U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-341
License No:	NPF-43
Report No:	50-341/99016(DRP)
Licensee:	Detroit Edison Company
Facility:	Enrico Fermi, Unit 2
Location:	6400 N. Dixie Hwy. Newport, MI 48166
Dates:	December 4, 1999 - January 12, 2000
Inspectors:	S. Campbell, Senior Resident Inspector J. Larizza, Resident Inspector
Approved by:	M. Ring, Chief Reactor Projects Branch 1 Division of Reactor Projects

EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report 50-341/99016(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The operators controlled the power reduction deliberately and per procedures for planned maintenance activities (Sections O1.1).

- The inspectors identified two examples of failures to document conditions in the control room unit log: the completion of an Improved Technical Specification surveillance for local leak rate testing, and actions taken for tripping a reactor recirculation pump differential pressure transmitter (Section O1.2).

- The licensee effectively completed Year 2000 (Y2K) transition checklists before the year change. No Y2K related equipment issues occurred during the year transition (Section O1.3).

- Operator responses to unexpected equipment problems that impacted plant operation were prompt and appropriate (Section O1.4).

- The inspectors determined that the licensee had implemented the freeze protection procedure. However, the inspectors noted that some preventive maintenance activities were not finished before the freeze protection season. Further, work requests and condition assessment resolution documents written for deficiencies identified during the previous freeze protection inspection were not prioritized to be completed before this freeze protection season and the freeze protection issues remained unresolved. Although checks had been completed, the licensee missed that the instructions for freeze protection checks at the meteorological tower did not exist (Section O2.1).

Maintenance

- Overall performance of the Division 1 non-interruptible air supply maintenance was performed per procedures. However, delays occurred from tag outs, scope changes to work packages, changes to post maintenance testing of a motor control center change out, and minor parts pre-staging problems (Section M1.1).

- The licensee developed and successfully performed a local leakage rate test in the reverse flow direction on primary containment penetration X-26. This allowed the licensee to stop potentially detrimental testing on the inboard isolation valve (Section M1.2).

- The Detroit Edison offsite department responsible for sampling the combustion turbine generator fuel oil ineffectively communicated the water and sediment sample results to Fermi 2 which resulted in filling impure fuel oil into the tank and rendering the station blackout combustion turbine generator inoperable (Section M1.3).

- The licensee resolved the combustion turbine generator fuel oil contamination by draining and filtering, and proposed actions to preclude recurrence (Section M1.3).

- The wrong size opening spring was found to be installed in the reactor core isolation cooling turbine governor control valve. This eventually resulted in valve failure to open fully. The cause was believed to be due to inattention to detail during maintenance (Section M1.4).

- The licensee took appropriate actions in refurbishing the three voltage regulator motors of the 480 volt 72E electrical bus. The decision to perform the post maintenance testing following the replacement of all three motors was not properly communicated to electrical maintenance personnel performing the actual field work (Section M1.5).

- While erecting scaffolding around a breaker switch for Division 1 low pressure coolant injection inboard isolation valve E1150F015A, maintenance workers bumped the switch causing inoperability of the residual heat removal low pressure coolant injection mode of operation (Section M1.6).

- An inadequate maintenance procedure resulted in improper wiring of a containment spray system valve and damage to the motor operator during maintenance and testing. The inadequate procedure was compounded by the fact that a crew change occurred while reconnecting the wires to the motor phases. One non-cited violation was identified (Section M1.7).

Engineering

- A 1994 corrective action to isolate the air supply for the high pressure core spray test return line control valve due to "hot shorts" during a postulated fire was not completed. Nevertheless, Generic Letter 86-010 did not require considering this valve for a "hot short" scenario (Section E1.1).

Plant Support

- The inspectors concluded that a condition assessment resolution document corrective action, written to develop a consistent method for tagging catch basin hoses, was not fully implemented since the inspectors identified inconsistencies in using radioactive material tags (Section R1.1).

Report Details

Summary of Plant Status

Unit 2 began this inspection period at 97 percent power. On December 10, 1999, power was reduced to 96 percent due to a process computer system malfunction. Power was returned to 97 percent the same day following repairs of the process computer. On December 12, 1999, power was reduced to 65 percent to perform reheater maintenance and turbine valve testing. Power was returned to 97 percent the following day. On December 31, 1999, prior to midnight, power was reduced to 80 percent in anticipation of potential electrical grid disturbances related to Y2K. Power was returned to 97 percent after midnight on January 1, 2000. On January 4, 2000, power level unexpectedly increased to 97.3 percent due to recirculation loop flow "A" and total core flow increase with no corresponding change in recirculation pump speed indication. Power was returned to 97 percent by lowering core flow. On January 7, 2000, power was reduced to 92 percent to insert four control rods in preparation for scram solenoid pilot valve replacement. On the same day, power was returned to 97 percent but later was reduced to 65 percent for scram solenoid pilot valve replacement. Power was returned to 97 percent on January 9, 2000.

I. Operations

O1 Conduct of Operations

O1.1 Power Reduction to Perform Reheater Maintenance and Turbine Valve Testing

a. Inspection Scope (71707)

On December 12, 1999, operators reduced power to 65 percent per General Operating Procedure 22.000.03, "Power Operation 25 percent to 100 percent to 25 percent," to repair a valve steam leak on the north reheater seal tank and to perform control rod drive testing, rod pattern adjustments, and turbine valve testing. The inspectors reviewed the operating procedure, reviewed the work control plans, attended the control room pre-evolution briefs and observed the power reduction.

b. Observations and Findings

Nine operations personnel and the reactor engineer attended the brief. The brief included discussions of past experiences with power reductions, expected plant parameters, proper communications, and methods to minimize distractions. No interruptions occurred during the brief.

The operators controlled the power reduction per procedures. The inspectors noted effective communications and self-checking. During the power change, several alarms for low gland seal steam pressure occurred. The operators assumed that an air line was disconnected to the valve operator for gland steam normal operating regulating valve N3013F433 or that the valve had seized and did not control steam flow to the No. 2 feedwater heater. While a burden to the operators, this issue did not have a

significant impact on safety and resolution was deferred until the next outage because the components were inaccessible. The problem had been previously documented in Condition Assessment Resolution Document (CARD) 99-18255.

c. Conclusions

The operators controlled the power reduction deliberately and per procedures for planned maintenance activities.

O1.2 Logging Improved Technical Specification (ITS) Surveillance

a. Inspection Scope (71707)

On December 21, 1999, the inspectors identified that a surveillance test and an ITS action had not been documented in the control room unit log. The inspectors reviewed Operations Conduct Manual, MOP06, Chapter 6, "Record Keeping," and Technical Manager Inservice Inspection Memo (TMIS) 99-0155, "Risk Assessment for Week of December 20, 1999," and interviewed operations personnel to follow up on the causes for the missed log entries.

b. Observations and Findings

On December 20, 1999, the inspectors reviewed TMIS 99-0155 and noted that local leak rate testing (LLRT) for valves T4600F400, T4600F401, and T4600F410, which are in the torus hard vent path, was scheduled for December 20 and 21. The TMIS required that the LLRT be completed before the Division 2 residual heat removal (RHR) surveillance tests to avoid an unacceptable instantaneous increase in risk configuration. The LLRT test procedures, which were performed for the three valves under Job Number 218199120, were signed out between 6:35 a.m. and 1:36 p.m. on December 20 and the sign-off completed at 10:12 a.m. on December 21.

On December 21, the inspectors reviewed the control room unit logs for the day and evening shifts for December 20 and 21, and did not see an entry for releasing and completing the surveillance. Normally, operators documented only time sensitive limiting condition for operations (LCOs) and the LLRT was not considered time sensitive. However, Operations Conduct Manual MOP06 required that the nuclear assistant shift supervisor make entries for starting and completing ITS related surveillance procedures.

Since the LLRT lasted through two shifts, the inspectors considered log tracking as a barrier to avoid an unacceptable instantaneous increase in risk configuration. The inspectors informed operations personnel and the licensee amended the logs with late entries and initiated CARD 99-18500 to document the concern.

This failure to follow procedures was considered a violation of minor significance and is not subject to formal enforcement action.

On December 27, at 2:00 p.m., LCO 99-0520 was entered when operators identified that reactor recirculation pump differential pressure transmitter, B31N112A, had

responded slowly. Improved Technical Specification 3.3.5.1.B.3 required tripping the channel within 24 hours. Operators initiated CARD 99-19345, placed the transmitter channel in trip at 10:55 p.m., and updated LCO 99-0520 that the action was taken.

However, on December 28, the inspectors reviewed the control room unit log and did not identify a log entry describing that ITS actions had been taken. Since the action was not documented, the LCO log index was incorrect to note a December 28 expiration date, and the daily plant status inaccurately documented that the plant remained in the LCO.

Operations Conduct Manual, MOP06, requires that the nuclear assistant shift supervisor make unit log entries for exits from LCOs and the actions taken. The inspectors informed the licensee of the missed entry. The licensee's staff appended the logs with late entries and initiated CARD 00-11003 to document the concern.

This failure to follow procedures was considered a second example of a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

The inspectors identified two examples of failures to document conditions in the control room unit log: the completion of an ITS surveillance for LLRT, and actions taken for tripping a reactor recirculation pump differential pressure transmitter.

O1.3 Observation During Date Rollover to Year 2000 (Y2K)

a. Inspection Scope (71707)

The inspectors reviewed Y2K contingency procedures and checklists and observed the operators reduce power to 80 percent in preparation for potential Y2K related computer problems that might have affected plant operations.

b. Observations and Findings

On December 31, 1999, the inspectors observed the operators prepare for the date transition to the Year 2000. The inspectors verified that the operators completed the Y2K contingency checklist before the date change. Operators reduced power to 80 percent as a precaution for potential power grid instabilities.

Following the date change, the Multi-Vendor Data Acquisition System that interfaces the power range monitor system to the process computer system and 3-D Monicore (a computer system for monitoring reactor core parameters) failed at midnight. This was not a Y2K related issue since it had been previously identified to fail during every December 30 and 31 date changes. Consequently, procedures had been prepared to reboot the system and correct the problem immediately.

The inspectors toured plant areas and verified that there were no other equipment, instrument, or recorder problems in the control, relay, computer or radwaste control rooms. The inspectors reviewed a sampling of radiation monitors and found no date change issues.

Operators increased reactor recirculation flow per procedures and restored power to 97 percent by 2:00 a.m. The inspectors noted effective communication during the plant power changes.

c. Conclusions

The licensee effectively completed Y2K transition checklists before the year change. No Y2K related equipment issues occurred during the year transition.

O1.4 Operator Response to Unexpected Equipment Deficiencies Impacting Power Operations

a. Inspection Scope (71707)

The inspectors interviewed operations and engineering personnel and reviewed CARDs and procedures to follow up on operator responses to unexpected equipment failures that impacted power operations.

b. Observations and Findings

On December 10, 1999, the cooling fan for the video display generator in the process computer failed. The operators entered Abnormal Operating Procedure 20.165, "Loss of Process Computer System," that required the operators reduce power by 1 percent. Operators properly performed the procedure action by reducing power to 96 percent. Power was restored to 97 percent after the fan power supply and fan were replaced. Corrective Action Resolution Document 99-19260 was written to document the failure.

On January 4, 2000, recirculation loop A and total core flow increased from 88 to 88.5 million pounds mass per hour without a recirculation pump speed change. The flow step change caused a 0.3 percent reactor power increase. In response, operators lowered core flow, which lowered reactor power to 97 percent and initiated CARD 00-11029 to document the condition. The unexpected step change in flow was a recurrence of a previous problem, but the licensee has so far been unsuccessful in identifying the cause. This ongoing issue was previously documented in Inspection Report 50-341/99014.

c. Conclusions

Operator responses to unexpected equipment problems that impacted plant operation were prompt and appropriate.

O2 Operational Status of Facilities and Equipment

O2.1 Freeze Protection Inspection

a. Inspection Scope (71714)

The inspectors reviewed Procedure 27.000.04, "Freeze Protection Line-Up Verification," to determine whether the procedure had been implemented in the plant. Additionally, the inspectors reviewed previous CARDs that were written following the inspectors' previous freeze protection inspections to determine whether corrective actions had been completed.

b. Observations and Findings

Between December 20 and 22, 1999, the inspectors consulted Procedure 27.000.04 and toured the general service water pump house; RHR complex; cooling towers; condensate storage, condensate return and demineralized water tanks. The inspectors confirmed that freeze protection measures per the procedure had been implemented.

The inspectors reviewed the work history for the freeze protection preventive maintenance (PM) events listed in Section 5.2 of Procedure 27.000.04. These events involved checking thermostats, removing and installing wall louver covers, inspecting and cleaning the auxiliary boilers, and calibrating and checking temperature and level loops. The inspectors noted that the licensee had completed 8 of the 14 PM events after the freeze protection season started on October 1. This was caused by inconsistencies with the PM task desired completion date and the start of the freeze protection season. The licensee was evaluating changing the desired completion dates.

The inspectors reviewed CARDS 99-00016, 99-00020, and 99-00021, that involved inoperable RHR complex heaters. Corrective Action Resolution Documents 99-00016 and 99-00021 were closed appropriately. Corrective Action Resolution Document 99-00020 documented a burned coil on heater X103B233. A low priority work request (WR) was generated and, consequently, repairs were not completed before this freeze protection season. Following the inspector identification of this issue, the heater repairs began.

Additionally, CARD 99-11315, which involved a freeze protection effectiveness review, remained open during this freeze protection season. The CARD was assigned a low priority and reassigned within the operations department. This slowed the CARD resolution and this CARD was not closed. The licensee recognized that, because of the low work request and CARD priorities, a single report of all freeze protection equipment and program issues was needed instead of handling issues individually.

Further, the inspectors reviewed CARD 99-11656, that was written to evaluate freeze protection checks at the meteorological tower. This CARD was closed crediting the freeze protection checks during the 6-month calibration under Procedures 45.614.0008, "Meteorological Monitoring - Primary System Maintenance," and 45.614.009, "Meteorological Monitoring - Secondary System Maintenance." However, the inspectors

reviewed these procedures and found no freeze protection check instructions. The licensee relied on vendor knowledge to perform the checks. Subsequent to the inspector's questions, the licensee confirmed the checks were completed. Although the licensee did not review the procedures while closing the CARD, the licensee assumed such instructions existed. Consequently, the licensee issued CARD 99-19218 for a procedure revision.

c. Conclusions

The inspectors determined that the licensee had implemented the freeze protection procedure. However, the inspectors noted that PM events were not finished before the freeze protection season. Further, WRs and CARDs written for deficiencies identified during the previous freeze protection inspection were not prioritized to be completed before this freeze protection season and the freeze protection issues remained unresolved. Although checks had been completed, the licensee missed that the instructions for freeze protection checks at the meteorological tower did not exist.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Division 1 Non Interruptible Air Supply (NIAS) System Preventive Maintenance Outage

a. Inspection Scope (62707)

The inspectors observed maintenance activities on the Division 1 non-interruptible air supply (NIAS) system. The inspectors discussed these activities with maintenance and engineering personnel and reviewed the following documents:

- CARDs: 99-11790; 99-12385; 99-17260; 99-17915; 99-17925,
- WRs: 000Z992945; 000Z994070; Q334970616; Q360990100; R078950106; Z883980100; 000Z993134; 000Z992359,
- Updated Final Safety Analysis Report (UFSAR) Sections: 9.3.1.2; 9.3.1.3; 7.6.1.17.2; 7.6.1.17.4.1; 7.6.17.4.4,
- UFSAR Table 12.1-26,
- Surveillance Procedure 24.129.01, "Station and Control Air System Valve Operability and Position Indication Verification Test,"
- Safety Tagging Records,
- LCO Sheet: System or Component Inoperable and Reason for Inoperability and,
- List of assigned personnel and Training Records.

b. Observations and Findings

On November 30, 1999, the licensee removed the Division 1 NIAS from service for preventive maintenance. The activities were planned and performed per established work and industrial safety procedures. Work boundaries were tagged per the Safety Tagging Records instructions.

During the activities the inspectors noted the following delays:

- A safety tag needed removal to allow working on a drain valve. The drain valve was within the maintenance work boundary and the red safety tag did not add additional protection.

- A new work package had to be developed to do work on valve F515A where a suspected blockage was noted following an attempt to verify flow from the prefilter automatic blow down. Some debris was found and the valve was replaced. The original WR gave instructions on troubleshooting and repairing the F515A solenoid valve.

- Following the replacement of motor control center (MCC) 72B-3A with a new breaker and during preparation of post maintenance testing (PMT), operations personnel identified issues with the PMT. The electrical planner was called to revise the PMT. Additionally there was an issue with the use of "minor revision" and the electrical planner was called again to further revise the PMT.

- Parts required for the job were not properly staged for WR Q320971208. The parts were staged at both warehouse "A" and "B." The requirements were to stage at warehouse "A" but the maintenance personnel were to retrieve from warehouse "B." This caused delay in completion of the work activity.

These delays were properly included in the licensee's maintenance critique of the activity.

c. Conclusions

Overall performance of the Division 1 NIAS maintenance was properly conducted per procedures. However, delays occurred from tag outs, scope changes to work packages, changes to PMT of a MCC change out, and minor parts pre-staging problems.

M1.2 Local Leakage Rate Test (LLRT) on Primary Containment Penetration X-26 Outboard Isolation Valves

a. Inspection Scope (62707)

The inspectors observed the LLRT on primary containment penetration X-26 outboard isolation Valves, T4800F407 and T4800F408. The inspectors participated in a conference call with licensee, NRC Region III and NRC Headquarters personnel. The inspectors reviewed the following:

- Procedure 23.406, "Primary Containment Nitrogen Inerting and Purge System,"
- Procedure 43.401.300, "LLRT Type 'C' - General,"
- CARD 99-19253,
- Temporary Modification 99-0018, "Installation of Flange Cover on Valve T4800F407" and,

- Temporary Modification 99-0023, "The Installation of Test Flange Upstream of Valve T4800F408."

b. Observations and Findings

Local leak rate testing of penetration X-26, required concurrent testing of three isolation valves. The inboard isolation valve is a 24-inch butterfly valve (drywell purge inlet supply valve T4803F601) and two outboard isolation valves (in parallel) are 24-inch butterfly valves (drywell air purge inlet vent valve T4800F407) and a 10-inch butterfly valve (nitrogen supply valve T4800F408).

On September 22, 1999, the licensee performed the required LLRT and determined that inboard valve T4803F601 leaked past the valve seat. The licensee requested and obtained from the NRC a Notice of Enforcement Discretion with compensatory measures from continued operation with this condition. This issue is further described in Inspection Report 50-341/99014. The compensatory measures included deenergizing the penetration valves in the closed position, installing a blank flange cover over the opening of valve T4800F407 and performing an LLRT every 45 days.

During a test on November 4, the licensee determined leakage from valve T4803F601 had increased. In response, the licensee proposed a new method of testing both outboard valves in the reverse flow direction. This test required disconnecting a nitrogen supply line, removing a spool piece downstream of valve T4800F408, and installing a test valve on the existing blank flange on outboard valve T4800F407. The proposed test was discussed by the licensee with the inspectors, NRC Region III and NRC Headquarters personnel.

On December 8, the inspectors observed the testing of the penetration. The test results indicated no leakage from valves T4800F407 and T4800F408. Since the outboard valves passed the test and ITS allowed plant operation with inboard valve T4803F601 deenergized closed, the licensee was no longer required to test this penetration every 45 days. The licensee plans to repair valve T4803F601 during the upcoming refueling outage, scheduled for the spring of the year 2000.

c. Conclusions

The licensee developed and successfully performed an LLRT in the reverse flow direction on primary containment penetration X-26. This allowed the licensee to stop potentially detrimental testing on inboard valve F601.

M1.3 Combustion Turbine Generators (CTGs) Storage Tank Fuel Oil Contamination

a. Inspection Scope (62707)

The inspectors reviewed the circumstances surrounding the contamination of the fuel oil in the CTG storage tank, the cleanup activities, and proposed actions to preclude future problems.

b. Observations and Findings

The licensee obtained fuel oil from a local supplier that was chemically analyzed by an offsite Detroit Edison laboratory before being delivered to Fermi 2. Lab results indicated that the oil had failed a pollution test requiring that the oil be tested for water and sediment. Water and sediment content of 2.5 percent were found but the lab did not communicate this information to Fermi 2 personnel after the fuel was sent to Fermi 2.

Four CTGs (11-1, 11-2, 11-3 and 11-4) have a common fuel oil tank and are operated when additional generation is required on high electrical demand days. Combustion turbine generator 11-1 is designated as an ITS CTG because the CTG is an additional electrical source to the onsite vital power diesel generators in the event of a loss of offsite power (station blackout).

On December 8, 1999, the licensee determined that CTG 11-2 was running poorly. Maintenance personnel removed the fuel oil filter and found contamination. The analysis of fuel oil from the bottom of the tank indicated water and sediment content greater than 1.0 percent while the acceptance limit was 0.1 percent. Since the fuel oil supply is common to all CTGs, CTG 11-1 was declared inoperable.

To correct the problem, the licensee drained approximately 12,000 gallons of fuel oil from the bottom of the tank and filtered the remaining 720,000 gallons. Following filtration, fuel oil tank oil samples indicated less than 0.05 percent water and sediment content. Combustion turbine generators 11-2 and 11-4 were run for approximately 72 hours without problems and CTG 11-1 was declared operable.

The licensee proposed corrective actions to test the fuel oil onsite per fuel oil standards before filling the fuel oil tank.

c. Conclusions

The Detroit Edison offsite department responsible for sampling the CTG fuel oil ineffectively communicated the water and sediment sample results to Fermi 2 personnel that resulted in filling impure fuel oil into the tank and rendering CTG 11-1 inoperable. The licensee resolved the contamination by draining and filtering, and proposed actions to preclude recurrence.

M1.4 Incorrect Valve Opening Spring Installed on Reactor Core Isolation Cooling (RCIC) Turbine Governor Valve

a. Inspection Scope (62707)

On December 8, 1999, during a PMT, the licensee discovered the spring was too short in RCIC turbine governor control valve E5150F044. The inspectors interviewed engineering personnel and reviewed the following documents to follow up on the issue:

- CARD 99-18377,
- CARD 99-02412,
- WR 000Z994106,

- System Procedure 23.206, "RCIC System,"
- Operating Experience Report 97-036/DM 97-077 and,
- Engineering Functional Analysis for CARD 99-02412.

b. Observations and Findings

In October 1999, the licensee had identified a sluggish response of valve E5150-F044 during stroking. Subsequent evaluation determined that the RCIC system remained operable. As a result, the operators manually operated the valve weekly to verify the valve remained operable even with the sluggish response. The function of the valve is to control the RCIC turbine speed by throttling the steam flow to the turbine. The valve is normally open while the RCIC system is in standby. No problems had been reported concerning sluggish valve operation until December 8, 1999, when operators manually stroked valve E5150F044 and the valve did not open fully because of insufficient opening force. This condition was documented in CARD 99-18377.

While performing WR 000Z994106, to determine the cause for the valve not opening fully, personnel found that the valve opening spring was 2.5 inches in length and the correct length should have been 3 inches. The licensee investigated to determine the cause of the wrong spring installation in the mechanism and found, in the same mechanism, a second 2.5-inch long spring used as shock absorption in the hydraulic servo mechanism actuator. The licensee concluded that a similar 2.5 inch spring was installed as the valve opening spring, instead of the 3-inch spring, during previous maintenance.

The licensee confirmed that maintenance procedures provided sufficient instructions for installing the correct size spring. The valve was reassembled with the correct spring, adjustments were made to the linkage and tests performed which confirmed no valve stroke problems.

The failure to perform maintenance properly per documented instructions is a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

The wrong size opening spring was found to be installed in the reactor core isolation cooling turbine governor control valve. This eventually resulted in valve failure to open fully. The cause was believed to be due to inattention to detail during maintenance.

M1.5 Replacement of Voltage Regulator 480V Bus 72E Motor

a. Inspection Scope (62707)

On December 13, 1999, the inspectors witnessed the replacement of the east drive motor in the Division 2 safety-related 480 volt regulator 72E. The inspectors reviewed WR 000Z99415 and the industrial safety requirements. The inspectors discussed observations of the activity with electrical maintenance and engineering personnel.

b. Observations and Findings

The east motor had failed (See Inspection Report 50-341/99015), and the voltage regulator could not be operated automatically or manually. Spare parts and replacement motors were unavailable and the motor was sent to the vendor for refurbishing. Management had requested that the regulator be placed in automatic control following east motor repairs before the end of the year. However, engineering personnel and the planners understood that all three motors needed refurbishment for the regulator to be placed in automatic control. This intent was not effectively communicated or understood by the remaining licensee organization.

Division 2 480 volt regulator 72E has three individual motors that operate in parallel and connect with a common drive shaft. The regulator adjusts and changes phase voltages from the safety-related 4160 volt bus 65E to the safety-related 480 volt Bus 72E. The regulator is set to override voltage variations from the grid (the 345 kV system) to maintain bus 72E voltages between 463.2 volts-alternating current and 503 volts-alternating current.

The licensee's system engineer realized that the remaining motors needed bearing replacement, which could be performed easily onsite. On December 13, the electricians replaced the east drive motor and contacted the operations department to clear tags to perform a PMT as required by the plan-of-the-day. However, the engineer stopped the electricians and clarified that three motors needed replacing. After discussions with supervision, the last two motors were removed, the bearings replaced and the motors reinstalled.

A PMT was performed and the voltage regulator was returned to service. Electrical work activity was performed following appropriate industrial safety requirements.

c. Conclusions

The licensee took appropriate actions in refurbishing the three voltage regulator motors of the 480 volt 72E electrical bus. The decision to perform PMT following the replacement of all three motors instead of after replacement of the first motor was not properly communicated to electrical maintenance personnel performing the actual field work.

M1.6 Impact on Safety Equipment While Erecting Scaffolding

a. Inspection Scope (62707)

On January 7, 2000, Division 1 low pressure coolant injection (LPCI) inboard isolation valve E1150F015A deenergized unexpectedly while maintenance personnel erected scaffolding near the switch. The inspectors reviewed Maintenance Conduct Manual MMA08, "Scaffolding,"and ITS LCO 3.5.1.c and j, and conducted interviews involving operations and maintenance personnel to follow up on this incident.

b. Observations and Findings

The licensee had been preparing for emergency equipment cooling water system maintenance that required installing scaffolding in front of MCC 72CF. Simultaneously, the Division 1 Core Spray (CS) System was inoperable because CS Division 1 outboard isolation valve E2150F004A was wired incorrectly.

Before erecting the scaffolding, maintenance and operations personnel conducted a pre-job brief that included human performance questions to prevent the occurrence of events. During the activity, no spotters were used to prevent bumping breaker switches. At 8:29 a.m., a worker accidentally bumped breaker switch 72CF, position 2C, and turned power off to valve E1150F015A, which rendered the RHR flow path inoperable during the LPCI mode of operation.

Because this loop was inoperable, the licensee determined that the auto swap from loop 2 to loop 1 would not allow water to the reactor pressure vessel during an accident and a loss of loop 2. Improved Technical Specification 3.5.1.j, required an entry into ITS 3.0.3 with two or more LPCI systems inoperable. An operator energized the valve and ITS 3.0.3 was exited at 8:37 a.m. A 4-hour report to the NRC was made per 10 CFR 50.72, (b)(2)(iii) for a condition that could have prevented the fulfillment of the safety function of systems needed to mitigate the consequences of an accident.

The licensee stopped work to discuss the event and the importance of being cautious while working around the MCC with the workers. The licensee also initiated CARD 00-11017 to document the event.

The inspectors reviewed MMA08 and interviewed maintenance personnel. The inspector's determined procedure requirements were met in that the scaffolds were erected under close supervision of persons who had been properly trained. However, the inspectors noted that the procedure was weak in that the procedure did not require using a spotter.

c. Conclusions

While erecting scaffolding around a breaker switch for Division 1 LPCI inboard isolation valve E1150F015A, maintenance workers bumped the switch causing inoperability of the RHR LPCI mode of operation. Operators promptly restored power, properly entered and exited ITS 3.0.3 and made the appropriate NRC notifications.

M1.7 Inadequate Wiring of Division 1 CS Outboard Isolation Valve E2100F004A

a. Inspection Scope (62707)

On January 5, 2000, valve E2100F04A failed PMT after the MCC breaker for the valve motor operator was replaced. The inspectors reviewed ITS 3.5.1, WR 000Z973489, and interviewed operations and maintenance personnel to follow up on the circumstances that caused the failure.

b. Observations and Findings

On January 5, 2000, the licensee performed maintenance on the Division 1 CS system that included replacing the MCC breaker for valve E2100F004A. Valve E2100F004A receives logic signals to open on high drywell pressure and low reactor water level and the valve is used to isolate upstream drywell inboard isolation valve E2100F005A (which is outside the drywell) to perform 18-month testing on valve E2100F005A. The breaker replacement was corrective action to Deviation Event Report (DER) 97-1085 to resolve inadvertent switch openings.

During the breaker replacement per WR007973489, electricians lifted the existing motor phase wires and labeled the wires sequentially from bottom to top. A shift change occurred while reconnecting the wires. The new electrical crew erroneously determined that the wires were sequentially labeled from top to bottom and, consequently, reversed the wires to motor phases 1 and 3.

While performing PMT, operators sent an open signal and since the wires were reversed, the valve closed. The valve wedge drove into the valve seat with sufficient force to electrically damage the motor. Subsequently, the licensee performed an evaluation for maximum torque needed to open the valve without damaging the motor generator gears and manually opened the valve. The licensee initiated CARD 00-11016 to document the condition.

Since a like-for-like motor was not available, Technical Service Request 30965 was written to justify differences in cable insulation class, full load and locked rotor amperes and the replacement motor not having a motor brake. The motor was replaced and tested successfully.

The inspectors reviewed WR 00Z973489 and found insufficient guidance for properly connecting the motor phase wires. The error was compounded with a crew change while performing the critical attribute of the job of connecting the wires.

10 CFR Part 50, Appendix B, Criterion V, requires that activities affecting quality shall be prescribed by documented instructions and procedures appropriate to the circumstances and shall be accomplished in accordance with these instructions or procedures. Work Request 000Z973489 provided documented instructions for performing work to replace a breaker on valve E2100F004A, a safety-related motor operated valve.

Contrary to the above, WR 000Z973489 was not appropriate to the circumstance in that instructions failed to ensure that the motor phases were reconnected properly after breaker replacement. Consequently, on January 5, 2000 the phases were connected incorrectly and the motor was damaged during PMT. This Severity Level IV violation is being treated as non-cited, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 50-341/99016-01(DRP)). This violation is in the licensee's corrective action program as CARD 00-11016.

c. Conclusions

An inadequate maintenance procedure resulted in improper wiring of a containment spray system valve and damage to the motor operator during maintenance and testing. The inadequate procedure was compounded by a crew change that occurred while reconnecting the wires to the motor phases. One non-cited violation was identified.

III. Engineering

E1 Conduct of Engineering

E1.1 Potential for Bypassing Standby Feedwater (SBFW) to the Reactor Pressure Vessel Due to "Hot Shorts" Caused by Fire in Plant Areas not Previously Identified

a. Inspection Scope (37551)

The inspectors followed up regarding hot shorts that could be created by fire in certain areas of the plant not previously identified in abnormal operating procedure. The inspectors reviewed the following:

- Fermi 2 Operating License NPF-24,
- CARD 99-17222,
- UFSAR Sections: 7.5.2.5.1; 7.5.2.4; 9A.3; 9A.4 and,
- Procedure 20.000.18, "Control of the Plant from the Dedicated Shutdown Panel."

The inspectors also interviewed engineering personnel.

b. Observations and Findings

In 1994, a motor operated valve actuator for the high pressure coolant injection (HPCI) test return line control valve E41F011 was replaced with an air operated valve having an ungrounded direct current solenoid actuator. Due to electrical cable runs, it was determined that "hot shorts" could be created during a fire in certain areas of the plant. Those hot shorts could cause the valve to open and divert standby feedwater to the condensate storage tank instead of the reactor. To prevent this from occurring, Abnormal Operating Procedure (AOP) 20.000.18, "Control of the Plant from the Dedicated Shutdown Panel," was supposed to be revised to direct the operators to isolate the air supply and close the valve.

On October 27, 1999, during a Fire Protection Audit, the licensee discovered that AOP 20.000.18 had not been revised to isolate air to the valve. The lack of instruction in AOP20.00.18 was caused by the inadequate involvement of the fire protection engineer during the review of the procedure change. The standby feedwater system was declared inoperable until AOP 20.000.18 was revised to include the instructions to isolate air to the valve. The licensee notified the NRC and wrote Corrective Action Resolution Document 99-17222 to document the condition.

The inspectors reviewed Generic Letter 86-010, "Implementation of Fire Protection Requirements." The Generic Letter stated that ungrounded direct current control circuits do not require evaluation, if it can be shown that only two "hot shorts" of the proper polarity without grounding could cause spurious operations, if it does not involve the high/low pressure interfaces. Besides the ungrounded circuit, the valve was considered not to involve a high/low pressure interface. Therefore this valve did not require evaluation for hot shorts.

The licensee also recognized that the valve did not need to be evaluated for a "hot short" condition after Licensee Event Report (LER) 99-006 was written to document the condition. Nevertheless, the licensee issued the LER.

c. Conclusions

A 1994 corrective action to isolate the air supply for the high pressure core spray test return line control valve due to "hot shorts" during a postulated fire was not completed. Nevertheless, Generic Letter 86-010 did not require considering this valve for a "hot short" scenario.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-341/99006-01: Plant Fire Protection Program Dedicated Shutdown Procedure Omitted a Required Action for Certain Fire Zones. This LER is closed per Section E1.1.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Use of Radioactive Material Tags on Plant Equipment

a. Inspection Scope (71750)

The inspectors noted inconsistencies for radiation protection labeling of radioactive drains and lead shielding. The inspectors reviewed CARD 99-15589, "Develop a Consistent Method for Catch Basins," and Procedures 65.000.303, "Temporary

Shielding," 67000.100, "Posting and Deposting Radiological Hazards," and 67.000.101, "Performing Surveys and Monitoring of Work."

b. Observations and Findings

During plant tours, the inspectors noted inconsistencies with affixing radioactive material tags to yellow tygon hoses used for draining drip pans and catch basins to contaminated floor drains. Subsequently, a radiation protection technician tagged the tygon hoses.

The licensee initiated CARD 00-12211 to document the condition. The inspectors reviewed Procedures 67.000.101 and 67.000100 and did not identify a requirement to use the tags on the hoses.

However, the inspectors noted that CARD 99-15589, initiated in June of 1999, required affixing radioactive material tags on tygon hoses routed from catch basins to drains. The CARD was closed to required reading of these expectations by radiation protection and radwaste personnel, which was verified by the inspectors.

Further, during the tours, the inspectors noted inconsistencies in using "CAUTION, DO NOT REMOVE," signs for temporary shielding. The inspectors reviewed Procedure 65.000.303 and determined that no requirement existed for placing the signs on temporary shielding. After discussing the inspectors findings, the licensee affixed placards to the temporary shielding.

c. Conclusions

The inspectors concluded that a CARD corrective action, written to develop a consistent method for tagging catch basin hoses, was not fully implemented since the inspectors identified inconsistencies in using radioactive material tags.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 12, 2000. 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

D. Gipson, Senior Vice-President, Nuclear Operations
W. O'Connor, Assistant Vice-President, Nuclear Assessment
P. Fessler, Plant Manager
J. Davis, Director, Nuclear Training
N. Peterson, Director, Nuclear Licensing
R. DeLong, Director, System Engineering
K. Hlavaty, Superintendent, Operations
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P. Wiltse, General Supervisor, Mechanical
C. Cassise, General Supervisor, Electrical
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A. Kowalczuk, Manager, Plant Support
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J. Pendergast, Principal Engineer, Licensing
K. Howard, Plant Support, Engineering
K. Harsley, Licensing

NRC

A. Vegel, Chief, Reactor Projects Branch 6
S. Campbell, Senior Resident Inspector
J. Larizza, Resident Inspector

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparations
IP 71750:	Plant Support Activities
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-341/99016-01	NCV	Failure of instructions to ensure that motor phases were reconnected properly after bucket replacement.

Closed

50-341/99016-01	NCV	Failure of instructions to ensure that motor phases were reconnected properly after bucket replacement.
50-341/99006-00	LER	Plant Fire Protection Program Dedicated Shutdown Procedure Omitted a Required Action for Certain Fire Zones.

Discussed

None

LIST OF ACRONYMS USED

AOP	Abnormal Operating Procedure
CARD	Condition Assessment Resolution Document
CFR	Code of Federal Regulations
CS	Core Spray System
CTG	Combustion Turbine Generator
DER	Deviation Event Report
HPCI	High Pressure Coolant Injection
ITS	Improved Technical Specification
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LPCI	Low Pressure Coolant Injection System
MCC	Motor Control Center
NASS	Nuclear Assistant Shift Supervisor
NCV	Non-Cited Violation
NIAS	Non-Interruptible Air Supply
NRC	Nuclear Regulatory Commission
PM	Preventative Maintenance
PMT	Post Maintenance Testing
RCIC	Reactor Coolant Isolation Cooling System
RHR	Residual Heat Removal
SBFW	Standby Feedwater
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WR	Work Request
Y2K	Year 2000