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

Report Nos. 50-369/93-18 and 50-370/93-18

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-1007

Facility Name: McGuire Nuclear Station 1 and 2

Docket Nos. 50-369 and 50-370 License Nos. NPF-9 and NPF-17

Inspection Conducted: August 22, 1993 - September 25, 1993

Inspector: Pani Lea Watkins for G. F. Maxwell, Senior Resident Inspector — October 18, 1993 Date Signed

Inspector: Pani Lea Watkins for T. A. Cooper, Resident Inspector — October 18, 1993 Date Signed

Approved by: M Lesser
M. S. Lesser, Section Chief
Division of Reactor Projects
10/19/93 Date Signed

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance observations, plant modifications, emergency preparedness training exercise, Augmented Inspection Team followup, followup on previous inspection findings and completion of a checklist for TI 2500/28 - Employee Concerns Program.

Results: In the areas inspected, one violation was identified for failure to follow procedure for control of fire watches that were supplied by a site contractor (paragraph 2.e.). The following unresolved items were identified: (1) Operation of Unit 2 systems and equipment - water hammer in letdown system (paragraph 2.g.), (2) Maintaining system configuration control - 2NV-464 (paragraph 2.g.), (3) Poor corrective action results in a non-isolable

reactor coolant leak - valve 2NC-14 (paragraph 4.c.), (4) Maintaining system configuration control - 2CF-130 (paragraph 8.b.6.), (5) Verify operability of equipment prior to placing the equipment into service or returning it to normal service - 2CF-130 (paragraph 8.b.10.), (6) Operation of Unit 2 systems and equipment - unplanned mode change (paragraph 8.b.12), and (7) Operation of Unit 2 systems and equipment - TS surveillance requirements on the ice condenser inlet door position monitoring system (paragraph 8.b.13).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Allgood, Safety Review Group
*T. Arlow, Safety Review Group
D. Baxter, Support Operations Manager
A. Beaver, Operations Manager
*J. Boyle, Work Control Superintendent
*R. Branch, General Supervisor, Mech. Maint.
D. Bumgardner, Unit 1 Operations Manager
B. Caldwell, Training Manager
*M. Cash, Engineering Supervisor
*W. Cross, Compliance Security Specialist
T. Curtis, System Engineering Manager
F. Fowler, Human Resources Manager
*E. Geddie, Station Manager
*G. Gilbert, Safety Assurance Manager
P. Guill, Compliance Engineer
*B. Hamilton, Superintendent of Operations
*F. Hayes, Manager, Human Resources
P. Herran, Engineering Manager
L. Kunka, Compliance Engineer
*T. McMeekin, Site Vice President
*M. Pacetti, Mechanical/Nuclear Engineer
*T. Pederson, Safety Review Supervisor
*N. Pope, Instrument & Electrical Superintendent
*K. Reece, Instrument & Electrical Section Manager
*D. Scearce, Commodities & Facilities Manager
R. Sharpe, Regulatory Compliance Manager
D. Tapp, Mechanical Maintenance General Superintendent
*B. Travis, Component Engineering Manager
*J. Washam, Safety Review Group
R. White, Mechanical Maintenance Superintendent

Other licensee employees contacted included craftsmen, technicians, operators, mechanics, security force members, and office personnel.

NRC Resident Inspectors

*G. Maxwell, SRI
*T. Cooper, RI

*Attended exit interview

2. Plant Operations (71707)

a. Observations

The inspection staff reviewed plant operations during the report period to verify conformance with applicable regulatory requirements. Control room logs, shift supervisors' logs, shift turnover records and equipment removal and restoration records were routinely reviewed. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel.

Activities within the control room were monitored during shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in applicable station administrative directives. The number of licensed personnel on each shift met or surpassed the minimum required by Technical Specifications (TS). The inspectors also reviewed Problem Investigation Process (PIPs) to determine if the licensee was appropriately documenting problems and implementing corrective actions.

Plant tours taken during the reporting period included, but were not limited to, the turbine buildings, the auxiliary building, electrical equipment rooms, cable spreading rooms, and the station yard zone inside the protected area.

During the plant tours, ongoing activities, housekeeping, fire protection, security, equipment status and radiation control practices were observed.

b. Unit 1 Operations

At 10:50 p.m., on August 21, 1993, the unit received indications from the process radiation alarms for the steam generator (S/G) monitors. Chemistry samples revealed that the "A" S/G had a leak of approximately 176 gallons per day (gpd). This exceeded the leakage rate at which the licensee was committed to commence plant shut-down. The licensee initiated shut-down on August 22, 1993. Cold shutdown was reached on August 23, 1993, for inspection of and repairs to the leaking S/G tubes. At the end of the inspection period the unit was still in mode 5.

c. Unit 2 Operations

The unit began the inspection period in cold shut-down for a refueling outage. Start-up began on August 28, 1993. On August 31, 1993, an unisolable steam leak through the 2CF-130 valve on the "C" S/G occurred, resulting in cool down from mode 3 to mode 5. This event was the subject of an NRC Augmented Inspection Team and the findings are documented in Inspection Report 50-369, 370/93-20. Heat-up began on September 5, 1993, following valve repairs. During heat-up in mode 3 a water hammer event occurred on the chemical and volume control system, resulting in a 10 to 15 gallons per minute (gpm) primary coolant leak through a broken nipple on a system vent line. The line was isolated, and repairs to the nipple were completed.

Start-up recommenced on September 12, 1993, and the unit was placed on-line on September 14, 1993. Full power operation was reached on September 22, 1993.

On September 27, 1993, the unit was shutdown for unidentified primary coolant leakage in excess of 1 gpm. An unusual event was declared because unit shutdown was required by Technical Specification (TS) for unidentified leakage in excess of 1 gpm.

d. Unit 1 Steam Generator Tube Leakage

On August 22, Unit 1 plant operations and chemistry personnel determined that steam generator tube leakage exceeded the plant administrative limit of 50 gallons per day (gpd). Operations personnel initiated a unit shutdown even though the TS allows a 500-gpd primary to secondary leak from any one steam generator. When the shutdown was initiated the leak rate was estimated to be about 176 gpd through the "A" steam generator.

On August 28, the plant was placed in cold shutdown and mid-loop operation for the installation of steam generator nozzle dams. The "C" steam generator served as the vent path for a steam generator tube inspection. The licensee visually identified a total of eight leaking tubes during an inspection of the primary side of the tubes at a pressure of 540 pounds per square inch on the secondary side. All but one of the identified leaks were from tubes that were sleeved during a 1990 outage. No leaking tubes were identified in S/G "C."

The inspection of the tubes revealed that the largest leak in S/G "A" was from tube 39-72. The licensee pulled this tube and a control tube (tube 07-78) for metallurgical evaluation and subsequent comparison. Both tubes had been sleeved in 1990. Inspections revealed that tube 39-72 had a 270-degree, through-wall circumferential crack under the sleeve. Further analysis revealed that the tube possessed a yield strength of approximately 13 percent higher than the certified value and a carbon content approximately 25 percent higher than the certified value. The tube's microstructure included intragranular carbides. These characteristics led the licensee to conclude that the tube was highly susceptible to primary water stress-corrosion cracking (PWSCC). Evaluation of tube 07-78 revealed that the tube was intact and, although susceptible to PWSCC, less susceptible than tube 39-72.

The licensee plugged 128 S/G tubes; of those tubes, 98 had been sleeved in 1990, and 30 were from the same material lot, or heat, as 39-72.

e. Fire on Unit 1 Fuel Building Roof

On August 12, 1993, contractor personnel were installing a new roof on the Unit 1 fuel building. The old roof had to be removed and replaced with new insulating materials and new roof paper.

While removing the old roofing, the contractor discovered that the deck plate under the roofing did not extend all the way to the east parapet structural I-beam, leaving a nine-inch gap between the deck plate and the I-beam. The gap-space had been leveled with insulating material and covered with a layer of asphalt. The contractor personnel left the filler insulation in place to maintain the roof level while applying the new material. The new material consisted of a layer of perlite insulation, approximately one inch thick, covered by asphalt-impregnated roofing paper. To adhere the roofing paper to the insulation, the contractor heated the asphalt in the paper with a propane torch.

Because the deck plate did not extend to the parapet and the fuel building is maintained under a negative pressure, air flowed into the fuel building when the old roofing was removed. When the flame of the torch came into contact with the excess asphalt on the existing roof, the roof ignited. The flames from the burning asphalt were sucked under the ridges in the deck plate and into the fuel building. The contractors could not detect the fire from the roof. When the roofing paper was laid over the exposed roof section, air flow through the gap was reduced and smoke was visible. Once the contractors noticed the smoke, they pulled back the roofing paper and used a dry chemical fire extinguisher to put out the fire. The licensee later determined that, according to their procedure, halon or CO_2 as the only acceptable fire extinguishers for hot work.

The inspectors assessed the contractor's fire protection controls and noted that the contractor's fire watch practices were problematic. They were not in compliance with the administrative requirements of the fire watch program, MSD 462, Hot Work Authorization, Revision 0. They failed to notify the control room of the fire. The contractors were not familiar with the hot work authorization procedure and had to be coached to complete a hot work authorization, MSD 462, Appendix A, Duke Power Company McGuire Nuclear Station Hot Work Permit. The contractor personnel were attempting to use the fire watch procedure, but had been given incorrect forms for doing this by one of their job sponsors; therefore, they failed to obtain the proper hot work permit. Failure to follow administrative requirements for fire watch is a Violation 369,370/93-18-01: Failure to follow procedure for fire watch requirements.

f. Unit 1 Steam Generator Siphoning Events

While Unit 1 was shutdown for the steam generator (S/G) tube inspection, water began spilling from the reactor coolant (NC) coldleg manway on "C" S/G. The water came from three U-tubes and out a temporary HEPA filter connection onto the containment floor. Originally, the licensee thought the HEPA package pulled a negative pressure in the steam generator, causing a siphoning effect to occur. The licensee lowered reactor coolant level below the tube sheet of the S/G to break the siphon. The HEPA filter system was removed.

Subsequently, during the next day there were several occurrences of water spilling out of the tubes for brief periods of time. In one other occurrence a continuous siphon was established and level was dropped to break the siphon. The spill occurred after the HEPA system had been removed, indicating that the system's configuration did not cause the phenomenon.

At the time of the siphoning event the unit was at ten percent pressurizer level with both nozzle dams in the "A," "B," and "D" S/Gs. The NC coldleg nozzle dam was in the "C" S/G, but the NC hotleg nozzle dam in the "C" S/G was removed. The pressurizer PORVs and reactor vessel head vents were open. The "C" S/G was the major vent path.

In addition, the CVCS (NV) letdown was in service, using RHR as the motive force through the demineralizers to the VCT. The VCT was at 65 degrees F and 45 psig with a blanket of nitrogen to prevent oxygen from intruding into the vessel. The reactor coolant system was at approximately 100 degrees F and atmospheric pressure. Calculations indicated that water in the VCT could have maintained approximately three times the nitrogen concentration in solution that was present in the reactor coolant.

RHR in the shutdown cooling configuration takes suction on the "C" NC hotleg. Therefore, the primary coolant flowpath is through the "C" NC hotleg. The licensee conjectured that as the water came from NV into the vessel, nitrogen was coming out of the vessel and flowing into the "C" NC hotleg. Periodically, the gas bubble would travel down the piping to the S/G. As the bubble traveled up the S/G tubes it would push a slug of water out through the tubes. Occasionally, this percolating would establish a siphon. The hotleg was located under the S/G tubes that had been spilling water, verifying the likelihood of this explanation.

To test their hypothesis the licensee secured letdown. Two small spills followed this action, but no further spills occurred.

The licensee evaluated the potential impact of not taking action to break the siphon. Reactor coolant level would have dropped to just below the S/G tubesheet, where the siphon would have been broken. The reactor vessel flange is also at this level, approximately 12 feet above the top of the core; therefore, this would have had minimal affect on decay heat removal.

g. Water Hammer in Unit 2 Letdown Lines

Background: On September 8, 1993, with the unit in Mode 3 following a scheduled refueling outage, an isolation valve (2NV-2) for the charging system (NV) letdown system closed without any operator action or explanation. The licensee initiated a maintenance work order (WO-93066224-01) to investigate and repair the problem. Instrumentation and Electrical (I&E) maintenance personnel evaluated the electrical controls and limit switches associated with 2NV-2 and could not explain the valve closure. The valve was returned to service following the evaluation.

On September 9, at 11:52 p.m., with the plant still in Mode 3 and the letdown system in service, the operators at the controls noticed that letdown flow was decreasing and 2NV-2 was going closed. Without ensuring that each of the letdown orifice isolation valve (2NV-458) closed as designed by an interlock with the system isolation valve 2NV-2, the operator at the controls entered abnormal operating procedure AP/2/A/5500/12, Loss of Normal Letdown Charging or Seal Injection Flow, isolated normal charging, and then established excess letdown.

Apparently, when 2NV-2 was going closed the limit switch interlock between it and letdown orifice isolation valve 2NV-458 (the only one of the three orifice isolation valves that was open) did not cause 2NV-458 to close. At that time valve 2NV-2 was closed and valve 2NV-458 was open. It appears that a steam void developed from a pressure reduction coupled with the existing water temperature (557 degrees Fahrenheit) in the section of piping between 2NV-2 and the regenerative heat exchanger.

On September 10, at 12:12 a.m., with 2NV-2 closed and the steam void in the piping between the 2NV-2 and 2NV-458, I&E personnel jumpered valve 2NV-2 and caused it to open. The valve was opened by I&E instead of an operator as part of the continued attempt to determine why 2NV-2 had closed earlier. Three minutes after I&E opened 2NV-2 the operator observed an increase in containment pressure and a decrease in primary system inventory. At 12:17 a.m., the operator closed 2NV -2, thereby isolating the letdown system. After isolating letdown, the operators determined that the increased reduction in primary inventory was apparently caused by a leak that had developed in the letdown system and stopped after the system was isolated. The leak-rate was estimated to have been between 10 and 15 gallons per minute.

Personnel were dispatched to the containment building and found a leak path through a partially opened high-point vent valve 2NV-464 in the letdown system. The leak path passed through the vent valve 2NV-464 and continued through a crack in a threaded nipple located downstream of the valve.

Engineering and Operations personnel reviewed the sequence of events described in the previous paragraph and determined that a steam void had formed in the piping between 2NV-2 and the regenerative heat exchanger. After I&E had jumpered 2NV-2 open, a water hammer was created and caused a surge in the piping between 2NV-2 and the letdown piping up to 2NV-35, 2NV-458, and 2NV-457. Valve 2NV-464 was attached at a high point on the affected piping.

A review of the records revealed that the threaded nipple on 2NV-2 was manufactured from a thinner pipe wall material than what was specified on design drawings (schedule 40 materials were used, although the design called for schedule 160 materials). Also the nipple was used as a hook-up point for system hydrostatic test pressures that previously have been applied to the letdown system. The inspectors noted that this pipe nipple was not designed to ASME specifications; the ASME Section III qualifications end at the valve itself. As a result of this event the licensee decided to verify the position of all unisolable high-energy vent and drain valves in lower containment.

The inspectors observed teams of plant operators checking all high-energy vent and drain lines located in lower containment. The teams then verified that the isolation valves were closed and associated pipe caps for these lines were tight. No significant leaks were identified and all pipe caps were tightened as appropriate. System and Component Engineering personnel surveyed the letdown system, performed stress analysis on the system, evaluated adjacent environmentally qualified equipment, inspected and evaluated the seismic supports, and required samples of the cracked piping to be taken and analyzed. Maintenance personnel replaced the old valve 2NV-464 and the associated pipe nipple with the appropriate ASME Section III type of valve and code piping. Maintenance personnel continued their investigation of the unexplained closing of 2NV-2 and found about one tablespoon of water inside the valve's electrical solenoid housing. The electrical insulation on the solenoid was tested and determined to be 700 MEG-OHMS, which was still acceptable. However, the valve solenoid and the air regulator were both replaced with new spare parts. A recorder and voltmeter were then connected to the valve's control circuit and the circuit was monitored for any abnormal changes.

The inspectors were present during various stages of the evaluations and work control activities. The evaluations and associated work activities were conducted in an organized and professional manner. Each potential problem was researched and evaluated by the assigned task teams and corrective action was taken as required.

The inspectors evaluated the circumstances and conditions that existed prior to the reactor coolant system leak and determined that Site Operations Management Procedure 1-13, Revision 9, requires the operator at the controls to (1) review routine operating data to ensure safe operation of his assigned unit, and (2) be responsible for the manipulation of controls that directly or indirectly affect core reactivity. The inspectors are continuing their review to determine (1) if an operator at the controls allowed maintenance test personnel to open an isolation valve (2NV-2) for the Unit 2 letdown system without taking precautions to ensure that the letdown line was not depressurized, and (2) why the system was not properly isolated prior to troubleshooting.

This finding is identified as an Unresolved Item 50-370/93-18-02, Operation of Unit 2 systems and equipment - water hammer in letdown system.

During the most recent Unit 2 refueling outage, a modification to the letdown system orifices was completed (modification MG 22413). The modification package contained a work order (WO-93052156) that authorized a hydrostatic test of the letdown system upon completion of the modification. The inspectors reviewed the completed hydrostatic test results for WO-93052156-03 and WO-93024063, which implemented procedure MP/0/A/7650/55, Controlling Procedure for Hydrostatic Testing of Duke Class "A", "B" and "C" Systems. The inspectors noted that the test procedure section 11.3.13 required that the system be properly restored by the closure of 2NV-464 following completion of the test; this step was signed-off in the procedure, indicating that it had been performed. The inspectors are attempting to determine if, upon completion of the hydrostatic test utilizing valve 2NV-464 and its associated pipe nipple, Operations personnel failed to verify that valve 2NV-464 was returned to the fully closed position before they placed the letdown system back into normal service.

This finding is identified as an Unresolved Item 50-370/93-18-03, Maintaining system configuration control - 2NV-464.

One violation was identified.

3. Surveillance Testing (61726)

a. Observed Surveillance Tests

Selected surveillance tests were reviewed and/or witnessed by the resident inspectors to assess the adequacy of procedures and performance as well as conformance with the applicable TS.

Selected tests were witnessed to verify that (1) approved procedures were available and in use, (2) test equipment was calibrated, (3) test prerequisites were met, (4) system restoration was completed, and (5) acceptance criteria were met.

The selected tests listed below were reviewed or witnessed in detail as follow-up and support to the AIT on Unit 2.

- Ice Bed Mass Verification: The inspectors reviewed the results of procedure PT/0/A/4200/18, Ice Bed Analysis, which was performed after the 24[illegible] ice baskets had been weighed. This test was conducted to verify compliance with TS 4.6.5.1.b.2 for periodic ice weight analysis. 144 ice baskets were randomly selected and weighed. The data were reanalyzed for a 95% confidence level. The analysis yielded a total ice weight of 2.8 million pounds. The inspectors verified that the ice inventory was well above the minimum TS limit of 2.1 million lbs.

- Verify Adequate Flow Passages: The inspectors reviewed completed procedure MP/0/A/7150/10, Inspection of Ice Condenser Flow Passages, and inspected the condition of the flow passages. This procedure is used to verify that flow passages in the ice condenser are clear from frost and ice buildup that could degrade the flow passages between the ice baskets. The inspectors noted that the licensee had inspected at least two ice baskets per bay as required by TS. No ice buildup or other debris was identified.

- Verify Lower Inlet Door and Door Position Monitoring System Operability: The inspectors witnessed portions of the licensee's performance of PT/0/A/4200/32, Periodic Inspection of Ice Condenser Lower Inlet Doors, and reviewed the completed procedure. This test verified the operability of the lower inlet doors. The test was then conducted successfully. The tests results indicated that no door adjustments were necessary. The door monitoring system functioned as required.

- Verify Ice Condenser Drain Operability: The inspectors reviewed procedure MP/0/A/7150/08, Inspection of Ice Condenser Floor Drains, and inspected the condition of the floor drains. This test was performed to verify the operability of the floor drain valves. The results of this test revealed that each of the 20 floor drain valves opened at the correct force and were free of ice and debris.

No violations or deviations were identified.

4. Maintenance Observations (62703)

a. Observation

Resident Inspectors reviewed and/or witnessed routine maintenance activities to assess procedural and performance adequacy and conformance with the applicable TS.

The selected activities witnessed were examined to verify that, where applicable, approved procedures were available and in use, prerequisites were met, equipment restoration was completed, and maintenance results were adequate.

The inspectors reviewed the following work packages or other documentation associated with activities performed by the licensee. The inspectors verified that, prior to Unit 2 mode change following the 2A S/G steam leak into containment, appropriate corrective action was completed on the following:

WORK ORDER	ACTIVITY
• WO 93063924	This WO requires inspection of the instrumentation in the area of 2CF-130 for damage. The licensee did not identify any damage to instrumentation due to water or moisture, but several material condition discrepancies were identified and corrected.
• WO 93063778	This WO required the plant staff to check and/or repair fire detection zone instrumentation that would not operate properly. Two smoke detectors that had failed were identified and restored to service prior to restart.
• WO 93063924	This WO was written to check or inspect the Reactor Coolant pump 2A to ensure that the inside of the motor, as well as electrical terminations, were dry. No problems were identified.
• WO 93064212	This WO was written to check/repair the control rod drive mechanisms. Two CRDMs had shorts and were removed and repaired prior to restart.

- WO 93012028 — This WO required the inspection of and repair to the incore instrumentation system. One motor starter was wet and needed to be dried; a second motor starter needed to be replaced. This work was completed prior to mode change.

- WO 93012355, 93012356, 93012357, 93012358 — These work orders required that the four reactor vent valves be cycled to ensure that the solenoid valves associated with them were operating properly. These valves were cycled prior to startup and operated properly.

- WO 93063924 — This WO required the staff to check or inspect the lower containment ventilation units. Aside from some minor material condition items that were corrected, the licensee did not identify any signs of moisture intrusion or damage.

The inspectors determined that the licensee had adequately identified equipment prone to moisture damage and had completed necessary repairs of identified problems.

b. Leak-Sealing 2NC-14 (WO 93022030)

On September 6, 1993, the resident inspectors visually inspected the 2NC-14 valve and verified that there was no leakage in modes 5 and 4. The inspectors examined a disassembled valve of the same type as 2NC-14 to become familiar with its design and maintenance.

By reviewing the work orders, holding discussions with the component engineer and the work planner, and visually inspecting the valve, it was determined that the valve had been leak repaired twice during the most recent Unit 2 refueling outage; once on the outer diameter (OD) and once on the inner diameter (ID) on the bonnet seal ring. Originally, the last leak on the valve was reported as a packing leak, but it was determined to be a leak from the ID of the seal ring.

On September 6, 1993, shortly after entering mode 3, it was reported that the 2NC-14 valve seal ring leakage increased from the as-noted condition by a significant amount. On September 7, 1993, at attempt was made to leak repair the valve at rated temperature and pressure. The inspectors witnessed the leak repair attempt and observed that even though the leak was reduced, it was not completely stopped.

The licensee decided to attempt to leak repair the valve, again, using a less dense sealant, which would provide greater penetration on the valve internals. The inspector witnessed the licensee redrill the same injection paths and blow sealant from previous injections out of the valve. On September 8, 1993, using the less dense sealant, the valve was repaired and the leak stopped.

Following the NV water hammer event on September 10, 1993, the licensee noticed that 2NC-14 had a bonnet leak. The licensee blew out the old sealant and leak repaired the valve with the less dense sealant. The inspectors visually inspected the valve and verified that the leak had stopped.

On September 27, with the unit at 100% power, Operations determined that the unidentified leak rate in containment exceeded the TS limit of 1 gpm. The reactor was shutdown and a containment entry was made. The primary contributor to the increase in unidentified leakage was found to be 2NC-14.

c. Maintenance History of 2NC-14

The inspectors reviewed the maintenance history of valve 2NC-14, the manual isolation valve to letdown. In March 1985 the valve was repacked. In May 1985 a new WR was issued to repack the valve again. The work was performed in April 1986. At that time the technicians had trouble removing the lantern ring. When the lantern ring was finally removed, the packing could not be removed. The licensee then installed one new piece of packing below the lantern ring and seven pieces above the lantern ring. The technician noted that the stuffing box was badly pitted and needed to be replaced.

In July 1989 the valve was disassembled for repair of a packing leak. Gouges were found in the top region of the stuffing box. The technician noted in the WR that he intended to replace the bonnet, stem, plug, washer, and lock nut. There was no spare bonnet, so only the stem, plug, washer, and lock nut were replaced. The assigned engineer determined that the bonnet was acceptable for use with just those repairs.

In July 1993, during the refueling outage, a bonnet leak was identified on 2NC-14. On September 3, 1993, during the AIT inspection, the resident inspectors pointed out to the Station Manager that 2NC-14 was identified on an outage schedule dated August 10, 1993, as having a seal ring leak (WO 9304744203). The inspectors asked why the valve had not been permanently repaired. Licensee management indicated that, to perform maintenance on this valve, the reactor would have had to have been drained to allow draining of the loop, and it would have added three to five days to the outage. Therefore, the licensee decided to leak-repair this valve instead of rebuild it. Sealant had been injected into this valve five times before the leak was stopped. As is stated in paragraph (b) of this section, on September 27 Unit 2 was shutdown due to an unidentified leak in containment that was caused primarily by 2NC-14.

On several occasions during the history of 2NC-14, maintenance technicians identified items that warranted repairs; however, the licensee determined that the discrepancies did not have significant impact, and the valves were not repaired. It is not apparent that efforts have been made to schedule work at a later time to repair these items. Subsequent maintenance activities did not preplan work on these items; they were corrected only if they contributed to the existing deficiency. The use of poor maintenance practices, which allowed 2NC-14 to degrade to a non-isolable primary system leak, is identified as an Unresolved Item 50-370/93-18-04, Poor corrective action results in a non-isolable reactor coolant leak - valve 2NC-14.

d. Use of Leak Sealant

The resident inspectors assessed the use of temporary leak sealants at the site. The licensee uses a contractor, USSI, to perform leak repairs. The predominant sealant used by USSI is supplied by Deacon Industries, Inc. The contractor repairs leaks by drilling through the valve to the area to be sealed, such as the stuffing box, and installing an injection fitting. A predetermined amount of sealant is injected, or sealant is injected until a maximum pressure that is below system pressure is reached.

The work is performed in accordance with licensee procedure, MP/O/A/7650/77, On-line Leak Sealing Initial Injection and the applicable contractor procedure. Repairs are performed on both safety-related and non-safety-related equipment. Prior to each safety-related job a temporary modification or minor modification must be issued, and required safety evaluations must be completed. Engineering personnel are involved in the evaluation and planning required prior to each leak repair.

The licensee's stated goal is to mechanically repair all ASME Class I valves during at next opportunity. During their review, the licensee identified one valve, 2NC-27, that had been overlooked. There are some ASME Class II valves with leak-sealed stuffing boxes that are considered to be permanently fixed. These valves are still tested to ensure that they meet all functional requirements, such as stroke times.

The resident inspectors reviewed work orders to understand the history of leak-repaired ASME Class I Valves. Ten Class I valves have been leak-repaired since 1981. There are two Class I valves that are still leak-repaired in Unit 2 and none in Unit 1. As was previously stated, the inspectors observed the leak-repairs of

2NC-14, the manual isolation for letdown suction. The other valve, 2NC-27, Loop A pressurizer spray valve, was leak-repaired in 1986.

The licensee stated that 2NC-27 should have been repaired prior to this time, but it had been overlooked. Currently, there is no leakage from 2NC-27. Both 2NC-14 and 2NC-27 are scheduled to be rebuilt during the next refueling outage.

e. Kerotest Valve Assembly Problems

Following the August 31, 1993, steam leak in containment caused by the misassembly of valve 2CF-130, the licensee reviewed tasks accomplished during the Unit 2 outage, including maintenance work on Kerotest Y-globe valves. The licensee indicated that valve 2KD-30, the diesel generator cooling water heat exchanger drain valve, had been assembled in the same manner as 2CF-130 with the spring guide installed improperly.

When the system was pressurized following maintenance, the technicians observed a leak. The system was drained, the valve was disassembled, and the installation problem was identified. The valve was reassembled correctly, an entry was made in the WO concerning the event, but a Problem Investigation Report (PIR) was not issued until after the 2CF-130 event.

The corrective action for both instances of misassembly (2KD-30 and 2CF-130) was to revise the procedure, MP/0/A/7600/06, Kerotest Y-type Globe Valve Corrective Maintenance, to include explicit directions for reassembly. Until awareness was enhanced by the steam leak through 2CF-130, no corrective action was planned, perhaps because the 2KD-30 problems had not been identified on a PIP. This is another example of the repetitive problems with the Site Corrective Action Program. This issue was previously identified as an Unresolved Item 369,370/93-13-03, PIP initiation issue. The inspectors will continue their evaluation of site practices in this area.

No violations or deviations were identified.

5. Installation and Testing of Modifications (37828)

Unit 2 Containment Spray (NS) Heat Exchanger Replacement, Modification MG 22403

- Background: In 1992, as a result of testing and analysis of the capabilities of the plant NS heat exchangers, the "2B" heat exchanger was judged to have marginal capability. Apparently this condition resulted from tube pitting and, subsequently, tube plugging.

- Modification/Replacement: Modification MG 22403 was initiated to replace NS "2B" heat exchanger during the Unit 2 Refueling Cycle (July - September, 1993). The modification required the new heat exchanger to be stainless steel with titanium tubes and the raw water cooling (RN) to be switched to tube-side.

- Evaluation: The inspectors reviewed the modification package, which contained: 1) the documents and data that resulted in the modification, 2) a completed 10 CFR 50.59 evaluation, 3) the modification scope and summary from various reviewers, 4) detailed documents and drawings, 5) procedures, and 6) post-modification tests to be completed.

- Observations: Assigned Region II inspectors conducted visual inspections of the installation. The results of their inspection were documented in Inspection Report 50-369, 370/93-12. The resident inspectors evaluated the completed procedure for the installation of the heat exchanger, TN/2/A/9700/065, Implementation Procedure for NSM 22403 Replacement of the 2B NS Heat Exchanger. This procedure initially was implemented on July 18, 1993, and was completed on August 5, 1993. The results covered the following general work activities: 1) general prerequisites, 2) replacement prerequisites, and 3) heat exchanger removal and replacement. On August 26, following installation of the heat exchanger, the inspectors observed the heat balance and flow test conducted on the heat exchanger. The test was conducted in accordance with procedure PT/2/A/4208/10B, NS 2B Heat Exchanger Heat Balance Test. During the test, the inspectors noted that the test crew was thoroughly familiar with the procedural requirements. The test was completed satisfactorily.

No violations or deviations were identified.

6. Followup on Previous Inspection Findings (92701, 92702)

The following previously-identified items were reviewed to verify that (1) the licensee's responses, where applicable, and actions were in compliance with regulatory requirements, and (2) corrective actions have been implemented. Selective verification included review of records, observations, and discussions with licensee personnel.

On September 9, 1993, members of the NRC staff met with the McGuire Emergency Preparedness staff to review URI 93-10-01, "Notification of the NRC within 30 days of a procedure change," and URI 93-10-03, "Maintaining Emergency Preparedness training current."

a. (Closed) URI 93-10-01: Notification of the NRC within 30 days of a procedure change in accordance with 10 CFR 50, Appendix E.V.

Licensees are required to submit any changes to the Emergency Plan or their Implementing Procedures to the NRC within 30 days of such changes. During the June 21-25, 1993, inspection, the inspector noted three instances of late notification to the NRC.

1. On June 1, 1992, the licensee notified the NRC that changes had been made to the Compliance Manual Section 13.2 on June 16, 1991, and again on December 17, 1991.

2. On September 22, 1992, the licensee notified the NRC that a change had been made to procedure OP/1/B/6200/48, "Operation of the Unit 1 Post Accident Liquid Sample System," on July 9, 1992 (approved approximately 11 weeks before the NRC was notified), and OP/2/B/6200/48, "Operation of the Unit 2 Post Accident Liquid Sample System," on July 22, 1992 (approximately nine weeks before the NRC was notified).

3. On April 26, 1993, the licensee notified the NRC that changes had been made to HP/1(2)/B/1009/15, "Unit 1 (2) Nuclear Post-Accident Containment Air Sampling System Operating," on March 26, 1993 (31 days before the NRC was notified), HP/0/B/1009/20, "Manual Procedure for Offsite Dose Projections," and HP/0/B/1009/21, "Estimating Food Chain Doses Under Post Accident Conditions," on March 24, 1993 (33 days before the NRC was notified).

   Initially, the inspector viewed these three late notifications as related instances, and the second and third instances as a failure of previous corrective actions. After further review of licensee's documentation and discussion with the licensee, the inspector concluded that the requirements of 10 CFR 50, Appendix E.V., had not been met. The inspector also concluded that the three instances were of no safety-significance and the root causes of the three instances were different.

   The EPIPs consisted of Emergency Preparedness procedures and selected Chemistry (OP) and Health Physics (RP) procedures. Prior to the NRC inspection of June 21-25, 1993, each group made changes to and approved their own procedures. Since the close of the inspection on June 25, 1993, the licensee changed the procedural approval process to require the Emergency Preparedness Manager's approval for any change to procedures identified as an EPIP. The inspector reviewed the procedure approval change form and concluded that this procedure approval change would prevent a similar reoccurrence of a late notification to the NRC. The inspector informed the licensee that, because the criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied, URI 50-369, 370/93-10-01 would be identified as a NCV.

NCV 50-369, 370/93-18-09: Notification of the NRC within 30 days of a procedure change in accordance with 10 CFR 50, Appendix E.V.

b. (Closed) URI 93-10-03: Maintaining Emergency Preparedness training current

McGuire Nuclear Station Emergency Plan, Section O.2, Station Organization Training requires Emergency Response Training for station emergency response personnel to be conducted in accordance with Emergency Planning Section Manual, Section 1.3, Emergency Response Training Program. Section 1.3 requires that annual training be provided to all Emergency Response personnel.

During the June 21-25, 1993, inspection, the inspector identified approximately 20 members of the emergency organization who appeared to have exceeded their required retraining dates by more than three months.

Further review of licensee's documentation and discussion with the licensee revealed that many of the personnel identified as having expired training were originally Corporate Emergency Response Organization (ERO) personnel who had been reassigned to the site ERO. Duke Power Company had merged their Corporate ERO into the site ERO. The inspector noted that training packages had been sent to the personnel with expired training on May 6, 1993; the deadline response date was June 31, 1993. Therefore, the licensee had identified this training issue, and the licensee had initiated corrective action, prior to the start of inspection 93-10. The inspector has concluded that this URI does not warrant any further action. The issue is closed.

7. Emergency Preparedness Site Training Exercise

On September 16, 1993, the inspectors observed, evaluated and participated as players in a site in-house emergency preparedness training exercise. The exercise began at 1:00 p.m. with a simulated 75 gpm tube leak in the "1A" steam generator. An Alert was declared and the Operations Support Center, Technical Support Center, and the Emergency Operations Facility were activated. The plant conditions evolved to an 800 gpm leak, resulting in a simulated off-site release of radiation and declaration of Site Area Emergency. The field monitoring teams from the station and the state of North Carolina were involved for their own practice. Players from the State of North Carolina Emergency Management and Radiation Protection Division also participated.

Following the exercise, the plant staff conducted a self-critique of the practice drill. Many of the critique items were administrative in nature (e.g. telephone number changes, information boards needing more data, etc.). Also, some concerns were identified regarding the communications systems (fire brigade radio), infrequent information updates, and the role assigned to certain players.

No violations or deviations were identified.

8. Augmented Inspection Team (AIT) Followup - Unit 2 (71707, 62703, 61726, 93702, 92701, 92702)

   a. Background: On August 31, 1993, while the unit was in Mode 3, a site contractor employee attempted to remove a pipe cap from a high energy drain line, located downstream of valve 2CF-130. The employee had been authorized by Work Order 93063230 to remove the pipe cap, place a special cap on the pipe, and inject the new cap with an approved leak-stop sealant. Valve 2CF-130 is a feedwater drain valve located on the shell side of the "A" steam generator. It is a non-isolable manually-operated "Kerotest" valve. During the most recent Unit 2 outage, maintenance work was performed on the valve. The valve was subsequently returned to operations for normal service. The post-maintenance testing of this valve did not require a check for leaks with the downstream pipe cap removed. Therefore, the valve's inability to close was not identified until the steam generator level, temperature and pressure were increased and the pipe cap started leaking.

      On August 31, when the contractor employee started loosening the pipe cap, it suddenly became a projectile. The plant experienced a non-isolable secondary steam leak into the containment building. A unit cooldown was initiated to reduce the amount of steam flowing into the containment. The resident inspectors and Region II management were notified of the general conditions of the plant and events leading up to the steam leak. Region II management met and an AIT was assembled. On the afternoon of September 1, 1993, the team arrived at the site with a charter from the Regional Administrator. The team remained at the site until September 5, 1993, at which time they conducted a pre-briefing with plant management. On September 7 the Region II Director of Reactor Safety returned to the site with AIT members and conducted a briefing with plant management and staff to discuss the facts gathered by the team.

   b. Evaluations and Observations: The AIT findings are documented in Region II Report 5-369,370/93-20. The resident inspectors assisted the team and conducted follow-up inspection for items identified during the AIT inspection. The items were classified by the resident inspectors as short-term actions and were evaluated as follows:

      1. Verify operability of the ice condenser inventory, lower inlet doors and drains. Assure NRC management that frost will not affect operability.

As a result of the steam leak on 2CF-130, lower containment temperature and pressure increased and the ice condenser lower inlet doors opened. The licensee observed melting of the ice bed in several bays (bay 12 and bays 19 through 24). The most significant ice melt occurred in bay 22, which was closest to the steam leak. To determine the impact of the ice melt, the licensee initially weighed 247 baskets in bays 11 through 13, and 19 through 24. The mean total ice weight and a 95%-confidence weight were estimated from these data. Ice mass operability projections to the end of the operating cycle (12/01/94) were made for each basket. Based on these projections, four baskets in bay 22 were estimated to weigh less than the Technical Specification limit of 1081 pounds. Therefore, the licensee decided to replenish these baskets. The licensee determined that approximately 2400 pounds of ice inventory was lost from the baskets.

The inspectors conducted several walkdowns of both the upper and lower ice condenser areas. Although there were signs of accelerated sublimation in some of the ice baskets visually inspected from the intermediate deck (the top of the ice baskets), no ice baskets appeared to have melted significantly. The inspectors confirmed that the baskets selected for weighing were the most likely to have been impacted by the ice condenser activation. For example, 61 of the 81 baskets in bay 22 (the most impacted bay) were weighed. The inspectors visually inspected a large sample of ice basket flow passages. The inspectors verified that these passages were clear of frost and ice. Particular attention was paid to bays most impacted by the event. The inspectors also visually inspected the inside of the lower ice condenser and lower containment and a sample of ice condenser floor drains. These valves were operable and clear of ice and other debris.

Based on these inspections and reviews, the inspectors determined that the licensee had adequately evaluated the effects of the ice condenser actuation.

2. Evaluate all equipment in containment exposed to high temperature, humidity, and water.

   Following the event, the licensee conducted an inspection and evaluation of various equipment inside lower containment to ensure that there was no adverse impact on equipment or components.

   The inspectors reviewed each of the work packages or other documentation available for the areas reviewed by the licensee. Also, the inspectors conducted detailed walkdown inspections of the containment building, and looking in all areas that could have been affected by the steam.

The inspectors determined that the licensee had adequately identified equipment that was prone to moisture damage and had completed necessary resolution of identified problems.

3. Visually inspect the electrical equipment inside containment that could have been impacted by the 2CF-130 leak, and verify that evaluations and/or repairs have been completed.

The inspectors conducted a walkdown of lower containment to visually inspect electrical equipment in the vicinity of 2CF-130, which could have been affected by the event. In addition, repairs to accessible areas identified by the licensee were visually verified to have been completed. The following areas and equipment were inspected during this walkdown:

- Reactor Coolant Pump Motors: The inspectors visually inspected all cables and associated terminal boxes associated with the nearest RCP (2A) to 2CF-130. All areas were dry and showed no evidence of water intrusion or water corrosion.

- Control Rod Drives: The inspectors inspected accessible portions of the CRDM cables during walkdowns. These areas appeared dry and undamaged from water intrusion. Inspectors noted that these cables are well insulated and not likely to be impacted from water intrusion.

- Incore Instrumentation: The inspectors inspected accessible portions of the incore instrumentation, including cabling and motor compartments. These areas were dry.

- Post Accident Monitoring Equipment: The inspectors inspected the lower containment fan rooms A and D, which were located nearest to the steam leak. The reactor building water level monitoring instrumentation is located in this area. This equipment appeared dry and free of water intrusion.

- Fire Detectors: The inspectors inspected several fire detectors in the vicinity of 2CF-130; all appeared to be dry.

- Containment Ventilation Fans and Vibration Detection System: The inspectors visually verified that this equipment was dry; no evidence of moisture damage was observed. The vibration panels for the A and D fans were visually inspected; based on control indications on the panel, it appeared to be operating properly and showed no signs of moisture damage.

- Reactor Vessel Head Vent Valves: The inspectors visually verified the condition of the reactor vessel head vent valves and their associated solenoid valves. These components were dry and showed no evidence of moisture intrusion. The licensee cycled these valves following the event and verified that they were operating properly.

- Electrical Penetrations: The inspectors visually verified the condition of electrical penetrations in the lower containment A and D fan rooms and near the incore seal table. Some of these penetrations near the seal table showed signs of moisture intrusion and rust indications. However, these conditions appeared to have existed prior to the steam leak event. The licensee evaluated the potential impact on these penetrations and determined that they were designed for venting and draining in the event of water or moisture intrusion.

4. Determine if ice condenser technical specification surveillance has been conducted as required prior to mode change.

   At the time of the evaluation, the plant was still in Mode 5. The inspectors reviewed the surveillance test results to verify compliance with T.S. Sections 4.6.5.1.b.2 (Periodic Ice Weight Analysis), ensure that periodic inspection of ice condenser lower inlet doors was conducted, verify that the ice condenser floor drains were operable, and ensure that flow passages were clear from frost and ice buildup.

   The inspectors concluded that the licensee adequately completed those TS surveillance requirements necessary to demonstrate operability of the Unit 2 ice condenser.

5. Determine if adequate evaluations were completed on the improper maintenance of 2CF-130 and other Kerotest packless valves.

   The inspectors verified through the review of records, interviews with maintenance personnel, and observation of valve-stroking that the Unit 2 Kerotest valves that were worked on during the recent refueling outage (2EOC-8) were evaluated. The records indicated that 31 of these valves were received maintenance work. Each valve was evaluated for proper reassembly, and no other valve inside Unit 2 containment was improperly reassembled and, subsequently, rendered inoperable. The evaluations included either stroke testing prior to a plant mode change or a review of completed documentation verifying that the valves had been full-stroke tested.

6. Determine if 2CF-130 was properly reassembled, after maintenance work and, if not, what actions are being taken to improve the work controls that allowed reassembly errors to be made.

   Valve 2CF-130 was removed from the steam generator drain line piping and disassembled. The valve's internal spring guide had installed incorrectly. The incorrect installation of the spring guide prevented the valve from closing.

   Corrective actions were promptly completed or put into place by the licensee. Specifically, the procedure that previously used by maintenance for servicing Kerotest packless valves, MP/0/A/7600/06, was revised to clarify re-assembly steps. The revision should help reduce the likelihood that another valve of this type will be incorrectly reassembled. In addition, this procedure is being evaluated by the plant staff for potential human factors enhancements.

   Based on available information the inspectors could not determine if the plant operators had sufficient information to maintain proper steam generator feedwater system configuration control as a result of incorrect reassembly of and subsequent leak through 2CF-130.

   This concern will be identified as an Unresolved Item 50-370/93-18-05, Maintaining system configuration control - 2CF-130.

7. Determine status of on-line pipe cap removals on pressurized high energy systems.

   The inspectors interviewed personnel in work planning, mechanical maintenance, and operations to discuss the use of pipe caps.

   Removal of pipe caps on systems with greater than 600 psig has been suspended until further notice. The inspectors reviewed the directives to each group and verified that they were being implemented and that personnel were aware of the requirements.

8. Determine if operations management increased interaction with vendors conducting work activities on plant equipment.

   A directive was issued to the operations staff. The directive requires that mechanical maintenance personnel accompany vendor representatives, such as the valve leak repair vendor (USSI), when the vendor group interacts with operations to obtain clearances or authorization to perform work.

The plant staff indicated that long-term actions that will require strengthening administrative controls (procedures and documented guidelines) are planned.

9. Determine if appropriate sensitivity (in response to the steam leak) to plant status and maintenance has been demonstrated by operators and operations managers.

   The inspectors interviewed personnel from several operations shifts and discussed this issue with operations management. Weaknesses were still noted concerning maintenance status on equipment, but there was some evidence that improvements have been started. Specifically, briefings on planned maintenance activities are being improved to acquaint operations personnel with scheduled maintenance.

10. Determine the adequacy of the post-maintenance testing of 2CF-130, original and planned for future.

   The original post-maintenance test required a visual inspection at rated temperature and pressure with the pipe cap on so that steam leaks past the pipe cap would be visible. If the pipe cap were intact, this would not indicate any problems with the associated valve. Even if the test did reveal a leak (which would indicate problems with both the valve and the pipe cap), the operating conditions would allow corrective maintenance on only the cap and not the valve. This post-maintenance test was inadequate for verifying the adequacy of the maintenance performed on the valve.

   The post-maintenance test has been revised to require that leak checks be performed with the pipe cap removed during steam generator fill and at various times during heat-up and pressurization.

   The inspectors did not have sufficient information to determine if adequate post-maintenance testing was completed on 2CF-130 prior its placement back into service.

   This concern will be identified as an Unresolved Item 50-370/93-18-06, Verify operability of equipment prior to placing the equipment into service or returning it to normal service - 2CF-130.

11. Determine if operations staff has minimized disturbances in the Control Room during shift turnovers.

   Following the event, the resident inspectors interviewed control room personnel, witnessed shift turnovers and verified that operations had improved methods for the conduct of shift briefings. Non-licensed operators are now briefed separately from the licensed operators and outside of the main control room, thereby reducing the number of people in the control room during turnover and briefing.

12. The inspectors evaluated an event that occurred during the TS cooldown following a steam leak into containment on August 31, 1993. At shift turnover the unit was in Mode 4 (340 degree F and 1180 psig). To reduce the cooldown rate during turnover, the licensed operator reduced steam dump demand and stopped blowdown.

    The reduction in steam dump and blowdown resulted in a reactor coolant system heatup. At 7:34 a.m., the unit reentered Mode 3; this mode change was unobserved by the licensed operators. Shortly thereafter, a radiation protection technician notified the operations staff that the steam flow out of the leaking 2CF-130 valve had increased. The operations staff investigated and observed that the unit was heating up instead of cooling down; they did not realize that a mode change had occurred. They brought the heatup to the attention of the shift operations crew, but it wasn't until that time that the control room SRO made the observation that a mode change had occurred.

    The operators suspended heatup and began cooling down. Mode 4 was reentered at 8:35 a.m. The inspectors are continuing to investigate the implications of this unplanned mode change. This item will be tracked as Unresolved Item 370/93-18-07, Operation of unit 2 systems and equipment - unplanned mode change.

13. Determine if a channel check of the inlet door monitoring system was performed within four hours after receiving an alarm.

    On August 31, 1993, during the steam leak from 2CF-130 into containment, all but four lower doors in the ice condenser opened. Personnel inside containment notified the control room that approximately six feet of ice had melted inside bay 22. When the doors opened at approximately 1:00 a.m., "Ice Condenser Inlet Door Open" alarms were received in the main control room.

    Technical Specification 4.6.5.4.a. requires that a channel check of the inlet door position monitoring system be performed within four hours after receiving the "Ice Condenser Inlet Door Open" alarm. It is not clear that the channel check was completed within four hours.

This item will be tracked as Unresolved Item 370/93-18-08, Operation of unit 2 systems and equipment - TS surveillance requirements on the ice condenser inlet door position monitoring system.

No violations or deviations were identified.

9. Exit Interview (30703)

The inspection scope and findings identified below were summarized on September 28, 1993, with the Station Manager and members of his staff. The following items were discussed in detail:

Violation 369,370/93-18-01: Failure to follow procedure for fire watch requirements (paragraph 2.e)

Unresolved Item 50-370/93-18-02, Operation of unit 2 systems and equipment - water hammer in letdown system (paragraph 2.g)

Unresolved Item 50-370/93-18-03, Maintaining system configuration control - 2NV-464 (paragraph 2.g)

Unresolved Item 50-370/93-18-04, Poor corrective action results in a non-isolable reactor coolant leak - valve 2NC-14 (paragraph 4.c)

Unresolved Item 50-370/93-18-05, Maintaining system configuration control - 2CF-130 (paragraph 8.b.6)

Unresolved Item 50-370/93-18-06, Verify operability of equipment prior to placing the equipment into service or returning it to normal service - 2CF-130 (paragraph 8.b.10)

Unresolved Item 370/93-18-07, Operation of unit 2 systems and equipment - unplanned mode change (paragraph 8.b.12)

Unresolved Item 370/93-18-08, Operation of unit 2 systems and equipment - TS surveillance requirements on the ice condenser inlet door position monitoring system (paragraph 8.b.13)

NCV 369,370/93-18-09, Notification of the NRC with 30 days of a procedure change in accordance with 10CFR50 Appendix E.V (paragraph 6.a)

The licensee representatives present offered no dissenting comments, nor did they identify as proprietary any of the information reviewed by the inspectors during the course of their inspection. The licensee was informed that the items discussed in paragraph 6 were closed.

Attachment to RII Report 93-18

PLANT NAME: McGuire **LICENSEE:** Duke Power **DOCKET #:** 50-369,370

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. **PROGRAM:**

1. Does the licensee have an employee concerns program? **(Yes or No/Comments)**

   Yes

2. Has NRC inspected the program? Report #__________

   No

B. **SCOPE:** (Circle all that apply)

1. Is it for:

   a. Technical? **(Yes, No/Comments)**

      Yes

   b. Administrative? **(Yes, No/Comments)**

      Yes

   c. Personnel issues? **(Yes, No/Comments)**

      Yes

2. Does it cover safety as well as non-safety issues? **(Yes or No/Comments)**

   Yes

3. Is it designed for:

   a. Nuclear safety? **(Yes, No/Comments)**

      Yes

   b. Personal safety? **(Yes, No/Comments)**

      Yes

   c. Personnel issues - including union grievances? **(Yes or No/Comments)**

      Yes

4. Does the program apply to all licensee employees?
   (Yes <u>or</u> No/Comments)

   Yes

5. Contractors?
   (Yes <u>or</u> No/Comments)

   Yes

6. Does the licensee require its contractors and their subs to have a similar program?
   (Yes <u>or</u> No/Comments)

   No

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?
   (Yes <u>or</u> No/Comments)

   Yes

C. **INDEPENDENCE:**

1. What is the title of the person in charge?

   No one person identified, but generally Human Resources Department has the leak in coordinating resolution.

2. Who do they report to?

   Ultimately to Executive Management

3. Are they independent of line management?

   Yes, Human Resources Personnel are responsible for conducting the investigations. If the issue/concern is of a technical nature the Station's Safety Assurance Manager is assigned to investigate the technical concerns. Both of these organizations report directly to the Station Vice President.

4. Does the ECP use third party consultants?

   No

5. How is a concern about a manager or vice president followed up?

   By Human Resources and Executive Management

D. **RESOURCES:**

1. What is the size of staff devoted to this program?

   McGuire Human Resources Consulting - 9, but not devoted full time.

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?

Human Resource individuals who conduct these investigations are individuals who have demonstrated investigation skills to factually and logically address employee concerns and issues. Typically these individuals have a minimum of 4 years experience working in the Human Resources function. Internal Duke Power training that is available, but not limited to and not required is as follows: Interviewing Skills, Exit Interviewing, How to Conduct an Investigation, Problem Solving and Decision Making, Effective Documentation and Writing Skills.

E. **REFERRALS:**

1. Who has followup on concerns (ECP staff, line management, other)?

   Human Resources Staff
   Safety Assurance Management

F. **CONFIDENTIALITY:**

1. Are the reports confidential?
   (Yes <u>or</u> No/Comments)

   Yes

2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)?
   (Circle, if other explain)

   Designated Human Resources professional working on the investigation.

3. Can employees be:

   a. Anonymous? **(Yes, No/Comments)**

      Yes

   b. Report by phone? **(Yes, No/Comments)**

      Yes

G. **FEEDBACK:**

1. Is feedback given to the alleger upon completion of the followup?
   (Yes <u>or</u> No - If so, how?)

   Yes

2. Does program reward good ideas?

   Indeterminant

3. Who, or at what level, makes the final decision of resolution?

   Determined by the level of recourse initiated.

4. Are the resolutions of anonymous concerns disseminated?

   If findings result in changes of work practices/procedures or other corrective action then change will be implemented and communicated through various means.

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

   Yes, by policy/procedure revision communications, training classes, company publications and newsletter.

H. **EFFECTIVENESS:**

1. How does the licensee measure the effectiveness of the program?

   Employee feedback, employee opinion survey

2. Are concerns:

   a. Trended? **(Yes <u>or</u> No/Comments)**

      Indeterminant, due to the low number and frequency of concerns.

   b. Used? **(Yes or No/Comments)**

      Based on observations at site, it depends on the impact of the concern

3. In the last three years how many concerns were raised?

   16 personal concerns

   Closed?

   16

   What percentage were substantiated?

   89%

   <u>Personal Concerns</u>

   16 for McGuire -- 95 total for power generation

   Closed?

   All Personal Concerns investigated and resolved

   <u>Technical Concerns</u>

   None in the last 3 years

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)?

   Employee opinion survey

5. How frequently are internal audits of the ECP conducted and by whom?

   Not audited

I. **ADMINISTRATION/TRAINING:**

1. Is ECP prescribed by a procedure? **(Yes <u>or</u> No/Comments)**

   Yes

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)?

   By Employee Benefits material, Company Procedure Manual also notices posted on Bulletin Board, Orientation for new employees and outage handbook for employees and vendors, general employee training, periodic reminders through site team notes

<u>ADDITIONAL COMMENTS:</u> **(Including characteristics which make the program especially effective or ineffective.)**

In the first quarter of 1993 a group was formed to review existing internal reporting systems through which employees might raise nuclear safety related complaints. If such system were determined by the group to be inadequate, then the group was charged with recommending either additional systems, modifications, or some combination of both. The group consisted of representatives from the three nuclear sites, Nuclear Licensing, Corporate Employee Relations, Corporate Communications, Customer Group and the Legal Department. The group determined that adequate systems are in place in the nuclear area for employees to raise concerns. The group made recommendations of implementing a 1-800 number for the purpose of allowing employees yet another method of raising concerns. They also recommended that the General Employee Training be specific to discuss that contractor employees may raise safety concerns by contacting the site Safety Assurance manager. This training is given to all contractors prior to work or at annual requalification of GET. This statement is scheduled to be added to all training material and posted on station company bulletin boards.

NAME: TITLE: PHONE #:
<u>G. F. Maxwell</u>/ <u>SRI</u> / <u>704-875-1681</u> **DATE COMPLETED:** <u>9/23/93</u>