U.S. NUCLEAR REGULATORY COMMISSION

REGION 3

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Licensee:	Detroit Edison Company (DECo)
Facility:	Enrico Fermi, Unit 2
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Dates:	October 26 through December 16, 1996
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EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report 50-341/96013

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of an announced 10 CFR 50.59 inspection by the Fermi 2 Project Manager.

Operations

- Performance of operations activities during plant startup, shutdown, and refueling activities were well-controlled. Communications and coordination were good (O1.2, O1.4). In contrast, a number of routine evolutions were not properly controlled and errors were made which resulted in one scram and overflowing the spent fuel pool (O4.1) A non-cited violation was issued for the performance related to the scram.

- Shutdown cooling was lost for 24 minutes when the suction valve shut and the running pump tripped. The exact cause was not determined, but was believed to be an invalid spurious trip (O2.2).

Maintenance

- The licensee identified two cases of lifted leads that were not relanded following maintenance. Both cases were found by workers but not reported or corrected until post maintenance checks. In one case, the investigation did not identify the cause. The inspectors determined the surveillance procedure was inadequate to verify proper system restoration (M1.2). A Notice of Violation was issued.

- Inspectors noted several material condition issues which were not corrected during the outage due to improper planning. Also, a number of instances of inadequate preventive maintenance were discussed (M1.3).

- The control center emergency makeup air filter overheated due to improper/inadequate maintenance (M2.1). The investigation was unable to determine how the heater came to be set 100F too high. Response to the event was proper, but the filter had to be replaced. Valves needed to deluge the filter were found incorrectly labelled.

- Two surveillances were started without meeting the plant conditions to complete the tests. Reviews by schedulers and operators were inadequate (M3.1).

Engineering

- The control rod position indication system upgrade project and the low pressure turbine replacement and steam path upgrade project were carefully planned and executed with few problems. Coordination for both projects was good. Both have yet to be tested completely, however (E2.1, E2.2).

- Safety Relief Valve setpoint testing indicated significant drift. Evaluations showed the plant would not have met its design basis and could have exceeded a safety limit. A modification to reduce the susceptibility to set point drift was implemented during the outage (E2.3).

- The inspectors identified informal and untimely corrective actions for a problem with the EDG 12 muffler. The issue was improperly assigned a low significance and closed. Corrective actions were rescheduled without reassessing the operability determination (E2.4). A Notice of Violation was issued.

- The inspectors identified that a technical specification (TS) change was required as a result of the core reload analysis. Existing rod block monitor (RBM) operability requirements were not adequate to prevent exceeding fuel mechanical overpower limits during a rod withdrawal error event, but the 50.59 evaluation did not determine a TS change was necessary (E3.1). A Notice of Violation was issued.

- The 10 CFR 50.59 program was generally adequate. However, a safety evaluation for the impact of using the Emergency Equipment Cooling Water (EECW) System to supplement drywell cooling during extended hot weather did not consider all applicable scenarios (E3.2).

Report Details

Summary of Plant Status

Unit 2 began this inspection period shutdown for its fifth refueling outage (RFO5). The plant was started up on November 29, but shutdown to investigate an indication problem with Safety Relief Valve (SRV) "A" on December 2. The plant was started up again on December 7, but shutdown the following day because the SRV "A" indication problem recurred and remained shutdown through the close of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. Inspectors noted a continued contrast in operator teamwork and performance between high-visibility operations and routine operations. Several self-revealing events which were caused by operator errors occurred during routine operations. This disparity has been documented in prior inspection reports and the most recent SALP report. Specific events and noteworthy observations are detailed in the sections below.

O1.2 Startup and Shutdown Observations

Inspectors observed the first partial startup and both shutdowns during this period. The inspectors observed good teamwork and mostly formal communications. Evolutions were performed in accordance with procedures. Briefings and the use of past experience were a particular noted strength. The startup schedule was detailed, enabling timely support of post maintenance testing (PMT) and evolutions by the entire site organization; this was an improvement for the last forced outage startup.

O1.4 Refueling Activities (60710)

Throughout the outage, inspectors observed refuel floor activities and fuel moves. Procedure adherence, communications, and formality were assessed. Radiation worker practices, safety practices, and foreign material exclusion controls were also observed.

Refueling bridge operations were formal and performed according to procedure, with good communications on the bridge and with the control room. Over 1100 core alteration steps were performed without error. Fuel sipping was performed to identify the two fuel bundles with small leaks which had been suspected, based on testing during the operating cycle.

In contrast to a nearly flawless performance during core alterations, production work on the refueling floor had several miscues, including removing the wrong reactor pressure vessel thermocouples, and the previously discussed overflowing the SFP, and tripping both Fuel Pool Cooling Pumps while filling MSLs simultaneously. Radworker practices were performed in accordance with licensee requirements, and Radiation Protection personnel provided good support.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

- Divisions 1 and 2 Residual Heat Removal
- Emergency Diesel Generators 11, 12, 13 and 14
- Divisions 1 and 2 Core Spray Systems
- Primary Containment

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

While inspecting the top of the torus, inspectors identified that several test plugs used to perform leak rate testing of the downcomer seal bellows were missing. Inservice Testing personnel were able to produce a memorandum which identified these caps as not being a primary containment boundary, but ensuring they were installed was identified as a good practice. As a result of this finding, the licensee was planning to change the surveillance for checking test connections at the end of an outage to add these connections.

During the same inspection, inspectors identified an example of insufficient space between the Scram Discharge Instrument Volume Drain Line and a fire header, several loose electrical junction box cover screws, and several loose pipe hangers for drywell pneumatics. These deficiencies were reported to the licensee. The first was assessed to be acceptable as is, the others were corrected.

O2.2 ESF Actuation Report on Loss of Shutdown Cooling

On December 3, with the plant in cold shutdown at 157F, shutdown cooling (SDC) was lost when the shutdown cooling suction valve (E11-F009) closed unexpectedly, tripping the running Residual Heat Removal (RHR) Pump C. The licensee believed the trip was due to an invalid reactor high pressure isolation signal though a specific cause was not determined. Shutdown cooling flow was restored after 24 minutes with no temperature rise in the reactor. This event was reported per 10 CFR 50.72.b(2)(ii), as an ESF Actuation to the NRC Operations Center as a four hour report. The inspectors identified no violations of NRC requirements.

Corrective actions and the root cause determination results for this event will be reviewed under Licensee Event Report (LER) 96-020.

O4 Operator Knowledge and Performance

O4.1 Operator Errors

O4.1.1 ESF Actuation Report for Unintentional Scram While Shutdown

On December 4, following completion of a control rod interlock surveillance, a licensed operator moved the Reactor Mode Switch from "Refuel" to "Shutdown." This initiated an expected manual scram signal. The operator reset the scram logic, then went to get the key to bypass the High Scram Discharge Instrument Volume (SDIV) Level scram logic. Before the logic was bypassed, however, the SDIV filled and initiated an unexpected scram on high SDIV water level. This event was reported per 10 CFR 50.72.b(2)(ii), as an ESF Actuation to the NRC Operations Center as a four hour report.

The inspectors reviewed applicable procedures and determined that Abnormal Operating Procedure 20.000.21, "Reactor Scram," Revision 38, required that the operator verify that a Scram Discharge Volume Level High alarm was received, then the Scram Discharge Volume High Water Level Scram, and then reset the scram. By performing this out of sequence, a second scram resulted. Failure to follow procedures was a violation. (50-341/96013-01). Corrective actions for this event will be followed up under LER 96-021.

O4.1.2 Mispositioned Valve Results in Overflowing the Spent Fuel Pool

a. Inspection Scope (92901)

The inspectors reviewed the events surrounding overflowing the Spent Fuel Pool (SFP). Administrative controls and training for valve operations by refueling floor workers were discussed with Refueling Floor supervision and Operations management. Surveys of the spill and other documentation were reviewed.

b. Observations and Findings

On October 30, the licensee overflowed the SFP. The normal method of filling the SFP, a manual valve located in a covered recess on the refueling floor, was found two turns open. Connecting to the same supply line was a hose connection used by the refueling crew for decontamination.

Because the valve pit was inside the contaminated area, Operations had permitted deconners to operate the valve used for the hose after obtaining control room permission. All refueling crew personnel were trained on this arrangement, and were instructed that the larger (manual SFP fill) valve was not required to be open to get water from the hose.

A short time before the SFP overflowed, deconners were unable to obtain water from the hose and asked permission to open the P11-F015 manual fill valve. Permission was denied. Operators then realized that no water was available to the Reactor Building fifth floor due to heavy plant usage of the water supply, so a second pump was started. Approximately a half hour later, the Fuel Pool Cooling Trouble Alarm was received. This alarm had five inputs which could cause the alarm, one of which was SFP Skimmer Surge Tank High Level. Because no SFP Skimmer Surge Tank water level indication was available in the control room, an operator was dispatched to the Reactor Building. He identified that water had filled the surge tanks, then filled the SFP until it overflowed into the ventilation ducts, just above the normal SFP water level. This resulted in spills on floors below as water dripped out of the ducts, so access to the Reactor Building was secured. Inspection and decontamination efforts permitted restoring access over the next seven hours. Contamination levels up to 110K DPM were detected, and the water spilled was estimated to be 100-200 gallons.

A licensee investigation was unable to determine how the manual fill valve was repositioned. The licensee suspected that the contract deconner who was attempting to use the hose and had requested permission to open the manual fill valve, had actually opened it before requesting permission. However, the individual denied doing so. Security performed an investigation to determine if wrongdoing was involved, but no evidence of malicious intent was found.

Also, the licensee determined that the SFP High Level Alarm was never received as it should have been. The level switches had not been calibrated in about two years. The switches were calibrated, and the periodicity of the preventive maintenance event was reduced.

Corrective actions included stopping all refueling floor work and reemphasized administrative controls on valve operations to all workers assigned to that area. The licensee also initiated an engineering request to install water level indication for the SFP in the control room, and were considering additional measures to avoid accidental filling of the SFP.

There were no personnel contaminations during this event.

c. Conclusions

Immediate corrective actions for this event were adequate. However, because a responsible individual could not be identified and a reason for the valve being mispositioned determined, more substantial corrective actions were delayed. Following discussions with the inspectors, Operations recognized that SFP system design contributed to this event, because operators must respond to the refueling floor to determine the cause of the alarm. These switches were not TS equipment and no NRC requirements were violated. However, the failure to obtain permission to operate the valves is a failure to follow procedures. (VIO) (50-341/96013-02)

O8 Miscellaneous Operations Issues (92700)

O8.1 Institute Of Nuclear Power Operations (INPO) Evaluation Review

The inspectors reviewed the June 1996 INPO evaluation of Fermi 2. The inspectors determined that no safety issues requiring NRC followup were identified.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

Attention to detail was an area of concern in maintenance work. Improperly landed leads and inconclusive surveillance documentation are discussed in M1.2. An improperly set charcoal heater following maintenance on a safety system is discussed in M2.1. Specific failures which led to these problems could not be determined by the licensee, which limited corrective actions.

a. Inspection Scope (62703)

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

- EDG 11 Loss of Offsite Power/Loss of Coolant Accident Surveillance
- EDG 11 Voltage Regulator Troubleshooting
- EDG 14 Loss of Offsite Power/Loss of Coolant Accident Surveillance
- Rod Worth Minimizer Operability Surveillance
- Position Indication Probe (PIP)/Cable Changeout Work
- PIP Post-Modification Testing
- SFP High Level Alarm Calibration
- Reactor Moisture Separator Installation
- Emergency Equipment Cooling Water/Service Water (EECW/SW) Cross-tie Check Valve Leak Rate Testing
- Work Activities Associated with Installation of Freeze Protection for both Divisions of the Ultimate Heat Sink
- Division 1 Control Air Compressor Capacity Test
- Hydraulic Control Unit Pressure and Level Switch Calibrations
- Scram Solenoid Pilot Valve Replacements
- Ultimate Heat Sink Cross-tie Valve (E1150-F601A) Repairs

b. Observations and Findings

Maintenance work observed was performed in a professional manner. In most cases, procedures were available and followed. However, the following issues were identified by the inspectors and discussed with senior licensee management:

- Inspectors noted that the source of hot water input to the northwest Emergency Core Cooling System (ECCS) Sump (D073), which was discussed in Inspection Report (IR) 96007, was not specifically identified prior to plant shutdown. As a result, the wrong Reactor Water Cleanup (RWCU) system valves were worked during the outage. When the plant was started up, leakage out of the RWCU was about 15 gpm by control room indication. A licensee inspection of the RWCU system was then performed, and the source of the leakage was identified. The correct valves were repaired following plant shutdown.

- A leaking Reactor Coolant Isolation Cooling (RCIC) system gland exhaust hose was not replaced during the outage because the wrong part was ordered for the second time. The leak was first identified in January 1996. Following shutdown from the aborted startup, the issue was again raised by Operations, and priority was placed on obtaining the correct hose. The hose was ordered and installed in three days.

- Inspectors identified three instances where radiologically controlled vacuum cleaners located adjacent to work areas had hoses crossing contamination area boundaries which were not properly secured to prevent the spread of contamination. In each case, Radiation Protection initiated appropriate corrective actions.

M1.2 Lifted Lead Issues

a. Inspection Scope (92902)

The inspectors investigated an issue that involved lifted electrical leads on safety related equipment which were not relanded following work. The inspectors interviewed maintenance engineers and supervisors from the electrical and I&C maintenance groups and reviewed work documentation and licensee investigation results. The findings were discussed with senior licensee management.

b. Observations and Findings

On November 10, a non-licensed operator on rounds identified that the "A" Reactor Recirculation Motor Generator (RRMG) field breaker was shut while the RRMG was shutdown. This breaker should have tripped during RRMG shutdown. Deviation Event Report (DER) 96-1616 was written to document the event and track corrective actions. Troubleshooting determined that there was a lifted lead (KK18) which affected the normal trip coil, which also performed an Anticipated Transient Without Scram safety function. However, the licensee was unable to determine any work activity which could have lifted the lead and not relanded it. Work documents showed that the lead was lifted during three surveillances, but surveillance documentation indicated that the lead was properly relanded. No other documented work in the vicinity of the lifted lead required or documented lifting it. As a result, there was no corrective action initiated.

The licensee investigation discovered that two I&C technicians found the KK18 lead lifted during unrelated work in the same panel. They taped the end, but never investigated or reported this discovery.

The inspectors determined that the safety function (ATWS Recirculation Pump Trip) was affected. However, the function remained operable because any of the redundant relays could have succeeded in tripping the pump during an ATWS.

The inspectors reviewed the completed surveillances and found that the documentation for relanding the KK18 lead was not conclusive; the I&C policy on how procedure steps were signed resulted in one person signing for all steps being performed, including verifications, based on reports from workers. The inspectors also determined that neither of the last two surveillances which were known to have lifted the KK18 lead, 44.030.251 and 44.030.253, "Division 1 Reactor Vessel Water Level Channel Functional Tests (Channels A and C)," adequately verified that it was relanded. The normal methodology used for I&C procedures for relanding leads was to either independently verify the lead to have been returned to normal, or else functionally test that part of the circuit. Neither was done in the case of these procedures.

c. Conclusions

The licensee's investigation of the RRMG field breaker problem did not identify a probable cause, did not recommend any corrective action, and did not identify the lack of procedural rigor. The inspectors were concerned particularly with the importance of the safety function affected. The inspectors believed that surveillance documentation was inconclusive and the procedure was inadequate to prove that the lead was landed and the RRMG Field Breaker functioned properly at the end of the work. The I&C policy of signing for step completion contributed to the inconclusiveness of the documentation. The inadequate surveillance procedures were considered a violation (VIO) (50-341/96013-03).

M1.3 Conclusions on Conduct of Maintenance

Maintenance activities were generally completed professionally. The licensee employed a larger number of contract workers during this outage than during past outages, but contractor control issues were limited. For the most part, adequate supervision of contract workers by licensee personnel was evident.

As discussed in this report, attention to detail during maintenance work, particularly in documentation and closeout reviews, was not always adequate. Several examples of inadequate scheduled preventive maintenance activities were evident in investigating equipment performance problems. Also, though not specifically determined, the inspectors concluded that the RRMG lifted lead and improperly set CCHVAC heater controller (M2.1) were due to improper restoration from maintenance activities.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Control Center Heating, Ventilation and Air Conditioning (CCHVAC) Filter Overheated - Preventive Maintenance Inadequacies Highlighted

a. Inspection Scope (93702, 92903)

The inspectors observed licensee response to alarms indicating a high temperature condition in the CCHVAC Emergency Makeup Filter (EMUF). The investigation results and maintenance issues identified by the licensee were discussed with the investigation team, system engineer, and senior management.

b. Observations and Findings

On October 25, the CCHVAC EMUF overheated following charcoal replacement. This resulted in a fire alarm and auto oxidation of the filter, an exothermic reaction. The fire brigade responded. Operators found that the heater was set at 250 degrees fahrenheit vice the correct setting of 150 degrees fahrenheit. The Alarm Response Procedure discussed lining up the fire protection system to deluge the filter if necessary, but the operators found that valve labels did not agree with the procedure or the system drawings. The licensee conservatively decided to deluge the filter and replace the charcoal when temperatures inside the filter did not consistently decline with the heater off, even though temperatures were well below the flashover point.

The heater cutout switches were found to be out of calibration 200 degrees fahrenheit high and not covered by scheduled preventive maintenance. Heater controllers were also found to be out of calibration. System records indicated that the heater cutout switches were supposed to be set 300 degrees fahrenheit higher that the fire alarm setpoint, rather than below the fire alarm setpoint. The design basis of this setpoint was being reviewed by the licensee at the end of this report period, as well as possible deactivation of the heater.

c. Conclusions

The inspectors considered the licensee's response to the event was appropriate and conservative. The inspectors considered that the licensee's investigation was sufficiently broad and detailed, and identified a number of existing equipment problems, most significantly a lack of scheduled preventive maintenance for some components. The four mislabelled water deluge valves were identified before they hampered fire brigade response. The lack of adequate preventive maintenance is a violation. Since the requirements of Section VII of NUREG-1600, "General Statement of Policy and Procedures for NRC Enforcement Actions" were met, this is considered to be a non-cited violation (NCV)(50-341/96013-04).

M3 Maintenance Procedures and Documentation

M3.1 Two Surveillances Started Without Meeting Required Plant Conditions - Pre-job Reviews Inadequate

a. Inspection Scope (92903)

Following findings in the last Resident Inspection Report (96010), that scheduled equipment lineup changes that affected shutdown cooling (SDC) were not adequately reviewed for plant impact. The inspectors reviewed scheduling of surveillances during the outage. Members of the Independent Safety Engineering Group (ISEG) were interviewed to determine what reviews were performed by ISEG. Operator logs and applicable DERs were reviewed for problems encountered. Findings were discussed with senior plant management.

b. Observations and Findings

Independent Safety Engineering Group (ISEG) reviews of the outage schedule were performed in two phases. The pre-outage review was performed several months in advance of the outage, and resulted in a detailed report which included safety system availability and required power sources, and a number of other useful data. However, the inspectors determined through discussions with ISEG that this report did not reflect the actual outage schedule by the time it was issued.

The second phase of review involved ISEG maintaining a running review of the impact of outage schedule changes. The Independent Safety Engineering Group acknowledged that this running review may not have been comprehensive because of the large number of schedule and scope changes made in the month before the outage. It became comprehensive again after the outage started and the number of changes became smaller. During the outage, ISEG reviewed the entire list of approved activities daily, and attended Fermi's Integrated Resource Support Team screening meetings to review non-scheduled work. However, the depth of reviews varied.

Two surveillances were begun without realizing that plant conditions were not appropriate. On October 3, Surveillance 42.302.04, "Division 2 Bus 65E/13EC UV Logic Functional Test," conflicted with Non-interruptible Air System being cross-tied for Reactor Building Closed Cooling Water (RBCCW) system outage. Deviation Event Report (DER) 96-1291 was written to document the event and track corrective actions. On October 28, Surveillance 44.030.052, "ECCS - RHR Division 2 Logic Functional Test" required securing Division 1 SDC at a time when it was required by TS, and an alternate method of removing decay heat was not available. Deviation Event Report (DER) 96-1511 was written to document the event and track corrective actions. Operators identified these conflicts after starting the surveillances, and responded properly by reporting the problem and backing out of the procedure. The inspectors reviewed the two surveillance procedures. The impact statement and prerequisites for 44.030.052 did not address the need to secure both divisions of shutdown cooling.

c. Conclusions

The inspectors determined that no technical specification (TS) requirements were violated. The surveillances were stopped before violations of TS occurred. However, the inspectors were concerned that licensee reviews of the impact of these surveillances, both in determining when to schedule performance and during operator preparation to run the tests, failed to identify that plant conditions were not appropriate.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Follow-Up Item 50-341/96010-02: Ultimate Heat Sink Cross-tie Valve (E1150-F601A) failed to operate. The licensee determined that the valve failed to stroke because a set screw had come loose in the gear connecting the motor operated actuator and the valve shaft. Repairs were performed, and the other three cross-tie valves inspected satisfactorily. corrective actions for this event will be reviewed under LER 96-14. This item is closed.

M8.2 (Closed) Unresolved Item 50-341/94016-04: Poor cleanliness in the torus and drywell. The inspectors conducted closeout inspections of the primary containment during the forced outage in April 1996 and at the conclusion of RFO5, and found cleanliness control much improved. Emphasis on housekeeping during work activities inside containment and detailed walkdowns during closeout preparations were evident. The suppression pool was observed by inspectors and found to be free of fibrous material and debris, with the interior coating in good condition. The licensee vacuumed the suppression pool during this outage to remove minor accumulations of rust chips. This item is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Control Rod Position Indication Replacement Project

a. Inspection Scope (92902, 92903, 37551, 40500)

Inspectors discussed Position Indication Probe (PIP) replacement plans with the project staff. Work in progress and testing performance were observed. DERs identifying problems were reviewed, and results discussed with members of the project team. Operator logs were reviewed for PIP problems following replacement.

b. Observations and Findings

The work for this project was carefully planned in great detail. Close cooperation among engineering and maintenance groups and vendors resulted in several innovations which simplified installation while improving the cable design and reliability. Pre-installation testing was maximized, so the majority of problems identified were found, documented, and corrected before the drywell work began.

Dose controls and shielding were well-planned, and constantly adjusted based on worker feedback. Actual dose was just under the original estimate of 25 Rem.

Lab testing of the new assemblies was performed under extreme laboratory conditions at elevated temperatures before the outage, which confirmed that past problems with loss of electrical continuity were not experienced by the new design.

Post modification testing identified a minor problem which caused position indication flickering during rod movement. Troubleshooting and vendor bench testing identified that this phenomenon was probably caused by slightly strong magnet or overly sensitive reed switches in some PIP probes. A number of PIP probes were replaced to minimize the problems, even though they were not expected to impact plant operation.

c. Conclusions

The PIP replacement project was planned and implemented well. Initial results indicated that past problems appeared to have been corrected. However, past problems were most significant at power with high core flow, which have not been experienced since replacements.

E2.2 Turbine Replacement

Inspectors discussed the low pressure turbine replacement and steam path upgrade plans with the project staff. Work in progress was observed and DERs identifying problems were reviewed. The work was carefully planned in great detail and performed smoothly. Few problems were encountered, although the turbine had not been rolled with steam at the conclusion of this report. The inspectors identified some early issues with housekeeping and radworker practices, which were discussed with the licensee staff, and improvement was later seen. Radiation Protection support was noted as particularly good, and was instrumental in the radworker practice improvements. Damper installation on the steam lines and high pressure turbine control valve problems corrected during valve inspections were expected to result in a reduction in steam line vibration and improved steam flow characteristics compared to last cycle.

E2.3 Safety Relief Valve (SRV) Failures and Resolution to LER 96-017

a. Inspection Scope (92902)

On December 1, during surveillance testing, safety relief valve (SRV) B21-F013A did not properly indicate when the valve was open, although secondary indications (steam flow and tailpipe temperature) did confirm that the valve opened and closed properly. Inspectors observed control room operators response to the failure, and reviewed applicable documentation including Surveillance Procedure 24.137.11, "Safety Relief Valve Operability Test," and Alarm Response Procedure 1D61, "SRV Open."

b. Observations and Findings

While attempting to cycle SRVs during plant startup, control room operators observed that when SRV B21F013A was commanded open, it failed to indicate open. The operators did note that main steam line flow and bypass valve position responded as expected for the valve actually opening. On a second attempt, the "open" light came on briefly. The SRV open indication, which was produced by a pressure switch connected to the SRV tailpipe, was declared inoperable and appropriate Technical Specification (TS) Limiting Conditions for Operation action requirements were initiated. Initial troubleshooting indicated possible instrument line blockage. The licensee decided to shutdown to correct this and several other equipment problems on December 2 (see section M1.3).

Troubleshooting did not identify a specific problem, but the licensee believed that some blockage was blown from the instrument line. The plant was again started up, but on December 7 Surveillance Procedure 24.137.11 was again unsatisfactory for SRV "A." The open indication for the SRV failed to remain energized when the valve was open and spuriously indicated open when the valve was being closed. Based on steam flow and bypass valve position changes, the SRV was verified to have opened and closed as required. The reactor was subsequently shutdown and additional troubleshooting was initiated.

The licensee decided the problem was likely a design problem, and did a detailed historical performance review of all SRVs. Vendor assistance was requested. Advanced flow modeling was performed which showed that the instrument tap existed near an area of low pressure due to sonic flow. A modification was implemented which moved the tap several feet downstream. All the SRV tailpipes were evaluated, but the remaining 14 were determined to be free from this problem. Also, historical data supported the conclusion that only SRV "A" had intermittent indication problems.

The investigation included a design and licensing basis review, which identified and corrected some documentation inconsistencies of minor consequence. The licensee was also evaluating this for a potential 10 CFR 21 report.

The modification was planned to be installed and tested after the conclusion of this inspection period. This will be tracked as an Inspection Followup Item to verify the modification was implemented and tested satisfactorily. (IFI) (50-341/96013-05)

c. Conclusions

During the first shutdown, the inspectors concluded that the licensee took reasonable actions to determine the pressure switch was functioning, then maintained a questioning attitude and planned for contingencies during the subsequent startup. When the problem recurred, pertinent data was collected and the reactor was appropriately shutdown in accordance with TS requirements. The subsequent investigation of the problem was broadened appropriately, and industry assistance was sought. Troubleshooting efforts displayed considerable coordination among the various work groups involved. No violations of NRC requirements were identified.

E2.4 Emergency Diesel Generator 12 Muffler - Corrective Actions for EDG Muffler Problem Informal and Operability Vague

a. Inspection Scope (92902, 40500)

The inspectors conducted a followup on an NRC-identified rattle in the EDG 12 muffler, as discussed in IR 96002. The disposition of the original DER and work request were reviewed. Findings were discussed with the system engineer, safety engineering, licensing, and senior management.

b. Observations and Findings

In January, 1996, inspectors identified a metallic rattle in the exhaust muffler for EDG 12 while the engine was running. The condition was documented in DER 96-0026. Based on a discussion with the vendor, a licensee determination was made that EDG 12 operability would not be impaired provided engine exhaust temperatures did not rise, the rattle did not get louder, and the rattle did not change locations in the muffler. The probable cause of the noise was determined to be "some sort of internal baffle failure," and the DER dispositioned the problem by scheduling the muffler to be replaced during Refueling Outage (RF) 05, to be completed by November 30.

The inspectors reviewed the issue and found that the muffler was no longer scheduled to be replaced during the outage. However, the DER was closed under a recent program, called "Closed to Process," (CTP). This process allowed closing DERs of low importance provided the disposition was traceable and handled under another process, such as a maintenance work request. In this case, the EDG 12 muffler was tracked under Work Request 000Z961758 and DER 96-0026 was closed.

System engineering had determined that the significance of the rattle was low because the vendor stated the likelihood of an internal muffler failure leading to blocked exhaust line was low. However, the inspectors noted that the consequences of a partially or fully blocked exhaust line would be reduced load capability for the EDG, up to complete loss of safety function. The inspectors determined that this was not evaluated by system engineering or safety engineering, despite the high safety significance of the EDG.

Subsequent to closing DER 96-0026, maintenance/planning decided to schedule the work for the next system outage, targeted for May, 1997. This was a considerable extension of the intended time to replace the muffler over what was assumed at the time the operability determination was made, yet the extension was not discussed with those responsible for making the original decisions because the DER was closed.

The inspectors found that the continued operability determination for EDG 12 was not formally documented or tracked. The EDG System Engineer was monitoring surveillance runs, listening to the muffler, and reviewing logs for exhaust temperature. Licensee management was unaware that there was an ongoing operability assessment or that a delay in replacing the muffler was planned until brought to their attention by the inspectors.

Following the inspectors' raising the above issues, the conditions being monitored to ensure continued EDG 12 operability in light of the muffler degradation were added to the monthly surveillance procedure. Licensee management decided to review the CTP program from the standpoint of lessons learned from this issue. Current operability was reviewed by the licensee and determined to be unchanged since the time of initial identification of the rattle.

c. Conclusions

The inspectors agreed based on their observations that the EDG 12 operability was unchanged. However, the inspectors were concerned that the CTP method of handling this issue did not handle ultimate resolution with the proper attention due a safety system. Low significance was assigned based on a low probability of catastrophic failure, rather than evaluating the consequences of further degradation. The CTP procedure did not require that changes to the intended corrective action be reviewed with those responsible for the original action. Also, the informal method by which the ongoing assessment of EDG 12 operability has handled was considered weak, particularly because it resided with a single individual. Failure to take corrective actions in a timely manner commensurate with the safety significance of the system was considered a violation of 10 CFR 50, Appendix B, Criterion XVI (VIO) (50-341/96013-06).

E2.5 UFSAR Requirement Review

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

As discussed in E2.3, the licensee identified a discrepancy in UFSAR description of the licensing basis of SRVs and associated accident monitoring indication. This issue was discussed with NRR, and licensee actions to verify the design by testing and resolve UFSAR inconsistencies were determined to be adequate.

E3 Engineering Procedures and Documentation

E3.1 Inspectors Identify Need for Technical Specification Change

a. Inspection Scope (92902, 71707)

The inspectors reviewed the Core Operating Limits Report (COLR) for Cycle 6 and the associated Technical Specification Clarification (TSC) 96-004. When it appeared that a TS change was required based on this review, the issue was discussed with NRR Technical Specifications Branch, as well as members of the licensee's Reactor Engineering and Licensing staffs. The associated preliminary evaluation and a safety evaluation were also reviewed.

b. Observations and Findings

Technical Specifications 3.1.4.3 and 3.3.6 described the conditions under which the Rod Block Monitor (RBM) must be operable. The Fermi Core Operating Limits Report for Cycle 6, Revision 0, stated that "In addition to these requirements, at least one RBM channel must be operable when moving control rods with thermal power greater than or equal to 30 percent of rated thermal power in order to protect for mechanical overpower limits."

The inspectors discussed this issue with Reactor Engineering and Licensing, and concluded that this statement inferred that the existing TS requirements were inadequate to protect the core during a rod withdrawal error event. NRR Technical Specifications Branch reviewed the issue, and agreed that a TS change was required. The licensee agreed and submitted a license amendment request on December 2. Based upon the licensee's commitment to make a license change submittal and administrative controls in place, NRR determined that Fermi could start up while the amendment was being reviewed.

The inspectors determined that Safety Evaluation 96-0128, Revision 0, and the associated Preliminary Evaluation, evaluating the COLR for the Cycle 6 core, were inadequate in that they improperly concluded that a TS change was not required to ensure that mechanical overpower limits would be met during a rod withdrawal error event. Instead, the licensee issued TSC 96-004 to indicate that the RBM operability requirements of the COLR would be followed, beyond the TS requirements.

c. Conclusions

The NRC concluded that a change was required to the existing TS in order to ensure that mechanical overpower limits would be met during a rod withdrawal error event. Failure to identify that a TS change was required during the review of the proposed modification to the facility was a violation of 10 CFR 50.59 (VIO) (50-341/96013-07).

E3.2 Program to Evaluate Changes, Tests and Experiments Pursuant to 10 CFR 50.59

a. Inspection Scope (37001)

The inspectors reviewed selected preliminary evaluations (PE) and safety evaluations (SE) performed by the licensee to satisfy the requirements of 10 CFR 50.59.

b. Observations and Findings

The inspectors reviewed a total of 41 PE and SE reports completed by the licensee within the last two years. Roughly half of the evaluations evaluated changes to the facility while the balance was split between changes to procedures and tests. Most of the evaluations had been performed in conformance with the regulations and the licensee's procedures. However, the inspectors did find problems in some of the evaluations.

The licensee prepared a preliminary evaluation and a safety evaluation (SE 96-0128) for the Core Operating Limits Report (COLR) for the Cycle 6 core. As discussed in detail in E3.1 above, the evaluations failed to identify the need to amend the TS to ensure fuel mechanical overpower limits would be met during a rod withdrawal error event.

The licensee prepared SE 95-0036 to evaluate operating the Emergency Equipment Cooling Water (EECW) system to supplement the Reactor Building Closed Cooling Water system. The SE did not fully evaluate the consequences of this change in the operation of EECW. In particular, the SE didn't evaluate the possibility that operating in this mode could cause reduced flows to essential loads under certain accident conditions. The licensee wrote DER 96-1836 to document the deficiency and track corrective actions.

In addition to these problems, the inspectors noted some weaknesses in the licensee program for evaluating changes, tests and experiments. The licensee procedures did not specify reviewing for any potential unreviewed safety question which might exist during the implementation of a change. Also, some reviewers appeared to interpret the scope of review under 10 CFR 50.59 for changes to procedures to only include those items specifically identified as procedures in the UFSAR. The inspectors determined that Revision 3 to MLS02, "Preliminary Evaluations and 10 CFR 50.59 Safety Evaluations," step 4.1.9, indicated that the scope of this review should be broader. Finally, some preliminary evaluations didn't contain sufficient information to allow a subsequent reviewer to fully understand the safety significance of the change. The licensee was made aware of these deficiencies and indicated that corrective actions were being evaluated.

c. Conclusions

The inspectors determined the licensee's 10 CFR 50.59 process to be generally adequate for the review of proposed changes. However, failure to perform an adequate evaluation for the COLR was cited as a violation in E3.1, and the EECW safety evaluation will be tracked as an Unresolved Item pending NRC review of the licensee re-evaluation (URI) (50-341/96013-08).

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

All Radiation Protection topics were discussed in the sections above. No separate writeup will be provided.

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 December 17, 1996. 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.

X3 Management Meeting Summary

On December 17, J. Hannon, Director, Project Directorate III-3, NRR met with D. Gipson, Senior Vice President, Nuclear and members of his staff on site to discuss the environment for reporting safety concerns at Fermi.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Booker, General Supervisor, Electrical Maintenance
C. Cassise, General Supervisor, Mechanical Maintenance
W. Colonnello, Director, Safety Engineering
R. Delong, Superintendent, System Engineering
T. Dong, NSSS, Technical Engineering
P. Fessler, Plant Manager, Operations
E. Kokosky, Superintendent, RP and Chemistry
R. McKeon, Assistant Vice President, Operations
W. Miller, Technical Support
J. Nolloth, Superintendent, Maintenance
J. Nyquist, Acting General Supervisor, ISEG
J. Plona, Technical Director
W. Romberg, Assistant Vice President and Manager, Technical
P. Smith, Director, Nuclear Licensing
G. Trahey, General Supervisor, ISEG
E. Vinsko, General Supervisor, I&C

NRC

M. Weston, NRR
G. Hammer, NRR

INSPECTION PROCEDURES USED

IP 37001:	10 CFR 50.59 Safety Evaluation Program
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60710:	Refueling Activities
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-341/96013-01	VIO	Unexpected Scram When Manual Scram Reset Prematurely
50-341/96013-02	VIO	Inadequate Procedure failed to prevent overfill of SFP
50-341/96013-03	VIO	Inadequate Procedure Failed to Verify Electrical Lead Properly Connected After Removal
50-341/96013-04	NCV	Inadequate preventive maintenance on CCHVAC
50-341/96013-05	IFI	SRV "A" Indication Modification and Testing
50-341/96013-06	VIO	Loose Baffle Plate in EDG 12 Not Repaired in a Timely Manner
50-341/96013-07	VIO	Inadequate Safety Evaluation Failed to Identify Required TS Change
50-341/96013-08	URI	EECW SE Failure to Fully Evaluate Consequences of Change to Supplement RBCCW System

Closed

50-341/96010-02	IFI	Ultimate Heat Sink Cross-Tie Valve Failed to Operate
50-341/94016-04	URI	Poor Cleanliness in Torus and Drywell

LIST OF ACRONYMS USED

CCHVAC	Control Center Heating Ventilation Air Conditioning
CFR	Code of Federal Regulations
COLR	Core Operating Limits Report
CTP	Close to Process
DER	Deviation Event Report
DPM	Disintegrations per minute
EDG	Emergency Diesel Generator
ECCS	Emergency Core Cooling System
EECW	Emergency Equipment Cooling Water
EMUF	Emergency Makeup Filter
ESF	Engineered Safety Feature
GPM	Gallons per Minute
I&C	Instrumentation and Control
INPO	Institute of Power Operations
IR	Inspection Report
ISEG	Independent Safety Engineering Group
LER	Licensee Event Report
MSL	Main Steam Line
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PIP	Position Indication Probe
PMT	Post Maintenance Testing
RBM	Rod Block Monitor
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Coolant Isolation System
RF	Refueling Outage
RFC	Refueling Floor Coordinator
RHR	Residual Heat Removal
RRMG	Reactor Recirculation Motor Generator
RWCU	Reactor Water Clean-Up
SALP	Systematic Assessment of Licensee Performance
SDC	Shutdown Cooling
SDIV	High Scram Discharge Instrument Volume
SE	Safety Evaluation
SFP	Spent Fuel Pool
SRV	Safety Relief Valve
TS	Technical Specification
TSC	Technical Specification Clarification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation