U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-341
License No:	NPF-43
Report No:	50-341/99010(DRP)
Licensee:	Detroit Edison Company
Facility:	Enrico Fermi, Unit 2
Location:	6400 N. Dixie Hwy. Newport, MI 48166
Dates:	June 19 through July 23, 1999
Inspectors:	S. Campbell, Senior Resident Inspector J. Larizza, Resident Inspector
Approved by:	A. Vegel, Chief Reactor Projects Branch 6 Division of Reactor Projects

EXECUTIVE SUMMARY

Enrico Fermi, Unit 2
NRC Inspection Report 50-341/99010(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 5-week period of resident inspection.

Operations

- The licensee identified that the safety tagging record for maintenance on the general service water (GSW) sluice gate did not provide adequate protection and resulted in a near miss while restoring the system. Lack of operator knowledge regarding the job scope and status of the work activity contributed to the inadequate safety tagging record protection (Section O1.1).

- The inspectors concluded that the licensee responded effectively to a small fire on the Division 2 Control Center Heating Ventilation Air Conditioning Makeup Radiation Monitor Sample Pump Motor. Operators used the correct procedures for extinguishing the fire, classifying the event and making the proper notifications (Section O1.2).

- The NRC determined that on May 4, 1999, the licensee failed to verify, within 2 hours, the operability of Standby Liquid Control System B after Emergency Diesel Generator 11 was removed from service. Consequently, the licensee did not perform this verification and did not place the unit in Hot Shutdown within 12 hours after both Emergency Diesel Generator 11 and Standby Liquid Control System B remained inoperable for approximately 32 hours. One cited violation of Technical Specification 3.8.1.1.c was identified (Section O8.1).

Maintenance

- Miscommunication among the maintenance crew and inadequate implementation of the safety tagging record program, by the protection leader, created a condition where the maintenance crew was not adequately protected during a GSW maintenance activity (Section O1.1).

- Observed maintenance and surveillance activities were performed in accordance with approved procedures by knowledgeable individuals (Section M1.1).

Engineering

- An engineer, who investigated the inspectors' concern of an unsecured emergency diesel generator oil drain line, did not meet management's expectations for correcting deficiencies when the engineer clamped the line without concurrence from the operations department and without a work request (Section O2.1).

- A modification to treat the GSW discharge header (the source of zebra mussel infestation) was not implemented as scheduled due to administrative delays including delays in developing effective procedures. Scheduling Biocide treatments late in Refueling Outage 6 resulted in treatments being performed with low GSW water temperatures, causing a delay in Biocide effectiveness. The delay in eradicating the

zebra mussels contributed to the fouling of the GSW heat exchangers and, as a result, presented a challenge to the plant operators (Section E1.1).

- The inspectors concluded, following system walkdowns and interviews with system engineers, that system engineers were generally knowledgeable of their respective systems. System health reports were established to evaluate system performance and Get Well plans were developed and implemented to improve system performance as needed (Section E4.1).

Plant Support

- Health physics and security personnel provided effective support during a small fire on the Division 2 Control Center Heating Ventilation Air Conditioning Makeup Radiation Monitor Sample Pump Motor (Section O1.2).

- The inspectors concluded that the reactor coolant samples were taken, labeled, handled, prepared for analysis in accordance with approved procedures. Chemistry personnel followed appropriate radiation work permit requirements and had received appropriate training for the activity. Chemistry personnel used properly calibrated equipment (Section R1.1).

- The licensee appropriately classified that the loss of the emergency notification system and telecommunications with Monroe County as an Unusual Event. The inspectors concluded that the licensee responded to the event in a prompt and conservative manner. Alternate communications were established effectively (Section P2.1).

Report Details

Summary of Plant Status

Unit 2 was operated at or near 97 percent power throughout the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Implementation of Safety Tagging Record (STR) Program

a. Inspection Scope (71707)

The inspectors interviewed operations and maintenance personnel and reviewed the following documents to followup on the circumstances that led to improper implementation of the tagging program for the general service water (GSW) system:

- Work Request 000Z990624, "West Sluice Gate Trips During Closure,"
- STR 99-0545, "GSW West Sluice Gate,"
- STR 99-0591, "GSW East and West Traveling Screens," and
- Condition Assessment Resolution Document (CARD) 99-14688, "Fuse Blew Due to Shorted Lead,"
- Procedure MOP 12 "Tagging and Protective Barrier System."

b. Observations and Findings

On June 1, 1999, operators tagged open the power supply to the west traveling screen in accordance with STR 99-0545 for maintenance personnel to repair a motor operator for a sluice gate. Besides the west traveling screen, this tagout de-energized the east traveling screen, GSW Pressure Switch to Traveling Screen B P41N001B and GSW Traveling Screen B Sprayer Solenoid Valve P41F001B. Maintenance personnel removed and taped the leads for P41N001B and P41F001B. The protection leader, who was responsible for ensuring that the tagout adequately protected personnel, signed in on the protection contract and the maintenance activity was started on June 2.

On June 6, 1999, the operators decided to remove the tagout so the east traveling screen could be operated to correct a high differential pressure condition. Subsequently, the protection contract was signed off by the maintenance protection leader. During discussions between the work control nuclear assistant shift supervisor and the maintenance foreman, the work control nuclear assistant shift supervisor determined that the work activity would not recommence for approximately 2 days. As a result, the operators decided to leave the east traveling screen in service.

On June 9, 1999, a work control shift foreman modified the tagout to alter the GSW traveling screen logic (by lifting a power lead) so the east traveling screen would operate without the west traveling screen. Consequently, the foreman did not know the scope or

the status of the job and did not communicate the modification of STR 99-0545 to the maintenance crew. Procedure MOP 12 did not require this communication be done. The modified STR caused the disconnected leads for P41N001B and P41F001B to be powered and caused STR 99-0545 to provide inadequate protection.

The same day, the licensee decided to perform preventive maintenance on the east traveling screen while maintenance personnel worked on the sluice gate motor operator. To perform the maintenance, the operators developed STR 99-0591 to remove power from essentially the same components listed on STR 99-0545 that included P41N001B and P41F001B. Without power to the leads, maintenance personnel were protected and continued working under STR 99-0545 without incident.

On June 14, 1999, the protection leader, who was not in the original work crew, had signed in on STR 99-0545 but did not meet management's expectations in verifying the tagout was adequate. As a result, the protection leader missed identifying that STR 99-0545 was inadequate. Subsequently, the protection leader was reassigned to another job and did not sign off on the protection contract. Consequently, the maintenance crew continued working without knowledge of whom the responsible protection leader was.

On June 17, 1999, mechanics completed Work Request 000Z990624. Without verifying that the protection was adequate, electricians removed the tape and began connecting leads for P41N001B and P41F001B in preparation to clear STR 99-0545 . Concurrently, operators began clearing STR 99-0591 after the electricians completed the preventive maintenance on the east traveling screen which caused the unconnected bare wires for P41N001B and P41F001B to be powered. Bare wires resting on the steel floor grating grounded, sparked, and a fuse blew. The work was stopped and operations personnel established a new protection order. The licensee initiated CARD 99-14688 to document the near miss.

Corrective actions for the incident included discussions between operations and maintenance personnel regarding Procedure MOP 12 requirements to identify and correct deficiencies in the STR process and to review training material to ensure adequate training was being conducted.

c. Conclusions

The licensee identified that the safety tagging record for maintenance on the GSW sluice gate did not provide adequate protection and resulted in a near miss while restoring the system. Lack of operator knowledge regarding the job scope and status of the work activity contributed to the inadequate safety tagging record protection.

Miscommunication among the maintenance crew and inadequate implementation of the safety tagging record program, by the protection leader, created a condition where the maintenance crew was not adequately protected during the GSW maintenance activity.

O1.2 Plant Staff Response to a Small Fire in the Auxiliary Building

a. Inspection Scope (71707)

On June 21, 1999, the inspectors observed the licensee's response to a fire on the Division 2 Control Center Heating Ventilation Air Conditioning (CCHVAC) Normal Makeup Radiation Monitor Sample Pump Motor. The inspectors reviewed the following documents to determine whether the licensee appropriately responded to the event:

- Procedure 23.625, "Process Gaseous Radiation Monitoring,"
- Emergency Procedure (EP) 101, Enclosure A, Tab H, "Classification of Emergencies,"
- Abnormal Operating Procedure (AOP) 20.000.22, "Plant Fires," and
- Technical Specification (TS) 3.3.7.1, Table 3.3.7.1-1, "Radiation Monitoring."

b. Observations and Findings

On June 21, 1999, operations personnel had cleared tags and started the Division 2 CCHVAC Normal Makeup Radiation Monitor Sample Pump to perform a post-maintenance test. The individual who started the pump waited approximately 1 minute and left the area. Twenty minutes later, another operator entered the room to check the pump fuses and noted a light smell of smoke and flames around the shaft of the pump motor. The operator contacted the control room and a fire brigade was mustered. The pump motor was subsequently de-energized and the small flames were extinguished within 7 minutes using a CO_2 fire extinguisher. The fire brigade was not used for this event.

The inspectors observed security, operations and health physics personnel respond appropriately to the fire. Security personnel were stationed at the key card reader to observe individuals enter the Auxiliary Building. Health physics personnel monitored the areas for radiation and surveyed the area for contamination. Operations personnel used AOPs, operations department instructions, and EPs appropriately to respond to the event, to classify the event properly, to perform the proper notifications, and to ensure license requirements were met. Command and control of the event from the control room was effective. Operations personnel stationed a fire watch at the sample pump following the event. Further, the licensee interviewed the individuals involved and issued CARDs 99-16078 and 99-16077.

c. Conclusions

The inspectors concluded that the licensee responded effectively to a small fire on the Division 2 CCHVAC Makeup Radiation Monitor Sample Pump. Operators used the correct procedures for extinguishing the fire, classifying the event and making the proper notifications.

Health physics and security personnel also provided effective support during a small fire on the Division 2 CCHVAC Makeup Radiation Monitor Sample Pump Motor.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

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

- Emergency Diesel Generator (EDG) 11,
- Residual Heat Removal Service Water System and Mechanical Draft Cooling Towers,
- Divisions 1 and 2 Switchgear Rooms,
- Emergency Equipment Cooling Water System,
- High Pressure Coolant Injection (HPCI) System,
- Reactor Core Isolation Cooling System.

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. In particular, the oil drain line for EDG 11 had a missing clamp on the north side and a south line was not under a clamp. Although this condition did not impact EDG operability, the engineer repaired the south line without concurrence of operations personnel and without a work request. This did not meet management's expectations for repairing safety-related systems. The licensee initiated CARD 99-15880 to document the inspectors' observations.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Unresolved Item (URI) 50-341/99007-01: Conduct of EDG 11 Maintenance Activity with Standby Liquid Control (SLC) Pump B Inoperable. On May 5, 1999, the inspectors identified that the licensee had removed Division 1 EDG 11 for maintenance while Division 2 SLC system was inoperable. With neither SLC B nor EDG 11 available, a method of injecting Boron into the core may not have been available during a loss of offsite power event. The licensee initiated CARD 99-13518 to document the inspectors' concern. Operator response to this issue, and evaluation of the circumstances related to this issue, were documented in Inspection Report 50-341/99009 dated July 12, 1999.

On May 25, 1999, the licensee completed the evaluation of TS 3.8.1.1.c applicability as documented in CARD 99-13518. The licensee determined that the SLC system was not a critical system required to mitigate a design basis accident (DBA). Therefore, the licensee concluded that TS 3.8.1.1.c did not apply to the SLC system. The licensee's basis for not considering the SLC system as a critical system and the applicability of TS 3.8.1.1.c was reviewed by the NRC staff.

On July 8, 1999, the NRC staff completed their review of the licensee's basis for their determination regarding TS 3.8.1.1.c applicability. The staff concluded that the licensee was in violation of TS 3.8.1.1.c when it did not commence a plant shutdown after EDG 11 became inoperable with SLC B inoperable. Further, the staff determined that

TS 3.8.1.1.c addressed all systems/components covered by the TS without regard to whether or not they were credited in the mitigation of a DBA. The SLC system is required by TS, as well as by regulation and is, therefore, subject to the provisions of TS 3.8.1.1.c. The staff determined that the Fermi TS bases do not alter the above positions.

The bases address the "safety function of critical systems." The bases did not elaborate on what constitutes a critical system and, as such, do not limit the TS applicability to systems/components credited for mitigating the consequences of a DBA. Therefore, the SLC is a critical system because it is covered by TS and required by regulations.

Technical Specification 3.8.1.1.b requires, in part, that while the plant is in Operational Conditions 1, 2, and 3, two separate and independent onsite alternating current electrical power sources, each consisting of two EDGs shall be operable. Action Statement 3.8.1.1.c requires, in part, that with one or both EDGs inoperable, verify within 2 hours that all required systems, subsystems, trains, components and devices that depend on the remaining onsite alternating current electrical power division as a source of emergency power are also operable; otherwise, be in at least Hot Shutdown within the next 12 hours.

Contrary to the above, within 2 hours of removing Division 1 EDG 11 from service at 3:00 a.m., on May 4, 1999 (with the plant in Operational Condition 1), the licensee failed to verify that components depending on the Division 2 Diesel as a source of emergency power were operable. Additionally, the licensee failed to place the plant in Hot Shutdown within the next 12 hours. Specifically, the Division 2 SLC B (a system that depends Division 2 Diesel as its source of emergency power) was inoperable at the time the Division I Diesel was removed from service. The concurrent inoperability of the Division 2 SLC B and the Division 1 Diesel lasted for approximately 32 hours until May 5, 1999, at 10:32 a.m., when the Division 2 SLC B was returned to service.

As of the end of the inspection period, the licensee had not recognized or acknowledged this violation and, therefore, had not adequately placed this issue in the corrective action program. Hence, this is a cited violation (NOV 50-341/99010-01(DRP)).

08.2 Closure of Severity Level IV Violations

The Severity Level IV violations listed below were issued in Notices of Violation prior to the March 11, 1999, implementation of the NRC's new policy for treatment of Severity Level IV violations (Appendix C of the Enforcement Policy). Because these violations would have been treated as non-cited in accordance with Appendix C, they are being closed out in this report.

- Violation 50-341/95003-02 — This violation is in the licensee's corrective action program as Deviation Event Reports (DERs) 95-0070, 94-0751, 94-0424, 93-0644, 93-0507, 93-0423, 93-0319, and 93-0312.

- Violation 50-341/97007-01 — This violation is in the licensee's corrective action program as DERs 97-1002, 97-1072.

- Violation 50-341/97007-03 This violation is in the licensee's corrective action program as DER 97-0910.

- Violation 50-341/98004-02 This violation is in the licensee's corrective action program as CARD 98-1066.

- Violation 50-341/98004-03 This violation is in the licensee's corrective action program as CARD 98-1066.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- Surveillance Procedure 42.302.11, Revision 32, "Channel Functional Test of Division 1 4160 Volt Bus 64C Undervoltage Circuits,"

- Surveillance Procedure 24.202.01, Revision 61, "HPCI [High Pressure Coolant Injection] Time Response and Operability Test at 1025 psi,"

- Surveillance Procedure 24.203.02, "Division 1 Core Spray System Pump and Valve Operability, and Automatic Initiation,"

- Procedure 47.000.02, "Mechanical Vibration Measurements for Trending, Vibration Monitored Machinery for Post Maintenance Testing (Core Spray Pump A, B, C, D),"

- Procedure 43.000.05, "Visual Examination of Piping and Components (VT-2)," and

- Work Request Z840970723, "Clean, Lubricate, Exercise Motor Control Center Fused Disconnect Switch Pivots with QD Cleaner and SILOO Lubricant."

Observed maintenance and surveillance activities were performed in accordance with approved procedures by knowledgeable individuals.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) URI 50-341/97013-04: Use of Pipe Sealant Compound in Pneumatic Systems. The solenoid operator valves (SOVs) in Divisions 1 and 2 Primary Containment Pneumatics Nitrogen Supply Isolation Valves T4901F466 and T4901F468, had a slight deposit of the pipe sealant on the end of a solenoid core. The presence of the compound caused valve sticking and stroke times above the allowed acceptance criteria. Deviation Event Reports 97-1200 and 97-1202 were written to address slow stoke times and potential solenoid operated valve deficiencies.

During the closeout of this issue in Inspection Report (IR) 50-341/99003, the inspectors reviewed the associated corrective actions that included laboratory testing, which had not been completed. Since then, laboratory testing was completed for 17 of the remaining 22 SOVs. The 17 SOVs had no presence of the compound. The inspectors concluded that the presence of the compound was limited to Primary Containment Pneumatics Nitrogen Supply Isolation Valves T4901F466 and T4901F468. The inspectors concluded that the corrective action to use graphite impregnated tape in lieu of pipe sealant compound was acceptable. The inspectors did not identify other concerns.

III. Engineering

E1 Conduct of Engineering

E1.1 Biocide Treatment of Zebra Mussels in GSW System

a. Inspection Scope (37551)

The inspectors interviewed engineering and chemistry personnel to follow up on the effectiveness of chemically treating the GSW system after several heat exchangers became fouled with zebra mussels. The inspectors reviewed the following documents that the licensee had initiated to document previous and current deficiencies:

- CARD 99-14374 "Improvements in System Operations to Deal With Zebra Mussel Fouling of GSW Supplied Heat Exchanger,"
- CARD 99-14254 "Northeast Hydrogen Cooler Outlet Temperature Higher than Other Coolers,"
- CARD 98-13269 "GSW Performance is Less Than Established Criteria,"
- CARD 97-11598 "GSW Pump 2 Zebra Mussel Infestation," and
- DER 96-0732 "Blockage of Cooling Flow Indicating Switch."

b. Observations and Findings

As previously documented in Inspection Report 50-341/99009 several nonsafety-related heat exchangers became fouled with zebra mussel shells. Extensive efforts from maintenance, operations, and engineering personnel were required to minimize the impact of the fouling on plant operation. During this inspection period the inspectors assessed past and current licensee efforts to minimize the impact of zebra mussel shells.

To mitigate zebra mussel growth the licensee continually adds Biocide to the GSW system in the summer and intermittently during the winter. However, the GSW discharge header cannot be treated effectively due to the potential for discharging Biocide to the lake, which is an environmental concern. Since the GSW header is not fully treated by the chemicals, some zebra mussels continue to grow, and periodically release. The released or dead shells then cause heat exchanger fouling. In addition, the probabilistic risk worth of the GSW system was relatively high due to its initiating

event frequency, which accounts for 6 percent of the initiating events to core damage frequency. Therefore, core damage frequency could be impacted if the initiating event increased, (i.e., GSW cooling decreased due to zebra mussel infestation or if system was out-of-service for maintenance).

In 1996, the licensee knew that past treatments of the discharge header had been ineffective when zebra mussels were discovered in the GSW Pump 2 casing as documented in DER 96-0732. The DER corrective action included the formation of a zebra mussel task force to investigate the problem. The task force recommended that the GSW system be modified to treat the GSW discharge header and to treat the GSW system in future refueling outages. However, due to administrative delays and delays in developing effective procedures to eradicate zebra mussels, the implementation of the modification was rescheduled for September 1999.

In Refueling Outage 6, the licensee attempted to treat the GSW system. The licensee did not want to schedule the treatment while the plant was in shutdown cooling to prevent the dead zebra mussel shells from fouling heat exchangers used to remove decay heat, specifically, the reactor building closed cooling water heat exchangers. Therefore, the treatment was scheduled at the end of the outage. Consequently, as delays in completing the shutdown cooling maintenance occurred, lake temperatures became lower than expected. General Service Water temperature decreased due to the lower lake temperatures and to the north cooling tower being in service for maintaining the unit in natural recirculation. The lower GSW temperature decreased the mortality efficiency of the Biocide by 50 percent.

Following this treatment, the licensee expected a release of dead zebra mussels within 2 weeks. Unfortunately, this did not occur because the cold water slowed zebra mussel metabolisms, thereby slowing the mortality rate, and the time for the zebra mussel byssal threads (used to attach the mussels to pipe walls and other mussels) to decay. Consequently, effectiveness of the treatment became evident when the dead zebra mussels released in early June of 1999, as documented in IR 50-341/99009.

Conclusion

A modification to treat the GSW discharge header (the source of zebra mussel infestation) was not implemented as scheduled due to administrative delays including delays in developing effective procedures. Scheduling Biocide treatments late in Refueling Outage 6 resulted in treatments being performed with low GSW water temperatures, causing a delay in Biocide effectiveness. The delay in eradicating the zebra mussels contributed to the fouling of the GSW heat exchangers and, as a result, presented a challenge to the operators.

Although slow in resolving the zebra mussel infestation on the nonsafety-related GSW system, licensee management has recognized this high risk system (an initiator to core damage frequency) and has focused the resources needed for correction.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineer Knowledge and Support of Risk Significant and Safety-Related Systems

a. Inspection Scope (37551)

The inspectors interviewed responsible engineers, reviewed drawings, system health reports, Get Well plans and walkdowns associated systems to determine the adequacy of engineering support for the following systems:

- GSW System,
- 345 kV Relay House and Relaying,
- Residual Heat Removal Service Water and Mechanical Draft Cooling Towers,
- Reactor Core Isolation Cooling System,
- Core Spray System,
- HPCI System,
- Reactor Water Cleanup System,
- Automatic Depressurization System and Safety Relief Valve,
- Emergency Equipment Cooling Water System,
- Emergency Equipment Service Water System.

b. Observations and Findings

Generally, the system engineers were familiar with the associated systems. The engineers evaluated the systems per the system health report guidelines and the maintenance rule program. The engineers developed and implemented Get Well plans to improve system deficiencies and rectify issues. In particular, the inspectors noted significant improvements in the reactor water cleanup, automatic depressurization system, safety relief valves, and the GSW Systems. The inspectors noted during the walkdown that the systems were in acceptable condition. The inspectors provided feedback to management on minor engineering program or knowledge deficiencies and management used the feedback to elaborate expectations of the engineering program to the engineers.

c. Conclusions

The inspectors concluded, following system walkdowns and interviews with system engineers, that the system engineers were generally knowledgeable of their respective systems. System health reports were established to evaluate system performance and Get Well plans were developed and implemented to improve system deficiencies as needed.

E8 Miscellaneous Engineering Issues (92903)

E8.1 Closure of Severity Level IV Violations

The Severity Level IV violations listed below were issued in Notices of Violation prior to the March 11, 1999, implementation of the NRC's new policy for treatment of Severity Level IV violations (Appendix C of the Enforcement Policy). Because these violations would have been treated as non-cited in accordance with Appendix C, they are being closed out in this report.

- Violation 50-341/97011-01014 — This violation is in the licensee's corrective action program as CARD 97-11876.
- Violation 50-341/96017-01 — This violation is in the licensee's corrective action program as DERs 96-1288 and 96-1289.
- Violation 50-341/99002-01 — This violation is in the licensee's corrective action program as CARDs 99-10431, 99-10432, 99-10434.

E8.2 (Closed) Licensee Event Report (LER) 50-341/97005-01: Inadequate Design or Consideration of Circuits Involved in Achieving Dedicated Shutdown. During a review of dedicated shutdown circuits, the licensee identified a condition where 14 Division 2 smoke/CO_2 isolation dampers would fail open during a design basis fire with a loss of offsite power. The opened dampers would have released smoke and/or CO_2 that required operators to don self-contained breathing apparatuses to ensure habitability for operating dedicated shutdown equipment. Corrective actions included modifying plant equipment and systems for staging self-contained breathing apparatuses in the affected areas and changing dedicated shutdown procedures. This LER revision was addressed during closure of LER 97005-00 in IR 50-341/97011. No violations were identified during review.

E8.3 (Closed) URI 50-341/98006-03: Dedicated Shutdown Procedure Inadequacies. Review of the licensee's determination of all potential drain paths from the condensate storage tank (CST) and whether other discrepancies exist in the licensee's fire hazard analysis. This item involved a discrepancy that did not permanently correct a deficiency in the station, AOP 20.000.18, "Control of the Plant from the Dedicated Shutdown Panel," that could have caused the inadvertent draining of the CST to the hotwell. The CST water was required for use by the standby feedwater system to bring the reactor to a Cold Shutdown condition during a postulated fire as defined in 10 CFR 50, Appendix R.

Procedure 20.000.18 has been revised to incorporate the proper sequence of de-energizing and closing valves to isolate the CST during a postulated Appendix R fire. The licensee's review has determined that there are no additional valves susceptible to a fire induced spurious actuation.

Technical Specification 6.8.1.a. states, in part, that written procedures be implemented for activities covering applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Section 5 in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, requires procedures describing immediate operator actions to rectify abnormal conditions. Contrary to the above, AOP 20.000.18,

"Control of the Plant from the Dedicated Shutdown Panel," provided inadequate immediate operator actions in that performance of the instructions could have caused the inadvertent draining of the CST to the hotwell during a postulated Appendix R fire. This Severity Level IV violation is being treated as non-cited, consistent with Appendix C of the NRC enforcement policy (NCV 50-341/99010-02(DRP)). This violation is in the licensee's corrective action program as CARD 98-14910.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Reactor Coolant System Analysis (71750)

On June 30, 1999, the licensee performed a reactor coolant analysis. The inspectors observed the chemistry surveillance activities; sampling, labeling, and handling of reactor coolant samples at the sample panel in the Reactor Building, and the preparation for and the gamma spectroscopy analysis of the samples in the chemistry laboratory. The inspectors noted that the reactor coolant samples were taken, labeled, handled, prepared and gamma spectroscopy analyzed in accordance with approved procedures. Chemistry personnel followed appropriate radiation work permit requirements and received appropriate training for the activity. The inspectors reviewed the samples, the gamma spectroscopy analysis data and the associated calculations and found them to be acceptable and within the allowed TS requirements. The technician used appropriately calibrated equipment.

P2 Status of Emergency Preparedness Equipment and Resources

P2.1 Cut Fiber Optic Cable Causes of Offsite Communication to be Impaired

a. Inspection Scope (71750)

The inspectors interviewed emergency response and operations organization personnel and reviewed the following documents to followup on the licensee's response and corrective actions to an unplanned loss of site communications:

- EP 101, Enclosure A, Supplement 6, "Unplanned Loss of Communication Capability,"
- EP 290, "Emergency notifications,"
- Licensing /Safety Conduct Manual MLS 05, Revision 9, "Notifications/General Reporting Requirements," and
- CARD 99-14750, "Loss of Onsite Telephone Communications."

b. Observations and Findings

On June 25, 1999, at 2:10 p.m., the Monroe County Sheriff was unable to receive calls from the Fermi 2 security organization because a fiber optic line had been accidentally severed offsite. The licensee established and maintained communication to the Monroe

County Sheriff via two-way radios. The partial loss of telephone communications offsite also created a problem with contacting Fermi 2 emergency response individuals living in Monroe County. Further, the licensee tested and found that the emergency notification system did not work.

In response to this condition, the licensee established communication outside the plant via the radiological emergency response preparedness communication (microwave) system. Due to the inability to contact the Monroe County Sheriff through the normal phone lines, the licensee declared an Unusual Event per EP 101 and made proper notifications to state and local authorities, plant management, and the NRC per EP 290 and MLS 05. Throughout the event, the licensee discovered that Fermi 2 emergency response individuals could be contacted using alpha-numeric pagers through the microwave system. As a result of the Unusual Event, the licensee partially staffed the Emergency Operations Facility and maintained a complement of members onsite to staff the Technical Support Center (TSC) until the fiber optic line was repaired and communications restored at 6:08 p.m.

The licensee initiated CARD 99-14750 as a result of the event. During the investigation, the licensee determined that sufficient microwave lines were available in the Emergency Operations Facility and the TSC. However, the licensee was evaluating whether to increase the non-microwave (administrative) lines in the TSC for habitability purposes since the majority of these lines are outside the TSC envelope. Further, during the event, the licensee discovered that the facsimile number for Wayne County was not programmed in the facsimile machine correctly. Subsequently, the licensee corrected this finding.

c. Conclusions

The licensee appropriately classified that the loss of the emergency notification system and telecommunications with Monroe County as an Unusual Event. The inspectors concluded that the licensee responded to the event in a prompt and conservative manner. Alternate communications methods were established effectively.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 23, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Proprietary information was identified and returned to the licensee.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Bragg, Supervisor, Audits
C. Cassise, Work Control
D. Cobb, Superintendent, Maintenance
J. Davis, Director, Nuclear Training
R. DeLong, Assistant to the Manager, Engineering
T. Dong, System Engineering
P. Fessler, Assistant Vice-President, Nuclear Operations
R. Fitzsimmons, Nuclear Security
M. Hall, Licensing, Independent Safety Engineering Group
K. Harsley, Licensing, Compliance
M. Khachaturian, Intern
E. Kokosky, Superintendent, Radiation Protection/Chemistry
P. Lynch, Work Control, Operations
W. O'Connor, Assistant Vice-President, Nuclear Assessment
P. Smith, Licensing, Compliance
S. Stasek, Supervisor, Independent Safety Engineering Group

NRC

S. Campbell, Senior Resident Inspector
A. Vegel, Chief, Reactor Projects Branch 6

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-341/99010-01	VIO	EDG 11 maintenance activity with SLC B inoperable
50-341/99010-02	NCV	inadequate abnormal operating procedure for dedicated shutdown

Closed

50-341/99007-01	URI	conduct of EDG 11 maintenance activity with SLC Pump B inoperable
50-341/95003-02	VIO	two examples of inadequate corrective actions
50-341/97007-01	VIO	failure to comply with Technical Specification 3.8.1
50-341/97007-03	VIO	failure to prevent recurrence of CST line freezing
50-341/98004-02	VIO	inappropriate instructions for fuel handling
50-341/98004-03	VIO	lack of critical controls during fuel bundle disassembly
50/341/97013-04	URI	use of pipe sealant compound in pneumatic systems
50-341/97011-01014	VIO	inadequate 50.59 to evaluate actions for emergency equipment cooling water in drywell cooling
50-341/96017-01	VIO	01A-Rods could not be reinserted
50-341/99002-01	VIO	errors made in three design calculations
50-341/97005-01	LER	inadequate design or consideration of circuits involved in achieving dedicated shutdown.
50-341/98006-03	URI	dedicated shutdown procedure inadequacies
50-341/99010-02	NCV	inadequate abnormal operating procedure for dedicated shutdown

Discussed

None

LIST OF ACRONYMS USED

AOP	Abnormal Operating Procedure
CARD	Condition Assessment Resolution Document
CCHVAC	Control Center Heating Ventilation Air Conditioning
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DBA	Design Basis Accident
DER	Deviation Event Report
EDG	Emergency Diesel Generator
EP	Emergency Procedure
GSW	General Service Water
HPCI	High Pressure Coolant Injection
IR	Inspection Report
LER	Licensee Event Report
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
SLC	Standby Liquid Control
SOV	Solenoid Operated Valve
STR	Safety Tagging Record
TS	Technical Specification
TSC	Technical Support Center
URI	Unresolved Item