UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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May 9, 2016

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

SUBJECT: FERMI NUCLEAR POWER PLANT, UNIT 2—NRC INTEGRATED INSPECTION REPORT 05000341/2016001

Dear Mr. Fessler:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Fermi Nuclear Power Plant, Unit 2 (Fermi 2). On April 7, 2016, the NRC inspectors discussed the results of this inspection with Mr. K. Polson and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

The NRC inspectors documented seven findings of very low safety significance (Green) in this report. Six of these findings involved violations of NRC requirements. In addition, the inspectors identified three performance deficiencies that were associated with Severity Level IV violations of NRC requirements evaluated through the traditional enforcement process. Two licensee-identified violations are also documented in this report. One of these licensee-identified violations was determined to be of very low safety significance and the other one was evaluated through the traditional enforcement process as Severity Level IV. The NRC is treating each of these violations as Non-Cited Violations (NCVs) consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of these NCVs, 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 Fermi 2.

If you disagree with a cross-cutting aspect assigned 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 Fermi-2.

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/

Billy Dickson, Chief
Branch 5
Division of Reactor Projects

Docket No. 50–341
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IR 05000341/2016001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–341
License No:	NPF–43
Report No:	05000341/2016001
Licensee:	DTE Energy Company
Facility:	Fermi Nuclear Power Plant, Unit 2
Location:	Newport, MI
Dates:	January 1 through March 31, 2016
Inspectors:	B. Kemker, Senior Resident Inspector P. Smagacz, Resident Inspector J. Nance, Resident Inspector - Perry
Approved by:	B. Dickson, Chief Branch 5 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000341/2016001; 01/01/2016–03/31/2016; Fermi Nuclear Power Plant, Unit 2; Licensed Operator Requalification Program, Maintenance Effectiveness, Operability Determinations and Functionality Assessments, Surveillance Testing, 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. Seven Green findings, six of which had an associated non-cited violation (NCV) of the U.S. Nuclear Regulatory Commission (NRC) regulations, were identified. In addition, three Severity Level IV NCVs of 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 April 29, 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 February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. A finding of very low safety significance with an associated NCV of 10 CFR 55.46(c), "Plant-Referenced Simulators," was self-revealed. The licensee failed to ensure the plant-referenced simulator demonstrated expected plant response to normal, transient, and accident conditions to which the simulator was designed to respond. Specifically, the licensee failed to maintain the simulator consistent with actual plant response when using the safety relief valves for reactor pressure control after a reactor scram. The licensee entered this issue into the corrective action program. To restore compliance, the licensee modified the simulator model to more accurately emulate actual reactor pressure vessel (RPV) water level response during manual control of reactor pressure using safety relief valves.

The performance deficiency was of more than minor safety significance because it adversely affected the human performance attribute of the Initiating Events cornerstone and affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the simulator provided unrealistic or negative training to licensed operators due to inaccurate modeling of the RPV level response during manual control of reactor pressure using safety relief valves as compared to the actual plant response. Although the simulator provided unrealistic or negative training to licensed operators, the inspectors concluded the unrealistic simulator training did not negatively impact licensed operator performance during the event since operators had successfully demonstrated manual control of RPV level and pressure for greater than 12 hours. Therefore, the finding was determined to be of very low safety significance. The inspectors concluded that because the discrepancy between the simulator and the plant existed since simulator use began (i.e., greater than three years ago), this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 1R11.3)

Green. A finding of very low safety significance with an associated NCV of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was self-revealed when the failure of a tube inside the east turbine building closed cooling water (TBCCW) heat exchanger caused a trip of the TBCCW pumps and a manual reactor scram due to the loss of all TBCCW. The heat exchanger tube failure occurred, in part, due to the licensee's failure to incorporate industry operating experience in order to perform adequate preventive maintenance on the component. The licensee entered this issue into the corrective action program and inspected all tubes in both TBCCW heat exchangers using a rotating pancake coil eddy current test during the Cycle 17 refueling outage. Any tubes identified with indications of stress corrosion cracking (SCC) were either plugged or replaced.

The performance deficiency was of more than minor safety significance because it was associated with the equipment performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the TBCCW heat exchanger tube failure resulted in a loss of all TBCCW and a reactor scram. In addition, the inspectors found this issue sufficiently similar to Example 7(c) in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," for not of minor safety significance. The finding was determined to be a performance deficiency of very low safety significance based on a detailed significance determination process review since the delta core damage frequency was determined to be less than 1.0E-6/year. The inspectors concluded this finding affected the cross-cutting aspect of trending in the problem identification and resolution area. Specifically, the licensee failed to analyze operating experiences concerning circumferential SCC information in the corrective action program and other assessments in the aggregate to identify programmatic and common cause issues [IMC 0310, P.4]. (Section 1R12.b.3)

Green. A finding of very low safety significance with an associated NCV of Technical Specification (TS) 5.4, "Procedures," was self-revealed when a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves was actuated. A reactor operator, who was maintaining RPV water level and reactor pressure following a plant scram, did not initiate reactor core isolation cooling (RCIC) system flow in time to maintain level above the Level 3 reactor protection system actuation setpoint. As an immediate corrective action, control room operators promptly restored RPV level by manual operation of the RCIC system. The licensee entered this issue into the corrective action program and provided remedial training for the reactor operator in the simulator, communicated lessons learned from this event with other licensed operators, and subsequently implemented improvements for licensed operator training and procedure changes to incorporate a revised strategy for manual control of RPV level and pressure control with main steam line isolation valves closed.

The performance deficiency was of more than minor safety significance because it was associated with the Human Performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the human performance error unnecessarily challenged a plant protection feature, which resulted in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves. In addition, the finding was sufficiently similar to Example 4(b) in IMC 0612, "Power Reactor Inspection

Reports," Appendix E, "Examples of Minor Issues," for not of minor safety significance since the error resulted in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves. The finding was determined to be of very low safety significance since it did not cause a reactor scram and a loss of mitigation equipment relied upon to transition the plant to a stable shutdown condition (e.g., loss of condenser, loss of feedwater). The inspectors concluded this finding affected the cross-cutting aspect of resources in the human performance area. Specifically, the licensee's evaluation identified the reactor operator had been performing a complicated task for a long period of time without adequate rest/recovery periods [IMC 0310, H.1]. (Section 4OA3.1)

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance with an associated NCV of TS 5.4, "Procedures." Specifically, the licensee failed to enter TS 3.3.1.1, Condition C when the high pressure stop valve (HPSV) closure and high pressure control valve (HPCV) fast closure reactor protection system (RPS) trip functions became inoperable while the main turbine bypass valves cycled open during a plant transient on January 6, 2016. The licensee entered this issue into the corrective action program for evaluation and identification of appropriate corrective actions. As an immediate corrective action, the licensee established an expectation to enter TS 3.3.1.1, Condition C, when the main turbine bypass valves are open above 29.5 percent power and declare the HPSV closure and HPCV fast closure RPS trip functions inoperable pending another resolution.

The performance deficiency was of more than minor safety significance because a failure to correctly implement TS Limiting Condition for Operation (LCO) requirements has the potential to lead to a more significant safety concern if left uncorrected. Specifically, a failure to declare an LCO not met, enter the applicable condition(s), and follow the applicable actions could reasonably result in operations outside of established safety margins or analyses. The finding was determined to be of very low safety significance based on a detailed significance determination process review since the delta core damage frequency was determined to be less than 1.0E-6/year. The inspectors concluded this finding affected the cross-cutting aspect of conservative bias in the human performance area. Specifically, the licensee failed to correctly interpret and implement the TS requirements due to a non-conservative interpretation of the TS Bases and a failure to reconcile differences between information in the annunciator response procedure and the TS Bases [IMC 0310, H.14]. (Section 1R12.b.1)

Green. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to demonstrate the residual heat removal heating, ventilation, and air conditioning (RHRHVAC) system would be able to maintain a required minimum temperature of 40 degrees Fahrenheit (°F) for the emergency diesel generator (EDG) fuel oil storage tank (FOST) rooms under minimum design conditions, potentially rendering the EDGs inoperable. The licensee entered this issue into the corrective action program and revised the operator rounds procedure to record ambient air temperature readings in the EDG FOST rooms on a daily basis when the outside ambient air temperature is below 45°F.

The performance deficiency was of more than minor safety significance because a failure to correctly incorporate design requirements into plant procedures has the potential to lead to a more significant safety concern if left uncorrected. Specifically, since the EDG FOST rooms were unmonitored and a subsequent calculation demonstrated the RHRHVAC system was not able to maintain the minimum required temperature in the rooms as described in the design basis, the EDGs could have been rendered inoperable without the licensee's knowledge. The finding was determined to be of very low safety significance since it affected the design or qualification of a mitigating structure, system, or component (SSC), for which the SSC maintained its operability or functionality. The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 1R15.b.2)

Cornerstone: Barrier Integrity

Green. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to include appropriate quantitative or qualitative acceptance criteria in its surveillance test procedures for fulfilling the monthly Technical Specification surveillance requirement to demonstrate operability of the standby gas treatment system (SGTS). The licensee entered this violation into its corrective action program to evaluate the issue and identify appropriate corrective actions. No immediate operability concern was identified.

The performance deficiency was of more than minor safety significance because it was associated with the procedure quality attribute for the control room and auxiliary building and adversely affected the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, by not providing appropriate acceptance criteria by which the operability of the SGTS trains could be assessed, the ability of the SGTS to collect and treat the design leakage of radionuclides from the primary containment to the secondary containment during an accident could not be assured. The finding was determined to be of very low safety significance because it involved only a degradation of the radiological barrier function provided by the SGTS. The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified. (Section 1R22.b.1)

Other Findings

Severity Level IV. The inspectors identified a Severity Level IV NCV of the 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report [LER] System." Specifically, the licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center after discovery of a condition that could have prevented the fulfillment of the safety function to shut down the reactor on February 21, 2015, and on January 6, 2016 (two separate occurrences). In addition, the licensee failed to submit a required LER within 60 days after discovery of the event on February 21, 2015. Subsequently, the licensee made an 8-hour notification call on February 25, 2016 to the NRC Operations Center via the Emergency Notification System to report the two events (Event Notices 51755 and 51756). On March 2, 2016, the licensee updated Event Notices 51755 and 51756 to include an additional reporting criterion. The licensee submitted LER 05000341/2015-008-00, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valve," on March 29, 2016, to report the February 2015 event. The licensee entered this issue into its corrective action program to evaluate the cause for its failure to satisfy the reporting requirements and to identify appropriate corrective actions.

Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that the performance deficiency was of minor significance based on "No" answers to the more-than-minor screening questions. However, in accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to report as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1). No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor significance and therefore not a finding. (Section 1R12.b.2)

<u>Severity Level IV</u>. The inspectors identified a Severity Level IV NCV of 10 CFR 50.73(a)(1), "Licensee Event Report [LER] System," for the licensee's failure to submit a required LER within 60 days after the discovery of an event on July 28, 2015, that was reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) as a condition prohibited by the plant's Technical Specifications. The condition involved the licensee's failure to complete required actions for an inoperable ultimate heat sink reservoir and for both emergency diesel generators in one division inoperable within the allowed completion times. The licensee subsequently submitted LER 05000341/2015-009-00, "Condition Prohibited by Technical Specification Due to Missed Entry into LCO [Limiting Condition for Operation] Condition," on March 31, 2016, to report the event. The licensee entered this issue into its corrective action program to evaluate the cause for its failure to satisfy the reporting requirements and to identify appropriate corrective actions.

Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that the performance deficiency was of minor significance based on "No" answers to the more-than-minor screening questions. However, in accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to report as required by 10 CFR 50.73(a)(1). No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor significance and therefore not a finding. (Section 1R15.b.1)

<u>Green</u>. The inspectors identified a finding of very low safety significance for the licensee's failure to implement its procedure standards when performing an apparent cause evaluation for a condition adverse to quality. Specifically, the inspectors determined that the licensee did not adequately develop the direct and apparent cause of the problem in the evaluation, did not correctly assess the impact of relevant internal and external operating experience, and did not identify appropriate corrective actions to address management behaviors that resulted in the problem. No violation of regulatory requirements was identified because the scope of issues evaluated by the licensee's procedure standards for performing the apparent cause evaluation was not limited to safety-related structures, systems, and components.

The performance deficiency was of more than minor safety significance because it would have the potential to lead to a more significant safety concern if left uncorrected. Specifically, the failure to adequately perform apparent cause evaluations could result in ineffective corrective actions for conditions adverse to quality and safety. The finding was determined to be of very low safety significance based on a qualitative evaluation of the potential consequences of the performance issue. The inspectors considered the three examples evaluated in the licensee's apparent cause evaluation and found the significance of each performance issue was not greater than very low safety significance. The inspectors concluded this finding affected the cross-cutting aspect of evaluation in the problem identification and resolution area. The licensee did not adequately evaluate the problem to ensure corrective actions would address the causes and extent of conditions commensurate with safety significance. Specifically, the apparent cause evaluation failed to identify and understand the basis for management decisions that contributed to the problem; therefore, corrective actions to address appropriate changes in management behaviors were not developed [IMC 0310, P.2]. (Section 4OA2.2)

Severity Level IV. The inspectors identified a Severity Level IV NCV of 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report [LER] System." Specifically, the licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center and also failed to submit a required within 60 days after discovery of a condition that resulted in the valid actuation of containment isolation signals affecting containment isolation valves in more than one system on September 13, 2015, and September 14, 2015 (two separate occurrences). Subsequently, the licensee made an 8-hour notification call on February 27, 2016 to the NRC Operations Center via the Emergency Notification System to report the events (Event Notice 51391, third update). The licensee entered this issue into its corrective action program to evaluate the cause for its failure to satisfy the reporting requirements and to identify appropriate corrective actions.

Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined the performance deficiency was of minor significance based on "No" answers to the more-than-minor screening questions. However, in accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to report as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1). No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor significance and therefore not a finding. (Section 4OA3.2)

Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

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

- On January 6, the licensee reduced power to about 91 percent due to unexpected closure of the #1 high pressure stop valve (HPSV) for the main turbine generator. The unit was returned to 100 percent on January 8, following corrective maintenance to replace a failed circuit card in the valve's control module.

- On February 27, the licensee reduced power to about 78 percent to perform a control rod pattern adjustment, remove a heater drains pump from service for valve maintenance, and perform main turbine control, stop, and bypass valve testing. During power ascension on February 28, a reactor recirculation runback from 90 percent power to 58 percent power occurred when feedwater heater drains were lost due to a feedwater heater level control valve malfunction. The unit remained at about 60 percent power to complete repairs. The unit was returned to 100 percent power on March 4.

- On March 15, the licensee reduced power to about 91 percent due to unexpected closure of the #1 HPSV for the main turbine generator. The unit was returned to 100 percent on March 19, following corrective maintenance to replace several circuit cards in the valve's control module.

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 Condition – Extreme Cold Conditions

a. Inspection Scope

Since extreme cold conditions were forecast in the vicinity of the plant during the week of January 10 through 15, 2016, the inspectors evaluated the licensee's overall preparations and protection for the expected weather conditions focusing on the emergency diesel generators (EDGs) and EDG service water system. The inspectors reviewed plant specific design features and implementation of procedures for responding to or mitigating the effects of extreme cold weather conditions on the operation of plant systems. The inspectors observed insulation, heat trace circuits, space heater operation, and weatherized enclosures to ensure operability/functionality of affected systems. 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 (CAP) with the appropriate characterization and significance. Selected condition assessment resolution documents (CARDs) were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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 2 residual heat removal (RHR) / RHR service water subsystem during Division 1 RHR/RHR service water subsystem maintenance;
- Division 1 EDG 11 and EDG 12 during planned maintenance on Division 2 EDG 13; and
- Division 2 emergency equipment cooling water (EECW) subsystem during Division 1 EECW subsystem maintenance.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety cornerstones. The inspectors reviewed operating procedures, system diagrams, Technical Specifications (TSs) 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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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 (71111.04S)

a. Inspection Scope

From February 1 through February 27, 2016, the inspectors performed a complete system alignment inspection of the standby gas treatment system (SGTS) to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. 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 ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding work orders was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure SGTS equipment alignment and material condition problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

This inspection 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:

- Reactor building second floor, Division 1 EECW;
- Turbine building first floor, lube oil storage area;
- Auxiliary building second floor, cable tray area and cable spreading room;
- Reactor building basement and sub-Basement, Division 1 RHR pump room; and
- Reactor building fourth floor, reactor recirculation motor generator sets.

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 CAP with the appropriate characterization and significance.

Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R06 Flood Protection Measures (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 anticipated operational 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:

- Reactor building northeast and southeast corner rooms.

In addition, the inspectors verified internal flooding related problems were entered into the licensee's CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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

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 February 11, 2016. 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. Documents reviewed are listed in the Attachment to this report.

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 27 and 28, 2016, the inspectors observed licensed operators in the control room perform a down power for control rod sequence exchange, remove a heater drains pump from service for valve maintenance, and perform main turbine valve testing. This activity 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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.3 Failure of the Plant-Referenced Simulator to Demonstrate Expected Plant Response for Safety Relief Valves

a. Inspection Scope

The inspectors interviewed licensed operators and training staff, and reviewed the licensee's apparent cause evaluation to evaluate the effectiveness of simulator training following an event in which a licensed reactor operator failed to maintain reactor pressure vessel (RPV) water level as directed during manual control of reactor pressure using safety relief valves after a reactor scram.

This inspection does not constitute an inspection sample as defined in IP 71111.11.

b. Findings

Introduction: A finding of very low safety significance with an associated NCV of 10 CFR 55.46(c), "Plant-Referenced Simulators," was self-revealed for the licensee's failure to ensure the plant-referenced simulator demonstrated expected plant response to normal, transient, and accident conditions to which the simulator was designed to respond. Specifically, the licensee failed to maintain the simulator consistent with actual plant response when using the safety relief valves for reactor pressure control after a reactor scram.

Description: On September 14, 2015, a reactor operator was controlling RPV water level with the reactor core isolation cooling (RCIC) system and reactor pressure with manual operation of the safety relief valves when RPV level reached the Level 3 reactor protection system (RPS) actuation setpoint, resulting in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves. Since all control rods were already fully inserted into the reactor following a manual reactor scram the day before, the RPS safety function was already fulfilled. Control room operators verified primary containment isolation valve isolations occurred as expected and promptly restored RPV level with manual operation of the RCIC system. Refer to Section 4OA3.1 of this inspection report for the inspectors' review of this event.

The reactor operator was assigned to monitor and maintain RPV level and reactor pressure per the emergency operating procedure prescribed level band of 173 to 214 inches and pressure band of 900 to 1050 pounds-per-square-inch gauge (psig). Each operation of a safety relief valve caused RPV level to swell about 20 to 25 inches for a 20 to 30 psig change in reactor pressure. Following closure of the safety relief valve, RPV level would lower significantly and RCIC system flow would be increased to overcome the loss of level. This sequence was repeated by the reactor operator about every 3 to 5 minutes. By the time the event occurred, the reactor operator had been successfully performing these actions for most of his 12-hour shift.

During review of this event, the inspectors noted control room operators had observed RPV water level swings due to safety relief valve lifting were much larger than typically seen during licensed operator training in the plant simulator. The level change reported by operators was roughly twice as much in the plant versus in the simulator. This made RPV level control more difficult within the relatively narrow band of 173 to 214 inches in the plant than had been experienced during recurring operator training in the simulator. The licensee initiated a simulator discrepancy report under CARD 16-20994 to obtain plant data and evaluate the simulator response to safety relief valve induced RPV level swells.

The inspectors questioned whether the modeling of the RPV level response during manual control of reactor pressure using safety relief valves met the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR), Paragraph 55.46(c)(1), which requires the simulator to demonstrate expected plant response to operator input and to normal, transient, and accident conditions.

The licensee evaluated the event by comparing the actual plant response during the event to the simulator's programmed response for safety relief valve performance and identified a change was needed to be made to the simulator's programmed response based on the plant data. The original safety relief valve response was tuned based on plant startup testing documentation, specifically STUT.020.026, "Safety Relief Valves." This document showed RPV water level increasing approximately 2 inches for safety relief valve "K" failure at power; however, plant data from the event showed reactor water level increasing 20 to 30 inches with safety relief valve openings. The inspectors noted the licensee had not utilized actual plant data from any previous operational occurrences during which control room operators used safety relief valves for reactor pressure control to update the simulator model. As a corrective action, plant data from the event was used to adjust the simulator response to safety relief valve openings during pressure control after a reactor scram with decay heat addition.

Analysis: The inspectors determined the licensee's failure to demonstrate the plant-referenced simulator would accurately reproduce the operating characteristics of RPV water level response during manual control of safety relief valves was contrary to the requirements of 10 CFR 55.46(c)(1) and was, therefore, a performance deficiency warranting a significance evaluation. Consistent with the guidance in Inspection Manual Chapter (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 adversely affected the Human Performance attribute of the Initiating Events cornerstone and affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the simulator provided unrealistic or negative training to licensed operators due to inaccurate modeling of the RPV level response during manual control of reactor pressure using safety relief valves as compared to the actual plant response. The inspectors also reviewed the examples of minor issues in IMC 0612, Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no similar examples.

In accordance with IMC 0609, "Significance Determination Process [SDP]," Attachment 0609.04, "Initial Characterization of Findings," Table 3, "SDP Appendix Router," dated June 19, 2012, the inspectors determined this finding involved simulator fidelity, and would require review using IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process (SDP)," dated December 6, 2011. The inspectors answered "No" to Question #15 in the SDP Flowchart, "Did deficient simulator performance, modeling, or fidelity negatively impact operator performance in the actual plant during a reportable event?" Although the simulator provided unrealistic or negative training to licensed operators (due to deficiencies in simulator performance, modeling, or fidelity), the inspectors concluded the unrealistic simulator training did not negatively impact licensed operator performance during the event since operators had successfully demonstrated manual control of RPV level and pressure for greater than 12 hours. Therefore, the inspectors determined the finding was of very low safety significance (Green).

The inspectors concluded that because the discrepancy between the simulator and the plant existed since simulator use began (i.e., greater than three years ago), this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

Enforcement: Title 10 of the Code of Federal Regulation (CFR), Paragraph 55.46(c), "Plant-Referenced Simulators," requires, in part, that a plant-referenced simulator used for the administration of the operating test must demonstrate expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond. Contrary to the above, prior to September 14, 2015, the licensee failed to assure the plant-referenced simulator used for the administration of the operating test demonstrated expected plant response to operator input for which the simulator was designed to respond. Specifically, the Fermi 2 simulator failed to accurately model the RPV water level response during manual control of reactor pressure using safety relief valves. The licensee entered this violation into its CAP as CARD 16-20994. Corrective action taken to restore compliance included modifying the simulator model to more accurately emulate actual RPV level response during manual control of reactor pressure using safety relief valves.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001–01, Failure of the Plant-Referenced Simulator to Demonstrate Expected Plant Response for Safety Relief Valves)**.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- CARD 15-25570; Potential issues with the timing of reactor building heating, ventilation, and air conditioning (RBHVAC) damper actuations for the east train;
- CARD 15-26469; Leak at weld on Weldolet for drain valve N2103F326;
- CARD 15-26472; Total loss of turbine building closed cooling water (TBCCW) following heat exchanger swap; and
- CARD 16-20156; #1 HPSV valve drifted to 25 percent open from 100 percent open at power.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four quarterly maintenance effectiveness inspection samples as defined in IP 71111.12.

b. Findings

(1) Failure to Correctly Interpret and Implement TS Requirements for RPS Trip Functions

Introduction: The inspectors identified a finding of very low safety significance with an associated NCV of TS 5.4, "Procedures." Specifically, the licensee failed to enter TS Limiting Condition for Operation (LCO) 3.3.1.1, Condition C when the HPSV closure and high pressure control valve (HPCV) fast closure RPS trip functions became inoperable due to the main turbine bypass valves cycled open during a plant transient on January 6, 2016.

Description: 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 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, 2016. The licensee documented the #1 HPSV malfunction in the CAP as CARD 16–20156.

The inspectors reviewed the licensee's apparent cause evaluation for the #1 HPSV malfunction and concurred with its conclusions. The first apparent cause was the failed servo driver circuit card in the #1 HPSV valve control module. A second apparent cause tied this circuit card failure to the trend in consequential equipment failures the licensee had seen due to circuit card malfunctions. The inspectors 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. This particular 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.

During the transient, the main turbine bypass valves cycled open for about 3½ minutes and then closed. The inspectors reviewed the control room logs and noted licensed operators did not declare the HPSV closure and HPCV fast closure functions inoperable (RPS Functions 9 and 10, respectively) and enter TS LCO 3.3.1.1, Condition C. However, according to the TS Bases for TS LCO 3.3.1.1, Functions 9 and 10, the turbine bypass valves must remain shut at thermal power greater than or equal to 29.5 percent for these functions to be considered operable. The inspectors also reviewed the operations shift manager's reportability/operability determination documented in CARD 16-20156 and found the shift manager had incorrectly concluded the RPS HPSV closure function was not affected. The shift manager did not address the HPCV fast closure function in his operability/reportability determination.

The inspectors determined that the licensee should have immediately entered TS LCO 3.3.1.1, Condition C when the main turbine bypass valves cycled open, which rendered the HPSV closure and HPCV fast closure RPS functions inoperable. Technical Specification LCO 3.3.1.1, Condition C, requires that with one or more functions with RPS trip capability not maintained, the RPS trip capability be restore within 1 hour. The inspectors noted the main turbine bypass valves were open for only about 3½ minutes, so the HPSV closure and HPCV fast closure functions were inoperable for less than the 1-hour completion time of TS LCO 3.3.1.1, Condition C; therefore, no violation of TS LCO 3.3.1.1 was identified.

The inspectors reviewed Procedure MOP-5, "Fermi 2 Operations Conduct Manual Chapter 5 – Control of Equipment," Revision 46, and concluded the licensee did not implement its procedure standards for control of equipment with respect to TS administration. Specifically, the licensee did not enter TS LCO 3.3.1.1, Condition C, when the HPSV closure and HPCV fast closure functions became inoperable as stipulated in Section 4.3 of the procedure. For the short duration (less than 2 hours) LCO entry, Step 4.3.3.3 requires the following information logged: (1) Time the component was rendered inoperable; (2) Applicable TS and required actions; (3) Duration allowed; (4) Actions taken, if applicable; and (5) Appropriate closeout entry when the LCO is exited, with two senior reactor operators' names. As discussed in Section 1R12.b.2 of this report, this failure to declare the two RPS functions inoperable contributed to the licensee's failure to satisfy the reporting requirements in 10 CFR 50.72.

A very similar event occurred on February 21, 2015, when the main turbine generator #2 HPSV malfunctioned, cycling partially closed and open multiple times with Fermi 2 operating initially at 100 percent power. The west main turbine bypass valve cycled open and then closed as expected to divert steam flow to the main condenser and mitigate the effects of the transient. This event was documented in CARD 15-41424, "#2 HPSV Went Closed and Then Open to 22 Percent Multiple Times." Control room operators reduced reactor power to about 91 percent and locked the #2 HPCV and #2 HPSV closed. The licensee replaced a failed comparator circuit card and a relay in the #2 HPSV valve control module to correct the problem. Operators subsequently restored the #2 HPCV and #2 HPSV to service and returned reactor power to 100 percent later the same day.

The inspectors reviewed the control room logs and noted licensed operators declared the HPSV closure and HPCV fast closure functions inoperable and entered TS LCO 3.3.1.1, Condition C, for the duration of time the west bypass valve was open (about 1 minute). The inspectors also reviewed the operations shift manager's reportability/operability determination documented in CARD 15-21424 and found the shift manager correctly concluded the RPS HPSV closure and HPCV fast closure functions were inoperable while the west main turbine bypass valve was open. However, as discussed below in Section 1R12.b.2, the licensee incorrectly concluded the inoperable RPS functions were not reportable in accordance with 10 CFR 50.72 and 10 CFR 50.73.

Analysis: The inspectors determined the licensee's failure to declare TS LCO 3.3.1.1 not met and enter Condition C when the HPSV closure and HPCV fast closure RPS trip functions became inoperable during a plant transient on January 6, 2016, was contrary to the requirements of TS 5.4.1.a, and was therefore a 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 that this performance deficiency was of more than minor safety significance, and thus a finding, because a failure to correctly implement TS LCO requirements has the potential to lead to a more significant safety concern if left uncorrected. Specifically, a failure to declare an LCO not met, enter the applicable condition(s), and follow the applicable actions could reasonably result in operations outside of established safety margins or analyses. 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 examples related to this issue.

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 that this finding affected the Mitigating Systems cornerstone, specifically the reactivity control systems contributor, and would require review using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, since at the time of the event the reactor was operating at power. 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 would require a detailed risk evaluation because the finding affected two separate RPS trip functions.

Detailed Risk Evaluation

The Region III senior reactor analyst (SRA) performed a bounding risk evaluation of the delta core damage frequency (ΔCDF) for the failure of the two automatic RPS trip functions during the time the main turbine bypass valves were open. A core damage event was very conservatively assumed to occur if the main turbine was not isolated following an event that required a turbine trip. The following inputs and assumptions were used:

- To determine the failure probability of not manually tripping the turbine following an event that required a turbine trip, the following was performed:

- o The human error probability (HEP) that control room operators would fail to manually trip the main turbine was determined using the Standardized Plant Analysis Risk (SPAR) human reliability analysis method per NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method," August 2005. Using SPAR-H, only the "Action" portion of the task was evaluated to be applicable since the action to verify a turbine trip is performed expeditiously following a reactor scram, and this action is frequently rehearsed by licensed operators during training evolutions. The performance shaping factor for "Stress" was determined to be "High," with the other performance shaping factors at a nominal value. This resulted in an HEP to manually trip the turbine of 2E-3.

- o The failure-to-close probability of a HPSV is 1.5E-3 per NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," February 2007, Table A.2.22-7 for Hydraulic-Operated Valves. Since there are four HPSVs that need to close to isolate the main turbine, the failure probability due to valve failure is 6.0E-3.

- o The total failure probability of not manually tripping the turbine following an event that required a turbine trip is the sum of the HEP (2E-3) and the valve failure probability (6.0E-3) or 8.0E-3.

- o To determine the failure probability of not manually closing the main steam line isolation valves (MSIVs) following an event that required a turbine trip and in which the HPSVs failed-to-close, a similar evaluation gives the failure probability of not manually closing the MSIVs following an event that required a turbine trip and in which the HPSVs failed-to-close is the sum of the HEP (2E-3) and the valve failure probability (6.0E-3) or 8.0E-3.

- The exposure time for the finding for when the automatic turbine trip functions were disabled was rounded up to approximately 5 minutes.

- The frequency of a plant transient (e.g., a reactor scram) is 0.72/year per the Fermi 2 SPAR model. A frequency of 1.0/year was conservatively assumed for the requirement of a turbine trip following a plant event.

Using the above inputs and assumptions, a bounding ΔCDF was calculated for the failure to isolate the main turbine following an event that required a turbine trip:

ΔCDF = [1.0/year] x [5 minutes/8760 hours/60 minutes per hour] x [8.0E-3] x [8.0E-3]

= 6.1E-10/year

Based on the results of 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 aspect of conservative bias in the human performance area. Specifically, the licensee failed to correctly interpret and implement the TS requirements due to a non-conservative interpretation of the TS Bases and a failure to reconcile differences between information in the annunciator response procedure and the TS Bases (IMC 0310, H.14).

Enforcement: Technical Specificiation 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 1.c, recommends administrative procedures for equipment control. Procedure MOP-5, "Fermi 2 Operations Conduct Manual Chapter 5 – Control of Equipment," Revision 46, implements the requirements of Regulatory Guide 1.33, Revision 2, Appendix A, Section 1.c, and contains guidance for maintaining proper plant configuration requirements, including TS LCO administration. Specifically, for a short duration (less than 2 hours) LCO entry, Step 4.3.3.3 of the procedure requires the following information logged: (1) Time the component was rendered inoperable; (2) Applicable TS and required actions; (3) Duration allowed; (4) Actions taken, if applicable; and (5) Appropriate closeout entry when the LCO is exited, with two senior reactor operators' names.

Contrary to the above, on January 6, 2016, the licensee failed to log entry into TS LCO 3.3.1.1, Condition C, when the HPSV closure and HPCV fast closure RPS trip functions became inoperable when the main turbine bypass valves cycled open during a plant transient. The licensee entered this violation into its CAP as CARD 16-21658. As an immediate corrective action, the licensee established an expectation to enter LCO 3.3.1.1, Condition C, when the main turbine bypass valves are open above 29.5 percent power and declare the HPSV closure and HPCV fast closure RPS trip functions inoperable pending another resolution.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001-02, Failure to Correctly Interpret and Implement TS Requirements for RPS Trip Functions**)

(2) Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Loss of RPS Trip Safety Functions

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System." Specifically, the licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center after discovery of a condition that could have prevented the fulfillment of the safety function to shut down the reactor on February 21, 2015, and January 6, 2016 (two separate occurrences). In addition, the licensee failed to submit a required Licensee Event Report (LER) within 60 days after discovery of the event on February 21, 2015.

Description: The inspectors reviewed CARD 16-20156, "#1 High Pressure Stop Valve Drifted to 25 Percent Open from 100 percent Open at Power." During the transient on January 6, 2016, the main turbine bypass valves cycled open as expected for about 3½ minutes and then closed. The inspectors reviewed the control room logs and noted licensed operators did not declare the HPSV closure and HPCV fast closure functions inoperable (RPS Functions 9 and 10, respectively) and enter TS LCO 3.3.1.1, Condition C. However, according to the TS Bases for TS 3.3.1.1, Functions 9 and 10, the turbine bypass valves must remain shut at thermal power ≥ 29.5 percent for these functions to be considered operable. The inspectors also reviewed the operations shift manager's reportability/operability determination documented in CARD 16-20156 and found the shift manager had incorrectly concluded the RPS HPSV closure function was not affected. The shift manager did not address the HPCV fast closure function in his operability/reportability determination. As a result, the licensee incorrectly concluded the inoperable RPS functions were not reportable in accordance with 10 CFR 50.72 and 10 CFR 50.73. No justification or reasoning was documented in the CARD for this conclusion.

A very similar event occurred on February 21, 2015, when the main turbine generator #2 HPSV malfunctioned, cycling partially closed and open multiple times with Fermi 2 operating initially at 100 percent power. The west main turbine bypass valve cycled open and then closed as expected to divert steam flow to the main condenser and mitigate the effects of the transient. This event was documented in CARD 15-41424, "#2 HPSV Went Closed and Then Open to 22 Percent Multiple Times." The inspectors reviewed the control room logs and noted licensed operators declared the HPSV closure and HPCV fast closure functions inoperable and entered TS LCO 3.3.1.1, Condition C, for the duration of time the bypass valve was open (about 1 minute). The inspectors also reviewed the operations shift manager's reportability/operability determination documented in CARD 15-21424 and found the shift manager correctly concluded the RPS HPSV closure and HPCV fast closure functions were inoperable while the west main turbine bypass valve was open. However, the licensee incorrectly concluded the inoperable RPS functions were not reportable in accordance with 10 CFR 50.72 and 10 CFR 50.73. No justification or reasoning was documented in the CARD for this conclusion.

The inspectors determined the loss of the RPS HPSV closure and HPCV fast closure functions was reportable under 10 CFR 50.72(b)(3)(v)(A) and 10 CFR 50.73(a)(2)(v)(A) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to shut down the reactor and maintain it in a safe shutdown condition. The condition was also reportable under 10 CFR 50.73(a)(2)(vii)(A) as an event where a single cause or condition caused two independent channels to become inoperable in a single system designed to shut down the reactor and maintain it in a shutdown condition. In response to the inspectors' questions, the licensee acknowledged its failure to report the two events in February 2015 and January 2016 and initiated CARD 16-21658 to evaluate the causes and to identify appropriate corrective actions. As discussed above in Section 1R12.b.1 of this inspection report, the inspectors identified a finding of very low safety significance with an associated NCV of TS 5.4, "Procedures," for the licensee's failure to declare TS LCO 3.3.1.1 not met and enter Condition C when the HPSV closure and HPCV fast closure RPS trip functions became inoperable when the main turbine bypass valves cycled open during the plant transient on January 6.

Analysis: The inspectors determined the licensee's failure to report these events in accordance with the requirements in 10 CFR 50.72 and 10 CFR 50.73 was a 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 the performance deficiency was not a finding of more than minor significance based on "No" answers to the more-than-minor screening questions. The inspectors also reviewed the examples of minor issues in IMC 0612, Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no examples related to this issue.

Violations of 10 CFR 50.72 and 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. This violation was also associated with a performance deficiency that has been evaluated as having minor safety significance by the SDP. The SDP, however, does not specifically consider regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and performance deficiency using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated performance deficiency. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make reports to the NRC as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1).

No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor safety significance and therefore not a finding.

<u>Enforcement</u>: Title 10 of the CFR, Paragraph 50.72(a)(1)(ii) requires, in part, that the licensee shall notify the NRC Operations Center via the Emergency Notification System of those non-emergency events specified in Paragraph (b) that occurred within three years of the date of discovery. In addition, 10 CFR 50.72(b)(3) requires, in part, that the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the applicable conditions. Moreover, 10 CFR 50.72(b)(3)(v)(A) requires, in part, that the licensee report any 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 shut down the reactor and maintain it in a safe shutdown condition.

Also, 10 CFR 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event and 10 CFR 50.73(a)(2)(v)(A) requires, in part, that the licensee report any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to shut down the reactor and maintain it in a safe shutdown condition. Furthermore, 10 CFR 50.73(a)(2)(vii)(A) requires, in part, that the licensee report any event where a single cause or condition caused two independent channels to become inoperable in a single system designed to shut down the reactor and maintain it in a shutdown condition.

Contrary to the above:

1. On February 21, 2015, and January 6, 2016, the licensee failed to notify the NRC Operations Center via the Emergency Notification System within eight hours of the occurrence of a condition that could have prevented the fulfillment of the safety function of systems that are needed to shut down the reactor and maintain it in a safe shutdown condition as required by 10 CFR 50.72(b)(3)(v)(A). The condition involved the loss of the HPSV closure and HPCV fast closure RPS trip functions.

2. The licensee failed to submit a required LER within 60 days after discovery of a condition on February 21, 2015, that could have prevented the fulfillment of the safety function of systems that are needed to shut down the reactor and maintain

it in a safe shutdown condition as required by 10 CFR 50.73(a)(2)(v)(A) and a single cause or condition that caused two independent channels to become inoperable in a single system designed to shut down the reactor and maintain it in a shutdown condition as required by 10 CFR 50.73(a)(2)(vii)(A). The condition involved the loss of the HPSV closure and HPCV fast closure RPS trip functions.

The licensee subsequently made an eight-hour notification call to the NRC Operations Center via the Emergency Notification System to report the events on February 25, 2016 (Event Notices 51755 and 51756). On March 2, 2016, the licensee updated Event Notices 51755 and 51756 to also include reporting the events under 10 CFR 50.72(b)(3)(v)(D) as a condition that could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident. The licensee submitted LER 05000341/2016-001-00, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves," on March 4, 2016; and LER 05000341/2015-008-00, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valve," on March 29, 2016. When the inspectors identified this issue, the licensee was still within the 60-day reporting time window to submit the LER for the January 2016 event. Refer to Sections 4OA3.4 and 4OA3.5 of this inspection report for the inspectors' review of these LERs.

In accordance with Section 6.9.d.9 of the Enforcement Policy, this violation was classified as a Severity Level IV NCV. The licensee entered this violation into its CAP as CARD 16-21658. Because this violation was not repetitive or willful, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. (**NCV 05000341/2016001–03, Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Loss of RPS Trip Safety Functions**)

(3) Failure to Incorporate Operating Experience into Preventive Maintenance Activities Associated with the TBCCW System

Introduction: A finding of very low safety significance with an associated NCV of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was self-revealed when the failure of a tube inside the east TBCCW heat exchanger caused a trip of the TBCCW pumps and a manual reactor scram due to the loss of all TBCCW. The heat exchanger tube failure occurred, in part, due to the licensee's failure to incorporate industry operating experience in order to perform adequate preventive maintenance on the component.

Description: On September 13, 2015, control room operators manually scrammed the reactor and tripped the main turbine generator due to a loss of cooling water supply to non-safety-related systems in the turbine building, including the main turbine oil and station air systems. Previously, control room operators had briefed and dispatched non-licensed operators to swap the TBCCW heat exchangers from the east train to the west train. During the transfer, control room operators received alarms indicating the existence of a leak in one of the heat exchangers from the general service water (GSW) system into the TBCCW system. This condition resulted in overfilling the TBCCW expansion tank, lifting the expansion tank relief valve, and eventually losing both operating TBCCW pumps. Since TBCCW provides cooling to various turbine building components, including the station air compressors and reactor feedwater pump lubricating oil coolers, this condition resulted in a loss of station air system pressure and also required operators to stop the reactor feedwater pumps. Eventually, operators had to close the main steam isolation valves due to low air system pressure, resulting in a loss of feedwater after scram. The licensee subsequently discovered a tube had failed in the east TBCCW heat exchanger. The inspectors evaluated operator actions in response to the event and documented this review in NRC Inspection Report 05000341/2015003. Refer to Section 4OA3.2 of this inspection report for the inspectors' review of the LER associated with this event.

As a result of the heat exchanger tube failure, the TBCCW expansion tank filled and pressurized resulting in the tank's relief valve lifting and discharging to the floor. As the tank became water solid, water began to enter the top reference leg (normally nitrogen filled) and either compressed or displaced the nitrogen in these lines. With water in the top reference leg, the differential pressure between the two reference legs decreased to a point that caused both running TBCCW pumps to trip and prevented them from restarting. Operators entered procedure AOP 20.128.01, "Loss of Turbine Building Closed Cooling Water System," and manually scrammed the reactor as directed by the procedure.

The root cause of the heat exchanger tube failure was determined to be circumferential stress corrosion cracking (SCC). The TBCCW heat exchangers are comprised of admiralty brass tubes and are subject to SCC during periods of extended wet lay-up. In its root cause evaluation, the licensee also identified that no preventive maintenance activities were created to identify circumferential SCC in its balance-of-plant heat exchanger program. The preventive maintenance activities that were prescribed consisted of standard bobbin coil eddy current testing. Detection of circumferential cracks required the use of advanced eddy current techniques, such as a rotating pancake coil test. Numerous examples of external industry operating experience involving cracks of heat exchanger tubes driven by SCC were documented in the CAP, including several similar failures of this instance. In each of the examples, the SCC occurred in a system cooled by treated or raw water that was laid up wet for extended periods of time. A common theme in the operating experience was that standard eddy current testing was not capable of detecting circumferential cracks in tubes composed of admiralty brass. Although abundant industry operating experience with SCC in admiralty brass tubed heat exchangers existed, appropriate adjustment to the licensee's preventive maintenance program to sufficiently test for SCC in the TBCCW heat exchangers was not performed.

The inspectors noted the TBCCW system was appropriately scoped within the licensee's Maintenance Rule Program. The Maintenance Rule (10 CFR 50.65) requires that licensees monitor the performance of SSCs sufficiently to provide reasonable assurance that these SSCs are capable of fulfilling their intended functions. The licensee's evaluation of the TBCCW heat exchanger tube failure correctly classified it as a maintenance preventable functional failure because a preventive maintenance task had not been created and performed to conduct advance eddy current testing on the TBCCW heat exchangers.

<u>Analysis</u>: The inspectors determined the licensee's failure to evaluate and take into account, where practical, industry operating experience associated with preventive maintenance on admiralty brass tubing for the TBCCW heat exchangers was contrary to

the requirements of 10 CFR 50.65(a)(3), and was therefore a performance deficiency warranting a significance evaluation. The inspectors concluded 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 Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. Specifically, the TBCCW heat exchanger tube failure resulted in a loss of all TBCCW and a reactor scram. In addition, the inspectors 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 this issue sufficiently similar to guidance provided in Example 7(c) that the issue was not of minor safety significance because this violation of 10 CFR 50.65(a)(3) had a consequence such as equipment problems attributable to failure to take industry operating experience into account when practicable.

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 Initiating Events cornerstone, specifically the transient initiator contributor, and would require review using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," and answered “Yes” to Question B, “Did the finding cause a reactor scram AND the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition (e.g. loss of condenser, loss of feedwater)?” Therefore, a detailed risk evaluation was required.

Detailed Risk Evaluation

The Region III SRA used the Fermi 2 SPAR Model, Version 8.20 and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations, Version 8.1.3. Since the finding was associated with an initiating event, the finding was evaluated using the Risk Assessment Standardization Project guidance for Initiating Events. For findings that cause initiating events to occur, there is no defined exposure time. The initiating event frequency was set equal to 1.0 in accordance with the Risk Assessment Standardization Project Manual. The conditional core damage probability (CCDP) is calculated and the numerical value of the CCDP is set equal to the ΔCDF for the risk evaluation (after multiplying the CCDP by one inverse year).

Evaluation of ΔCDF Contribution

For this issue, a transient initiating event was assumed with: (1) the loss of the TBCCW system being modelled as the common-cause failure of both TBCCW pumps to run (set to TRUE or failed), and (2) the failure of the MSIVs to remain open basic event also being set to TRUE.

Two modifications were made to the Fermi 2 SPAR model by Idaho National Laboratory, which maintains the SPAR models for the NRC. 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 such 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 2).

Using the Fermi 2 SPAR model with the above modifications, the CCDP associated with the finding was determined to be 4.77E-7. The dominant sequence was: (1) a transient initiating event, (2) failure of the power conversion system and its recovery, (3) failure of the RHR system, (4) failure of the containment vent system, and (5) failure of the standby feedwater system following containment failure.

Since the total estimated ΔCDF was greater than 1.0E-7/year, the SRA used IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," dated May 6, 2004, to determine the potential risk contribution due to large early release frequency (LERF). Fermi 2 is a General Electric boiling water reactor-4 plant with a Mark I containment. Table 5.1 from Appendix H (Phase 1 screening) indicated this issue required further evaluation since Anticipated Transient Without Scram (ATWS) and High Reactor Coolant System (RCS) Pressure sequences were important for boiling water reactors with Mark I containments. Table 5.2 from Appendix H (Phase 2 analysis) listed a LERF factor of 0.3 for ATWS sequences. For High RCS Pressure sequences (RCS pressure greater than 250 psig at the time of reactor vessel breach), Table 5.2 had a LERF factor of 0.6 if the drywell is flooded, and 1.0 if the drywell is not flooded.

A review of the dominant core damage sequences revealed the following:

1) There were four ATWS sequences that represented a total CCDP of 1.61E-7. Based on a LERF factor of 0.3, the conditional large early release probability (CLERP) due to the ATWS core damage sequences is 4.83E-8.

2) There was one High RCS Pressure sequence (i.e., the failure of RCS depressurization) that represented a CCDP of 6.48E-8. The sequence was a non-loss-of-coolant-accident sequence that may not result in the drywell being flooded. Based on a LERF factor of 1.0, this sequence has a CLERP of 6.48E-8.

The total CLERP is the sum of the CLERP due to the ATWS core damage sequences (i.e., 4.83E-8) and the High RCS Pressure sequence (i.e., 6.48E-8). The total CLERP is therefore 1.13E-7 (White). The numerical value of the CLERP is set equal to the delta large early release frequency (ΔLERF) for the risk evaluation (after multiplying the CLERP by one inverse year).

<u>Evaluation of ΔLERF Contribution</u>

The SRA determined that the risk characterization of the issue for ΔLERF using the LERF factors specified in IMC 0609 Appendix H was conservative for this SDP evaluation for the following reasons:

1) The dominant core damage sequences would not significantly contribute to LERF risk due to timing considerations. The applicable sequences involve a failure of high pressure injection and a failure to depressurize the RCS, resulting in the failure of any injection to the RCS (e.g., no low pressure injection from the core spray or low pressure coolant injection systems). These accident sequences (i.e., no RCS injection) are similar to the accident conditions that would be encountered during a station blackout (SBO) event without high pressure injection available. This is further discussed in Paragraph 2 below.

2) Per Table 4 or NUREG-1935, “State-of-the-Art Reactor Consequences Analyses (SOARCA) Report,” dated November 2012, the timeline from the start of core damage to lower head failure (and subsequent release to the environment) during a SBO event without high pressure injection available is approximately 7 hours. The SRA reviewed licensee document “Fermi Unit 2 - 2015 Population Update Analysis,” which shows an estimate of 4 hours and 40 minutes for the 100 Percent Emergency Planning Zone evacuation time estimate. Based on the 4 hour and 40 minutes timeframe for Emergency Planning Zone evacuation, and the dominant LERF sequences being later (i.e., approximately 7 hours per NUREG-1935), the SRA believes in most cases Emergency Planning Zone evacuation would be completed before early release to the environment.

3) Results of NRC-sponsored accident progression analyses in ERI/NRC 03-204, "The Probability Of High Pressure Melt Ejection-Induced Direct Containment Heating Failure in Boiling Water Reactors with Mark I Design," dated November 2003, indicates that without RCS injection during a SBO event, there is a high probability the RCS would subsequently depressurize as a result of either temperature-induced creep rupture of the steam lines or a stuck open safety relief valve (due to cycling at high temperature). ERI/NRC 03-204 estimates a 0.9 probability of creep rupture of the steam lines during a SBO event, and approximately a 0.5 probability of a stuck open safety relief valve (if any safety relief valve was available). If RCS depressurization occurs, the High RCS Pressure sequences and their contribution to ΔLERF are eliminated.

4) Fermi 2 has guidance in its Extensive Damage Mitigation Guidelines that would also have plant operators flood the drywell floor using an alternating current independent pump and water source. It would be reasonable to expect the required actions to implement this strategy of flooding the drywell floor could be completed within a 7-hour time frame between the start of core damage to lower head failure (and subsequent release to the environment).

As a result of the above considerations, the SRA concluded the risk due to ΔLERF is equivalent to the ΔCDF results for the event (i.e., the risk characterization of the issue should be based on the ΔCDF result).

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

This finding affected the cross-cutting aspect of trending in the area of problem identification and resolution. Specifically, the licensee failed to analyze information from the CAP and other assessments in the aggregate to identify programmatic and common cause issues. Examples of operating experience concerning circumferential SCC had been entered into the CAP, but the information was not analyzed and no actions were taken (IMC 0310, P.4).

Enforcement: Title 10 of the CFR, Paragraph 50.65(a)(3) requires, in part, that performance and condition monitoring activities and associated goals and preventive maintenance activities shall be evaluated at least every refueling cycle provided the interval between evaluations does not exceed 24 months. The evaluations shall take into account, where practical, industry-wide operating experience. Adjustments shall be made, where necessary, to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs due to monitoring or preventive maintenance.

Contrary to the above, prior to September 13, 2015, the licensee failed to incorporate operating experience involving circumferential SCC of admiralty brass heat exchanger tubes into its balance-of-plant heat exchanger program when it was practical to do so and to adjust its preventive maintenance with the objective of preventing failures. Consequently, on September 13, 2015, a TBCCW heat exchanger tube failure resulted in a loss of all TBCCW and a reactor scram. The licensee entered this issue into its CAP as CARD 15–26472. As an immediate corrective action, the licensee inspected all tubes in both TBCCW heat exchangers using a rotating pancake coil eddy current test during the Cycle 17 refueling outage. All tubes identified with indications of SCC were either plugged or replaced. In addition, the licensee initiated an action to examine all heat exchangers on site for similar conditions and to add advanced eddy current testing methodology if not already included. Long-term corrective actions include replacing all tubes in the TBCCW heat exchangers with a material that is less susceptible to SCC.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001–04, Failure to Incorporate Operating Experience into Preventive Maintenance Activities Associated with the TBCCW System)**

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:

- Planned maintenance during the week of January 24 through 30 including EDG 13 maintenance and emergent maintenance on the west stator cooling water pump;
- Planned maintenance during the week of January 19 through 23 including Division 1 RHR subsystem maintenance and emergent maintenance on the diesel fire pump;
- Planned maintenance during the week of February 21 through 27 including Division 2 non-interruptible air supply subsystem and high pressure coolant injection (HPCI) system maintenance;

- Emergent maintenance during the week of February 28 through March 5 on feedwater heater 5S level control valve malfunction; and
- Planned maintenance during the week of March 7 through 11 including Division 1 EECW/emergency equipment service water (EESW) maintenance.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

This inspection constituted five 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 issues in the following CARDs:

- CARD 15-25243; Missed TS entry - Division 2 EECW-UHS [Ultimate Heat Sink] safety system outage - July 2015;
- CARD 16-20500; NRC identified question regarding EDG fuel oil storage room temperature below UFSAR cited minimum temperature;
- CARD 15-29229; Valve E1100F078 is unable to be stroked from the main control room - valve Is currently closed;
- CARD 15-29087; Valve B3105F031A jogged open unexpectedly during performance of 44.040.009 logic functional surveillance; and
- CARD 16-21733; Open and close contactors did not meet pick-up acceptance criteria.

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 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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

(1) Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's TSs

Introduction: The inspectors identified a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.73(a)(1), "Licensee Event Report System," for the licensee's failure to submit a required LER within 60 days after the discovery of an event that was reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) as a condition prohibited by the plant's TSs. The condition involved the licensee's failure to complete TS required actions for an inoperable UHS reservoir and for both EDGs in one division inoperable within the allowed completion times.

Description: On July 28, 2015, the licensee removed the Division 2 EECW system and UHS reservoir from service to perform scheduled maintenance. Upon completion of the maintenance later that day, the licensee identified a required action of TS 3.7.2, Condition B, for an inoperable UHS reservoir was not completed. A note in the action statement to enter the applicable conditions and required actions of TS 3.8.1 for EDGs made inoperable by an inoperable UHS reservoir was not performed. The licensee documented this issue in the CAP as CARD 15-25243.

The inspectors reviewed the licensee's reportability evaluation for the CARD and questioned the licensee's conclusion. The licensee concluded the missed TS 3.8.1 entry was not reportable as a condition prohibited by the plant's TSs because the 14-day allowed outage time for an inoperable EDG was not exceeded. The licensee's evaluation did not consider its failure to perform the required action of TS 3.7.2 and the other applicable required actions of TS 3.8.1.

The inspectors noted for one inoperable EDG, TS 3.8.1, Condition A, includes six required actions (A.1 through A.6). Required Actions A.1, A.2, and A.3 are required to be completed within 1, 4, and 8 hours, respectively. Additionally, for both EDGs in one division inoperable, TS 3.8.1, Condition B, includes four required actions (B.1 through

B.4). Required Actions B.1 and B.2 are required to be completed within 1 and 4 hours, respectively. The elapsed time of the missed TS 3.8.1 LCO entry from 4:00 a.m. to 9:15 p.m. (17.25 hours) was greater than the completion times of TS 3.8.1, Conditions A.1, B.1, A.2, B.2, and A.3, which were not performed. Inasmuch as required actions and completions times for Conditions A and B were not satisfied, Condition G, which required entry into Mode 3 within 12 hours, was also not met.

Technical Specification 3.8.1, Required Actions A.1 and B.1, require performance of Surveillance Requirement (SR) 3.8.1.1 to verify the correct breaker alignment and indicated power availability of each required electrical circuit within 1 hour and once per 8 hours thereafter. Required Actions A.2 and B.2, are conditional and require declaring required feature(s), supported by the inoperable EDG(s), inoperable when the redundant required feature(s) are inoperable within 4 hours from discovery of the inoperable EDG(s) concurrent with inoperability of redundant required feature(s). Required Action A.3, requires verification of combustion turbine generator (CTG) 11-1 availability to supply Division 1 electrical loads during a SBO once every 8 hours. The inspectors noted the reportability evaluation in CARD 15-25243 did not evaluate whether TS 3.8.1, Required Actions A.2 and B.2, were applicable based on determination of the existence of inoperable required feature(s) concurrent with the inoperable EDGs. Redundant required feature failures consist of inoperable feature(s) associated with a division redundant to the division that has an inoperable EDG; in this case, it referred to the inoperable required features in Division 1 since Division 2 EDGs were inoperable. Furthermore, the licensee’s reportability evaluation only discussed the applicability of required actions for one inoperable EDG (i.e., Required Actions A.1 through A.6) and did not consider both EDGs in one division inoperable due to the inoperable UHS reservoir.

In response to the inspectors’ questions, the licensee verified Required Actions A.2 and B.2 were not applicable because no redundant required feature(s) were inoperable concurrent with the 17.25-hour TS 3.8.1 LCO conditions applicability. Therefore, only Required Actions A.1, B.1, and A.3 were not satisfied. Upon discovery of these missed required actions on July 28, the licensee promptly performed them and verified the offsite power circuits were operable and CTG 11-1 was available. The inspectors documented a licensee-identified NCV of TS 3.7.2 and TS 3.8.1 in Section 4OA7 of this inspection report.

Analysis: The inspectors determined the licensee’s failure to report this issue as a condition prohibited by the plant’s TSs in accordance with the requirements in 10 CFR 50.73 was 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 the performance deficiency was not a finding of more than minor significance based on “No” answers to the more-than-minor screening questions. The inspectors also reviewed the examples of minor issues in IMC 0612, Appendix E, “Examples of Minor Issues,” dated August 11, 2009, and found no examples related to this issue.

Violations of 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. This violation was also associated with a performance deficiency that has been evaluated as having minor safety significance by the SDP. The SDP, however, does not specifically consider regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and performance deficiency using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated performance deficiency. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make a report to the NRC as required by 10 CFR 50.73(a)(1).

No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor safety significance and therefore not a finding.

Enforcement: Title 10 of CFR, Paragraph 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event. In addition, 10 CFR 50.73(a)(2)(i)(B) requires, in part, that the licensee report any event or condition which was prohibited by the plant's TSs.

Contrary to the above, the licensee failed to submit a required LER within 60 days after discovery of a reportable condition on July 28, 2015. Specifically, with the Division 2 UHS reservoir inoperable, the licensee failed to enter the applicable conditions and required actions of TS 3.8.1 for EDGs made inoperable by an inoperable UHS reservoir as required by TS 3.7.2, Condition B. Consequently, with both EDGs in one division inoperable, the licensee failed to complete TS 3.8.1, Required Actions A.1 and B.1, to perform SR 3.8.1.1 for operable offsite circuits within 1 hour and once per 8 hours thereafter, and also failed to complete TS 3.8.1, Required Action A.3, to verify the status of CTG 11-1 once per 8 hours. In addition, with the required actions and associated completion times of Conditions A and B not met, the licensee failed to complete TS 3.8.1, Required Action G, to be in Mode 3 within 12 hours. The failure to complete these TS required actions is a condition prohibited by the plant's TSs. The licensee submitted LER 05000341/2015-009-00, "Condition Prohibited by Technical Specification Due to Missed Entry into LCO Condition," on March 31, 2016, to report the event.

In accordance with Section 6.9.d.9 of the Enforcement Policy, this violation was classified as a Severity Level IV violation. The licensee entered this violation into its CAP as CARD 16-20566. Because this violation was not repetitive or willful, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. (**NCV 05000341/2016001–05, Failure to Satisfy 10 CFR 50.73 Reporting Requirements for a Condition Prohibited by the Plant's Technical Specifications**).

(2) Failure to Translate Design Requirements of the Residual Heat Removal Heating, Ventilation, and Air Conditioning (RHRHVAC) System into Procedures

Introduction: The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to demonstrate the RHRHVAC system would be able to maintain a required minimum temperature of 40 degrees Fahrenheit (°F) for the EDG fuel oil storage tank (FOST) rooms under minimum design conditions, potentially rendering the EDGs inoperable.

Description: On January 12, 2016, the inspectors performed a walkdown of the RHR Complex. Using an infrared laser gun that measures surface temperatures, the inspectors found surfaces in the EDG FOST rooms (i.e., walls, storage tanks, pumps) were well below the ambient air temperature in the adjoining rooms. The inspectors also noted there was no temperature monitoring for the FOST rooms since the rooms had no thermostats, nor were plant operators performing temperature monitoring of the rooms during their routine rounds. The inspectors brought these observations to the licensee's attention, and an operator was sent to take wet bulb ambient temperatures for the EDG FOST rooms. These temperature readings were recorded as 60, 53, 54, and 63°F for EDG 11, 12, 13, and 14 FOST Rooms, respectively.

The inspectors reviewed the UFSAR and other design basis documents for the EDG FOST rooms and RHRHVAC system. Design basis document X41-03, "Residual Heat Removal Complex HVAC," Section 4.1.6.1, states the RHRHVAC system is required to maintain the ambient air temperatures of the EDG FOST rooms (and all other rooms in the RHR Complex) at 65°F. The section also states that "maintenance of 65 degrees assures an adequate margin above the low temperature alarm setpoint of 45 degrees for the rooms. The 45 degrees room alarm will notify operations personnel of decreasing ambient conditions near the low-end design temperature (40 degrees) of the EDGs so that appropriate action can be taken." The inspectors noted the alarm is generated from temperatures in the engine rooms only and not the FOST rooms. Also, UFSAR Section 9.4.7.5.1, states that "the electric unit heaters will maintain RHR Complex equipment rooms at an ambient temperature of 65 degrees during normal operation and shutdown." However, there are no electric heaters installed in the FOST rooms as they would present a fire hazard. Therefore, ambient temperatures of the FOST rooms were solely maintained by the RHRHVAC system via heating in the adjacent rooms.

The inspectors questioned whether the RHRHVAC system would be able to maintain the low-end design limit of 40°F if the system was operating at its minimum design requirements of -10°F outside ambient temperature and the other rooms in the RHR Complex were at the 65°F minimum. The licensee initiated CARD 16-20500 to document the inspectors' question. The licensee had no design calculation available to demonstrate the RHRHVAC system could maintain temperatures in the FOST rooms above the design minimum temperature. On February 6, 2016, the licensee completed an evaluation that determined the RHRHVAC system would be unable to maintain the 40°F limit for the FOST rooms. Based on this result, the inspectors concluded the design requirements of the RHRHVAC system were not adequately translated into maintenance and monitoring procedures to ensure the EDG FOST rooms were maintained above the designed temperature limit. This failure could have resulted in unknown inoperability of the EDGs. No current operability concern was identified.

Analysis: The inspectors determined the licensee's failure to translate design requirements of the RHRHVAC system into procedures to ensure the EDG FOST rooms remained above the design temperature limit of 40°F was contrary to the requirements of 10 CFR 50, Appendix B, Criterion III, "Design Control," and was, therefore, a 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 a failure to correctly incorporate design requirements into plant procedures has the potential to lead to a more significant safety concern if left uncorrected. Specifically, since the EDG FOST rooms were unmonitored and a subsequent evaluation demonstrated the RHRHVAC system was not able to maintain the minimum required temperature in the EDG FOST rooms as described in the design basis, the EDGs could have been rendered inoperable without the licensee's knowledge. 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 examples related to this issue.

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 SSCs and Functionality contributor, and would require review using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012. 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 concluded it was a finding of very low safety significance (Green) since it was a performance deficiency affecting the design or qualification of a mitigating SSC, for which the SSC maintained its operability or functionality.

The inspectors concluded that because this condition had existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

Enforcement: Title 10 of the CFR, Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the design basis for the SSCs are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, prior to February 6, 2016, the licensee failed to incorporate the design requirements of the RHRHVAC system into procedures and instructions for monitoring and ensuring the RHRHVAC system could maintain the EDG FOST rooms above the design temperature limit as stated in the design basis. The licensee entered this violation into its CAP as CARD 16–20500. As an immediate corrective action, the licensee revised the operator rounds procedure to record ambient air temperature readings in the EDG FOST rooms on a daily basis when the outside ambient air temperature is below 45°F.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001–06, Failure to Translate Design Requirements of the RHRHVAC System into Procedures)**

1R18 Plant Modifications (71111.18)

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed the following plant temporary modifications:

- TM 15-0052; Remove TBCCW pump motor trips CARD 15-28559; and
- TM 15-0032; Radwaste building ventilation system steam coil freeze protection.

The inspectors reviewed the temporary modifications and the associated 10 CFR 50.59 screening/evaluations against applicable system design basis documents, including the UFSAR and the TS, to verify whether applicable design basis requirements were satisfied. The inspectors reviewed the control room logs and interviewed engineering and operations department personnel to understand the impact that implementation of the temporary modifications had on operability and availability of the affected system.

In addition, the inspectors verified problems associated with the installation of temporary plant modifications were entered into the licensee’s CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two temporary 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:

- Work Order 35468203; Disassemble valve, inspect and clean, rework as required (for standby feedwater pump 'A' discharge check valve);
- Work Order 38571174; Perform 24-Month preventive maintenance tasks per 34.307.001 on EDG 13;
- Work Order 35730909; Disassemble valve, inspect and clean, rework as required (for Standby Feedwater Pump 'B' Discharge Check Valve);
- Work Order 43667868; EESW south pump failed acceptance criteria;
- Work Order E419120100; Perform valve and actuator overhaul and air-Operated-valve diagnostic testing; and
- Work Order 37482717; Replace Division 1 control center heating, ventilation, and air conditioning equipment room return isolation damper solenoid valve.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the following surveillance testing results 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:

- 24.204.01; Division 1 low pressure coolant injection and suppression pool cooling/spray pump and valve operability test;
- 24.404.02(04); Division 1(2) SGTS filter and secondary containment isolation damper operability test;
- 24.404.03; Standby gas treatment system valve operability test;
- 24.206.01; RCIC system pump and valve operability test; and
- 24.307.15; Emergency diesel generator 12 - start and load Test.

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 CAP with the appropriate characterization and significance. Selected CARDs were reviewed to verify corrective actions were appropriate and implemented as scheduled. Documents reviewed are listed in the Attachment to this report.

This inspection constituted three in-service tests and two routine surveillance tests, for a total of five surveillance testing inspection samples as defined in IP 71111.22.

b. Findings

(1) Inadequate Test Criteria in SGTS Flow/Heater Operability Surveillance Test

Introduction: The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to include appropriate quantitative or qualitative acceptance criteria in its surveillance test procedures for fulfilling the monthly TS SR to demonstrate operability of the SGTS.

Description: The inspectors reviewed the licensee's performance of surveillance testing that was accomplished in accordance with Procedures 24.404.02, "Division 1 SGTS Filter and Secondary Containment Isolation Damper Operability Test," Revision 43; and, 24.404.04, "Division 2 SGTS Filter and Secondary Containment Isolation Damper Operability Test," Revision 42. Section 5.1 of these procedures was performed to satisfy TS SR 3.6.4.3.1, which requires each standby gas treatment (SGT) subsystem (or train) to be operated for ≥ 15 continuous minutes with the heaters operating once every 31 days. As described in the UFSAR, the safety function of the SGTS is to minimize the offsite release of radioactive materials that leak from the primary containment into the secondary containment following a design basis accident to limit the offsite and control room dose to the guidelines of 10 CFR 50.67.

According to the Bases for TS SR 3.6.4.3.1: "Operating each SGT subsystem from the main control room for ≥ 15 minutes ensures that both subsystems are operable and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action."

During review of Procedures 24.404.02 and 24.404.04, the inspectors noted the procedures did not have specific steps to ensure that flow blockage did not exist by verifying each SGT subsystem provided sufficient air flow. Although SGT subsystem inlet flow was recorded, there was no quantitative acceptance criteria in the procedures to evaluate whether each subsystem was capable of providing the minimum required air flow to meet its safety function. According to the UFSAR, the SGTS was designed with a flow control valve that maintains flow at 4000 cubic feet per minute (± 10 percent); however, there was no comparison of the recorded flow rates with the design flow rate to ensure the fan and/or the flow control valve were operating properly or that there was no flow blockage. Additionally, although pre-filter and high efficiency particulate air (HEPA) filter differential pressures were evaluated by a reference to the precautions and limitations section of Procedure 23.404, "Standby Gas Treatment System," Revision 54, the criteria provided in that normal operating procedure were only for dirty filter replacements. The criteria were not used to evaluate whether each subsystem was capable of providing the minimum required air flow to meet its safety function.

In addition, although SGT subsystem inlet and outlet temperatures were recorded once after the exhaust fan was started, there was no appropriate quantitative acceptance criteria in the procedures to evaluate whether the heater was capable of providing sufficient heat to eliminate moisture on the adsorbers and HEPA filters. The inspectors noted the acceptance criteria was simply to verify the outlet temperature was greater than the inlet temperature. This was not an adequate acceptance criteria for two reasons. First, it did not consider the inherent temperature instrument inaccuracy of ±4.5°F for each of the two temperature indicators. Second, it takes some minimum amount of time for the heater to raise air temperature after the SGT subsystem is started and for the inlet and outlet temperature readings to stabilize. The procedure did not account for this by requiring temperature measurements after some minimum warmup and stabilization time.

Analysis: The inspectors determined that the licensee's failure to include appropriate quantitative or qualitative acceptance criteria in its surveillance test procedures for the monthly TS SR to demonstrate operability of the SGTS was contrary to the requirements of 10 CFR 50, Appendix B, Criteria V, “Instructions, Procedures, and Drawings,” and was therefore, a 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 that this performance deficiency was of more than minor safety significance and thus a finding, because it was associated with the procedure quality attribute for the control room and auxiliary building and adversely affected the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, by not providing appropriate acceptance criteria by which the operability of the SGTS trains could be assessed, the ability of the SGTS to collect and treat the design leakage of radionuclides from the primary containment to the secondary containment during an accident could not be assured. 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 Barrier Integrity cornerstone, specifically the auxiliary/reactor building contributor, and would require review using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” June 19, 2012. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 3, “Barrier Integrity Screening Questions,” and determined this finding was a licensee performance deficiency of very low safety significance (Green) because it involved only a degradation of the radiological barrier function provided by the SGTS.

The inspectors concluded that because this condition has existed for greater than three years, this issue would not be reflective of current licensee performance and no cross-cutting aspect was identified.

<u>Enforcement</u>: Title 10 of the CFR, Part 50, Appendix B, Criteria V, “Instructions, Procedures, and Drawings” requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, the licensee failed to incorporate appropriate quantitative or qualitative acceptance criteria in surveillance test procedures 24.404.02, “Division 1 SGTS Filter and Secondary Containment Isolation Damper Operability Test,” Revision 43, and Procedure 24.404.04, “Division 2 SGTS Filter and Secondary Containment Isolation Damper Operability Test,” Revision 42, to demonstrate the operability of the SGTS as described in the TS Bases, an activity affecting quality. Specifically, the procedures did not have specific steps to verify each SGT subsystem provided sufficient air flow and to verify whether the heater was capable of providing sufficient heat to eliminate moisture on the adsorbers and HEPA filters. The licensee entered this violation into its CAP as CARD 16–21037. No immediate operability concern was identified.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001-07, Inadequate Test Criteria in SGTS Flow/Heater Operability Surveillance Test)**

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 (PI). To determine the accuracy of the PI data reported, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed each LER from January 1 through December 31, 2015, determined the number of scrams that occurred, and verified the licensee's calculation of critical hours. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. The inspectors noted there were two unplanned scrams reported by the licensee in 2015.

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

b. Findings

(1) (Closed) Unresolved Item (URI) 05000341/2015001-03, Unplanned Scrams per 7,000 Critical Hours Performance Indicator Question

On February 10, 2014, the licensee was lowering reactor power using a combination of reactor recirculation flow and control rods to enter a refueling outage. Normally, the licensee's general operating procedures governing plant shutdown would direct operators to lower power to about 20 percent before inserting a manual reactor scram. However, at about 66 percent power, the control rod select logic function of the control rod position indication system malfunctioned, resulting in an inability to manually move control rods. Both insertion and withdrawal of control rods were unavailable. The licensee made a decision to revise its operating procedure, creating a completely new section directing operators to initiate a manual scram if the control rod select function was not working and the reactor was less than 75 percent power. Based on the fact that a scram was the desired outcome to enter the refueling outage and the malfunction with the control rod select logic was added to the general operating procedure, the licensee regarded this as a planned scram and did not report it against the PI.

Based on review of the NEI 99-02 PI reporting guidance, the inspectors questioned the licensee's decision not to report this scram against the PI. Although scrams that are part of a normal planned operation or evolution (e.g., a scram initiated from 35 percent power or less during a planned plant shutdown) are not counted against the PI per the NEI 99-02 guidance, the licensee does not normally scram from 66 percent power in the course of a normal plant shutdown and did not originally plan to do so. The licensee made a change to its operating procedure as a work-around for an equipment failure to allow operators to scram from a much higher power than the procedure normally directed.

The inspectors opened URI 05000341/2015001-03 to resolve open questions regarding interpretation of the PI guidance with respect to reporting this scram. After further discussion of this reporting discrepancy with licensee management, the licensee concluded the scram should have been counted as an unplanned scram during the first quarter of 2014 and made a correction in its data submittal for the fourth quarter of 2015. The inspectors noted that had the licensee correctly reported the unplanned scram, the PI would not have crossed the Green-to-White threshold of 3.0 at any time in 2014. Since the threshold was not exceeded, the inspectors concluded the licensee's failure to report this scram under the Unplanned Scrams per 7,000 Critical Hours PI constituted a violation of 10 CFR 50.9, "Completeness and Accuracy of Information," of minor significance and is not subject to enforcement action in accordance with the NRC's Enforcement Policy. The licensee entered this violation into its CAP as CARD 16-20565.

The inspectors identified no other issues of concern during verification of this PI. URI 05000341/2015001-03 is closed.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors verified the Unplanned Scrams with Complications PI. 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, 2015, determined the number of scrams that occurred, and evaluated each of the scrams against the PI definition. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. The inspectors noted there was one unplanned scram with complications reported by the licensee in 2015.

This inspection constituted one Unplanned Scrams with Complications PI 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 PI. To determine the accuracy of the PI data reported, PI 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, 2015, determined the number of power changes greater than 20 percent of full power that occurred, evaluated each of the power changes against the PI definition, and verified the licensee's calculation of critical hours. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. The inspectors noted there was one unplanned power change reported by the licensee in 2015.

This inspection constituted one Unplanned Power Changes per 7,000 Critical Hours PI 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 PI. To determine the accuracy of the PI 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, 2015, determined the number of safety system functional failures that occurred, evaluated each LER against the PI definition, and verified the number of safety system functional failures reported. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. The inspectors noted there was one safety system functional failure reported by the licensee in 2015.

This inspection constituted one Safety System Functional Failures PI 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 that issues were being entered into the licensee's CAP 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 CAP 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 CARD for in-depth review:

- CARD 15-25133; Managers do not properly assess the operational impact of some degraded conditions.

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. Documents reviewed are listed in the Attachment to this report.

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

b. Findings and Observations

(1) Failure to Follow Apparent Cause Evaluation Procedure

Introduction: The inspectors identified a finding of very low safety significance for the licensee’s failure to implement its procedure standards when performing an apparent cause evaluation for a condition adverse to quality. Specifically, the inspectors determined the licensee did not adequately develop the direct and apparent cause of the problem in the evaluation, did not correctly assess the impact of relevant internal and external operating experience, and did not identify appropriate corrective actions to address management behaviors that resulted in the problem. No violation of regulatory requirements was identified because the scope of issues evaluated by the licensee’s procedure standards for performing the apparent cause evaluation was not limited to safety-related SSCs.

Description: The inspectors reviewed the licensee’s apparent cause evaluation and associated corrective actions for CARD 15-25133, “Managers Do Not Properly Assess the Operational Impact of Some Degraded Conditions,” and discussed the following issues and observations with licensee management:

a) The problem statement from the CARD and the apparent cause evaluation were: “Managers do not properly assess operational impact of some degraded conditions at the station, resulting in delay or lack of repair that complicated or initiated plant events." The inspectors noted the direct cause identified in the licensee's evaluation was simply a restatement of the problem rather than the *direct cause* of the problem. The direct cause of the problem was not actually developed in the evaluation.

b) The licensee determined the apparent cause was: "Operations management did not consistently apply conservative bias to assess the full operational impact of degraded equipment." The inspectors noted this apparent cause singled out operations management without any reason even though feedback provided to the licensee from its industry peers, which formed the problem statement for the CARD and the apparent cause evaluation, did not confine the problem only to operations management.

c) To determine the apparent cause of the problem, the licensee used a barrier analysis. The results of the barrier analysis indicated that personnel performance was the major barrier breakdown and procedures/processes should be enhanced. However, corrective actions, including those actions identified as enhancements, to address the problem were limited to changes in processes (e.g., procedure revisions to change processes and provide guidance, metrics or performance indicators, and benchmarking). The inspectors noted, with the exception of a one-time required reading sheet for operations management and senior reactor operators, there were no corrective actions to address changes in the management behaviors that actually resulted in the problem (e.g., conservative bias in decision making, inadequate recognition of risk, and tolerance of degraded equipment).

d) The licensee reviewed internal and external operating experience during the apparent cause evaluation and, based on this review, concluded the problem could not have been prevented by an appropriate application of lessons learned from previous operating experience. Based on the inspectors' understanding of the cause of the problem and the three examples provided to the licensee by its industry peers to explicate the problem statement, the inspectors did not concur with this conclusion. The inspectors found there was substantial internal and external operating experience that could have been used by the licensee prior to the three events; which could have prevented the events had the licensee thoroughly evaluated and applied it. For example, the inspectors found the licensee had discounted previous operating experience from the NRC and industry involving exhaust manifold fires on Fairbanks-Morse engines at other facilities, as well as at Fermi 2, and incorrectly concluded in its cause evaluation for the fire that the event was not preventable based on its review of operating experience. In addition, the inspectors noted there was also substantial industry operating experience available specifically related to the apparent cause of the problem that could have been used by the licensee (e.g., Significant Operating Experience Report 10-2, "Engaged, Thinking Organizations," dated September 7, 2010).

The inspectors noted that the CARD was categorized by the licensee as a condition adverse to quality. The inspectors reviewed Procedure MQA-15, "Quality Assurance Conduct Manual Chapter 15 – Apparent Cause Evaluations," Revision 17, and concluded, based on the above observations, the licensee did not implement its procedure standards when performing the apparent cause evaluation. Specifically, the licensee did not adequately develop the direct and apparent cause of the problem in the evaluation as stipulated in Section 6.6, did not correctly assess the impact of relevant internal and external operating experience as stipulated in Section 6.7, and did not identify appropriate corrective actions as stipulated in Section 6.9 to address the management behaviors that resulted in the problem.

In response to the inspectors' questions and observations, the licensee initiated CARD 16-20925 to identify the causes for the inadequate apparent cause evaluation and to identify appropriate corrective actions.

Analysis: The inspectors determined the licensee's failure to implement its procedure standards when performing an apparent cause evaluation for a condition adverse to quality was a 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 would have the potential to lead to a more significant safety concern if left uncorrected. Specifically, the failure to adequately perform apparent cause evaluations could result in ineffective corrective actions for conditions adverse to quality and safety. 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 examples similar to this issue.

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 would require evaluation using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria," dated April 12, 2012, since it was a programmatic issue associated with multiple cornerstones that could not readily be evaluated under any of the other SDP appendices. The inspectors concluded that the finding was of very low safety significance (Green) based on a qualitative evaluation of the potential consequences of the performance issue. The inspectors considered the three examples evaluated in the licensee's apparent cause evaluation and found the significance of each performance issue was not greater than very low safety significance.

The inspectors concluded this finding affected the cross-cutting area of problem identification and resolution and the cross-cutting aspect of evaluation. The licensee did not adequately evaluate the problem to ensure corrective actions would address the causes and extent of conditions commensurate with safety significance. Specifically, the apparent cause evaluation failed to identify and understand the basis for management decisions that contributed to the problem; therefore, corrective actions to address appropriate changes in management behaviors were not developed. (IMC 0310, P.2)

Enforcement: No violation of regulatory requirements was identified because the scope of issues evaluated by the licensee's procedure standards for performing the apparent cause evaluation was not limited to safety-related SSCs. The licensee entered this finding into its CAP as CARD 16-20925. **(FIN 05000341/2016001-08, Failure to Follow Apparent Cause Evaluation Procedure)**

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors reviewed repetitive or closely related issues documented in the licensee's CAP to look for trends not previously identified. This included a review of the licensee's quarterly trend coding and analysis reports to assess the effectiveness of the licensee's trending process. The inspectors also reviewed selected CARDs regarding licensee-identified potential trends to verify that corrective actions were effective in addressing the trends and implemented in a timely manner commensurate with the significance. Documents reviewed are listed in the Attachment to this report.

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 remained marginally effective at identifying, monitoring, and correcting adverse performance trends. This has been reflected in the licensee's quarterly trend coding and analysis reports. The inspectors noted several adverse performance trends have remained open for the entire year, with some of these adverse performance trends being categorized as continuing trends in the 1st quarter report of 2015. For example, human performance and industrial safety trends have been open for over a year with little or no improvement. 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. As discussed below, the inspectors identified an adverse performance trend associated with event reporting.

(2) Adverse Performance Trend in Reportability Related Issues

During this quarter, the inspectors identified an adverse performance trend associated with 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 Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System." This inspection report documents three Severity Level IV NCVs for the licensee's failure to satisfy the NRC's reporting requirements. In response to the inspectors' identification of these issues, the licensee initiated CARD 16-21857, "Adverse Trend in Reportability Related Issues," to evaluate the problem and identify appropriate corrective actions. Because the inspectors have documented violations for the separate reporting deficiencies, a separate finding for the identification of this adverse trend is not documented in this inspection report.

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

.1 Inadvertent Reactor Water Low Level RPS Actuation Due to Operator Error

a. Inspection Scope

On September 14, 2015, a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves was actuated. A reactor operator who was maintaining RPV water level and reactor pressure following a plant scram the day before did not initiate RCIC system flow in time to maintain level above the Level 3 RPS actuation setpoint. The inspectors interviewed licensed operators and reviewed Control Room logs, plant procedures, plant process computer data, and the licensee's apparent cause evaluation report 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 NCV of TS 5.4, "Procedures," was self-revealed when a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves was actuated. A reactor operator who was maintaining RPV water level and reactor pressure following a plant scram the day before did not initiate RCIC system flow in time to maintain level above the Level 3 RPS actuation setpoint.

Description: On September 13, 2015, control room operators manually scrammed the reactor and tripped the main turbine generator due to a loss of cooling water supply to nonsafety related systems in the turbine building, including the main turbine oil and station air systems. The inspectors evaluated operator actions during the event and documented this review in NRC Inspection Report 05000341/2015003. Refer to Section 1R12.b.3 of this inspection report for the inspectors' review of the TBCCW heat exchanger tube failure, which resulted in the manual reactor scram.

Following the manual scram, on September 14, at 6:47 p.m., a reactor operator was controlling RPV water level with the RCIC system and reactor pressure with manual operation of the safety relief valves when RPV level reached the Level 3 RPS actuation setpoint, resulting in a valid automatic reactor scram signal and isolation signal for Group 4, 13 and 15 primary containment isolation valves. Since all control rods were already fully inserted into the reactor, the RPS safety function was already fulfilled. Control room operators verified primary containment isolation valve isolations occurred as expected and promptly restored RPV level with manual operation of the RCIC system.

The reactor operator was assigned to monitor and maintain RPV water level and reactor pressure per the emergency operating procedure prescribed level band of 173 to 214 inches and pressure band of 900 to 1050 psig by the control room supervisor. Each operation of a safety relief valve caused RPV level to swell about 20 to 25 inches for a 20 to 30 psig change in reactor pressure. Following closure of the safety relief valve, RPV level would lower significantly and RCIC system flow would be increased to overcome the loss of level. This sequence was repeated by the reactor operator every 3 to 5 minutes. By the time the event occurred, the reactor operator had been successfully performing these actions for most of his 12-hour shift.

The licensee's apparent cause evaluation attributed the direct cause to a human performance error. The reactor operator who was maintaining RPV level and reactor pressure did not initiate RCIC system flow in time to maintain level above the Level 3 RPS actuation setpoint of 173.4 inches. The reactor operator believed he had initiated RCIC system flow; however, the operator apparently became distracted during turnover discussion with an on-coming reactor operator and did not validate or achieve an expected response from the RCIC flow controller. Reviewing plant process computer data from just prior to the event, it was noted there had been no manual change to the

RCIC flow controller output, and therefore, no resulting change in RCIC system flow for approximately 12 minutes. The apparent cause was determined to be operator fatigue from repetitive task demands.

The licensee completed an 8-hour notification call (Event Notification 51391) on September 14, 2015 to report the valid automatic reactor scram signal as required by 10 CFR 50.72(b)(3)(iv)(A) as an event or condition that resulted in a valid actuation of the RPS. The licensee submitted LER 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water," in accordance with 10 CFR 73(a)(2)(iv)(A) as an event or condition that resulted in automatic actuation of the RPS. Refer to Section 4OA3.2 of this inspection report for the inspectors' review of the event notification and the LER.

Analysis: The inspectors determined the licensee's failure to maintain RPV water level 173 inches to 214 inches in accordance with the emergency operating procedure was contrary to the requirements of TS 5.4.1.b, and was therefore a 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 human performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the human performance error unnecessarily challenged a plant protection feature, which resulted in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves. 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 this issue was sufficiently similar to guidance provided in Example 4(b) that the issue was not of minor safety significance since the error resulted in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves.

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 Initiating Events cornerstone, specifically the transient initiators contributor, and would require review using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, since at the time of the event the reactor was in Mode 3 (hot shutdown) without the RHR system in service for shutdown cooling. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," and determined it was a finding of very low safety significance (Green) since it did not cause a reactor scram and the loss of mitigation equipment relied upon to transition the plant to a stable shutdown condition (e.g., loss of condenser, loss of feedwater).

The inspectors concluded this finding affected the cross-cutting aspect of resources in the human performance area. The direct cause of the event was attributed to a human performance error with the apparent cause being operator fatigue from repetitive task demands. The licensee's evaluation identified the reactor operator had been performing a complicated task for a long period of time without adequate rest/recovery periods (IMC 0310, H.1).

Enforcement: Technical Specification 5.4.1.b requires that written procedures be established, implemented, and maintained, covering the emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33. NUREG-0737, Supplement 1, "Clarification of TMI [Three Mile Island] Action Plan Requirements: Requirements for Emergency Response Capability," Section 7.1.d, requires the licensee to implement its upgraded emergency operating procedures. Emergency Operating Procedure 29.100.01 SH 1, "RPV Control," Revision 14, implements the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33 and contains guidance, in part, for control of RPV water level under off-normal and emergency operating conditions. Specifically, Step L-2 of this procedure directed operators to restore and maintain RPV water level 173 inches to 214 inches with an available water source.

Contrary to the above, on September 14, 2015, the licensee failed to implement emergency operating procedure 29.100.01 SH 1, Step L-2 when a reactor operator failed to maintain RPV water level 173 inches to 214 inches as directed by the control room supervisor. Consequently, RPV water level reached the Level 3 RPS actuation setpoint, resulting in a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves. The licensee entered this violation into its CAP as CARD 15-26521. The licensee provided remedial training for the reactor operator in the simulator, communicated lessons learned from this event with other licensed operators, and subsequently implemented improvements identified for licensed operator training and procedure changes to incorporate a revised strategy for manual control of RPV level and pressure control with MSIVs closed.

Because this violation was not repetitive or willful, was of very low safety significance, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000341/2016001–09, Inadvertent Reactor Water Low Level Reactor Protection System Actuation Due to Operator Error)**

.2 Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment Isolation Valve Actuations

(Open) LER 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water"

a. Inspection Scope

On September 13, 2015, control room operators manually scrammed the reactor and tripped the main turbine generator due to a loss of cooling water supply to nonsafety related systems in the turbine building, including the main turbine oil and station air systems. The inspectors evaluated operator actions during the event and documented this review in NRC Inspection Report 05000341/2015003. Refer to Section 1R12.b.3 of this inspection report for the inspectors' review of the TBCCW heat exchanger tube failure, which resulted in the manual reactor scram.

On September 14, 2015, a reactor operator who was maintaining RPV water level and reactor pressure following the plant scram the day before did not initiate RCIC system flow in time to maintain level above the Level 3 RPS actuation setpoint. As a result, a valid automatic reactor scram signal and isolation signal for multiple primary containment isolation valves was actuated. Refer to Section 4OA3.1 of this inspection report for the inspectors' review of the inadvertent Level 3 RPS actuation event.

The licensee completed a notification call (Event Notification 51391) on September 14 at 2:46 a.m. to report the manual reactor scram as required by 10 CFR 50.72(b)(2)(iv)(B) as an event or condition that resulted in actuation of the RPS when the reactor is critical and the loss of secondary containment function 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 updated this event notification twice. The first update was on September 14 at 5:45 a.m. and reported the manual initiation of the RCIC system as required by 10 CFR 50.72(b)(3)(iv)(A). The second update was on September 14 at 9:35 p.m. and reported the inadvertent Level 3 RPS actuation as required by 10 CFR 50.72(b)(3)(iv)(A).

The licensee submitted LER 05000341/2015–006–00 to report all of the above events. The manual reactor scram was reported as required by 10 CFR 50.73(a)(2)(iv)(A), as an event or condition that resulted in manual or automatic actuation of the RPS. The loss of secondary containment function was reported as required by 10 CFR 50.73(a)(2)(v)(C), as an event or condition that could have prevented the fulfillment of a safety function needed to control the release of radioactive material. The manual initiation of the RCIC system and the inadvertent Level 3 RPS actuation was reported as required by 10 CFR 50.73(a)(2)(iv)(A).

The inspectors reviewed the original 10 CFR 50.72 event notification, the two event notification updates, and the LER to determine whether the licensee satisfied the reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System." Documents reviewed as part of this inspection are listed in the Attachment to this report.

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

b. Findings

Introduction: The inspectors identified a Severity Level IV NCV of the NRC's reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System." Specifically, the licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center and also failed to submit a required LER within 60 days after discovery on September 13, 2015, and September 14, 2015, (two separate occurrences) of a condition that resulted in the valid actuation of containment isolation signals affecting containment isolation valves in more than one system.

Description: The inspectors reviewed LER 05000341/2015–006–00, "Reactor Scram Due to Loss of Turbine Building Closed Cooling Water." The inspectors determined that the RPV water level reached the Level 3 setpoint during the initial manual scram on September 13, 2015 and on September 14, 2015 when the reactor operator failed to maintain RPV level. As a result of reaching the Level 3 setpoint, there was a valid automatic actuation of the primary containment isolation logic for Groups 4, 13, and 15 primary containment isolation valves. The inspectors noted automatic actuation of primary containment isolation valve logic in more than one system was reportable under 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in valid actuation of general containment isolation signals affecting containment isolation valves in more than one system. However, while both the 10 CFR 50.72 event notification form (Event Notification 51391) and the LER narrative stated all isolations and actuations for Level 3 occurred as expected, the valid automatic actuation signal for multiple primary containment isolation valves was not explicitly described in either event report. Reporting the containment isolation valve logic actuations was also not included in licensee's 10 CFR 50.72 event notification by checking the appropriate box on the notification form and describing valid actuation of primary containment isolation logic. The inspectors noted 10 CFR 50.73(b)(2)(ii)(K) specifically required the licensee to include in the narrative description all automatically and manually initiated safety system responses. The licensee completed that requirement for the manual reactor scram but did not complete that for the primary containment isolation valve logic actuations. It appeared the only reason the appropriate box was checked on the LER form is that under 10 CFR 50.73 a reactor scram with the reactor initially critical and primary containment isolation valve actuations are reported under the same criterion (i.e., the same box would be checked).

In response to the inspectors' questions, the licensee acknowledged its 10 CFR 50.72 event notifications and its LER did not correctly report the valid actuation of containment isolation signals affecting containment isolation valves in more than one system and prepared revisions to the event notification and the LER. During its review of the reporting discrepancies, the licensee identified the closure of MSIVs and the subsequent valid automatic actuation signal for MSIVs and drain valves that occurred when main condenser vacuum reached the high condenser pressure primary containment isolation setpoint was also not correctly reported. The manual and automatic actuations of primary containment isolation valve logic for the MSIVs were reportable under 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in the valid actuation of general containment isolation signals affecting multiple MSIVs. The inspectors documented a licensee-identified NCV of 10 CFR 50.72(a)(1) and 10 CFR 50.73(a)(1) in Section 4OA7 of this inspection report.

Analysis: The inspectors determined the licensee's failure to report these events in accordance with the requirements in 10 CFR 50.72 and 10 CFR 50.73 was 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 the performance deficiency was not a finding of more than minor significance based on "No" answers to the more-than-minor screening questions. The inspectors also reviewed the examples of minor issues in IMC 0612, Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no examples related to this issue.

Violations of 10 CFR 50.72 and 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. This violation was also associated with a performance deficiency that has been evaluated as having minor safety significance by the SDP. The SDP, however, does not specifically consider regulatory process impact.

Thus, although related to a common regulatory concern, it is necessary to address the violation and performance deficiency using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated performance deficiency. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make reports to the NRC as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1).

No cross-cutting aspect is associated with this traditional enforcement violation because the associated performance deficiency was determined to be of minor safety significance and therefore not a finding.

Enforcement: Title 10 of the CFR, Paragraph 50.72(a)(1)(ii) requires, in part, that the licensee shall notify the NRC Operations Center via the Emergency Notification System of those non-emergency events specified in Paragraph (b) that occurred within three years of the date of discovery. Moreover, 10 CFR 50.72(b)(3) requires, in part, that the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the applicable conditions. In addition, 10 CFR 50.72(b)(3)(iv)(A) requires, in part, that the licensee report any event or condition that results in valid actuation of any of the systems listed in Paragraph (b)(3)(iv)(B) and 10 CFR 50.72(b)(3)(iv)(B)(2) lists general containment isolation signals affecting containment isolation valves in more than one system or multiple MSIVs.

Further, 10 CFR 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event and 10 CFR 50.73(a)(2)(iv)(A) requires, in part, that the licensee report any event or condition that resulted in manual or automatic actuation of any of the systems listed in Paragraph (a)(2)(iv)(B). Also, 10 CFR 50.73(a)(2)(iv)(B)(2) lists general containment isolation signals affecting containment isolation valves in more than one system or multiple MSIVs.

Contrary to the above:

1. The licensee failed to notify the NRC Operations Center via the Emergency Notification System of a non-emergency event specified in Paragraph (b) within eight hours of two events on September 13, 2015, and September 14, 2015. The events involved the valid automatic actuation of the primary containment isolation logic for Groups 4, 13, and 15 primary containment isolation valves, which involved containment isolation valves in more than one system.

2. The licensee failed to submit a required LER within 60 days after discovery of two events on September 13, 2015, and September 14, 2015. The events involved the valid automatic actuation of the primary containment isolation logic for Groups 4, 13, and 15 primary containment isolation valves, which involved containment isolation valves in more than one system.

In accordance with Section 6.9.d.9 of the Enforcement Policy, this violation was classified as a Severity Level IV violation. The licensee entered this violation into its CAP as CARD 16-20564 and subsequently made an 8-hour notification call to the NRC Operations Center via the Emergency Notification System to report the event on February 27, 2016, (Event Notice 51391, third update). The inspectors reviewed the revised event notification and determined the information provided did not raise any new issues or change the conclusion of the initial review.

Because this violation was not repetitive or willful, and was entered into the licensee's CAP, it is being treated as a NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy (**NCV 05000341/2016001–10, Failure to Satisfy 10 CFR 50.72 and 10 CFR 50.73 Reporting Requirements for Primary Containment Isolation Valve Actuations**).

LER 05000341/2015–006–00 remains open pending the inspectors' review of the licensee's resolution of the 10 CFR 50.73 reporting discrepancies.

.3 (Closed) LER 05000341/2015-005-00, "Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction"

(Closed) LER 05000341/2015–005–01, "Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction," Supplement 1

On August 12, 2015, while restoring the RBHVAC system after surveillance testing, a malfunction affecting the east supply fan damper resulted in improper damper alignment and caused secondary containment pressure to exceed the TS limit of -0.125 inches water gauge for approximately 5 seconds. The SGTS was already in operation and restored secondary containment pressure to within the TS limit after Control Room operators secured the RBHVAC system.

The licensee completed an 8-hour notification call (Event Notification 51313) on August 12, 2015 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 05000341/2015-005-00 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 licensee supplemented the LER to correct a technical error in the original report.

The licensee completed an apparent cause evaluation that concluded the cause was setpoint drift of the east RBHVAC supply fan damper time delay relay that opened the damper sooner than it should have in the system startup sequence. This resulted in the supply fans forcing more air into secondary containment than was being removed, causing secondary containment pressure to rise. The inspectors did not identify any significant safety issue not addressed in the licensee's cause evaluation and LER.

The inspectors concluded there was no finding associated with this event since the performance issue was determined not to be within the licensee's ability to reasonably foresee and prevent. This event was similar to an event that occurred on November 24, 2013. Set point drift due to lack of a preventive maintenance strategy for calibration was identified as the cause for that event. For the event described in this LER, the licensee was unable to identify a failure mechanism for the time delay relay. However, because the licensee had implemented appropriate preventive maintenance activities for the damper time delay relay after the 2013 event and the failure mechanism could not be identified, the inspectors determined there was no performance deficiency associated with this event.

Although the 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 continued in operation and would have 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.

This inspection constituted two event follow-up inspection samples as defined in IP 71153.

LER 05000341/2015-005-00 and LER 05000341/2015-005-01 are closed.

.4 <u>(Closed) LER 05000341/2016-001-00, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves"</u>

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 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 Section 1R12.b.1 of this inspection report, 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. However, the inspectors identified the licensee had failed to declare TS LCO 3.3.1.1 not met and enter Condition C when the HPSV closure and HPCV fast closure RPS trip functions became inoperable while the main turbine bypass valves cycled open during the plant transient. The performance issue related to this reporting oversight, the safety significance, the cause, and the corrective actions are discussed in more detail in Section 1R12.b.2 of this inspection report.

The licensee subsequently made an 8-hour notification call to the NRC Operations Center via the Emergency Notification System on February 25, 2016, to report the event (Event Notice 51755) in accordance with 10 CFR 50.73(a)(2)(v)(A) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to shut down the reactor and maintain it in a safe shutdown condition. On March 2, 2016, the licensee updated the Event Notice to include reporting the event also under 10 CFR 50.72(b)(3)(v)(D) as an event or condition that could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident.

The licensee submitted 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 inspectors determined the information provided in the LER did not raise any new issues or change the conclusion of the initial review.

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

LER 05000341/2016–001–00 is closed.

.5 <u>(Closed) LER 05000341/2015-008-00, "Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valve"</u>

On February 21, 2015, with Fermi 2 operating at 100 percent power, the main turbine generator #2 HPSV malfunctioned, cycling partially closed and open multiple times. The west main turbine bypass valve cycled open and then closed as expected to divert steam flow to the main condenser and mitigate the effects of the transient. Control Room operators reduced reactor power to about 91 percent and locked the #2 HPCV and #2 HPSV closed. The licensee replaced a failed comparator circuit card and a relay in the #2 HPSV valve control module to correct the problem. Operators subsequently restored the #2 HPCV and #2 HPSV to service and returned reactor power to 100 percent later the same day.

The inspectors reviewed this issue and concluded there was no performance deficiency associated with the #2 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 and relay were 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. However, the inspectors identified a Severity Level IV NCV of 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors," and 10 CFR 50.73(a)(1), "Licensee Event Report System." The licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center after discovery of a condition that could have prevented the fulfillment of the safety function to shut down the reactor as required by 10 CFR 50.72(b)(3)(v)(A). In addition, the licensee failed to submit a required LER within 60 days after discovery of the event as required by 10 CFR 50.73(a)(2)(v)(A). The performance issue related to this reporting oversight, the safety significance, the cause, and the corrective actions are discussed in more detail in Section 1R12.b.2 of this inspection report.

The licensee subsequently made an 8-hour notification call to the NRC Operations Center via the Emergency Notification System on February 25, 2016, to report the event

(Event Notice 51756) in accordance with 10 CFR 50. 72(b)(3)(v)(A) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to shut down the reactor and maintain it in a safe shutdown condition. On March 2, 2016, the licensee updated the Event Notice to include reporting the event also under 10 CFR 50.72(b)(3)(v)(D) as an event or condition that could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident.

The licensee submitted LER 05000341/2015–008–00 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 inspectors determined the information provided in the LER did not raise any new issues or change the conclusion of the initial review.

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

LER 05000341/2015–008–00 is closed.

4OA6 Management Meetings

Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. K. Polson and other members of the licensee's staff on April 7, 2016. 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 two violations of very low safety significance (Green) or Severity Level IV were identified by the licensee and are violations of NRC requirements that meet the criteria of the NRC Enforcement Policy for being dispositioned as NCVs.

- Technical Specification 3.7.2, "Emergency Equipment Cooling Water (EECW) / Emergency Equipment Service Water (EESW) System and Ultimate Heat Sink (UHS)," Required Actions, Note 1, states: "Enter applicable Conditions and Required Actions of LCO 3.8.1, 'AC [Alternating Current] Sources – Operating,' for diesel generators made inoperable by UHS." Technical Specification 3.8.1, Condition A is required when one EDG is inoperable and Condition B is required when both EDGs in one division are inoperable.

  Technical Specification 3.8.1, Required Actions A.1 and B.1, state: "Perform SR 3.8.1.1 for operable offsite circuit(s) within 1 hour and once per 8 hours thereafter," and TS 3.8.1, Required Action A.3, states: "Verify the status of CTG 11-1 once per 8 hours."

Contrary to the above, on July 28, 2015, with the Division 2 UHS reservoir inoperable, the licensee failed to enter the applicable conditions and required actions of TS 3.7.2 and subsequently, failed to enter TS 3.8.1 for both Division 2 EDGs made inoperable by an inoperable UHS reservoir. Consequently, with both EDGs in one division inoperable, the licensee failed to complete TS 3.8.1, Required Actions A.1 and B.1, to perform SR 3.8.1.1 for operable offsite circuits within 1 hour and once per 8 hours thereafter, and also failed to complete TS 3.8.1, Required Action A.3, to verify the status of CTG 11-1 once per 8 hours. In addition, with the required actions and associated completion times of Conditions A and B not met, the licensee failed to complete TS 3.8.1, Required Action G, to be in Mode 3 within 12 hours. The failure to complete these TS required actions is a violation of TS 3.8.1.

The issue was determined to be of very low safety significance (Green) because it did not represent an actual loss of function of a single train (or division) for greater than its TS allowed outage time. The licensee entered this violation into its CAP as CARD 15-25243.

- Title 10 of the CFR, Paragraph 50.72(a)(1)(ii) requires, in part, that the licensee shall notify the NRC Operations Center via the Emergency Notification System of those non-emergency events specified in Paragraph (b) that occurred within three years of the date of discovery and 10 CFR 50.72(b)(3) requires, in part, that the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the applicable conditions. Moreover, 10 CFR 50.72(b)(3)(iv)(A) requires, in part, that the licensee report any event or condition that results in valid actuation of any of the systems listed in Paragraph (b)(3)(iv)(B) and 10 CFR 50.72(b)(3)(iv)(B)(2) lists general containment isolation signals affecting containment isolation valves in more than one system or multiple MSIVs.

  In addition, 10 CFR 50.73(a)(1) requires, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event and 10 CFR 50.73(a)(2)(iv)(A) requires, in part, that the licensee report any event or condition that resulted in manual or automatic actuation of any of the systems listed in Paragraph (a)(2)(iv)(B). Paragraph (a)(2)(iv)(B)(2) in 10 CFR 50.73 lists general containment isolation signals affecting containment isolation valves in more than one system or multiple MSIVs.

  Contrary to the above:

  1. The licensee failed to notify the NRC Operations Center via the Emergency Notification System of a non-emergency event specified in Paragraph (b) within eight hours of an event on September 14, 2015. The event involved the valid manual and automatic actuation of the primary containment isolation logic for multiple MSIVs.

  2. The licensee failed to submit a required LER within 60 days after discovery of an event on September 14, 2015. The event involved the valid manual and automatic actuation of the primary containment isolation logic for multiple MSIVs.

  Violations of 10 CFR 50.72 and 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the licensee failed to make a report to the NRC as required by 10 CFR 50.72(a)(1)(ii) and 10 CFR 50.73(a)(1). The licensee entered this violation into its CAP as CARD 16-20564.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

L. Bennett, Superintendent, Nuclear Operations
R. Breymaier, Manager, Performance Engineering and Fuels
M. Caragher, Director, Nuclear Production
W. Colonnello, Director, Nuclear Work Management
B. Crone, General Supervisor, Operations Training
J. Haas, Principle Engineer, Licensing
C. Harris, Manager, Performance Improvement
S. Hassoun, Acting Manager, Licensing
T. Holmberg, Acting Manager, Training
L. Kantola, Manager, Outage and Work Management
E. Kokosky, Director, Organization Effectiveness
R. LaBurn, Manager, Radiation Protection
J. Louwers, Manager, Nuclear Quality Assurance
R. Matuszak, Manager, Plant Systems Engineering
J. May, Manager, Chemistry
M. O'Connor, Manager, Security
L. Peterson, Director, Nuclear Engineering
G. Piccard, Manager, Nuclear Operations
K. Polson, Site Vice President
W. Raymer, Manager, Maintenance
B. Rumans, General Supervisor, Radiation Protection Technical Services
D. Sadowyj, Lead Engineer, Corrective Action Program
P. Southwell, General Supervisor, Radiation Protection ALARA
S. Ward, Senior Engineer, Licensing

U.S. Nuclear Regulatory Commission

B. Dickson, Chief, Reactor Projects Branch 5

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000341/2016001–01	NCV	Failure of the Plant-Referenced Simulator to Demonstrate Expected Plant Response for Safety Relief Valves (Section 1R11.3)
05000341/2016001–02	NCV	Failure to Correctly Interpret and Implement TS Requirements for RPS Trip Functions (Section 1R12.b.1)
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 1R12.b.2)
05000341/2016001–04	NCV	Failure to Incorporate Operating Experience into Preventive Maintenance Activities Associated with the TBCCW System (Section 1R12.b.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 1R15.b.1)
05000341/2016001–06	NCV	Failure to Translate Design Requirements of the RHRHVAC System into Procedures (Section 1R15.b.2)
05000341/2016001–07	NCV	Inadequate Test Criteria in SGTS Flow/Heater Operability Surveillance Test (Section 1R22.b.1)
05000341/2016001–08	FIN	Failure to Follow Apparent Cause Evaluation Procedure (Section 4OA2.2.b.1)
05000341/2016001–09	NCV	Inadvertent Reactor Water Low Level Reactor Protection System Actuation Due to Operator Error (Section 4OA3.1)
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 4OA3.2)

Closed

05000341/2016001–01	NCV	Failure of the Plant-Referenced Simulator to Demonstrate Expected Plant Response for Safety Relief Valves (Section 1R11.3)
05000341/2016001–02	NCV	Failure to Correctly Interpret and Implement TS Requirements for RPS Trip Functions (Section 1R12.b.1)
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 1R12.b.2)
05000341/2016001–04	NCV	Failure to Incorporate Operating Experience into Preventive Maintenance Activities Associated with the TBCCW System (Section 1R12.b.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 1R15.b.1)
05000341/2016001–06	NCV	Failure to Translate Design Requirements of the RHRHVAC System into Procedures (Section 1R15.b.2)

05000341/2016001–07	NCV	Inadequate Test Criteria in SGTS Flow/Heater Operability Surveillance Test (Section 1R22.b.1)
05000341/2015001-03	URI	Unplanned Scrams per 7,000 Critical Hours Performance Indicator Question (Section 4OA1.b.1)
05000341/2016001–08	FIN	Failure to Follow Apparent Cause Evaluation Procedure (Section 4OA2.2.b.1)
05000341/2016001–09	NCV	Inadvertent Reactor Water Low Level Reactor Protection System Actuation Due to Operator Error (Section 4OA3.1)
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 4OA3.2)
05000341/2015-005-00	LER	Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction (Section 4OA3.3)
05000341/2015-005-01	LER	Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction, Supplement 1 (Section 4OA3.3)
05000341/2016-001-00	LER	Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves (Section 4OA3.4)
05000341/2015-008-00	LER	Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valve (Section 4OA3.5)

<u>Discussed</u>

05000341/2014004-03	NCV	Failure to Promptly Correct a Condition Adverse to Quality on EDG 11 (Section 4OA2.2.b.1)
05000341/2015–006–00	LER	Reactor Scram Due to Loss of Turbine Building Closed Cooling Water (Section 4OA3.2)

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

- CARD 16-20500; NRC Identified Question Regarding EDG Fuel Oil Storage Room Temperature Below UFSAR Cited Minimum Temperature
- Procedure 20.000.01; Acts of Nature; Revision 49
- Procedure 20.131.01; Loss of General Service Water System; Revision 28

1R04 Equipment Alignment

- CARD 09-23411; Relay 122C in the H21P295A Panel Chattering
- CARD 13-21211; Preventive Maintenance Performance on Known Broken Equipment
- CARD 14-26230; Engineering Evaluation for Operability – P50F417
- CARD 14-26235; Component Found Outside Calibration
- CARD 14-26619; Engineering Evaluation
- CARD 14-27416; Increased Vibration on Division 1 SGTS Exhaust Fan Motor
- CARD 15-20173; Discrepancy Identified in EDP-37204.B006 Change
- CARD 15-20206; Discrepancies with EDP-37204.A003 Changes
- CARD 15-25468; T4600 Equipment Trend Evaluation
- CARD 15-25723; Size 0 Contactor Acceptance Criteria Not in 35.306.008
- CARD 15-25745; SGTS Heaters Contactors 121-C and 122-C Discrepancies
- CARD 15-27416; Increased Vibration on Division 1 SGTS Exhaust Fan Motor
- CARD 15-27431; Evaluate Regulator Pressure on T4600F406
- CARD 15-27625; Liquid Penetrant Examinations and Raychem Installation Performed in the Reactor Building While Standby Gas Treatment Is in Operation
- CARD 15-27687; T4600F406 Exhibiting Negative Margin During As-left Testing
- CARD 15-28499; 47.000.94, Test 4, Is Above Its Total Maximum Leakage as Written
- CARD 16-21485; NRC Resident Question Regarding Air Operated Valve T4600F006
- Diagram 6M721-2709; Diagram Standby Gas Treatment and Primary Containment Purge System Reactor Building; Revision AA
- Drawing M-2083; Residual Heat Removal (RHR) Division 2; Revision BV
- Drawing M-5706-1; Residual Heat Removal (RHR) Division II Functional Operating Sketch; Revision AH
- Drawing M-5729-2; Emergency Equipment Cooling Water (Division II) Functional Operating Sketch; Revision AY
- Drawing M-5734; Emergency Diesel Generator System Functional Operating Sketch; Revision BF
- Procedure 23.127; Reactor Building Closed Cooling Water/Emergency Equipment Cooling Water System; Revision 140
- Procedure 23.205; Residual Heat Removal; Revision 129
- Procedure 23.307; Emergency Diesel Generator System; Revision 121
- Procedure 23.404; Standby Gas Treatment System; Revision 54
- Work Order 29769201; Relay 122C in the H21P295A Panel Is Chattering

- Work Order 36847612; EDP-37204 Replace 150VA Transformer 4T in Panel H21P295A with 150VA Micron Transformer

1R05 Fire Protection

- CARD 15-24783; Extensive Damage Mitigation Fire Truck Still Winterized
- CARD 16-00132; Fire Extinguisher Boxes Need to be Repaired/Replaced
- CARD 16-20776; NRC Question Concerning Reactor Building Column Line 12 Controls
- Fire Protection Engineering Evaluation FPEE-09-0004; Requirements for Temporary Intervening Combustibles in Modes 1, 2 & 3; February 13, 2009
- Fire Protection Pre Plan FP-AB-2-9C; Auxiliary Building Cable Tunnel, Zone 9, Elevation 613’6”; Revision 3
- Fire Protection Pre Plan FP–AB–2M–11; Auxiliary Building Cable Spreading Room, Zone 11, Elevation 630’; Revision 5
- Fire Protection Pre Plan FP–RB–2–10b; Reactor Building, Emergency Equipment Cooling Water South, Zone 10, Elevation 613'6"; Revision 4
- Fire Protection Pre Plan FP-RB-4–17b; Reactor Building Recirculation System Motor Generator Area, Zone 17, EL. 659'6"; Revision 4
- Fire Protection Pre Plan FP–RB–B2b; Reactor Building Basement Northwest Corner Room, Zone 2, EL. 562’ 0”; Revision 3
- Fire Protection Pre Plan FP-TB; Turbine Building; Revision 9
- NRC Generic Letter 86-10; Implementation of Fire Protection Requirements; April 24, 1986
- Operations Conduct Manual MOP11; Fire Protection; Revision 16
- Operations Conduct Manual MOP23; Plant Storage; Revision 2
- Procedure 28.507.01; Fire Barrier Inspection; Revision 10
- Procedure 28.507.03; Fire Door Inspection – Balance of Plant; Revision 29

1R06 Flood Protection Measures

- CARD 15–27737; Reactor Building Equipment Drain Sump Check Valve Exceeded Leakage Limit
- CARD 15–28448; Reactor Building Floor Drain Sump Check Valve Exceeded Leakage Limit
- Drawing 6M721-2223; Diagram Equipment Drains All Floors Auxiliary and Reactor Buildings; Revision X
- Drawing 6M721–2224; Diagram Floor Drains All Floors Auxiliary and Reactor Buildings; Revision Y
- Work Order 34292184; Inspect/Test 480VAC MCC 72E–3A Position 1C
- Work Order 37582413; Perform 47.000.84 Section 6.2 LLRT [Local Leak Rate Testing] for Equipment Drain Check Valves – G1101F1410 & 1411
- Work Order 37582415; Perform 47.000.84 Section 6.4 LLRT For Floor Drain Check Valves – G1101F1407 & 1408
- Work Order 38117563; LLRT Failure Rework G1101F1407
- Work Order 38344205; Perform General Maintenance on MCC 72E-3A
- Work Order 44131585; LLRT Failure Reactor Building Equipment Drain Sump Check Valve G1101F1411 Exceeded Leakage Limit
- Work Order 44132136; Perform 47.000.84 Section 6.2 LLRT For Equipment Drain Check Valves – Partial for G1101F1411
- Work Order 44230646; Post Maintenance Test for G1101F1407 – Perform Section 6.4 Only of 47.000.84

1R11 Licensed Operator Requalification Program

- CARD 15-26521; Level 3 Actuation While Maintaining RPV Level/Pressure With RCIC and Safety Relief Valves
- CARD 16-20994; Obtain Plant Data and Evaluate Simulator Response to Safety Relief Valve Induced Level Swells
- Reactivity Maneuvering Plan; February 2016 RPA; Revision 0

1R12 Maintenance Effectiveness

- Apparent Cause Evaluation CARD 1620165; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power; Revision 0
- CARD 13-20522; Unusual RBHVAC Damper Alignment Cause Entry into EOPs
- CARD 14-28597; EDG-11 Conditional Probability Performance Criteria Exceeded
- CARD 15-20154; Pump P4400-C002B Division 2 EECW Makeup Pump Exceeded IST Alert Criteria
- CARD 15-20182; P4400 Equipment Trend Evaluation
- CARD 15-21424; #2 HPSV Went Closed and Then Open to 22 Percent Multiple Times
- CARD 15-21427; TS 3.3.1.1, RPS Instrumentation Bases Is Overly Conservative Which Unnecessarily Causes Entry Into Short Duration LCO
- CARD 15-22595; Main Steam Line Radiation Monitor Did Not Produce Hi-Hi Trip Outputs During Surveillance 44.010.028
- CARD 15-25570; Potential Issues with the Timing of the RBHVAC Damper Actuations for the East Train of RBHVAC
- CARD 15-26469; FO 15-02: Leak at Weld at Weldolet for Drain Valve N2103F326
- CARD 15-27179; Evaluate Standby Feed Water System for Maintenance Rule a(1) Status
- CARD 15-27216; G3352F220 Failed to Close
- CARD 15-27239; Could Not Close G3352-F220 from Main Control Room Due to Leading Shielding on the Declutch Lever
- CARD 15-27445; Maintenance Rule Review Against New Performance Criteria
- CARD 15-27626; Evaluate EDG Heat Exchanger Tubes for Potential for Stress Corrosion Cracking
- CARD 16-20156; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power
- CARD 16-20570; NRC Concerns with Maintenance Rule Functional Failure Evaluation for CARD 15-26469
- CARD 16-21194; Predicted Cavitation Damage Downstream of the Min Flow Portion of N2103F307B
- CARD 16-21658; NRC Senior Resident Question on TS 3.3.1.1 Entry When Turbine Bypass Valves Opened on January 6, 2016
- Control Room Logs; February 21, 2015
- Control Room Logs; January 6, 2016
- EF2-PRA-002; Accident Sequence Analysis Notebook; Revision 2
- Equipment Apparent Cause Evaluation CARD 1620165; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power; Revision 0
- ERI/NRC 03-204; The Probability Of High Pressure Melt Ejection-Induced Direct Containment Heating Failure in Boiling Water Reactors with Mark I Design; November 2003
- Event Notification 51755
- Event Notification 51756
- Fermi 2 Operating License and Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report

- Letter from Gary Dupuy, Engineering Support Organization to Jim Matthews, System Engineering-NSSS; Failure Analysis of One Agastat Relay for Fermi 2; January 5, 2016
- NUMARC 93–01; Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants; Revision 4A
- NUREG/CR-6883; The SPAR-H Human Reliability Analysis Method; August 2005
- NUREG/CR-6928; Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants; February 2007
- NUREG-1935; State-of-the-Art Reactor Consequences Analyses (SOARCA) Report; November 2012
- Procedure AOP 20.128.01; Loss of Turbine Building Closed Cooling Water System; Revisions 15 and 16
- Procedure ARP 4D21; Bypass Valve Manual Jacking Not at Zero; Revision 7
- Root Cause Evaluation CARD 15-26472; Forced Outage 15-02; Total Loss of TBCCW Following Heat Exchanger Swap; Revision 0
- System Health Report; N2103 Standby Feedwater; 3rd & 4th Quarter 2015
- System Health Report; P4300 TBCCW; 3rd & 4th Quarter 2015
- System Health Report; T4100 RBHVAC; 3rd & 4th Quarter 2015
- Work Order 43902604; Leak at Weld at Weldolet for Drain Valve

1R13 Maintenance Risk Assessments and Emergent Work Control

- CARD 162–2106; The POD had Two High Risk to Generation Activities Scheduled at the Same Time
- Procedure MOP05; Control of Equipment; Revision 46
- Procedure MOP05–100; Protected Equipment; Revision 0
- Procedure ODE–16; Operations Department Expectation - Risk Assessment and Operation of Equipment Out-of-Service; Revision 2
- Procedure ODE–20; Operations Department Expectation - Protected Equipment; Revision 19
- Risk Management Plan; Calibrate Division 1 EECW Make-Up Tank/Pump Instruments After P4400F124A Replacement
- Risk Management Plan; N6200F077B – Risk Management Plan for Work Request N812140100
- Risk Management Plan; P4500C002A EESW South Pump Motor Replacement
- Risk Management Plan; Perform 44.030.250 RX Water Level (L2) ATWS-RPT Division 2 Functional Test

1R15 Operability Determinations and Functionality Assessments

- CARD 07-26155; HPCI Gear Reducer Bearings
- CARD 09-26991; Numerous Valve Failures During Surveillance Testing
- CARD 14-28479; HPCI Auxiliary Oil Pump Did Not Restart When Tripping HPCI Turbine
- CARD 15-25243; Missed Technical Specification Entry – Division 2 EECW-UHS Safety System Outage July 2015
- CARD 15-27413; Safety Relief Valve Solenoid Cable Deterioration
- CARD 15-27451; Recurring Condition Unexpected Bearing Damage (Wiping) on HPCI High Speed Gearbox Journal Bearings
- CARD 15-27472; HPCI Low Speed Bearings Do Not Meet As Found Acceptance Criteria
- CARD 15-27488; Constant Supports on Increased Frequency Require Engineering Evaluation
- CARD 15-27778; EDG 12 Standby Jacket Coolant Pump Found Not Running During Rounds
- CARD 15-28970; Work Request needed to Reduce Differential Pressure Across the E1100F078 Check Valve

- CARD 15-29087; B3105F031A Jogged Open Unexpectedly During Performance of 44.040.009 Logic Functional Surveillance
- CARD 15-29093; Abnormal Response of B3105F031A During 44.040.009
- CARD 15-29229; E1100F078 Is Unable to Be Stroked from the Main Control Room – Valve Is Currently Closed
- CARD 16-20500; NRC Identified Question Regarding EDG Fuel Oil Storage Room Temperature Below UFSAR Cited Minimum Temperature
- CARD 16-20566; NRC Question on Reportability of CARD 15-25243
- CARD 16-20588; Revision to 27.000.02 Attachment 2 Required
- Design Calculation DC-4953 Volume 1; RHR Complex – Abnormal Operation Damper Lineups; Revision I
- Drawing E-N-0085; Lighting RHR Complex One Line Diagram Details & Notes; Revision AT
- Drawing E-N-0089; Lighting RHR Complex 1st Floor Elevation 590’-0”; Revision N
- Drawing N-2000; RHR Complex Elevations; Revision L
- Drawing N-2006; RHR Complex Grade Floor Plan Center South Area; Revision O
- Drawing N-2113; RHR Complex Ventilation Unit Heater Arrangement Grade Floor Plan Elevation 590’-0” Division I & II; Revision E
- Drawing N-2273; RHR Complex Framing Plan at Elevation 595’-0” Center South Area; Revision AD
- Fermi 2 Plant Technical Specifications
- NUREG 1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Revision 3
- Work Order 38557642; Perform 24.204.06 Division 2 Low Pressure Coolant Injection & Torus Cooling/Spray Pump & Valve Operability Test

<u>1R18 Plant Modifications</u>

- CARD 15-28685; Long Standing Equipment Deficiency Requires Permanent Fix
- CARD 15-28690; Inappropriate Use of the Temporary Modification Process Investigation
- CARD 15-29825; NSRG 4th Quarter Meeting Concern – Temporary Modification Installed Defeating Low Suction Pressure Trip for TBCCW
- CARD 16-20140; NQA – Temporary Modification 15-0032 Operations Contingency Is not Proceduralized
- CARD 16-20498; Fuel Oil Leak from Diesel Fire Pump Fuel Oil Supply Line
- CARD 16-20516; NSRG Concern: Temporary Modification 15-0052 Potentially Increases Risk of TBCCW Pump Damage
- CARD 16-21129; Long Term Strategy for Radwaste Heating, Ventilation, and Air Conditioning
- Procedure 20.128.01; Loss of Turbine Building Closed Cooling Water System; Revision 16
- Procedure ARP 5D13; TBCCW Head Tank Pressure High/Low; Revision 6
- Procedure ARP 5D14; TBCCW Head Tank Level High/Low; Revision 8
- Temporary Modification 09-0021; Block Open the Radwaste Ventilation System, RWHVAC, Building Steam Coil V4100B002, East and West Plenum; Revision 0
- Temporary Modification 10-0053; Block Open the Radwaste Ventilation System, RWHVAC, Building Steam Coil V4100B002, East and West Plenum; Revision 0
- Temporary Modification 15-0032; Radwaste Building Ventilation System Steam Coil Freeze Protection; Revision 0
- Temporary Modification 15-0052; Remove TBCCWS Pump Motor Trips; Revision 0
- Temporary Modification 16-0001; Temporary Fuel Supply Line for Diesel Fire Pump; Revision 0

1R19 Post-Maintenance Testing

- CARD 16-21733; Open & Close Contactors Did Not Meet Pick-up Acceptance Criteria
- CARD 16-22145; Pump Alignment to New Motor Outside Acceptance Criteria per 35.000.237
- CARD 16-22162; P4500C002A Motor Phase Temperatures Reached Higher than Expected Values
- CARD 16-22164; Modine Heater Blowing on Division 1 EESW Pump Motor Causing High Motor Winding Temperatures
- Procedure 24.107.03; Standby Feedwater Pump and Valve Operability and Lineup Verification Test; Revision 41
- Procedure 24.202.08; HPCI Time Response and Pump Operability Test at 1025 PSI; Revision 9
- Procedure 24.208.02; Division 1 EESW and EECW Makeup Pump and Valve Operability Test; Revision 69
- Procedure 24.307.47; Emergency Diesel Generator 13 – Fast Start Followed by Load Reject; Revision 13
- Procedure 24.413.03; Control Room Emergency Filter Monthly Operability Test; Revision 34
- Technical Evaluation TE-E11-08-078; Removal of RHR Complex Pump Room Roof Plugs under LCO 3.0.9; Revision D
- Technical Evaluation TE-P45-16-006; EESW Division 1 Motor Did Not Meet Alignment Guidelines of 35.000.237; Revision 0
- Work Order 35468203; NEIL Required – Disassemble Valve, Inspect and Clean, Rework as Required
- Work Order 35730909; NEIL Required – Disassemble Valve, Inspect and Clean, Rework as Required
- Work Order 37482588; Calibrate Division 1 Control Center Heating, Ventilation, and Air Conditioning Emergency Make-Up & Recirculation Air Temperature Switch
- Work Order 37482717; Replace Division 1 Control Center Heating, Ventilation, and Air Conditioning Equipment Room Return Isolation Damper Solenoid Valve
- Work Order 38571174; Perform 24 Month Preventive Maintenance Tasks per 34.307.001 on Emergency Diesel Generator – 13
- Work Order 43667868; EESW South Pump Failed PI Acceptance Criteria per 35.329.007
- Work Order E419120100; Perform Valve and Actuator Overhaul and Air-Operated Valve Diagnostic Testing

1R22 Surveillance Testing

- American Society of Mechanical Engineers Code for Operation and Maintenance of Nuclear Plants, Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants; 2004 Edition
- CARD 14-25103; IST Program Self-Assessment Deficiencies (TMIS 14-0064)
- CARD 15-20955; Failed Relief Valve Test
- CARD 15-20969; Failed Relief Valve Test
- CARD 15-28134; Unacceptable Visual Examination of Snubber E113146-G17B
- CARD 15-29524; Relief Valve Failed Post Maintenance Test
- CARD 15-29540; IST Program Deficiencies
- CARD 16-20613; 24.204.01 Delayed Due to M&TE Issue
- CARD 16-20614; E1150F017A Failed to Stroke Open During 24.204.01
- CARD 16-20825; NRC Concern – SGTS Surveillances May Not Be Meeting TS SR 3.6.4.3.1 Requirements

- CARD 16-21031; NRC Question Why T4600F406, T4600F420, and T4600F421 Was Not in the IST Scope
- CARD 16-21037; NRC Comments Regarding SGTS Monthly Surveillance
- CARD 16-21042; IST Program Improvement
- CARD 16-21316; NRC Concern – 24.206.01 References Incorrect Technical Specification
- Drawing 6M721-2709; Diagram Standby Gas Treatment and Primary Containment Purge System Reactor Building; Revision AA
- Drawing 6M721-5829; Classification Boundary Drawing Stand-By Gas Treatment System ISI-T46-1; Revision F
- Drawing M-5709-1; Reactor Core Isolation Cooling Functional Operating Sketch; Revision AM
- Fermi 2 Inservice Testing Program for Pumps and Valves, Fermi 2 Third 10 Year Interval, Part 5: IST Scope Table; Revision 0
- Fermi 2 Standby Gas Treatment System Design Basis Document T46-00; Revision B
- Fermi 2 Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- Procedure 23.404, Standby Gas Treatment System, Revision 54
- Procedure 24.204.01; Division 1 Low Pressure Coolant Injection and Suppression Pool Cooling/Spray Pump and Valve Operability Test; Revision 75
- Procedure 24.206.01; RCIC System Pump and Valve Operability Test; Revision 79
- Procedure 24.307.15; Emergency Diesel Generator 12 – Start and Load Test; Revision 58
- Procedure 24.404.02; Division 1 SGTS Filter and Secondary Containment Isolation Damper Operability Test; Revision 43
- Procedure 24.404.03; Standby Gas Treatment System Valve Operability Test; Revision 41
- Procedure 24.404.04; Division 2 SGTS Filter and Secondary Containment Isolation Damper Operability Test; Revision 42
- Work Order 38565119; Perform 24.404.02 Section 5.1 Division 1 SGTS Filter Operability
- Work Order 38572277; Perform 24.404.04 Section 5.1 Division 2 SGTS Filter Operability
- Work Order 42286055; Perform 24.307.15 Section 5.1 EDG 12 Start and Load Test – Slow Start

4OA1 Performance Indicator Verification

- CARD 15-21383; NRC Performance Indicator for Unplanned Scrams
- CARD 16-20565; NRC Unresolved Item for Unplanned Scram Performance Indicator (URI 2015001-03)
- NEI 99 02; Regulatory Assessment Performance Indicator Guideline; Revision 7

4OA2 Problem Identification and Resolution

- 3rd Quarter Station Trend Report
- 4th Quarter Station Trend Report
- Apparent Cause Evaluation CARD 15-21742; Operations Procedure Implementation Requirements and Commitments Contained in Operations Department Expectations Is Contrary to the Quality Assurance Program; April 9, 2015
- Apparent Cause Evaluation CARD 15-25133 “Managers Do Not Properly Assess the Operational Impact of Some Degraded Conditions”; Revision 1; September 16, 2015
- Audit Report 15-0103; Quality Assurance Audit of the Operations Program and Emergency Operation Procedures; March 23, 2015
- CARD 14-23397; RFPs Seem Slow to Respond to Level and Power Changes
- CARD 14-23404; Response Characteristics from the Reactor Feedpump Tuning Seems to Respond Slowly to Reactor Water Level Changes

- CARD 15-21462; NQA Audit Recommendation: Operations Fundamentals/Conduct of Operations – Improvement Recommendations
- CARD 15-21742; NQA Audit Finding: Operations Procedure Implementation Requirements and Commitments Contained in Operations Department Expectations Is Contrary to the Quality Assurance Program
- CARD 15-24903; Adverse Trend Maintenance Observation Performance
- CARD 15-24904; Trend Maintenance Planning Work Package Quality
- CARD 15-24971; PI USA KPI 1.12 – Self-Identification Rate – June Declining Trend
- CARD 15-25133; Managers Do Not Properly Assess the Operational Impact of Some Degraded Conditions
- CARD 15-25305; Declining Trend in HU Event Free Day (EFD) Resets for 3Q2015
- CARD 15-25329; NQA Audit Concern – Questionable Use of TS 3.0.2
- CARD 15-25423; Potential Emerging Trend Identified as a Result of 2nd Quarter 2015 Maintenance Rework Program Trend Analysis
- CARD 15-25540; USA KPI OPS-GEN-CLKRST – Total Clock Resets – RED for July 2015
- CARD 15-25825; Adverse Trend in Foreign Material Exclusion
- CARD 15-26192; Nuclear Safety Culture 1st Half 2015 Senior Lead Team Review
- CARD 15-26426; NQA Audit Deficiency – Adverse Trend Identified with CTG Equipment Reliability
- CARD 15-27061; Work Performed Without Protection
- CARD 15-27242; Component Removed Without Adequate Protection
- CARD 15-27332; USA KPI OPS-GEN-CLEARTAG – Tagging Is Red for September 2015
- CARD 15-27336; RF 17 Adverse Station Trend in Protective Tagging
- CARD 15-27350; Error with Implementation of Major Revision to Work Order 38570311
- CARD 15-28210 Potential Emerging Trend: In-Process Rework due to Weld Quality
- CARD 15-28610; USA KI MAINT – TECH-FMEPROG – FME Program Effectiveness Rated Red for October 2015
- CARD 15-28680; Continued Trend in Foreign Material Found in Discharged Irradiated Fuel
- CARD 15-28681; Potential Trend in Risks to Defect Free Operation in Cycle 18
- CARD 15-28716; USA KPI OPS-GEN-CLEARTAG – Tagging is Red for October 2015
- CARD 15-28718; USA KPI OPS TECH – REACTMGT – Boiling Water Reactor Reactivity Management Rated RED for October 2015
- CARD 15-28796; FME Incident – Crimp Rubber Released from Crimping Tool
- CARD 15-29138; NRC Residents 3Q15 Exit Observation – Trend Analysis Program Effectiveness (System Engineering)
- CARD 15-30220; 10CFR50.65(a)(3) Assessment Recommendation: Evaluate Gaps in Incorporating OE into the PM Program
- CARD 16-20925; NRC Questions Concerning Closed CARD 15-25133 “Managers Do Not Properly Assess the Operational Impact of Some Degraded Conditions”
- Common Cause Analysis CARD 15-21017; Degrading Trend Local Power Range Monitors; July 1, 2015
- Common Cause Analysis CARD 15-27336; RF 17 Adverse Trend in Protective Tagging; January 4, 2016
- Common Cause Analysis CARD 15-29308; NQA Audit Finding: Repeat Performance Errors/Events During RF17 Refueling Activities; December 16, 2015
- Common Cause Analysis CARD 15-29359; RF 17 Trend: Equipment Issues with Switchgear, Breakers, and Motor Control Centers; November 25, 2015
- Common Cause Analysis Report CARD15-27336; RF 17 Adverse Station Trend in Protective Tagging; January 13, 2016
- NQA Audit Report 16-0102; Evaluation and Corrective Action and Operating Experience Programs

- Procedure FBP-80; Fermi 2 Business Practice - Unit Condition and Operational Residual Risk; Revision 3
- Procedure MQA15; Quality Assurance Conduct Manual Chapter 15 – Apparent Cause Evaluations; Revision 17
- Procedure ODE-6; Operations Department Expectation - Operator Challenges; Revision 15

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

- Apparent Cause Evaluation CARD 15-26521; Level 3 Actuation While Maintaining RPV Level/Pressure With RCIC and Safety Relief Valves; Revision 0
- Apparent Cause Evaluation CARD 16-20165; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power; Revision 0
- CARD 15-21424; #2 HPSV Went Closed and Then Open to 22 Percent Multiple Times
- CARD 15-21427; TS 3.3.1.1, RPS Instrumentation Bases Is Overly Conservative Which Unnecessarily Causes Entry Into Short Duration LCO
- CARD 15-25570; Potential Issues with the Timing of the RBHVAC Damper Actuations for the East Train of RBHVAC
- CARD 15-26521; Level 3 Actuation While Maintaining RPV Level/Pressure With RCIC and Safety Relief Valves
- CARD 15-26653; Forced Outage 15-02 RCIC Assessment
- CARD 16-20156; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power
- CARD 16-20564; NRC Senior Resident Issues/Questions Associated With LER 2015-006
- CARD 16-20994; Obtain Plant Data and Evaluate Simulator Response to Safety Relief Valve Induced Level Swells
- CARD 16-21249; NRC Question on LER 2015-005
- CARD 16-21658; NRC Senior Resident Question on TS 3.3.1.1 Entry When Turbine Bypass Valves Opened on January 6, 2016
- Control Room Logs; February 21, 2015
- Control Room Logs; January 6, 2016
- Control Room Logs; September 13 through 15, 2015
- Emergency Operating Procedure 29.100.01 SH 1, “RPV Control,” Revision 14
- Equipment Apparent Cause Evaluation CARD 13-20522; Unusual RBHVAC Damper Alignment Caused Entry into EOP’s; Revision 1
- Equipment Apparent Cause Evaluation CARD 1620165; #1 HP Stop Valve Drifted to 25 Percent Open from 100 Percent Open at Power; Revision 0
- Event Notification 51391; original and 3 updates
- Event Notification 51755; original and 1 update
- Event Notification 51756; original and 1 update
- Fermi 2 Technical Specifications
- Fermi 2 Updated Final Safety Analysis Report
- LER 05000341/2015-005-00; Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction
- LER 05000341/2015-005-01; Secondary Containment Declared Inoperable Due to RBHVAC Damper Malfunction; Supplement 1
- LER 05000341/2015–006–00; Reactor Scram Due to Loss of Turbine Building Closed Cooling Water
- LER 05000341/2015-008-00; Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valve

- LER 05000341/2016-001-00; Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Reactor Protection System Functions Considered Inoperable Due to Open Turbine Bypass Valves
- NUREG 1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 3
- NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980
- NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability," January 1983
- Performance Improvement & Learning Action Request CARD 15-26521; October 5 through October 12, 2015
- System Health Report; T4100 RBHVAC; 3rd Quarter 2015

LIST OF ACRONYMS USED

°F	Degrees Fahrenheit
ΔCDF	Delta Core Damage Frequency
ΔLERF	Delta Large Early Release Frequency
10 CFR	Title 10 of the *Code of Federal Regulations*
CAP	Corrective Action Program
CFR	Code of Federal Regulations
ADAMS	Agencywide Document Access and Management System
ATWS	Anticipated Transient Without Scram
CARD	Condition Assessment Resolution Document
CCDP	Conditional Core Damage Probability
CLERP	Conditional Large Early Release Probability
CTG	Combustion Turbine Generator
EDG	Emergency Diesel Generator
EDP	Engineering Design Package
EECW	Emergency Equipment Cooling Water
EESW	Emergency Equipment Service Water
FOST	Fuel Oil Storage Tank
GSW	General Service Water
HEP	Human Error Probability
HEPA	High Efficiency Particulate Air
HPCI	High Pressure Coolant Injection
HPCV	High Pressure Control Valve
HPSV	High Pressure Stop Valve
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LLRT	Local Leakage Rate Testing
MSIV	Main Steam Line Isolation Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
psig	Pounds-Per-Square-Inch Gauge
RBHVAC	Reactor Building Heating, Ventilation, and Air Conditioning
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRHVAC	Residual Heat Removal Heating, Ventilation, and Air Conditioning
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SBO	Station Blackout
SCC	Stress Corrosion Cracking
SDP	Significance Determination Process
SGT	Standby Gas Treatment
SGTS	Standby Gas Treatment System
SOARCA	State-of-the-Art Reactor Consequences Analyses

SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirement
SRA	Senior Risk Analyst
SSC	Structure, System, and/or Component
TBCCW	Turbine Building Closed Cooling Water
TMI	Three Mile Island
TS	Technical Specification(s)
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item

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Sincerely,

/RA/

Billy Dickson, Chief
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