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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EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report No. 50-341/97[illegible]

This inspection included aspects of licensee performance in the areas of operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection. During this period, improvements were noted in the performance of safety system outages and resolution of numerous longstanding equipment problems. The licensee effectively coordinated activities to place the plant in single loop operation to effect the repair of a misaligned Reactor Recirculation Motor Generator (RRMG) tachometer-generator coupling. The licensee restored the plant to operation without any significant problems the same day.

Operations

- The licensee continued to operate the plant well. Generally, plant equipment performance was good with few exceptions such as the RRMG. Control room operators exhibited a strong questioning attitude during the replacement of the RRMG tachometer generator. (O1.1)

- Inadequate coordination and review in the preparation for work resulted in briefly rendering a significant portion of a safety system division inoperable. Control room operators later recognized the error and took required actions a short time after the Technical Specification (TS) Condition for Limiting Operation (LCO) had expired. A violation was identified for this failure to comply with TS LCO requirements for site AC power availability. This violation was the result of work control process implementation problems. (O1.2)

- Operators did not declare the Diesel Fire Pump inoperable when oil sample results were out-of-specified tolerance values. The licensee subsequently identified this error and declared the pump inoperable. A non-cited violation was identified for this issue. (O1.3)

- Single loop reactor plant operation was well-planned and executed. Good teamwork, communication, and coordination of activities were evident. (O1.4)

- The inspectors identified that corrective actions for an event in April 1997 involving the Emergency Diesel Generator Starting Air Compressors were incomplete. The licensee did not initiate procedure changes to ensure proper equipment configuration control and proper return to service. In addition, training on the event was not timely. (O3.1)

- A violation was identified for inadequate corrective actions to prevent freezing of Condensate Storage Tank instrument lines which resulted in a repeat event. (O8.4)

Maintenance

- Improvements in the control of work activities were noted in the areas of work schedule adherence and out-of-service times for safety related equipment. (M1.1)

- The problem identification, assessment, and repair planning associated with the Reactor Recirculation Motor Generator Tachometer-Generator replacement was thorough and conservative. Outside experience including vendor support was promptly sought. Contingencies were planned for, including simulator training on several potential scenarios. Maintenance System Engineering, Chemistry, and Radiation Protection personnel provided excellent support to the operations staff in preparing for and executing the tachometer-generator repair and error-free single loop operation.(M1.2)

- Safety system outage performance improved. Critical, integrated reviews during the planning process resulted in reduced problems during the conduct of work. Items for improvement were identified during system outage critiques and the licensee promptly implemented recommended actions. System Outage Managers and Work Week Managers had a strong role in effecting improvements and in fostering coordination and communications across organizational lines. (M2.1)

- The inspectors identified that the licensee had not adequately tested Reactor Recirculation Motor Generator High Speed Stops. The alternate testing methodology being used by the licensee did not meet the requirements of Surveillance Requirement 4.4.1.1.2., resulting in a violation. (M3.1)

- The inspectors identified a violation for the licensee's failure to perform required capacity testing on the Division 1 24/48V Battery following cell replacement. The licensee was slow to complete a formal assessment of the operability of the battery when its capacity was brought into question. Also, the battery capacity testing schedule was not revised when new cells were installed. (Violation)(M3.2)

- The licensee identified that surveillance requirements for Turbine Stop Valve Closure and Turbine Control Valve Fast Closure scram override functions had not been properly implemented since initial plant operations. This resulted in a non-cited violation. (M3.3)

Engineering

- The performance of the General Service Water System was significantly improved. The licensee implemented modifications and operational changes to resolve a number of longstanding equipment problems. (E2.1)

- The inspectors observed that prompt, conservative action was taken to suppress a small reactor fuel leak at the earliest indication of a problem. Coordination between Reactor Engineering and Operations personnel was a strength. The inspectors noted that site personnel were sensitive to changed plant conditions. (E3.1)

- Engineering personnel implemented system improvements to the Reactor Core Isolation Cooling, Residual Heat Removal Service Water, Control Rod Position Indication, and Main Turbine Steam systems to effectively resolve longstanding equipment problems. Operator distractions were reduced while improving plant reliability. (E8.3 - E8.9)

Plant Support

- No significant issues were identified in the Plant Support functional area during this inspection period.

Report Details

Summary of Plant Status

At the start of this inspection period, the plant was starting up from a forced outage. Power had been increased to approximately 87 percent when a small reactor fuel leak was detected on May 10. Power was reduced May 12 to conduct power suppression testing, which resulted in successfully locating and suppressing power in the leaking bundle. Power was then increased to 94 percent. A degraded seal on Reactor Recirculation Pump "A" resulted in the licensee deciding to maintain pump speed nearly constant, so power was allowed to coast down to about 91 percent. Power was reduced to approximately 35 percent and the plant was operated in single loop on June 27 to replace a misaligned Reactor Recirculation Motor Generator (RRMG) tachometer-generator that had been vibrating excessively. On June 19, an unexpected high pressure coolant injection system division "A" isolation occurred. The isolation signal was received during surveillance testing and was determined by the licensee to be spurious. The plant was operating at 96 percent at the end of this inspection period. A mid-cycle outage was planned to replace the degraded Reactor Recirculation Pump seal and the leaking fuel bundle.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. Specific events and noteworthy observations are detailed in the sections below.

Material condition deficiencies required the plant to operate under special conditions and required the licensee to conduct infrequently performed evolutions during this inspection period. This provided a significant challenge to operations personnel in preparing for and executing single loop operations to support repairs to the "A" RRMG. The inspectors observed that operations personnel were involved in all aspects of preparation activities and provided a focus on safety. Operations management requested an evaluation of the risk associated with continuing to operate and the best measures to take until the RRMG repairs could be made. Simulator training was conducted for all operating shifts on planned and contingency operations related to the RRMG problems. This issue is further discussed in Section O1.4 below.

The inspectors noted that since plant restart in early May 1997, plant equipment has performed well. However, the inspectors noted that operator actions were required in response to several problems that caused control room alarms on a daily or more frequent basis. These included:

- Offgas Preheater Drain Level High
- Reactor Water Cleanup System Blowdown Line High Pressure

- Main Generator Seal Face High Temperature
- Main Generator Supervisory Trouble Alarms
- Reactor Recirculation Pump "A" Seal Pressure Oscillations

The inspectors noted that these items were not captured on the Operations Equipment Concerns/Operator Workaround List. However, the significance of these equipment problems and the scope of operator actions required were considered by the inspectors to be much lower than during the previous cycle.

O1.2 Technical Specification (TS) Actions Not Taken When Cooling Tower Fan Removed from Service

a. Inspection Scope (71707)

The inspectors conducted an independent assessment of an event in which TS actions were not implemented as required. Applicable work request, tagout and Limiting Condition for Operation (LCO) documents were reviewed, and operators involved in the event were interviewed.

b. Observations and Findings

On June 24, operations personnel tagged out the "B" Ultimate Heat Sink (UHS) Mechanical Draft Cooling Tower (MDCT) Fan for scheduled repairs to the fan brake as part of the Division 2 Residual Heat Removal (RHR) system outage. Approximately an hour later, a licensed operator questioned whether the tagout rendered the UHS and all associated systems inoperable. The Nuclear Shift Supervisor (NSS) and the Nuclear Assistant Shift Supervisor (NASS) reviewed the work scope and tagout in detail and concluded that the Division 2 UHS was rendered inoperable by tagging out the MDCT Fan.

The licensee then declared the Division 2 Emergency Equipment Service Water, Residual Heat Removal Service Water (RHRSW), and Diesel Generator Service Water systems inoperable in accordance with TS requirements for an inoperable UHS. This rendered the equipment supplied by these systems inoperable, including Emergency Diesel Generators (EDGs) 13 and 14. Technical Specification 3.8.1.1. required that with one or both EDGs in a required division inoperable, operators demonstrate the operability of remaining onsite and offsite AC sources within one hour. This was completed approximately one hour and 22 minutes after the "B" MDCT fan had been rendered inoperable. A short time later, MDCT fan tags were cleared and work planned for the fan brake was rescheduled. The inspectors discussed this event with the shift senior reactor operators and determined that the LCO Record Sheet listed all applicable TS action statements for the Division 2 RHR System Outage including those that were not followed.

c. Conclusions

The inspectors concluded that inadequate coordination and review in the preparation for work resulted in briefly rendering a large portion of a safety system

division inoperable. Control room operators later recognized the error and took required actions a short time after the LCO had expired. Work control process unnecessarily challenged control room operators and led to the failure to comply with TS requirements for verifying AC power availability. The inspectors determined that while control room licensed operators were responsible for recognizing the consequences of the planned work, including the associated tagout, the ability of control room operators to meet this expectation was challenged by problems with the work control process which resulted in documents with incorrect information being provided to the operators. Failure to comply with TS 3.8.1.1 requirements upon rendering the "B" MDCT fan inoperable, was considered a violation. (VIO)(50-341/97007-01)

O1.3 Diesel Fire Pump (DFP) Not Declared Inoperable Following Out of Tolerance Fuel Oil Sample

a. Inspection Scope (92901)

The inspectors reviewed the circumstances surrounding why the diesel fire pump was not declared inoperable following receipt of unsatisfactory results from a diesel fire pump fuel oil sample. Control room logs, procedures, and sample results were viewed and operators involved in the event were interviewed.

b. Observations and Findings

Performance Scheduling and Tracking (PST) Job AC12970318 required sampling the DFP Fuel Oil Storage Tank. The subject PST was initiated to implement Technical Requirement Manual Surveillance Requirement 9A.6.2.2.2 for obtaining a sample once per 92 days in accordance with American Society Testing Materials (ASTM) national standards ASTM-D270-65, and checking against acceptance limits specified in Table 1 of ASTM-D975-77 for viscosity, water and sediment. The inspectors reviewed the initial analysis results that indicated a high water and sediment content of 0.1 percent, mainly composed of solid material.

The results were reported to the lubrication engineer, who requested that a second sample be taken. The results of the first sample analysis were also reported to the NASS as being greater than Action Level A values specified in Table 1 described above and actions specified in MCGO3 "Chemistry Sampling and Analysis, Section 4.6." Although the results did not meet the surveillance requirements, the DFP was not declared inoperable. Action Level A required that another sample be taken within 24 hours of the analysis completion, or at the next opportunity, either purify or change the existing fuel oil and resample for the out-of-tolerance parameter every month until the sample results were normal.

The results of the second sample were also out of tolerance. These results were reported to the NSS, who then questioned if the DFP was inoperable given the results. The NSS was informed by the chemistry technician that the DFP remained operable despite the out of tolerance values.

Two days after the initial sample, the lubrication engineer reviewed the Updated Final Safety Analysis Report (UFSAR) for diesel fuel oil quality operability requirements and determined that the DFP had been inoperable since the initial sample was taken. The operability statement was reviewed by engineering and operations personnel and the DFP was declared inoperable as of the date of the original sample.

The inspectors verified that a work request had been written to drain, inspect, flush and refill the DFP fuel oil tank. The inspectors reviewed the UFSAR and noted that the seven day allowed outage time specified in the UFSAR had not been exceeded. The exact cause of the out-of-tolerance condition was unknown.

c. Conclusions

The inspectors concluded that the control room operators, upon receiving sample results from chemistry technicians, did not formally declare the DFP inoperable although sample results indicated that a parameter was out-of-tolerance. After a second sample was analyzed, control room operators questioned the operability of the fire pump but were incorrectly informed that the fire pump remained operable. Failure to recognize and formally declare the DFP inoperable for two days is a violation of operating administrative procedure MOPO5, "Control of Equipment," Step 2.4.2 which states that an LCO entry shall be made for all Technical Specification, ODCM, and UFSAR Fire Protection Conditions for operations determined to be inoperable. Since the licensee identified and corrected this discrepancy before exceeding a Technical Requirement Manual LCO requirement, this event is not being cited because the requirements of Section IV of the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG 1600, have been met (NCV)(50-341/97007-02). However, the inspectors were concerned that station personnel did not recognize and take appropriate actions upon identifying that a system or component's surveillance results were outside the acceptance criteria.

O1.4 Observations on Single Loop Operation

a. Inspection Scope (71707, 61726)

Due to the infrequent nature of this evolution, the inspectors conducted extensive observations of operations related to entry into and recovery from single loop plant operation. Applicable Technical Specifications, the UFSAR, and plant procedures were reviewed. Operations activities and briefings in the control room and the plant were observed for procedural adherence and regulatory compliance. Situational surveillance requirements were verified to be performed as required. The interface between Operations and Reactor Engineering personnel for reactivity manipulations were observed to verify complete communications and conservative operations.

b. Observations and Findings

The inspectors observed thorough briefings for major steps in the single loop operation's. The senior line managers assigned to supervise this infrequently performed test/evolution conducted each briefing in a professional manner, supported by the lead organizations for each part of the briefing. The inspectors noted an improvement in the area of discussions on contingency actions during briefings. Responsibilities for specific actions were clearly assigned at these briefings, and NSS/NASS priorities were discussed and were properly conservative. Simulator training sessions were conducted for all involved operators and management personnel in preparation for this evolution. Detailed reviews of surveillance and operating procedures were conducted through tabletop reviews. The inspectors observed that the overall sequence of operations, surveillance testing and work was precisely followed. No significant difficulties were encountered. Senior line managers and test directors effectively contributed to the coordination of activities, limiting the burden on the operating shift.

Reactivity manipulations were observed to be deliberate and controlled, with formal communications between the operator and reactor engineer. When minor adjustments were proposed for power-flow stability considerations, the plan was properly discussed with the NSS. Operator awareness of power-flow conditions and the margin to the Stability Awareness Region of the Power-Flow Map were excellent throughout the evolution. The inspectors periodically reviewed situational surveillance data during the evolution and noted that all required data was recorded and trended as required. Plant conditions were carefully manipulated throughout the evolution so as to minimize thermal transients and simplify recovery of the idle loop.

The complex evolution of idle loop recovery was performed in a particularly controlled and coordinated manner. The NASS provided a clear plan which was well executed. Potential equipment concerns which could have affected the planned operations, such as possible degradation of the "A" Reactor Recirculation Pump seal, control rod position indication problems, and further degradation of the "A" RRMG tachometer-generator coupling, were carefully monitored. No significant problems developed. The inspectors noted that adequate personnel were available to perform all required tasks. Support for each evolution was timely and communications between organizations was good. Non-priority jobs were carefully planned to avoid impacting priority work.

The only notable problem the inspectors observed involved a tagout issue with the "A" RRMG. The tagout removed the RRMG field breaker from service for personnel protection during tachometer-generator work. However, when the tagout was put in place, core flow instrumentation logic was altered so that core flow improperly indicated forward flow in the idle loop, when actual flow was in the reverse direction. This was significant because the reactor was operating in the Stability Awareness Region at the time and this problem resulted in non-conservative core

flow indications. Control room operators promptly recognized the problem and the tagout was corrected to place the breaker in the proper position. A discussion of planning and work aspects for this evolution is provided in Section M1.2.

c. Conclusions

The evolution for entry into single loop and subsequent recovery was conducted in a careful, coordinated manner. Operations support was excellent. The operators in the control room and in the field performed as a team. The evolution was well-planned, and the plan was followed. The successful completion of this complex evolution was the result of a high degree of teamwork and preparation by the licensee. The inspectors observed that control room operators were prompt in identifying and correcting the problem with core flow indication which was caused by incorrectly hanging the tagout on the RRMG field breaker. However, the tagout review and procedure for entry into single loop should have identified this problem.

O2 Operational Status of Facilities and Equipment

O2.1 Safety System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following safety-related systems and engineered safety feature systems:

- EDGs 11 and 12 Ventilation and Fuel Oil Subsystems
- Reactor Core Isolation Cooling (RCIC) System
- Division 2 Emergency Equipment Cooling Water
- Division 2 Emergency Equipment Service Water
- Division 1 and 2 24/48 Volt Batteries
- Division 1 and 2 Control Center Heating, Ventilation and Air Conditioning Systems
- Division 1 and 2 Standby Gas Treatment Systems
- Diesel Fire Pump
- High Pressure Coolant Injection (HPCI)

The inspectors concluded that equipment operability, material condition, and housekeeping were acceptable. The inspectors did not identify any concerns as a result of these walkdowns, which indicated that walkdowns by operators and system engineers were effective in identifying problems. The inspectors noted that safety system performance and availability were good.

O3 Operations Procedures and Documentation

O3.1 NRC Identified Incomplete Corrective Actions for Previous Event

a. Inspection Scope (71707, 61726, 40500)

The inspectors observed a surveillance run of EDG 12, following which an oil sample for the EDG 12 Starting Air Compressor (SAC) was scheduled. The

inspectors reviewed the oil sampling procedure to verify that corrective actions for a previous mispositioning event had been incorporated. The issue was discussed with the NSS, the Operating Engineer, and the Surveillance Group Supervisor.

b. Observations and Findings

Inspection Report 50-341/97003 discussed an April 3, 1997 event in which the EDG 11 SAC was turned off to draw an oil sample but was not restored to service. Corrective actions for this event included changing 32 operations procedures and job procedures to include steps to secure the compressor, draw the sample, then independently verify proper restoration.

On June 12, the inspectors noted that the procedure for PST Job AF12970314, "Sample EDG 12 SAC Oil," had not been corrected. The inspectors informed the NSS before work was begun that the procedure did not incorporate the subject corrective actions and expressed concern that the problem could be repeated. The NSS verified what corrective actions were planned, but did not take steps to stop work in the field or inform the operator performing the work of the procedure deficiencies. As a result, the operator removed the SAC from service without control room knowledge or procedural guidance; the compressor was, however, properly restored and independently verified (without being formally documented).

Subsequent to the inspectors identifying the procedural deficiency, the licensee identified that the procedure for obtaining a SAC oil sample for EDG 13 had the same deficiency when an oil sample was drawn on April 28. Both procedures were corrected. The inspectors identified that operator training for the April 3 event had not yet been conducted at the time of this event. As a result, operators were unfamiliar with the details of the previous event and used the superseded version of the procedure.

c. Conclusions

The inspectors identified that the licensee had not corrected all of the applicable procedures or completed training to prevent a recurrent failure to return the SAC to service upon drawing an oil sample. Although the operating shift did not take actions to correct the procedure when prompted by the inspector, the SAC was restored properly and the operability of the EDG was maintained. The inspectors concluded that this event did not involve a violation of regulatory requirements because the SAC was successfully returned to service.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Inspection Followup Item 50-341/96007-01: Placement of Scaffold Near Safety-Related Equipment. The licensee implemented an improved scaffold control tagging system which clearly indicated the status of scaffolding (from erection and inspection, through use and removal). Requirements for the approvals and

inspections were changed to be more uniform since previous requirements for the activities were confusing as they varied by plant location. Survey results for completed scaffolds were also clearly indicated on the tags.

The inspectors observed the use of the new system and found it to be a significant improvement. Plant personnel indicated that the new tags reduced the confusion about scaffolding status. The inspectors inspected scaffolding throughout the plant, and found that each scaffold had clear documentation of status and approval, as well as radiological survey results. The inspectors reviewed administrative procedure MMA08, "Scaffolding," Revision 2, and noted that inspection criteria for use by operators in approving the scaffolding were clear and placed emphasis on avoiding any impact on safety-related equipment operation. Improvements made by the licensee to control scaffolding were adequate to avoid blocking access to or preventing the operation of safety-related equipment. This item is closed.

O8.2 (Closed) Violation 50-341/96007-05: Scaffolding in Auxiliary Building Not Inspected by Operators. The licensee concluded that this violation was caused by an unclear procedure in that notification of operations personnel when a new scaffold required inspection and the documentation required for satisfactory completion of the inspection were not clearly defined. The inspectors reviewed changes made to administrative procedure MMA08, "Scaffolding," in Revision 2, and noted that the procedure specified responsibilities for notifying operations personnel to conduct inspections at the appropriate time. The inspectors inspected scaffolding throughout the plant and found that each scaffold had clear documentation of proper inspection and approval. Corrective actions appeared adequate to prevent recurrence of the violation. This item is closed.

O8.3 (Closed) Inspection Followup Item 50-341/96016-01: Clarity of Engineered Safety Feature (ESF) Actuation Reportability Decisions. In response to NRC concerns with unclear control room log entries regarding planned ESF actuations during testing, the licensee changed licensing administrative procedure MLS05, "Notifications/General Regulatory Reporting Requirements," and the General Regulatory Reporting Requirements List. The inspectors noted that the changes clarified the criteria for considering an ESF actuation "planned." The inspectors reviewed control room log entries on a daily basis and did not identify any additional examples of potentially reportable ESF actuations which were logged in an unclear manner. This item is closed.

O8.4 (Closed) Unresolved Item 50-341/96016-07: Condensate Storage Tank (CST) Freeze Protection. The inspectors reviewed documentation and conducted interviews for the freezing of CST level indication instrument lines on January 17, 1997. The inspectors had two concerns.

The first concern pertained to the differences in actions taken by two different operating crews in response to freezing of the CST transmitter sensing line. Freezing of the sensing line in January 1992 rendered both channels of CST low level instrumentation inoperable. The operating crew took immediate actions to correct the condition which included realigning the suction for both HPCI and RCIC.

In contrast, the operating crew did not take actions to realign the HPCI and RCIC suctions during the January 1997 event. In that case, the sensing line was restored to operable conditions prior to the expiration of the associated TS 24 hour LCO. Although both responses were in compliance with TS, the inspectors were concerned that each operating crew would respond differently. This concern was addressed with operations management.

The inspectors were also concerned because freezing of the instrument lines inhibited the automatic suction swapover from the CST to the suppression pool for the HPCI and RCIC systems on a low CST level condition. In addition, the CST low level alarm to alert operators to manually perform the swapover would not function with frozen lines. Failure to perform an automatic or manual swapover could potentially hamper both HPCI and RCIC from performing as required.

When a control room annunciator for low temperature in the CST instrument cabinet was received, control room personnel identified that the instrument lines were frozen because the CST level recorders were off scale high. Investigation by the licensee revealed that the door to the CST instrument panel, located outside the plant, had been pried open to obtain log readings because the cabinet lock had frozen.

The CST/CRT/DST TEMP LOW annunciator was designed to warn operators of low CST instrumentation cabinet temperature. However, the inspectors identified that the cabinet low temperature annunciator setpoint was too low to provide adequate advance warning to prevent instrument line freezing, as was demonstrated in this event. The inspectors reviewed corrective actions for the January 1992 CST instrument line freezing event and noted that the annunciator setpoint had not been evaluated to provide adequate warning to control room operators. In addition, the inspectors discovered the CST cabinet was not fully secured during a plant tour on June 5, even though a sign with specific instructions was on the instrument cabinet door as a previous corrective measure.

The inspectors concluded that corrective actions for the freezing of instrument lines for CST level transmitters were inadequate to prevent recurrence. Proposed corrective actions did not consider preventive measures, such as the adequacy of the cabinet low temperature alarm setpoint, to warn of heater failure, or an improperly closed instrument cabinet door. The failure to implement prompt and thorough corrective actions to prevent a repeat occurrence is considered a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions." (VIO)(50-341/97007-03)

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703, 61726)

The inspectors observed all or portions of the following work and surveillance activities. Work practices and procedure adherence were assessed. Tagout isolation and administration were observed and reviewed. Radiological work practices and Radiation Protection support of work were observed. Work packages were reviewed for completeness and adequacy as well as plant impact and TS action implementation requirements. Surveillance procedures were reviewed and compared to TS, the UFSAR, and system design basis documentation to ensure requirements were being properly tested.

- EDG 12 Slow Start Surveillance
- EDG 12 Engine Inspections Activities
- Reactor Coolant Isolation System (RCIC) Pump Discharge Pressure Instrument Functional Check
- E5150-F059 Motor Operator Valve Actuator Preventative Maintenance
- Vibration Monitoring of RRMG "A" Tachometer-Generator
- EDG 12 Muffler Internal Inspection
- Residual Heat Removal (RHR) Pump D Meggar
- RHR Pump B Breaker Relay Testing
- RHR Division 2 Room Cooler Preventive Maintenance
- Emergency Equipment Cooling Water Division 2 Pump and Valve Operability Surveillance
- Main Lube Oil Cooler Inspection and Cleaning
- Diesel Fire Pump Surveillance Testing
- RRMG "A" Tachometer-generator Replacement
- RRMG Set High Speed Stop Setpoint Surveillance
- Average Power Range Monitor Gain Adjustments for Single Loop
- Control Rod Operability Surveillance
- Average Power Range Monitor "E" Channel Functional Test
- Control Rod Drive Stall Flow Measurements
- Active Seismic Monitoring System Channel Check
- Fire Suppression and Sprinkler System Valve Operability Test
- Core Flow Unit "A" Functional Test
- Diesel Fire Pump Operability Test

b. Observations and Findings

The inspectors noted that work schedule adherence had improved. Overall schedule adherence had been as high as 93 percent, with some work groups attaining 100 percent adherence during some weeks. Emergent work was reduced

to about 10 percent of the total work performed each week. At times during the previous operating cycle, emergent work was as high as 66 percent of all work.

Work control and maintenance personnel had been placing increased emphasis on reducing the average age of backlogged items and managed to reduce the non-outage corrective maintenance backlog below their goal of 425 items, attaining the lowest backlog since the plant began operation. In the process of reducing backlogged work, equipment performance and plant thermal efficiency improved.

The inspectors observed that the awareness of what work required LCO entry had improved at the craft level. Problems encountered were being raised and resolved promptly for jobs with LCOs, which was a noticeable improvement over past performance. Supervisory involvement in jobs with LCOs was also improved.

c. Conclusions

Improvements in the control of work activities were evident. Improvement was most notable in schedule adherence, supervisory involvement in the field, and giving high priority to work with an associated LCO. Critical work reviews appeared to have reduced the number of problems during jobs with LCOs, ultimately contributing to reduced out-of-service times. The efforts of work week managers appeared to have a positive impact in these improvements and in fostering improved coordination and communications across organizational lines.

M1.2 Reactor Recirculation Motor Generator Tachometer Replacement

a. Inspection Scope (92903, 62703, 92902)

The inspectors attended planning and assessment meetings involving the licensee's staff for the "A" Reactor Recirculation Motor Generator (RRMG) tachometer-generator replacement. Vibration monitoring and trending for the tachometer-generator were observed. Work activities during the replacement were observed. The probable cause of identified equipment problems and maintenance history for equipment were discussed with the applicable system engineer and component engineer.

b. Observations and Findings

On May 21, the system engineer identified that the tachometer-generator for the "A" RRMG set had high vibration. The licensee assigned a team to evaluate the problem. The team determined that the RRMG tachometer-generator coupling was misaligned and resulted in excessive wear of the nylon coupling. Various vendors were contacted for assistance and expertise. The licensee established plant conditions to minimized the impact of a failure of the RRMG until repairs could be made. Due to possible indications of seal degradation of the associated reactor recirculation pump, a replacement seal was obtained, and contingency plans were developed for a plant outage to replace the seal if necessary. Operating shift personnel were trained on single loop operations in the simulator. Mockup training

of maintenance personnel was conducted for the repair work. All operating and surveillance procedures were reviewed in detail.

On June 27, the plant was placed in a single loop condition and the "A" RRMG was successfully repaired, as discussed in Section O1.4 above. Additional non-priority work was accomplished to take advantage of the lower power and dose rates in of the plant. During inspections of normally inaccessible parts of the plant, the licensee identified a small cracked weld which was leaking steam from an auxiliary system. The leak was promptly repaired.

c. Conclusions

The inspectors concluded that the assessment and repair of the RRMG tachometer generator were detailed and conservative. Outside experience including vendor support was promptly sought. Maintenance, Reactor and System Engineering, Chemistry, and Radiation Protection organizations provided excellent support in preparing for and executing the tachometer-generator repair and single loop operation.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 System Outage Performance

a. Inspection Scope (62703, 92903)

The inspectors observed planning and work associated with system outages for EDGs 11, 12, 13 and 14, Division 1 Non-interuptible Air System, and RCIC. The inspectors conducted interviews with work planners, work week managers, system outage managers, and craft personnel. Outage schedules, tagouts, and LCO documentation were reviewed to ensure that TS requirements were met.

b. Observations and Findings

The inspectors assessed the effectiveness of safety system outages conducted during this inspection. The inspectors noted that system outage performance, with the exception of the RCIC outage, was notably improved over outages in previous months.

The inspectors observed a number of critical work review meetings. These meetings, attended by planning, maintenance, and operations personnel discussed critical work in detail to identify problems. These meetings were conducted a week before the work was scheduled to be accomplished. The inspectors observed that attendees challenged each other on changes to the scope of work. Proposed improvements from these meetings effectively reduced outage times by eliminating schedule conflicts. Additionally, these meetings ensured that parts and personnel were available to accomplish the task.

The inspectors noted that work in the field was started promptly. Preparations for the outage in the form of walkdowns, parts availability checks, contingency considerations, and incorporation of past experience were improved. This improvement was done in large part because packages were planned and distributed for review earlier. Pre-staging of parts and equipment was more prevalent than in the past. First line supervisors from craft groups, as well as planners and engineers, were visibly more involved with work in progress. The improved coordination and reviews reduced parts availability problems and most tagout problems.

System outage managers provided good, timely briefs to management. These included evaluations of safety impact of the work. These briefings were effective in ensuring that Maintenance Rule and performance goals were met. These briefings also ensured that emergent work was properly handled.

The inspectors determined that the lessons learned were documented and incorporated into future outage planning activities as a result of post-outage critiques. For example, when the first EDG outage identified a problem with a starting air subsystem check valve seat, work packages for the remaining, EDG outages were revised to incorporate the lessons learned.

Although planned work activities were completed as scheduled for the RCIC system outage, the outage exceeded the planned duration due to unexpected emergent work issues. Total outage time was 88.3 hours, almost triple the original scheduled outage time. An example of an unexpected emergent issues occurred during post maintenance surveillance testing when operations personnel questioned the validity of steps performed in the surveillance test. Specifically, RCIC flow controller setpoint was raised to 645 gallons per minute to satisfy TS system criteria above the normal band of 635 gallons per minute. However, at the conclusion of the test, the setpoint was to be restored back to its original standby value. The operators then questioned whether this practice maintained a proper system flow rate. The licensee issued a controller setpoint change. This issue will be tracked as an inspection followup item pending inspectors review of the methodology used to justify the new setpoint. (IFI)(50-341/97007-04)

Other examples of unexpected emergent issues occurred during RCIC testing when significant oil and steam leaks developed. These leaks necessitated a prompt system shutdown. The oil leak nearly drained the system, but system damage was avoided by prompt operator response. The steam leak was partially caused by an improper turbine gland exhaust valve lineup. The affected valves were found by the licensee not to be included on the system valve lineup. The valve lineup was corrected.

c. Conclusions

The inspectors concluded that the system outage performance, on most systems, was notably improved. Planning and scheduling involved critical, integrated reviews which appeared to have reduced problems during work. System outage critiques

appeared to be effective in identifying and implementing lessons learned into subsequent outages.

M3 Maintenance Procedures and Documentation

M3.1 Reactor Recirculation Motor Generator (RRMG) Set High Speed Stops Not Tested

a. Inspection Scope (61726, 92903)

The inspectors reviewed a number of surveillance activities Associated with the RRMG. The inspectors questioned how the licensee fulfilled the TS (SR 4.4.1.1.2) requirements for testing RRMG set high speed stops.

b. Observations and Findings

On April 17, the licensee performed surveillance 54.000.20, "Reactor Recirculation System MG Set Scoop Tube Positioner Operability," to verify the high speed stops (HSS) were properly set. The surveillance was performed on the Reactor Recirculation System Motor Generators (RRMG) to comply with Technical Specification (TS) Surveillance Request (SR) 4.4.1.1.2. SR 4.4.1.2 required that mechanical and electrical HSS are demonstrated to be set lower than 110 percent and 107 percent, respectively, of core flow.

When the surveillance was performed, the plant was in a shutdown condition, so the reactor engineering and licensee personnel determined that the intent of the SR was met by verifying that the stops were in the same position as during the previous cycle. The maximal allowable surveillance interval expired on May 24, 1997. On June 3, the inspector reviewed methodology for meeting the SR 4.4.1.1.2 requirements and questioned its vitality.

On June 4, NRC staff determined that the methodology used by the licensee for setting the RRMG HSS did not meet the requirements of SR 4.4.1.1.2. The licensee was notified on June 4 and while they did not agree with the NRC position, the RRMG HSS were reset to a value lower than 110 and 107 percent of core flow that could be properly tested under existing plant conditions. Surveillance testing of the HSS were then performed satisfactorily. Failure to perform SR 4.4.1.1.2 with the required interview period was a violation (VIO) (50-341/97007-05).

Conclusions

The inspectors determined that the testing methodology for the setting of the high speed stop for the RRMGs endorsed by engineering and licensing personnel did not ensure compliance with the Technical Specification for Surveillance Requirements 4.4.1.1.2.

M3.2 Battery Capacity Was Not Determined Following Replacement of Three Cells

a. Inspection Scope (92903)

The inspectors reviewed the licensee's post maintenance requirements (PMT), and identified that work on the Division 1 24/48V Battery did not conform to procedural requirements. The applicable work request was discussed with the electrical maintenance supervisor responsible for the work, the system engineer, work planner, and the Work Planning Supervisor to determine what reviews were performed.

b. Observations and Findings

The licensee replaced a three-cell jar in the Division 1 24/48 volt Battery on April 15, 1997. The new cells were properly checked for individual cell voltage and electrolyte specific gravity/level before installation, but maintenance administrative procedure MMA11, "Post Maintenance Testing," also required a capacity test following this work.

The inspectors reviewed Work Request 000Z971148 with the electrical work group supervisor and determined that a capacity test was not performed. The system engineer stated that the licensee's test facility determined the capacity of new battery cells, but that test results were not obtained at the time of work, and were not reviewed as part of the job preparation. The planner stated that PMT for this work request had been specified by the system engineer during planning stages, and was also discussed with the responsible work group supervisor. However, none of the three reviewed the PMT guidelines and recognized that a capacity test was required. Failure to comply with the PMT requirements of administrative procedure MMA11 was a violation. (VIO)(50-341/97007-06)

The inspectors noted that after changing, the new cells were at the minimum acceptable voltage. On June 12, the inspectors questioned whether the battery had sufficient capacity to perform its intended function during a loss of AC power. The licensee tested another 3-cell jar purchased at the same time and maintained the same as the jar in question. This indicated a capacity of 95.9 percent. On July 2, an operability evaluation was performed. The evaluation indicated that cell capacity could be considered to be 95.9 percent for the installed cells. This capacity was sufficient to support the design load profile of the battery in which it was installed, as a considerable design margin existed in this case for battery capacity. The inspectors reviewed the evaluation and determined that the conclusions were technically adequate.

c. Conclusions

The inspectors determined that reference to administrative procedures during planning, review, and post maintenance testing of this work was weak. As a result, the PMT specified in the work request did not meet licensee administrative requirements.

The inspectors were concerned that the licensee took almost three weeks to complete a formal assessment of the operability of the battery when it was brought into question.

M3.3 Missed Surveillance for Turbine Stop Valve (TSV) Closure and Turbine Control Valve (TCV) Fast Closure Scram Functions

a. Inspection Scope (92901)

The inspectors interviewed engineering personnel, reviewed applicable procedures, control room logs, and design basis documentation. The inspectors discussed the issues with station operations, compliance, and engineering personnel.

b. Observations and Findings

While increasing reactor power following plant startup, the licensee identified that the TSV Closure and TCV Fast Closure Channel Functional Tests had not been performed prior to entry into Operational Condition 1, as required by TS 3.3.1. The channel functional tests were then performed, and the TSV Closure and TCV Fast Closure scram functions were declared operable within 24 hours of discovery, as allowed by TS 4.0.3 following identification of a missed surveillance.

The inspectors reviewed Technical Specifications and noted that the Channel Functional Tests were required to be performed every 92 days in accordance with Table 4.3.1.1.-1, and prior to entry into Condition 1. The TSV Closure and TCV Fast Closure Channel Functional Tests had not been performed within their required frequency due to the length of the recent maintenance outage. The surveillance was not scheduled to be performed prior to entry into Operational Condition 1 but was scheduled to be performed at 27 percent power. The licensee did not properly implement Technical Specifications based on a belief that the test should be performed prior to turbine first stage pressure of 161.9 psig. On May 7, while at 27 percent power control room personnel recognized that they had exceeded 161.9 psig without performing the required surveillance. Reactor power was immediately lowered to 22.9 percent and turbine first stage pressure to 156.6 psig to performed the surveillance. The applicability requirements had been missed since initial plant operation due to the same misinterpretation of the TS requirements. The inspectors verified that the surveillances were satisfactorily performed.

The inspectors noted that licensee's corrective actions included modifying the existing surveillance procedure to reflect the Operational Mode 1 applicability for these functions. The surveillance scheduling and tracking data base was also updated to reflect Operational Condition 1 functions and the correct applicability for this specification was included in the operating experience segment of the operator requalification training.

c. Conclusion

The inspectors concluded that the licensee incorrectly implemented the surveillance requirement that the TSV closure and TCV fast closure scram functions be tested prior to entry into Operational Condition 1. The failure to performed TS required surveillances prior to entry into an applicable operational mode was a violation of TS requirement 4.0.4. This violation will not be cited because the requirements of NUREG 1600, "General Statement of Policy and Procedures for NRC Enforcement Actions," Section VII.B.1. were met. (NCV)(50-341/97007-07)

M8 Miscellaneous Maintenance Issues (92903)

M8.1 (Closed) Inspection Followup Item 50-341/96010-09: Reactor Coolant Isolation System Returned to Service, without PMT to Verify Operability, With Work Package Partially Completed. Nuclear quality assurance personnel conducted a surveillance of all deactivated work packages in response to NRC concerns, and identified no similar instances where partially completed work affecting system operability. The inspectors reviewed a sample of 10 deactivated work packages for safety systems and identified no concerns. The licensee changed maintenance administrative procedure MWC02, "Work Control," Section 4.11 (Work Request Deactivation/Reactivation), to clearly specify that when deactivating a work package, PMT necessary to restore the system must be performed. Based on the lack of further examples and appropriate corrective actions by the licensee, this item is closed.

M8.2 (Open) Inspection Followup Item 50-341/95012-07: Combustion Turbine Generator (CTG) 11-1 Did Not Meet Committed Reliability. The licensee performed a review of CTG 11-1 run history in order to take into account all applicable data. The licensee specified local guidelines for calculating reliability based on existing guidance in the national standard NSAC 108, "The Reliability of Emergency Diesel Generators at U.S. Nuclear Power Plants." The inspectors reviewed the licensee's guidelines and determined that they seemed reasonable.

As discussed in Inspection report 50-341/96012, the licensee conducted a major refurbishment of CTG 11-1, partly in response to NRC concerns about the generator reliability. The inspectors monitored CTG 11-1 performance since refurbishment and found that reliability actually declined after refurbishment. Five valid start/load failures occurred during the first 35 demands after refurbishment. Numerous other problems of a more minor nature were encountered, some of which caused out of service time.

The inspectors noted that six months after completing the refurbishment, operator experience with the new systems was still low due to the infrequent operation of the CTG. As a result, the operations system expert for CTGs and the system engineer were called frequently when problems occurred. Also, the inspectors identified that the CTG 11-1 alarm response procedures were incomplete. As a result, inspectors noted that at times, operators were challenged when alarms and anomalous indications were received for which no written guidance was available.

This made it difficult in some situations for the Control Room operators to determine if CTG 11-1 was operable.

The inspectors noted that CTG 11-1 continued to be classified as a Maintenance Rule a.1 Category system following refurbishment, due to the above noted performance. The licensee was revising the system performance improvement plan at the conclusion of this inspection period to encompass the equipment issues discussed above. This item will remain open pending NRC assessment of additional licensee efforts to improve CTG 11-1 reliability and performance.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Implementation of General Service Water (GSW) System Improvements

a. Inspection Scope (92902, 92903)

The inspectors observed GSW system modification planning and implementation. GSW system performance was monitored, particularly during high-demand periods.

b. Observations and Findings

The NRC identified several concerns with the GSW system performance in the summer of 1995. These included excessive pipe vibration, valve cavitation, through-wall pipe leaks, and pressure control difficulties. In response, the licensee conducted a thorough system performance review and engineering modelling of the system with the assistance of an architect-engineering firm.

Major improvement items implemented included:

- Installation of a fire protection system jockey pump and separating the fire protection system from the GSW system.
- Lowering GSW system operating pressure to reduce valve cavitation and pipe erosion problems. Pumps were destaged to reduce the discharge pressure from 155 psig to about 120 psig.
- Changed pressure control method and widened the pressure band to eliminate the need for manual pressure adjustments in the field. Two restricting flow orifices were installed in place of pressure control valves for Turbine Building Closed Cooling Water System and Reactor Building Closed Cooling Water System (RBCCW) to improve temperature control.
- Installed local temperature indicators to improve performance monitoring.

These modifications were completed with the exception of the destaging for one GSW pump. Two additional modifications are scheduled to be implemented with the plant on line during the current cycle:

- Install a drywell cooling system to supplement cooling to the drywell and select other RBCCW and emergency equipment cooling water loads during peak hot weather conditions.

- Install an additional GSW/RBCCW heat exchanger to add redundancy.

c. Conclusions

The inspector determined that the licensee efforts to improve GSW system performance were effective. The inspectors noted that system performance has been improved. Valve cavitation and pipe vibration were not observed to be problems.

E2.2 High Pressure Core Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Keep-fill Questioned Following Surveillance Test Problem

a. Inspection Scope (92902)

The inspectors reviewed surveillance procedures and interviewed engineering personnel. The inspectors reviewed the UFSAR and other related design basis documentation.

b. Observations and Findings

On June 16 during performance of Surveillance 44.030.153, "Emergency Core Cooling System - High Pressure Coolant Injection (HPCI) Condensate Storage Tank Level Functional Test," the RCIC Condensate Storage Tank (CST) suction isolation valve (E5150-F010) failed to automatically close as required. Operations personnel declared RCIC and the associated CST low level instrumentation inoperable. Both HPCI and RCIC suction paths were realigned to the suppression pool. Troubleshooting by station personnel on the affected valve did not reveal any problems. The valve was manually opened and stoked closed, as expected. The surveillance was then successfully performed.

Because the suction paths for HPCI and RCIC were isolated, operators questioned whether keep-fill for HPCI and RCIC were effective. UFSAR Section 6.3.2.2.5 stated that the system was kept filled during normal operation to preclude any voiding in either systems discharge piping. Voiding in the discharge piping could cause delays in the delivery of emergency core coolant and potentially cause water hammers. The systems were normally kept filled by the static head provided by the CST.

Plant support engineering personnel performed an informal calculation for both HPCI and RCIC and determined there was a possibility that the RCIC discharge piping

might not remain full with suction aligned to the suppression pool. As a result, RCIC was declared inoperable when the system pressure became too low. The systems were properly filled and vented when the normal suction paths were restored. The surveillance test was reperformed successfully and the RCIC system was returned to operable status.

The inspectors questioned past operability, since on previous occasions the suctions for both HPCI and RCIC had been transferred for an extended period of time to the suppression pool. The licensee evaluated known extended periods where suction was aligned to the suppression pool. The licensee determined that the longest time was about 24 hours or about the same amount of time as the recent event. The licensee determined that no past operability concerns existed.

The licensee determined that in the future, the systems would be declared inoperable when system pressure indicated that a positive pressure could no longer be maintained at the limiting locations. Permanent corrective actions were being developed at the conclusion of this inspection.

c. Conclusions

The inspectors considered that a good questioning attitude was exhibited by the operators in verifying the HPCI and RCIC systems remained filled. Corrective actions, past system operability and the keepfill design will be reviewed by the inspectors following completion of the licensee's evaluation of the technical issues. This issue will be tracked as an Inspection Followup Item. (IFI)(50-341/9700?-08)

E3 Engineering Procedures and Documentation

E3.1 Conservative, Aggressive Actions Taken to Identify and Suppress Small Fuel Leak

a. Inspection Scope (92902)

The inspectors reviewed indications and sample results indicating a possible small fuel leak, and discussed the indications with Fuels Group and Chemistry personnel. Fuel performance was monitored on a daily basis. Licensee procedures for fuel reliability actions were reviewed. Major plant evolutions were reviewed to determine the impact to fuel performance.

b. Observations and Findings

On May 10, reactor engineering personnel identified that off gas radiation monitor indicated a slight increasing trend. Samples obtained and analyzed by chemistry personnel confirmed a small fuel leak. The licensee reduced power to conduct power suppression testing on May 12. A single leak was identified in a fuel bundle near the core center. Control rods were inserted to suppress power and limit release rate from the leak. In response to this leak, the licensee administratively limited linear heat generation rate.

The licensee believed that the leak had actually developed during the previous operating cycle, but was so small that it was masked by two other small fuel leaks. In addition, fuel sipping during the previous refueling outage had been limited to a sample of 80 bundles.

The licensee established a Fuel Reliability Action Plan (FRAP) with the assistance of the fuel vendor. The inspectors observed that the FRAP provided low thresholds for monitoring for a degrading conditions, and the FRAP was promptly revised when conditions warranted. Region-based inspectors performed independent calculations for release rates to the public. The NRC calculations confirmed licensee conclusions that increased dose to the public as a result of the fuel leak were negligible. See Inspection Report 50-341/97009 for a more detailed discussion of confirmatory dose calculations.

During the period of initial offgas radiation monitor increase, work in appropriate parts of the plant were curtailed and access restricted to limit personnel exposure until the effect on dose rates were understood. Radiation protection personnel accompanied operators on rounds into affected areas during this period to survey radiological conditions.

The inspectors confirmed through discussions with the site management that the licensee planned to conduct a mid cycle outage in Fall of 1997. The mid-cycle outage will enable the licensee to replace the leaking fuel and conduct fuel sipping to identify any other leaking fuel bundles.

c. Conclusions

The inspectors observed that coordination between engineering and operations with regard to this issue was frequent and thorough. The prompt, conservative action taken to identify and suppress the fuel leak at the earliest indication of a problem was viewed as a strength.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Violation 50-341/96013-07: Failure to Submit a Technical Specification (TS) Change Request for Rod Block Monitor (RBM). The violation occurred because the licensee had concluded that the basis for the existing RBM TS requirement only addressed protection of the minimal critical power ratio safety limit, while the Cycle 6 Core Operating Limits Report determined that credit for a rod block was necessary to protect for mechanical overpower limits (one percent plastic strain) of the fuel. To ensure meeting the mechanical overpower limits, the licensee included a requirement in the core operating limits report to ensure at least one RBM channel was maintained operable above 30 percent power. The 10 CFR 50.59 Safety Evaluation had improperly concluded that no TS change was required because the new requirement was not prohibited by or in conflict with the existing TS. A TS change was requested to expand the applicability statement of TS 3.1.4.3 and Tables 3.3.6-2 and 4.3.6-2, such that the RBM was required to be operable when power was above 30 percent. This was approved on May 15, 1997, in License

Amendment 112. The inspectors considered corrective actions for this violation to be adequate. This item is closed.

E8.2 (Closed) Violation 50-341/96013-06: Inadequate Corrective Actions for Emergency Diesel Generator (EDG) 12 Muffler Rattle. In response to inspectors' concerns about having delayed corrective actions to the muffler, the licensee re-evaluated the operability of EDG 12 and determined that it remained operable. Monitoring of engine and exhaust parameters was included in all EDG 12 surveillance procedures to formally evaluate continued engine operability until the muffler internals could be inspected.

The licensee conducted a visual inspection of the interior of the muffler on May 14, and identified that the cause of the rattle was a broken baffle support weld which allowed an angle iron to vibrate. Engineering personnel assessed the muffler as operable with this existing condition. Repairs were scheduled for the next system outage. Periodic monitoring to assess EDG 12 performance continued. The inspectors observed the muffler inspection and discussed the results with the system engineer, and concluded the licensee's operability assessment was reasonable.

The inspectors were concerned that the original corrective actions were untimely because the repairs were delayed without the knowledge of the organization responsible for the original operability determination. This was because the original DER was "closed to process" because the repair was scheduled and completion was tracked. In response to "closed to process" concerns, the licensee then reviewed DERs which were closed via the Closed to Process provisions and identified no further examples where scheduling of corrective actions was linked to an operability assessment, as it was in this case. The inspectors reviewed a sample of DERs Closed to Process, and identified no additional concerns. This item in closed.

E8.3 (Closed) Inspection Followup Item 50-341/96004-10: Reactor Core Isolation Cooling System Steam Admission Valve (E5150-F045) Seat Leakage. The inspectors reviewed the engineering evaluation that determined the leakage was excessive, but did not affect system operability. The licensee added to applicable procedures temporary corrective actions to torque the valve shut following a system run. The valve was replaced with an identical globe valve in October 1996, but this valve also had seat leakage following plant startup. The valve was replaced with a gate valve in March 1997, and was successfully tested during the subsequent startup, exhibiting adequate seat tightness during several test runs. This item is closed.

E8.4 (Closed) Inspection Followup Item 50-341/95008-04: Control Rod Position Indication Probe Problem Investigation Results. The licensee conducted an extensive review of the cause of intermittent loss of individual control rod position indications, including laboratory testing under simulated service conditions of vibration and temperature. The licensee replaced all the position indication probes and associated cabling in the drywell in October 1996. The inspectors observed

that the problems were mostly corrected, although a few minor problems existed at the end of the fall refueling outage. These were subsequently corrected. Based on a successful repair, this item is closed.

E8.5 (Closed) Inspection Followup Item 50-341/96003-04: Turbine Steam Line Drain Valve Motor Operator Separated from Valve. The licensee's root cause investigation determined that the failure of the bolts fastening the actuator to the valve body were caused by fatigue from drain line vibration. In October 1996, the licensee installed viscosity dampers on the main steam lines. Since the plant returned to high power, drain line vibrations were reduced by about 40 percent. The vibration reduction effect was less on the turbine control valve vibrations, but the data was still being collected and assessed for these valves. The licensee inspected the seven sister valve actuators in October and replaced the actuator bolts, although none were found damaged. The bolts were Grade 8 bolts, the strongest available, but engineering analysis showed the bolts could be overstressed at the vibration amplitude actually observed after the failure was recognized. Licensee corrective actions appeared adequate to preclude recurrence. This item is closed.

E8.6 (Open) Inspection Followup Item 50-341/96003-03: Turbine Steam Control Valve Vibration. During the refueling outage in fall 1996, the licensee identified that the main turbine high pressure control valves had excessive wear between the stem and the disk, allowing some disk wobble due to steam flow. The licensee determined that the excessive wear was caused by improper hardening during manufacture. After consulting the vendor, the valves were repaired and properly hardened. This item will remain open pending licensee evaluation at 100 percent power.

E8.7 (Closed) Violation 50-341/96004-05: Failure to Test RHRSW Drain Lines. On March 31, 1996, the NRC inspector identified that the Emergency Equipment Service Water return lines to the mechanical draft cooling towers (MDCTs) were susceptible to freezing because of plugged drain lines. In response to the violation the licensee changed the applicable system design basis document and UFSAR to include discussions of the drain lines function. A system modification was implemented to move the drain lines to a location less susceptible to plugging and to make verification of flow from the drain lines easier. The system operating procedure was modified to include instructions to verify the drain lines function during system operation. Training for Plant Support Engineering on lessons learned from the event was conducted on September 21, 1996. The inspectors reviewed the design basis document and the UFSAR were found to be updated adequately. Training documents were also reviewed and found to be adequate. Interim corrective actions and system modifications made in response to this violation are discussed in E8.8 below. This item is closed.

E8.8 (Closed) Violation 50-341/96006-05: Inadequate Corrective Actions for RHRSW Drain Line Plugging. Following the above violation, inspectors again identified partial plugging of the RHRSW drain lines on July 29, 1996. The licensee was relying on interim corrective actions pending implementation of a system modification. Following unplugging of the lines, the licensee committed to performing inspections by the system engineer to ensure proper functioning of the drain lines. However, the inspectors identified that the system engineer was not specifically monitoring the system during periods of operation, and had failed to detect the declining trend in drain line flow rate. In response to this violation, the licensee changed the system operating procedure to include drain line flow verification during system operation to be performed by operators. The drain lines were removed, and new lines were connected to a vertical run of pipe such that sediment would not collect at the drain lines. The drain lines were routed so that flow would be readily visible as it entered a drain funnel, facilitating flow rate monitoring. Inspectors walked down the modifications and observed flow from the drains during system operation. Corrective actions appeared to adequately address the drain line plugging and inadequate monitoring of drain line performance. This item is closed.

E8.9 (Closed) Violation 50-341/96007-08: Failure to Implement Modification to RHRSW Drain Lines as Specified in Safety Evaluation. NRC inspectors observing implementation of Engineering Design Package 28556 identified that the modification was simultaneously performed on both lines in Division 1, contrary to specific instructions in Safety Evaluation 96-0086 to perform one at a time. The inspectors determined that the work instructions did not include all implementation instructions and restrictions listed in the safety evaluation. The work was planned to be performed with the system operable and in standby, so the safety evaluation stipulation was intended to limit the amount of water which could leak into the RHRSW pump room if the system automatically initiated.

The licensee performed an analysis of the potential impact of simultaneously performing work on both drain lines in a division, and determined the impact was acceptable in that it would not impact equipment operability or personnel safety. The safety evaluation was then revised to allow simultaneous performance during work on the other division.

The inspectors reviewed several administrative procedures which were changed to strengthen interfaces of safety evaluation preparation, work planning, and modification preparation to ensure that all implementation instructions are included in work instructions. The inspectors considered the revised requirements to be adequate to ensure work instructions for modifications incorporated safety evaluation implementation requirements. Training documents were also reviewed and found to be adequate. Based on the above review, this item is closed.

IV. Plant Support

No significant issues were identified in the Plant Support functional area during this inspection period.

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 June 30, 1997. The licensee acknowledged the findings presented.

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

X3 Management Meeting Summary

On May 21, 1997, B. Beach, Regional Administrator, Region III, R. Gardner, Acting Deputy Director, Reactor Projects, Region III, and M. Slosson, Acting Director for the Division of Reactor Program Management, Office of Nuclear Reactor Regulation (NRR) visited the site to discuss plant performance and observe the condition of the plant. The three toured the plant extensively and monitored control room condition and operator performance. A meeting with P. Fessler, Plant Manager, and D. Cobb, Operations Superintendent, was held to discuss plant performance and improvement initiatives in personnel performance and plant design improvements. B. Beach and M. Slosson also met briefly with L. Gipson and P. Borer, Senior Vice President and Assistant Vice President, respectively.

Also, on May 22, J. Hannon, Director, Project Directorate III-I, Reactor Projects III/IV, NRR, visited the site. Interviews with senior licensee management and staff were held to discuss plant performance, particularly in the area of maintenance.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Bartman, Chemistry Supervisor
S. Booker, Electrical Maintenance Superintendent
D. Cobb, Operations Superintendent
W. Colonnello, Work Week Manager
R. Delong, Superintendent, System Engineering
T. Dong, NSSS, Technical Engineering
P. Fessler, Plant Manager
J. Greene, Superintendent of Maintenance Support
K. Howard, Superintendent, Plant Support Engineering
E. Kokosky, Superintendent, RP and Chemistry
J. Korte, Director, Nuclear Security
R. Laubenstein, Mechanical Maintenance Superintendent
P. Lynch, NSS, Operations
R. Matthews, I&C Maintenance Superintendent
W. Miller, Work Week Manager
J. Moyers, NQA Director
N. Peterson, Acting Director, Nuclear Licensing
J. Plona, Technical Director
T. Schehr, Operating Engineer
J. Sweeney, Supervisor of Audits, NQA

NRC

A. Kugler, Fermi 2 Project Manager, NRR
A. Ulses, Reactor Systems Branch, NRR
R. Glinski, Reactor Inspector, Region III

CHECK PROCEDURES

INSPECTION PROCEDURES USED

IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-341/97007-01	VIO	Failure To Comply With TS 3.8.1.1
50-341/97007-02	NCV	Data Inadequate to Ensure Component Operability
50-341/97007-03	VIO	Failure to Prevent Recurrence of CST Line Freezing
50-341/97007-04	IFI	RCIC System Outage Exceeded Established Outage Times due to Emergent Work Issues
50-341/97007-05	VIO	Failure to Perform SR 4.4.1.1.2 Within Required Period
50-341/97007-06	VIO	Failure to Comply with PMT Requirements
50-341/97007-07	NCV	Failure to Perform TS Surveillance for TSV and TCV
50-341/97007-08	IFI	Evaluation of HPCI and RCIC Operability When Suction is Aligned to the Suppression Pool

Closed

50-341/95008-04	IFI	Control Rod Position Indication Probe Problem Investigation Results
50-341/96003-04	IFI	Turbine Steam Line Drain Valve Motor Operator separated From Valve
50-341/96004-05	VIO	Failure to Test Residual Heat Removal Service Water Drain Lines
50-341/96004-10	IFI	RCIC Steam Admission Valve Seat Leakage Evaluation
50-341/96006-05	VIO	Inadequate Corrective Actions for RHRSW Drain Line Plugging
50-341/96007-01	IFI	Placement of Scaffold Near Safety-Related Equipment
50-341/96007-05	VIO	Scaffolding in Auxiliary Building Not Inspected by Operators
50-341/96007-08	VIO	Failure to Implement Modification to RHRSW Drain Lines as Specified in Safety Evaluation
50-341/96010-09	IFI	RCIC Returned to Service Without PMT to Verify Operability With Work Package Partially Complete
50-341/96013-06	VIO	Inadequate Corrective Actions for EDG 12 Muffler Rattle
50-341/96013-07	VIO	Failure to Submit a TS Change Request for RBM

50-341/96016-01	IFI	Clarity of ESF Reportability Decisions
50-341/96016-07	URI	Condensate Storage Tank Freeze Protection

Discussed

50-341/95012-07	IFI	CTG 11-1 Did Not Meet Committed Reliability
50-341/96003-03	IFI	Turbine Steam Control Valve Vibration

LIST OF ACRONYMS USED

AC	Alternating Current
CST	Condensate Storage Tank
CTG	Combustion Turbine Generator
DER	Deviation Event Report
DFP	Diesel Fire Pump
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FRAP	Fuel Reliability Action Plan
GSW	General Service Water
HPCI	High Pressure Coolant Injection System
HSS	High Speed Stops
IFI	Inspection Followup Item
LCO	Limiting Condition for Operation
MDCT	Mechanical Draft Cooling Tower
NASS	Nuclear Assistant Shift Supervisor
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSS	Nuclear Shift Supervisor
PMT	Post Maintenance Testing
PST	Performance Scheduling and Tracking
RBCCW	Reactor Building Closed Cooling Water
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RRMG	Reactor Recirculation Motor Generator
SAC	Starting Air Compressor
SR	Surveillance Requirements
TCV	Turbine Control Valve
TS	Technical Specification
TSV	Turbine Stop Valve
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
VIO	Violation