U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-341/95014

FACILITY
Fermi Nuclear Plant, Unit 2

License No. NPF-43

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

DATES
November 21, 1995 through January 9, 1996

INSPECTORS
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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 inspection was performed for non-routine events and for certain previously identified items.

RESULTS

Assessment of Performance

The inspectors concluded that performance within the area of **OPERATIONS** was mixed with continued problems with procedural compliance. Daily operations were performed well, and the power reduction was handled professionally. However, the following concerns indicated that improvements are still needed in the area of procedural compliance:

- Despite careful work planning and shift briefings, operators deviated from the tagout sequence and improperly manipulated the non-interruptible air supply system, resulting in an unintentional isolation and compressor auto start. This was a repeat of an event earlier in the year, for which training was performed.

- CO_2 was unintentionally initiated while attempting to defeat fire detectors for maintenance in the DC motor control center area. Lack of system knowledge and use of a commonly used but unapproved method contributed to this event.

The inspectors concluded that performance within the area of **MAINTENANCE** was mixed. High-visibility work continued to be done well, but more routine work continued to have problems:

- Main generator hydrogen cooler repairs were well-coordinated and performed in a deliberate manner.

- The licensee identified that incorrect oil was added to the reactor core isolation cooling pump bearings which resulted in the system being declared inoperable. Licensee corrective actions were prompt and conservative. The occurrence of the event indicates a weakness in the licensee's lubrication program.

- Inadequate maintenance practices resulted in a spill from a radwaste filter because the gasket was apparently not tightened properly.

The inspectors concluded that performance in the area of **ENGINEERING** continued to be effective. A recent focus on system engineer walkdowns has shown an increase in the number of material condition deficiencies identified. While some improvements were noted in the plant modification process, post-maintenance testing problems continued to exist. The following concerns were identified by the licensee:

- The temporary modification to replace the alternate air system compressor and modify the system reflected a lack of coordination between engineering, maintenance and operations. Administrative and post-maintenance testing details were missed initially, but identified by the licensee.

- The licensee identified that the heat balance calculation did not properly account for a source of cool water to the reactor, and therefore had likely exceeded the maximum licensed power level by up to 1 MWt on occasions during the first three fuel cycles.

- The automated emergency callout system (ECOS) was rendered partially inoperable by corporate telephone system changes. Inadequate communications and modification control resulted in the site not realizing that ECOS was affected for 3 days.

The inspectors concluded that performance in the area of **PLANT SUPPORT** continued to be a strength. The chemistry, radiological environmental monitoring and on-site safety review programs were determined to be effective. A particular strength was the licensee's control of reactor water chemistry and recovery from the December 25, 1993, turbine event.

The inspectors concluded that performance in the area of **SAFETY ASSESSMENT AND QUALITY VERIFICATION** continued to be mixed.

- Quality assurance continued to identify problems, but corrective actions were too narrow or ineffective in some cases to prevent recurrence. Chemistry examples were identified.

- Management initiatives to improve procedural adherence and procedure quality appeared to have initially positive results. Station personnel appeared to have accepted the higher standards.

Summary of Open Items
Violations: None
Unresolved Items: None
Inspector Follow-up Items: Identified in Section 3.5
Non-cited Violations: Identified in Sections 1.1, 4.4.

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.

1.1 Repeat Inadvertent Non-interruptible Air Supply (NIAS) Isolation While hanging a tagout for a planned Division 1 NIAS outage on December 5, 1995 operators improperly isolated the system, resulting in an unexpected auto start of the Division 1 Control Air Compressor (CAC).

This was a repeat of a similar event earlier that year which was caused by an inadequate procedure. The applicable procedure had been changed to clarify how Division 1 was to be correctly taken out of service. Previous corrective actions included a careful review of procedures and tagout documents to ensure a repeat problem would not occur. Briefings were conducted for shift and work control personnel. However, operators hanging the tagout failed to follow the sequence of steps required by the tagout. As a result, the operators shut Valve P50-F440 prior to pulling the fuses. When the valve was shut with the isolation logic still energized, the logic recognized a low pressure (sensed in an isolated portion of the system) and started the CAC and completed the isolation. Deviation Event Report (DER) 95-0981 was written to document the event and track corrective actions.

The inspectors concluded that the tagout and briefings were sufficient to have avoided the isolation. Licensee review of this event determined that the operators violated the tagout procedure by not following the prescribed tagout sequence. The operators involved were removed from licensed duties and upgraded on procedural compliance and the specifics of the event. Additionally, the licensee planned additional corrective actions that included improved training on the system and the event for all operators in the near future. Additionally, the simulator will be used to demonstrate the event and reinforce the correct way to remove the system from service.

Failure to follow the tagout in the order specified is a violation of maintenance procedure MOP12, "Tagging and Protective Barrier System," Revision 1, which requires that equipment be removed from service and tags hung according to the sequential steps indicated on the tagout. However, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria in section VII.B(1) of the NRC Enforcement Policy.

1.2 Unintentional CO_2 Initiation Caused by System Knowledge Weakness On December 20, workers were preparing to test the 2A-2 Battery Charger with a new load bank. Operations directed that fire protection personnel place plastic bags over the fire detectors in the DC motor control center (MCC) area to prevent inadvertent CO_2 initiation if heating in the load bank raised dust in the air. This was a common practice at Fermi.

The affected fire zone had dual fire detectors, both of which must alarm to initiate a CO_2 injection. While bagging the first detector, it alarmed. A control room operator was able to reset the annunciator in the control room. The operators directed bagging of the second detector. The second detector also alarmed, initiating CO_2 injection into the room.

Personnel in the area evacuated the room and reported no smoke or fire. As a precautionary measure, the Nuclear Shift Supervisor (NSS) directed the evacuation of the auxiliary and the turbine buildings.

The shift determined that the event was not reportable because site personnel were not significantly hampered. The NSS determined that atmospheres outside the affected room and adjacent rooms were not a health hazard. Self-contained breathing apparatuses were needed only to enter the affected room to sample the atmosphere. Operators were not hindered in moving about the plant during the event.

DER 95-1068 was written to document the event and track corrective actions. The licensee determined the cause of this event to be inadequate knowledge of the fire detection and suppression system. Specifically, the control room annunciator had no control function, but the local fire protection panel, which controlled CO_2 initiation, required resetting. While the shift fire protection personnel presumably understood this, they failed to properly communicate that the alarm needed to be reset at the local fire panel before proceeding.

The inspectors were concerned that the resident inspectors were not called to inform them of this after-hours event. Licensee personnel focussed on reportability aspects and did not consider an informal report to the residents. The inspectors considered the shift's actions after initiation of the event to be proper and conservative. The inspectors considered the initiating actions to be another example of weaknesses in system knowledge and communications.

1.3 Engineered Safety Feature Systems Material Condition During inspection of engineered safety feature systems, the accessible portions of the following systems were walked down.

- Emergency Diesel Generator (EDG) 12
- Standby Liquid Control System
- High Pressure Coolant Injection System
- Standby Gas Treatment System, Divisions 1 and 2
- 130/260V Batteries, Divisions 1 and 2
- Core Spray System, Division 2

Overall condition of safety systems remained good, and availability remained high. General housekeeping remained excellent, and material condition remained steady.

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. High visibility work continued to be done well, but more routine work continued to have problems.

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

- Main Unit Generator Hydrogen Cooler Repairs
- 2A-2 130 Volt Battery Charger Repair
- East Stator Water Cooling Pump Motor Replacement
- Main Unit Generator Brush Replacement
- Standby Liquid Control Supply Tank Sample and Analysis
- Average Power Range Monitor Calibration
- Surveillance of Non-indicating Excess Flow Check Valves
- Drywell Personnel Access Airlock Interlock Checks
- Local Leakrate Test of Outer Personnel Access Airlock Door
- EDG 12 Operability Surveillance
- 2A-2 130V Battery Charger Preventive Maintenance
- High Pressure Coolant Injection Oil Sample and Post-run Walkdown

For most activities observed, the inspectors noted safe work practices, except as described in section 2.5. The activities observed were performed satisfactorily in accordance with procedures. Some problems were identified as discussed below.

2.2 Rad Waste Filter Leak Overflowed Into Basement On November 26, the waste collector filter (WCF) gasket leaked during a water transfer, resulting in about 6000 gallons of floor drain water being spilled into the WCF pit. The leak rate exceeded the capacity of the floor drain in the pit, and water built up until it pushed out a foam seal. The majority of the water then drained into the waste surge tank (WST) basement below. The radiological aspects of this spill were determined to be insignificant, but inadequate maintenance practices were the cause.

Operators in the rad waste control room noticed that tank levels did not correlate during the transfer, indicating that all the water was not going where it was intended. The transfer was stopped and the cause investigated. Approximately 4 inches of water were found on the floor in the WST basement with the sump pumps operating.

Cleanup efforts were prompt, and only slight contamination was found in a few areas. Because the water being transferred at the time of the leak was floor drain water with little or no activity expected, the licensee believed the contamination identified had previously existed under some of the tanks in the WST basement and had been washed free during the spill.

The WCF was disassembled, and the upper rubber gasket was found to be pushed out in two places. Operations performed a test and verified that system pressure could not be raised high enough to overpressurize the filter. Maintenance history indicated that the joint had been disassembled for maintenance in March 1995, and the work procedure had been changed from tightening fasteners to a specified torque value to tightening until the gasket extruded. The licensee determined that the

most likely cause of the gasket failure was improper tightening such that uneven pressure was applied to the joint. The procedure was changed to specify a torque value consistent with how condensate system filters and demineralizers are handled, which was used when restoring the WCF following this event.

The inspectors considered this to be an example of problems with routine maintenance work. Reviews to ensure the adequacy of changes to gasket material and tightening procedure were not sufficient to prevent this failure.

2.3 Main Generator Cooling Water Leak

Hydrogen Cooler Repairs

On December 10 while at 96 percent power, the control room received the Generator Liquid Leak Detection High annunciator, which indicated the presence of liquid in the bottom of the main unit generator casing. Investigation revealed the source of the water to be from the general service water system, which cools the generator hydrogen coolers. Power was reduced as a precautionary measure. Troubleshooting revealed that the southeast cooler was leaking.

After consultation with the vendor, the licensee decided to install a temporary modification to isolate the cooler by replacing the isolation butterfly valves with blank flanges and continue operation with the three remaining coolers. This modification was expected to have little impact on plant operations until lake temperatures rise during the summer. The planning for the repair was thorough and deliberate, and work was well-coordinated.

Hydrogen Ignition During Generator Drain Valve Operation

To verify that water intrusion into the generator casing stopped following repairs to the cooler, operators were performing a shiftly surveillance to blow down the casing drain lines. On December 18, while performing this surveillance, an operator observed a light mist followed by a flame coming from the drain line. The operator quickly closed the drain valve.

DER 95-1050 was written to document the occurrence and track corrective actions. An investigation showed only a few similar occurrences in the industry, with no known specific cause. This surveillance was normally performed weekly at Fermi, with no previous occurrences. Pending completion of their investigation, operations discontinued further performance of this surveillance, and issued a night order to open the turbine casing drains only in response to the annunciator for moisture in the generator casing.

Downpower Activities Mostly Well-Coordinated

During the power reduction to identify the source of leakage into the main generator and effect repairs, the licensee took advantage of the

lower radiation levels to perform main turbine valve testing, main turbine overspeed testing, and engineering and operator walkdowns of areas not normally accessible at high power.

With the exception of a problem with loss of control of two radiation area boundaries (section 4.3), the scope of work was closely controlled and well-coordinated.

2.4 Wrong Lubricant Used in Reactor Core Isolation Cooling (RCIC) Pump Bearings On December 27, during analysis of a quarterly oil sample, the licensee identified that approximately 25 percent of the oil in the RCIC pump inboard and outboard bearings was the wrong type. The mixed oil was determined not to adversely affect the machine, but the oil was promptly flushed and replaced with the correct lubricant. Deviation Event Report 96-0003 was written to document the occurrence and track corrective actions.

The inspectors questioned the adequacy of the licensee's lubrication program, which apparently allowed this problem to occur. The resident inspectors will follow up on this issue and assess the licensee's lubrication program during future routine inspections.

2.5 Repeat Safety Battery Charger Card Failure On December 17, maintenance performed the 18-month preventive maintenance on the 130 Volt Battery Charger 2A-2. This was a validation of changes made to the procedure following identification that the procedure was inadequate, for which a violation was issued in Inspection Report 341/95012. During performance, the workers identified that two of the three cards which control current rectification had failed, and the charger was incapable of producing its rated output. This was the same initiator which contributed to the 2A-1 Charger event documented in Inspection Report 341/95012.

The licensee identified the failure as a repeat, replaced all three cards, and was in the process of determining the failure mode of the 2A-2 Cards at the close of this inspection. Deviation Event Report 95-1063 was written to document this and previous charger card failures and to track corrective actions. The 2A-1 Cards were not available for examination to determine if the failure mode was common to both chargers. The licensee planned to check the other chargers with the same type of card to determine if more failures exist.

The phase cards, which failed in both 2A-1 and 2A-2 Chargers, were not detectable under normal system operation because a single phase was intact in each, which was capable of sufficient output (about 60 amps) to carry normal DC system loads (about 20 amps).

Following card replacement while taking current measurements inside the energized high voltage charger cabinet, the inspector identified unsafe electrical safety practices by the electrician, including failure to use any safety gloves and failure to remove metal and loose items from his body. These observations were discussed with the electrical supervisor on the job site. The supervisor indicated that a review of electrical safety practices would be conducted.

The inspectors noted that, in addition to the repetitive nature of this failure, repair times were slow due to lack of qualified spare parts. The availability of spare parts affected the length of outages on both the 2A-1 and 2A-2 Chargers. The 2A-1 Charger was out of service almost two months, and the 2A-2 Charger was out of service for 11 days. The inspectors will follow up on safety battery charger reliability and availability of spare parts during future routine inspections.

2.6 Power Ascension Testing On November 27-28, power ascension testing continued briefly. A power level of 98 percent was reached and data taken. Dynamic portions of the pressure regulator testing was only partially completed due to high vibration of the turbine valve unitized actuators. The licensee subsequently lowered power back to 96 percent. The licensee planned to collect additional data necessary for turbine rotor replacement in the near future, and then discontinue power ascension testing for the remainder of the cycle.

The licensee intended to complete system checks and insert high vibration automatic trips shortly after the end of this inspection. The trips will require meeting a two-out-of-two-once logic where a hi-hi alarm (12 mils) must be coincident with a hi alarm on the adjacent bearing (setpoints vary among bearings).

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function. A recent focus on system engineer walkdowns has shown an increase in the number of material condition deficiencies identified.

3.1 Main Steam Line Hanger Failure Identified During Licensee Walkdown During walkdowns performed in normally inaccessible areas of the plant while at reduced power for generator hydrogen cooler repairs (section 2.3), the licensee identified a broken pipe hanger which supported a 27-inch section of main steam line "A" piping. The support was part of a pair of struts which supported the pipe at that location. Initial analysis showed the failure mode was high cycle fatigue. Engineering analysis determined that the remaining strut provided adequate support for the pipe, and that measured pipe stresses from vibration were below a level which would be a concern for fatigue (i.e. below the endurance limit), so the failure was not an operability concern. Plant support engineering was pursuing adding dampening supports to reduce steam line vibration at the time this failure was identified. DER 95-1026 was written to document occurrence and track corrective actions.

3.2 50.72 Report of Exceeding Maximum Licensed Power Level On December 13, the licensee reported to the NRC via the emergency notification system that it was likely that the plant had exceeded its maximum licensed power level by up to 1 MWt during Fuel Cycles 1, 2 and 3 (limits were 3292 MWt for Cycle 1 and 3293 MWt for Cycles 2 and 3). This determination was made in response to industry identification that control rod drive water flow to the reactor recirculation pump seals (4 gpm at Fermi) was not properly accounted for in the plant heat balance calculation at some BWRs. The licensed maximum power level was not exceeded during Cycle 4 or the current cycle because full power has not been closely approached since the licensed maximum power level was

increased to 3430 MWt. The licensee intended to document the event in LER 95008.

3.3 Poor Communications Hinder Temporary Modification Implementation In the Fall of 1995, the licensee implemented a temporary modification to the station air system to install a screw-type air compressor outside the turbine building to supplement the existing compressors and to evaluate the new type for future replacement of the installed compressors. The new compressor and associated equipment were installed outside the turbine building, and were designated the Alternate Air System.

After successful testing and being placed in service, the compressor developed repeated problems. The licensee decided to replace the compressor with an identical unit and perform a few minor modifications to the associated equipment. However, lack of coordination and poor communications resulted in the following licensee-identified problems:

- Work to install the new compressor was performed without signing on to the work-in-progress section of the temporary modification package. The revised temporary modification package stated that the work was done under the wrong work request number (the original work request was listed).

- During the post-installation testing of the new compressor, heat tracing was disconnected and water that collected at the bottom of the receiver froze, damaging the drain valve. Following valve repair, the test sequence was not revised to include post-maintenance testing of the valve until operations caught the mistake.

- Testing included required air flow rates, but no method to measure air flow rates was specified and no installed equipment existed to fulfill this function.

- The revised temporary modification included information on operating in low temperature weather, but this information was not added to the equipment operating procedures.

While some improvements were noted in the plant modifications process since the last engineering and technical support inspection (Inspection Report 341/95009), this work indicated that problems continue to exist in the plant modification process.

3.4 Offgas Flow and Radiation Level Indication Spikes Investigated Operators identified that occasional spikes in offgas flow and radiation level indication appeared to correlate with securing the torus water management system (TWMS). TWMS was used to maintain suppression pool water level and chemistry. This system was mostly used to periodically pump down the torus due to inleakage. In this mode, water is rejected to the main condenser via piping which tapped into the heater feed pump minimum flow line.

System engineering believed that a source of minor air inleakage existed in the heater feed pump minimum flow line which allowed a gas bubble to

build up in a high point of the piping during no-flow conditions, which is then "burped" out when TWMS is secured. The gas flowed to the condenser and was removed by the offgas system several minutes later, registering as spikes on the flow and radiation monitors instruments.

Initial licensee testing has supported this theory, although further testing is planned. Testing completed so far confirmed that the instruments are working properly. This was considered a good effort by engineering to resolve problems. The inspectors will continue to follow this testing during future routine inspection activities.

3.5 Primary Containment Airlock Test Connection Untested On December 11, the inspectors observed surveillances on the primary containment personnel access airlock which checked airlock door interlocks and then performed a local leak rate test (LLRT) on the outer airlock door seal. During the LLRT, a 1-inch NPS pipe cap was removed to vent the inside of the airlock so that any leakage past the inner seal on the outer door would not pressurize that space and affect the LLRT measurement. Upon successful completion of the LLRT, the cap was replaced without any testing on the joint. The joint appeared to require a type B LLRT, based on a lack of applicable exemption. The safety significance of this untested joint is low, based on Fermi's Probablistic Safety Assessment. This issue was not resolved at the close of the inspection period, and will be tracked as an inspection followup item (341/95014-01) pending further information from NRR.

3.6 Inspectors Identified Clear Plastic on the Refuel Floor On December 5, inspectors found an empty, large clear plastic bag in a desk drawer in the office on the refuel floor in the reactor building. The entire floor was designated an exclusion zone for clear plastic by the licensee to preclude the possibility of getting plastic into the fuel pool undetected. The potential consequences of this would include blocking natural convection cooling flow to one or more spent fuel bundles, causing overheating. The licensee documented the issue in DER 95-0973.

Licensee investigation identified a general decline in housekeeping on the refuel floor, and identified some other possible clear plastic items of small size. The licensee required all personnel requiring access to the refuel floor to sign an acknowledgement of the station policy of excluding clear plastic from the refuel floor before keycard access was granted to the refuel floor. Additionally, signs were hung at each access door to the refuel floor stating that clear plastic was not allowed inside. The licensee was considering adding a clear definition of unacceptable clear plastic items to the policy acknowledgement form and to the administrative procedure for the control of refueling operations. This definition would be communicated to station personnel who already have access to the refuel floor. Additionally, the licensee was considering reducing the clear plastic exclusion area to coincide with the tool control area surrounding the fuel pool, consistent with other utilities' practice.

The licensee responded to the inspectors' concern promptly and removed all potentially clear plastic from the area. Based on the licensee's review, the safety significance was low. The inspectors will monitor licensee's corrective actions during future routine inspections.

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 effective.

4.1 Chemistry and Radiological Environmental Monitoring Program was Satisfactorily Implemented with Strengths and Weaknesses Reactor water chemistry control and non-radiological analytical comparisons were strengths. Although quality assurance audits of chemistry had good focus and findings, chemistry was not effective in resolving all identified issues and findings. Weaknesses were observed by the NRC inspectors in the laboratory quality control program, specifically the control of laboratory reagents and calibration check trend charts. Additionally, post accident sampling system material condition problems were identified. Additional weaknesses in sampling techniques were identified.

4.1.1 Excellent Control of Reactor Water Chemistry The licensee's control of reactor water chemistry and recovery from the December 25, 1993, turbine event was excellent. The reactor water chemistry trends indicated some minor elevated concentrations of chloride and sulfate (ranging up to 50 parts per billion (ppb) in early 1995 due to hideout of contaminants and resolution of condenser tube leakage. During the latter half of 1995, impurities in reactor chemistry decreased and were well maintained; chloride and sulfate concentrations averaged less than 1 ppb and about 2.2 ppb, respectively. Reactor water conductivity was slightly higher than average at 0.14 microsiemen/centimeter from elevated levels of chromate. The licensee attributed the chromate to the dissolution of a coating on a replacement reactor recirculation pump impeller. Although the chromate was not hypothesized as a corrosion contributor, there was a notable increase in the chromium-51 coolant activity. The licensee was addressing this issue during the inspection.

The licensee increased the concentration of dissolved oxygen (DO) in the reactor feedwater to preserve the integrity of the protective corrosion film on the feedwater piping. Following the condenser re-tubing projects and condenser tube leak repairs, feedwater DO concentration decreased below the recommended industry band of 15 to 200 ppb. Although some engineering problems with the injection system remained to be resolved by the licensee, the oxygen injection system maintained the level of DO between 20 and 60 ppb. These actions are acceptable. The licensee will modify the system to resolve this issue.

4.1.2 Strong Non-radiochemical Analytical Laboratory Capabilities and Continuing Training of Chemistry Technicians The licensee demonstrated excellent performance in the NRC non-radiological confirmatory measurements. The inspectors submitted non-radiological chemistry samples (i.e. chloride, sulfate, zinc, and boron) to the licensee, which were analyzed in the range of typical plant samples using routine methods and instruments. All of the licensee's results were in agreement with known concentrations. Some minor biases were observed in the zinc analysis results, which the licensee was evaluating.

The inspectors observed periodic refresher training provided to chemistry technicians. The training session observed, post accident sampling system sampling and system review, was performance-based and provided emphasis on sampling methodology and the circumstances under which each sample would be taken. The inspector concluded that refresher training provided was determined to be excellent.

4.1.3 Weaknesses in Laboratory Quality Control The inspectors identified problems concerning the labelling and control of chemistry reagents. The inspectors found a container of Ph buffer which was labeled incorrectly, bearing an incorrect lot number and manufacturer's expiration date. Chemistry personnel informed the inspectors that the staff reused the pH reagent bottles and that the label was from a different lot of the same type of chemical. Based on the inspectors' observations of the poor labeling practices, chemistry management released a memorandum to chemistry staff communicating the expectations that information on reagent bottles correctly describe the contents of the bottles.

Additionally, the inspectors noted that a number of reagents were over 10-20 years old and some reagents had degraded to the extent of oxidizing and discoloring their containers. Although Chemistry Procedure MCE04, Revision 0, "Chemistry Quality Control and Verification," appeared to require laboratory standards of concentrations greater that 100 parts per million to have a one year shelf life, certain chemistry standards were labeled with indefinite shelf lives. As the above reagents were not used in analyses required by technical specifications, no regulatory requirements had been violated. The inspector concluded that control of chemistry reagents in the laboratory appeared to be a weakness.

Although quality control trend charts were available for most laboratory instrumentation, the inspectors identified that the quality control analyses (i.e. calibration checks) for cations via the ion chromatograph (IC) did not have a control chart. The results of these analyses were documented in a table, and an acceptance limit of 10 percent was applied to the result. Although no obvious bias was evident, the lack of trend chart lessened the licensee's ability to detect biases in instrument performance. Additionally, the inspectors noted documentation problems in the table; for example, several entries were crossed out without initials or descriptions, and there was no documentation of follow-up for analyses which did not meet the acceptance criteria.

The inspectors discussed the above quality control concerns with licensee management and chemistry supervisory personnel. Although chemistry management removed the degraded chemicals from storage, they disagreed with the inspectors' interpretation of the procedural requirements for one year shelf lives for certain reagents. The licensee acknowledged the inspectors' overall concerns and planned to evaluate its chemical control process and investigate the need for trending quality control results for the IC.

4.1.4 Material Condition Effected Operability of the Post Accident Sampling System (PASS) Operability During the inspection, the inspectors observed a chemistry engineer technician (CET) obtaining a liquid and

dissolved gas sample from the PASS panel. The CET's knowledge of the sampling system and technique were good; however, the inspectors noted that several subsystems of the PASS panel did not function properly. Prior to retrieving the dissolved gas sample, the pressure monitor exhibited wide fluctuations (plus/minus >0.5 pounds per square inch) that prevented obtaining the sample. The same procedure also required the recording of the liquid sample line radiation monitor reading, which the CET recorded a de minimis reading. The inspectors noted that the needle on the monitor was off scale low and that the green "normal" light was not illuminated. When questioned about the operability of the monitor, the CET could not determine operability or the validity of the reading. Lastly, the inspectors noted that a hydraulic line on the liquid large volume transfer cask was cracked and a small amount of hydraulic fluid was on the floor. It appeared that licensee personnel had noted the leaking fluid and had placed absorbent material on the floor to contain the leak. The inspectors expressed their concern that if the hydraulic line failed, the licensee would be unable to obtain the liquid large volume PASS sample until the line was repaired or replaced.

The CET was able to obtain an undiluted liquid sample from the PASS panel. Isotopic comparisons between the PASS sample and a routine reactor coolant grab sample indicated that the PASS sample was representative of the bulk reactor coolant. However, the above described material condition problems indicated a need for additional management attention. The inspectors discussed each of these issues with the licensee. The licensee agreed to review its preventative maintenance program for the PASS system. DER 95-1005 was written to evaluate the PASS preventive maintenance program.

4.1.5 Radiological Environmental Monitoring Program (REMP) was Satisfactorily Implemented with Two Exceptions The inspectors reviewed the annual reports which contained the requirements of the licensee's Technical Specifications and Offsite Dose Calculation Manual. The data contained in the 1993 and 1994 annual reports did not indicate any adverse environmental effect from licensee operations. The reports contained good documentation. The inspectors toured several sampling locations and observed the replacement of air particulate and charcoal filters. The inspectors concluded that the licensee had upgraded the power supplies to its liquid samplers and was effective in limiting power interruptions.

The sample collector's techniques was adequate, with two exceptions. The licensee's REMP procedure stated that the particulate filter was to be removed and replaced, followed by the charcoal filter. However, the inspectors observed the technician removing and replacing the charcoal filter first, followed by the particulate filter. The inspectors were concerned because the operation was not performed in the sequence indicated by the procedure and the technician's technique may potentially dislodge and lose sample material that was not imbedded into the filter. Any potential losses would be small and would not be expected to significantly alter the outcome of the sampling results.

The second sampling problem concerned the technician's practice of tapping the sampling head to dislodge the particulate filter from the retaining element. The technician stated that during freezing

conditions, moisture between the filter and head would freeze, causing difficulty in removing the filter. The inspectors' concern also pertained the loss of a small quantity of the sample material could be lost. When the inspectors discussed these work practices with the licensee, both practices were immediately discontinued and the technician was retrained on the expected sampling procedure.

4.2 Followup of Previously Identified Items A review of previously opened items (violations, unresolved items, and inspection followup items) was performed per NRC Inspection Procedure 92901.

4.2.1 (Closed) Inspection Follow-up Item No. 50-341/93015-01 Procedure NPP-CH1-02, Revision 4, "Chemistry Quality Verification and Quality Control of Chemistry Equipment," was unclear in the assignment of analyses of inter-laboratory quality control samples. Subsequently, the licensee has replaced Procedure NPP-CH1-02 with Procedure MCE04, Revision 0, "Chemistry Quality Control and Verification." Procedure MCE04 assigned the chemistry technicians and chemistry engineering assistants the responsibility for analysis of quality verification samples.

4.3 Cold Weather Preparations The inspectors completed a review of the licensee's process to ready the site for cold weather operations. The inspectors' review included direct observation of components and systems potentially affected by cold weather, log reviews to check for cold weather related problems, interviews with licensed personnel, and documentation review of the licensee's Cold Weather Preparation Procedure (27.000.04, "Freeze Protection Lineup Verification").

The inspectors identified the following:

- 27.000.04 listed a number of preventive maintenance (PM) procedures that were to be performed by maintenance to implement the freeze protection program. This list included three items which were 18 month PMs which were not due until late spring 1996. These items were calibration of temperature instruments for the condensate storage tank (CST), condensate return tank (CRT), and distillate storage tank.

- None of the 27.000.04 checklists energizes or periodically checks the heaters for the CST/CRT level instrument enclosure or checks these enclosures properly sealed. CST level instrumentation is required to be operable by technical specifications. After the inspectors raised the concern, maintenance determined that a preventive maintenance event turns the heaters on and verified proper operation, which had been successfully performed, but was not listed in 27.000.04. Additionally, operators access those cabinets daily, and were expected to verify proper heater operation and cabinet closure.

- Licensee performance of monthly checks for freeze protection appeared to be thorough, and had identified a number of minor deficiencies for which work requests were issued. Inspector spot checks using licensee checklists identified no new deficiencies

The licensee intended to revise 27.000.04 to remove the PMs for calibration of tank temperature instruments and add the level instrument heater PM. The maintenance history showed calibration of the tank temperature instruments had the correct periodicity and was not affected by winter conditions. The licensee agreed that the level instrument heaters should have been included in the winter preparations program.

A review of DERs which documented problems related to cold weather indicated mostly minor problems which were easily fixed. However, a heater failure in the auxiliaries compartment of Combustion Turbine Generator (CTG) 11-1 led the licensee to declare it inoperable until repaired the next day due to past problems starting at low temperatures. CTG 11-1 provides the station with its station blackout power source. Also, Fermi has experienced a number of problems with its south cooling tower de-ice system which have distracted operators but have not proven operationally limiting.

Overall, the inspectors concluded that the freeze protection program at Fermi was effective.

4.4 Radiation Protection Issues During routine observation of plant activities 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.

- Station dose for 1995 was 27.5 rem. This was below the site goal of 30 rem. Additionally, the 3-year average for site dose was low at 91.7 rem.

- To support the freeze seals required for the main generator hydrogen cooler repairs, a liquid nitrogen trailer was brought into the turbine building and radiologically restricted area (RRA) on December 13. During a plant tour, the inspectors identified 2 soda cans on the trailer, both unopened. The licensee did not adequately inspect the trailer to ensure inappropriate materials were removed prior to the trailer entering the RRA.

- During the power reduction to support hydrogen cooler repairs, several areas of the plant which were high radiation areas at high power were reposted to radiation areas, as applicable, and entries were made for equipment walkdowns. However, on December 13, the inspectors identified a loss of radiation area boundary control, in that the 3,4,5-North heater room did not have the yellow and magenta rope across the door and the radiation area sign was backwards. Radiation protection investigated, and determined that the area was a radiation area and should have had the rope and sign hung across the doorway. An engineer was identified as having been the last one in the room, and had apparently inadvertently left the rope hung wrong. The engineer had also left another radiation area barrier down earlier, which radiation protection also corrected. The barriers were down for approximately 1-1/2 hours.

Radiation personnel promptly took corrective action following inspector identification of the problem including interviewing the engineer and checking other postings. The failure to ensure that the heater room was adequately posted as a "radiation area" was a violation. Due to the limited duration and minimal safety significance of this event, this violation was minor and will not be cited because of the criteria specified in the NRC Enforcement Policy were satisfied.

4.5 Emergency Callout System (ECOS) Rendered Inoperable by Telephone Upgrade On November 27, Detroit Edison implemented an upgrade to its phone system. In addition to installing new hardware, the change required that when calling between sites, the entire 7 digit phone number be dialed instead of the previous method of dialing the last 5 digits.

Detroit Edison used an automated ECOS to call required personnel, either onsite or at home, to respond during emergency events. The system is located off the Fermi site. Due to changes to the phone system, ECOS was unable to contact anyone onsite because the ECOS software was not changed to dial 7 digits. This problem was not identified until 3 days later. In attempting to correct the problem, the ECOS system hard drive failed, preventing automatically calling personnel at home as well, and required vendor repair. The backup system, manually calling personnel, was instituted while ECOS was inoperable.

The licensee wrote DER 95-0950 to document the problem and track corrective actions. The initial cause of the problem appeared to be inadequate communication and modification control in that the Fermi organization was not aware that the modifications being made at that time would affect ECOS. While the inability to automatically call personnel onsite went unrecognized for 3 days, site announcing systems would have functioned, so the safety significance of the error is low. However, this was considered another example of poor modification control (section 3.3).

4.6 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.

4.6.1 Protected Area Access Improperly Authorized On January 3 the licensee identified that a supervisor on the night shift had improperly activated keycards for two individuals without all the requirements being met. Both individuals entered the protected area shortly before day shift. The error was discovered shortly thereafter, and the individuals were escorted. Inspectors will review the event, and licensee corrective actions during future routine inspections of the security program.

5.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

Inspectors used Inspection Procedure 40500 to evaluate licensee self-assessment activities.

5.1 Management Initiatives on Personal Accountability and Procedural Adherence Station management made efforts to focus attention on procedural adherence during this inspection period. The plant manager held a series of meetings with all station personnel on December 8 to

discuss work control and procedural adherence issues discussed in Inspection Reports 341/95012 and 341/95013 and to delineate management expectations clearly in these areas, and site news letters have discussed the topic.

Management implemented a policy of zero-tolerance of procedural non-compliance during this inspection period. Individuals have been held accountable for failure to follow procedures, including administrative procedures, by having their access to the protected area revoked until upgrading on the specific problem and procedural compliance in general.

The inspectors observed that these initiatives have been fully implemented on site and have had positive results. Station personnel clearly accepted the high standards set for them and, as a result, began to question the adequacy of some procedures, as documented in a number of DERs and over 200 procedure change requests.

5.2 Onsite Review Organization (OSRO) Appeared Effective The inspectors attended OSRO meetings on December 20 and 22 and verified that the applicable requirements of Technical Specification 6.5.1 were met. The OSRO members were cognizant of issues and were candid and open in their discussions. Overall, the inspectors concluded the OSRO was effective based on the observation of the meetings. The committee reviewed a variety of topics, including administrative procedure changes, a plant modification, a special test, and a Furmanite repair of a feedwater heater valve. In general, the members appeared to perform adequate reviews, displayed a questioning attitude and did not hesitate to table a topic to resolve questions. The members appeared to have a good safety focus.

5.3 Self Assessment and Corrective Actions The inspectors reviewed the quality assurance audits performed over the last 2 years for the chemistry and REMP program areas. The audits were performance based and covered a broad spectrum of program areas. The audit findings had very good technical merit, but several findings appeared to lack resolution.

The inspectors noted that certain repeated quality assurance audit findings were very similar to the weaknesses identified by the NRC (Sections 4.1.3 and 4.1.4). Over the last three years, the quality assurance audits identified problems associated with PASS and control of chemistry standards and reagents. NRC observations validated the weaknesses, but also indicated the failure of chemistry to fully correct the problems. Additionally, the 1994 quality assurance audit identified a problem with daily calibration checks similar in nature to the NRC findings concerning the trending of cation IC calibration tests. The inspectors noted that the licensee corrected the specific item identified in the quality assurance audit but did not expand the focus of corrective actions to ensure that the problem was isolated and that similar problems were corrected and prevented. The inspectors discussed the lack of effective corrective action with senior licensee management, who acknowledged the inspectors' concerns.

5.4 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.

5.4.1 (Closed) Followup Item 341/93022-01 Inadequate Corrective Actions Program. The specific event discussed was the feed water valve stem ejection resulting in personnel injuries when the valve was disassembled while still pressurized. While the inspectors noted some improvement in identifying and corrective actions, most notably through the increased number of DERs written, some problems continue to exist. As discussed in Inspection Report 341/95012, corrective actions in the areas of work control, communications, and procedural compliance have not been completely effective in preventing problems in these areas. This item will be tracked under Violation 341/95012-02a.

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.

At the conclusion of the inspection on January 9, 1996, 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.

* M. Adams, NSO, Operations
* S. Bartman, Supervisor, Chemistry
* P. Bienich, Supervisor, Plant Engineering
* S. Booker, Assistant Supervisor, Maintenance
* D. Breiding, NSO, Operations
* R. Buehler, NASS, Operations
* M. Caragher, Material Engineer
* C. Cassise, General Supervisor, Maintenance
* G. Childs, NPPO, Operations
* W. Colonnello, Director, Safety Engineering
* J. Conen, Supervisor, Licensing
* R. Delong, Superintendent, Rad/Chem
* R. Eberhardt, Director, Nuclear Training
* W. Emerson, Supervisor, I&C
* P. Fessler, Plant Manager, Operations
  D. Gipson, Senior Vice President, Generation
* L. Goodman, Director, Nuclear Licensing
* L. Crissman, GSRPO, Radiation Protection
* R. Hambleton, Lead Engineer, ISI
* K. Howard, Supervisor, Mechanical & Civil
* J. Hughes, General Supervisor, Electrical Maintenance
* R. Johnson, Acting Director, NQA
* J. Kauffman, ERS, RERP
* D. Keskitalo, Engineer, RP
* J. Korte, Director, Nuclear Security
  R. McKeon, Assistant Vice President/Manager, Operations
* W. Miller, Superintendent, System Engineering

* R. Newkirk, Supervisor, Licensing
* J. Nolloth, Superintendent, Maintenance
* W. O'Connor, Manager, Nuclear Assessment
* D. Ockerman, Supervisor, Operations
* M. Offerle, General Supervisor, Radwaste
* R. OSullivan, Nuclear Fuel, Reactor Engineering
* M. Parrish, Chemistry, Rad Protection
* S. Peterman, NSS, Operations
* S. Pettinari, Outage Coordinator
* J. Plona, Technical Manager, Engineering
* R. Pospiech, Chemistry Engineer, Rad Protection
* K. Riches, Compliance, Licensing
* D. Roc, Supervisor, Electrical
  W. Romberg, Assistant Vice President and Manager, Technical
* G. Scarfo, Supervisor, PSE Design
* T. Schehr, Engineer, Operations
* L. Talamantes, Supervisor, ISO
* E. Vinsko, I&C General Supervisor, Maintenance

Senior Management Meeting

On December 19, 1995 a management meeting was held in the Region III office in Lisle, Illinois with the Regional Administrator and the NRC Staff, to discuss the recurrence of work control problems as documented in Inspection Report 95012, dated December 12. The licensee staff presented a corrective action plan to improve plant performance in the areas of procedural compliance and procedural adequacy. Implementation of the licensee's initiative was discussed in section 5.1 of this report.

7.0 VIOLATION FOR WHICH A "NOTICE OF VIOLATION" WILL NOT BE ISSUED

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of the NRC Enforcement Policy. These tests are: 1) the violation was identified by the licensee; 2) the violation would be categorized as Severity Level IV or V; 3) within a reasonable time period; and 4) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for previous violation. Violations of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued are discussed in Sections 1.1 and 4.4.

8.0 DEFINITIONS

8.1 Inspection Followup Items Inspection followup items are matters which have been discussed with the licensee, which will be reviewed by the inspector and which involve some action on the part of the NRC or licensee or both. An inspection followup item disclosed during the inspection is discussed in Section 3.5.