95-09
PRR

September 19, 1995

Mr. D. R. Gipson
Senior Vice President
Nuclear Generation
The Detroit Edison Company
6400 North Dixie Highway
Newport, MI 48166

SUBJECT: NRC INTEGRATED INSPECTION REPORT NO. 50-341/95009

Dear Mr. Gipson:

This refers to the inspections conducted by Messrs. A. Vegel, C. O'Keefe, and others of this office from June 24 through August 15, 1995. The inspection included a review of activities authorized for your Fermi 2 facility. At the conclusion of the overall inspection effort, the findings from each inspection were discussed with those members of your staff identified in the enclosed report at an integrated inspection exit.

Areas examined during the inspection are identified in the report. Within these areas, the inspections consisted of a selective examination of procedures and representative records, interviews with personnel, and observation of activities in progress. The purpose of the inspection effort was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements.

The results of the inspection revealed both strengths and weaknesses in performance. Strengths were noted in radiation protection, chemistry performance, the fire protection program, and operator response to two events. However, several weaknesses associated with the engineering efforts for some of the modifications implemented during the last refueling outage were also identified. We understand that many of the 265 modifications implemented improved operation and overall plant material condition. However, several fundamental engineering process problems were identified associated with the sample of modification we evaluated. These problems included inadequate management oversight of engineering activities, insufficient knowledge of the design by some members of the engineering staff, insufficient design reviews by several levels of staff and management, poor interface between engineering groups, vendors, and contractors, insufficient pre-installation or pre-startup testing to simulate plant conditions, and poor work control practices. We understand that your engineering management team has committed to identify root causes and aggressively and promptly pursue resolutions to prevent recurrence. In addition, numerous initiatives were undertaken to improve engineering performance based on your own self-assessment. We commend you on this effort. Nevertheless, material conditions at the plant remain a concern to us and resolution of some significant repetitive equipment problems continues to merit rigorous engineering resolution.

During this inspection period, as in several previous inspections, poor identification and communication of equipment deficiencies continued to be a problem. NRC inspectors continued to be the first to identify problems to your management team which were known at the operator and system engineer level. Poor communication of problems to management may impede the timely review and assessment of equipment problems. For example, the water hammer events in the reactor water cleanup and condensate systems during this inspection period both had occurred previously.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation. The violation is of concern because it indicated a lack of sensitivity to the large number of failures experienced during emergency lighting tests. Contrary to industry practice of 100 percent testing of emergency lighting, your program tested only 25 percent. This reduced sample and resulting greater time between tests should have increased your sensitivity to failure; yet your program was insensitive to identifying a trend in the large number of failures identified by the inspectors.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC's Public Document Room. To the extent possible, you response should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction. However, if you find it necessary to include such information, you should clearly indicate the specific information that you desire not to be placed in the PDR, and provide the legal basis to support your request for withholding the information from the public.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

/s/G. C. Wright for

W. L. Axelson, Director
Division of Reactor Projects

Docket No. 50-341
License No. NPF-43

Enclosure:
1. Notice of Violation
2. Inspection Report
No. 50-341/95009

cc w/encl: J. Conen, Principal
Compliance Engineer
P. A. Marquardt, Corporate
Legal Department
James R. Padgett, Michigan Public
Service Commission
Michigan Department of
Public Health
Monroe County, Emergency
Management Division

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We will gladly discuss any questions you have concerning this inspection.

Sincerely,

M. P. Phillips, Chief
Reactor Projects Section 2B

Docket No. 50-341
License No. NPF-43

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   No. 50-341/95009

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NAME	Du Pont/dtp		Gardner		Creed		~~Phillips~~	
DATE	09/14/95		09/14/95		09/14/95		09/14/95	

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NOTICE OF VIOLATION

Detroit Edison Company

Docket No. 50-341
License No. NPF-43

During an NRC inspection conducted on June 24 - August 15, 1995, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600 (60 FR 34380), June 30, 1995, the violation is listed below:

10 CFR 50, Appendix B, Criterion XVI, states, in part, that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above, from November 1994 to August 1995, the licensee failed to identify and take prompt corrective action for a high failure rate (14 of 41) of emergency lighting units that were needed for operation of safe shutdown equipment (341/95009-05).

This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Detroit Edison Company is hereby required to submit a written statement or explanation to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D. C. 20555 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Lisle, Illinois,
this 14th day of September 1995

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-341/95009

FACILITY
Fermi Nuclear Plant, Unit 2

License No. NPF-43

LICENSEE
Detroit Edison Company
6400 North Dixie Highway
Newport, MI 48166

DATES
June 24 through August 15, 1995

INSPECTORS
A. Vegel, Senior Resident Inspector
C. O'Keefe, Resident Inspector
Z. Falevits, Lead Engineering Assessment Inspector
A. Dunlop, Reactor Inspector
G. Replogle, Reactor Inspector
S. Dupont, Reactor Inspector
R. Langstaff, Reactor Inspector
S. Stasek, Senior Resident Inspector, Davis-Besse
M. Bielby, Reactor Operations Assessment Representative
D. Schrum, Reactor Inspector

APPROVED BY

M. P. Phillips, Chief
Reactor Projects Section 2B

9/14/95
Date

AREAS INSPECTED

An integrated inspection effort by resident and region-based inspectors of Fermi's performance in the areas of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspections were performed for non-routine events and for certain previously identified items. Temporary Instruction (TI) 2515/128, Revision 1, "Reactor Vessel Water Level Instrumentation Modifications," was closed based on results of this inspection.

RESULTS

Assessment of Performance

The following assessments were based on activities during this report period.

The inspectors concluded that overall performance within the area of OPERATIONS was good.

- Operator responses to a reactor water cleanup transient and a reactor sample line leak were prompt and effective.

- Communication of equipment problems between other departments, operations, and management continued to be a weakness.

- The licensee was slow to recognize indications of cooling water system degradation and poor material conditions, especially with the general service water (GSW) system.

The inspectors concluded that performance within the area of MAINTENANCE was mixed.

- Overall, maintenance activities were planned and executed well.

- Some testing activities indicated weaknesses in procedure adequacy or technician preparation.

- Fire protection equipment maintenance was mostly good, except for a failure to recognize the cause for a significant number of failures in emergency lighting.

The inspectors concluded that performance in the area of ENGINEERING was poor.

- Several fundamental engineering process problems were identified, including inadequate management oversight of engineering activities, insufficient knowledge of the design by engineering staff, insufficient design reviews by several levels of staff and management, poor interface between engineering groups and vendors/contractors, insufficient pre-installation or pre-startup testing to simulate plant conditions, and poor work control practices.

- Inadequate inter- and intra-organizational communications continued to hamper engineering effectiveness.

- Engineering began a significant self-improvement effort, which was not far enough along to be assessed.

The inspectors concluded that overall performance in the area of PLANT SUPPORT was excellent.

- Radiation protection and chemistry performance continue to be excellent.

- The fire protection program was also excellent; however, inadequate maintenance support resulted in a violation related to emergency lighting failures.

- The annual emergency preparedness exercise conducted during this inspection period was good.

- Repeated loss of power to the building housing the emergency operations facility during this inspection period was a weakness.

- Security effectiveness was mixed; while the guard force was effective in dealing with storm-related system problems, they failed to promptly identify and compensate for a component degradation that they inadvertently caused.

The inspectors concluded that SELF-ASSESSMENT efforts in the engineering area were good.

- As a result of the problems encountered with certain modifications implemented in RF04, the engineering organization conducted a self-assessment of performance. Because initial efforts in this regard were unsatisfactory, the licensee created an engineering improvement organization that performed an effective root cause evaluation for the RF04 problems identified.

Summary of Open Items

Violations: Identified in Section 4.6.2
Unresolved Items: Identified in Sections 3.2 and 3.5.1
Inspector Follow-up Items: Identified in Sections 3.3, and 3.9.1
Non-cited Violations: Identified in Section 3.8.1

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of ongoing plant operations. The plant operated at or near full power for the entire inspection period. Short term power reduction was conducted during the inspection period for control rod adjustments and turbine valve testing. Overall, operator performance was good. Operator responses to a reactor water cleanup (RWCU) transient and a reactor sample line leak were prompt and effective. Communication of equipment problems between other departments, operations, and management continued to be a weakness. The licensee was slow to recognize indications of cooling water system degradation and poor material conditions, especially with the general service water (GSW) system.

1.1 Inadequate Procedure Results in RWCU Hydraulic Transient On July 25, with the plant operating at 95 percent reactor power, a pressure transient occurred in the RWCU system due to the order of valve manipulations specified in the restoration procedure. During performance of post maintenance testing on the Inboard Isolation Motor Operated Valve G3352-F001 during restoration of the system, the valve tripped on excessive torque in the mid position. Simultaneously, a loud noise was heard in the control room and a high vibration alarm was received for Drywell Cooling Fan Number 6. Following the event, walkdowns of the accessible portions of the system were conducted, with only minor insulation damage noted. The valve was subsequently restroked successfully. Licensee investigation determined the apparent cause for the event was void formation between the inboard and outboard RWCU containment isolation valves due to system cooldown, coupled with inadequate filling and venting prior to system restoration. When Inboard Valve G3352-F001 was opened, water at reactor pressure rapidly filled the void, causing a water hammer event. The licensee modified the RWCU restoration procedure to ensure the pipe segment between the two valves was adequately filled. Subsequently, the RWCU system was restored to service without further problems.

Based on discussions with the licensee's staff, similar RWCU hydraulic transients had occurred previously since 1988. However, apparently no comprehensive effective corrective action was taken to prevent recurrence. The water hammer event on July 25 was documented in Deficiency Event Report (DER) 95-0531. An engineering evaluation of the effect on the RWCU system was in progress, though preliminary results indicated that sufficient piping design margin existed. The inspectors will continue the followup licensee evaluation of the event during a routine inspection of engineering activities.

1.2 Prompt Response to Reactor Sample Line Leak Caused by Flowmeter Glass Failure On August 1, at approximately 12:50 a.m., a chemistry technician reported a 0.5 gpm reactor coolant leak from the process sample sink area, which was aligned to the recirculation system at the time. He requested control room personnel to isolate the leak by shutting the recirculation sample line containment isolation valves manually. This conservative action was proper, and probably avoided a personnel contamination event due to the spray from the leak and the proximity of the local manual isolation valves. Quick control room response limited the volume of the spill. Radiation protection responded quickly to the spill, performed personnel and area contamination surveys, and promptly decontaminated the area. Approximately 120 square feet had been contaminated to a level of 90,000 dpm.

Investigation revealed the source of the leak to be a cracked flowmeter glass. The glass was rated for 100 psig, with an expected pressure of 15-30 psig in operation. The inline relief valve was tested and determined not to be a factor in the glass failure. Licensee corrective actions included initiation of DER 95-0549 to document event occurrence and track corrective actions. Licensee corrective actions and root cause determination will be followed during routine inspections.

1.3 Engineered Safety Feature Systems Material Condition Indicate a Lack of Attention to Detail During inspections of engineered safety feature (ESF) system, the accessible portions of the following systems were walked down.

- Emergency Diesel Generators 12, 13, and 14
- Emergency Equipment Cooling Water System
- Standby Liquid Control System
- Core Spray System

The diesel generator rooms' appearance were good and freshly painted. However, no maintenance work request was written for Fuel Oil Sample Valve R3006-F156, which was leaking fuel oil. In another diesel room, with the diesel running, the inspectors identified various leaks on the diesel engine and noted that mechanical joints were painted over. In addition one valve stem and several instances of rust were painted over.

On August 1, 1995, inspectors identified that the air positioner for Core Spray Keep Fill Valve E21F026A was short cycling. Subsequent licensee investigation determined the air positioner was not operating properly and a work request was written to correct the problem. Based on these examples of problems found in the plant where no DER or work request had been initiated, continued licensee attention is warranted to ensure that potential equipment problems are identified and corrected consistent with the safety importance of the systems.

1.4 Poor Material Condition of General Service Water System (GSW) and Reactor Building Closed Cooling Water (RBCCW) System Degradation

1.4.1 General Service Water System Repetitive Equipment Problems This system was ranked as the eighth most important system in the licensee's assessment of system importance based on the Fermi Individual Plant Examination (IPE). However, given its importance, it did not appear that the system was receiving commensurate safety focus, as exemplified by the following problems:

Repetitive P41-F012 GSW test valve failures: The P41-F012 Valve failed and was replaced in August 1994 and again in June 1995. The P41-F012 is in the test return line, which was normally used to test an out of service GSW pump. This valve design was not intended to be throttled. However, the licensee utilized the test line as a bypass line to control system pressure when valves in the normal bypass line failed due to severe wear. The bypass flow throttle valves were subsequently replaced with orifices, but the licensee opted to continue to use the P41-F012 flow-path with the "normal" bypass flow-path as a backup.

Corrective actions appeared to be weak in that the cause of the two failures was not adequately addressed. The P41-F012 failed again because the installed valves were not designed for throttling flow in the harsh environment. The high amount of silt in the system, combined with severe cavitation, periodically destroyed the valve. The site considered purchasing an appropriate valve for this application but considered the additional cost to be prohibitive. The licensee planned to have a contractor evaluate the design of the system and to make design change recommendations. The P41-F012 Valve will continue to be used in the same application until the contractor finishes the evaluation.

Repetitive thru-wall pipe cracks downstream of P41-F012: During a system walk-down, the inspectors identified two pin hole leaks in piping just downstream of P41-F012. This was a repetitive pipe failure as evidenced by a repaired weld (on the other side of the pipe) with the word "Leak" written close to the repair. Subsequently, the licensee replaced that section of piping.

Repetitive pump packing failures: There were repetitive excessive packing leaks on the GSW pumps. The system engineer was aware of the problem and indicated that the failures could be prevented by establishing a program to periodically inspect and tighten the packing. However, he further claimed that cumbersome work control procedures made the establishment of an effective packing maintenance program difficult. The inspectors considered the barriers to fixing the repetitive packing problems to be a weakness in the minor maintenance program.

Failure to include the system in an erosion/corrosion program: Although the system has a history of erosion/corrosion related thru-wall pipe leaks and repetitive valve failures, the licensee was still not actively monitoring for erosion or corrosion in the GSW system. The inspectors considered the approach to the repetitive erosion/corrosion problems to be reactive, rather than proactive, and was indicative of a poor safety focus when dealing with these types of problems, especially given the system's importance in core damage reduction taken credit for in the IPE. At the end of the inspection period, the licensee initiated action to determine the scope of the problem in the system.

Number 4 strainer oil leak: During a walkdown, an oil leak was noted coming from the gear box associated with the number 4 Strainer Backwash System. The system engineer indicated that the leak had existed for three weeks and a work request was written. However, the inspectors did not consider the corrective measures to be prompt. There was no way of checking the oil level in the gear box and gear failure could occur without precursors, potentially disabling the backwash capability of the strainer.

Need to operate five pumps to maintain plant cooling requirements: The GSW system was originally intended to be operated with a maximum of four GSW pumps, with one installed spare. However, the site occasionally had to operate the fifth GSW pump to meet plant needs during warm weather conditions.

Silting and mussels were clogging GSW coolers: The GSW system was known to contain silt and dead zebra mussel shells. A high silt level in the service water bay (approximately seven feet) resulted in problems with the GSW strainers (holes) and the introduction of debris in the system. This was a significant problem because the first stage service water impellers were approximately 17 inches from the bottom of the bay. One GSW pump failure was attributed to the silt problem. As corrective measures, the service water bay was cleaned during the previous outage and procedural controls were established to limit the amount of zebra mussel and silt buildup. The controls appeared to be acceptable but the existing debris in the system continued to cause periodic problems, such as flow restriction in the RBCCW and turbine lube oil heat exchangers.

1.4.2 <u>Reactor Building Closed Cooling Water (RBCCW) Unable to Meet Design Specifications</u> There were indications that the RBCCW system was operating in a degraded condition, partially due to degradation problems with the GSW system, which provided the cooling water for RBCCW.

The RBCCW system appeared to have degraded when compared to the original design basis of the system. Through discussions with licensee personnel and a review of historical documents, the inspectors determined that the original design basis of the drywell cooling system, which takes cooling water from the RBCCW system, was to maintain drywell temperature at 135 degrees with a maximum lake temperature of 85 degrees. However, after an RBCCW heat exchanger was cleaned, with lake temperature 74 degrees, drywell temperature was still 138 degrees. This seemed to indicate that the RBCCW system had degraded since initial construction. In order to compensate, the licensee planned to use the safety-related emergency equipment service water (EESW) system to maintain drywell temperatures below Technical Specification limits during warm weather. A degraded GSW system and drywell coolers could also be contributors to the decrease in RBCCW system performance.

The licensee indicated that the operational problems associated with the GSW system, and its potential effects on RBCCW, were associated with design deficiencies versus system degradation. The licensee planned to use the contractor evaluation and recommendations for improving the GSW design and make improvements to the system during the next refueling outage. The NRC will continue to monitor the licensee's progress at addressing RBCCW system deficiencies during normal inspection activities.

1.5 <u>Follow-up on Non-Routine Events</u> NRC Inspection Procedures 90712 and 92700 were used to perform a review of written reports of non-routine events. The following items were closed with no significant strengths or weaknesses noted.

1.5.1 (Closed) LER 341/93014, Revision 1 Automatic reactor shutdown following the December 25, 1993, main turbine failure. The details of the event and inspection results were documented in Inspection Reports 50-341/93028 and 50-341/94003. Additionally, the results of the Augmented Inspection Team was documented in Inspection Report 50-341/93029. Based on these inspections, this LER is closed.

1.5.2 (Closed) LER 341/94001, Revision 0 Loss of Division I power due to weather conditions and a failed breaker. The details of the event and inspection results were documented in Inspection Report 50-341/94005. Based on this inspection, this LER is closed.

1.5.3 (Closed) LER 341/95003, Revision 0 Reactor water level instrumentation error - leakage from reference leg. On February 27, 1995, with the plant cold, all control rods inserted, and the mode switch in Startup, the narrow range reactor water level instrumentation failed a channel check surveillance because the difference between channels exceeded five inches. Over the next 12 hours, efforts to correct the level divergence, which grew to 10 inches, were unsuccessful. An Unusual Event was declared when a shutdown was required by Technical Specifications (TS) 3.3.1 and 3.3.2; the mode switch was placed in Shutdown and the Unusual Event was immediately terminated. The division 2 reference leg was refilled, and the indicated divergence was corrected, possibly indicating some draindown of that reference leg. The reactor water level instrumentation backfill system was not in service at the time, per procedure, and was not related to the indication problem. This event is not similar to reactor water level divergence problems seen at Pilgrim, which were related to noncondensible gas evolution in the reference legs during depressurization. The licensee believed the draindown to be leakage through an equalizing valve, and developed a plan to monitor for similar problems during a future outage. The inspectors identified no additional concerns. This LER is closed.

1.6 Followup on Previously Opened Items A review of previously opened items (violations, unresolved items, and inspection follow-up items) was performed per NRC Inspection Procedure 92901. No significant strengths or weaknesses were identified.

1.6.1 (Closed) Inspection Followup Item (IFI) 341/93013-01 Problems with Valve G33-F053B remote operation and review of potential applicability to other reach-rod operated valves. Valve G33-F053B reach rod problems were corrected and a valve position label plate was placed on a nearby wall to correctly identify its position. Plant and system engineering conducted a review of the population of valves with reach rods and determined that a generic problem did not exist.

1.6.2 (Closed) Unresolved Item 341/93016-01 Weaknesses in the conduct of an observed firewatch round. Licensee corrective actions included clarification of firewatch responsibilities. Training has been conducted on the updated responsibilities. The inspector made an hourly rounds tour with a firewatch and determined that the firewatch was knowledgeable of responsibilities, management expectations, and was cognizant of plant conditions that affected his duties.

1.6.3 (Closed) IFI 341/93016-03 Frequent transfer of the high pressure coolant injection (HPCI) suction from the condensate storage tank to the torus. The licensee's evaluation identified several causes for the transfer frequency. In addition, several torus level instruments were found out-of-calibration. Engineering evaluated the design tolerance of the transfer setpoints and determined that the design was vulnerable to instrument error and drift. Lastly, the licensee determined that a small amount of in-leakage to the torus existed from the safety relief valves (SRVs). The effected instruments were immediately calibrated. Additionally, the instruments were modified with transmitters that had narrower spans to reduce the effects of instrument errors. The SRVs were repaired during the fourth refueling outage. The licensee's corrective actions were effective in preventing frequent unnecessary suction transfer.

1.6.4 (Closed) Violation 341/93018-01 Nuclear power plant operator (NPPO) failed to follow an annunciator response procedure when the low gland steam pressure annunciator alarmed. All operating personnel received training on the event and on management's expectations concerning panel awareness during transients. Additionally, the reactor scram abnormal operating procedure was revised to ensure the proper operation of the gland seal system. Both the specific and broader concerns of the issue were addressed and corrective actions were effective in preventing recurrence.

1.6.5 (Closed) IFI 341/93028-03 Evaluation of long term effects of oil intrusion into the turbine building heating, ventilation, and air conditioning (TBHVAC) exhaust ductwork. The licensee determined that the oil intrusion did not have any affect on the TBHVAC operation or contribute to the May 21, 1994, exhaust fan failure. The inspector reviewed the licensee's evaluation and agreed with the conclusion.

1.6.6 (Closed) Violation 341/94007-01 Failure to follow procedures causes inadvertent loss of power to electrical Buses 68K and 72T. The inspector reviewed licensee investigation results and corrective actions documented in DER 94-0187. The inspectors concluded that corrective actions were adequate.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and testing activities. Overall, maintenance activities were planned and executed well. Some testing activities indicated weaknesses in procedure adequacy and/or technician preparation. Fire protection equipment maintenance was mostly good, except as described in Section 4.4.2.

2.1 Observation of Work and Testing The following maintenance and surveillance activities were observed:

- Division I EECW Pump/Valve Operability Test
- EESW Pump and Valve Operability Test
- EDG 13 Start and Load Test
- SDV High Water Level Calibration/Functional Check, Channel B1/B
- SDV High Water Level Calibration/Functional Check, Channel B2/D

- Turbine Generator Mechanical Overspeed On Load Test
- 480V Unit Substation Regulator 72F Repair
- Main Lube Oil Cooler Cleaning
- Reactor Water Cleanup System Outage

For all activities observed, the inspectors noted safe work practices. The activities observed were performed satisfactorily in accordance with procedures. Some problems were identified as discussed below.

2.2 Weaknesses in Procedural Detail or Crew Preparation The inspectors noted two examples where surveillance activities were not properly completed on the first attempt. In both cases, the inspectors considered the examples as indicators of weaknesses in the adequacy of technician preparation and or procedure completeness.

2.2.1 Inconsistent Crew Response to Calibration of Scram Discharge Volume High Water Level Channel On July 24, 1995, during performance of Surveillance 44.010.076, RPS-Scram Discharge Volume High Water Level Calibration/Functional Check, Channel B1/B, the I&C technicians were unable to calibrate the detector. Operations was informed that the calibration failed, the detector was declared inoperable, and a limiting condition for operation (LCO) action statement was entered. Upon discussing the problem with a supervisor, the technicians returned and performed a number of pressurization and venting cycles on the variable leg of the detector line using the air rig connected for the surveillance to remove residual moisture. The detector was checked again and found to be giving repeatable results, but a calibration adjustment was required. The detector was returned to service approximately 5-1/2 hours after starting the surveillance, and the LCO was exited.

The following shift, Surveillance 44.010.078, RPS-Scram Discharge Volume High Water Level Calibration/Functional Check, Channel B2/D, was performed. The new shift was told that the lines had to be blown dry, so they performed the same pressurization and venting cycles on the D detector, but this time before taking data. The "D" instrument was also found to require calibration. No LCO was entered the second time because the technicians noted that only the highest data point was required to pass per the LCO, which it had. Additionally, even though the "D" instrument required calibration, the inspectors identified that "None" was recorded in the discrepancies block of the surveillance tracking form, and the surveillance trend record indicated that it was performed satisfactorily (i.e. recorded as no calibration was required).

In addition to the performance differences between the two crews, the inspectors were concerned that poor supervisory review could have impeded trending if not identified by the NRC and corrected. Both crews performed steps not in the surveillance procedure in order to make the surveillance work; however, the licensee felt this was within the skill of the craft and no additional procedural steps were necessary. I&C management expectations were that the second crew performed properly, with the exception of the administrative errors; and the first crew unnecessarily entered the LCO. Licensee management felt that both crews should have known as craft skill that this type of detector needs to be blown dry prior to calibrating with air. However, given the disparity in crew performance on this job, a Professional Advice form was submitted to add information to ensure water is completely removed prior to taking as found data. Deviation Event Report 95-0579 was written to document this issue.

The inspectors were also concerned that, by performing steps that have not been reviewed by engineering, the calibration and operability of the detectors could have been compromised. In response to inspectors' concerns, plant engineering reviewed this issue and determined that the practice of using pressurization and venting cycles to remove moisture was acceptable and did not adversely affect instrument accuracy or operability.

2.2.2 Electric Fire Pump Surveillance had to be Re-performed due to Improper Pitot Tube Position On July 27, 1995, during surveillance testing of the Fermi 2 electric fire pump, the flow rate check was unsatisfactory. The test was re-performed based on past experience that a pitot tube position adjustment was required to get accurate results. The licensee identified this problem and documented it in DER 95-0546.

2.3 Vital Bus 72F Regulator Repair Well-Planned The internal cooling fan for the voltage regulator for vital Bus 72F exhibited signs of impending bearing failure. The licensee performed an operability evaluation to determine that continued operation was acceptable if the fan failed in service with the reactor at power. Prior to replacing the fan, a pre-job walkdown identified that personnel protection against exposed live bus bars was desirable. The licensee then designed a dielectric shield for use during the replacement. Operators conducted a thorough brief to cover contingency actions in the event of a problem. The repair was performed in a controlled manner when no operator distractions existed. Inspectors determined that preparations and coordination of different organizations in support of this repair were excellent.

2.4 Power Ascension Testing During this inspection period power ascension testing activities were on hold. Power ascension activities are planned to recommence after seasonal load demand has subsided. This item will remain open pending completion of inspector evaluation of power ascension activities.

2.5 Follow-up on Previously Opened Items A review of previously opened items (violations, unresolved items, and inspection follow-up items) was performed per NRC Inspection Procedure 92902. No significant strengths or weaknesses were identified.

2.5.1 (Closed) Violation 341/94005-04 Maintenance personnel operated instrument valves. The licensee conducted extensive training with all maintenance personnel. Additionally, the superintendent of maintenance held meetings with all maintenance personnel to reinforce the expectations for the proper conduct of maintenance activities. The corrective actions were appropriate and effective in preventing recurrence.

2.5.2 (Closed) Unresolved Item 341/94013-01 Reactor cavity draining evolution potential for draining down the vessel. On October 7, 1994, during the performance of Surveillance Procedure 44.010.061, "Functional Test of the SCRAM Test Switches and Backup SCRAM Valve Operation," reactor water was drained from the vessel to the torus sump via the control rod drives. This evolution was forwarded to the NRC's Office of Nuclear Reactor Regulation for review to determine if this constituted an operation with the potential to drain down the reactor vessel (OPDRV), since such an operation was prohibited by Technical Specifications. By letter dated August 28, 1995, from Mr. J. N. Hannon, NRR to Mr. W. L. Axelson, Region III, NRR concluded that "although many operational problems occurred, the reactor vessel was not close to being drained and Fermi 2 was not in an OPDRV condition." Based on this conclusion, this item is closed.

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function. In addition, a followup inspection of engineering and technical support activities was conducted this inspection period. Several fundamental engineering process problems were identified, including inadequate management oversight of engineering activities, insufficient knowledge of the design by engineering staff, insufficient design reviews by several levels of staff and management, poor interface between engineering groups and vendors/contractors, insufficient pre-installation or pre-startup testing to simulate plant conditions, and poor work control practices. In addition, inadequate inter- and intra-organizational communications continued to hamper engineering effectiveness. As a result of the problems encountered with certain modifications implemented in RF04, the engineering organization conducted a self-assessment of performance. Because initial efforts in this regard were unsatisfactory, the licensee created an engineering improvement organization that performed an effective root cause evaluation for the RF04 problems identified. The Engineering organization then began a significant self-improvement effort, which was not far enough along to be assessed.

3.1 Continued Problems with Communications and Interface Between Engineering and Other Groups During several previous inspections, NRC personnel have identified weaknesses in the area of communications. The inspectors concluded that the five communication deficiencies that follow are indicative of a continuing weakness and demonstrated the need for additional management attention in this area.

3.1.1 Inadequate System Turnover The inspectors noted that the RBCCW system engineer had problems answering questions about the system and was not well informed about system problems. The engineer stated that he had the system approximately three months and had not received a turnover from the previous system engineer. Discussions with the engineer's supervisor revealed that the licensee had previously identified this concern and had taken steps to correct the problem, including making plans to have the previous system engineer return to the site for an appropriate turnover.

3.1.2 Failure to Communicate Problems to the Reactor Building Closed Cooling Water (RBCCW) System Engineer During the week of June 26, 1995, drywell temperature was approaching the Technical Specification limit of 145 degrees Fahrenheit. At one point, the temperature was 144.7 degrees. The problem was known to be associated with the RBCCW heat exchangers, but the system engineer was not informed of the trouble until the drywell temperature was above 144 degrees. It was the NRC resident inspector who informed the engineer of the concerns. Additionally, a maintenance supervisor was aggressively, but informally, performing system monitoring (on his own initiative) of the RBCCW heat exchangers, but failed to communicate the results of his efforts to the RBCCW system engineer.

3.1.3 Failure to Follow the Program for Repetitive Problems A maintenance supervisor was informally, but aggressively, attempting to resolve repetitive GSW pump packing failures and problems with the RBCCW heat exchangers. However, the supervisor did not write a DER to address the repetitive problems. The failure to write the DERs was not of major safety-significance, but the intent of the program was to ensure that repetitive problems received appropriate management and engineering attention to ensure that they did not recur. Subsequently the licensee established a surveillance for packing adjustments and performance trending. Also, DER 95-0566 was initiated on this issue for trending purposes.

3.1.4 Failure to Communicate Condensate System Transient On July 26, 1995, an inspector observed excessive pipe movement and heard a loud bang from the area of the normal and emergency condenser relief station. The inspector informed the control room of the event occurrence. Subsequent licensee walkdowns of the affected piping identified numerous pipe supports that were damaged or improperly configured. The root cause of the event was under review at the conclusion of this inspection period. The licensee determined that the transient had also occurred previously; system engineers had noted excessive pipe movement on July 15. Although engineers were investigating the cause, no DER was written to document and communicate the abnormal occurrence until July 26, following NRC observation of the transient.

3.1.5 Failure to Communicate Core Spray Keep Fill Valve Problems On August 1, 1995, a positioner problem with the Core Spray Keep Fill Valve E21 F026A, was not communicated to the control room operators until prompted by NRC inspectors.

3.2 50.59 Safety Evaluation Screening Process may be Inadequate The inspectors had concerns with the licensee's process to determine if a safety evaluation was required. Fermi's philosophy on 50.59 Safety Evaluations was that a safety analysis need not be performed unless the words in the Updated Final Safety Analysis Report (UFSAR) were changed. The licensee failed to recognize that a component, system or function that is described in the safety analysis report can be adversely affected by a newly added design change (e.g., pressure regulator modification, PIP cable assemblies modification), or by a change to a part (e.g., pump impeller or RPS system relay) which affects existing system functionality, but which does not change the actual words in the UFSAR. A 50.59 Safety Evaluation, appears appropriate to determine whether the proposed change affects the design and/or function of any SSC described in the UFSAR. This issue will be tracked as an Unresolved item pending receipt of an interpretation of 50.59 applicability from NRR (341/95009-01).

3.3 Questionable Emergency Equipment Cooling Water (EECW) Heat Exchanger Rating On July 11, 1995, the inspectors observed performance of the EECW Pump and Valve Operability Surveillance Test 24.207.08, and noted an indicated EECW flow rate of approximately 1670 gpm. Vendor specifications and UFSAR Table 9.2-3 for the EECW heat exchanger listed 1450 gpm shell side flow (emergency equipment service water flows through the tube side). The inspectors questioned whether the 1670 gpm flow rate observed was acceptable, and whether the heat exchangers would be susceptible to flow induced vibration damage at this flow. Licensee preliminary evaluations determined that the increased flow rates were acceptable; however, no engineering calculation or documented analysis was available to support this conclusion. Pending inspector review of the licensee's evaluation of the acceptability of increased shell flow in the EECW heat exchanger this item will be tracked as an Inspection Followup Item (341/95009-02).

3.4 (Closed) Temporary Instruction (TI) 2515/128, Revision 1 Plant hardware modification to reactor vessel water level instrumentation (NRC Bulletin 93-03). The objective of this TI was to verify and evaluate licensee implementation of hardware modifications in response to NRC Bulletin 93-03, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," and evaluate the licensee's performance implementing the requirements of 10 CFR 50.59 with respect to this design modification.

The inspectors determined that the licensee's implementation of the modification required by Bulletin 93-03 was good. The required 50.59 Safety Review was adequate. Normal, maximum, and minimum system flow rates were selected with appropriate engineering justification, and post-installation testing verified that proper indication was not excessively affected by operational transients or operating conditions of the backfill system or the control rod hydraulic system. Operating procedures for the system were complete, and took into account lessons learned from post installation testing.

Appropriate actions to be taken if the system became inoperable were specified. The check valves forming the boundary between the modification and the safety-related instrumentation system were included in the periodic leak testing program. Manual isolation valves in the reference leg of the reactor water level instrumentation were administratively controlled through the Locked Valve Program to preclude inadvertent closing, which would result in a reactor trip on high pressure or low water level if the backfill system were in service at the time.

Backfill system flow required periodic adjustments to raise flow rate after it dropped to the lower limit. The licensee was evaluating potential causes and industry experience to determine what actions would be required to correct this trend. The inspectors noted that there were no planned maintenance items associated with this system, including periodic replacement of the fine-mesh filters, which was among the possible problems being considered. The licensee was planning to look into the need for a periodic maintenance program for the system.

3.5 <u>Several Engineering Weaknesses Associated with Refueling Outage (RF04) Modifications</u> Fermi had implemented 265 engineering design changes (EDPs) during RF04. Most benefitted the operation and material condition of the plant and addressed longstanding workarounds. However, the inspectors determined that the majority of the 265 modifications implemented in RF04 were designed during the outage with little pre-planning or prioritization of work. As a result, some of the modifications did not function as expected and challenged the plant operators and engineering organizations. The inspectors focused the review on six I&C-related modifications that failed to function as expected. Each of the six modifications attempted to address a longstanding engineering problem, and consisted of the installation of mainly new systems or components. These modifications were:

EDP-9207, Feedwater Control System Improvements
EDP-10201, Pressure Regulator Monitoring System
EDP-10257, Main Turbine Gland Steam Controller Changes
EDP-11566, Install Air Operated Valve E4150-F011 (HPCI/RCIC Test Return)
EDP-13679, Install Position Indicating Probe (PIP) Cable & Connectors
EDP-26356, Condenser Level Transmitters and Low Level Switches

In summary, the weaknesses associated with these modifications could be characterized as the following general headings:

- Management and engineering oversight of the ambitious RF04 modifications were inadequate to ensure that the modifications achieved their design objectives.

- Engineering supervisors, responsible engineers, and in some cases, the plant modification review group failed to conduct appropriate design reviews.

- Communication and interface between engineering, other groups, and outside vendors was poor.

- There was a lack of knowledge on the part of engineering staff of the design of the system or component being modified and a failure to recognize the need to obtain contract expertise in performing EDP design work.

- Pre-installation or pre-startup testing to simulate plant operating conditions, as appropriate, was inadequate in some of the modifications.

- Work control practices and workmanship (mainly relating to EDP-13679) were poor.

The licensee was in the process of determining root causes and developing a comprehensive plan to correct the above problems, in addition to the specific problems associated with each of the modifications. The inspectors will evaluate the licensee's corrective actions during future inspections.

The following is a brief description of each modification, problems encountered, and associated engineering weaknesses.

3.5.1 EDP-9207: Feedwater Control System Improvements This modification was intended to reduce the likelihood of reaching a high water level in the reactor vessel during a transient following a scram; however, during an actual scram on April 9, 1995, the feedwater system failed to respond as expected and reactor level dropped to the Level 2 setpoint. The licensee identified two significant problems with this modification. The post-accident scram setdown logic settings were inadequate to prevent reaching a low reactor vessel water Level 2 setpoint, and the feedwater demand limiter was improperly set.

Inadequate setdown logic setting due to insufficient validation testing, poor interface between design groups, and insufficient understanding of design: In the first case, the engineers had determined the settings based on information derived from the RETRAN computer model; however, the model did not account for a May 1988 feedwater controller modification. The licensee had performed some testing of the program to check for this modification previously, but the inspectors found the testing to be inadequate to demonstrate inclusion of the modification in the model. The failure of the computer model to reflect the as-built plant configuration was indicative of poor interface between design groups. The inadequate validation testing of the program demonstrated a weak understanding of the RETRAN program design characteristics. At the time of the inspection, the licensee had not determined the corrective measures necessary to address the problems with the modification and the RETRAN software. This will remain as an unresolved item (341/95009-03) pending further NRC review of the licensee's corrective actions.

Improperly set feedwater demand limiter due to use of unverified data, poor design practices, and insufficient independent review: In the second case, the engineer had used an input signal value that was associated with the unmodified demand limiter to determine the value for the automatic speed increase signal. He believed that the signal used corresponded to 2700 rpm. The inspectors determined that sufficient design information existed to determine the correct input signal without inappropriately relying on unverified plant data. The design engineer demonstrated poor design practices for this portion of the modification. Additionally, the independent review of the modification was deficient because the reviewer did not question this practice.

3.5.2 EDP-10201: Pressure Regulator Monitoring System (PRMS) This modification was to provide backup protection in case of pressure regulator failure in some modes, to enhance regulator testability, and to provide online monitoring capability of the pressure regulating system. However, due to spurious electrical signals generated from the PRMS cabling/wiring to the pressure regulator control system on April 25, 1995, the turbine bypass valves went full open, then full closed in a period of about five seconds, resulting in a reactor scram.

The design for this modification had been provided by General Electric (GE), who had indicated that the system was non-intrusive (would not affect the actual pressure regulator control system).

Vendor provided inaccurate data, but modification still installed due to insufficient knowledge of the design, inadequate engineering oversight of the contractor, and poor design acceptance testing: The inspectors determined that GE support and interface to plant engineering and engineering oversight of contractor design and testing was poor. There was too much reliance on the vendor with little oversight by the licensee. Plant management was informed that the PRMS was non-intrusive; however, plant engineering was not fully knowledgeable of the design or function of the PRMS due to poor design reviews, and thus failed to note that the system was intrusive and failed to plan an effective design change acceptance test. In addition, during installation, eight DERs and six engineering change requests were issued to correct engineering problems. The average number for other modifications was much lower. Communication problems between groups contributed to not correcting this design deficiency.

3.5.3 <u>EDP-10257: Main Turbine Gland Steam Controller Changes</u> This modification was designed to replace the single gland steam pressure controller with two controllers; one to control during startup and the other to control during normal plant operations. However, the gland steam system was still unable to control turbine packing pressure in automatic, as small changes to the controller in the startup mode caused large pressure swings. The gland seal system had six and eight inch valves, while other similar plants had four and six inch valves; and the actuator did not provide the type of control necessary to perform the intended function of reducing pressure from 975 psig down to 2 psig.

Oversized valves and incapabilities of actuator not recognized in design due to ineffective communication with vendor and insufficient knowledge: Engineering initially focused on the single gland steam pressure controller as the only problem. Discussions with the system engineer indicated that it was unclear whether the controller was able to automatically control pressure when the gain was properly set for this mode of operation. A contributing problem may have been ineffective communications with the vendor. Better communications could have identified the different size valves and outdated actuators as problems earlier in the process.

3.5.4 <u>EDP-11566: Install Air Operated Valve (AOV) E4150-F011 (HPCI/RCIC Test Return)</u> This modification was designed to increase the capability of the valve to close under worst case differential pressure conditions and to allow automatic (and remote manual) throttling of the valve to support surveillance testing. During post-installation testing of the High Pressure Coolant Injection system, the licensee identified two problems with the modification. First, the valve was over-responding to small step changes in the closed direction because the three-way valve was not responding as expected (blocking flow to the slow speed portion of the system in the shut direction), and second, when the valve was approximately 8 percent open, it would not fully close. In the first case, this caused the HPCI system pressure to increase to 1500 psig, exceeding the nominal pipe rating by 170 psi. The licensee performed an engineering evaluation and determined that pipe stresses were within code allowable limits.

Control valve used in improper application due to insufficient design knowledge of ASCO valve, insufficient pre-installation testing, insufficient contractor oversight, and insufficient independent reviews: The inspectors reviewed the pre-installation testing for this modification and determined that the testing was insufficient to demonstrate that the valve could perform acceptably in the plant. Specifically, the air control system was not tested for small step position changes, even though this was a new design. Additionally, the licensee's independent reviews and contractor oversight did not ensure a quality design. The ASCO three-way valve was used in an application for which it was not intended - the valve was only designed to allow flow in one direction, but the installed configuration required the valve to allow air flow in two directions. An ASCO representative readily explained the problems observed, indicating that the designer, the independent reviewer, and the Fermi site engineering oversight of the project did not appropriately evaluate this design.

After the design was found to be faulty, the licensee modified the air control system, which appeared to be effective based on trouble-free pre- and post-installation testing.

Valve would not fully close from 8 percent open due to overtorqued packing: An additional problem related to this modification was noted in the vendor's response to licensee information. This valve also demonstrated problems when closing from the eight percent open position because the "live-loaded" packing was over-torqued. The licensee identified that the vendor recommendations for torquing (50 ft-lbs) were excessive. The licensee repacked the valve in accordance with the licensee's packing program, torqued the packing to 25 ft-lbs, and requested that the vendor modify the packing recommendations to avoid future problems. However, the revised vendor recommendations were to allow torquing of the packing to a range of 35-50 ft-lbs, which still allowed the packing to be over-torqued. The inspectors were concerned because the corrective actions taken by the vendor might not prevent recurrence. This issue will be pursued with the Nuclear Reactor Regulation Branch of the NRC concerning generic implication. In response to the inspectors' finding, the licensee initiated discussions with the vendor and planned to formally request appropriate corrective measures. The licensee's actions were acceptable.

3.5.5 <u>EDP-26356: Condenser Level Transmitters and Low Level Switches</u> This modification was designed to replace the installed level transmitters and switches to provide better level indication for the condenser. After installing and testing one of the Barton d/p switches, the licensee determined that the response time was unacceptable. Subsequent discussions with Barton engineering staff indicated that the type of switches ordered would not work for the intended application.

Inappropriate level switches ordered due to inadequate communications between design and system engineering, insufficient contractor oversight, and failure to perform pre-installation test: System engineering suggested the Barton d/p switch based on review of the

Barton catalog and discussions with the local supplier; however, they assumed that plant engineering would follow the normal practice of contacting Barton engineering to ensure the instrumentation would be designed to the specification necessary for this application. Due to poor communications and inadequate contractor oversight, the contractor performing the EDP completed the EDP without performing the necessary engineering work involved in ordering the switches. The plant modification review group (PMRG), system, and plant engineering did not question the lack of design specifications normally required for this process, and the inappropriate transmitters were ordered and one installed. The inspectors determined the root causes of the EDP ineffectiveness were as follows: inadequate communications between system engineering, plant engineering, vendor, PMRG, and contractor resulting in the ordering of the wrong level switches; inadequate oversight of contractor; and not bench testing the Bartons prior to initial installation due to the work load of I&C technicians.

3.5.6 <u>EDP-13679: Install Position Indicating Probe (PIP) Cable and Connectors</u>
This modification was installed to address operator problems experienced in the past with rod position display errors caused by the PIPs. The modification consisted of installing flexible J-loop cables, replacing the PIP lower housing design to prevent intrusion of moisture to the probe, and reworking the PIP head to accommodate the new Whittaker assemblies. As a result of the modification, the rate of PIP deficiencies during operations significantly increased, as previously documented in Inspection Report No. 50-341/95008, and included flickering, flashing, missing, intermittent and superimposed digits, control rod full in and full out indication problems and loss of or faulty thermocouple input data. Based on licensee laboratory testing, it appears that the QLN (J-loop to flower pot interface) is the source of many of the PIP failures. The inside diameter of the sockets in the QLN were found to be enlarged during testing to the extent that their signal transmitting ability may be degraded. Also, pin engagement in the connectors may be impacted by thermal effects from plant conditions. Other potential problems included: (1) silicon contamination of the J-loop connector pins, (2) broken field cable wires, (3) shorted, pulled out or misaligned pins in the connectors, (4) low PIP magnet strength, (5) miscalibration or mispositioning or failure of PIP reed switches, (6) flower pot housing to PIP probe sheath screw damage, (7) vibration and temperature-related problems, (8) CRDM thermocouple loss of data, (9) RPIS faulty power supplies, (10) water intrusion into connectors and cables, (11) flower pot gasket problem, (12) tightness of Deutsch adopter to J-loop interface, and (13) fitup between J-loop related components.

Multiple deficiencies associated with design, fabrication, installation, testing, and operation The inspectors determined that significant deficiencies were encountered during design, fabrication, installation, testing and operation phases of this modification. The following concerns were noted by the NRC inspectors:

- Engineering oversight of vendor design/fabrication activities was weak and ineffective.

- Licensee inspections to examine the vendor QA program were not conducted even though the EDP was classified as QA1.

- The vendor used a new flower pot gasket design without informing the licensee.

- Qualification test data was not provided to certify that the assemblies were qualified under dynamic, humidity, and thermal conditions.

- The vendor used improper catalyst to cure the epoxy potting in the flex conduit wires during the manufacturing process. As a result, broken wires were found in field installed cables.

- The vendor used excessive sealant during fabrication on the socket assembly area of at least five installed J-loop connectors, resulting in open circuits in the connector pins.

- During the manufacturing process, J-loop connector pin contact surfaces were contaminated by silicon spray resulting in open circuits.

- The attachment to the flower pot caused damage to the probe wiring to the Deutsch connector, resulting in possible shorting problems.

- Pre-testing conducted on the PIP J-loop assemblies prior to installation was ineffective in identifying problems that appeared during actual plant operation.

- Calibration performed on the PIP reed switches was incorrectly done since at least 1988, (baseline measurement reference to PIP probe plate was top to bottom vs. bottom to top).

- Water spraying under the vessel with no controls or precautions resulted in water intrusion to PIP cables and connectors resulting in corrosion of the pins or connectors.

- J-loop connectors to the PIP had to be re-tightened in June 1995 due to poor licensee work control practices during RF04.

- Poor workmanship was exhibited during implementation of this modification, when the organic cables had been severely bent (coiled) during re-training of PIP cables.

3.6 <u>Management Initiatives to Improve Engineering</u> As a result of the problems encountered with certain modifications implemented in RF04, the engineering organization began a self-assessment of performance. Because initial efforts in this regard were unsatisfactory, the licensee created an engineering improvement organization that performed an evaluation of the modification problems and reached similar conclusions to those of the NRC. Licensee senior management determined that some significant changes were needed to improve technical performance of engineering, and were in the process of developing new initiatives to address longstanding engineering issues. These initiatives had not progressed sufficiently to allow for assessment of their effectiveness. The newly developed initiatives included, but were not limited to the following:

- Backlog Reduction Project This project was intended to reduce the 17 man-year plant engineering backlog to a workable level. Engineering department personnel were being selected to fill this group, with the intent being to backfill the department with contractor support.

- System Engineering Handbook The purpose of the handbook was to improve consistency in system engineering performance and foster teamwork and accountability. The handbook included roles, responsibilities, expectations and goals for system engineers and was intended to encourage system engineers to be proactive rather than reactive and to increase system performance monitoring activities. It effectively communicated management expectations for system engineering performance.

- Component Engineering Group The purpose of this group was to evaluate component failures and identify root cause and corrective actions. The group would be located in the maintenance organization so that specific equipment problems would be identified and corrected quickly and efficiently, where system engineer experience might not be sufficient. When fully implemented, this initiative was expected to reduce portions of the system engineering backlog of work.

- Engineering Improvement Group This group was recently established to foster self-assessment and facilitate improvement within engineering, and to identify engineering problems before they were identified by outside assessment groups. The initial results of their work concerning the problems associated with RF04 modifications (discussed above) was still in draft at the conclusion of this inspection.

- Project Evaluation Review Committee (PERC) This committee was established to prioritize major engineering projects and assure that subsequent changes would be controlled and effectively managed.

- Re-engineering the Modification Process This effort was initiated to redefine the development of EDPs. This included revising the EDP procedures to incorporate a flow chart format showing the development process for EDPs, reducing redundancy, and developing a conduct manual and practice standards.

- Error Reduction Task Force This initiative began in 1994 to reduce the number of errors that had been identified with EDPs. The task force identified four problem areas in need of improvement: (1) inattention to detail; (2) procedure violations/interpretations; (3) lack of standards; and (4) unclear philosophy concerning what was wanted or required. Several corrective actions were identified by the task force, including the following: develop and issue conduct manual and practice standards for engineering; provide training for preparing EDPs; implement group meetings to provide a feedback mechanism of plant issues and lessons learned from previous errors; and ensure EDP owner and checker are technically qualified for the type of modification under development.

- System Engineering Meetings On July 11, 1995, the inspectors attended a system engineering group meeting. During this meeting of all system engineers, technical issues and engineering concerns were raised. The meeting was a positive interface where engineering issues were communicated and resolved.

- Vendor Manual Program Improvement Study This study was initiated due to the following concerns with the vendor manual program: adequacy of technical reviews for impacts to plant programs and procedures; timeliness of reviewing and implementing vendor issuances; and timeliness of issuing vendor manuals. These concerns were documented by the NRC in inspection report No. 50-341/93028. The study identified several recommendations to improve the vendor manual process to ensure the impact on plant equipment and procedures would be addressed in a timely manner. The recommendations were still under review by station management at the time of the inspection.

These initiatives had not progressed sufficiently to allow for assessment of their effectiveness, which will be assessed during future inspections.

3.7 Replacement Level Switches Reveal System Perturbations Resulting in Excessive Cycling of the Condensate Return System The correct level instrumentation was designed and ordered from Barton for the condenser and recently installed by EDP-27301 (See section 3.5.5 above for discussion on the incorrect level instrumentation being installed). However, other condenser level problems developed. The new level instrumentation identified system perturbations that were not known based on the previous installed instrumentation, such as level oscillations caused by pressure changes within the condenser. As a result of the level oscillations, there was constant cycling of the condenser makeup and letdown controls. A preliminary corrective action was isolating the emergency letdown valve, which reduced the cycling effect. A separate TSR was being developed to address these new concerns. The frequent cycling of the condenser makeup and letdown contributed to the occurrence of the hydraulic transients documented in Section 3.1.4 of this report.

3.8 Follow-up on Non-Routine Events NRC Inspection Procedures 90712 and 92700 were used to perform a review of written reports of non-routine events. Engineering evaluations were found to be safety conscious. All engineering evaluations and operability determinations reviewed by the inspector were supported by accurate and thorough technical documentation. The following items were closed:

3.8.1 (Closed) LER 341/94007, Revision 0 Improperly installed control center heating ventilation and air conditioning (CCHVAC) duct hanger. On October 27, 1994, the licensee identified an improperly installed CCHVAC duct hanger. Due to the hanger not meeting seismic design criteria, the licensee evaluated the condition as being outside the design basis. The event was previously documented in Inspection Report No. 50-341/94016. During this inspection period the inspector reviewed licensee documentation, including DER 94-0641, and determined that licensee investigation of the problem was thorough and corrective actions were adequate to prevent recurrence. The failure to erect the CCHVAC hanger in accordance with quality standards commensurate with the importance of the safety function to be performed was a violation of 10 CFR 50, Appendix A, Criterion 1. The failure is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

3.8.2 (Closed) LER 341/95004, Revision 0 Unexpected Reactor Water Level 2 and ESF Actuations after planned scram. The event occurrence was documented previously in Inspection Report No. 50-341/95004. During this inspection period the inspectors reviewed LER 95004, dated May 9, 1995. The licensee determined that the probable cause of reaching Level 2 during this event was the selection of parameters used in post scram feedwater logic modification per EDP 9207, installed during the fourth refueling outage. Inspector review of EDP 9207 adequacy is documented in Section 3.5.1 of this report.

3.9 Follow-up on Previously Opened Items NRC Inspection Procedure 92903 was used to perform a review of previously opened items (violations, unresolved items, and inspection follow-up items). No significant strengths, weaknesses, nor problems were identified, and the following items were closed:

3.9.1 (Closed) Unresolved Item 341/93016-04 Inadequate licensee assessment of possible residual heat removal (RHR) system water hammer under certain conditions. NRC Information Notice (IN) 87-10 described possible water hammer scenarios that resulted from realignment of RHR and core spray pump discharge paths from a suppression pool alignment following a loss of coolant accident. The inspector reviewed the current IN evaluation package during this inspection period and identified several aspects that appeared incomplete, namely:

- The probabilistic risk assessment (PRA) evaluation referenced the maximum allowed timeframe (per year) for RHR run time in suppression pool cooling mode without indicating how this would be tracked or how an actual run time greater than that analyzed would be assessed.

- The IN indicated that the core spray system could be prone to the same problem if operated in test return mode to the suppression pool; however, the inspector was unable to find where this had been evaluated by the licensee.

- The engineering functional analysis (EFA 94-001) indicated that operator training was to be conducted with RHR Division II designated as the preferred division for suppression pool cooling and associated procedures were to be revised to address this matter; however, the inspector could not ascertain that these actions had been completed to date.

The issues discussed in the IN were also to be the subject of a BWR Owners Group report scheduled to be published August 31, 1995. This IFI is closed; however, the licensee's actions to address the BWROG report and the above three issues will be tracked as Inspection Followup Item 341/95009-04.

3.9.2 (Closed) IFI 341/93016-05 Untimely followup on RCIC suction pressure alarms. The licensee determined the most likely cause for the alarms was seat leakage past Steam Admission Valves E51-F045 and E51-F095 and/or In-Line Check Valve E51-F014. Troubleshooting/rework of the subject valves was subsequently completed with the resultant elimination of the suction pressure alarms. This item is closed.

3.9.3 (Closed) IFI 341/94009-01 Alternative method of meeting the ASME code requirements. This item involved an instance where the licensee's program for testing two Low Pressure Coolant Injection Check Valves E1100 F050 A&B, was not consistent with the ASME code. In response to the finding, the licensee performed calculations which demonstrated that an operability problem did not exist and believed that the calculations further demonstrated that an alternative method of testing was in place that would meet the intent of the Code. In a letter from the NRC to the licensee dated March 30, 1995, the NRC agreed with the licensee's position. This item is closed.

3.9.4 (Closed) Violation 341/94012-01 This violation involved two examples of inadequate translation of design requirements. The first example involved incorrect DC interrupt ratings for fuses used in Design Calculations (DC) 2912 and 2913. The NRC determined that incorrect fuse interrupt ratings were used in the marked-up revision to fuse coordination calculations DC-2912 and DC-2913 which were applicable to EDP-13850 and EDP-14022 design. The fuse interrupt ratings used were for AC circuit applications and were inappropriate for DC circuit applications as required by the modifications. Deviation Event Report (DER) 94-0724 was initiated to revise the appropriate design calculations and specifications and to provide training on fuse selection and application to plant engineers. The design calculations and specifications were revised and the training was completed.

The second example involved a failure to translate vendor design documents into station drawings and field installations, namely ground terminal Number 6 of the EDGs UF relay was not wired to ground as required by the General Electric (GE) Vendor Manual, and the schematics and wiring diagrams failed to depict the ground connection. To address this problem the licensee issued EDP-27116. The relays were subsequently tested and functioned properly.

3.9.5 (Closed) Violation 341/94012-02 This violation involved two examples of failure to follow procedures. In the first case, the licensee failed to use tension links, breakable line, or a tension monitoring device for pulling cables. To address this concern the licensee reviewed 550 work packages for all QA Level 1 and BOP cables in QA Level 1 raceways pulled since 1985 to ensure that cable installations were acceptable. DER 94-0465 was initiated to perform a design evaluation and Maintenance Procedure 35.CON.013 and Design Specification 3071-128-EP were revised to address usage of pulling monitoring devices. The licensee concluded that cables pulled in the past without pulling tension monitoring devices had not exceeded the maximum allowable pulling tension. The NRC reviewed the licensees evaluation and found it acceptable.

The second example involved the failure to perform the required preliminary safety evaluation (PE) for a TSR on "Equivalent Part Identification." To address this concern the licensee issued TSR-26037, Revision A, and DER 94-0509 to evaluate the extent of the problem. During the engineering review, three additional TSR's were identified which lacked a complete PE. The three TSR's were revised to include a complete PE. In addition, training on FIP-CM1-01, Revision 9, was provided to all organizations that are authorized to disposition TSRs.

3.9.6 <u>(Closed) Unresolved Item 341/94012-04</u> Failure to account for degraded pump performance in design calculations. This item pertained to design calculations that had inadvertently neglected emergency equipment cooling water (EECW) and residual heat removal service water (RHRSW) pump design basis degradation. In response to the issue, the licensee performed a review of calculations and determined that the safety-related service water systems were operable but identified that the design margins were not as large as previously thought. At the time of the inspection, the licensee planned to revise surveillance procedures for testing the pumps and heat exchangers to ensure that the systems remained operable. These steps were acceptable.

3.9.7 <u>(Closed) Unresolved Item 341/94012-05</u> Net positive suction head for RHRSW pumps. The operating procedures did not address the potential runout concern with one RHRSW pump providing injection into the reactor pressure vessel. The licensee revised SOP 23.208 to include a caution to throttle injection flow to the reactor pressure vessel if only one RHRSW pump was operating to avoid pump runout. This item is closed.

3.9.8 <u>(Closed) IFI 341/94016-05</u> Cable insulation treeing. Licensee DER 94-0569 was issued to evaluate a concern identified at the Peach Bottom Plant relative to underground cables that failed due to "Cable Treeing" phenomenon. Treeing is an electrical pre-breakdown found in solid dielectric cable insulation which can lead to cable failure. The primary dielectric affected by treeing is cross linked polyethylene (XLPE). Fermi Engineers performed a review of medium voltage cables and concluded that XLPE cables were not used at Fermi and therefore the treeing issue was not applicable. This item is closed.

3.9.9 <u>(Closed) IFI 341/95002-02</u> Determination of inlet pressure for the RHRSW pump test. The licensee responded in a letter from R. McKeon dated April 7, 1995, which described the calculation methodology. Based on discussions with the inservice test coordinator, pipe friction losses were determined to be negligible (<2 psig) and as such, not included in the calculation. The licensee's calculation was determined to be acceptable. This item is closed.

3.9.10 (Closed) Violation 341/94012-03, 2nd Example Technical Specification (TS) required surveillance testing deficiencies. The licensee identified numerous instances of inadequate TS related overlap and permissive interlock testing, failure to test all components in the logic system and failure to test all logic combination paths for a trip signal. Failure to meet surveillance testing requirements was a recurring problem at Fermi. To address this issue, management established engineering teams to review all overlap procedures, schematics, load diagrams, and design calculations to determine if all TS surveillance testing requirements were identified and performed. Various DERs were issued to document and correct the noted deficiencies. The inspectors reviewed the licensee's actions to address this issue and found them to be comprehensive and thorough.

3.9.11 (Closed) Violation 341/94012-03, 3rd Example Failure to correct non-conforming conditions for an extended period of time. The EDG output breaker tripped during testing on numerous occasions with no flag indication when the underfrequency (UF) relay actuated. This was due to inadequate current available to the UF relay coil. Although this deficiency was identified by the licensee's Relay Department during earlier relay tests in 1989, 1991, and 1992, the results were signed off as satisfactory by all reviewers. Corrective action was not initiated to address this design deficiency and the system engineer was not aware of this deficiency. To address this concern EDP-27116 was implemented in October 1994 to increase the target coil current so that the flag would seal in. In addition, the licensee performed a sample review of field-completed planned maintenance items and identified numerous instances of notes made internal to the work package that were not documented under the summary of work completed. Based on this review, the PM coordinators performed a complete review of the entire PM event work package to ensure all notes or comments were properly identified and the appropriate corrective action was performed to address any noted deficiencies.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750 and 83750 were used to perform an inspection of Plant Support Activities. Radiation protection and chemistry performance continue to be excellent. The fire protection program was also excellent; however, inadequate maintenance support resulted in a violation related to emergency lighting failures. The annual emergency preparedness exercise conducted during this inspection period was good. Repeated loss of power to the building housing the Emergency Operations Facility during this inspection was a weakness. Security effectiveness was mixed; while the guard force was effective in dealing with storm-related system problems, they failed to promptly identify and compensate for a component degradation that they inadvertently caused.

4.1 Continued Excellent Performance in Radiological Controls The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc., and randomly examined radiation protection instrumentation for use, operability, and calibration. No deficiencies were identified.

Radiation protection appeared to be proactive in examining the radiological implications of implementing the new chemistry controls programs - namely zinc injection, oxygen injection, and hydrogen water chemistry (HWC). The radiation protection organization aggressively pursued training for all radiation workers to understand the expected radiological changes in the plant caused by implementing HWC.

As discussed in Section 1.2 above, radiation protection performance in response to the reactor sample line leak was excellent.

4.2 Security and Safeguards

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan.

During this inspection period, the licensee experienced two security events. On July 5, an intrusion detector was inadvertently made inactive while intending to make a different sensor with the same number inactive. The error was discovered an hour later and immediate compensatory measures were taken. A one hour emergency notification was made for the uncompensated intrusion alarm, but later retracted as not meeting reportability requirements.

On August 3, severe weather caused security alarms to overload the alarm monitoring system. Security officers were dispatched as compensatory actions. This event was reported to the NRC Operations Center via the ENS. Overall security response was good. The security shift supervisor did a good job controlling the situation and keeping informed of equipment status.

4.3 Emergency Preparedness

On August 2, the licensee conducted an annual emergency preparedness exercise involving onsite response only, with the exception of offsite fire department support. Overall control of the exercise and participant performance was good. While the scenario was not overly challenging to operators and did not involve an offsite release of radioactivity, mini-scenarios exercising many different groups gave the exercise good training value.

The inspectors noted the following:

- The Technical Support Center (TSC) was not always controlling actions, but rather seemed to be collecting information. Communications were frequently slow getting to the Emergency Director. The TSC was initially noisy and generally disorganized, but decorum improved as the exercise progressed.

- The Operations Support Center (OSC) was well-organized and thinking ahead of the problem, smoothly controlling 19 separate field teams.

- Security support was good. While they were late to be informed that offsite fire assistance was on the way, they recovered and allowed proper emergency access in a reasonable amount of time. Security control of access for fire fighting was excellent.

- Coordination between the onsite fire brigade and the Frenchtown Fire Department fighting the simulated EDG 14 oil fire was poor. The fire brigade did a good job evaluating the fire and attempting to manually initiate the CO_2 system. However, the fire brigade expected the Frenchtown Fire Department to take charge when they arrived, but they did not. The fire brigade did a good job once they took charge. Additionally, the fire department did not arrive with a full compliment, contributing to a slow combined response.

- Emergency Operations Facility (EOF) performance was good, including communications with offsite officials and within the EOF.

- Overall Control Room teamwork and response were good; however, the Control Room and TSC were slow to realize all the implications of the power loss to Division I buses. The TSC could have provided additional support in this area.

The poor coordination between the fire brigade and offsite fire department was of concern. The licensee intended to address this deficiency during annual joint training scheduled for September, which will include a joint fire drill.

The exercise met its objectives. Event classification, notifications and communications, assembly and accountability were good. Dose assessment and coordination of monitoring teams was good. Protective measures were not required by the scenario. The post-exercise critiques at each facility were a strength. Concerns were voiced openly and suggestions were presented as to how to prevent the problems seen from recurring in the future. The inspectors felt the post-drill evaluation was of an outstanding caliber.

4.4 <u>Repeated Loss of Power to the Emergency Operations Facility</u> During severe weather, the Nuclear Operations Center lost power repeatedly. Due to backup diesel generator failures, the Emergency Operations Facility also lost power during some of these events. The plant support organization, which was responsible for this facility, believed lightning strikes had caused the power losses.

The backup diesel, which automatically started each time, sometimes tripped without any indication of a problem. It was manually restarted without a problem. The diesel problem was also believed to be lightning strike related. Given the several examples where the backup diesel tripped without any indication of a problem, causing a loss of power to the EOF, licensee management did not appear to be aggressively resolving the problem. The inspectors will continue to monitor this problem.

4.5 Chemistry

During this inspection period, the licensee began injecting depleted zinc into feedwater using a passive system which used the reactor feed pumps for the driving head. Zinc concentration was being slowly raised to a target level of 5-10 ppb to keep cobalt in solution for removal in the reactor water cleanup system rather than plating out on recirculation system piping. This was expected to reduce radiation levels in the drywell during outages. Use of depleted zinc was expected to avoid increased radiation levels in main steam piping during operation and on the refuel floor during refueling operations seen at plants using undepleted zinc. No change in radiation levels had been detected to date.

The licensee also began injecting low levels of oxygen in the condensate system at the end of the inspection period. The oxygen, injected upstream of the condenser pumps, should raise condensate oxygen levels to the EPRI ideal range for minimizing corrosion rates. This was intended to further reduce metal concentrations in feed piping and the reactor.

4.6 Fire Protection Inspection The inspector performed a routine inspection of the licensee's fire protection programs using Inspection Procedures 64704 and 92702. Overall, the fire protection program was excellent.

4.6.1 Plant Areas Reflect Excellent Fire Protection Practices The material condition of fire protection equipment was good. Most fire doors in the plant were in excellent condition which included self-closure and latching. No discrepancies were noted with sprinklers, fire main valves, headers, hose stations, or extinguishers. Fire fighting gear was in good condition and well organized. The licensee completed regular surveillances on fire brigade equipment to ensure that critical items were available. The diesel and electric fire pumps were in good condition during the walkdown and equipment history indicated high reliability. The inspectors identified a fire main header brace that had two bolts missing. The licensee was evaluating the condition during the inspection. In addition, the licensee was working on fire damper design deficiencies and a project to reduce detector false alarms controlled and monitored in fire water systems. Zebra Mussels were being adequately controlled and monitored. There was a decrease in the number of Zebra Mussel shells during the last water main flushing.

The control of normal combustibles was excellent, with very few transient combustibles in the plant. Storage cages in the plant contained a limited amount of combustibles. Flammable liquids were stored appropriately. Oil leaks in the plant were not excessive. The backlog of open fire protection deficiencies was low. Also, the number of fire protection impairments in the plant requiring a fire watch was low.

4.6.2 Emergency Lighting Inadequately Maintained Emergency lighting surveillances, which include the Appendix R Safe-Shutdown Emergency Lights, were performed on an 18 month cycle, with 25 percent of the lights tested each cycle. A review of the 1994 surveillance indicated a high failure rate. Approximately one-third of the batteries required replacement. The licensee replaced the batteries, but failed to identify the numerous failures as a condition needing a prompt evaluation for root cause. Also, no additional surveillances were performed on the remaining 75 percent of the emergency lights to determine their condition, and no evaluation of the operability of emergency lighting was conducted. Given the importance of the emergency lighting system to mitigating an accident, the failure to evaluate and take timely corrective actions for a high failure rate of emergency lights is a condition adverse to quality, and a violation of 10 CFR Part 50, Appendix B, Criterion XVI, (341/95009-05).

Following the inspector's identification of this issue, the licensee made an operability determination that the emergency lighting was still operable, based on the fact that following the surveillance the lights were still lit, even though the batteries did not meet the voltage acceptance criteria. Based on the fact that there was still lighting, the licensee assessed the significance of this condition as low. This assessment was later revised when it was determined that some emergency lights had not been discharge tested, some were completely inoperable prior to discharge testing, and some were found non-functional during monthly surveillance testing. Subsequently, the licensee performed additional surveillances to determine the extent of the emergency lighting problems and repaired inoperable emergency lighting units. Corrective actions were in progress at the end of this inspection period.

4.6.3 Fire Brigade and Fire Brigade Equipment in Good Condition Training records indicated the fire brigade members had received adequate classroom and offsite fire fighting training. The onsite fire drill requirements had been met by all brigade members who were listed as qualified.

Fire fighting brigade equipment was in good condition. The equipment was located at strategic locations in the plant allowing for a faster response to fires.

The inspectors observed a fire drill in the turbine building. The overall assessment of the drill was excellent. Five fire brigade members responded in a timely manner, appropriate fire fighting clothing was donned, and the correct equipment was brought to the simulated fire and used appropriately. The control room staff and the fire brigade leader used proper command and control to organize the fire fighting effort.

During a post-drill critique, the evaluators and drill participants gave their insights on problems encountered during the drill. The staffs' overall assessment was that this was a good drill with very few problems.

4.6.4 Fire Protection Staff Knowledgeable and Effective The staff was experienced, knowledgeable, and proactive in dealing with most fire protection-related problems. Good cooperation was observed among the staff. Fire protection supervision was very knowledgeable about the fire protection program. The low number of fires during the past two years indicated good fire prevention practices in the plant.

5.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

Inspectors used Inspection Procedure 40500 to evaluate licensee self-assessment activities. Licensee self-assessment of engineering activities was mixed. Fire protection self assessment activities were good.

The review of self-assessment included nuclear quality assurance (NQA) and independent safety evaluation group (ISEG) reports performed on engineering activities. A preliminary copy of Plant Engineering Critique No. 95-006 dated July 5, 1995, and an Engineering Improvement Review dated June 16, 1995, of the six RF04 modifications selected by the licensee as most problematic were provided for review. The licensee was assessing their past engineering performance to prevent recurrence of problems. An engineering improvement organization had been established to perform these assessments. The licensee had performed several earlier assessments of engineering activities associated with the RF04 modifications; however, they did not wish to take any credit for them. Engineering management indicated that the previous assessments had been of extremely poor quality, and not very useful; hence, the establishment of the engineering improvement organization to perform the assessment.

The inspectors determined that NQA identified some of the major problems that contributed to the EDPs failures discussed in Section 3.0 above. NQA identified numerous errors with EDPs, which led engineering to implement the Error Reduction Task Force to address this concern. But while the NQA report on vendor manuals concluded there was not a concern with respect to NQA level 1 components, several of the EDPs reviewed indicated better communications with vendors were necessary. Nuclear Quality Assurance did recommend several program enhancements, such as those identified in the vendor manual improvement study.

Audit investigations for fire protection were detailed and thorough. The audits were effective in identifying problems in the fire protection program.

6.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

On July 13 G. Grant, Director, Division of Reactor Safety, Region III, met with various members of senior plant management to discuss engineering issues and plant material condition.

At the conclusion of the inspection on August 16, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

* R. McKeon, Assistant Vice President/Manager, Operations
* W. Romberg, Assistant Vice President and Manager, Technical

* P. Fessler, Plant Manager, Operations
* D. Nordquist, Director, Quality Assurance
* J. Walker, Director, Plant Engineering
* D. Ockerman, Superintendent, Operations
* J. Plona, Technical Manager
* W. Colonnello, Director, Safety Engineering
  R. Delong, Superintendent, Rad/Chem
* R. Eberhardt, Director, Nuclear Training
  D. Gipson, Senior Vice President, Generation
  L. Goodman, Director, Nuclear Licensing
* J. Korte, Director, Nuclear Security
* J. Malaric, Supervisor Modifications, Technical Engineering
  J. Nolloth, Superintendent, Maintenance
* G. Smith, Director, Technical
* R. Szkotnicki, Supervisor, Quality Assurance
* G. Trahey, Supervisor, ISEG