U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-341/86039(DRP)

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

Licensee: Detroit Edison Company
2000 Second Avenue
Detroit, MI 48226

Facility Name: Fermi 2

Inspection At: Fermi Site, Newport, Michigan

Inspection Conducted: December 16, 1986, through February 2, 1987

Inspectors: W. G. Rogers
M. E. Parker

J. M. Ulie

Approved By: E. G. Greenman, Deputy Director
Division of Reactor Projects

3/19/87
Date

Inspection Summary

Inspection on December 16, 1986, through February 2, 1987, (Report No. 50-341/86039(DRP))

Areas Inspected: Routine, unannounced inspection by resident inspectors of licensee action on inspector identified items, operational safety, maintenance, surveillance, containment isolation valve, report review, onsite followup of events at operating reactors, and management meetings.
Results: One violation was identified in Paragraph 6 (operational ascension in violation of Technical Specifications LCO 3.0.4) and no deviations were identified. Two open items were identified (Paragraphs 2.b and 8) and two unresolved items were identified (Paragraphs 4 and 8).

DETAILS

1. Persons Contacted

   a. Detroit Edison Company

      *F. Agosti, Vice President, Nuclear Operations
      L. Bregni, Compliance Engineer
      *S. Catola, Chairman, NSRG
      L. Collins, Systems Engineering, Nuclear Engineering
      J. DuBay, Superintendent Services
      *O. Earle, Technical Engineer
      R. Eberhardt, Rad-Chem Engineer
      S. Frost, Licensing
      *J. Leman, Superintendent, Maintenance and Modification
      *R. Lenart, Plant Manager, Nuclear Production
      L. Lessor, Consultant to the Plant Manager, Nuclear Production
      J. Malaric, Maintenance Modification Staff
      *R. May, Maintenance Engineer
      *G. Ohlemacher, Assistant Maintenance Engineer
      *W. Orser, Vice President, Nuclear Engineering
      J. Plona, Assistant Operations Engineer
      *E. Preston, Operations Engineer
      *T. Randazo, Director, Regulatory Affairs
      W. Ripley, Startup Director
      L. Schuerman, General Supervisor, Nuclear Engineering
      *F. Sondgeroth, Licensing Engineer
      *B. R. Sylvia, Group Vice President, Nuclear Operations
      *G. Trahey, Director, Quality Assurance
      *W. Tucker, Acting Superintendent, Operations
      C. Weber, General Supervisor, Radwaste

   b. U.S. Nuclear Regulatory Commission

      *M. Farber, Region III
      *M. Parker, Resident Inspector
      *W. Rogers, Senior Resident Inspector
      J. Ulie, Region III

   *Denotes those who attended the exit meeting on February 3, 1987.

   The inspectors also interviewed others of the licensee's staff during this inspection.

2. Followup on Inspector Identified Items (92701)

   a. (Closed) Open Item (341/84049-20): The licensee during a November 2, 1984, meeting with NRR in Bethesda, Maryland, committed to install a fuel warmer on the fuel oil supply filter for the combustion turbine generator (CTG). This CTG provides power to the post fire alternative shutdown system. The purpose of the fuel warmer is to assure that the fuel does not gel (waxing) during extremely cold weather, causing the CTG to fail to start.

The licensee in their letter dated October 29, 1985, (VP-85-0202), committed to install a fuel warmer; the exact configuration of the fuel supply for the CTG starting diesel was not known. Subsequently, this configuration was determined. According to the licensee's letter, the starting diesel and the fuel oil supply components for the CTGs are located in a heated compartment and are not exposed to sub-freezing temperatures. On June 30, 1986, an inspector confirmed that the starting diesel and the fuel oil supply components for the CTGs are located in a heated compartment; however, the heater supplying heat to this compartment is not supervised. The inspector's concern during the June 1986 inspection regarded a potential for a malfunction of this heater, thereby allowing the compartment temperature to drop, and potentially allowing the fuel oil to gel during extremely cold temperatures. The licensing engineer at the exit interview on July 1, 1986, mentioned that upon licensee resolution of this concern, updating of the licensee's October 29, 1985, letter would take place.

Subsequently, by letter dated December 10, 1986, the licensee provided the NRC with clarifying information for the present configuration. According to this letter a thermo-blending (float tank) unit was originally installed in the fuel line for the diesel starting engine for CTG No. 11 and subsequently verified by the resident inspectors on February 4, 1987; the CTG No. 11 starting diesel is located in an enclosed compartment on the CTG skid as verified by the inspector on June 30, 1986; two electric heaters (7.5 kw and a 10 kw) provide heat to the compartment and the enclosed float tank (having fuel oil in the float tank providing the initial supply of warm fuel); operators make regularly scheduled rounds, commensurate with existing weather conditions, to the CTG site; and Section III.L.6 of Appendix R to 10 CFR 50 indicates shutdown systems installed to ensure post fire shutdown capability need not be designed to meet single failure design criteria or other design basis accident criteria. Furthermore, Section 7.2 of Enclosure 2 of Generic Letter 86-10 dated April 24, 1986, referencing Section C.1.6 of BTP CMEB 9.5-1 states that a "Worst case fire need not be postulated to be simultaneous with nonfire-related failures in safety systems, plant accidents, or the most severe natural phenomena."

Based on the licensee's clarifying information, this item is considered closed.

b. (Closed) Unresolved Item (341/85029-01(DRP)): Review of 217 inaccessible valves to enhance maintenance serviceability. The inspector reviewed the nature of the unresolved issue and considered the matter an open item. Therefore, Unresolved Item (341/85029-01(DRP)) is closed and Open Item (341/86039-01(DRP)) is initiated on the subject.

c. (Closed) Unresolved Item (341/85029-03): Reactor water cleanup pump maintenance not in accordance with the maintenance procedure. The pump repair was completed under an EDP and a revised maintenance procedure which encompassed the General Electric Field Disposition Instruction. A memorandum was issued to the maintenance foremen and journeymen emphasizing procedure compliance. Since initiating the unresolved item, the inspectors have not encountered a widespread disregard of procedures during mechanical maintenance activities. Therefore, this matter is considered closed.

3. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the period from December 17, 1986, to February 2, 1987. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the reactor building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the Division I and Division II Hydrogen Thermal Recombiner system to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning, and calibrated.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

On January 4, 1987, while performing scram time testing, a licensed operator inadvertently scrammed Control Rod 14-39 instead of Rod 14-43. This testing was being performed in the relay room with coordination between the control room. Control Rod 14-39 was already fully inserted prior to the rod scram and this action had no effect on the reactor. Control Rod 14-39 scram switch was subsequently returned to normal and all further scram time testing was stopped. The licensee has evaluated the circumstances and has since required a second verifier, similar to control rod manipulations in the control room, to observe all scram time testing at the individual scram switches in the relay room.

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

Station maintenance activities on safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine the status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed:

- Division II hydrogen recombiner blower seal replacement.
- Division I and Division II hydrogen recombiner temporary modification to throttle seal cooling flow.
- HPCI minimum flow valve (E41-F012) repair.

Following completion of maintenance on the hydrogen thermal recombiner, the inspectors verified that these systems had been returned to service properly.

During the troubleshooting of HPCI Minimum Flow Valve E41-F012, the inspector noted that the procedure for performing maintenance was not reviewed/approved by the onsite review committee (OSRO). Technical Specification 6.5.1.6.c requires OSRO approval of all procedures required by Technical Specification 6.8, which, in turn, requires written procedures for those activities identified in Appendix A, Regulatory Guide 1.33, Revision 2, February 1978. The inspector brought this situation to the attention of licensee QA management. In the ensuing discussion, the inspector was informed that a Technical Specification change request was being submitted to NRR to modify the review/approval bodies for plant procedures. The change request was submitted in letter VP-NO-87-0003 on January 7, 1987. Therefore, this matter is considered unresolved (341/86039-02(DRP)) pending NRR decision on the change request.

No violations or deviations were identified in this area.

5. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications and verified that: testing was performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following test activities:

- Division II Core Spray Cold Shutdown Valve Operability Test, 24.203.06.
- RCIC System Pump Operability and Valve Test, 24.206.01.
- Post LOCA Thermal Recombiner Functional Test, 24.409.01
- HPCI System Pump and Valve Operability Test, 24.201.02

The inspectors performed a record review of completed surveillance tests. The review was to determine that the test was accomplished within the required Technical Specification time interval, procedural steps were properly initiated, the procedure acceptance criteria were met, independent verifications were accomplished by people other than those performing the test, and the tests were signed in and out of the control room surveillance log book. The surveillance tests reviewed were:

- 44.010.72 - RPS Scram Discharge Volume High Water Level.
- 44.010.74 - RPS Scram Discharge Volume High Water Level, Division II, Channel B2, Functional Test.
- 24.139.02 - SLC Pump and Check Valve Operability Test.
- 24.608 - Rod Sequence Control System Functional Test.
- 44.020.156 - NSSSS RWCU Area, Area Ventilation Differential and NRHX Temperature, Division I, Functional Test.
- 44.020.157 - NSSSS RWCU Area, Area Ventilation Differential and NRHX Temperature, Division I, Functional Test.
- 44.020.158 - NSSSS RWCU Area, Area Ventilation Differential and NRHX Temperature, Division I, Calibration.

No violations or deviations were identified in this area.

6. Containment Isolation Valve, E51-F007 (93702)

During shutdown of the plant on August 7, 1986, following a fire in a Division I electrical Bus 2PA-1 circuit breaker cubicle the primary system pressure reduction actuated the closing circuitry of Valve E51-F007. This is a normal expected occurrence during shutdown since the valve receives an ESF signal to close at 62 psig. The valve went partially closed as exhibited by the open and closed pushbutton lights being simultaneously illuminated. The reactor operator noticed the condition and responded by putting the keylock switch associated with the valve to the "operate" position and pushed the closed pushbutton. With pressing the pushbutton the open light immediately extinguished indicating the valve was almost closed. The licensee continued the shutdown and initiated a DER.

The licensee conducted a followup on the DER which included a review of the electrical schematic for the valve. The schematic showed two electrical pathways were present to close the valve. The schematic also showed the valve position indication circuitry.

The first pathway was through the keylock switch when in the "operate" position, the close pushbutton, a torque switch and limit switch in a parallel arrangement and the closing coil. The keylock switch is a special Detroit Edison feature. Normally, the switch is in the "locked" position which maintains the closing circuitry for the valve in the de-energized condition by opening a contact. Therefore, pushing the closed pushbutton will not energize the circuit and close the valve. By placing a key in the keylock switch and turning to "operate" the contact closes and allows valve closure upon pushing the closed pushbutton. The parallel limit switch/ torque switch arrangement is such that the limit switch will open at 95% valve closure and the torque switch will open when the valve is closed and seated in the valve body with a predetermined amount of force.

The second pathway was through the ESF contact, a limit switch, the first pathway's limit switch/torque switch in a parallel arrangement and the closing coil. The ESF contact is normally open unless a high steam flow, high RCIC turbine pressure, high RCIC room temperature or low steam pressure is sensed by the ESF instruments. The single limit switch was set to open at 95% valve closure.

Position indication in the control room was based on two limit switches. The first limit switch controls the red (open) light and is set to illuminate from 100% valve opening to 95% valve closure. The second limit switch controls the green (close) light and is set to illuminate from 100% valve closure to 95% valve opening.

With the information from the schematic it was apparent that the valve had functioned as designed. When the expected low steam pressure condition was sensed the ESF contact closed. This energized the closing coil and started valve closure. The green position light illuminated after 5% valve closure. Valve closure continued until the single 95% valve closure limit switch opened. The red position light remained illuminated due to extremely minor differences in the characteristics of this 95% valve closure contact opening in the position indication circuitry and the 95% valve closure contact opening in the second pathway's single limit switch. When the operator put the keylock switch in "operate" and pushed the closed pushbutton, Pathway No. 1 energized the closing coil until the valve completed its travel and seated into the valve body with enough torque to open the torque switch. The red light in the position indication circuitry went out almost immediately since it was so close to the 95% valve closure position.

This valve design constituted an invalidation of the operability of Valve E51-F007. Technical Specification Limiting Condition for Operation 3.6.3 Table 3.6.3-1 designates this valve as an automatic containment isolation valve. Footnote (a) 8. of Table 3.6.3-1 describes the four ESF signals which initiate closure of the valve, one of which is low steam pressure. Technical Specification 3.0.4 does not allow a licensee to ascend to Operational Condition 1, 2, or 3 without all containment isolation valves operable. Since initial operation of the plant until discovery of the inadequate valve design the licensee ascended to Operation Condition 2 or 3 on six occasions (June 21, 1985; June 29, 1985; August 10, 1985; September 5, 1985; September 13, 1985; and August 4, 1986). Therefore, each of these operational condition ascensions constituted a violation of Technical Specification Limiting Condition for Operation 3.0.4 (341-86039-03(DRP)).

The licensee researched the testing history on the valve and determined that leak rate testing had always been performed with the keylock switch used to close the valve. Therefore, leak rate testing would not have discovered the inadequacy. All other testing would have been validation of the as-built condition to the design schematic (point-to-point checks, continuity, etc.). Per discussion with plant personnel, observation of dual position indication had not been noted before on previous shutdowns. This is easily understandable due to the close tolerances of the two limit switches in question. Any slight physical or electrical change during the outage would have altered the sequence of operation of these two limit switches and revealed the problem during the shutdown.

The root cause of this situation was the failure of the electrical engineer to properly design the closing circuitry for valve E51-F007, RCIC inboard isolation valve.

7. Report Review (90713)

During the inspection period, the inspector reviewed the licensee's Monthly Operating Report for November 1986. The inspector confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

8. Followup of Events (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements and that corrective actions would prevent future recurrence. The specific events are as follows:

- January 26, 1987 — Automatic RWCU isolation during troubleshooting of isolation instrumentation.
- January 7, 1987 — Unusual Event caused by a chlorine leak at the circulating water pump house.
- December 30, 1986 — Manual RWCU isolation due to leaking demineralizer isolation valves.

- December 27, 1986 Automatic RWCU isolation due to leaking head gasket on the A filter demineralizer.

- December 26, 1986 Both thermal recombiners divisions inoperable.

- December 26, 1986 HPCI & RCIC inoperable simultaneously.

- December 20, 1986 Reversed thermocouple leads render a portion of the RWCU leak sensing system inoperable.

During followup of the December 26, 1986, simultaneous HPCI/RCIC event, a number of issues were identified. Those issues of potential escalated enforcement significance are identified in Inspection Report No. 50-341/87002. The remaining issues are presented below.

The RCIC system was declared inoperable due to an out-of-calibration flow transmitter and was recalibrated. The inspector reviewed the maintenance history on the transmitter. This revealed that the transmitter had failed numerous calibration checks in the last two years. The inspector pursued what immediate corrective actions were taken by the licensee beyond recalibration of the transmitter after the second/third calibration check failure. None were taken. There was an engineering design package (EDP) for eventual replacement of the transmitter at a future date. However, there was not a utilization of the equipment maintenance/performance history to trigger deeper root cause analysis of the erratic transmitter. The inspector considers this situation to be an inadequacy in the corrective maintenance/equipment evaluation program. The action the licensee intends to take to improve this area is an Open Item (341/86039-04(DRP)).

During the review of the flow transmitter instrument loop, the inspector questioned how the instrument tolerances were factored into the flow control network to assure 600 gpm is truly supplied by the RCIC system. Through discussion with the licensee, it was apparent that the licensee did not feel a need to factor in the instrument tolerances. The inspector had preliminary discussions with NRR on the subject with the conclusion that the licensee should take the tolerances into account. Following discussion of the situation with the licensee, the flow control setpoints on HPCI and RCIC were increased to take the tolerances into account. This matter is considered unresolved (341/86039-05(DRP)) pending further input from the licensee or NRR on why the tolerances should not be taken into account.

The inspector reviewed numerous Deviation Event Reports (DERs). Of the group reviewed, three events were viewed by the inspector as having significance. The events were:

- DER 87-006 - Failure to inform the NSS of an instrument out of calibration.

- DER 87-030 - Failure of an EDG to start.

- DER 87-025 - Failure to properly verify an EDG breaker was returned to service.

No violations or deviations were identified in this area.

9. Management Meetings (30702B)

On January 21, 1987, the licensee made a presentation to NRC Region III in Glen Ellyn, Illinois, to discuss steam line vibration problems. The licensee had observed instrument line failures while operating in early January. The licensee described their steam bypass line vibration monitoring program, the main steam line instrument line failure mechanism and corrective actions.

On December 30, 1986, Region III Regional Administrator, J. G. Keppler; NRR Licensing Division Director, R. Bernero; and Region III Deputy Division Director, E. Greenman; went on a tour of the facility and discussed their observations with the licensee at the tour's conclusion.

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. Unresolved items disclosed during the inspection are discussed in Paragraphs 4 and 8.

11. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 2.b and 8.

12. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on February 3, 1987, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.