2 and considered that the various heavy load lifts reviewed were adequate; however, the adequacy of protection from one alternate heavy load drop scenario (hatch plug drop on the hatch opening) was not established within the documented 10 CFR 50.59 evaluation. The inspectors discussed this alternate scenario with the responsible engineering personnel who informed the inspectors that based on an informal calculation of the subject potential failure, it was determined not to be a safety issue. However, the licensee indicated that a revision to the existing 10 CFR 50.59 evaluation was being performed to more thoroughly document the safety reviews performed to support the evolution.

c. Conclusions

The licensee's efforts to identify and eliminate a RCS leak within the Unit 2 pressurizer cubicle were well planned and executed. Evaluations of the leakage source were adequate. However, an NCV was identified concerning a failure to totally remove a vent rig from a pressurizer vent valve. Documentation of the required safety reviews to support the leak search evolutions within the pressurizer cubicle while generally adequate, was less than thorough in documenting one alternate heavy load scenario.

**O4 Operator Knowledge and Performance**

**O4.1 Unit 2 SG Power Operated Relief Valve (PORV) Lines Found Inoperable**

a. Inspection Scope (71707, 40500, 90712)

The inspectors reviewed the facts and circumstances related to two Unit 2 SG PORV lines that were discovered inoperable. The inspectors reviewed the applicable TSs, previous work orders, maintenance and surveillance procedures, emergency and abnormal operating

procedures, and the vendor manual for the valve. The design basis document, the Updated Final Safety Analysis Report (UFSAR), and the plant probabilistic risk assessment (PRA) were also reviewed. Corrective actions and LER 50-370/99-001-00, Failure to Comply With the Operability Requirements and Required Actions of TS 3.7.4, Steam Generator Power Operated Relief Valves and Former Selected Licensee Commitment 16.10.1, were reviewed. The inspectors also performed field walkdowns of both Unit 1 and Unit 2 SG PORVs to assess material condition and verify proper system configuration.

b. Observations and Findings

On May 4, 1999, while evaluating PIPs associated with SG PORVs, engineering personnel determined that a condition had existed which could have placed Unit 2 in an unanalyzed condition. Specifically, on March 14, 1999, and March 20, 1999, with Unit 2 in Mode 5, plant operators discovered that two of four SG PORVs were inoperable. Valve 2SV-1 was found incapable of manual operation on March 14, 1999, and on March 20, 1999, valve 2SV-7 was found incapable of manual operation. These valves are normally air-operated PORVs and are on the D and C steam lines, respectively. The manual actuator on these valves can be used to open and close the valves without air. The manual actuator on the valve is designed to perform a safety-related function. The TS bases state that the SG PORVs are operable when they are capable of fully opening and closing manually using the handwheel. According to the UFSAR, the function of these valves is to allow operators to manually perform a cooldown of the RCS during a design basis accident (DBA) steam generator tube rupture (SGTR) with a loss-of-offsite power. Operator action is required to mitigate the consequences (off-site release through a stuck open PORV) of the DBA. The RCS cooldown is performed in conjunction with the auxiliary feedwater system.

During implementation of periodic test (PT) 2/A/4250/033, Revision 4, Main Steam PORV Movement Test, a manual override shaft drive key (small metal key approximately  $\frac{1}{2}$  x  $\frac{3}{8}$  x  $1\frac{1}{8}$  inches) on each valve's actuator shaft had loosened to the point that the manual override extension would not engage. This test is performed to satisfy TS Surveillance Requirement 3.7.4.1 which was a new surveillance for LCO 3.7.4 that became effective November 11, 1998, under the Improved Technical Specifications (ITS). Prior to this time, there were no TS requirements for SG PORV operability other than a containment isolation capability. Once the condition was recognized, plant operators removed a protective boot covering the manual override shaft, located the shaft key, reinserted the key, and completed the test. The involved operators documented the condition in PIPs 2-M99-1155 and 2-M99-1316.

The licensee's engineering personnel performed a review of the PIPs as required by NSD 203. During the review, engineering determined that the valves were not capable of performing their manual function as required by TS 3.7.4. The licensee also concluded that the inability of the valves to perform their manual function may have existed for some time during the past plant operating cycle. The previous PT was satisfactorily performed in December 1997. Engineering personnel concluded that the conditions discovered on March 14, 1999, and March 20, 1999, were reportable to the NRC and a 10 CFR 50.72 notification was made (see Inspection Report 99-03). The licensee also documented the condition in LER 50-370/99-001-00 dated June 3, 1999.



The licensee determined that the two PORVs in question did not have the appropriate type of shell cap installed on the manual override drive. The other six SG PORVs had a shell cap design which incorporated a lock screw design to hold the shaft key in place. Valves 2SV-1 and 2SV-7 had a different style shell cap that did not have a lock screw to hold the cap and key in place. The inspectors observed that shaft keys were held in place by friction, contrary to what the LER indicated (held by gravity). The licensee was not able to establish why these two valves had a different type of cap design installed.

Immediate corrective actions to return the PORVs to operable status included replacing the shaft keys for 2SV-1 and 2SV-7 and peening each valve's key in place. The inspectors verified that the keys were reinstalled and peened in place. The planned long-term corrective actions include the procurement and installation of shell caps with the lock screw design. The inspectors concluded that both the immediate and proposed long-term corrective actions were adequate.

The inspectors determined that the licensee was conservative in concluding that the PORVs had been inoperable since performance of the PT in December 1997, and in issuing the 10 CFR 50.72 report and the LER. The inspectors' conclusion is based on information identified in NUREG-1022, Event Reporting Guidelines 10 CFR 50.72 and 50.73, Section 3.2.2. TS Prohibited Operation or Condition. This section states, in part, that it should be assumed that the discrepancy occurred at the time of its discovery, unless there is firm evidence, based on a review of relevant information (e.g., the equipment history and cause of failure) to believe that the discrepancy existed previously.

The licensee performed a review of selected plant documentation as a result of the PIPs, to determine if there were previous occurrences of missing shaft keys. During the review, the licensee determined that on July 25, 1996, the shaft key for valve 2SV-1 was found to be missing from valve 2SV-1. The missing key for 2SV-1 was replaced under Work Order 96045633. The licensee informed the inspectors that no PIP or evaluation was initiated to determine the root cause as to why the shaft key was missing such that corrective actions to prevent recurrences could have been implemented. The licensee's failure to identify and implement adequate corrective actions following valve 2SV-1 shaft key replacement in July 1996, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIPs 2-M99-1155 and 2-M99-1316. It is identified as NCV 50-370/99-04-02: Failure to Take Adequate Corrective Actions Following PORV Shaft Key Replacement.

During a system walkdown performed on June 4 and 5, 1999, the inspectors identified that SG PORV 2SV-13 (Unit 2 B steam line PORV) had a pipe cap screwed onto the end of the instrument air vent valve. None of the vent valves for the other seven station SG PORVs were capped. The inspectors were concerned because the operating instructions (posted near each PORV) for manual valve operation included a step to open the vent valve. A pipe cap could have defeated this step. The inspectors immediately notified the shift work manager (SWM) and showed him the capped line. The inspectors observed the SWM attempt to remove the threaded cap by hand; however, the cap was on more than hand-tight. A work request was written and the cap was promptly removed. PIP 2-M99-2733 was

written to investigate why the cap was installed and left in place and to also evaluate past operability of PORV 2SV-13. Upon subsequent evaluation, the licensee indicated that the manual operation of the PORV would not have been impaired by the capped line since the positioner would eventually bleed off air pressure. The inspectors considered this acceptable for emergency operations. The licensee was not able to determine when and why the cap was installed. The inspectors determined that the air system for the PORVs is not safety-related and this installed cap would not impact the safety-related function of the valves. Hence, this configuration control issue is not subject to enforcement action.

The inspectors observed that the visible material condition of the SG PORVs and housekeeping in the doghouses were adequate. Posted operating instructions for each PORV were clearly written, visible, and positioned within a few feet of each valve. An emergency tool kit located in each dog house (ladder, flashlight, batteries, additional hearing protection, torque bar for PORV block valve use) was pre-positioned near the valves for use in emergency conditions. The inspectors determined that these items were added to the doghouses following an operations' department self-assessment (SA) conducted in 1997 to aid operators during emergency conditions.

c. Conclusions

A non-cited violation was identified for failure to provide adequate corrective actions to prevent recurrence of a Unit 2 SG PORV shaft key problem. A negative observation was made for an NRC identified configuration control problem involving an inappropriately capped air vent for SG PORV 2SV-13. Housekeeping in the doghouses and the material condition of the PORVs were adequate. Licensee implemented recommendations from a 1997 self-assessment on the PORVs' accessibility improved operators' ability to successfully complete time critical actions.

**O8 Miscellaneous Operations Issues (92901, 90712)**

- O8.1 (Closed) LER 50-370/99-001-00: Failure to Comply With the Operability Requirements and Required Actions of TS 3.7.4, Steam Generator Power Operated Relief Valves and Former Selected Licensee Commitment 16.10.1

This LER is closed based on the review completed in Section O4.1.

## II. Maintenance

### **M1 Conduct of Maintenance**

#### **M1.1 General Comments**

##### **a. Inspection Scope (61726, 62707)**

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

- SM/O/B/8430/001, Revision 003, SSF Cummins Diesel PM
- PT/O/4200/002, Revision 019, SSF Operability Test
- WO 98169223, Replace Control Room Air Handling Unit Fan Bearing
- MP/O/A/7450/005, Revision 005, Control Room Ventilation (VC) Ductwork and AHU Access
- MP/O/A/7450/006, Revision 003, Control Room AHU Corrective Maintenance
- WO 98091368-05, PM - Underwater Inspection of Raw Water Intake Structures

##### **b. Observations and Findings**

The inspectors witnessed selected maintenance activities and surveillance tests to verify that approved procedures were available and in use; test equipment was calibrated; test prerequisites were met; system restoration was completed; and acceptance criteria were met. In addition, the inspectors reviewed or witnessed routine maintenance activities to verify, where applicable, that approved procedures were available and in use, prerequisites were met, equipment restoration was completed, and maintenance results were adequate.

##### **c. Conclusions**

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

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

#### **M2.1 Inoperable Emergency Diesel Generator (EDG) due to Governor Control Problems**

##### **a. Inspection Scope (61726, 62707)**

The inspectors reviewed the facts and circumstances surrounding inoperability of the Unit 2 EDG 2A which was identified on May 11, 1999. The inspectors attended troubleshooting meetings, walked down the affected components, and observed work activities. NRC operability reviews (walkdowns) were also performed for the operable 2B EDG.

b. Observations and Findings

While performing PT, 2/A/4350/002A, Diesel Generator 2A Operability Test, operators experience difficulty while attempting to load the EDG to 1,000 kilowatts. The EDG would not maintain the correct load and after several attempts at manual control, the EDG was shut down in a controlled fashion. For the next several days, the licensee performed a variety of reviews on the governor and other control systems. Vendor support was obtained early into the evolution and extensively utilized. Licensee management was actively involved in the various review meetings which discussed the troubleshooting efforts. Required TS surveillances for the 2B EDG were complied with during the period of inoperability for the 2A EDG.

The licensee identified the apparent cause of the 2A EDG problem as an open circuit in an auxiliary switch in breaker cubical 2ETA-16 (normal offsite feeder breaker to the EDG). This breaker cubicle contact switch normally provides droop control to the control governor and voltage regulator control circuits which is necessary for stable operation when connected to the grid during EDG testing. The circuit is not utilized during the emergency mode of EDG operation. In that the identified failure only affected the manual test circuit of operation, the licensee did not consider this event a functional failure of the EDG system for purposes of the Maintenance Rule. At the end of the inspection period, the licensee was continuing to evaluate the root cause of the auxiliary switch problem. Corrective actions included restoring the unit to operable status by utilizing a spare breaker cubicle to replaced the failed component and to perform TS operability verification runs. The EDG was declared operable at approximately 8:30 p.m., on May 13, 1999. The inspectors discussed the specific failure with engineering personnel and determined that, although it has not been a historical problem at McGuire, the subject breaker cubicle components which caused this failure were not within a routine testing or preventative maintenance program. Based on the above event, the licensee informed the inspectors that a review will be conducted to determine what additional corrective actions may be warranted to preclude future similar problems involving breaker cubical contact switches. These corrective actions were being tracked via PIP 2-M99-2449.

c. Conclusions

Maintenance and engineering efforts to troubleshoot and repair the 2A EDG were focused and well controlled. This focus allowed the licensee to promptly resolve the identified problem and restore the diesel to an operable configuration. As a result of the apparent root cause, the licensee was reviewing the established breaker preventative maintenance program for enhancements to preclude future problems in this area.

**M4 Maintenance Staff Knowledge and Performance****M4.1 Repair of Control Room Ventilation Air Handling Unit (AHU) Under an Emergency TS Change****a. Inspection Scope (62707, 40500, 37551)**

The inspectors evaluated the repairs associated with a failed Train B AHU bearing. The inspectors reviewed the maintenance procedures, corrective actions for a previous bearing failure, work history, vendor drawings and instruction manual, and other plant information. Technical Specifications, NRC Generic Letter 91-18, Revision 1, contingency actions, and manual compensatory measures were reviewed prior to and during the evolution. The inspectors attended the associated PORC meeting and reviewed results of the Nuclear Safety Review Board (NSRB) review.

**b. Observations and Findings**

The McGuire control room area ventilation system (CRAVS) is safety-related and consists of a two-train system with a chiller, air handling unit (AHU), ductwork, and filters for each train. Each train is designed to maintain an acceptable control room environment following a DBA. On June 9, 1999, a maintenance technician identified noise in the Train B AHU. Vibrational analysis confirmed a problem existed between the shaft and at least one of four bearings. Following engineering review and recommendations, operators started the Train A, shutdown Train B, and declared the Train B inoperable.

By letter dated June 10, 1999, the licensee sought an emergency TS change from the NRC to support use of compensatory measures while performing repairs to the Train B AHU. The proposed work involved removal of a small personnel access cover (approximately 2 feet by 4 feet bolted plate) affecting common duct work for both trains in order to access the Train B AHU internals. The licensee sought NRC approval based on recent guidance and interpretations from the Office of Nuclear Reactor Regulation regarding CRAVS TSs and the use of manual compensatory measures during repairs that would temporarily degrade both trains during the maintenance activity (see Inspection Report 99-03). By letter dated June 11, 1999 (issued at approximately 5:00 pm), the NRC granted the licensee a one-time only emergency TS change to permit repairs of the Train B AHU, provided that adequate administrative controls were in place for compensatory measures to install the ductwork access cover, in a timely manner, should plant conditions warrant restoration.

The inspectors observed a thorough pre-job briefing involving operations, maintenance, engineering, and safety assurance personnel that was conducted just prior to the NRC issuance of the licensee amendment. Plant work activities that could challenge the CRAVS were deferred as recommended by PORC/NSRB review. Comprehensive compensatory measures (dedicated personnel in radio contact between the control room and the CRAVS AHUs) and clear entry conditions were established. Contingency actions for a loss of running CRAVS train due to a chiller trip and entry into the associated abnormal procedure (AP) and realignment of the B train chiller to the Train A AHU were also discussed.

During the maintenance, the inspectors observed a crack across the face of the drive-end bearing. According to the industry expert present, the failure mode was attributed to improper installation. The inspectors discussed previous system experience with plant personnel who indicated that a similar bearing failure occurred previously in March 1999 and was documented in PIP 0-M99-1582.

The inspectors noted that MP/0/A/7450/006, Revision 002, Control Room AHU Corrective Maintenance, (used in the March 1999 bearing replacement) did not provide set screw torque values for the locking collar and no bearing/shaft clearance measurements were provided. The licensee's root cause team arrived at similar conclusions with additional insights on the lack of adequate instructions for locking collar positioning. The licensee also indicated that belt tension reduction was the corrective action for the March bearing repair. A subsequent examination by the licensee indicated that belt tension represented a small fraction of the load (less than 3 percent). The licensee did not send the failed bearing in March to the licensee's metallurgy lab to assist in identifying the failure mode. In addition, the inspectors observed that the replacement bearing shipping box contained a sheet with specific vendor information with a table of set screw torque values for the locking collar. Maintenance personnel indicated that these vendor instructions were not included with the parts pulled from the warehouse for the maintenance performed in March 1999. Apparently, the parts used in the March maintenance were older stock and did not contain this guidance. New bearings were procured for the June 11, 1999, repair which did contain the vendor information. The inspectors reviewed the AHU vendor manual which only indicated the type of bearing to be used for replacement.

The inspectors identified a violation of 10 CFR Part 50, Appendix B requirements. Specifically, 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that in the case of significant conditions adverse to quality, that measures shall assure that the condition is determined and corrective actions taken to preclude repetition. Sufficient measures were not taken in March 1999 to assure that the CRAVS Train B AHU bearings were properly repaired, as evidenced by the June 1999 bearing failure. The failure to implement adequate corrective actions at that time is considered a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP 0-M99-2854. This NCV is identified as NCV 50-369,370/99-04-03: Inadequate Corrective Action for Air Handling Unit Bearing Failures.

Corrective maintenance on June 11, 1999, involved moving the AHU shaft approximately 1.25 inches forward in order to obtain an acceptable clearance between the bearing and the shaft since micrometer readings indicated that the shaft had narrowed at the bearing/shaft interface. Shaft narrowing was also indicated by metal shaft shavings due to the failed bearing. Using calibrated tools, maintenance personnel installed the locking collar in accordance with MP/0/A/7450/006, Revision No. 003 which incorporated the torque values for the set screw. Maintenance on the B AHU was completed at approximately 10:30 pm on June 11, 1999. A post-maintenance run was performed with vibrational analysis that indicated satisfactory performance of the AHU. The inspectors considered that the licensee's work planning for the current activity was thorough. Maintenance execution to

repair the bearing was performed expeditiously and in accordance with plant procedures. Maintenance supervisors and engineering support personnel were present throughout the repair.

c. Conclusions

The June 11, 1999, CRAVS AHU B bearing corrective maintenance was performed in accordance with the work order, procedures, and Technical Specifications. Compensatory measures were conservative with thorough PORC and NSRB review and comment. Detailed and complete pre-job briefing included discussions regarding contingency actions should the running train of control room ventilation become inoperable during the planned maintenance. Strong maintenance supervisory oversight and engineering support were provided. System engineering's use of an independent bearing expert was appropriate. An NCV was identified for inadequate corrective actions following a failed AHU bearing in March 1999, after a repetitive bearing failure was experienced in June 1999.

**M8 Miscellaneous Maintenance Issues (92902)**

- M8.1 (Closed) LER 50-369/98-005-00: Two Auxiliary Building Filtered Ventilation Exhaust System Were Inoperable Longer Than the Action Time Allowed by TS 3.7.7

(Closed) Unresolved Item (URI) 50-369,370/98-08-01: Inoperable Auxiliary Building Ventilation (VA) Systems

During reviews of auxiliary building ventilation system control circuitry and load lists to support upcoming maintenance activities, the licensee determined that Operations Procedure OP/0/A/6450/003, Auxiliary Building Ventilation System, Revision 22, did not provide guidance to operators that electrically deenergizing one unit's auxiliary building filtered ventilation exhaust system (ABFVES) fan would render the opposite unit's ventilation system inoperable. The function of the systems is to automatically place the VA systems in a filtered exhaust mode, if required. Action statement "d" of the existing TS 3.7.7 stated that with both systems inoperable, restore at least one of the systems to operable status within 24 hours or be in at least hot standby within the next 6 hours and in cold shutdown within the following 30 hours.

Upon identification of the problem, the licensee reviewed historical maintenance and testing records within the last two years and determined that both the Unit 1 and Unit 2 ABFVES had been past inoperable for a number of periods less than 24 hours wherein the inoperability of both units' ABFVES was not recognized and the 24-hour LCO was not entered. The number of occasions were 5 and 10 times for Unit 1 and 2 respectively. More significantly, the licensee also identified two periods within the previous two years in which the Unit 1 VA breakers were opened greater than 24 hours and both systems were not declared inoperable nor was the 24-hour LCO complied with. The duration of these occasions were 70 and 36 hours in excess of the 24-hour TS action LCO. No records were identified which indicated that the Unit 1 ABFVES was inoperable for greater than 24 hours as a result of the opening of the Unit 2 ABFVES breakers.

Upon discovery, the licensee verified that both VA systems were currently operable. Additional corrective actions included performing a detailed review of past inoperable conditions and to determine the cause for this oversight, which was attributed to an unrecognized system impact. The licensee also established interim guidance which directed operations staff to declare both ABFVES systems inoperable if a fan on either system was electrically deenergized and to take compensatory measure to place the opposite unit's system in filter mode. Plant procedures were reviewed to identify necessary changes and revisions were completed to ensure compliance with TS. The inspectors reviewed the interim guidance and subsequent plant procedure changes and concluded that the licensee's response to this event was appropriate. The filtered exhaust portion of the auxiliary building ventilation system is not safety-related. However, system operability is required by TS and credit is taken for the system's operation in postulating control room and offsite dose consequences. The inspectors noted that the ABFVES was not required to perform its design basis functions during the periods of inoperability and therefore the actual safety impact was minimal. In addition, the licensee determined that in the event of an accident, the VA system would have automatically shifted to the required filter mode by actuation of process radiation monitor EMF41. EMF41, in part, monitors the inlet ducting for the Unit 1 and 2 VA systems. The licensee's review of equipment maintenance records did not identify any times in which EMF41 was inoperable when a fan on a single VA system was electrically deenergized. This also reduced the potential impact of the licensee identified problem.

Subsequent to the issuance of the subject LER, the licensee performed testing of different ABFVES fan configurations, including the lineup which existed during the subject event. The testing identified that the configurations that existed would have resulted in the system remaining operable for the periods identified in the LER. Based on the new information, the licensee has subsequently revised their TS and its Bases to allow for entry into the LCO for the affected ABFVES fan configurations.

The inspectors concluded that the licensee's previous failure to enter the LCO of TS 3.7.7 and/or comply with TS 3.7.7 for a number of periods prior to identification of the problem will be identified as NCV 50-369,370/99-04-04: Failure to Comply with TS 3.7.7 when Electrically Deenergizing Auxiliary Building Filtered Exhaust System Fans. This Severity Level IV violation is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PIP 0-M98-2485. The subject LER and URI are closed.

### III. Engineering

#### **E2 Engineering Support of Facilities and Equipment**

##### **E2.1 Year 2000 (Y2K) Readiness Program Review (TI 2515/141)**

The staff conducted an abbreviated review of Y2K activities and documentation using Temporary Instruction (TI) 2515/141, "Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants." The review addressed aspects of Y2K management



planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The reviewers used Nuclear Energy Institute/Nuclear Utilities Software Management Group (NEI/NUSMG) 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review.

During the review, the licensee stated that the Y2K Readiness Project activities were 90% completed with contingency planning being approximately 90% complete, and that both programs were on target to be completed by their scheduled due dates.

Conclusions regarding the Y2K readiness of the facility are not included in this report. The results of this review will be combined with the results of reviews of other licensees in a summary report to be issued by July 31, 1999.

## **E8 Miscellaneous Engineering Issues (92903)**

### **E8.1 (Closed) LER 50-370/98-002-00: EDG 2A Inoperable from May 12 to June 3, 1998**

The root cause and corrective actions for this equipment problem were documented in PIP 2-M98-1713 and completed on August 28, 1998. These items were previously reviewed in NRC Inspection Report 50-369,370/98-07 and regulatory significance was determined in conjunction with an adverse trend of EDG component failures which occurred following overhaul of EDGs. There have been no additional cylinder valve insert problems which indicated that the corrective actions were adequate to prevent recurrence. This LER is closed.

### **E8.2 (Closed) Inspector Followup Item (IFI) 50-369,370/98-04-05: Alternate AC (AAC) Source Testing Per Nuclear Management and Resources Council (NUMARC) 87-00, B.10**

The inspector reviewed the licensee's periodic testing of the SSF diesel generator, which is the licensee's AAC source, to determine if the testing was consistent with the regulatory guidance and adequately verified the SSF diesel station blackout (SBO) capability. Regulatory Guide (RG) 1.155, SBO, August 1988, provided the regulatory guidance related to AAC sources with NUMARC 87-00 referenced as an acceptable methodology for implementation. The inspector reviewed the licensee's periodic test procedure and observed performance of the test on May 20, 1999. This test adequately verified the capability of the SSF diesel to perform its design function. Additionally, operator training and job performance measures were used to verify the capability of the operators to start the SSF diesel in the required ten-minute period. The inspector concluded that the licensee's testing and training was adequate to assure the capability of the AAC source for SBO consistent with regulatory guidance. This IFI is closed.

#### IV. Plant Support

##### **R1 Radiological Protection and Chemistry Controls**

###### R1.1 General Comments (71750)

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

#### V. Management Meetings

##### **X1 Exit Meeting Summary**

The resident inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 22, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

#### PARTIAL LIST OF PERSONS CONTACTED

##### Licensee

Barron, B., Vice President, McGuire Nuclear Station  
 Bhatnagar, A., Superintendent, Plant Operations  
 Boyle, J., Manager, Civil/Electrical/Nuclear Systems Engineering  
 Byrum, W., Manager, Radiation Protection Cash, M., Manager, Regulatory Compliance  
 Dolan, B., Manager, Safety Assurance  
 Evans W., Security Manager  
 Geddie, E., Manager, McGuire Nuclear Station  
 Peele, J., Manager, Engineering  
 Loucks, L., Chemistry Manager  
 Thomas, K., Superintendent, Work Control  
 Travis, B., Manager, Mechanical Systems Engineering

#### INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering  
 IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems  
 IP 62707: Maintenance Observations  
 IP 61726: Surveillance Observations  
 IP 71707: Conduct of Operations  
 IP 71750: Plant Support

IP 90712: Event Reports  
 IP 92901: Followup - Operations  
 IP 92902: Followup - Maintenance  
 IP 92903: Followup - Engineering  
 TI 2515/141: Review of Year 2000 Readiness of Computer Systems at Nuclear Power Plants

#### ITEMS OPENED, CLOSED, AND DISCUSSED

##### Opened

50-370/99-04-01	NCV	Failure to Follow Pressurizer Vent Restoration Procedure (Section O2.2)
50-370/99-04-02	NCV	Failure to Take Adequate Corrective Actions Following PORV Shaft Key Replacement (Section O4.1)
50-369,370/99-04-03	NCV	Inadequate Corrective Action for Air Handling Unit Bearing Failures (Section M4.1)
50-369,370/99-04-04	NCV	Failure to Comply with TS 3.7.7 when Electrically De-energizing Auxiliary Building Filtered Exhaust System Fans (Section M8.1)

##### Closed

50-370/99-001-00	LER	Failure to Comply With the Operability Requirements and Required Actions of Technical Specification 3.7.4, Steam Generator Power Operated Relief Valves and Former Selected Licensee Commitment 16.10.1 (Section O8.1)
50-369/98-005-00	LER	Two Auxiliary Building Filtered Ventilation Exhaust Systems were Inoperable Longer Than Time Allowed by TS 3.7.7 (Section M8.1)
50-369,370/98-08-01	URI	Inoperable Auxiliary Building Ventilation (VA) Systems (Section M8.1)
50-370/98-002-00	LER	EDG 2A Inoperable from May 12 to June 3, 1998 (Section E8.1)
50-369,370/98-04-05	IFI	Alternate AC (AAC) Source Testing Per NUMARC 87-00, B.10 (Section E8.2)

##### Discussed

50-370/99-003-00	LER	Inadvertent Actuation of Turbine Driven Auxiliary Feedwater Pump (Section O2.1)
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## LIST OF ACRONYMS USED

AAC	-	Alternate Alternating Current
ABFVES	-	Auxiliary Building Filtered Ventilation Exhaust System
AFW	-	Auxiliary Feedwater
AHU	-	Air Handling Unit
AP	-	Abnormal Procedure
CFR	-	Code of Federal Regulations
CRAVS	-	Control Room Area Ventilation System
DBA	-	Design Basis Accident
EDG	-	Emergency Diesel Generator
EP	-	Emergency Procedure
GPM	-	Gallons Per Minute
IFI	-	inspector Followup Item
IR	-	Inspection Report
ITS	-	Improved Technical Specification
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MNS	-	McGuire Nuclear Station
NCV	-	Non-Cited Violation
NEI	-	Nuclear Energy Institute
NRC	-	Nuclear Regulatory Commission
NSRB	-	Nuclear Safety Review Board
NUMARC	-	Nuclear Management and Resources Council
NUSMG	-	Nuclear Utilities Software Management Group
PDR	-	Public Document Room
PIP	-	Problem Investigation Process
PORC	-	Plant Operating Review Committee
PORV	-	Power Operated Relief Valve
PSIG	-	Pounds Per Square Inch Gauge
PRA	-	Probabilistic Risk Assessment
PT	-	Periodic Testing
RCS	-	Reactor Coolant System
RG	-	Regulatory Guide
SA	-	Self Assessment
SBO	-	Station Blackout
SSF	-	Standby Shutdown Facility
SG	-	Steam Generator
SGTR	-	Steam Generator Tube Rupture
SWM	-	Shift Work Manager
TDAFW	-	Turbine Driven Auxiliary Feedwater
TI	-	Temporary Instruction
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Items
VA	-	Auxiliary Building Ventilation
VC	-	Control Room Ventilation
Y2K	-	Year 2000