UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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May 1, 2017

Mr. Paul Fessler, Senior VP
and Chief Nuclear Officer
DTE Energy Company
Fermi 2 - 210 NOC
6400 North Dixie Highway
Newport, MI 48166

SUBJECT: FERMI POWER PLANT, UNIT 2—NRC INTEGRATED INSPECTION REPORT 05000341/2017001

Dear Mr. Fessler:

On March 31, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Fermi Power Plant, Unit 2 (Fermi 2). On April 11, 2017, the NRC inspectors discussed the results of this inspection with Mr. M. Caragher and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

The NRC inspectors documented two findings of very low safety significance (Green) in this report. Each of these findings involved violations of NRC requirements. In addition, one licensee-identified violation was documented in this report. The NRC is treating each of these violations as Non-Cited Violations consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of the Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001, with copies to: (1) the Regional Administrator, Region III; (2) the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and (3) the NRC Resident Inspector at the Fermi 2 Power Plant.

In addition, if you disagree with the cross-cutting aspect assignment to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Fermi 2 Power Plant.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA Karla Stoedter Acting for/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

Docket No. 50–341
License No. NPF–43

Enclosure:
Inspection Report 05000341/2017001

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Letter to Paul Fessler from Kenneth Riemer dated May 1, 2017

SUBJECT: FERMI POWER PLANT, UNIT 2—NRC INTEGRATED INSPECTION REPORT 05000341/2017001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–341
License No:	NPF–43
Report No:	05000341/2017001
Licensee:	DTE Energy Company
Facility:	Fermi Power Plant, Unit 2
Location:	Newport, MI
Dates:	January 1, 2017 through March 31, 2017
Inspectors:	B. Kemker, Senior Resident Inspector P. Smagacz, Resident Inspector K. Pusateri, Acting Resident Inspector M. Doyle, Reactor Engineer
Approved by:	K. Riemer, Chief Branch 2 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000341/2017001; 01/01/2017 – 03/31/2017; Fermi Power Plant, Unit 2; Identification and Resolution of Problems, Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by the resident inspectors. Two Green findings, each of which had an associated Non-Cited Violation (NCV) of the U.S. Nuclear Regulatory Commission (NRC) regulations, were identified. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated October 8, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated July 2016.

NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance with an associated NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when plant operators discovered a thick white smoke plume coming from the emergency diesel generator (EDG) 14 engine exhaust manifold during surveillance testing. Consequently, operators shut down the engine and removed it from service. The licensee failed to have work instructions for maintenance on the safety-related EDG appropriate to ensure insulation blankets on the engine's exhaust manifold were replaced with insulation blankets conforming to the approved engineering design. The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions. The licensee replaced the insulation blankets with insulation blankets conforming to the approved engineering design.

The finding was of more than minor safety significance because it was related to the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, operators shutdown the engine after discovering a thick white smoke plume coming from the engine's exhaust manifold , which resulted in unplanned inoperability and unavailability of this onsite emergency power source. The finding was determined to be of very low safety significance because it did not represent an actual loss of function of a single train for greater than its Technical Specification (TS) allowed outage time nor did it represent a loss of function of a non-TS train designated as high safety significant in accordance with the licensee's Maintenance Rule Program. The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of documentation. Plant activities are governed by comprehensive, high-quality, programs, processes and procedures. Design documentation, procedures, and work packages are complete, thorough, accurate, and current. In this case, the licensee's process for implementing and maintaining engineering configuration control of the newly designed EDG exhaust manifold insulation blankets was inadequate because it did not follow the licensee's formal engineering configuration management process. (IMC 0310, H.7) (Section 4OA2.2.b.1)

Green. A finding of very low safety significance with an associated Non-Cited Violation of TS 3.1.7, "Standby Liquid Control (SLC) System," was self-revealed when the licensee measured the boron concentration in the SLC storage tank and discovered the concentration was below the minimum requirement of 8.5 percent. Specifically, the licensee failed to adequately monitor and identify a decreasing trend in SLC storage tank sodium pentaborate concentration concurrent with known dilution of the SLC storage tank during pump and valve testing. The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions and restored the SLC sodium pentaborate concentration to within TS limits.

The finding was of more than minor safety significance because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a lower than allowable sodium pentaborate concentration affected the SLC system's ability to shut down the reactor during a design basis event. The finding was determined to be a licensee performance deficiency of very low safety significance during a detailed Significance Determination Process review since the delta core damage frequency (ΔCDF) was determined to be less than 1.0E–6/year. The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of resources. Specifically, the licensee failed to ensure equipment and procedures were adequate to support nuclear safety. This issue would have been avoided if the system monitoring plan was trending tank level via a pressure indicator. Also, chemistry had no administrative limits in their procedure to add boron prior to the minimum TS limit was reached and the system engineer was not a reviewer on the routine surveillance procedure and was not trending the concentration as a backup. (IMC 0310, H.1) (Section 4OA3.8)

Licensee-Identified Violations

A violation of very-low safety significance that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Fermi 2 Power Plant was operated at or near 100 percent power during the inspection period with the following exceptions:

- On January 4, the licensee reduced power to about 75 percent, fully inserted two control rods and removed them from service for maintenance on hydraulic control units prior to a downpower for a control rod pattern adjustment. The unit was returned to full power the following day.
- On January 6, the licensee reduced power to about 65 percent to perform maintenance on a main turbine high pressure control valve unitized actuator; a control rod pattern adjustment; scram time testing of two control rods following maintenance on hydraulic control units; and main turbine stop, control, and intercept valve testing. The unit was returned to full power on January 8. The control rod pattern adjustment was the first of two control rod sequence exchanges to establish the final control rod pattern for full power operation.
- On January 9, the licensee reduced power to about 78 percent to perform a control rod pattern adjustment and main steam isolation valve testing. The unit was returned to full power the following day.
- On February 5, a loss of the south reactor feedwater pump and resultant reactor recirculation system runback from near full power to about 47 percent power occurred while operators were reducing power following loss of the south heater drains pump due to an electrical ground fault. The licensee subsequently raised power to about 58 percent later the same day. On February 6, the licensee restarted the south reactor feedwater pump and removed the north reactor feedwater pump from service for maintenance and raised power to about 63 percent. The unit remained at about 63 percent power until repairs were completed to the north reactor feedwater pump on February 8, at which time the licensee raised power to about 77 percent.
- On February 9, the licensee reduced power to about 57 percent to perform a control rod pattern adjustment. This control rod pattern adjustment was the first of three control rod sequence exchanges to establish the final control rod pattern for full power operation. The unit was returned to full power on February 13.
- On March 18, the licensee removed the unit from service and commenced the Cycle 18 refueling outage (RF–18). The unit was shut down for RF–18 at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Conditions—Thunderstorms and High Wind

a. Inspection Scope

Since thunderstorms and high winds were forecasted for the evening of February 24, the inspectors evaluated the licensee's overall preparations and protection for the expected weather conditions focusing on the EDGs and off-site power switchyards. The inspectors reviewed plant specific design features and implementation of procedures for responding to or mitigating the effects of thunderstorms and high wind conditions on the operation of plant systems. The inspectors observed housekeeping practices surrounding the switchyards and material condition and operating status of the EDGs in case of a loss of off-site power. The inspectors also discussed potential compensatory measures with plant operators.

In addition, the inspectors verified adverse weather protection problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected condition assessment resolution documents (CARDs) were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one readiness for impending adverse weather condition inspection sample as defined in Inspection Procedure (IP) 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns (71111.04Q)

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Division 1 EDGs during EDG 14 maintenance;
- Division 1 residual heat removal (RHR) / RHR service water (RHRSW) subsystems during planned maintenance on Division 2 RHR/RHRSW subsystems; and
- Division 2 RHR subsystem alignment for shutdown cooling operation.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones. The inspectors reviewed operating procedures, system diagrams, TS requirements, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and were available. The inspectors observed operating parameters and examined the material condition of the equipment to verify there were no obvious deficiencies.

In addition, the inspectors verified problems associated with plant equipment alignment were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted three partial system walkdown inspection samples as defined in IP 71111.04.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

From February 7 through March 21, the inspectors performed a complete system alignment inspection of the turbine building closed cooling water system to verify the functional capability of the system. This system was selected because it was considered risk significant from an initiating events perspective. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding work orders (WOs) was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the corrective action program database to ensure system equipment alignment problems were being identified and appropriately resolved.

These activities constituted one complete system walkdown inspection sample as defined in IP 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns focusing on the availability, accessibility, and condition of firefighting equipment in the following risk-significant plant areas:

- Turbine Building First Floor – Heater Drains Pump Rooms;
- Auxiliary Building Third Floor – Reactor Protection System Motor Generator Sets & Motor Control Center Area;
- Turbine Building First Floor – Reactor Feedwater Pump Rooms;
- Auxiliary Building First Floor Mezzanine – Cable Run Area; and
- Reactor Building First Floor – Steam Tunnel.

The inspectors reviewed these fire areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and implemented adequate compensatory measures for out-of-service, degraded, or inoperable fire protection equipment, systems, or features in accordance with the licensee's Fire Protection Plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events Report with later additional insights, their potential to impact equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors verified fire hoses and extinguishers were in their designated locations and available for immediate use; fire detectors and sprinklers were unobstructed; transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

In addition, the inspectors verified problems associated with plant fire protection were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted five quarterly fire protection inspection samples as defined in IP 71111.05Q.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flooding analyses and design documents, including the Updated Final Safety Analysis Report (UFSAR), engineering calculations, and plant response procedures, to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the service water systems.

The inspectors performed a walkdown of accessible portions of the following plant areas to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were functional, and the licensee complied with its commitments:

- Auxiliary Building - Third, Fourth, and Fifth Floors.

In addition, the inspectors verified internal flooding related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one internal flooding inspection sample as defined in IP 71111.06.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

.1 Annual Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors reviewed the licensee's examination of the EDG 14 lube oil, jacket water, and air coolant heat exchangers. The inspectors assessed the as-found and as-left condition of the heat exchangers by direct observation and document reviews to verify no deficiencies existed that would adversely impact the heat exchangers' ability to transfer heat to the EDG service water system and to ensure the licensee was adequately identifying and addressing problems that could affect the performance of the heat exchangers. The inspectors observed portions of the inspection and cleaning activities and reviewed documentation to verify the inspection acceptance criteria specified in procedure MES 54, "Heat Exchanger Component Monitoring Program, Revision 5, were satisfactorily met.

The inspectors also reviewed the licensee's examination of the Division 2 RHR heat exchanger. The inspectors assessed the as-found and as-left condition of the heat exchanger by direct observation and document reviews to verify no deficiencies existed that would adversely impact the heat exchanger's ability to transfer heat to the RHRSW system and to ensure the licensee was adequately identifying and addressing problems that could affect the performance of the heat exchanger. The inspectors observed portions of the inspection, cleaning, and eddy current testing activities and reviewed documentation to verify the inspection acceptance criteria specified in MES 54 were satisfactorily met.

In addition, the inspectors verified heat sink performance related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two annual heat sink performance inspection samples as defined in IP 71111.07.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspectors observed licensed operators during evaluated simulator training on January 31 and February 7. The inspectors assessed the operators' response to the simulated events focusing on alarm response, command and control of crew activities, communication practices, procedural adherence, and implementation of Emergency Plan requirements. The inspectors also observed the post-evaluation critique to assess the ability of the licensee's evaluators to identify performance deficiencies. The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

This inspection constituted one quarterly licensed operator requalification program simulator inspection sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observations During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On February 6, the inspectors observed licensed operators in the control room perform power maneuvers and stabilization of the plant following a transient on the feedwater system. Also, on March 18, the inspectors observed licensed operators in the control room perform selected portions of a plant shutdown to enter a refueling outage. These activities required heightened awareness, additional detailed planning, and involved increased operational risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance, and task completion requirements.

In addition, the inspectors verified problems related to licensed operator performance were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one quarterly licensed operator heightened activity/risk inspection sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated the licensee's handling of selected degraded performance issues involving the following risk-significant structures, systems, and components (SSCs):

- CARD 17–21143; MDCT [Mechanical Draft Cooling Tower] ‘A’ Brake Pressure Regulator Is Indicating 0 Psig [Pounds-Per-Square-Inch-Gage].

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the SSCs. Specifically, the inspectors independently verified the licensee's handling of SSC performance or condition problems in terms of:

- appropriate work practices;
- identifying and addressing common cause failures;
- scoping of SSCs in accordance with 10 CFR 50.65(b);
- characterizing SSC reliability issues;
- tracking SSC unavailability;
- trending key parameters (condition monitoring);
- 10 CFR 50.65(a)(1) or (a)(2) classification and reclassification; and
- appropriateness of performance criteria for SSC functions classified (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSC functions classified (a)(1).

In addition, the inspectors verified problems associated with the effectiveness of plant maintenance for risk-significant SSCs were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted one quarterly maintenance effectiveness inspection sample as defined in IP 71111.12.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for maintenance and emergent work activities affecting risk-significant and/or safety-related equipment listed below to verify the appropriate risk assessments and risk management actions were performed prior to removing equipment for work:

- Emergent maintenance during the week of January 1–7 on EDG 14 and planned maintenance on the SLC system and reactor water cleanup Train B, EDG 13 and EDG 14 logic functional testing, and replacement of three hydraulic control unit accumulators;
- Planned maintenance during the week of January 23–27 on EDG 14;
- Emergent maintenance during the week of February 6–10 on MDCT fans ‘A’ and ‘B’, and planned maintenance on EDG 11 and north reactor feedwater pump; and
- Planned maintenance during the week of March 13–17 on the reactor water cleanup system and pre-outage activities.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work in the plant’s daily schedule, reviewed control room logs, verified plant risk assessments were completed as required by 10 CFR 50.65(a)(4) prior to commencing maintenance activities, discussed the results of the assessment with the licensee’s probabilistic risk analyst and/or shift technical advisor, and verified plant conditions were consistent with the risk assessment assumptions. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid, redundant safety-related plant equipment necessary to minimize risk was available for use, and applicable requirements were met.

In addition, the inspectors verified maintenance risk-related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted four maintenance risk assessment and emergent work control inspection samples as defined in IP 71111.13.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Determinations and Functionality Assessments

a. Inspection Scope

The inspectors reviewed the following issues:

- CARD 16–29742; Inappropriate Operability Determination in CARD 14–25229;
- CARD 16–27189; Main Steam Isolation Valve TS Surveillance Requirement (SR) 3.6.1.3.7 Not Correlated to Plant Safety Analysis;
- CARD 16–26153; Limerick TS Change – High Pressure Coolant Injection (HPCI)/ Reactor Core Isolation Cooling (RCIC) Level 8 Trip Signal;
- CARD 17–21717; Nuclear Safety Review Group Question on HPCI/RCIC Level 8 Trip Signal at Low Reactor Pressure; and

- CARD 17–21165; Mispositioned Component - Nitrogen Pressure Regulator MDCT Fan ‘A’.

The inspectors selected these potential operability/functionality issues based on the safety significance of the associated components and systems. The inspectors verified the conditions did not render the associated equipment inoperable/non-functional or result in an unrecognized increase in plant risk. When applicable, the inspectors verified the licensee appropriately applied TS limitations, appropriately returned the affected equipment to an operable or functional status, and reviewed the licensee’s evaluation of the issue with respect to the regulatory reporting requirements. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. When applicable, the inspectors also verified the licensee appropriately assessed the functionality of SSCs that perform specified functions described in the UFSAR, Technical Requirements Manual, Emergency Plan, Fire Protection Plan, regulatory commitments, or other elements of the current licensing basis when degraded and/or nonconforming conditions were identified.

In addition, the inspectors verified problems associated with the operability or functionality of safety-related and risk-significant plant equipment were entered into the licensee’s corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted five operability determination and functionality assessment inspection samples as defined in IP 71111.15.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Permanent Modifications

a. Inspection Scope

The inspectors reviewed the engineering analyses, modification documents, and design change information associated with the following permanent plant modifications:

- [Engineering Design Package] EDP–37731; Remove RHR Cross-Tie Valves; and
- EDP–37272; RCIC Pump Discharge High Point Vent Relocation.

During this inspection, the inspectors evaluated the implementation of the design modification and verified, as appropriate:

- The compatibility, functional properties, environmental qualification, seismic qualification, and classification of materials and replacement components were acceptable;
- The structural integrity of the SSCs would be acceptable for accident/event conditions;
- The implementation of the modification did not impair key safety functions;

- No unintended system interactions occurred;
- The affected significant plant procedures, such as normal, abnormal, and emergency operating procedures, testing and surveillance procedures, and training were identified, and necessary changes were completed;
- The design and licensing documents were either updated or were in the process of being updated to reflect the modifications;
- The changes to the facility and procedures as described in the UFSAR were appropriately reviewed and documented in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments;"
- The system performance characteristics, including energy needs affected by the modifications continued to meet the design basis;
- The modification test acceptance criteria were met; and
- The modification design assumptions were appropriate.

Completed activities associated with the implementation of the modification, including testing, were also inspected, and the inspectors discussed the modification with the responsible engineering and/or operations staff.

In addition, the inspectors verified problems associated with the installation of permanent plant modifications were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two permanent modification inspection samples as defined in IP 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance testing activities to verify procedures and test activities were adequate to ensure system operability and functional capability:

- WO 38444863; EDG 11 West Starting Air Receiver A011 Pressure Relief Valve Swap;
- WO 43656061; Replace Agastat Relay in P50P402A, Division 1 Non-Interruptible Air Supply Dryer Control Cabinet;
- WO 46676663; Replace West Control Rod Drive Pump Motor;
- WO 46966894; EDG 11 Heat Exchanger Bundles Not Oriented Correctly;
- WO 43024769; Test RHR Logic 'A' Time Delay Relays Located in H11P617;
- WO 45927598; Contingency – Motor Replacement for E1150–F015A;
- WO 44152016 and WO 44152950; Perform 24.307.11(12) EDG No. 11(12) ECCS [Emergency Core Cooling System] Start and Load Rejection Test and Loss of Bus 64B(C); and
- WO 44606373; EDP–37115 RF–18, Tie-in Tubing, Shuttle Valve and Post-Maintenance Test for Air-Operated Valve P5000–F440.

The inspectors reviewed the scope of the work performed and evaluated the adequacy of the specified post-maintenance testing. The inspectors verified the post-maintenance testing was performed in accordance with approved procedures, the procedures contained clear acceptance criteria that demonstrated operational readiness and the acceptance criteria were met, appropriate test instrumentation was used, the equipment was returned to its operational status following testing, and the test documentation was properly evaluated.

In addition, the inspectors verified problems associated with post-maintenance testing activities were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted eight post-maintenance testing inspection samples as defined in IP 71111.19.

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Unit 2 Refueling Outage (RF-18)

a. Inspection Scope

The licensee commenced the Cycle 18 refueling outage on March 18. The inspectors began their inspection of the refueling outage activities, which are expected to conclude in the next inspection period.

This inspection does not constitute an inspection sample as defined in IP 71111.20.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed surveillance testing results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety functions and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- 24.307.34; Diesel Generator Service Water, Diesel Fuel Oil Transfer and Starting Air Operability Test – Emergency Diesel Generator 11;
- 42.307.01; Logic System Functional Test of Division 1 Emergency Diesel Generator Emergency Core Cooling System Emergency Start Circuits and Auto Trip/Bypass Circuits;
- 24.208.02; Division 1 Emergency Equipment Service Water and Emergency Equipment Cooling Water Makeup Pump and Valve Operability Test;

- 24.623; Reactor Manual Control/Reactor Mode Switch/Refueling Platform – Refueling Interlocks; and
- 43.401.303(304); Local Leakage Rate Testing for Penetration X–9A(B).

The inspectors observed selected portions of the test activities to verify the testing was accomplished in accordance with plant procedures. The inspectors reviewed the test methodology and documentation to verify equipment performance was consistent with safety analysis and design basis assumptions, test equipment was used within the required range and accuracy, applicable prerequisites described in the test procedures were satisfied, test frequencies met TS requirements to demonstrate operability and reliability, and appropriate testing acceptance criteria were satisfied. When applicable, the inspectors also verified test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable.

In addition, the inspectors verified problems associated with surveillance testing activities were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled.

This inspection constituted two in-service tests, one containment isolation valve leakage rate test, and two routine surveillance tests, for a total of five surveillance testing inspection samples as defined in IP 71111.22.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a scheduled licensee emergency drill on February 14 to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The drill was planned to be evaluated and was included in the performance indicator data regarding drill and exercise performance. The inspectors observed emergency response operations in the control room simulator and technical support center to determine whether the event classifications, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also reviewed the licensee's drill critique to compare any inspector-observed weaknesses with those identified by the licensee in order to evaluate the critique and to verify whether the licensee was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents.

This inspection constituted one emergency preparedness drill inspection sample as defined in IP 71114.06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7,000 Critical Hours

a. Inspection Scope

The inspectors verified the Unplanned Scrams per 7,000 Critical Hours Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in Nuclear Energy Institute (NEI) 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed each Licensee Event Report (LER) from January 1 through December 31, 2016, determined the number of scrams that occurred, and verified the licensee's calculation of critical hours. The inspectors also reviewed the licensee's corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. The inspectors noted there were no unplanned scrams reported by the licensee in 2016.

This inspection constituted one Unplanned Scrams per 7,000 Critical Hours Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors verified the Unplanned Scrams with Complications Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed each LER from January 1 through December 31, 2016, determined the number of scrams that occurred, and evaluated each of the scrams against the performance indicator definition. The inspectors also reviewed the licensee's corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. The inspectors noted there were no unplanned scrams reported by the licensee in 2016.

This inspection constituted one Unplanned Scrams with Complications Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.3 Unplanned Power Changes per 7,000 Critical Hours

a. Inspection Scope

The inspectors verified the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed power history data from January 1 through December 31, 2016, determined the number of power changes greater than 20 percent of full power that occurred, evaluated each of the power changes against the performance indicator definition, and verified the licensee's calculation of critical hours. The inspectors also reviewed the licensee's corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. The inspectors noted there were two unplanned power changes reported by the licensee in 2016.

This inspection constituted one Unplanned Power Changes per 7,000 Critical Hours Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.4 Safety System Functional Failures

a. Inspection Scope

The inspectors verified the Safety System Functional Failures Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed each LER from January 1 through December 31, 2016, determined the number of safety system functional failures that occurred, evaluated each LER against the performance indicator definition, and verified the number of safety system functional failures reported. The inspectors also reviewed the licensee's corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. The inspectors noted the licensee submitted fourteen LERs in 2016 reporting the loss of safety function of SSCs under 10 CFR 50.73(a)(2)(v), two of which were reported under the Safety System Functional Failures Performance Indicator. The licensee completed engineering analyses for the remaining twelve events and concluded the safety function was maintained.

This inspection constituted one Safety System Functional Failures Performance Indicator verification inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's corrective action program at an appropriate threshold, adequate attention was being given to timely corrective actions, and adverse trends were identified and addressed. Some minor issues were entered into the licensee's corrective action program as a result of the inspectors' observations; however, they are not discussed in this report.

This inspection was not considered to be an inspection sample as defined in IP 71152.

b. Findings

No findings were identified.

.2 Annual In-depth Review Samples

a. Inspection Scope

The inspectors selected the following issues for in-depth review:

- CARD 16–28674, EDG 14 Shutdown During 24.307.17 Due to Thick Smoke;
- CARD 16–28286, Internal N–1 Contingency Threshold Exceeded Four Times on 10/17/2016; and
- CARD 16–26255, Recurrent Trend in Foreign Material Found in Discharged Irradiated Fuel.

As appropriate, the inspectors verified the following attributes during their review of the licensee's corrective actions for the above CARD and other related CARDs:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the root and contributing causes of the problem; and
- identification of corrective actions, which were appropriately focused to correct the problem.

The inspectors discussed the corrective actions and associated evaluations with licensee personnel.

This inspection constituted three annual in-depth review inspection samples as defined in IP 71152.

b. Findings

(1) Inadequate Work Instructions for Maintenance on EDG 14

Introduction

A finding of very low safety significance with an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when plant operators discovered a thick white smoke plume coming from the EDG 14 engine exhaust manifold during surveillance testing. Consequently, operators shut down the engine and removed it from service. The licensee failed to have work instructions for maintenance on the safety-related EDG appropriate to ensure insulation blankets on the engine's exhaust manifold were replaced with insulation blankets conforming to the approved engineering design.

Discussion

On October 31, 2016, during the performance of surveillance testing on EDG 14, plant operators discovered a thick white smoke plume coming from the opposite control side of the engine exhaust manifold. Operators shut down the engine and removed it from service. The EDG was inoperable for about 20 hours to investigate and correct the cause.

The inspectors reviewed the licensee's direct cause evaluation in CARD 16–28674 for this event and questioned its conclusions. The direct cause was the gaskets in the front engine cover allowed minor seepage of lube oil to come into contact with the hot engine exhaust manifold, resulting in the oil burning and creating thick smoke. There were two corrective actions identified in the direct cause evaluation. The first corrective action was to properly torque the front engine cover fasteners as recommended by the EDG vendor (Fairbanks-Morris). The system engineer noted that no further leakage was found after the fasteners were torqued. The second corrective action was to replace the exhaust manifold insulation blankets with a new design that would prevent oil accumulation on the exhaust manifold underneath the insulation.

The inspectors noted the cause for this event and the impact on operability/availability of EDG 14 were the same as for an EDG 11 exhaust manifold fire on March 20, 2014. The inspectors reviewed the licensee's equipment apparent cause evaluation for this previous event. The direct cause was a lube oil leak from the EDG 11 front engine cover on the control side, which seeped through the seam of the insulation blanket on the turbocharger inlet flange area and accumulated on top of the exhaust manifold underneath the insulation. The accumulation of oil on the exhaust manifold resulted in the fire after the exhaust manifold heated up during engine operation for a surveillance test and reached the flash point temperature of the oil. After the fire was extinguished, mechanical maintenance personnel found multiple bolts loose on the front cover of the engine. However, after torqueing these bolts, the leak was still evident a few hours later. While the engine was in standby, a slow drip rate of less than 1 drop-per-5 minutes of oil pooled on top of the four-barrel exhaust to the turbocharger.

The bolts on the front engine cover are loosened each time the top cover is removed from the engine and re-torqued each time the cover is replaced. Each time this process was performed, the fiber gasket in between the front cover and the engine block was compressed and decompressed. This compression cycle degraded the gasket's ability to prevent oil from leaking out the front cover when the engine was idle.

Corrective actions following the EDG 11 exhaust manifold fire included: (1) replacing insulation on all four EDG exhaust manifolds with a different configuration to eliminate the seam that is located right under the corner of the front cover, (2) retightening the bolts on the front engine covers of all four EDGs, (3) replacing the front engine cover gaskets on all four EDGs, and (4) revising the preventive maintenance job plans and system engineering walkdowns to specifically look for small fuel oil or lube oil leaks that can come into contact with the exhaust manifold or leak onto the insulation. Refer to NRC Inspection Report 05000341/2014004 for the inspectors' review of this previous event.

The inspectors noted system engineering stated in the direct cause evaluation for the EDG 14 event that the engine did not yet have the insulation modified with a flap to prevent oil pooling on the exhaust manifold. However, the inspectors found this was not consistent with what the licensee had documented as completed corrective actions for the EDG 11 event in CARD 14–22612. The corrective action from the apparent cause evaluation for the EDG 11 fire to replace the insulation on EDG 12 and EDG 14 exhaust manifolds was completed on August 10, 2015, with a note that WO 38298165 for EDG 14 was completed on December 29, 2014. Review of the work order shows the work was done and inspected satisfactorily by the system engineer.

In response to the inspectors' questions, the licensee determined the corrective action had inadvertently been undone shortly after the newly modified insulation blankets had been installed. CARD 15–23171 was written on May 2, 2015, when EDG 14 was shut down during a post maintenance run due to excessive smoke from the opposite control side exhaust manifold. Oil had soaked the manifold and insulation during installation of a new split front cover design. The oil was cleaned up and new insulation blankets were installed on both sides of the exhaust manifold under a minor revision to the work order (WO 37178516) without engineering input or inspection of the new insulation. The licensee concluded the installation was not correct since the insulation blankets were not the new design. The licensee subsequently initiated an apparent cause evaluation to further understand how the lapse in control of the design configuration of the insulation blankets had occurred.

The inspectors reviewed the licensee's apparent cause evaluation for this problem. The apparent cause was lack of procedural guidance on the fabrication and installation of EDG exhaust manifold insulation. The exhaust manifold insulation blanket design was updated to prevent oil accumulation; however, the old style insulation blanket that did not have the flap to divert oil from the exhaust manifold was installed following maintenance. Instructions within the maintenance procedures and vendor manual did not provide enough detail to include the necessary information for proper installation of the newly designed insulation blanket. The inspectors noted the apparent cause evaluation did not address the breakdown in the engineering design change process or what was lacking in the process that resulted in the loss of control of the revised insulation blanket design. System engineering changed the design of the EDG exhaust manifold insulation blankets but did not follow its design change process to incorporate the change into plant drawings, procedures, and/or the vendor manual. This was considered to be a weakness in the licensee's evaluation of the problem. In response to the inspectors' questions, the licensee revised the apparent cause to be engineering design documentation was not updated to ensure proper configuration control of the revised insulation blankets was maintained.

Analysis

The inspectors determined the licensee's failure to have work instructions for maintenance on safety-related EDG 14 appropriate to ensure insulation blankets on the engine's exhaust manifold were replaced with insulation blankets conforming to the approved engineering design, was contrary to the requirements of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and was therefore a licensee performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined this performance deficiency was of more than minor safety significance, and thus a finding, because it was related to the Equipment Reliability attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, operators shutdown the engine after discovering a thick white smoke plume coming from the engine's exhaust manifold , which resulted in unplanned inoperability and unavailability of this onsite emergency power source. The inspectors also reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no similar examples.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, " SDP [Significance Determination Process] Appendix Router," dated June 19, 2012, the inspectors determined this finding affected the Mitigating Systems Cornerstone, specifically the Mitigating Systems contributor, and would require review using IMC 0609, Appendix A, "SDP for Findings At-Power," dated June 19, 2012, since the reactor was operating at power when this issue was discovered. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," and determined it was a licensee performance deficiency of very low safety significance (Green) because it: (1) was not a deficiency affecting the design or qualification of a mitigating SSC, (2) did not represent a loss of system and/or function, (3) did not represent an actual loss of function of at least a single train for greater than its TS allowed outage time OR two separate safety systems out-of-service for greater than its TS allowed outage time, and (4) did not represent an actual loss of function of one or more non-TS trains or equipment designated as high safety significant in accordance with the licensee's Maintenance Rule Program for greater than 24 hours.

The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of documentation. Plant activities are governed by comprehensive, high-quality, programs, processes and procedures. Design documentation, procedures, and work packages are complete, thorough, accurate, and current. In this case, the licensee's process for implementing and maintaining engineering configuration control of the newly designed EDG exhaust manifold insulation blankets was inadequate because it did not follow the licensee's formal engineering configuration management process. (IMC 0310, H.7)

Enforcement

Title 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings.

Title 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design.

Contrary to the above, on May 3, 2015, the licensee failed to have instructions for performing maintenance on safety-related EDG 14 that was appropriate to the circumstances to ensure insulation blankets on the engine’s exhaust manifold were replaced with insulation blankets conforming to the approved engineering design. Additionally, the licensee failed to implement design control measures for a change to the design of insulation blankets on the EDGs commensurate to those applied to the original design. Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee’s corrective action program, it is being treated as a Non-Cited Violation, consistent with Section 2.3.2.a of the NRC Enforcement Policy **(NCV 05000341/2017001–01, Inadequate Work Instructions for Maintenance on EDG 14)**.

The licensee entered this violation into its corrective action program for evaluation and identification of appropriate corrective actions (CARD 16–28674). Corrective actions for this issue included replacing the insulation blankets with insulation blankets conforming to the approved engineering design, revising maintenance procedures to include fabrication and installation instructions for EDG exhaust manifolds, preparing an engineering change document revising the EDG vendor manual to include insulation fabrication details, and completing a work order to tighten bolts on the front engine covers to minimize oil leakage.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors reviewed repetitive or closely related issues documented in the licensee’s corrective action program to look for trends not previously identified. This included a review of the licensee’s quarterly trending reports to assess the effectiveness of the licensee’s trending process. The inspectors also reviewed selected CARDs regarding licensee-identified potential trends to verify corrective actions were effective in addressing the trends and were implemented in a timely manner commensurate with the significance.

This inspection constituted one semi-annual trend review inspection sample as defined in IP 71152.

b. Assessment and Observations

No findings were identified.

(1) Overall Effectiveness of Trending Program

The inspectors determined the licensee's trending program was generally effective and has shown improvement in identifying, monitoring, and correcting adverse performance trends. This has been reflected in the licensee's quarterly trending reports. Relatively recent cognitive trending inputs (especially from the Management Review Committee) have bolstered the trending process with valuable insights. The inspectors noted several longstanding station level adverse performance trends (human performance, industrial safety, and equipment reliability) were considered to be closed by the licensee in its third quarter trending report based upon improved trending data. While improvements have been seen in each of these areas, the inspectors noted there were several additional human performance and equipment reliability incidents indicative of continuing adverse performance in both the fourth quarter of 2016 and the first quarter of 2017 and, with hindsight, questioned whether the licensee closed these adverse trends prematurely. The inspectors noted the licensee reopened the human performance trend in the fourth quarter of 2016 and initiated a common cause evaluation based on an increase in the number of human performance incidents from previous quarters.

The inspectors reviewed several common cause evaluations performed by the licensee to evaluate potential adverse performance and equipment trends. In general, these evaluations were performed well and identified appropriate corrective actions to address adverse trends that were identified. The inspectors observed that aside from the twelve common cause evaluations initiated in 2016, the licensee's analysis of adverse performance trends was often performed at the lowest level with minimal evaluation, with many issues simply "closed to trend." However, the licensee recently began performing trend condition evaluations for some of the CARDs written identifying potential adverse trends in order to gain improved insights into the conditions. The inspectors noted nine trend condition evaluations were performed in the third quarter of 2016 and two were performed in the fourth quarter of 2016. The inspectors reviewed several of these and found the evaluations were generally performed well.

When this review was last performed in the third quarter of 2016, the inspectors documented adverse performance trends associated with unrestrained materials near the 345-kilovolt and 120-kilovolt switchyards, unacceptable control of transient combustible and flammable materials in the plant, and inadequate evaluation of degrading/nonconforming plant conditions for functionality, operability, and/or reportability (NRC Inspection Report 05000341/2016003). Since then, the inspectors have noted the licensee has improved its control of loose materials in and around the switchyards such that no additional examples were found; however, more examples related to the other two adverse performance trends were identified.

Because examples of these adverse performance trends have been entered into the licensee's corrective action program and separate findings have been documented when the associated performance issues have risen to a more than minor significance threshold, no additional finding of significance was identified.

(2) Adverse Performance Trend with Unacceptable Control of Transient Combustible and Flammable Materials

During fire protection walkdowns in safety-related and risk-significant areas of the plant during April and May 2016, the inspectors identified multiple instances of the licensee's failure to follow its procedural requirements for the controls of combustible materials. Accordingly, the inspectors documented a finding of very low safety significance with an associated Non-Cited Violation of TS 5.4, “Procedures,” in NRC Inspection Report 05000341/2016002 for this issue. The inspectors noted the licensee’s quality assurance department also identified several issues with the control and storage of flammable liquids during this time. The licensee initiated CARD 16-24413, “Emerging Trend with Transient Combustible Storage,” to identify this problem as an adverse performance trend. The CARD referenced three of the NRC-identified issues captured in the finding. The licensee’s evaluation of the problem determined the cause to be poor work quality and failure of site leadership to reinforce procedure standards for the control of transient combustible materials.

The inspectors reviewed CARD 16–24413 and noted it was closed to another CARD issued about the same time (CARD 16–24400, “Quality Assurance Audit Deficiency – Non-compliance with Flammable Liquids Locker Controls, Repeat Audit Deficiencies”). The inspectors reviewed CARD 16–24400 and noted it was also closed with several corrective actions implemented in December 2016; however, it appears these corrective actions have not been in place for sufficient time to become fully effective.

Since documenting this adverse performance trend in the third quarter of 2016, the inspectors and the licensee have identified additional issues with the control and storage of transient combustible and flammable materials. Although this adverse performance trend has continued, the inspectors noted that identification of many of these additional issues were the result of the licensee’s efforts to search for improper storage of flammable and transient combustible materials to correct the problem.

(3) Adverse Performance Trend in Evaluating Degraded/Nonconforming Plant Conditions for Functionality, Operability, and/or Reportability

During the first three quarters of 2016, the inspectors observed an adverse performance trend in the licensee’s evaluation of degraded/nonconforming plant conditions for functionality, operability, and/or reportability. The inspectors identified and documented an adverse performance trend specific to the licensee’s failure to correctly complete required event notifications and reports to the NRC as required by 10 CFR 50.72(a)(1), “Immediate Notification Requirements for Operating Nuclear Reactors,” and 10 CFR 50.73(a)(1), “Licensee Event Report System,” in the first quarter of 2016 (NRC Inspection Report 05000341/2016001). The inspection report documented three Severity Level IV Non-Cited Violations for the licensee’s failure to satisfy the NRC’s reporting requirements. In addition, the inspectors documented a finding with an associated Non-Cited Violation for the licensee’s failure to correctly evaluate and implement TS Limiting Condition for Operation (LCO) requirements for inoperable high pressure stop valve (HPSV) closure and high pressure control valve fast closure functions during a plant transient.

During the Component Design Basis Inspection (CDBI) completed in September 2016, NRC inspectors identified multiple examples wherein the quality of operability determinations and the timeliness of their performance did not meet the guidance in IMC 0326, “Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety,” dated December 3, 2015 (NRC Inspection Report 05000341/2016007). The inspection team documented a finding of very low safety significance with an associated Non-Cited Violation for the licensee’s failure to promptly identify, document, and evaluate conditions adverse to quality with respect to functionality and/or operability in accordance with its procedure standards. The inspection team also documented a finding of very low safety significance with an associated Non-Cited Violation for the licensee's failure to correctly evaluate TS LCO requirements for inoperable mechanical draft cooling tower fans when fan brakes were non-functional.

Additionally, during the third quarter of 2016, the inspectors documented a finding of very low safety significance with an associated Non-Cited Violation for the licensee's failure to perform an operability determination in accordance with its procedure standards for a degraded/non-conforming condition affecting the Division 1 reactor pressure vessel reference leg backfill system to assess the impact on affected reactor water level and pressure instrumentation when the minimum reference leg backfill flow rate could not be maintained (NRC Inspection Report 05000341/2016003).

In response to the inspectors' identification of the reporting issues during the first quarter of 2016, the licensee initiated CARD 16–21857, "Adverse Trend in Reportability Related Issues," to evaluate the problem and identify appropriate corrective actions. In response to the inspectors' identification of the incorrect TS application issues, the licensee initiated CARD 16–26798, "Inadequate Interpretation of Technical Specifications Identified by NRC," to evaluate the problem and identify appropriate corrective actions. In response to the inspectors' identification of the issues with quality and timeliness of operability determinations, the licensee initiated CARD 16–26633, "2016 CDBI – NRC Concern for Operability Determination Justifications and Timeliness," to evaluate the problem and identify appropriate corrective actions.

In November 2016, the NRC completed IP 92723, "Follow Up Inspection for Three or More Severity Level IV Traditional Enforcement Violations in the Same Area in a 12-Month Period," to assess the licensee's evaluation of five Severity Level IV Non-Cited Violations that occurred within the area of impeding the regulatory process from July 1, 2015, to June 30, 2016. The results of the inspection were documented in NRC Inspection Report 05000341/2016004. The inspectors determined appropriate corrective actions were specified for the causes identified for each of the Severity Level IV violations that were reviewed. No additional issues of concern were identified during the inspection.

Since documenting this adverse performance trend in the first and third quarters of 2016, the inspectors documented one Severity Level IV Non-Cited Violation for the licensee's failure to satisfy the NRC's reporting requirements in the fourth quarter of 2016 (NRC Inspection Report 05000341/2016004). The inspectors also documented a finding with an associated Non-Cited Violation for the licensee's failure to correctly evaluate and implement TS LCO requirements for inoperable loss of voltage and degraded voltage instrument channels, inoperable EDGs, and an inoperable offsite power circuit. Additionally, during this quarter, the inspectors documented a licensee-identified Non-Cited Violation for the licensee's failure to correctly interpret and satisfy applicable TS LCOs for HPCI and RCIC systems instrumentation during plant shutdowns and plant startups (Sections 4OA3.10 and 4OA7.1). The licensee had been aware of a non-conforming condition affecting compliance with the TS requirements for HPCI and RCIC systems instrumentation under low reactor pressure conditions for over 2 months (since August 2016) and did not correctly address it prior to a planned maintenance outage in early November 2016. This resulted in additional TS violations that should have been prevented had the licensee completed a correct and timely evaluation of the non-conforming condition.

During this quarter, the inspectors reviewed CARDs 16–21857, 16–26798, and 16–26633 and noted the CARDs were all closed and corrective actions were implemented. The corrective actions appeared to be appropriate to address the problems identified. Although this adverse performance trend has continued, the inspectors concluded the corrective actions have not yet been in place for a sufficient time to fully measure their effectiveness.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000341/2016–001–01, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves," Supplement 1

On January 6, 2016, with Fermi 2 operating at 100 percent power, the main turbine generator #1 HPSV drifted from full open to about 25 percent open. The main turbine bypass valves cycled open as expected to divert steam flow to the main condenser and mitigate the effects of the transient until reactor operators could reduce reactor power. Control room operators reduced reactor power to about 91 percent and locked the #1 high pressure control valve (HPCV) and #1 HPSV closed. The licensee performed troubleshooting and found a failed servo driver circuit card in the #1 HPSV valve control module and replaced it to correct the problem. Operators subsequently restored the #1 HPCV and #1 HPSV to service and returned reactor power to 100 percent on January 8.

As discussed in NRC Inspection Report 05000341/2016001, the inspectors reviewed this issue and concluded there was no performance deficiency associated with the #1 HPSV malfunction because the cause of the circuit card failure was not reasonably within the licensee's ability to foresee and prevent. The circuit card was not previously known to have age/wear related failure modes and sufficient internal and/or external operating experience did not exist to warrant a preventive replacement strategy.

The licensee submitted licensee event report (LER) 05000341/2016–001–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) shut down the reactor and maintain it in a safe shutdown condition, and (D) mitigate the consequences of an accident. The licensee also reported the event in accordance with 10 CFR 50.73(a)(2)(vii) as an event where a single cause or condition caused two independent channels to become inoperable in a single system designed to: (A) shut down the reactor and maintain it in a shutdown condition, and (D) mitigate the consequences of an accident.

The licensee submitted supplement 1 to the original LER to update the cause of the event and corrective actions based on the results of a component failure analysis. The cause was determined to be a failed valve control module servo driver to the valve's unitized actuator servo valve loop due to faulty connectors in the unitized actuator from wear and fatigue. Although the cause was later determined to be somewhat different than originally believed, the inspectors determined the information provided in this LER supplement did not raise any new issues or change the conclusion of the initial review (i.e., there was no performance deficiency associated with the #1 HPSV malfunction because the cause of the failure was not reasonably within the licensee's ability to foresee and prevent.)

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–001–01 is closed.

.2 <u>(Closed) Licensee Event Report 05000341/2016–010–00, "Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather"</u>

On October 26, 2016, the TS limiting pressure for the secondary containment pressure boundary was not met numerous times due to high wind conditions affecting the Fermi 2 site. Each instance was about 1 second in duration. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building heating, ventilation, and air conditioning (HVAC) system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52320) on October 27 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition, that at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee submitted LER 05000341/2016–010–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the standby gas treatment system (SGTS) would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

During evaluation of this event, the licensee completed a past reportability review of instances when secondary containment pressure exceeded the TS limit due to known effects of high winds between October 1, 2016 and November 18, 2016. Numerous instances were found during this period wherein digital secondary containment pressure recorder data showed the TS limiting value for secondary containment vacuum had been exceeded. Most instances were from 1 to 2 seconds in duration, with none of the recorded instances lasting longer than 30 seconds. The highest recorded pressure was +1.138 inches water column. In each instance, all plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system or SGTS returned secondary containment pressure below the TS limit without additional operator action. These additional instances were not observed by operators, and therefore the secondary containment was not declared inoperable at the time, no event notification was made at the time, and no LER was previously submitted for them. The licensee performed this review consistent with a similar review it completed for the 3-year period between September 1, 2013 and September 30, 2016 after it had reported several earlier events in 2016 involving the loss of the secondary containment function due to high wind conditions. As described in LER 05000341/2016–008–00, "Past Instances of Secondary Containment Pressure Exceeding Technical Specification Due to Adverse Weather," the secondary containment pressure recorders are digital and display a single data point every second. In order to observe a momentary pressure spike, an operator would have to be looking directly at this display at the time the pressure exceeded the TS limit. The inspectors reviewed and closed LER 05000341/2016–008–00 in NRC Inspection Report 05000341/2016004. As a corrective action to address these recurring events, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–010–00 is closed.

.3 (Closed) Licensee Event Report 05000341/2016–013–00, "Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather"

On November 19 and 20, 2016, the TS limiting pressure for the secondary containment pressure boundary was not met numerous times due to high wind conditions affecting the Fermi 2 site. Each instance was about 1 second in duration. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52380) on November 20 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition, that at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee provided two updates to the event notification while the high wind conditions recurred throughout the day on November 20. The licensee submitted LER 05000341/2016–013–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

During evaluation of this event, the licensee completed a past reportability review of instances when secondary containment pressure exceeded the TS limit due to known effects of high winds between November 19, 2016 and December 15, 2016. In addition to those instances observed on November 19 and 20, numerous instances were found during this period wherein digital secondary containment pressure recorder data showed the TS limiting value for secondary containment vacuum had been exceeded. Most instances were from 1 to 2 seconds in duration, with none of the recorded instances lasting longer than 30 seconds. The highest recorded pressure was +1.326 inches water column. In each instance, all plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system or SGTS returned secondary containment pressure below the TS limit without additional operator action. The additional instances were not observed by operators, and therefore the secondary containment was not declared inoperable at the time, no event notification was made at the time, and no LER was previously submitted for them. The secondary containment pressure recorders are digital and display a single data point every second. In order to observe a momentary pressure spike, an operator would have to be looking directly at this display at the time the pressure exceeded the TS limit. As a corrective action to address these recurring events, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–013–00 is closed.

.4 <u>(Closed) Licensee Event Report 05000341/2016–014–00, “Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather”</u>

On November 28 and 29, 2016, the TS limiting pressure for the secondary containment pressure boundary was not met numerous times due to high wind conditions affecting the Fermi 2 site. Each instance was about 1 second in duration. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52398) on November 29 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition that, at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee provided one update to the event notification while the high wind conditions recurred throughout the day on November 29. The licensee submitted LER 05000341/2016–014–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

During evaluation of this event, the licensee completed a past reportability review of instances when secondary containment pressure exceeded the TS limit due to known effects of high winds between November 19, 2016 and December 15, 2016. This review is discussed above in Section 4OA3.3. As a corrective action to address these recurring events, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–014–00 is closed.

.5 <u>(Closed) Licensee Event Report 05000341/2016–015–00, "Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds"</u>

On December 14, 2016, while restoring the east train of reactor building HVAC after a surveillance test on the Division 1 SGT subsystem, the TS limiting pressure for the secondary containment pressure boundary was not met for approximately 6 seconds due to high wind conditions affecting the Fermi 2 site. The maximum secondary containment pressure observed was approximately 0.040 inches vacuum water gauge. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system along with the SGTS already in operation returned secondary containment pressure below the TS limit.

The cause of this momentary loss of the secondary containment safety function was determined to be the combined effects of the reactor building HVAC startup sequence with high wind gust conditions outside the reactor building. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. During reactor building HVAC startup, the exhaust fan starts prior to the supply fan. Then respective dampers open in the same order to maintain a negative pressure in the reactor building. Although the licensee determined the associated time delay relays functioned as intended, it noted there was limited margin to ensure pressure would not increase during the startup sequence. As a corrective action from a similar event reported in LER 05000341/2016–005–00, "Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds," the licensee implemented a design change to increase the time delay between the start of the exhaust fan and the supply fan. Although this modification increased the margin to the TS limit for secondary containment vacuum, an additional corrective action related to high wind effects had not yet been completed.

The licensee completed an 8-hour notification call (Event Notification 52432) on December 14 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition that, at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee submitted LER 05000341/2016–015–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

As a corrective action to address these recurring events due to high wind conditions, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–015–00 is closed.

.6 <u>(Closed) LER 05000341/2016–016–00, "Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather"</u>

On December 14, 2016, the TS limiting pressure for the secondary containment pressure boundary was not met numerous times due to high wind conditions affecting the Fermi 2 site. Each instance was about 1 second in duration. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system returned secondary containment pressure below the TS limit.

The licensee completed an 8-hour notification call (Event Notification 52434) on December 15 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition that, at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee provided one update to the event notification while the high wind conditions recurred throughout the day on November 29. The licensee submitted LER 05000341/2016–016–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

During evaluation of this event, the licensee completed a past reportability review of instances when secondary containment pressure exceeded the TS limit due to known effects of high winds between November 19, 2016 and December 15, 2016. This review is discussed above in Section 4OA3.3. As a corrective action to address these recurring events, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–016–00 is closed.

.7 (Closed) Licensee Event Report 05000341/2016–017–00, "Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds"

On December 15, 2016, while restoring the east train of reactor building HVAC after a surveillance test on the Division 1 SGT subsystem, the TS limiting pressure for the secondary containment pressure boundary was not met for approximately 6 seconds due to high wind conditions affecting the Fermi 2 site. The maximum secondary containment pressure observed was approximately 0.044 inches vacuum water gauge. TS 3.6.4.1.1 requires secondary containment pressure to be less than or equal to -0.125 inches water column for operability. All plant equipment responded as required to the changing environmental conditions and the reactor building HVAC system along with the SGTS already in operation returned secondary containment pressure below the TS limit.

The cause of this momentary loss of the secondary containment safety function was determined to be the combined effects of the reactor building HVAC startup sequence with high wind gust conditions outside the reactor building. The Fermi 2 UFSAR states high winds may create a negative pressure change on the leeward side of the reactor building, which results in a higher indicated pressure inside the reactor building. During reactor building HVAC startup, the exhaust fan starts prior to the supply fan. Then respective dampers open in the same order to maintain a negative pressure in the reactor building. Although the licensee determined the associated time delay relays functioned as intended, it noted there was limited margin to ensure pressure would not increase during the startup sequence. As a corrective action from a similar event reported in LER 05000341/2016–005–00, "Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds," the licensee implemented a design change to increase the time delay between the start of the exhaust fan and the supply fan. Although this modification increased the margin to the TS limit for secondary containment vacuum, an additional corrective action related to high wind effects had not yet been completed.

The licensee completed an 8-hour notification call (Event Notification 52437) on December 15 to report the inoperable secondary containment as required by 10 CFR 50.72(b)(3)(v)(C) as an event or condition that, at the time of discovery, could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The licensee submitted LER 05000341/2016–015–00 to report this event in accordance with 10 CFR 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

The inspectors concluded there was no finding associated with this event since the condition was determined not to be within the licensee's ability to reasonably prevent. Although secondary containment was declared inoperable due to briefly exceeding the TS value for secondary containment vacuum, the structural integrity of the secondary containment was not degraded at the time. Upon receipt of an accident signal, the SGTS would have automatically started and restored secondary containment vacuum to within the bounding UFSAR Chapter 15 analyses. The accident analysis for a loss-of-coolant-accident does not assume secondary containment is under vacuum throughout the duration of an accident and contains conservative leakage assumptions that bound the effects of a postulated ground level release.

As a corrective action to address these recurring events due to high wind conditions, on December 23, the licensee implemented a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the instruments.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–017–00 is closed.

.8 (Closed) Licensee Event Report 05000341/2016–011–00, "Standby Liquid Control Inoperable Due to Sodium Pentaborate Concentration Outside of Technical Specifications

a. Inspection Scope

On October 28, 2016, the licensee discovered the SLC system was inoperable because the sodium pentaborate solution in the SLC storage tank had been diluted over time by leakage past demineralized water system fill valves. This resulted in a loss of system function for the SLC system. The licensee restored the SLC storage tank sodium pentaborate concentration to within the TS limits promptly after discovery.

The licensee completed an 8-hour notification call (Event Notification 52331) on October 28 to report the inoperable SLC system in accordance with 10 CFR 50.72(b)(3)(v) as an event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) shut down the reactor and maintain it in a safe shutdown condition, (C) control the release of radioactive material, and (D) mitigate the consequences of an accident. The licensee submitted LER 05000341/2016–011–00 to report this event in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation or condition which was prohibited by the plant's TSs. The licensee also reported this event in accordance with 10 CFR 50.73(a)(2)(v) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) shut down the reactor and maintain it in a safe shutdown condition, (C) control the release of radioactive material, and (D) mitigate the consequences of an accident.

The inspectors interviewed licensee staff and reviewed control room logs, plant procedures, and the licensee's apparent cause evaluation for the event.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

b. Findings

Introduction

A finding of very low safety significance with an associated Non-Cited Violation of TS 3.1.7, "Standby Liquid Control System," was self-revealed when the licensee measured the boron concentration in the SLC storage tank and discovered the concentration was below the minimum requirement of 8.5 percent.

Description

On October 28, 2016, operators in the main control room received an alarm for SLC storage tank high level. The main control room and local level indications were above the high SLC storage tank level alarm setpoint. The SLC storage tank was then manually measured to confirm level indication and found to be below the high level alarm setpoint. A chemistry sample of the tank was performed to determine the sodium pentaborate solution concentration. The results of the chemistry sample indicated the sodium pentaborate concentration was 8.3 percent. TS SR 3.1.7.5 required the concentration to be within the limits of Figure 3.1.7–1 of 8.5 to 9.5 percent. As a result of the chemistry analysis, TS 3.1.7, Condition B was entered for two SLC subsystems inoperable. Within 5 hours, the licensee restored SLC pentaborate concentration to within limits, and the LCO was exited.

A review of the event determined the SLC storage tank level had been slowly increasing over several months due to introduction of water through one or both of the demineralized water isolation valves. These valves were closed but leaking by their seats. On October 9, 2016, a SLC pump and valve operability surveillance test was performed in accordance with SR 3.1.7.7. Following completion of the test, which involved cycling one of the isolation valves, the valve's seat leak-by increased as a more substantial increase in SLC storage tank level occurred. This increased leak-by was not detected by operators until the occurrence of the high level alarm on October 28. Since the water leaking by the valves was demineralized, dilution of the sodium pentaborate concentration continued after the test. Previous sodium pentaborate concentration samples were taken on September 15 and October 13, and both resulted in satisfactory samples of 8.7 percent.

The inspectors reviewed the licensee's apparent cause evaluation for the event and agreed with the conclusions. The direct cause of the event was water leakage past the demineralized water supply valve. This undetected dilution of the sodium pentaborate solution was due to inadequate system monitoring of the SLC tank level and sodium pentaborate concentration. Tank level was monitored daily by operators using either of two gauges; however, these gauges did not have sufficient sensitivity for operators to detect small incremental changes in level. In addition, the licensee was not trending boron concentration with data gathered from the monthly 74.000.19, "Chemistry Routine Surveillance," and chemistry had no administrative limit to maintain boron concentration with sufficient margin prior to reaching the TS limit.

<u>Analysis</u>

The inspectors determined the licensee's failure to maintain SLC storage tank sodium pentaborate concentration above the TS minimum required value was contrary to the requirements in TS 3.1.7, "Standby Liquid Control," and was therefore a licensee performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined this performance deficiency was of more than minor safety significance, and thus a finding, because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a lower than allowable sodium pentaborate concentration would have affected the SLC system's ability to successfully shutdown the reactor during a design basis event. The inspectors also reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no similar examples.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding affected the Mitigating Systems Cornerstone, specifically the Mitigating Systems contributor, and would require review using IMC 0609, Appendix A, "SDP for Findings At-Power," dated June 19, 2012, since the reactor was operating at power when this issue was discovered. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," and answered "Yes" to Question 2, "Does the finding represent a loss of system and/or function?" Therefore, a detailed risk evaluation was warranted.

Detailed Risk Evaluation

To evaluate the risk significance of the finding, a Senior Reactor Analyst used the Fermi 2 Standardized Plant Analysis Risk (SPAR) Model, Version 8.21 and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations, Version 8.1.4.

Two modifications were made to the Fermi 2 SPAR model by Idaho National Laboratory from a previous risk analysis. The first modification of the SPAR model was performed to remove the assumed dependency between the operator action to vent containment and the operator action to start/control RHR in the suppression pool cooling mode. This change was made consistent with the current SPAR model philosophy that these two actions are separate enough in time that the failure to vent the containment is independent from the failure to start/control RHR. The second modification allowed continued core injection using the standby feedwater system (with a probability of 91 percent) and the control rod drive system (with a probability of 19 percent) even after containment vent system failure. These probabilities of standby feedwater system and control rod drive system success after containment failure are based on the types and probabilities of drywell and suppression pool failures that could occur to the containment and the effects on each type of failure on the systems. The applicable information was taken from the licensee's "Accident Sequence Analysis Notebook," [EF2–PRA–002, Revision 1].

The low boron concentration in the SLC tank was evaluated as a failure of the SLC tank in the Fermi 2 SPAR model. The exposure time was conservatively set to 15 days. Using the SPAR model, the ΔCDF for a failure of the SLC tank for 15 days was determined to be 1.4E–7/year for both internal and external events. The dominant sequence was a transient initiating event with a failure of the reactor protection system (i.e., an anticipated transient without scram (ATWS)) and with a failure of the SLC system.

Since the ΔCDF was greater than 1E–7/year, an evaluation of the delta large early release frequency (ΔLERF) was performed per IMC 0609 Appendix H, "Containment Integrity Significance Determination Process," dated May 6, 2004. The LERF Factor for ATWS sequences for a Mark I containment similar to Fermi 2 is 0.3. Since all the dominant sequences for the finding were ATWS related, an estimate of the ΔLERF is obtained by multiplying the ΔCDF by the LERF Factor of 0.3 to obtain a ΔLERF of 4.2E–8/year.

Based on the detailed risk evaluation, the inspectors determined the finding was of very low safety significance (Green).

The inspectors concluded this finding affected the cross-cutting area of human performance and the cross-cutting aspect of resources. Specifically, the licensee failed to ensure equipment and procedures were adequate to support nuclear safety. This issue would have been avoided if the system monitoring plan was trending tank level via a pressure indicator. Also, chemistry had no administrative limits in their procedure to add boron prior to the minimum TS limit was reached and the system engineer was not a reviewer on the routine surveillance procedure and was not trending the concentration as a backup. (IMC 0310, H.1)

Enforcement

TS 3.1.7, "Standby Liquid Control (SLC) System," states two SLC subsystems shall be operable in Modes 1 and 2. TS 3.1.7, Required Action B states with two SLC subsystems inoperable, restore one SLC subsystem to operable status within 8 hours. Required Action C states with the required action and associated completion time not met be in Mode 3 within the next 12 hours.

TS 3.0.1, "Surveillance Requirement (SR) Applicability," states, in part, SRs shall be met during the modes or other specified conditions in the applicability for individual LCOs. Failure to meet a surveillance, whether such failure is experienced during the performance of the surveillance or between performances of the surveillance, shall be failure to meet the LCO.

TS SR 3.1.7.1 states verify the available volume of sodium pentaborate solution is within the limits of Figure 3.1.7.1. Figure 3.1.7.1 specifies a minimum sodium pentaborate concentration of 8.5 percent.

Contrary to the above, between October 13 and October 28, 2016, with Fermi 2 operating in Mode 1, the licensee failed to maintain the available volume of sodium pentaborate within the limits of Figure 3.1.7.1 by maintaining a minimum sodium pentaborate concentration of 8.5 percent. During this time, the licensee did not satisfy TS 3.1.7, Required Actions B and C. This is a violation of TS 3.1.7.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's corrective action program, it is being treated as a Non-Cited Violation consistent with Section 2.3.2.a of the NRC Enforcement Policy **(NCV 05000341/2017001–02, Failure to Maintain Adequate SLC Storage Tank Boron Concentration)**.

The licensee entered this violation into its corrective action program to evaluate the issue and identify appropriate corrective actions (CARD 16–28619). Corrective actions taken include restoring the SLC storage tank sodium pentaborate concentration to within the TS limit, revising the SLC system monitoring plan to include trending of storage tank level and sodium pentaborate concentration, and replacing the two demineralized water valves that were leaking by their seats.

LER 05000341/2016–011–00 is closed.

.9 (Closed) Licensee Event Report 05000341/2016–012–00, "Unanalyzed Condition for Control Rod Drop Accident at Low Reactor Power"

On November 2, 2016, a non-conservatism in the current Fermi 2 design and license basis for the control rod drop accident (CRDA) was identified by the licensee while performing a re-evaluation of the radiological consequences in support of a potential license amendment. The current CRDA analysis assumed the fission products released as a result of a CRDA are transported to the main condenser and then released from there. An unanalyzed condition was identified where a forced release from the gland seal exhausters could occur that would exceed dose limits in 10 CFR 100.11 and Standard Review Plan 6.4 when operating at less than 10 percent reactor power.

The licensee completed an 8-hour notification call (Event Notification 52342) on November 2, 2016, to report this condition as required by 10 CFR 50.72(b)(3)(ii)(B) as an unanalyzed condition that significantly degrades plant safety. The licensee submitted LER 05000341/2016–012–00 to report this event in accordance with 10 CFR 50.73(a)(2)(ii)(B) as an unanalyzed condition that significantly degraded plant safety.

The inspectors reviewed the licensee's engineering functional analysis for the unanalyzed condition and agreed that existing safety systems along with limited operator action would mitigate the CRDA at low power. Since the new CRDA analysis was performed in accordance with current regulatory guidance, was not required by regulations prior to discovery, and current installed safety-related systems would be able to mitigate the accident, the inspectors did not identify a performance deficiency for this unanalyzed condition.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2016–012–00 is closed.

.10 <u>(Closed) Licensee Event Report 05000341–2017–002–00, "High Water Level Indications at Low Reactor Pressures Causes Some Functions of High Pressure Coolant Injection System and Reactor Core Isolation Cooling System to Be Inoperable"</u>

In August 2016, the licensee identified a non-conforming condition affecting the HPCI and RCIC systems instrumentation functions of high drywell pressure (HPCI only) and manual initiation (both HPCI and RCIC) during low reactor pressure conditions. Per TS 3.3.5.1, "ECCS Instrumentation," and TS 3.3.5.2, "RCIC System Instrumentation," these instrumentation functions are required to be operable in Modes 1, 2, and 3 with reactor steam dome pressure above 150 psig. The reactor pressure vessel water level high (Level 8) trips for HPCI and RCIC at Fermi 2 originate from the wide range level instruments, which are calibrated for full power pressure and temperature conditions. These instruments read higher than actual level during plant startup and shutdown when reactor pressure is much lower. During plant startup, the systems are placed in standby at 150 psig with the exception of the Level 8 trips being present. The Level 8 trips do not clear until reactor pressure is sufficient for wide range level instrumentation to read on-scale. Similarly, during plant shutdown, Level 8 trips actuate during plant cooldown while still above 150 psig. Once actuated, the Level 8 trips prevent the HPCI and RCIC systems from operating.

The licensee learned of this issue that was previously identified by NRC inspectors at another licensee's facility during a meeting with industry peers in July 2016. The licensee entered this issue into its corrective action program for evaluation. The licensee's initial evaluation of this condition in August incorrectly concluded it was not an operability concern for plant startup and that the plant was operating within its original license basis. The non-conforming condition was considered to be only a literal TS compliance issue that could be addressed through a license amendment to enhance the applicable TS LCOs. Nothing further was done to address the non-conforming condition.

In January 2017, the licensee became aware of a second licensee's emergency license amendment for this same condition to permit it to restart a unit following a forced outage and reevaluated this issue for its applicability at Fermi 2. On January 19, the licensee determined it would need a license amendment to correct the non-conforming condition prior to its next plant startup. In addition, as a result of the non-conforming condition, the licensee completed a past operability determination on February 13 and concluded it had not complied with the TSs during previous plant shutdowns and startups. Twelve occurrences during the previous three years (six plant startups and six shutdowns) were identified wherein the licensee did not satisfy the TS requirements. Two of these occurrences were in November 2016, about two months after the licensee initially identified the non-conforming condition.

On November 7, 2016, the licensee removed Fermi 2 from service for a planned maintenance outage without addressing the TS compliance issue beforehand. During plant shutdown, with the unit in Mode 3, the Level 8 trips were present in a manner that would have prevented the injection of HPCI and RCIC by the high drywell pressure and manual initiation functions for about four hours without the licensee declaring the HPCI and RCIC systems instrumentation functions inoperable and entering the applicable TS LCOs. This resulted in a condition that was prohibited by the plant's TS. The unit was restarted on November 11. During plant startup, the licensee changed operational modes, entering conditions requiring the HPCI and RCIC systems instrumentation to be operable. TS 3.0.4.a states when a LCO is not met, entry into an operational mode or other specified condition in the applicability shall only be made when the associated actions to be entered permit continued operation in the operational mode or other specified condition in the applicability for an unlimited period of time. Inasmuch as the licensee did not satisfy TS 3.3.5.1 and TS 3.3.5.2 for operable HPCI and RCIC systems instrumentation prior to Fermi 2 entering Mode 2 with reactor steam dome pressure above 150 psig on November 11, this resulted in a condition that was prohibited by the plant's TS.

The licensee submitted LER 05000341/2017–002–00 to report this event in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation or condition which was prohibited by the plant's TSs. Accordingly, the inspectors documented a licensee-identified Non-Cited Violation in Section 4OA7.1 of this inspection report. The licensee also reported the event in accordance with 10 CFR 50.73(a)(2)(v)(D) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident. During plant shutdowns and startups, the Level 8 trip signal was present in a manner that would have prevented the injection of HPCI by the high drywell pressure and manual initiation functions. Since HPCI is a single train system, the inoperability of HPCI could have prevented the system from fulfilling its safety function to mitigate the consequences of an accident. Because the instances described in this LER occurred in the past and there was no loss of safety function at the time of discovery, no event notification was made under the corresponding requirement in 10 CFR 50.72.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

LER 05000341/2017–002–00 is closed.

.11 Retraction of Event Notifications and Cancellation of Licensee Event Reports for Secondary Containment Wind Events

On March 17, 2017, the licensee retracted nine Event Notifications and cancelled ten LERs that had reported previous occasions when the TS limiting pressure for the secondary containment pressure boundary was not met due to high wind conditions affecting the Fermi 2 site. The following Event Notifications were retracted: 52076, 52084, 52205, 52320, 52380, 52398, 52432, 52434, and 52437. The following LERs were cancelled: 05000341/2016–003, 05000341/2016–004, 05000341/2016–007, 05000341/2016–008, 05000341/2016–010, 05000341/2016–013, 05000341/2016–014, 05000341/2016–015, 05000341/2016–016, and 05000341/2016–017.

The licensee re-reviewed the conditions associated with these Event Notifications and LERs in light of improved secondary containment differential pressure indication and determined the Fermi 2 secondary containment was operable; and, therefore there was no loss of the secondary containment safety function during each of the events reported. The inspectors reviewed the licensee's past operability/reportability evaluation and identified no issues of concern with it. The secondary containment pressure recorders are digital and had been programmed to display a single data point every second. During high wind gusts, a negative pressure change on the leeward side of the reactor building would cause a momentary higher indicated pressure that was not indicative or actual pressure inside the reactor building. As a corrective action to address these recurring events, on December 23, 2016, the licensee completed a programming change to the digital secondary containment pressure recorders to average the instantaneous pressure data to reflect actual pressure in the reactor building by dampening the effects of momentary wind gusts on the recorders.

The inspectors previously reviewed each of the LERs and identified no findings associated with the events since the condition (i.e., high winds) was determined not to be within the licensee's ability to reasonably prevent.

This inspection constituted one event follow-up inspection sample as defined in IP 71153.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction 2515/192, "Inspection of the Licensee's Interim Compensatory Measures Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems"

a. Inspection Scope

The objective of this performance based temporary instruction (TI) is to verify implementation of interim compensatory measures associated with an open phase condition (OPC) design vulnerability in electric power systems for operating reactors. The inspectors conducted an inspection to determine if the licensee had implemented the following interim compensatory measures. These compensatory measures are to remain in place until permanent automatic detection and protection schemes are installed and declared operable for the OPC design vulnerability. The inspectors verified the following:

- The licensee had identified and discussed with plant staff the lessons-learned from the OPC events at the US operating plants including the Byron Station OPC event and its consequences. This includes conducting operator training for promptly diagnosing, recognizing consequences, and responding to an OPC event.
- The licensee had updated plant operating procedures to help operators promptly diagnose and respond to OPC events on off-site power sources credited for safe shutdown of the plant.
- The licensee had established and continue to implement periodic walkdown activities to inspect switchyard equipment such as insulators, disconnect switches, and transmission line and transformer connections associated with the offsite power circuits to detect a visible OPC.
- The licensee had ensured that routine maintenance and testing activities on switchyard components have been implemented and maintained. As part of the maintenance and testing activities, the licensee assessed and managed plant risk in accordance with 10 CFR 50.65(a)(4) requirements.

b. Findings and Observations

No findings were identified. The inspectors verified the criteria of the TI were met.

4OA6 Management Meetings

.1 Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. M. Caragher and other members of the licensee's staff on April 11, 2017. The licensee acknowledged the findings presented. Proprietary information was examined during this inspection, but is not specifically discussed in this report.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements that meets the criteria of the NRC Enforcement Policy for being dispositioned as a Non-Cited Violation.

- TS 3.3.5.1, "ECCS Instrumentation," states the ECCS instrumentation for each function in Table 3.3.5.1–1 shall be operable. As specified in Table 3.3.5.1–1, Function 3b, HPCI System High Drywell Pressure (4 channels) and Function 3f, HPCI System Manual Initiation (1 channel) are required to be operable in Modes 1, 2, and 3 with reactor steam dome pressure greater than 150 psig. TS 3.3.5.1, Required Action A.1 states with one or more channel(s) inoperable, immediately enter the condition referenced in Table 3.3.5.1–1 for the channel. Table 3.3.5.1–1, Function 3b, references Condition B for inoperable HPCI System High Drywell Pressure channels. Required Action B.2 states declare the HPCI system inoperable within 1 hour from discovery of loss of HPCI initiation capability and Required Action B.3 states place the affected channel(s) in trip within 24 hours. Table 3.3.5.1–1, Function 3f, references Condition C for an inoperable HPCI System Manual Initiation channel. Required Action C.2 states restore the channel to operable status within 24 hours. If the required actions and associated completion times of Condition B or C are not met, Required Action G.1 states immediately declare the associated supported feature (i.e., HPCI system) inoperable.

TS 3.5.1, "ECCS – Operating," states, in part, each ECCS injection subsystem shall be operable in Modes 1, 2, and 3, except HPCI is not required to be operable with reactor steam dome pressure less than or equal to 150 psig. With the HPCI system inoperable, Required Action E.1 states immediately verify by administrative means RCIC system is operable and Required Action E.2 states restore HPCI system to operable status in 14 days. If the required actions and associated completion times of Condition E are not met, Required Action I.1 states be in Mode 3 in 12 hours. LCO 3.0.4.b is not applicable to HPCI.

TS 3.3.5.2, "RCIC System Instrumentation," states the RCIC instrumentation for each function in Table 3.3.5.2–1 shall be operable in Modes 1, 2, and 3 with reactor steam dome pressure greater than 150 psig. As specified in Table 3.3.5.2–1, Function 4, RCIC System Manual Initiation (one channel per valve) is required to be operable. TS 3.3.5.2, Condition A states with one or more channels inoperable, immediately enter the condition referenced in Table 3.3.5.2–1 for the channel. Table 3.3.5.2–1, Function 4, references Condition C for an inoperable RCIC System Manual Initiation channel. Required Action C.1 states restore the channel to operable status within 24 hours. If the required actions and associated completion times of Condition C are not met, Required Action E.1 states immediately declare the RCIC system inoperable.

TS 3.5.3, "RCIC System," states the RCIC system shall be operable in Modes 1, 2, and 3 with reactor steam dome pressure greater than 150 psig. With the RCIC system inoperable, Required Action A.1 states immediately verify by administrative means HPCI system is operable and Required Action A.2 states restore RCIC system to operable status in 14 days. If the required actions and associated completion times of Condition A are not met, Required Action B.1 states be in Mode 3 in 12 hours. LCO 3.0.4.b is not applicable to RCIC.

TS 3.0.4, "Limiting Condition for Operation (LCO) Applicability," Paragraph (a) states, in part, when a LCO is not met, entry into an operational mode or other specified condition in the applicability shall only be made when the associated actions to be entered permit continued operation in the operational mode or other specified condition in the applicability for an unlimited period of time. This specification shall not prevent changes in modes or other specified conditions in the applicability that are part of a shutdown of the unit.

Contrary to the above:

1. On six occasions (February 10, 2014, April 16, 2014, March 19, 2015, September 13, 2015, May 3, 2016, and November 7, 2016), the licensee entered Mode 3 following plant shutdowns without declaring the HPCI system instrumentation functions of high drywell pressure and manual initiation inoperable and entering LCO 3.3.5.1. During the shutdowns, Fermi 2 was in Mode 3 for up to fifteen hours with reactor steam dome pressure greater than

150 psig without the licensee satisfying TS 3.3.5.1, Required Actions A.1, B.2, and G.1. This is a violation of TS 3.3.5.1.

With HPCI inoperable as specified by TS 3.3.5.1, Required Actions B.2 and G.1, the licensee did not satisfy TS 3.5.1, Required Action E.1. This is a violation of TS 3.5.1.

2. On six occasions (February 10, 2014, April 16, 2014, March 19, 2015, September 13, 2015, May 3, 2016, and November 7, 2016), the licensee entered Mode 3 following plant shutdowns without declaring the RCIC system instrumentation function of manual initiation inoperable and entering LCO 3.3.5.2. During the shutdowns, Fermi 2 was in Mode 3 for up to fifteen hours with reactor steam dome pressure greater than 150 psig without the licensee satisfying TS 3.3.5.2, Required Action A.1. This is a violation of TS 3.3.5.2.

3. On six occasions (March 28, 2014, April 21, 2014, April 3, 2015, November 25, 2015, May 12, 2016, and November 11, 2016), the licensee entered Mode 2 with reactor steam dome pressure greater than 150 psig during plant startups without declaring the HPCI system instrumentation functions of high drywell pressure and manual initiation inoperable and entering LCO 3.3.5.1. For up to nineteen hours during this time, the licensee did not satisfy TS 3.3.5.1, Required Actions A.1, B.2, and G.1. This is a violation of TS 3.3.5.1.

   With HPCI inoperable as specified by TS 3.3.5.1, Required Actions B.2 and G.1, the licensee did not satisfy TS 3.5.1, Required Action E.1. This is a violation of TS 3.5.1.

4. On six occasions (March 28, 2014, April 21, 2014, April 3, 2015, November 25, 2015, May 12, 2016, and November 11, 2016), the licensee entered Mode 2 with reactor steam dome pressure greater than 150 psig during plant startups without declaring the RCIC system instrumentation function of manual initiation inoperable and entering LCO 3.3.5.2. For up to nineteen hours during this time, the licensee did not satisfy TS 3.3.5.2, Required Action A.1. This is a violation of TS 3.3.5.2.

5. On six occasions (March 28, 2014, April 21, 2014, April 3, 2015, November 25, 2015, May 12, 2016, and November 11, 2016), the licensee entered Mode 2 with reactor steam dome pressure greater than 150 psig during plant startups without meeting the LCOs of TS 3.3.5.1 and TS 3.3.5.2 for HPCI and RCIC systems instrumentation functions of high drywell pressure (HPCI only) and manual initiation (both HPCI and RCIC). This is a violation of TS 3.0.4.

   This violation was entered into the licensee's corrective action program as CARD 16–26153. The violation was determined to be of very low safety significance (Green) during a detailed Significance Determination Process review since the ΔCDF was determined to be less than 1.0E-7/year.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

N. Avrakotos, Manager, Radiological Emergency Response Preparedness
L. Bennett, Director, Nuclear Operations
R. Breymaier, Manager, Performance Engineering
M. Caragher, Executive Director, Nuclear Production
D. Domski, Engineer, Plant Systems Engineering
I. Finney, General Supervisor, NSSS Systems Engineering
J. Haas, Supervisor, Licensing
C. Harris, Manager, Performance Improvement
D. Hemmele, Superintendent, Nuclear Operations
E. Kokosky, Director, Organization Effectiveness
R. Laburn, Manager, Radiation Protection
B. Leimkuehler, Performance Engineering
M. Lake, Supervisor, Reactor Engineering & PSA
K. Locke, General Supervisor - Electrical, Plant Systems Engineering
J. Louwers, Manager, Nuclear Quality Assurance
S. Maglio, Manager, Licensing
K. Mann, Supervisor, Regulatory Compliance
R. Matuszak, Manager, Plant Systems Engineering
D. Noetzel, Director, Nuclear Engineering
M. O'Connor, Manager, Nuclear Security
G. Patzsch-Velaquez, Performance Engineering
K. Polson, Site Vice President
W. Raymer, Director, Nuclear Maintenance
N. Schafer, NSSS Systems Engineering

U.S. Nuclear Regulatory Commission

K. Riemer, Chief Reactor Projects, Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000341/2017001–01	NCV	Inadequate Work Instructions for Maintenance on EDG 14 (Section 4OA2.2.b.1)
05000341/2017001–02	NCV	Failure to Maintain Adequate SLC Storage Tank Boron Concentration (Section 4OA3.8)

Closed

05000341/2017001–01	NCV	Inadequate Work Instructions for Maintenance on EDG 14 (Section 4OA2.2.b.1)
05000341/2016–001–01	LER	Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves, Supplement 1 (Section 4OA3.1)
05000341/2016–010–00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.2)
05000341/2016–013–00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.3)
05000341/2016–014–00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.4)
05000341/2016–015–00	LER	Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds (Section 4OA3.5)
05000341/2016–016–00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather (Section 4OA3.6)
05000341/2016–017–00	LER	Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds (Section 4OA3.7)
05000341/2017001–02	NCV	Failure to Maintain Adequate SLC Storage Tank Boron Concentration (Section 4OA3.8)
05000341/2016–011–00	LER	Standby Liquid Control Inoperable Due to Sodium Pentaborate Concentration Outside of Technical Specifications (Section 4OA3.8)
05000341/2016–012–00	LER	Unanalyzed Condition for Control Rod Drop Accident at Low Reactor Power (Section 4OA3.9)
05000341/2017–002–00	LER	High Water Level Indications at Low Reactor Pressures Causes Some Functions of High Pressure Coolant Injection System and Reactor Core Isolation Cooling System to Be Inoperable (Section 4OA3.10)
2515/192	TI	Inspection of the Licensee’s Interim Compensatory Measures Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems (Section 4OA5.1)

Discussed

05000341/2014004–03	NCV	Failure to Promptly Correct a Condition Adverse to Quality on EDG 11 (Section 4OA2.2.b.1)
05000341/2016002–01	NCV	Failure to Control Combustible Materials (Section 4OA2.3.2)
05000341/2016001–03	NCV	Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Loss of RPS Trip Safety Functions (Section 4OA2.3.3)
05000341/2016001–05	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's Technical Specifications (Section 4OA2.3.3)
05000341/2016001–10	NCV	Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment Isolation Valve Actuations (Section 4OA2.3.3)
05000341/2016001–02	NCV	Failure to Correctly Interpret and Implement TS Requirements for RPS Trip Functions (Section 4OA2.3.3)
05000341/2016007–16	NCV	Failure to Timely Identify, Document, and Evaluate Conditions that Challenge Operability (Section 4OA2.3.3)
05000341/2016007–01	NCV	Inadequate Procedure for Addressing Non-Functional Mechanical Draft Cooling Tower Fan Motor Brake System (Section 4OA2.3.3)
05000341/2016003–01	NCV	Failure to Perform an Operability Determination for Division 1 RPV Reference Leg Backfill System Not Providing Adequate Flow (Section 4OA2.3.3)
05000341/2016004–03	NCV	Failure to Satisfy 10 CFR 50.73 Reporting Requirements for Loss of LOP Instrumentation and AC Electrical Power Safety Functions (Section 4OA2.3.3)
05000341/2016004–02	NCV	Failure to Correctly Interpret and Implement TS Requirements for LOP Instrumentation and AC Electrical Power Functions (Section 4OA2.3.3)
05000341/2016008–00	LER	Past Instances of Secondary Containment Pressure Exceeding Technical Specification Due to Adverse Weather (Section 4OA3.2)
05000341/2016005–00	LER	Secondary Containment Pressure Exceeded Technical Specification Due to Reactor Building HVAC Restart During High Winds (Sections 4OA3.5 and 4OA3.7)

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply the NRC inspectors reviewed the documents in their entirety, but rather, selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather

- Procedure 20.000.01; Acts of Nature; Revision 50
- Procedure MOP01-200; Severe Weather Guidelines; Revision 0

1R04 Equipment Alignment

- CARD 15-29757; Condensation Puddles Under South End of East Turbine Building Closed Cooling Water Heat Exchanger
- CARD 16-00420; Outboard Bearing for the South Turbine Building Closed Cooling Water System Pump (P4300C003) is Warmer than the North Pump
- CARD 16-21657; N3021C013, Number Five Low Pressure Intercept Valve Unitized Actuator Oil High Temperature Alarm, 4D6
- CARD 16-24321; P4300 Turbine Building Closed Cooling Water System was Evaluated to be (a)(1)
- CARD 16-25572; N3021C005, High Pressure Stop Valve 1 Turbine Valve Actuator (Unitized Actuator)
- CARD 16-26225; 7D61: West Station Air Compressor Trouble Due to High Oil Temperature
- CARD 16-26994; Extent of Condition: Request Work Order to Replace High Pressure Unitized Actuator Inlet/Outlet Turbine Building Closed Cooling Water Isolation Valves
- CARD 16-28298; Extent of Condition: Request Work Order to Replace High Pressure Unitized Actuator Inlet/Outlet Turbine Building Closed Cooling Water Isolation Valves
- Fermi 2 Health Summary; Third Quarter 2016 Turbine Building Closed Cooling Water System
- Procedure 23.128; Turbine Building Closed Cooling Water System; Revision 45
- Procedure 23.205, Attachment 11A; Shift to Division 1 Residual Heat Removal Shutdown Cooling Verification
- Procedure 23.205; Placing Division 1 Residual Heat Removal in Shutdown Cooling Mode; Revision 132
- Procedure 23.205; Residual Heat Removal System; Revision 131
- Procedure 23.208; Residual Heat Removal Complex Service Water Systems; Revision 111
- Procedure 23.307; Emergency Diesel Generator System; Revision 122
- Sketch 6M721—5734; Emergency Diesel Generator System Functional Operating Sketch; Revision BF
- WO 38081729; P43F405 (Turbine Building Closed Cooling Water D/P Containment Valve) – Valve does not Appear to be Moving While Actuator is Moving
- WO 45408702; EDP 37709 Turbine Building Closed Cooling Water System Implementation – SPV
- Work Week 1705 Strategy Document; Division 2 Residual Heat Removal/ Residual Heat Removal Service Water Train Outage; January 30, 2017

1R05 Fire Protection

- CARD 17-20633; C02 Boundary Door D41 Latch Broken

- Fire Protection Pre Plan FP-AB-3-14c; Auxiliary Building, East Reactor Protection System Division 1 Motor Generator Set Room, Zone 14, Elevation 643’6”; Revision 3
- Procedure FP-AB-1-6d; Auxiliary Building First Floor Mezzanine, Zone 6, Elevation 603’6”; Revision 4
- Procedure FP-TB; Turbine Building; Revision 9

1R06 Flood Protection

- CARD 08-23459; NRC Concern: Unshrouded Division 2 Emergency Equipment Cooling Water Piping Routed in Division 1 Switchgear Room
- CARD 08-23602; NRC Concern: Moderate Energy Line Break Drain Path Compromised by Unsealed Hatch
- CARD 16-29475; Potential Misclassification of AB 3/4 and 4/5 Hatches as Limiting Condition of Operation 3.0.9 Barriers
- CARD 17-21851; NRC Identified – Update UFSAR Section 3.6.2.3.4.1.2
- CARD 17-21865; NRC Identified – Investigate Revision of 35.000.242
- Procedure 35.000.242; Barrier Identification/Classification; Revision 55
- Regulatory Issue Summary RIS 01-009; Control of Hazard Barriers; April 2, 2001
- Technical Evaluation TE-A58-08-069; Temporary Removal of Auxiliary Building Fourth and Fifth Floor Hatch Covers; Revision 0
- Technical Service Request TSR-36051; Add Spray Barrier Over AB4 Hatch Cover; Revision 0
- UFSAR Section 3.6.2; Protection Against Dynamic Effects Associated with the Postulated Rupture; Revision 20

1R07 Heat Sink Performance

- CARD 17-20735; Verify Acceptability of Installed Tube Bundle for Heat Exchangers for EDG 14
- CARD 17-20759; EDG 11 Heat Exchanger Bundles not Oriented Correctly
- CARD 17-20788; EDG 14 Tube Bundle Orientation to Eddy Current Results
- CARD 17-22773; Residual Heat Removal Heat Exchanger Coating
- Engineering Functional Analysis EFA-R30-17-001; EDG 11 Heat Exchanger Tube Bundles Mis-oriented; Revision 0
- Heat Exchanger Inspection Report; EDG 14 – Air Coolant Heat Exchanger; January 23, 2017 – January 25, 2017
- Heat Exchanger Inspection Report; EDG 14 – Jacket Cooling Heat Exchanger; January 23, 2017 – January 25, 2017
- Heat Exchanger Inspection Report; EDG 14 – Lube Oil Heat Exchanger; January 23, 2017 – January 25, 2017
- MES 54; Heat Exchanger Component Monitoring Program; Revision 5
- Technical Evaluation TE-R30-17-008; CARD 17-20759 Past Operability; Revision 0

1R11 Licensed Operator Requalification Program

- Procedure 22.000.03; Power Operation 25% to 100% to 25%; Revision 101
- Procedure 22.000.04; Plant Shutdown from 25% Power; Revision 79

1R12 Maintenance Effectiveness

- CARD 16-30023; Nitrogen Bottles for E1156C001A, Mechanical Draft Cooling Tower Fan A, Found to be at Zero Pounds

- CARD 17-20553; Low Nitrogen Bottle Pressure on the High Pressure Bottle for A Mechanical Draft Cooling Tower Fan Brake
- CARD 17-21143; Mechanical Draft Cooling Tower A Brake Pressure Regulator is Indicating 0 psig
- CARD 17-21163; Dipstick Dropped in Oil Tube
- Fermi 2 Control Room Log; February 9, 2017
- System Health Report E1156; RHR Mechanical Draft Cooling Tower Fans and Ultimate Heat Sink; 3rd and 4th Quarter 2016

1R13 Maintenance Risk Assessment and Emergent Work Control

- CARD 17-21058; South Heater Drain Pump Tripped Causing a Subsequent Plant Transient and Reactor Recirculation Runback
- CARD 17-21060; Instantaneous Core Thermal Power Level Exceeded Reportability Assessment Power Level in MOP19
- ODMI 17-001; North Reactor Feed Pump Vibration Step Change; Revision 0
- Reactivity Maneuvering Plan; January 2017 Radiation Protection Advisor; Revision 0

1R15 Operability Determinations and Functionality Assessments

- CARD 08-25246; Reactor Building Auxiliary Steam Heating and Control Rod Drive Line Break Definition
- CARD 11-23400; IER Level 1 11-1 Review Result: DC-5426 Volume I Discrepancies
- CARD 12-25925; Self-Assessment Deficiency: Revisit and Re-Evaluated Moderate Energy Line Break Definition Previously Addressed in 08-25246
- CARD 14-25229; Design Discrepancy Related to Assumed High Energy Line Break Area for 15psig Heating Steam
- CARD 15-28013; T2300F410 Running Torque High During As-left Air Operated Valve Testing
- CARD 16-26153; Limerick Tech Spec Change – High Pressure Coolant Injection-Reactor Core Isolation Cooling Level 8 Trip Signal
- CARD 16-26697; 2016 CDBI Inspection – Main Steam Isolation Valve Calculation DC-0469 Discrepancy with UFSAR 5.5.5.1.e
- CARD 16-27189; Main Steam Isolation Valve TS Surveillance Requirement 3.6.1.3.7 not Correlated to Plant Safety Analysis
- CARD 16-28470; Operations Decision Expectation-12 Remote Shutdown System Section Review
- CARD 16-28585; Review DC-6538 for Potential Impact on License Agreement Request
- CARD 16-29382; Request Evaluation for the Minimum Design Temp for Emergency Diesel Generator's Fuel Oil Storage Room(s)
- CARD 16-29742; Inappropriate Operability Determination in CARD 14-25229
- CARD 16-29743; CARD 14-25229 Investigation Failed to Identify Potential Operability Issue
- CARD 16-29897; Potential Auxiliary Steam Line High Energy Line Break not Discussed in Auxiliary High Energy Line Break EFA-T41-16-008
- CARD 17-20083; Evaluate Site Processes for CARDs with Operable but Degraded or Non- Conforming Status
- CARD 17-20173; Weld Found Leaking After the Associated Work Order was Returned to Service
- CARD 17-20643; Review Timeliness of Evaluation of Limerick Unresolved Item Regarding High Pressure Coolant Injection/Reactor Core Isolation Cooling in CARD 16-26153
- CARD 17-21165; Mispositioned Component Nitrogen Pressure Regulator Mechanical Draft Cooling Tower Fan A

- CARD 17-21717; Nuclear Safety Review Group Question on HPCI/RCIC Level 8 Trip Signal at Low Reactor Pressure
- Design Calculation DC-5991; Air Operated Valve Stem Force Requirements and Actuator Capacity for B2103F022A; Revision A
- DTE Letter NRC-17-0010 to NRC; License Amendment Request to Revise Technical Specifications for Emergency Core Cooling System Instrumentation and Reactor Core Isolation Cooling System Instrumentation; February 23, 2017
- EFA-T41-16-008; Pipe Break Evaluation of Heating Steam Lines; Revision 0
- GEH 003N8634; Fermi 2 Main Steam Isolation Valve Closing Speed Evaluation; Revision 0
- Letter from Exelon to NRC; Emergency License Amendment Request – Proposed Changes to the High Pressure Core Spray System and Reactor Core Isolation Cooling System Actuation Instrumentation Technical Specifications; November 26, 2016
- Letter from Exelon to NRC; License Amendment Request – Proposed Changes to the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System Actuation Instrumentation Technical Specifications; April 4, 2016
- NRC Information Notice 90-53; Potential Failures of Auxiliary Steam Piping and the Possible Effects on the Operability of Vital Equipment; August 16, 1990
- Operations Department Expectation ODE-12; Limited Condition of Operations; Revision 39
- Operations Department Expectation ODE-11; CARD Operability/ Reportability Determination Expectations; Revision 22
- Procedure 22.000.02; Plant Startup to Twenty-five Percent Power; Revision 95
- Procedure 23.202; High Pressure Coolant Injection System; Revision 110
- Procedure 23.206; Reactor Core Isolation Cooling System; Revision 99A
- Technical Evaluation TE-B21-16-035; Cycle 18 Main Steam Isolation Valve Closure Surveillance Test; Revision 0
- Technical Evaluation TE-E11-17-016; Analysis of Degraded Mechanical Draft Cooling Tower Fan Brake; Revision 0

1R18 Plant Modifications

- Apparent Cause Evaluation 16-22815; Temporary Modification 15-0042: Ahlberg Mast Camera; Revision 0
- CARD 15-22955; NQA – Inadequate Documentation Justifying Application of RTV 732 Sealant to Penetrations per Work Order 42565748
- CARD 15-27651; NQA – ASME Parts Installed and Welded on B31N004B Prior to NQA Review for Traceability
- CARD 15-27707; E1100F620B is Leaking Through its Tell Tale Drain Valve E1100F625B
- CARD 16-22815; Currently Installed Temporary Modification 15-0042 Has an Expected Removal Date of Post RF17
- CARD 16-28367; NQA Audit Deficiency – Temporary Video Equipment/ Free Air Cables, Cameras not Removed as Required by Technical Evaluation TE-D50-12-070
- CARD 17-10751; Assumption Error in Appendix R Calculation DC-5783 Volume 1
- CARD 17-20480; Request Work Order for Implementation of EDP 37731 Residual Heat Removal Cross-tie
- CARD 17-20481; Request Work Orders for Implementation of EDP 37792, Remove Residual Heat Removal Reservoir Cross tie Valves
- CARD 17-21293; Post Modification Testing Failure – Open Stroke Time of T4600F407 Outside of Acceptance Criteria Band Following Hardened Containment Vent System Modification Tie- in
- CARD 17-21726; NRC Identified EDP 37272 States 2 to 1 Ratio on All Socket Welds. Engineering Change Request Required to Change this Verbiage

- Design Calculation DC-0559; Volume of Reservoir – Residual Heat Removal Complex; Revision D
- Design Calculation DC-0622; RHRSW System – Direct Water Injection to Reactor Pressure Vessel – Hydraulic Analysis; Revision C
- EDP-37272; Reactor Core Isolation Cooling Pump Discharge High Point Vent Relocation; Revision 0
- EDP-37731; Change Valves E1150F601A/B and E1150F601A, E115F601B, E1150F602A, and E1150F602B; Revision 0
- Fermi 2 UFSAR 9.2; Revision 20
- Sketch 6WM-E51-5307-1; Piping Isometric Reactor Core Isolation Cooling Pump Discharge Vent Line Reactor Building; Revision 0
- WO 43579247; EDP-37272 Cycle 18 Refueling Outage Installation Reactor Core Isolation Cooling High Point Vent
- WO 46896660; Request Work Orders for Implementation of EDP 37792, Remove Residual Heat Removal Reservoir Cross Tie Valves

1R19 Post-Maintenance Testing

- CARD 17-22281; E1150F015A Failed Motor Inspection
- CARD 17-22391; Air Leak from P5000F402 Actuator
- CARD 17-22435; P5000F402 Failed to Stroke During As-Left Diagnostic Testing
- Procedure 23.307; Emergency Diesel Generator System; Revision
- Procedure 24.129.04; Control Air Valve Operability/Position Indication Verification/ Isolation Integrity Test; Revision 46
- Procedure 24.204.01; Division 1 Low Pressure Coolant Injection and Suppression Pool Cooling/Spray Pump and Valve Operability Test; Revision 79
- Procedure 24.307.10; EDG 11 – Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Tests of Bus 64B Breakers; Revision 42
- Procedure 24.307.11; EDG 12 – Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Tests of Bus 64C Breakers; Revision 45
- WO 38444863; Perform American Society of Mechanical Engineers as Found and as Left Relief Valve Testing
- WO 43656061; Replace Agastat Relay in P50P402A, Division 1 Non-Interruptible Air Supply Dryer Control Cabinet
- WO 44152016; Perform 24.307.10 EDG 11 Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Tests of Bus 64B
- WO 44152934; Perform 24.204.05 Section 5.1 Division 1 Residual Heat Removal Local Valve Position Indication and Stroke
- WO 44152950; Perform 24.307.11 EDG 12 Emergency Core Cooling System Start and Load Rejection Test and Logic Functional Tests of Bus 64C
- WO 44606373; EDP-37115 Cycle 18 Refueling Outage, Tie-in Tubing, Shuttle Valve and Post Modification Testing for Air Operated Valve P5000F440 (Division 1 Control Air Compressor)
- WO 46676663; Replace West Control Rod Drive Pump Water
- WO 46966894; EDG 11 Heat Exchanger Bundles not Oriented Correctly
- WO 46974874; Perform 24.307.34 Diesel Generator Service Water Operability Test – EDG 11
- WO A394130100; Perform Valve Actuator Overhaul and Air Operated Valve Diagnostic Testing

1R20 Refueling and Other Outage Activities

- Operations Conduct Manual MOP13; Conduct of Refueling and Core Alterations; Revision 17

- Procedure 82.000.04; Refueling and Core Post – Alteration Verification; Revision 50
- Procedure 23.205; Residual Heat Removal System; Revision 132
- Procedure 22.000.05; Pressure/Temperature Monitoring During Heatup and Cooldown; Revision 49

1R22 Surveillance Testing

- CARD 17-21352; While Performing Procedure 42.307.01, Acceptance Criteria Step Failed During 72 Hour Limited Conditions of Operation
- Card 17-22310; Clarification to 24.623
- CARD 17-22310; Clarification to 24.623
- Procedure 24.204.01; Division 1 Low Pressure Coolant Injection and Suppression Pool Cooling/Spray Pump and Valve Operability Test; Revision 79
- Procedure 24.208.02; Division 1 Emergency Equipment Service Water and Emergency Equipment Cooling Water Makeup Pump and Valve Operability Test; Revision
- Procedure 24.307.14; EDG 11 – Start and Load Test; Revision 58
- Procedure 24.307.34; Diesel Generator Service Water, Diesel Fuel Oil Transfer and Starting Air Operability Test – EDG 11; Revision 52
- Procedure 24.623; Reactor Manual Control/Reactor Mode Switch/Refueling Platform – Refueling Interlocks; Revision 56
- Procedure 24.623; Reactor Manual control/Reactor Mode Switch/Refueling Platform – Refueling Interlocks; Revision 56
- Procedure 42.307.01; Logic System Functional Test of Division 1 Emergency Diesel Generator Emergency Core Cooling System Emergency Start Circuits and Auto Trip/Bypass Circuits; Revision
- Procedure 43.000.003; Visual Examination of Snubbers; Revision 48
- Procedure 43.401.303; Local Leakage Rate Testing for Penetration X-9A; Revision 38
- Procedure 43.401.304; Local Leakage Rate Testing for Penetration X-9B; Revision 43
- WO 43250733; Perform 42.307.01Division 1 Emergency Diesel Generator Emergency Core Cooling System Emergency Start Circuits and Auto Trip/Bypass Logic Functional Test
- WO 44087703; Perform 24.208.02 Division 1 Emergency Equipment Service Water Pumps and Valve Operability
- WO 44097723; Perform 24.208.02 Division 1 Emergency Equipment Cooling Water Makeup Pump and Valve Operability
- WO 44107717; Final 43.401.304 Local Leak Rate Testing for X-9B (Test-1:B2100F010B)
- WO 44134176; Final 43.401.303 Local Leak Rate Testing for X-9A (Test-1:B2100F010A)

4OA1 – Performance Indicator Verification

- NEI 99 02; Regulatory Assessment Performance Indicator Guideline; Revision 7
- NUREG 1022; Event Report Guidelines, 10 CFR 50.72 and 50.73; Revision 3

4OA2 – Problem Identification and Resolution

- Apparent Cause Evaluation 16-26255; Recurrent Trend in Foreign Material Found in Discharged Irradiated Fuel; Revision 2
- Apparent Cause Evaluation 16-28674; EDG 14 Shutdown Due to Thick Smoke Coming from the Opposite Control Side Exhaust Manifold; Revision 0
- Apparent Cause Evaluation 16-28286; Multiple Entries Into Offsite Power Limiting Condition for Operation Due to Declaration of Internal N-1 Contingency Delta Voltage of Greater Than 1.6%

- Apparent Cause Evaluation 16-21857; Adverse Trend in Reportability Related Issues; Revision 1
- Archive Narrative Log; Fermi 2 Archived Operator Log; October 31, 2016 to November 1, 2016
- CARD 14-22612; EDG 11 Manually Tripped During Surveillance Test Due to Fire from Turbo Lagging
- CARD 14-25079; EDG 11 Control Side Exhaust Manifold Blanket Rework
- CARD 16-21857; Adverse Trend in Reportability Related Issues
- CARD 16-23605; Emerging Trend of Design Deficiency Rework Events Within Engineering
- CARD 16-23868; Declining Trend in Reliability in Off Gas System Radiation Monitoring and Acceptance
- CARD 16-24239; Emerging Trend in Maintenance: Rework Due to Inadequate Procedure Use and Adherence
- CARD 16-24400; NQA Audit Deficiency – Non-compliances with Flammable Liquids Locker Controls, Repeat Audit Deficiencies
- CARD 16-24413; Emerging Trend with Transient Combustible Storage
- CARD 16-24839; Trend of Marotta Regulator Failures
- CARD 16-25524; NQA Audit Deficiency – Trending has not been Effectively Implemented to Identify Adverse Trends in Training Related Activities/ Events
- CARD 16-25717; Emerging Trend in Operator Performance
- CARD 16-26154; Trend in Reactivity Management Issues from Human Performance
- CARD 16-26255; Recurrent Trend in Foreign Material Found in Discharged Irradiated Fuel
- CARD 16-26267; Adverse Trend of Events Associated with the High Pressure Stop Valves, Low Pressure Stop Valves and Low Pressure Isolation Valves
- CARD 16-26558; Spent Fuel Pool Foreign Material Trend
- CARD 16-26633; 2016 CDBI-NRC Concern for Operability Determination Justifications and Timeliness
- CARD 16-26798; Inadequate Interpretations of Technical specifications Identified by NRC
- CARD 16-26944; Emerging Trend in Implementation of the Corrective Action Program
- CARD 16-27909; NQA – Notice of Escalation – Untimely Initiation of CARDs
- CARD 16-28123; Change Management Failure
- CARD 16-28286; Internal N-1 Contingency Threshold Exceeded Four times On 10/17/2016
- CARD 16-28293; Common Cause Analysis of Rework Events
- CARD 16-28410; NQA Audit Deficiency – Trending has not been Effectively Implemented to Identify Adverse Trends in the Design Configuration Management Program
- CARD 16-28674; EDG 14 Shutdown During 24.307.17
- CARD 16-29205; Third Quarter 2016 Station Trend Report – Emerging Trend in Corrective Action Program Quality
- CARD 16-29512; MRC Identified Cognitive Trend in Unanalyzed Condition NRC Reportable Events During 3rd and 4th Quarters of 2016
- CARD 16-29513; MRC Identified Cognitive Trend in Secondary Containment NRC Reportable Events During 3rd and 4th Quarters of 2016
- CARD 17-21593; Evaluate Screening Determination for CARD 16-28674
- CARD 17-22240; Foreign Material Exclusion Plan Violation
- CARD 17-22312; Foreign Material Exclusion Introduced into Suppression Chamber Torus
- CARD 17-22432; Loss of Foreign Material Exclusion Controls LPT-2 During Disassembly
- CARD 17-22452; NQA – LP2 Foreign Material Exclusion Area Control/ Postings
- CARD 17-22494; NQA – Reactor Core Isolation Cooling High Risk Foreign Material Exclusion Plan Requirements not Followed
- CARD 17-22556; NQA – Poor Housekeeping Observed in Reactor Core Isolation Cooling Quad

- CARD 17-22664; Work in High Risk Foreign Material Exclusion Area Without Foreign Material Exclusion Monitor
- CARD 17-22732; Recovered Piece of Foreign Material from Spent Fuel Pool
- CARD 17-22805; South Heater Drain Pump – Drop Bolt into Pump Suction Tank
- CARD 17-22819; Inadequate Lanyard on Tool in High-risk Foreign Material Exclusion Area
- Common Cause Analysis Report; Trend in Reactivity Management Issues from Human Performance; August 4, 2016
- DTE Letter NAPI-16-0021; From C. Tomkinson, Corrective Action Program, to C. Harris, Performance Improvement Manager; Third Quarter Station Trend Report; November 16, 2016
- DTE Letter NAPI-17-0001; From C. Tomikinson, Corrective Action Program, to C. Harris, Performance Improvement Manager; Fourth Quarter 2016 Station Trend Report; February 21 , 2017
- DTE Letter NAQA-16-0057; From J. Louwers, Manager of Nuclear Quality Assurance, to M. Caragher, Nuclear Production Director; Notice of First Level Issue Escalation – Untimely Initiation of CARDs; October 5, 2016
- DTE Letter NP-16-0039; From M. Caragher, Nuclear Production Director, to J. Louwers Manager of Nuclear Quality Assurance; Response to Notice of First Level Issue Escalation – Untimely Initiation of CARDs; October 14, 2016
- DTE Letter NPOP-16-0054; From G. Piccard, Nuclear Operations Manager, to M. Caragher, Nuclear Production Director, and L. Peterson, Nuclear Engineering Director; Reactivity Management Trends for June 2016; July 12, 2016
- Final Report; 2015 Fermi 2 Nuclear Power Plant Grid Reliability Analysis for Year 2016 System, Performed by Ming Wu, PE and Joshua Niemi, ITC Holdings Corp.; December 9, 2015
- Hazard Barrier Target Analysis; Prevention of Foreign Material Depositing on Spent Fuel Assemblies; June 20, 2013
- NUC-001; Nuclear Plant Operating Agreement for the Fermi 2 Nuclear Power Plant; Revision 9
- Reactor Engineering Standing Order 18-005; Revision 0
- Technical Evaluation 14-22612; EDG 11 Manually tripped During Surveillance Test Due to Fire from Turbo Lagging
- Technical Evaluation TE-R30-17-013; Review of Shutting Down EDG 14 During Surveillance 24.307.17 Due to Thick Smoke; Revision 0
- Technical Evaluation TE-S40-17-017; N-1 Past Operability; Revision 0
- TMPE 15-0191; Letter from K. Hullum-Lawson, Manager, PSE, DTE Energy to J. Andree, Manager, METC/ITC Transmission Planning, ITC Holdings Corp., 2015 Fermi 2 Input Parameters for 2016 Study Grid Adequacy Study Fermi PST Event AG80; October 9, 2015
- UFSAR 8.2-1; Offsite Power System; Revision 20
- WO 38298165; Modify Exhaust Blankets on EDG 14
- WO 43259825; Torque Check EDG 14 Front Cover Fasteners

4OA3 Follow-Up of Events and Notices of Enforcement Discretion

- 50.59 Evaluation 16-0251; Revision A of DC-4804 Volume 1, "Secondary Containment Drawdown During Design Basis Accident Loss of Coolant Accident", and Related LCR-16-082-UFS Revision 0, Affecting UFSAR Section 6.2.3.3.2 and Figure 6.2-2.1; Revision 0
- Apparent Cause Evaluation CARD 16-20156; Turbine High Pressure Stop Valve 1 Closed, Isolating a Turbine Steam Lead; Revision A
- Apparent Cause Evaluation CARD 16-28619; Sodium Pentaborate Concentration Low Identified in Standby Liquid Control Tank; Revision 0

- CARD 16-20156; Number 1 High Pressure Stop Valve Drifted to 25% Open from 100% Open at Power
- CARD 16-28545; High Wind Condition Encountered on Site Result in the Technical Specification for Secondary Containment Pressure Boundary not Being Met Numerous Times
- CARD 16-28552; Revise LER 2016-001 to Reflect Changes to Cause and Corrective Actions
- CARD 16-28616; Abnormal Indications While Investigating 3D3, Standby Liquid Control Tank Level High Alarm
- CARD 16-28619; Sodium Pentaborate Concentration Low
- CARD 16-28628; Request Work Order to Replace the Demineralized Water Isolation Valves for Standby Liquid Control Storage Tank
- CARD 16-28738; Non-Conservative Fermi 2 Control Rod Drop Accident Licensing Design Basis
- CARD 16-29351; Division 1 Reactor Building Differential Pressure Recorder Response
- CARD 16-29353; Due to High Winds, Reactor Building Pressure Exceeded the Technical Specification Limit (-0.125 Inches WC) Several Times
- CARD 16-29518; Secondary Containment Declared Inoperable Due to High Winds
- CARD 16-29951; Secondary Containment Pressure > Technical Specification Limit Momentarily During Reactor Building HVAC Startup
- CARD 16-29971; Due to the High Winds, Reactor Building Pressure Exceeded the Technical Specification Limit (-0.125 Inches WC) Several Times
- CARD 16-29978; Reactor Building HVAC Outside Air Damper Failed to Open
- Correspondence, DTE Letter from J. Owens and C. Metheny, Engineering Support Organization, to D. Valleroy; Failure Analysis of 2 Cannon Connectors and Associated Cable for Fermi 2 QA Traveler No. N/A, Test Req. WO 35802373, P.O. No. N/A, Test Material Master No. N/A, Stock Material Master No. N/A, Engineering Support Organization Report 16J075-0037; June 24, 2016
- DTE Letter NRC-17-0029; Cancellation of Licensee Event Reports for Secondary Containment Wind Events; March 17, 2017
- Engineering Functional Analysis EFA-T41-16-007; Impact of GSE Release Path on Radiological Consequences of the Control Rod Drop Accident; Revision 0
- Engineering Functional Analysis EFA-T41-16-007; Impact of GSE Release Path on Radiological Consequences of the Control Rod Drop Accident; Revision A
- Equipment Apparent Cause Evaluation CARD 16-20156; Number 1 High Pressure Stop Valve Drifted to 25% Open From 100% Open at Power
- Equipment Apparent Cause Evaluation CARD 16-28619; Sodium Pentaborate Concentration Low
- Event Notification 16-0016; Unanalyzed Condition for Control Rod Drop Accident at Low Power
- Event Notification 17-002; Retracted Event Notifications: 52076, 52084, 52205, 52320, 52380, 52398, 52432, 52434, and 52437
- Event Notification 52320; Secondary Containment Technical Specification not Met
- Event Notification 52331; Standby Liquid Control Technical Specification not Met
- Event Notification 52331; Standby Liquid Control Technical Specification not Met
- Event Notification 52380; Secondary Containment Technical Specification not Met
- Event Notification 52398; Secondary Containment Technical Specification not Met
- Event Notification 52432; Startup of the Reactor Building HVAC System Resulted in the Technical Specification for Secondary Containment Pressure Boundary not Being Met for Approximately One Second
- Event Notification 52434; Secondary containment Technical Specification Not Met

- Event Notification 52437; Startup of the Reactor Building HVAC System Resulted in the Technical Specification for Secondary containment Pressure Boundary not Being Met for Approximately One Second
- Failure Analysis FA16N0735-01-01; Averaging Circuit and Gain Amplifier PCB P/N: 650-30X-3156, DTE Energy PO# 4700965738, ATC Nuclear JN16N0735; Revision 0
- Failure Analysis FA16N0735-02-001; Linear Variable Differential Transformer. Driver and Demodulator PCB P/N: 650-30X-3153, DTE Energy PO# 4700965738, ATC Nuclear JN16N0735; Revision 0
- Fermi 2 Control Room Log; October 28, 2016
- Fermi 2 Control Room Log; October 29, 2016
- LER 2016-001-01; Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves; Revision 1
- LER 2016-010-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather; Revision 00
- LER 2016-011-00; Standby Liquid Control Inoperable Due to Sodium Pentaborate Concentration Outside of Technical Specifications
- LER 2016-012-00; Unanalyzed Condition for Control Rod Drop Accident at Low Reactor Power; Revision 0
- LER 2016-013-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather; Revision 00
- LER 2016-014-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather; Revision 0
- LER 2016-015-00; Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds; Revision 0
- LER 2016-016-00; Secondary Containment Pressure Exceeded Technical Specification Due to Adverse Weather; Revision 0
- LER 2016-017-00; Secondary Containment Pressure Exceeded Technical Specification During Reactor Building HVAC Restart Due to High Winds; Revision 0
- LER 2017-002-00; High Water Level Indications at Low Reactor Pressures Causes Some Functions of High Pressure Coolant Injection System and Reactor Core Isolation Cooling System to be Inoperable; Revision 0
- Licensing Position Paper; Capability of Standby Liquid Control to Perform Required Functions; January 2017
- Technical Evaluation TE-T41-17-009; Review of 2016 Secondary Containment LERs Due to Wind Effects; Revision 1

4OA5 Other Activities

- 120 kV Switchyard/Relay House Walkdown Checklist
- 345 kV Switchyard/Relay House Walkdown Checklist
- Augmented Quality Program AQP-0002; ITC – Fermi Interface 120 kV and 345kV Switchyards; Revision 6
- CARD 12-26876; Training Review of New Procedure
- DTE Letter NANL-12-0054; from T. Conner; Fermi 2 Response to Automatic Reactor Scram Resulting from a Design Vulnerability in the 4.16-k-V Bus Undervoltage Protection Scheme; August 13, 2012
- Nuclear Training Course Plan LP-GN-909-1121M; Just-In-time Training, IER L2 12-14
- Nuclear Training Lesson Plan LP-OP-802-2002; Integrated Electrical Events; Revision 7
- Operating Procedure 47.000.88; Infrared Inspection; Revision 6
- Procedure 20.300.PHASE; Loss of Phase; Revision 0

- Procedure 24.307.14; EDG 11 – Start and Load Test; Revision 58
- Procedure 24.307.15; EDG 12 – Start and Load Test; Revision 58
- Procedure 24.307.16; EDG 13 – Start and Load Test; Revision 56
- Procedure 24.307.17; EDG 14 – Start and Load Test; Revision 57
- SS-OP-802-2001; Operating Characteristics and Procedures Emergency/Abnormal Events Scenarios; Revision 17
- Temporary Instruction 2515/192; Inspection of the Licensee's Interim Compensatory Measures Associated With the Open Phase Condition Design Vulnerabilities in Electric Power Systems; November 9, 2016

LIST OF ACRONYMS USED

ΔCDF	Delta Core Damage Frequency
ΔLERF	Delta Large Early Release Frequency
ADAMS	Agencywide Document Access and Management System
ATWS	Anticipated Transient without Scram
CARD	Condition Assessment Resolution Document
CDBI	Component Design Basis Inspection
CFR	*Code of Federal Regulations*
CRDA	Control Rod Drop Accident
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDP	Engineering Design Package
HPCI	High Pressure Coolant Injection
HPCV	High Pressure Control Valve
HPSV	High Pressure Stop Valve
HVAC	Heating, Ventilation, and Air Conditioning
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
MDCT	Mechanical Draft Cooling Tower
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OPC	Open Phase Condition
PARS	Publicly Available Records System
Psig	Pounds-per-square-inch-gage
RCIC	Reactor Core Isolation Cooling
RF-18	Cycle 18 Refueling Outage
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
SDP	Significance Determination Process
SGTS	Standby Gas Treatment System
SLC	Standby Liquid Control
SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirement
SSC	Structure, System, and/or Component
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	Work Order