U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	McGuire Generating Station, Units 1 and 2
Location:	12700 Hagers Ferry Road Huntersville, NC 28078-8985
Dates:	September 21 - November 1, 1997
Inspectors:	S. Shaeffer, Senior Resident Inspector M. Sykes, Resident Inspector M. Franovich, Resident Inspector R. Chou, Regional Inspector (Sections E1.1 and E1.2) N. Economos, Regional Inspector (Sections M4.1 through M4.3)
Approved by:	C. Ogle, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

McGuire Generating Station, Units 1 and 2
NRC Inspection Report 50-369/97-17, 50-370/97-17

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a six-week period of resident inspection. In addition, it included the results of two regional inspections specifically reviewing the Unit 2 steam generator replacement project.

Operations

- In general, the conduct of operations was professional and safety conscious. (Section O1.1)

- The inspectors concluded that the licensee reported a potential non-conservatism in a Technical Specification in accordance with the requirements of 10 CFR 50.72. The administrative limits established to compensate for the potential non-conservatism in Technical Specifications appeared to be adequate. (Section O1.2)

- General material condition and housekeeping of the Unit 2 ice condenser system appeared good. Observed Unit 2 maintenance activities were being accomplished with established procedures. The licensee's evaluation and monitoring of Unit 1 ice bed temperature anomalies and floor temperature alarm were adequate. (Section O2.1)

- The licensee took prudent actions to develop procedures specifically for the loss of auxiliary feedwater recirculation capability. The inspectors reviewed the procedures and concluded that adequate guidance was incorporated to respond to events where auxiliary feedwater recirculation capability may be lost. (Section O3.1)

- The inspectors concluded that operators maintained adequate focus during the Unit 2 shutdown and responded appropriately to equipment malfunctions during the evolution. A failure of a rod control system component resulted in additional burden on operators during this critical plant evolution. Licensee management was aware of the repetitive nature of the problem and had taken some prior actions to focus additional resources on the problem. (Section O4.1)

- The licensee provided adequate training for station personnel and maintained good command and control during core offload. No problems were identified during the core offload evolution, which was indicative of excellent personnel and equipment performance. Good oversight of generic spent fuel pool storage issues was apparent. (Section O4.2)

- The inspectors concluded that the mispositioning of the non-safety Auxiliary Feedwater Condensate Storage Tank supply system was repetitive in nature, indicated operator inattention to detail, and that the licensee's evaluations of a similar 1995 problem and the 1997 problem with the alignment of supply valves could have been more rigorous. The inspectors concluded that this condition had the potential for

diverting operator focus and resources away from other complications that could arise during an event; thereby, challenging overall operator response. (Section O4.3)

- The licensee was currently conducting an extensive review of the safety to non-safety interface of the auxiliary feedwater system, focusing on system design and operator required actions. In addition, the licensee was preparing to perform a root cause assessment of their latest component mispositioning data to continue to improve in this area. (Section O4.3)

- With regard to the identification of an overpower condition, the operators continue to exhibit a good questioning attitude and good attention to plant operating conditions. Overall, the licensee continues to exhibit heightened awareness to reactivity events and has a low threshold for classifying these type events as significant for root cause analyses to be performed. (Section O4.4)

Maintenance

- In general, monitored maintenance and testing activities were completed satisfactorily. Overall control of testing activities was good and indicative of management oversight. (Section M1.1)

- The licensee's planned maintenance evolution for the 2B emergency diesel generator was well implemented. Foreign material exclusion controls during the activities provided adequate protection for the open configuration of the engine. The subsequent surveillance testing activities performed were adequate to ensure equipment operability. (Section M2.1)

- Licensee actions in response to a potentially degraded auxiliary feedwater condition were acceptable. Reducing the acceptance criteria for vent flow in order to eliminate an immediate concern was acceptable. The inspectors also concluded that any further reduction in continuous vent flow rates could challenge the auxiliary feedwater system during a standby shutdown system event and heightened monitoring and timely corrective actions were warranted to prevent future inoperability of these components. (Section M2.2)

- Minor Modification MM-8410 to replace certain isolation drain valves and associated piping in the reactor coolant system crossover pipe was being performed following applicable code requirements. Prefabricated subassemblies and field welds exhibited good workmanship attributes and material records were retrievable and in order. Quality Control inspections and visual examinations were performed as required. Engineering evaluations and input were appropriate. (Section M4.1)

- Welder performance qualifications were consistent with code requirements and were being closely monitored by cognizant licensee personnel. The weld filler metal control program was well organized and capable of supporting steam generator replacement project welding. (Section M4.2)

- Volumetric and surface inservice inspection of designated welds were performed satisfactorily by qualified and well trained personnel following approved non-destructive examination procedures. (Section M4.2)

- The steam generator replacement project was progressing well within the licensee's pre-established timetable. Cutting activities followed approved procedures and were closely monitored. Lifts of heavy components were well planned and implemented in a safe manner. (Section M4.3)

- Housekeeping around the steam generator replacement work project work area showed significant improvement over the two previous Duke facility steam generator replacement projects. (Section M4.3)

- The inspectors confirmed through observation of project activities and discussions with licensee representatives that the steam generator replacement project organization was effective in adequately planning and safely executing the Unit 2 steam generator replacement project effort. (Section M6.1)

- The licensee's development of a special test in response to NRC concerns to assure operability of the interior fire suppression loop piping was good. However, initial test performance problems did not allow for valid data to be taken. The problems identified indicated that some fire suppression equipment may have limited preventive maintenance being performed. (Section M8.1)

Engineering

- The required lifting plan, path, load tests, and lifting equipment inspections generated or performed for the safe lifting and transfer operations of the old and new steam generators were adequate. One weakness and one Non-Cited Violation were identified for qualified crane operators not signing and dating in the procedures for the steps which they performed, and for performing procedure steps out of sequence. (Section E1.1)

- The licensee performed adequate preparations, supporting calculations, and had acceptable drawings and other documents to ensure the installation of the new short segment of guard pipe during the steam generator replacement project. An Inspector Followup Item was identified for a clarification of load and moment sign transformation application from Unit 1 to Unit 2. (Section E1.2)

- Communications between engineering and operations regarding anticipated spent fuel pool temperatures when isolating one spent fuel cooling pump were not effective. Adjustments to the required surveillance monitoring of the pool may also have been beneficial during periods of anticipated temperature increases, particularly when associated computer alarm points were unavailable. (Section E4.1)

- An Inspector Followup Item was identified concerning a potentially non-conservative Technical Specification for the hydrogen mitigation system may exist and that insufficient information was available to determine adequacy of the current Technical Specification. No immediate safety or operability issues existed since plant procedures required testing all installed igniters. (Section E4.2)

Plant Support

- An October 1, 1997, emergency preparedness drill adequately demonstrated the set objectives with two exceptions. Appropriate focus was being applied to these exception areas to improve future performance. The licensee's conservative timing of the drill and continued aggressive drill schedule were identified as area strengths. (Section P5.1)

- An Inspector Follow up Item was identified concerning potential problems involving multiple security guards not accurately performing vehicle accountability searches. (Section S4.1)

Report Details

Summary of Plant Status

Unit 1

Unit 1 operated at approximately 100 percent power during the inspection period.

Unit 2

Unit 2 began the inspection period at approximately 100 percent power. On October 3, the unit was shutdown in a controlled manner to facilitate the end-of-cycle 11 refueling outage. The outage also included replacement of the Unit 2 steam generators. The licensee completed offloading of the reactor core to the Unit 2 spent fuel pool on October 12. The unit remained defueled for the remainder of the inspection period. At the end of the period, the licensee had accomplished safe disassembly and removal of all the old steam generators and had begun installing the new steam generators within the containment.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

01.2 10 CFR 50.72 Notifications

a. Inspection Scope

During the inspection period, the licensee made one notification to the NRC. The inspectors reviewed the notification issue for impact on the operational status of the facility and equipment.

b. Observations and Findings

On October 23, 1997, the licensee made a four-hour, non-emergency notification to the NRC in accordance with 10 CFR 50.72 requirements concerning potential non-conservativism within a Technical Specification (TS) power versus flow prohibited operation area.

While reviewing the basis for TS 3/4.2.5, Departure from Nucleate Boiling, (DNB) parameters, a potential non-conservativism was identified by the licensee for reactor power operation with less than 382,000 gallons per minute (gpm) flow. At the time of the notification, Unit 1 was operating at approximately 100 percent power with reactor coolant system (RCS) flow greater than 382,000 gallons and Unit 2 was defueled. In these operating conditions, there were no constraints imposed on operation of either unit as a result of this identified potential non-conservatism. The licensee established administrative controls to take appropriate operator actions (ie, reduce reactor power) if RCS flow parameters went below 382,000 gpm. At the end of the inspection period, the licensee was continuing to evaluate this issue and identifying appropriate actions to adjust the TS as required. The licensee indicated their intention to submit a Licensee Event Report (LER) on the subject.

c. Conclusions

The inspectors concluded that the licensee reported a potential non-conservatism in TS in accordance with the requirements of 10 CFR 50.72. The administrative limits established to compensate for the potential non-conservatism in TS appeared to be adequate.

02 Operational Status of Facilities and Equipment

02.1 Ice Condenser System Operability

a. Inspection Scope (71707, 62707)

The inspectors evaluated the material condition and maintenance activities of the Unit 2 ice condenser system (ICS) and reviewed operational issues with the Unit 1 ICS. During the Unit 2 outage, the inspectors also walked down the ICS to examine its overall condition and followup on a recent event involving mechanical binding of the lower inlet doors (previously discussed in Inspection Report 50-369,370/97-16).

b. Observations and Findings

During outage ice making operations for Unit 2, the Unit 1 ice condenser average ice bed temperatures started to trend upwards at a slow rate of approximately 0.4 degrees Fahrenheit per day. Normally, the average ice bed temperatures are typically in the mid-teens (degrees Fahrenheit). At the same time, floor cooling indication alarmed in the control room. The overall ice bed temperature increase was attributed by the licensee to two conditions. First, chillers for Unit 1 operations were diverted to Unit 2 for ice making operations and second, normal cooling water temperatures had increased due to a temperature inversion in the Lake Norman cooling supply. The licensee diverted chillers back to Unit 1 service to recover ice condenser temperatures. At no time did the average ice bed temperature challenge TS requirements. The floor cooling alarm was attributed to a temperature setpoint drift in the

temperature indicator for the alarm. The floor cooling system was not affected since this indicator has no control function for the floor cooling system.

The inspectors performed a walkdown of the Unit 2 ICS during ongoing maintenance activities, including ice basket settling and refill operations. The inspectors examined the floor for foreign material and identified two metal plates that were too large for the vacuum system to pickup. The inspectors questioned ICS technicians to establish the type and magnitude of debris collected through vacuuming ice and cleaning of the waste ice removal system. Technicians responded that minor amounts of debris which were collected in the waste system were composed mostly of tape and materials used during outage ice condenser servicing. The inspectors discussed with licensee management the importance of inspecting vacuumed debris to ensure no evidence of broken ICS components were overlooked (for example, sheet metal screws). The inspectors also examined the floor for signs of deterioration. Superficial mechanical damage to the wear slab was noted from previous maintenance activities such as scraping of floor ice.

c. Conclusions

General material condition and housekeeping of the Unit 2 ICS appeared good. Observed Unit 2 maintenance activities were being accomplished with established procedures. The licensee's evaluation and operational monitoring of the Unit 1 ice bed temperature anomalies and floor temperature alarm were adequate.

03 Operations Procedure and Documentation

03.1 Loss of Auxiliary Feedwater (AFW) Recirculation Capability

a. Inspection Scope (71707)

The inspectors evaluated the licensee's actions to correct procedural deficiencies identified following the September 6, 1997, dual unit reactor trip.

b. Observations and Findings

During the dual unit trip that occurred on September 6, 1997, the operators lost Unit 1 AFW recirculation capability due to the recirculation valves failing closed upon de-energization of the KXA power supply. The loss of recirculation capability was not immediately recognized by control room operators during the event and was also not recognized during the post-trip review (see Inspection Report 50-369,370/97-15). In an effort to provide additional guidance to operators, the licensee developed and approved Procedures AP/1/A/5500/05 and AP/2/A/5500/05, Loss of Unit 1 and Unit 2 Auxiliary Feedwater Recirculation Capability. These procedures identify symptoms associated with a loss of AFW recirculation capability and provide instructions on how to control AFW flow when the AFW miniflow valves are not available

to ensure pump minimum flow requirements are met.

The newly developed procedures also provided requirements on motor-driven pump starting/duty cycles and turbine-driven pump starting. Additional guidance for turbine-driven pump operation was also provided for locally resetting turbine trip throttle valves.

c. Conclusions

The inspectors concluded that the licensee's action to develop procedures specifically for the loss of AFW recirculation capability was prudent. The inspectors reviewed the procedures and concluded that adequate guidance was incorporated to respond to events where AFW recirculation capability may be lost.

04 Operator Knowledge and Performance

04.1 Shutdown For Unit 2 End-Of-Cycle 11 (2EOC11) Outage

a. Inspection Scope (71707)

The inspectors reviewed and evaluated the shutdown of Unit 2 to Mode 3 for the 2EOC11 steam generator replacement and refueling outage. The inspectors focused on activities that could impact nuclear and personnel safety to verify that licensee controls were sufficient.

b. Observations and Findings

On October 2, 1997, control room operators began a controlled shutdown of Unit 2 in accordance with Procedure OP/2/A/6100/02, Controlling Procedure for Unit Shutdown. The inspectors reviewed scheduled work activities to confirm that the licensee performed adequate risk evaluations of shutdown activities prior to the outage and monitored the shutdown activities.

During shutdown load reduction, the operators recognized that rods failed to respond with a Taverage (Tavg) and Treference (Tref) error of approximately +2.2 degrees Fahernheit. Control rod response was expected at a temperature error of 1.5 degrees Faherenheit. The operators halted the load decrease and took manual rod control in accordance with Procedure AP/2/A/5500/14, Rod Control Malfunction, to correct the temperature error. Maintenance personnel were contacted to evaluate the reactor control system malfunction. The licensee continued the controlled shutdown with rod control in manual. Operators brought Unit 2 to Mode 3 (Hot Shutdown) on October 3, 1997, at 4:16 a.m.

The licensee conducted an evaluation of the reactor control system failure. The licensee identified a short circuit trip condition at a 7300 control card as the apparent cause. The failed card prevented inward control rod motion while rods were in automatic. The card was replaced and tested to verify operability. The inspectors verified that the failure of the 7300 control card did not prevent manual operation of

the control rods and would not have prevented control rod insertion due to a manual or automatic reactor trip signal.

The inspectors performed a review of similar events and confirmed that a similar card failure occurred on January 20, 1997, preventing automatic control rod operation during a Unit 2 load reduction following the loss of the Unit 2 isolated phase bus cooling fans. Although the control card failures experienced have not affected safe shutdown of the unit, additional operator effort was necessary to complete the load reductions. The inspectors recognize that although the affected portion of the rod control system is not safety-related, operators rely upon the system to operate properly during routine and abnormal load changes. The inspectors reviewed the McGuire UFSAR and confirmed that no credit was taken in UFSAR accident analyses for the rod control system.

c. Conclusions

The inspectors concluded that operators maintained adequate focus during the Unit 2 shutdown and responded appropriately to equipment malfunctions during the evolution. The inspectors noted that the failure of a rod control system component resulted in a burden on operators during this critical plant evolution. Licensee management was aware of the repetitive nature of the problem and had taken some prior actions to focus additional resources on the problem.

04.2 Unit 2 Core Offload

a. Inspection Scope (71707)

The inspectors reviewed the licensee's reactor core offloading plans to verify adequate training of fuel handling personnel. Spent fuel pool (SFP) criticality management was also evaluated. Recently discovered boraflex degradation of the Unit 2 spent fuel racks was also evaluated to confirm no potential adverse impact on spent fuel loading was experienced.

b. Observations and Findings

The inspectors reviewed training documents and established procedures and verified that the fuel handling senior reactor operator (FHSRO) was responsible for direct supervision of core alterations and was expected to have no concurrent responsibilities. The documents adequately emphasized that reactivity additions or core alterations were not allowed without the direct supervision of the FHSRO. Additionally, the inspectors observed that the FHSRO was actively in charge of the fuel handling bridge during core alterations. During the evolution, there were no indications of fuel damage, unexpected reactivity changes or

changes in refueling or spent fuel pool water levels. Control rod shuffling and control rod drag testing were also successfully performed in the spent fuel pool without incident. The inspectors also periodically reviewed plant parameters and other requirements stipulated by the TS refueling section. Operators were actively monitoring all TS related parameters. No non-compliances were identified.

Prior to fuel movement, the licensee increased SFP boron concentration in accordance with the core operating limits report and the TS for refueling operations. Boric acid was added directly to the SFP by dumping boron through a funnel and chute. Appropriate attention was applied to ensure adequate mixing in the pool and to minimize introduction of foreign material. To ensure k_{eff} would be less than or equal to 0.95, more conservative limits were imposed for unrestricted storage of fuel in Region 1 of the SFP than required by TS Table 3.9-1, Minimum Qualifying Burnup Versus Initial Enrichment for Unrestricted Region 1 Storage. These administrative limits were generated to account for degraded boraflex material in the spent fuel racks. However, the fuel discharged from the reactor to Region 1 of the pool was significantly less reactive than the limits for Region 1 unrestricted storage. Spent fuel pool water clarity and lighting were adequate to support fuel movement.

c. Conclusions

The inspectors concluded that the licensee provided adequate training for station personnel and maintained good command and control during core offload. No problems were identified during the core offload evolution, which was indicative of excellent personnel and equipment performance. Good oversight of generic spent fuel pool storage issues was apparent.

04.3 Valves Mispositioned in the Auxiliary Feedwater System

a. Inspection Scope (71707, 40500)

The inspectors reviewed the facts and circumstances related to auxiliary feedwater condensate storage tanks (AFWCSTs) supply valves being discovered in the wrong position. The inspectors discussed the issues with station personnel, reviewed the AFW operating procedure, and also performed field verification and evaluation of the equipment. The inspectors reviewed the event as part of a continuing followup on the licensee's efforts to reduce the rate of plant system mispositions.

b. Observations and Findings

On September 23, 1997, the licensee discovered that two nonsafety-related supply valves (1CA157 and 1CA158) were open and supplying the AFWCSTs, when only one valve should have been open. Valve 1CA157 provides a makeup path from the Unit 1 condenser hotwell pump discharge header and valve 1CA158 provides makeup from the Unit 2 condenser hotwell pump discharge. Normally, one valve is open and limited by

procedure to be throttled to pass no more than 100 gpm. Plant personnel discovered 1CA157 was open to pass 100 gpm and 1CA158 was open fully, with a flow through the valve of approximately 120 gpm. According to the licensee, this configuration occurred between the time of the dual unit reactor trip that occurred on September 6, 1997, and the discovery date of September 23, 1997.

During the dual unit trip, in response to decreasing levels in the AFWCSTs, the control room SRO dispatched an operator to the valves to investigate and to increase makeup to the tanks. According to the licensee's Problem Investigation Process (PIP) 0-M97-3474, the operator went to Unit 1 and misread the sight glass flow element as reading no flow and therefore believed valve 1CA157 was closed. Poor lighting, location, and condition of the flow element apparently contributed to this error. The operator then proceeded to Unit 2 with the mindset that Unit 2 was supplying flow to the AFWCSTs. Valve 1CA158 was found open and set to deliver 100 gpm. The operator then fully opened valve 1CA158 to approximately 120 gpm. The operator did not fill out a configuration control card (CCC) to document the new position of 1CA158.

The inspectors discussed the following issues with operations management. The inspectors were concerned that CCC cards were not used and, more importantly, that 1CA158 was opened beyond the procedural limit of 100 gpm, as specified in Procedure 1/OP/A/6250/02, Revision 63, Auxiliary Feedwater System. Operations management responded that operators have been reminded that valve position is controlled by procedure, the repair and restoration process, or CCCs. It was also the responsibility of the individual who manipulates a valve to fill out CCCs. Based on the discussions, it appeared that the control room SRO directed the operator to exceed the 100 gpm limit. The inspectors considered that this problem may have been the result of unclear expectations or communications. The licensee initially investigated these procedure adherence issues and determined that, although inappropriate, the limits provided in the operating procedure were not overly restrictive. One of the immediate corrective actions was for an engineering review of the flow limits. This determined that a revision to the AFW operating procedure could be made to increase the flow limit to 120 gpm without detriment.

The inspectors identified two additional human factors related observations that may have contributed to the misposition. A review of the operating procedure for valve alignment revealed that both valves have a Unit 1 prefix (i.e., 1CA157 and 1CA158) although one supply path was from the Unit 2 condenser hotwell. This condition could mislead operators to believe that only one unit was replenishing the AFWCSTs. Also, scaffolding for the 1CA158 was positioned to access the valve, but not to easily read the associated flow element.

The inspectors also reviewed a previous configuration issue involving 1CA157 and 1CA158. In 1995, following a Unit 1 reactor trip, a control room SRO dispatched an operator to investigate decreasing AFWCST level during the event (note: there was only one AFWCST at that time). The

operator identified that both valves were closed and proceeded to open one valve to deliver 50 gpm (the procedural limit at that time). PIP 0-M95-0357 was written and dispositioned as a potential valve misposition. The licensee concluded that one valve must have been open prior to the event or the level in the AFWCST would have decreased from the water draining through idle AFW pumps, through the recirculation lines, and returned to the upper surge tanks, which are under a vacuum. No engineering analysis was presented in the PIP to support this conclusion.

The inspectors were aware that the licensee was conducting an extensive review of the safety to non-safety interface of the AFW system, focusing on system design and operator required actions. In addition, the licensee was preparing to perform a root cause assessment of their latest component mispositioning data to continue to improve in this area.

c. Conclusions

The inspectors concluded that the mispositioning of the non-safety auxiliary feedwater condensate storage tank supply system was repetitive in nature, indicated operator inattention to detail, and that the licensee's evaluations of a similar 1995 problem and the 1997 problem with the alignment of supply valves could have been more rigorous. The inspectors concluded that this condition had the potential for diverting operator focus and resources away from other complications that could arise during an event; thereby, challenging overall operator response. The licensee is conducting an extensive auxiliary feedwater system interface review and preparing to perform a root cause review of this latest mispositioning.

04.4 Reactor Overpower Condition

a. Inspection Scope (71707)

The inspectors reviewed the facts and circumstances related to an overpower condition that occurred on Unit 1.

b. Observations and Findings

On October 15, 1997, operators noticed Unit 1 reactor power was exceeding 100 percent of rated thermal power. Reactor power was approximately 100.11 percent for a period of 4 minutes and 12 seconds. Operators reduced turbine power by 1 megawatt to compensate.

A review of plant information revealed that secondary steam pressure had decreased before the event, the pressurizer level had also some minor fluctuations, and Tavg decreased a small amount. The licensee determined that some steam drains did cycle during this time but were not considered to be the root cause of the steam pressure decrease. The licensee classified this as a potential significant problem and was continuing the performance of a root cause analysis. Preliminary

results were focusing on governor valve position control or possible grid fluctuation as contributing factors to the steam pressure decrease.

c. Conclusions

The inspectors concluded that the operators continue to exhibit a good questioning attitude and good attention to plant operating conditions. Overall, the licensee continues to exhibit heightened awareness to reactivity events and has a low threshold for classifying these type events as significant for root cause analyses to be performed.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) LER 50-369/96-07: Mode Related Missed TS Surveillance on Containment Integrity Due to a Technical Inaccuracy

(This item was previously reviewed as Non-Cited Violation 50-369/96-10 02.) The inspectors evaluated the licensee's planned and completed actions identified in the LER. The inspectors confirmed that the licensee had immediately revised the procedure to included the proper surveillance frequency for the shutdown containment integrity verification and provided additional guidance to guard against subsequent inadequate reviews of mode related surveillances. The licensee also developed a Quality Improvement Team to review the event and identify necessary changes to the process. The team completed the review, identifying areas for improvement and initiated revisions to correct the deficiencies identified by the team. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62707)

a. Inspection Scope

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

PT/2/B/4350/02B	2B Emergency Diesel Generator Operability Test
PT/1/A/4200/08	Auxiliary Feedwater Suction Pipe Venting
PT/2/A/4209/12A	Centrifugal Charging Pump 2A Head Curve Performance Test
PT/2/A/4206/15A	Safety Injection Pump Head 2A Curve Performance Test

b. Observations and Findings

The inspectors witnessed selected surveillance tests to verify that approved procedures were available and in use, test equipment in use was calibrated, test prerequisites were met, system restoration was completed, and acceptance criteria were met. In addition, the inspectors reviewed and 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. Conclusion

The inspectors concluded that these and other monitored activities were completed satisfactorily. Overall control of testing activities was good and indicative of involved management oversight.

M2 Status of Maintenance Facilities and Equipment

M2.1 2B Emergency Diesel Generator (EDG) Overhaul

a. Inspection Scope (62707)

The inspectors observed 2B EDG preventive maintenance activities to evaluate preventative maintenance activities and diesel engine condition as a result of an extensive engine overhaul.

b. Observations and Findings

The inspectors conducted routine observations of EDG maintenance activities and held discussions with licensee personnel to evaluate maintenance activities. The complete overhaul of the unit was the first complete rebuild for the engine. The licensee disassembled the diesel engine and evaluated critical component conditions. Magnetic particle inspection of equipment was performed to identify indications in cylinder liners and pistons, as well as the crankshaft and bearings. The licensee discovered minor component wear; however, no major concerns were identified. Wear indications were noted at the first idler gear, indicative of abrasives in the diesel engine lube oil system. The licensee was aware that lube oil contamination had occurred previously when abrasives were introduced into the lube oil system years before. The idler gear indications did not cause engine performance degradation, yet the licensee opted to replace the idler gear to ensure engine reliability. The licensee did not identify any significant piston, crankshaft, or camshaft wear. The licensee also identified minor abrasions on the main bearings. Many components were replaced, including cylinder liners and most rubber items. The engine was reassembled and tested. The inspectors periodically reviewed maintenance activities in progress and inspected the as found condition of the components. No specific problem were noted.

The licensee performed the TS 4.8.1.1.2e required 24-hour diesel run prior to the unit overhaul in accordance with Procedure PT/2/A/4350/36B, D/G (Diesel Generator) 2B 24-Hour Run. The testing was completed satisfactorily. Following the overhaul, the licensee completed manufacturer recommended break-in runs and a 12-hour hot soak run. The licensee confirmed component conditions (hot bearing deflection) were within acceptance limits. Technical Specification 4.1.1.2 required operability testing was performed and the unit was returned to service.

c. Conclusion

The inspectors concluded that the licensee's planned maintenance evolution for the 2B EDG was well implemented. Foreign material exclusion controls during the activities provided adequate protection for the open configuration of the engine. The subsequent surveillance testing activities performed were adequate to ensure equipment operability.

M2.2 Flow Induction Through Nuclear Service Water Vent Line

a. Inspection Scope (62707)

The inspectors reviewed licensee actions to resolve items identified during quarterly venting of the auxiliary feedwater system suction piping.

b. Observations and Findings

On October 31, during performance of Procedure PT/1/A/4200/08, Auxiliary Feedwater Suction Pipe Venting, the flow acceptance criteria of 3 gpm through 1RN1066 (the standby shutdown system nuclear service water supply to auxiliary feedwater continuous vent) was not met. The licensee determined the flow rate as 1.2 gpm. The Standby Shutdown System (SSS) was designed to respond to fire or sabotage events utilizing the turbine-driven auxiliary feedwater (TDAFW) pump as the relied upon heat removal pump during SSS events. The nuclear service water system is the safety-related assured suction source for the AFW System. The continuous vents were established at various high point locations to ensure that nuclear service water offgassing did not result in voiding of TDAFW pump suction supply piping; thereby, rendering the TDAFW pump inoperable. The vents were routed to the groundwater sump system. Given this low flow and because of potential voiding, the licensee declared the TDAFW pump and the SSF inoperable. The licensee postulated that the vent lines had become partially plugged with sediment from the normal lake source and were evaluating if future replacement was required.

The licensee took actions to identify the cause of the reduced vent flow. The licensee attempted to flush the portion of piping with air and water to dislodge any material that may have been present. Only a minor increase in flow rate was obtained. The licensee also performed additional evaluations of the established acceptance criteria and

determined that a 1 gpm flow rate was adequate to maintain system operability. The acceptance criteria specified in Procedure PT/1/A/4200/08 was revised to reflect a 1 gpm acceptance criteria. Subsequently, the TDAFW and SSS were declared operable. The Unit 2 continuous vent flow rate was verified greater than 3 gpm during surveillance testing performed September 24, 1997.

c. Conclusions

Licensee actions to revise the procedure reducing the acceptance criteria were acceptable. The inspectors also concluded that any further reduction in continuous vent flow rates could challenge the auxiliary feedwater system during an SSS event and heightened monitoring and timely corrective actions were warranted to prevent future inoperability of these components.

M4 Maintenance staff Knowledge and Performance

M4.1 Modification to Replace Certain Isolation Drain Valves and Associated Piping in the Reactor Coolant (NC) Crossover Lines (Unit 2)

a. Inspection Scope (62700/55050)

The inspector determined by observation and document review, the adequacy of work activities in regard to the replacement of certain isolation drain valves and associated piping in the NC system crossover piping.

b. Observation and Findings

Background

Minor Modification MM-8401 was issued to control the work for replacing NC crossover loop isolation drain valves 2NC0005, 2NC0095, 2NC0106, and 2NC0253. The licensee determined that the existing valves could not adequately perform their design function due to material degradation. These valves leaked during startup and caused water hammer damage to the NC drain tank.

Observation

By review of the modification package, the inspector ascertained that the licensee planned to replace the existing two-inch Kerotest globe valves with the same size Anderson Greenwood bellows sealed type globe valves. Also, the licensee planned to install blank flanges downstream of each of the replacement valves to provide additional protection against NC system leakage. Although these flanges were not required by design, they were being installed to provide additional conservatism and protection against leakage.

This modification involves Duke Class A and E piping. The code class break occurs at the secondary drain valves and involves only one weld.

Also, the downstream piping and blank flange assemblies were Code Class E, but were rated for the higher side pressure of 2485 psig for conservatism. The licensee determined this modification would have no adverse impact on the operation of the NC system or interconnecting systems.

The licensee's code reconciliation evaluation determined that the design requirements of the code used for the manufacture of the replacement valves (i.e., American Society of Mechanical Engineers (ASME) Code Section III, 1980) was consistent with design conditions, under the construction code of record, ASME Code Section III, 1971 Edition. For example, the pressure/temperture design parameter for this line was 2485 pounds per square inch gauge (psig) at 650 degrees Fahernheit versus 2675 psig at 650 degrees Fahernheit under the 1980 Edition of the aforementioned code. Additional documents reviewed included replacement valve quality records, construction and post-maintenance testing requirements, the unreviewed safety question evaluation and piping material control records. The subject valves and associated piping were prefabricated on site as subassemblies and subsequently tied into the system by welding. This activity was performed in accordance with Procedure SM/0/A/8140/001, Revisions 000 and 001. Welds downstream of the replacement valves were classified as Duke Class E and were fabricated in accordance with American National Standards Institute (ANSI) Code B31.1, 1973 Edition. The tie-in weld to the NC system, upstream of the replacement valve was classified as Duke Class A and was fabricated and tested to ASME Code Section III, 1971 Edition through Winter 1971 Addenda.

The inspector observed completed welds and welding in progress on Class E welds in NC Loop A to determine weld appearance, workmanship, cleanliness and documentation as required by the applicable codes. Welds inspected and the associated process control sheets reviewed, were as follows: WL2FW 116-21, 22, 23, 24, 25, 41, 42, 43, and 44. All welds except 43 and 44 were fillet welds. Welds 43 and 44 were full penetration groove welds. All the aforementioned welds were fabricated and inspected in accordance with ANSI Code B31.1 requirements. All records and isometrics reviewed were in order.

c. Conclusion

Minor Modification MM-8410 to replace certain isolation drain valves and associated piping in the NC system crossover pipe was being performed following applicable code requirements. Prefabricated subassemblies and field welds exhibited good workmanship attributes and material records were retrievable and in order. Quality Control inspections and visual examinations were performed as required. Engineering evaluations and input were appropriate.

M4.2 Inservice Inspections of Safety-Related Welds (Unit 2)

a. Inspection Scope (73753)

Through work observation, procedure and records review, the inspector determined the adequacy of inservice inspection activities during the current Unit 2 EOC11 refueling outage. Inservice Inspection (ISI) examined welds had been scheduled for this outage by the licensee's approved 10 year Inservice Inspection Plan.

b. Observations and Findings

The inspector observed surface and volumetric examination on one weld of the chemical and volume control system. This weld was identified as follows:

Item	Weld No.	Examination Type	Results
C05.021.057	2NV2FW189-14	Ultrasonic (UT)	No rejectable indications (NRI)
C05.021.057A	2NV2FW189-14	Liquid Penetrant	NRI

The ultrasonic examination was performed with Procedure NDE-600, Revision 10, which complied with the requirements of ASME Code Section XI, 1989 Edition. This procedure had been reviewed and approved by the Authorized Nuclear Inspector (ANI) and the licensee's Level III examiner. The examination was performed by well trained personnel in a conservative manner as demonstrated by the use of supplementary transducers to further investigate apparent indications. The surface examination (i.e., liquid penetrant examination) was performed with Procedure NDE-35, Revision 16, which complied with applicable code requirements. The examination was performed in a satisfactory manner by well trained personnel. Results of this examination revealed that the subject weld was free of rejectable indications.

In addition, the inspector reviewed records of completed ISI examinations to verify completeness and accuracy. These records were associated with the following welds:

ISI Item	Weld No.	Description	Results
		Liquid Penetrant	
B09.021.002	2NC2FW15-25	Reducer to Tee	NRI
B09.021.010	2NC2FW49-19	Pipe to Valve	NRI
B09.040.122	2NV255RC2C-1	Pipe to RCP-2 Cold Leg	NRI

C05.011.148A	2NI2FW26-14	Pipe to elbow	NRI
		Ultrasonic	
G01.001.004	2RCP-2D	Flywheel	NRI
		Visual	
F01.020.258B	2MCASNV5321S Revision 1	Rigid Support	Acceptable
F01.020.261B	2MCRNV5140 Revision 2	Rigid Support	Acceptable
F01.020.266B	2MCRNV4788 Revision 3	Mechanical Snubber	Acceptable
F01.020.436C	2MCASMH141 Revision 6	Hydraulilc Snubber	Acceptable

A review of personnel qualifications, material and equipment certifications showed that the records were in order.

c. Conclusion

Volumetric and surface inservice inspections on designated welds were performed satisfactorily by qualified and well trained personnel who followed applicable non-destructive examination (NDE) procedures. Examination records were complete and accurate.

M4.3 Steam Generator Replacement Project (SGRP) (Unit 2)

a. Inspection Scope (50001)

The inspector observed and evaluated the adequacy of cutting the primary and secondary piping for SGRP purposes and transporting the vertical enclosures. The inspector also reviewed housekeeping in the lower containment and observed weld material issue activities.

b. Observations and Findings

Severing Existing Piping from Steam Generators (SGs)

At the time of this inspection, October 20-24, 1997, the licensee was in the process of completing the cuts to sever the existing SGs from associated piping. Through discussions with cognizant personnel and field inspections, the inspector observed cutting activities on NC piping in loops B, C, and D. The cutting operation was progressing smoothly using the same equipment utilized for McGuire 1 SGRP. Material removal per cut was kept low, about 0.004 inches, which meant that heat generation was kept relatively low, also minimizing machining stresses, increasing cutting tool life and making chip removal more manageable.

Housekeeping around the work area showed significant improvement over the two previous Duke facility SGRPs. For example, unnecessary tools were kept to a minimum, metal chips were being gathered and stored for easy removal, debris was essentially absent from the work area and throughout the upper and lower containment areas.

This same observation was noted on the NC pipe cuts. The location where the severance cut was made on the NC pipe was moved closer to the final weld prep surface than it was on the two previous SGRPs. This action was taken to minimize the amount of material on pipe-ends that needed to be beveled and was based on previous knowledge that material removal on earlier SGRPs was conservative. Accordingly, the licensee determined that the severance cuts would be made such that the material left would be between 0.0 inches to + 0.125 inches on the SG side of the old weld centerline. Weld centerlines were located with the use of photogametry. The bi-metallic interface on the old weldments was determined by the licensee with the aid of eddy current. Finally, Framatome Technologies used this photogametry data to machine the weld preps on the replacement SGs stored in the onsite manufacturing facility. The licensee used UT measurements during the severing process to determine remaining material thickness and to make adjustments as necessary to assure concentricity with piping internal diameter.

In addition, the inspectors noted that the cuts on the main steam lines, at the nozzle and on the vertical sections (candy cane) were made with the use of a specially designed cutting torch. The material next to the cut exhibited a minimum amount of discoloration that was associated with the torch cutting process. This indicated that the process was well controlled and the thickness of the effected material was negligible. In addition, the inspectors noted that the degree of component movement associated with these cuts was negligible.

Lift and Transport Vertical SG Enclosures

SG enclosures were being lifted from existing locations, out of the reactor containment building and transported to a temporary storage area. This activity was performed by the same contractor who performed heavy lifts in the two previous Duke facility SGRPs. The inspectors observed the lift and transportation of the subject components for SGs B and C. The work was performed in a safe manner with conservatism and appropriate controls to minimize the risk of personnel injury. The lifting devices used (i.e., polar crane and outside lift system) had been properly tested, as required and were in compliance with applicable requirements.

Inspection of Filler Metal Issue Station

Control of filler metal material was implemented through Procedure CF-426, Revision 0, Issue and Control of Weld Material.

The inspectors reviewed the procedure for completeness and clarity and performed an inspection of the filler metal issue station. As such the

inspectors verified material segregation, storage, rod oven temperature control, and instrument calibration. Warming ovens were being monitored for proper temperature and results were documented. In addition, the inspectors reviewed warming oven loading logs and issue slips for completeness and accuracy. A copy of the subject procedure was located at the subject issue station. The inspectors also determined that housekeeping was satisfactory.

Review of Welder Performance Qualification Records

Qualification of welders scheduled to perform welding on the NC pipe welds was done at Framatome Technologies main facility. The actual test was done on a plate, in the flat 1G position, using ER 309 stainless steel filler metal wire. The licensee used the gas tungsten arc welding process documented in Data Sheet L-165B, Revision 3. As permitted by the ASME Code Section IX, Paragraph QW-302.2 the welder test coupons were radiographed for acceptance at McGuire by the licensee's non-destructive examination group. The radiographic procedure used for this work effort was RT-104, Revision 7, Acceptance Standard C. The inspectors reviewed radiographs of 10 welder test coupons to verify weld quality and found them to be acceptable.

c. Conclusion

Steam generator replacement activities were progressing well within the licensee's established schedule. Severing of NC loop piping and other secondary piping was well planned, executed and closely monitored by the licensee to assure good results. Similarly, heavy lifts were performed conservatively with adequate licensee oversight. Weld material control activities and welder performance qualification records were consistent with applicable requirements and the licensee's procedures. Housekeeping around the work area showed significant improvement over the two previous Duke facility SGRPs.

M6 Maintenance Organization and Administration

M6.1 SGRP Organization and Administration Activities

a. Inspection Scope (50001)

The inspectors reviewed the current SGRP organization and administration to evaluate the effectiveness in supporting SGRP activities.

b. Observations and Findings

The licensee's organization and administration of the Unit 2 SGRP remained essentially the same as that for the Unit 1 SGRP. The inspectors noted that staffing reductions occurred in both the engineering and maintenance workforce. The reductions have not significantly affected organizational effectiveness or impacted safe steam generator replacement. The inspectors performed routine evaluations of work activities and confirmed adequate staffing and

support to effectively implement the replacement project activities.

The licensee established aggressive personnel exposure and safety goals for the Unit 2 SGRP. The inspectors periodically attended daily project management meetings and confirmed that the goals and actual project performance were reviewed and evaluated. Departures from expected performance received additional review and evaluation.

c. Conclusions

The inspectors confirmed through observation of project activities and discussions with licensee representatives that the SGRP organization was effective in adequately planning and safely executing the Unit 2 SGRP effort.

M8 **Miscellaneous Maintenance Issues** (92902)

M8.1 (Open) Inspector Followup Item (IFI) 50-369,370/97-09-03: 3-Year Fire System Testing

This item was previously identified based on the inspectors' concerns that no periodic testing of the McGuire fire suppression system interior loop piping was being performed. Subsequently, the licensee developed a special flow test designed to verify operability of the subject system. The inspectors witnessed portions of an initial test of the auxiliary building loop piping and attended pre-job briefing for the test. The inspectors considered that the briefing was adequate for the evolution and that all involved personnel were made aware of their expectations.

During the collection of test data for the procedure, system indications fluctuated, which brought into question the validity of the data. Upon further investigation, the test performers identified that one of three pressure control valves (PCV) in the system was opening prematurely, causing inaccurate data measurement. The licensee secured the test configuration and evaluated the degraded condition for operability. Based on the data and the redundancy within the system, the licensee determined that the fire suppression system was operable; however, one PCV was inoperable. A priority work request was written to adjust the PCV to its proper setpoint and verify operability of the other two PCVs. The inspectors monitored the licensee's test recovery actions and concluded they were adequate. The inspectors discussed the PCV problem with licensee fire protection personnel. Based on the preliminary information, it appeared that the PCVs for the system may receive only limited preventative maintenance, which may have contributed to the problem. The licensee plans on reperforming the loop flow test at a later date once all known problems are corrected.

The inspectors concluded that the licensee's development of the test to assure operability of the interior fire suppression loop piping was good. However, initial test performance problems did not allow for valid data to be taken. The problems identified indicated that some fire suppression equipment may have limited preventative maintenance

being performed. The inspector will continue to monitor the licensee's activities in this area.

III. Engineering

E1 Conduct of Engineering

E1.1 Review of Installation of SGRP Outside Lifting System (OLS) for Unit 2

a. Inspection Scope (50001)

The inspectors: examined the Steam Generator Replacement Project (SGRP) Outside Lifting System (OLS) components erected outside of the Unit 2 equipment staging building; reviewed the adequacy of the SGRP lifting and transport programs and load test records, ensuring that they were prepared and tested in accordance with regulatory requirements, appropriate industrial codes, and standards; and verified that the maximum anticipated loads to be lifted would not exceed the capacity of the lifting equipment and supporting structures.

b. Observations and Findings

The lifting and transporting systems for the SGRP for McGuire Unit 2 were either identical or similar to the systems used in the Catawba or McGuire Nuclear Plant Unit 1 SGRP. The Catawba Nuclear Plant is another Duke Power nuclear plant with similar design. Duke successfully replaced the steam generators in both units in June 1996 and April 1997. Therefore, Duke power had adequate experience in the replacement of the steam generators.

The inspectors reviewed the lifting programs, documents, drawings, and load test records that control the SGRP activities.

The licensee listed ANSI codes and NUREG 0612, "Control of Heavy Loads at Nuclear Power Plants," 1980, as references in the SGRP Lifting Program. These references will be used as guidelines or standards for the SGRP lift activities. As specified in ANSI N45.2.15, Hoisting, Rigging, and Transporting of Items for Nuclear Power Plants, 1981, the licensee performed a 110 percent load test for the OLS and transporters which will transfer the steam generators to or from the storage facility.

The crane inspection and load test records performed for preparation of the SGRP lifts were reviewed by the inspectors to verify that the licensee successfully performed the required inspections and load tests. During the review on the load test record for the procedures TN/2/B/9260/00/02C, Outside Lifting System Load Test, Revision 0 and TN/2/B/9205/00/25C, Proof Test the Steam Generator Haul Route Inside the Protected Fence Area, Revision 0, the inspectors found that the persons who signed and dated for the steps of the crane operation were not qualified crane operators. The licensee, however, stated that the steps

were performed by qualified crane operators, although they were not the ones to sign and date the steps of the procedures. Qualified crane operators indeed performed the entire crane operation and signed in on the job briefing sheet. However, a craft foreman on the ground signed in the locations of the procedure steps for the crane operators in order to verify that those steps were performed and completed because these operators were seated inside the elevated crane cab during the crane lift operations. The inspectors verified that these operators were qualified crane operators.

The above problem was also identified to the licensee during the Unit 1 SGRP operation. The licensee stated that they are still in the process of revising the procedures to add space for both supervisor or foreman in charge and crane operators to sign and date in the steps performed by the qualified crane operators. This is identified as a weakness.

The inspectors also found that steps 4.3.25, 4.3.26, and 4.3.27 of the Procedure TN/2/B/9260/00/02C were performed out of sequence and required approvals prior to performing the steps out of sequence. PIP 2-M97-3707 was issued to evaluate the root cause and to resolve the problem for the steps performed out of sequence in Procedure TN/2/B/9260/00/02C. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consisted with Section IV of the NRC Enforcement Manual. This is identified as NCV 50-370/97-17-03: Procedure Steps Performed Out of Sequence.

The inspectors walked down the OLS outside the equipment stage building. The OLS consists of an overhead crane and a similar rail road system. The railroad system extends into the inside of the reactor building for picking up or delivering the steam generators. Then the overhead crane system will lift the steam generators to or from a transporter. The transporter will transfer the old steam generators to the storage facility for temporary storage until the licensee decommissions the reactor vessel at the permanent storage location. The inspectors decided the erected lifting system and the rail system were adequate and could achieve the intended function for the SGRP.

c. Conclusions

The required lifting plan, path, load tests, and lifting equipment inspections generated or performed for the safe lifting and transfer operations of the old and new SGs were adequate. One weakness and one NCV were identified for qualified crane operators not signing and dating in the procedures for the steps that they performed, and for performing procedure steps out of sequence.

E1.2 Evaluation of Modification of Main Steam Guard Pipe for Unit 2 Steam Generator Replacements

a. Inspection Scope (50001)

The inspectors reviewed the licensee's plan to modify the main steam guard pipe during the SGRP to verify the adequacy of these activities.

b. Observations and Findings

The guard pipe to protect against a rupture of the main steam pipe for Unit 1 was cut into two portions near the nozzle of the Steam Generator (SG) in order to cut the main steam pipe around that area during Unit 1 SGRP in April 1997. The top portion of the guard pipe was removed along the main steam pipe. The lower portion was cut into several pieces for removal. During the reconnection of guard pipes to restore the original design after the new SG was in place, the licensee encountered difficulty in the alignment and fit-up before welding them together. The problem of the reconnection of the guard pipes increased worker radiation doses.

Based on NRC Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, the arbitrary intermediate pipe break protection is no longer required. However, the terminal end break protection is still required. Therefore, the guard pipe is not required except at the terminal ends such as nozzles. Thus, the short segment of the guard pipe around the SG nozzle is still required for restriction of steam flow into the cavity due to a break at the nozzle area. The short segment of guard pipe is not required to reconnect to the top portion of the guard pipe which is integrated with the main steam pipe.

The licensee plans to modify the original design by providing a short segment of guard pipe around the SG nozzle area without reconnecting it to the top portion of the original guard pipe. A new short segment of guard pipe with two horizontal half circular restrictor plates welded to it, called a guard pipe collar, will be installed and the restrictor plates will rest on the SG nozzle transition area with no weld between the new SG and collar. The short segment will remain in place under its own weight. In the event of a nozzle break event, the pressure above the internal restrictor plate is greater than the pressure below the restrictor plates, thus creating a significant downward force holding the collar to the SG piping. This force, along with the collar's weight, will act to resist any upward drag forces resulting from steam rushing out of the collar.

The inspectors considered that the new design of the guard pipe collar is adequate. However, the design drawing MC-2419-13.20-05, Revision B, did not specify the location of the restrictor plates relative to the SG nozzle weld line in order to assume that the restrictor plates will always remain below the SG nozzle weld line to prevent the uplift of the collar. After discussing this with the inspectors, the licensee's engineers issued a Variation Notice VN-29510/P2F to add a section view

to the drawing with a control dimension for QC verification that the top of the guard pipe collar restrictor plates are installed below the SG nozzle weld line for the terminal end break protection. The inspectors reviewed this VN and considered it to be adequate.

The inspectors reviewed the following calculations in the areas related to the modification for the guard pipe collar:

- MCC-1206.48-07-1101, Calculation of Pipe Rupture Load by Computer Analysis for Main Steam System, Revision 3

- MCC-1206.02-71-0025, Guard Pipe Flow Area, Revision 13

- MCC-1206.02-71-0091, Rigorous Stress Analysis of Piping Problem 2 SMA, Revision 15

The break opening area in the short segment of guard pipe of Unit 2 is 3.75 square feet and is less than the maximum allowable break area of 3.85 square feet stated in the safety analysis report. The inspectors considered the calculations were adequate to reflect the modifications except for the discrepancies stated below.

During the review of calculation MCC-1206.02-71-0091, the inspectors found that discrepancies existed in the transformation signs for forces and moments among three coordinates for plant Global, Unit 1, and Unit 2 (mirror image of Unit 1) in sheet 7 of the calculation.

The license's engineers quickly responded to the inspector's question and generated a simple three-dimensional stick model using the SUPERPIPE program. The stick model used the mirror image location and direction for Units 1 and 2. There was one coordinate used for Units 1 and 2. The results showed the correct sign transformation as shown on sheet 7 of the calculations. However, for the unique coordinate shown, this demonstration model is different from the three coordinates shown in the sheet 7 of the calculations. If the calculations used are just one coordinate for both Units 1 and 2 and the calculation changed the signs in forces and moments for Unit 2 due to the mirror image of Unit 1, the sign transformation shown in sheet 7 is correct. However, the additional coordinate was clearly indicated on that sheet for Unit 2 for the mirror image.

The licensee also quickly reviewed the stress and support calculations. The results indicated that no incorrect application of load or movement direction occurred. The calculation concluded that it was highly unlikely that there are any components or structures which are not qualified due to inappropriate directional interpretation of sheet 7 in the Unit 2 main steam piping analysis calculations file. However, the inspectors consider that it is necessary to examine further several samples of stress and support calculations and verify accuracy of the conclusion made by the licensee for Unit 2 in order to make sure that no incorrect application of loads or moments transformed from Unit 1 to Unit 2. The above coordinate problem is identified as Inspector

Followup Item (IFI) 50-370/97-017-04: Load and Moment Sign Transformation Application from Unit 1 to Unit 2.

c. Conclusions

The licensee performed adequate preparations, supporting calculations, and had acceptable drawings and other documents to ensure the installation of the new short segment of guard pipe during the SGRP. An Inspector Followup Item was identified for a clarification of load and moment sign transformation application from Unit 1 to Unit 2.

E4 Engineering Staff Knowledge and Performance

E4.1 Spent Fuel Pool System Monitoring During Anticipated Changes

a. Inspection Scope

The inspectors reviewed the licensee's control of the Unit 2 spent fuel SFP cooling system during anticipated changes in system operating parameters.

b. Observations and Findings

During the Unit 2 outage, the normal, train B power supply to safety-related components, 2ETB, was scheduled to be interrupted to perform scheduled maintenance for approximately 48 hours. Based on the extent of the work, the licensee estimated that if needed, 2 ETB could be restored within several hours. The primary impact of this activity on Unit 2 safety-related components was the loss of power to the train B SFP cooling pump. During the evolution, both the normal and the emergency power supplies for the 2B SFP pump were unavailable due to 2ETB being taken out of service. However, both the normal and emergency power supplies were available to supply power to the A train SFP cooling pump. Coincidentally, operators were monitoring the Unit 2 SFP via a 12-hour conditional surveillance, due to the normal Unit 2 SFP computer monitoring point being out of service.

Initial conditions for the evolution were that both trains of the SFP cooling system were in operation due to the recent reactor core offload to the Unit 2 SFP completed on October 12,1997. On October 23, 1997, the licensee isolated the B train SFP cooling pump two days prior to taking 2ETB out of service. At this time, the calculated time for SFP boiling was approximately 13 hours without any cooling.

After the operating shift took the B train SFP cooling pump out of service, the SFP temperature started to rise due to the decreased SFP cooling. The operators were aware of the condition and were applying increased attention to the SFP temperature. However, after approximately 5 hours, the SFP temperature had risen 12 degrees ..

Operators questioned whether this heat-up rate was expected and where the SFP temperature would peak. The operators elected to restart the 2B SFP pump to provide additional cooling to the SFP while further exploring the expected temperature rise with engineering.

On October 24, 1997, the inspectors discussed the evolution with engineering and operations personnel. The inspectors determined that although engineering personnel had established that isolating one of the SFP pumps would not challenge the design basis temperature for the SFP, operators were not informed on the expected system response. The licensee documented this communication and control problem via PIP 2-M97-3959 and agreed with the inspectors' observations.

The inspectors also reviewed the abnormal operating procedure associated with the SFP cooling system, Procedure AP/2/A/5500/41, Loss of Spent Fuel Cooling or Level. The entry symptoms for the procedure were 1) operator aid computer (OAC) alarm spent fuel pool temperature high or 2) both SFP cooling pumps off. The inspector noted that due to the coincident OAC replacement project, the normal anticipatory OAC alarm point for the SFP temperature high alarm was not available. Consequently, operators were required to perform conditional surveillances of the SFP temperature every 12 hours via a control room indication. Operators indicated they were monitoring the temperature of the SFP more frequently after stopping of the 2B SFP pump. The inspectors considered that the minimum conditional surveillance frequency of 12 hours may not have been ideal during the anticipated SFP temperature increase.

c. Conclusions

The inspectors concluded that communication between engineering and operations regarding anticipated spent fuel pool temperature increase following isolation of one spent fuel cooling pump were not effective. Formal adjustment to the required surveillance monitoring interval of the SFP may also have been warranted given that the associated computer alarm points were unavailable.

E4.2 Hydrogen Mitigation System (HMS) Operability Requirements

a. Inspection Scope

The inspector reviewed the facts and circumstances related to an NRC identified discrepancy between the UFSAR and TS pertaining to the HMS.

b. Observations and Findings

According to UFSAR section 6.2.7 and station drawings for the HMS, the HMS consists of two trains of igniters with a total of 70 igniter glow plugs and associated transformers for each unit. However, the inspectors noted that TS 3/4.6.4.3 reflects a total of 66 igniters with 32 of 33 per train required operable. The inspector verified that all 70 igniters were surveillance tested by Periodic Test 4350/23A and B

Hydrogen Mitigation Igniter Current Verification. The inspectors reviewed the NRC's supplemental Safety Evaluation Report Nunber 7 on the McGuire Nuclear Station and identified that during the licensing of Unit 2, a licensing condition was noted indicating four additional igniters would be added to the 66 at the next refueling outage for Unit 1 and the first refueling outage for Unit 2. The four igniters were added to both units; however, the TS were not updated to reflect the new total. The licensee responded that the new Improved Standard Technical Specification future upgrade project had accounted for the 70 igniters, although it would not be implemented for some time.

c. Conclusions

The inspector identified an inconsistency between the number of installed hydrogen igniters and TS. No immediate safety or operability issues existed since plant procedures required testing all installed 70 igniters. This is identified as Inspector Followup Item 50-369,370/97-17-01: Adequacy of Hydrogen Mitigation System Operability Requirements. This item will remain open pending further review of the adequacy of the current TS in relation to the design and licensing basis.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Violation (VIO) 50-369/96-11-02: Failure to Implement Temporary Modification Process

This violation dealt with the inappropriately controlled installation of a temporary security fence on a Unit 1 exterior valve vault. The inspectors reviewed the licensee's actions to prevent implementation of modifications without completely executing the requirements of the McGuire Modifications Manual. Written guidance was provided to supervisors, managers, and engineering staff on adhering to station processes. Formal training was provided to the operations staff and drills were conducted to validate expected response times following installation of the security barrier. The licensee's actions included revisions to the McGuire Modifications Manual to provide additional guidance on the initiation criteria for temporary modifications. The inspectors concluded that the identified corrective actions have been completed. These corrective actions, coupled with the current licensee processes for evaluating changes to facility structures, systems, and components were considered adequate. This item is closed.

IV. Plant Support

P5 Staff Training and Qualification In Emergency Preparedness

P5.1 Emergency Preparedness (EP) Staff Training and Qualification (71750)

a. Inspection Scope

The inspectors monitored the results of EP drill 97-4 conducted with

shift A in the simulator control room on October 1, 1997.

b. Observations and Findings

During this drill, the Technical Support Center, Operations Support Center, and Emergency Operations Facility (EOF) were fully activated. State and County participation was limited to receiving emergency notification messages only. Based on the inspectors' observations and results of the licensee's drill critique summary, the inspectors concluded that the drill adequately demonstrated the set objectives with two exceptions. One involved the site assembly time not being met in that all personnel were not accounted for within 30 minutes and the other was that the EOF was not considered operational within 75 minutes of event declaration. The inspectors discussed the identified concerns with EP management and considered that appropriate focus was being applied to these areas to improve future performance. The inspectors also recognized that the current drill was conducted during a very conservative time (ie. beginning of a major unit outage) and this was indicative of the licensee's continued emphasis on challenging the EP area performance. The licensee's conservative timing of the drill and continued aggressive drill schedule was identified as an area strength.

c. Conclusion

An October 1, 1997 emergency preparedness drill adequately demonstrated the set objectives with two exceptions. Appropriate focus was being applied to these exception areas to improve future performance. The licensee's conservative timing of the drill and continued aggressive drill schedule was identified as an area strength. (Section P5.1)

S4 Security Staff Knowledge and Performance

S4.1 Security Performance Problems During Protected Area Vehicle Verifications (71750)

a. Inspection Scope

The inspectors reviewed activities associated with the licensee's identification of security guard performance issues at the McGuire Nuclear Station.

b. Observations and Findings

The inspectors were made aware of a potential problem involving multiple security guards not accurately performing vehicle accountability searches. The inspectors discussed the matter with licensee security management and were informed that actions had been taken to address the identified problem and that no current concern regarding security guard performance existed.

c. Conclusion

Based on the provided information, the inspectors identified an IFI to allow further NRC review of the issue. This item is identified as IFI 50-369,370/97-17-02: Potential Inaccurate Records Associated with Vehicle Searches.

V. Management Meetings

X1 Exit Meeting Summary

The inspection results were presented to members of licensee management at the conclusion of the inspection on November 4, 1997, and on November 13, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Barron, B., Vice President, McGuire Nuclear Station
Boyle, J., Civil/Electrical/Nuclear Systems Engineering
Byrum, W., Manager, Radiation Protection
Cash, M., Manager, Regulatory Compliance
Cross, R., Regulatory Compliance
Dolan, B., Manager, Safety Assurance
Geddie, E., Manager, McGuire Nuclear Station
Herran, P., Manager, Engineering
Loucks, L., Chemistry Manager
Morgan, R., Steam Generator Replacement Project (SGRP) Supervisor
Rhyne, K., SGRP Engineering Supervisor
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical Systems Engineering
Tuckman, M., Senior Vice President, Nuclear Duke Power Company

NRC

S. Shaeffer, Senior Resident Inspector, McGuire
M. Franovich, Resident Inspector, McGuire
M. Sykes, Resident Inspector, McGuire
N. Economos, Regional Inspector
R. Chou, Regional Inspector

INSPECTION PROCEDURES USED

IP 71707: Conduct of Operations
IP 62707: Maintenance Observations
IP 61726: Surveillance Observations

IP 40500: Self-Assessment
IP 37551: Onsite Engineering
IP 71750: Plant Support
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

OPENED

50-369,370/97-17-01	IFI	Adequacy of Hydrogen Mitigation System Operability Requirements (Section E4.2)
50-369,370/97-17-02	IFI	Potential Inaccurate Records Associated with Vehicle Searches (Section S4.1)
50-370/97-17-03	NCV	Procedure Steps Performed Out of Sequence (Section E1.1)
50-370/97-17-04	IFI	Load and Moment Sign Transformation Application from Unit 1 to Unit 2 (Section E1.2)

CLOSED

50-369/96-07	LER	Mode Related Missed TS Surveillance on Containment Integrity due to a Technical Inaccuracy (Section O8.1)
50-369/96-11-02	VIO	Failure to implement Temporary Modification Process (Section E8.1)

DISCUSSED

50-369,370/97-09-03	IFI	3-Year Fire System Testing (Section M8.1)

LIST OF ACRONYMS USED

ALARA - As Low As Reasonably Achievable
AFW - Auxiliary Feedwater
AFWCST - Auxiliary Feedwater Condensate Storage Tanks
ANI - Authorized Nuclear Inspector
ANSI - American National Standards Institute
ASME - American Society of Mechanical Engineers
CCC - Configuration Control Cards
CFR - Code of Federal Regulations
DNB - Departure from Nucleate Boiling
EDG - Emergency Diesel Generator
EOC - End of Cycle

EOF	-	Emergency Offsite Facility
EP	-	Emergency Preparedness
ESF	-	Engineered Safety Feature
FHSRO	-	Fuel Handling SRO
GL	-	Generic Letter
GPM	-	Gallons Per Minute
HMS	-	Hydrogen Mitigation System
ICS	-	Ice Condenser System
IFI	-	Inspector Followup Item
IR	-	Inspection Report
ISI	-	In Service Inspection
MOV	-	Motor-Operated Valve
MSSV	-	Main Steam Safety Valve
RC	-	Reactor Coolant System
NCV	-	Non-Cited Violation
NRC	-	Nuclear Regulatory Commission
NRI	-	No Rejectable Indication
NRR	-	NRC Office of Nuclear Reactor Regulation
OAC	-	Operator Aid Computer
OLS	-	Outside Lifting System
PCV	-	Pressure Control Valves
PDR	-	Public Document Room
PIP	-	Problem Investigation Process
PM/PT	-	Preventive Maintenance / Periodic Testing
PSIG	-	Pounds per Square Inch Gauge
QC	-	Quality Control
RCA	-	Radiologically Controlled Area
RCS	-	Reactor Coolant System
RWP	-	Radiation Work Permit
RWST	-	Refueling Water Storage Tank
SFP	-	Spent Fuel Pool
SG	-	Steam Generator
SGRP	-	Steam Generator Replacement Project
SSS	-	Standby Shutdown System
SRO	-	Senior Reactor Operator
TDAFW	-	Turbine Driven Auxiliary Feedwater
TM	-	Temporary Modification
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
USQ	-	Unreviewed Safety Question
UT	-	Ultrasonic Test
VN	-	Variation Notice
VIO	-	Violation
WO	-	Work Order