UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TX 76011-4511

August 14, 2014

Kevin Mulligan
Site Vice President Operations
Entergy Operations, Inc.
Grand Gulf Nuclear Station
P.O. Box 756
Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION – NRC INSPECTION REPORT 05000416/2014003

Dear Mr. Mulligan:

On June 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Grand Gulf Nuclear Station, Unit 1. On July 17, 2014, the NRC inspectors discussed the results of this inspection with you and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented one finding of very low safety significance (Green) in this report. This finding involved a violation of NRC requirements. Further, inspectors documented a licensee-identified violation, which was determined to be of very low safety significance, in this report. The NRC is treating these violations as non-cited violations consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspectors at the Grand Gulf Nuclear Station.

If you disagree with a cross-cutting aspect assignment 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 IV; and the NRC resident inspectors at the Grand Gulf Nuclear Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” 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 (PARS) component of the NRC’s Agencywide Documents 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/

Don Allen, Branch Chief
Project Branch C
Division of Reactor Projects

Docket No.: 50-416
License No.: NPF-29

Enclosure:
Inspection Report 05000416/2014003
w/Attachment: Supplemental Information

Electronic Distribution to Grand Gulf Nuclear Station

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000416
License:	NPF-29
Report:	05000416/2014003
Licensee:	Entergy Operations, Inc.
Facility:	Grand Gulf Nuclear Station, Unit 1
Location:	7003 Baldhill Road Port Gibson, MS 39150
Dates:	April 1 through June 30, 2014
Inspectors:	R. Smith, Senior Resident Inspector B. Rice, Senior Resident Inspector
Approved By:	Don Allen Chief, Project Branch C Division of Reactor Projects

SUMMARY

IR 05000416/2014003; 04/01/2014 – 06/30/2014; Grand Gulf Nuclear Station; Operability Determinations and Functionality

The inspection activities described in this report were performed between April 1 and June 30, 2014, by the resident inspectors at the Grand Gulf Nuclear Station. One finding of very low safety significance (Green) is documented in this report. This finding involved a violation of Nuclear Regulatory Commission requirements. Additionally, NRC inspectors documented in this report one licensee-identified violation of very low safety significance. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, “Significance Determination Process.” Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, “Components Within the Cross-Cutting Areas.” Violations of Nuclear Regulatory Commission requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, “Reactor Oversight Process.”

Cornerstone: Mitigating Systems

- Green. The inspectors reviewed a self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the failure to promptly reinstate an essential-critical preventative maintenance task after they identified that it had been improperly retired. Specifically, the licensee did not reinstate and complete Preventive Maintenance Task PMRQ 50024451-04 prior to the failure of diode CR6 on May 21, 2013, which resulted in the division 2 diesel generator failing its monthly functional test and the licensee declaring it inoperable. The operators secured the diesel generator and wrote Condition Report CR-GGN-2013-03423 documenting the issue. The licensee performed a Failure Modes Analysis evaluation to determine the possible cause for the observed conditions. During troubleshooting efforts, the licensee addressed the potential transformer (PT1), the potential transformer’s fuses, inline fuses, and the voltage regulator circuit bridge diodes. The Failure Modes Analysis evaluation showed that all of the listed components were in satisfactory condition, except that one of the six diodes used in the voltage regulator circuit diode bridge, Diode CR6, had shorted. The licensee replaced the shorted diode and returned the diesel generator to operational status on May 24, 2013.

  The licensee’s failure to implement PMRQ 50024451-04 after discovering it had been improperly retired was a performance deficiency, in that it represented a failure to promptly correct a condition adverse to quality. The performance deficiency is more than minor and therefore a finding because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone’s objective of ensuring the availability, reliability, and capability of systems that respond to prevent undesirable consequences. Specifically, Diode CR6 remained in the voltage regulator circuit bridge until it failed, thereby triggering a failure of the division 2 diesel generator, which caused the diesel generator to be inoperable. Using NRC Inspection Manual Chapter 0609, Attachment 4, “Initial Characterization of Findings,” dated June 19, 2012, the inspectors determined that the issue affected the Mitigating Systems Cornerstone. In accordance with NRC Inspection Manual Chapter 0609, Appendix A, “The Significance Determination Process (SDP) for Findings at Power,” dated June 19, 2012, the inspectors determined that the issue required a detailed risk evaluation because the finding represents

an actual loss of function of a single train for greater than its Technical Specification allowed outage time. The total exposure period was 15 days. The allowed outage time was 14 days. The senior reactor analyst performed a detailed risk analysis and determined the delta-CDF was less than 1.0×10^{-6} and the delta-LERF was less than 1.0×10^{-7}, therefore this finding was of very low safety significance (Green). The apparent cause of this finding was that the licensee did not recognize the risk of not performing the preventive maintenance task, which led to the decision to exclude the task from the division 2 allowed outage time schedule. Therefore, the finding has a cross-cutting aspect in the human performance area associated with conservative bias because the licensee did not use decision-making practices that emphasize prudent choices over those that are simply allowable [H.14]. (Section 1R15)

Licensee-Identified Violations

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

PLANT STATUS

The Grand Gulf Nuclear Station began the inspection period at approximately 20 percent thermal power. The operators continued in power ascension activities until 100 percent thermal power was reached on April 19, 2014.

On April 23, 2014, the operators reduced power to 87 percent thermal power due to elevated vibration readings on heater drain pump B.

On April 27, 2014, the operators further reduced power to 70 percent thermal power due to the loss of group two cooling on the main transformer A.

On April 28, 2014, the operators reduced power to 52 percent thermal power to remove heater drain pump B from service and to place heater drain pump A in service. The station also restored group two cooling on the main transformer A. The operators then commenced power ascension activities and reached 100 percent thermal power on May 4, 2014.

On June 6, 2014, the operators reduced power to 85 percent thermal power to perform a monthly control rod exercise. Upon completion, they commenced power ascension activities and reached 100 percent thermal power on June 7, 2014.

On June 20, 2014, the operators commenced a planned down power to 42 percent thermal power for a control rod sequence exchange, and after completion, they continued power ascension activities through the end of the inspection period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Summer Readiness for Offsite and Alternate AC Power Systems

a. Inspection Scope

On May 15, 2014, the inspectors completed an inspection of the station’s off-site and alternate-ac power systems. The inspectors inspected the material condition of these systems, including transformers and other switchyard equipment to verify that plant features and procedures were appropriate for operation and continued availability of off-site and alternate-ac power systems. The inspectors reviewed outstanding work orders and open condition reports for these systems. The inspectors walked down the switchyard to observe the material condition of equipment providing off-site power sources. The inspectors assessed corrective actions for identified degraded conditions and verified that the licensee had considered the degraded conditions in its risk evaluations and had established appropriate compensatory measures. The inspectors verified that the licensee’s procedures included appropriate measures to monitor and maintain availability and reliability of the off-site and alternate-ac power systems.

These activities constituted one sample of summer readiness of off-site and alternate-ac power systems, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

.2 Readiness to Cope with External Flooding

a. Inspection Scope

On April 13, 2014, the inspectors completed an inspection of the station's readiness to cope with external flooding. After reviewing the licensee's flooding analysis, the inspectors chose five plant areas that were susceptible to flooding:

- Culvert 1
- Culvert 8A
- Culvert 9A
- Diesel generator breezeway
- Control building and auxiliary building roofs

The inspectors reviewed plant design features and licensee procedures for coping with flooding. The inspectors walked down the selected areas to inspect the design features, including the material condition of seals, drains, and flood barriers. The inspectors evaluated whether credited operator actions could be successfully accomplished.

These activities constituted one sample of readiness to cope with external flooding, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdown

a. Inspection Scope

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

- April 9, 2014, standby gas treatment system A following a surveillance

- April 28, 2014, control room air conditioner A and standby fresh air A while maintenance was being performed on the train B equipment

- May 13, 2014, high pressure core spray system with the reactor core isolation cooling system in a maintenance outage

- June 25, 2014, division 1 diesel generator during division 2 diesel generator scheduled maintenance

The inspectors reviewed the licensee’s procedures and system design information to determine the correct lineup for the systems. They visually verified that critical portions of the systems or trains were correctly aligned for the existing plant configuration.

These activities constituted four partial system walk-down samples as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

.2 Complete Walkdown

a. Inspection Scope

On April 16, 2014, the inspectors performed a complete system walk-down inspection of the reactor core isolation cooling system (RCIC). The inspectors reviewed the licensee’s procedures and system design information to determine the correct RCIC system lineup for the existing plant configuration. The inspectors also reviewed outstanding work orders, open condition reports, and other open items tracked by the licensee’s operations and engineering departments. The inspectors then visually verified that the system was correctly aligned for the existing plant configuration.

These activities constituted one complete system walk-down sample, as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Inspection

a. Inspection Scope

The inspectors evaluated the licensee’s fire protection program for operational status and material condition. The inspectors focused their inspection on five plant areas important to safety:

- April 9, 2014, division 1 electrical switch gear room 1A309
- April 9, 2014, division 2 electrical switch gear room 1A308
- May 6, 2014, division 1 electrical switch gear room 1A219
- May 6, 2014, division 2 electrical switch gear room 1A221
- June 24, 2014, division 2 diesel generator room 1D303

For each area, the inspectors evaluated the fire plan against defined hazards and defense-in-depth features in the licensee’s fire protection program. The inspectors

evaluated control of transient combustibles and ignition sources, fire detection and suppression systems, manual firefighting equipment and capability, passive fire protection features, and compensatory measures for degraded conditions.

These activities constituted five quarterly inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On April 24, 2014, the inspectors completed an inspection of the station's ability to mitigate flooding due to internal causes. After reviewing the licensee's flooding analysis, the inspectors chose four plant areas containing risk-significant structures, systems, and components that were susceptible to flooding. During Refueling Outage RF18, which was completed in the spring of 2012, the station installed a condensate full flow filtration (CFFF) system in the turbine building. The inspectors evaluated the impact that the addition of the CFFF system to the turbine building had on the station's internal flooding analysis. The inspectors identified safety-related valves and instrumentation that were in the vicinity of the CFFF piping. The areas assessed were:

- 166 foot elevation of the turbine building
- 133 foot elevation of the turbine building
- 113 foot elevation of the turbine building
- 93 foot elevation of the turbine building

The inspectors reviewed plant design features and licensee procedures for coping with internal flooding. The inspectors walked down the selected areas to inspect the design features, including the material condition of seals, drains, and flood barriers. The inspectors evaluated whether operator actions credited for flood mitigation could be successfully accomplished.

These activities constitute completion of one flood protection measures sample, as defined in Inspection Procedure 71111.06.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11)

.1 Review of Licensed Operator Requalification

a. Inspection Scope

On April 23, 2014, the inspectors observed a crew of licensed operators in the plant's simulator during requalification "as left" evaluation. The inspectors assessed the performance of the operators and the evaluators' critique of their performance. The inspectors assessed the following areas:

- Licensed operator performance
- The ability of the licensee to administer evaluations
- The modeling and performance of the control room simulator
- The quality of post-scenario critiques
- Follow-up actions taken by the licensee for identified discrepancies

These activities constitute completion of one quarterly licensed operator requalification program sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

.2 Review of Licensed Operator Performance

a. Inspection Scope

On April 1 and 2, 2014, the inspectors observed the performance of on-shift licensed operators in the plant's main control room. At the time of the observations, the plant was in a period of heightened activity due to plant startup following a reactor scram. The inspectors observed the operators' performance of the following activities:

- On April 1, 2014, the inspectors observed the operating crew operating the turbine at 1800 revolutions per minute in preparation for synchronizing the main generator to the grid.

- On April 2, 2014, the inspectors observed the coordination of local actions to open valve 1N21F009B, the feedwater heater 6B discharge valve that would not open automatically from the main control room. This was to allow the operating crew to shift reactor water level control from startup level control to master level control.

- On April 2, 2014, the inspectors observed the operating crew placing feedwater level control into master level control and withdrawing control rods to increase power to 26 percent rated thermal power in preparation for recirculation pump upshift, including a reactivity pre-job brief.

- On April 2, 2014, the inspectors observed the operating crew upshift reactor recirculation pumps to fast speed, including raising reactor water level to approximately 40 inches narrow range in anticipation of level decrease on pump upshift. During the upshift of recirculation pumps, the inspectors observed the crew respond to HI-HI level in the 6A feedwater heater.

In addition, the inspectors assessed the operators' adherence to plant procedures, including conduct of operations procedure and other operations department policies.

These activities constitute completion of one quarterly licensed operator performance sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed two instances of degraded performance or condition of safety-related structures, systems, and components (SSCs):

- April 16, 2014, unsuccessful draw down test of the standby gas treatment system

- April 22, 2014, local leak rate test failures of an isolation valve associated with the containment isolation system

The inspectors reviewed the extent of condition of possible common cause SSC failures and evaluated the adequacy of the licensee's corrective actions. The inspectors reviewed the licensee's work practices to evaluate whether these may have played a role in the degradation of the SSCs. The inspectors assessed the licensee's characterization of the degradation in accordance with 10 CFR 50.65 (the Maintenance Rule), and verified that the licensee was appropriately tracking degraded performance and conditions in accordance with the Maintenance Rule.

These activities constituted completion of two maintenance effectiveness samples, as defined in Inspection Procedure 71111.12.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed two risk assessments performed by the licensee prior to changes in plant configuration and the risk management actions taken by the licensee in response to elevated risk:

- May 12-15, 2014, reactor core isolation cooling system outage
- May 19-23, 2014, ESF 12 transformer maintenance

The inspectors verified that these risk assessments were performed timely and in accordance with the requirements of 10 CFR 50.65 (the Maintenance Rule) and plant procedures. The inspectors reviewed the accuracy and completeness of the licensee's risk assessments and verified that the licensee implemented appropriate risk management actions based on the result of the assessments.

The inspectors also observed portions of three emergent work activities and severe weather in the area that had the potential to cause an initiating event or to affect the functional capability of mitigating systems:

- April 2, 2014, with increased risk due to severe weather in the area, the licensee entered their off-normal procedure for severe weather and took appropriate actions to ensure the site would be minimally affected due to thunderstorms, high winds, and a tornado watch in the area.

- April 14, 2014, with increased risk due to severe weather in the area, the licensee entered their off-normal procedure for severe weather and took appropriate actions to ensure the site would be minimally affected due to thunderstorms, high winds, and a tornado watch in the area.

- April 28-29, 2014, with increased risk due to severe weather in the area, the licensee entered their off-normal procedure for severe weather and took appropriate actions to ensure the site would be minimally affected due to thunderstorms, high winds, and a tornado watch in the area.

The inspectors verified that the licensee appropriately developed and followed a work plan for these activities. The inspectors verified that the licensee took precautions to minimize the impact of the work activities on unaffected structures, systems, and components (SSCs).

These activities constitute completion of five maintenance risk assessments and emergent work control inspection samples, as defined in Inspection Procedure 71111.13.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed four operability determinations that the licensee performed for degraded or nonconforming SSCs:

- April 9, 2014, operability determination of standby service water tower A, Condition Report CR-GGN-2014-03320

- May 7, 2014, operability determination of primary and secondary isolation valves in the condensate transfer system, Condition Report CR-GGN-2014-03960

- May 12, 2014, operability determination for an incorrectly sealed drywell electrical penetration, Condition Report CR-GGN-2014-1214

- May 15, 2014, operability determination of RCIC following over-speed testing, Condition Report CR-GGN-2014-04120

The inspectors reviewed the timeliness and technical adequacy of the licensee's evaluations. Where the licensee determined the degraded SSC to be operable, the inspectors verified that the licensee's compensatory measures were appropriate to provide reasonable assurance of operability. The inspectors verified that the licensee had considered the effect of other degraded conditions on the operability of the degraded SSC.

These activities constitute completion of four operability and functionality review samples, as defined in Inspection Procedure 71111.15.

The inspectors also reviewed Condition Report CR-GGN-2013-03423 as a follow-up inspection to a sample that was documented in NRC Inspection Report 05000416/2013003. The subject of the condition report was the failure of a division 2 diesel generator voltage regulator diode. The finding from this review is documented below.

b. Findings

Introduction. The inspectors reviewed a self-revealing Green non-cited violation of Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly reinstate an essential-critical preventative maintenance (PM) task after the licensee identified that it had been improperly retired. Specifically, the licensee did not reinstate and complete PM Task PMRQ 50024451-04 prior to the failure of Diode CR6 on May 21, 2013, which resulted in the division 2 diesel generator failing its monthly functional test and the licensee declaring it inoperable.

Description. On May 21, 2013, during the division 2 standby diesel generator monthly surveillance test per Procedure 06-OP-1P75-M-0002, "Standby Diesel Generator (SDG) 12 Functional Test," Revision 133, an 'UNDERFREQUENCY' alarm sounded concurrently with a drop in indicated voltage (from approximately 4220 Volts to approximately 2100 Volts) as seen on the division 2 incoming voltmeter and the division 2 diesel generator AC voltage indicator. This occurred shortly after raising incoming voltage to approximately 50 Volts above running voltage. The operators secured the diesel generator and wrote Condition Report CR-GGN-2013-03423 documenting the issue.

The licensee performed a Failure Modes Analysis (FMA) evaluation to determine the possible cause for the observed conditions. During troubleshooting efforts, the licensee addressed the potential transformer (PT1), the potential transformer's fuses, inline fuses, and the voltage regulator circuit bridge diodes. The FMA evaluation showed that all of the listed components were in satisfactory condition, with the exception of one of the

six diodes used in the voltage regulator circuit diode bridge Diode, CR6, had shorted. The licensee replaced the shorted diode and returned the diesel generator to operational status on May 24, 2013.

During the inspectors' review of this issue, they found the licensee had experienced similar issues with degraded diodes on the voltage regulator circuit as described in Condition Report CR-GGN-2002-02384. Based on that condition report, the licensee developed a preventative maintenance strategy to begin testing the diodes on all three divisions of diesel generators and to replace any suspect components prior to causing a loss of excitation event.

The inspectors also reviewed Condition Report CR-GGN-2012-10283, which the licensee originated on August 29, 2012. In this condition report, the licensee described an issue in which PM Task PMRQ 50024451-04, used to test the diodes, was retired in 2009 due to the PM task being incorrectly categorized as non-critical. The operability determination for Condition Report CR-GGN-2012-10283 stated the late date of the reinstated PM task, including a 25 percent grace period, was October 29, 2012. The licensee completed actions to administratively reinstate the PM task on October 31, 2012; however, the licensee did not schedule or complete the PM task during the division 2 allowed outage time maintenance period scheduled for October 29, 2012, to November 7, 2012. Furthermore, the licensee did not schedule or complete the PM task prior to the diode failure on May 21, 2013.

The inspectors also reviewed the surveillance history of the diesel generator and determined the following:

- April 25, 2013, – The division 2 diesel generator successfully completed the monthly surveillance run.

- May 21, 2013, – The division 2 diesel generator failed its surveillance due to a failed diode in the voltage regulator circuitry, and the licensee declared it inoperable.

- May 24, 2013, –The licensee replaced the diode, the division 2 diesel generator successfully completed its surveillance test, and the licensee declared it operable.

Analysis. The licensee's failure to implement PMRQ 50024451-04 after discovering it had been improperly retired was a performance deficiency, in that it represented a failure to promptly correct a condition adverse to quality. The performance deficiency is more than minor and therefore a finding because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to prevent undesirable consequences. Specifically, Diode CR6 remained in the voltage regulator circuit bridge until it failed, thereby triggering a failure of the division 2 diesel generator, which caused the diesel generator to be inoperable. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, the inspectors determined that the issue affected the Mitigating Systems Cornerstone. In accordance with NRC Inspection Manual

Chapter 0609, Appendix A, “The Significance Determination Process (SDP) for Findings at Power,” dated June 19, 2012, the inspectors determined that the issue required a detailed risk evaluation because the finding represents an actual loss of function of a single train for greater than its Technical Specification allowed outage time. The senior reactor analyst performed a detailed analysis. The total exposure period was 15 days. The allowed outage time was 14 days.

For the internal events portion, the analyst made the following influential assumptions:

1. On May 21, 2013, the division 2 emergency diesel generator failed approximately 10 minutes after starting. The failure was treated as a “Failure to Start” because it occurred in the first hour of operation.

2. The analyst determined that only the loss of offsite power sequences were affected by the performance deficiency. Therefore, the analyst only solved the loss of offsite power sequences.

3. The total exposure period was 15 days. The analyst used an exposure time of “T/2 + repair time,” consistent with the “Risk Assessment of Operational Events (RASP) Handbook,” Volume 1, “External Events,” Revision 2, Section 2.4, which stated:

    > For a failure that could have occurred at any time since the component was last operated (e.g., time of actual failure cannot be determined due to the nature of the failure mechanism), the exposure time (*T*) is equal to one-half of the time period since the last successful functional operation of the component (*T/2*) plus repair time.

    The last successful operation of the component was on April 25, 2013, when the licensee conducted a 24-hour run of the diesel generator. The failure date was May 21, 2013. The T exposure period was 26 days. The T/2 exposure period was 26/2 = 13 days. The repair time was an additional 2 days. Thus, the T/2 plus repair time period was 13 + 2 = 15 days.

4. The analyst assumed that the diode failure made the division 2 emergency diesel generator non-functional and non-recoverable. However, if a failure of either of the division 1 or division 3 emergency diesel generators occurred, these failures could be recovered.

5. The analyst allowed the normal emergency diesel generator recovery events to occur when either (or both) the failure of the division 1 and/or the division 3 emergency diesel generators appeared in the cutsets. The SPAR model assumed that operators would only attempt to recover one emergency diesel generator. As long as the division 1 and/or division 3 emergency diesel generators were also failed, then one of these diesels could be the recovered diesel. The analyst could not justify recovery of the division 2 emergency diesel generator within the 24-hour probabilistic risk assessment mission time. The licensee used over 2 days to troubleshoot and repair the circuit.

6. The analyst ruled out additional consideration of common cause failures and set the basic event for the division 2 emergency diesel generator failure to start

(EPS-DGN-FS-DGB) to a probability of 1.0. This allowed the nominal common cause failure probabilities to occur. The common cause events of interest included failure of the other emergency diesel generators because of the same proximate cause within the first 24 hours. The division 3 emergency diesel generator was of a different design (included different subcomponents) and was not vulnerable to the same common cause failure mechanism. For the division 1 emergency diesel generator, the licensee had completed several surveillance tests, since the noted division 2 failure, and had accumulated approximately 37 hours of run time. The failure mechanism did not surface. In addition, the licensee had completed the periodic diode checks on this emergency diesel generator consistent with their original preventive maintenance program.

Note: Had common cause remained a concern, the analyst could have used the True function, which would have increased the common cause failure probability for the remaining diesel generators by approximately a factor of 100.

Quantification

1. The analyst used the NRC's Standardized Plant Analysis Risk (SPAR) Model for Grand Gulf, Revision 8.22, with a truncation limit of 1E-11. The analyst assumed average failure rates as well as average test and maintenance for all non-affected components.

2. The analyst took the following steps to isolate the cutsets into two groups to allow recovery of the division 1 and 3 emergency diesel generators, but not the division 2 emergency diesel generators.

    a. The analyst solved the SPAR model, assuming that the division 2 emergency diesel generator failed.

    b. The analyst used the "slice" function to isolate the cutsets that included division 1 and division 3 failures. The analyst allowed the normal emergency diesel generator recoveries to occur for these cutsets. The conditional core damage probability (CCDP) for this set of cutsets was 1.3E-5. This assumed an entire year of exposure. Considering the 15-day exposure period, the CCDP = 1.3E-5 * 15/365 = 5.3E-7.

    c. The analyst inverted this set of cutsets. The resultant cutsets included division 2 diesel generator failures but not division 1 or 3 emergency diesel generator failures. This also included other cutsets where none of the emergency diesel generators failed. The analyst allowed these cutsets to remain in the group, which was conservative.

    d. The 30-minute, 1-hour, 4-hour, and 8-hour diesel generator recoveries appeared in the dominant cutsets. To adjust the cutsets to remove recovery credit, the analyst would normally multiply each cutset by 1/(applicable non-recovery value). The 8-hour non-recovery value (0.298) was the most conservative to use for this purpose, 1/(8-hour non-recovery) = 3.4. To simplify the calculation, the analyst multiplied all of the applicable cutsets by this factor, which was very

conservative. The resultant CCDP for the 15-day exposure period was: CCDP = 5.1E-6 * 15/365 * 3.4 = 2.1E-7.

e. The total CCDP for both groups of cutsets was 5.3E-7 + 2.1E-7 = 7.4E-7.

3. The nominal case CCDP for the 15-day exposure period was:
1.4E-6 * 15/365 = 5.8E-8.

4. The incremental CCDP (delta-core damage frequency [CDF]) for internal events was: 7.4E-7 – 5.8E-8 = 6.8E-7/year.

External Events. To identify the external event loss of offsite power initiators, the analyst reviewed the "Grand Gulf Nuclear Station Individual Plant Examination of External Events (IPEEE)," dated November 15, 1995. The IPEEE specified that the 1975 standard review plan criteria were met for high winds, floods, transportation accidents, and nearby facility accidents, so those events were not considered further. The weather related loss of offsite power initiator was already included in the SPAR model. The remaining accident initiators included seismic and fire.

Seismic. The analyst performed a simplified bounding analysis to address seismic contributors. The analyst referenced the NRC's "Risk Assessment of Operational Events Handbook," Volume 2, "External Events," Revision 1.01, to determine the seismic induced loss of offsite power initiating event frequency. The value was included in Table 1, "Frequencies of Seismically-Induced LOOP Events," which was 2.4E-5/year. Seismic induced loss of offsite power events are not considered recoverable.
The analyst included the following bounding assumptions to determine the delta-CDF for seismic initiators:

- Seismic Initiating event frequency = 2.4E-5/year
- Set grid related loss of offsite power to 1.0.
- Set all offsite power non-recovery probabilities to 1.0.
- Set all emergency diesel generator non-recovery probabilities to 1.0 (very conservative division 1 and three diesels were recoverable).

The analyst solved only the grid related loss of offsite power sequences. The resultant CDF was: 2.5E-5/year * 3.9E-3 * 15/365 = 4E-9/year. This bounded the delta-CDF. Therefore, the delta-CDF was less than 4E-9/year.

Fires. The fire events of interest included those that could initiate a loss of offsite power. The licensee's IPEEE screened out most fire areas as being non-risk significant. The IPEEE identified the following potentially important fire compartments where a fire could result in a loss of offsite power:

Compartment	Description
CA201	Auxiliary Building Corridors – 199' elevation
CA301	Auxiliary Building Corridors – 139' elevation

CC202	division I Switchgear Room
CC210	division 3 Switchgear Room
CC215	division 2 Switchgear Room
CR	Control Room

A simplified equation for the change to the core damage from fires is as follows:

CDF = Fire Frequency (λ) * non-suppression probability (PNS) * CCDP*exposure

Delta-CDF = λ * PNS * ($CCDP_{edg\ fails}$ – $CCDP_{edg\ ok}$) * 15/365

$CCDP_{edg\ ok}$ = is the conditional core damage probability assuming the performance deficiency did not exist.

$CCDP_{edg\ fails}$ = CCDP where the performance deficiency does exist.

Assumptions for Fire Scenarios:

- The analyst did not include fire scenarios that already assumed that the division 2 emergency diesel generator would fail as a consequence of the fire.

- The analyst assumed that offsite power would be lost for each scenario. This was very conservative because the fires would need to be of sufficient size to reach different components (cables etc.). Since these areas also included wet pipe automatic sprinkler systems, the analyst assumed that a failure of the suppression system would also be required. The analyst assumed a 0.02 suppression system failure probability.

- Where the failure of balance of plant equipment was specified, the analyst noted that balance of plant equipment would already be lost as a consequence of the loss of offsite power. The analyst did not make additional adjustments for the balance of plant equipment.

- The analyst used the SPAR model to calculate the CCDPs and only solved the plant centered loss of offsite power sequences. For the CCDP calculations, the plant centered loss of offsite power frequency was 1.0.

- The analyst assumed an exposure period of 15 days.

- When cables from a specific division (1, 2, or 3) were assumed damaged, the analyst failed all of equipment in the applicable division. As a surrogate for divisional cables, the analyst failed the applicable emergency diesel generator. This would result in a failure of all divisional equipment. In addition, the analyst failed all emergency diesel generator recoveries. This was conservative because it was possible to damage only a few divisional components in the fire and not affect the emergency diesel generator.

- The analyst allowed the normal offsite power recoveries to occur. The failure of offsite power is assumed to occur because of fire induced faults on offsite power cables. Based on the fire locations, the analyst determined that these cables could be isolated and offsite power could be aligned to the secondary systems.

- The analyst used Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," to determine fire initiation frequencies, non-suppression probabilities, and fire damage times. The following generic information was included in this analysis.

    - divisional cable fire frequency = 1.4E-3 (highly loaded)
    - Control room cabinet fire frequency = 4.8E-3/cabinet
    - Control room fire identification time = 0 minutes

- For control room fires, the analyst assumed that each scenario could be initiated by a fire that started in one of three cabinets. This increased the fire frequency to 4.8E-3.

- For control room fires, the analyst used a non-suppression probability of 0.02. The control room is a continuously occupied area. Control room fires are expected to be promptly identified and suppressed. Operators have access to fire suppression equipment as well as self-contained breathing apparatus.

- Operators could still operate division 1 equipment from the remote shutdown panel. If all other equipment failed, operators would attempt this action. The analyst credited this action and assumed a nominal human error probability of 2.2E-2 (see NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Model"). Failure of division 1 equipment required both failure in the control room as well as the failure to complete the action at the remote shutdown panel.

The analyst evaluated the following fire scenarios:

Scenario	Assumed Failed equipment	λ	Supp System Fails or PNS or	CCD_e dg2 failed	CCDP edg2 ok	Control Room Remote Shutdown Panel Credit	ICCDP* Fire freq* PNS* 15/365
CA201-1	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CA201-7	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CA301-1	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr

CA301-3	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CC202-1b	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CC202-2a	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CC202-2b	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CC202-2c	Division 1 cables	1.4E-3	.02	4.7E-3	2.7E-4	Na	5E-9/yr
CC210-2	Division 3 cables	1.4E-3	.02	4.8E-3		Na	5E-9/yr
CR-2	Division 1 and Balance of Plant	4.8E-3	.02	4.7E-3	2.7E-4	.022	4E-10/yr
CR-4	Division 3 and Balance of Plant	4.8E-3	.02	4.8E-3	2.8E-4	Na	5E-9/yr
CR-5	Division 1, Division 3, and Balance of plant	4.8E-3	.02	1.6E-1	5.3E-3	.022	1.3E-8/yr
CR-9	Offsite Power	4.8E-3	.02	2.8E-4	2.7E-4	Na	1E-9/yr
						Total	**6.4E-8/yr**

Total Delta-CDF = 6.8E-7/year + 4E-9/year + 6.4E-8/year = 7.4E-7/year (Green). The dominant core damage sequences included loss of offsite power events that lead to station blackout. Equipment that helped mitigated the risk included the reactor core isolation cooling system and equipment that could be powered from the remote shutdown panel.

Large Early Release Frequency (LERF): To address the contribution to the LERF, the analyst used NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process." For boiling water reactors (BWR-6 with a Mark 3 containment), the failure of the division 2 emergency diesel generator was a potential

LERF contributor. For the LERF analysis, the analyst used the "Risk-Informed Inspection Notebook for Grand Gulf Station Unit 1," Revision 2.1a. The analyst noted that the LERF important core damage sequences were limited to those that included the failure of both the division 1 and 2 emergency diesel generators.

The analyst identified the LERF factors for the applicable loss of offsite power sequences. In a few instances the LERF factor was 0, but in most cases the LERF factor was 0.2.

The analyst used the internal events SPAR model and the "slice" function to identify the cutsets that included the failure of both diesels. The CCDP was 9.6E-6. Assuming a 15-day exposure period and a 0.2 LERF factor, the bounding LERF was 9.6E-6 * 0.2 * 15/365 = 7.8E-8. Therefore, the delta-LERF was less than 7.8E-8/yr. Since the delta-CDF was less than 1.0×10^{-6} and the delta-LERF was less than 1.0×10^{-7}, this finding was of very low safety significance (Green).

The apparent cause of this finding was the licensee did not recognize the risk of not performing the PM task, which led to the decision to exclude the task from the division 2 allowed outage time schedule. Therefore, the finding has a cross-cutting aspect in the human performance area associated with conservative bias because the licensee did not use decision making practices that emphasize prudent choices over those that are simply allowable [H.14].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to this requirement, on or before August 29, 2012, the licensee did not promptly identify and correct a condition adverse to quality. Specifically, the licensee did not reinstate and complete PM Task PMRQ 50024451-04 prior to the failure of Diode CR6 on May 21, 2013, which resulted in the division 2 diesel generator failing its monthly functional test and the licensee declaring it inoperable. This violation is being treated as a non-cited violation (NCV), consistent with Section 2.3.2.a of the Enforcement Policy because it was of very low safety significance (Green) and it was entered into the licensee's corrective action program as Condition Report CR-GGN-2014-02141 to address recurrence. (NCV 05000416/2013-3423, "Failure to Promptly Reinstate an Essential-Critical Preventative Maintenance Task for a High-Critical Component").

1R18 Plant Modifications (71111.18)

a. Inspection Scope

On June 26, 2014, the inspectors reviewed a permanent plant modification that replaced the use of turbine first stage pressure transmitter signals with power range neutron monitoring system signals to control various functions including low power and high power setpoints, turbine stop valve closure and control valve fast closure SCRAM enable/bypass, end of cycle recirculation pump transfer pump enable/bypass, feedwater low power set-down, and hydrogen water chemistry trips.

The inspectors reviewed the design and planned implementation of the modification. The inspectors verified that work activities involved in implementing the modification

would not adversely impact operator actions that may be required in response to an emergency or other unplanned event.

These activities constitute completion of one sample of permanent modifications, as defined in Inspection Procedure 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed five post-maintenance testing activities that affected risk-significant SSCs:

- April 30, 2014, control room standby fresh air unit B blower test after fan B replacement
- May 6, 2014, average power range monitor channel one after broadcaster card replacement
- May 12, 2014, control room air conditioner B after compressor replacement
- May 15, 2014, RCIC system following a system outage
- May 15, 2014, steam supply valve (valve E51-F0045), cooling water valve (valve E51-F046), and the condensate storage tank supply valve (valve E51-F010) for the reactor core isolation cooling system following maintenance on the valves

The inspectors reviewed licensing- and design-basis documents for the SSCs and the maintenance and post-maintenance test procedures. The inspectors observed the performance of the post-maintenance tests to verify that the licensee performed the tests in accordance with approved procedures, satisfied the established acceptance criteria, and restored the operability of the affected SSCs.

These activities constitute completion of five post-maintenance testing inspection samples, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed five risk-significant surveillance tests and reviewed test results to verify that these tests adequately demonstrated that the SSCs were capable of performing their safety functions:

In-service tests:

- April 11, 2014, residual heat removal system A quarterly motor operated valve (MOV) surveillance

Other surveillance tests:

- April 8, 2014, station battery banks 1A3, 1B3, and 1C3 pilot cell surveillance

- May 13, 2014, division 1, 4160 VAC degraded voltage functional test and calibration

- May 23, 2014, ESF transformer 12 deluge test

- June 4, 2014, drywell high pressure emergency core cooling water system (ECCS) functional test channel A

The inspectors verified that these tests met technical specification requirements, that the licensee performed the tests in accordance with their procedures, and that the results of the test satisfied appropriate acceptance criteria. The inspectors verified that the licensee restored the operability of the affected SSCs following testing.

These activities constitute completion of five surveillance testing inspection samples, as defined in Inspection Procedure 71111.22.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors observed an emergency preparedness drill on May 7, 2014, to verify the adequacy and capability of the licensee’s assessment of drill performance. The inspectors reviewed the drill scenario, observed the drill from the simulator control room and the emergency operations facility and attended the post-drill critique. The inspectors verified that the licensee’s emergency classifications, off-site notifications, and protective action recommendations were appropriate and timely. The inspectors

verified that any emergency preparedness weaknesses were appropriately identified by the licensee in the post-drill critique and entered into the corrective action program for resolution.

These activities constitute completion of one emergency preparedness drill observation sample, as defined in Inspection Procedure 71114.06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures (MS05)

a. Inspection Scope

For the period of April 1, 2013, through March 31, 2014, the inspectors reviewed licensee event reports (LERs), maintenance rule evaluations, and other records that could indicate whether safety system functional failures had occurred. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, and NUREG-1022, “Event Reporting Guidelines: 10 CFR 50.72 and 50.73,” Revision 3, to determine the accuracy of the data reported.

These activities constituted verification of the safety system functional failures performance indicator for the site, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.2 Reactor Coolant System Specific Activity (BI01)

a. Inspection Scope

The inspectors reviewed the licensee’s reactor coolant system chemistry sample analyses for the period of April 1, 2013, through March 31, 2014, to verify the accuracy and completeness of the reported data. The inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample on October 16, 2013. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, to determine the accuracy of the reported data.

These activities constituted verification of the reactor coolant system specific activity performance indicator for the site, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.3 Reactor Coolant System Total Leakage (BI02)

a. Inspection Scope

The inspectors reviewed the licensee's records of reactor coolant system total leakage for the period of April 1, 2013, through March 31, 2014, to verify the accuracy and completeness of the reported data. The inspectors observed the performance of reactor coolant system leakage surveillance procedure on April 8, 2013. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the reported data.

These activities constituted verification of the reactor coolant system leakage performance indicator for the site, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review

a. Inspection Scope

Throughout the inspection period, the inspectors performed daily reviews of items entered into the licensee's corrective action program and periodically attended the licensee's condition report screening meetings. The inspectors verified that licensee personnel were identifying problems at an appropriate threshold and entering these problems into the corrective action program for resolution. The inspectors verified that the licensee developed and implemented corrective actions commensurate with the significance of the problems identified. The inspectors also reviewed the licensee's problem identification and resolution activities during the performance of the other inspection activities documented in this report.

b. Findings

No findings were identified.

.2 Semiannual Trend Review

a. Inspection Scope

To verify the licensee was taking corrective actions to address apparent adverse trends that might indicate the existence of a more significant safety issue, the inspectors reviewed corrective action program documentation associated with the following issues associated with the division 1 and 2 diesel generator air start systems:

- Multiple occurrences of the divisions 1 and 2 standby diesel generator air dryer malfunctions challenging the motor driven and diesel driven air compressor reliability (Condition Report CR-GGN-2014-00468)

- Multiple occurrences of elevated dew points within the divisions 1 and 2 standby diesel generator air start system which could lead to corrosion of the air start receivers (Condition Report CR-GGN-2012-00273)

Furthermore, the licensee identified an emerging cross-cutting theme in H.5 ("Work Management: The organization implements a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. The work process includes the identification and management of risk commensurate to the work and the need for coordination with different job groups or job activities") and H.8 ("Procedure Adherence: Individuals follow processes, procedures, and work instructions"). The inspectors reviewed the licensee's response to these themes to verify that the licensee had taken, was taking, and/or planned to take appropriate actions to address them.

The documents reviewed during this trend review are listed in the Attachment.

These activities constitute completion of one semiannual trend review sample, as defined in Inspection Procedure 71152.

b. Observations and Assessments

The inspectors' review of the trends identified above produced the following observations and assessments:

- For multiple occurrences of air dryer malfunctions, the licensee initiated Condition Report CR-GGN-2014-00468 identifying the reliability of the divisions 1 and 2 air drying towers as "unacceptably low." Furthermore, the system engineer identified the air dryer reliability issue as a significant system issue requiring resolution in the standby diesel generator system health report. Immediate corrective actions included enhancing the model work orders to improve the reliability of the components within the air dryer system and evaluating the system configuration to ensure optimum performance. Long term corrective action involved upgrading the air dryer system to a newer more reliable design.

- For multiple occurrences of elevated dew points within the air start system, the licensee initiated Condition Report CR-GGN-2012-00273 and determined that the elevated dew points were directly related to the reliability of the air dry

system. In April 2013, the licensee performed visual inspections of the division 1 air receivers and observed minimal corrosion. The resident inspectors also inspected the air receivers and verified the licensee's findings. The licensee scheduled inspections of the division 2 air receivers during a planned maintenance window scheduled for June 2014. Furthermore, the licensee performed non-destructive examinations that resulted in no indications of degradation.

The inspectors determined these trends with the diesel generator air dryer assembly and elevated dew points in the air start system represented a weakness in the licensee's ability to address reliability issues associated with non-safety related equipment that supports safety related equipment. The inspectors concluded that the licensee had also recognized equipment reliability as an area for improvement and developed corrective actions via a recovery plan to address them.

- For the emerging cross-cutting theme due to receiving three findings with the H.5 cross-cutting aspect, the licensee initiated Condition Report CR-GGN-2014-3006 to perform a common cause analysis. The licensee concluded that although the three findings were assigned the H.5 cross-cutting aspect, the causes were sufficiently diverse such that a common cause did not exist. The inspectors reviewed the causal analysis as well as the original documentation of the findings that were assigned H.5 and determined that the conclusions made by the licensee were reasonable.

- For the emerging cross-cutting theme due to receiving three findings with the H.8 cross-cutting aspect, the licensee initiated Condition Report CR-GGN-2013-07616 to perform a common cause analysis. The licensee concluded that the cause was the same as that of a root cause evaluation performed under Condition Report CR-GGN-2013-3639. The inspectors previously reviewed the root cause as documented in NRC Inspection Report 05000416/2013004 (ML13331B343) and identified no issues. The inspectors reviewed Condition Report CR-GGN-2013-3639 and verified it accurately captured the findings of the causal analysis performed under Condition Report CR-GGN-2013-07616. The inspectors determined the licensee's conclusions and corrective actions were reasonable.

For these emerging cross-cutting themes, the inspectors determined that the licensee had entered the emerging themes into the corrective action program in a timely manner, completed an appropriate evaluation of the themes, developed and scheduled corrective actions to address the identified weaknesses and areas for improvement, and had completed/implemented most of the corrective actions at the time of this inspection. Thus, as a result of this inspection, the inspectors concluded that the licensee's actions and progress in addressing the emerging trends in H.5 and H.8 have been appropriate.

c. Findings

No findings were identified.

.3 Annual Follow-up of Selected Issues

a. Inspection Scope

The inspectors selected one issue for an in-depth follow-up:

- On April 7, 2014, the inspector reviewed Condition Report CR-GGN-2013-0037, which addressed a non-cited violation that was issued in NRC Inspection Report IR 05000416/2013002 for the failure to maintain design control of set point calculations for instruments required by technical specifications. The inspectors reviewed the associated corrective actions and determined the steps taken by the licensee adequately addressed the violation. The inspectors also reviewed Engineering Changes EC 39554 and EC 39605 to verify the set point calculations were adjusted to account for the change from 18-month cycles to 24-month cycles.

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

These activities constitute completion of one annual follow-up sample as defined in Inspection Procedure 71152

b. Findings

No findings were identified.

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

.1 (Closed) Licensee Event Report 05000416/2013-0005-00: "Reactor Pressure Vessel Steam Pressure Less than 0 psig During Six Plant Startups Resulting in a Violation of Technical Specification 3.4.11, RCS Pressure and Temperature (P/T) Limits."

a. Inspection Scope

On December 12, 2013, with the plant operating in Mode 1 at 100 percent thermal power, Grand Gulf Nuclear Station (GGNS) discovered that during the past six startups, the reactor pressure vessel (RPV) steam pressure was below zero (0) pounds per square inch gage (psig) with the main steam isolation valves open and the mechanical vacuum pumps running without entering Limiting Condition of Operation LCO 3.4.11, RCS Pressure and Temperature Limits. From December 12, 2010, through December 12, 2013, there were six occurrences of reactor pressure being less than 0 psig. The reactor pressure/temperature curves in the GGNS Pressure and Temperature Limits Report have a minimum pressure value of 0 psig referenced on the curve. The lowest pressure identified in the six occurrences was approximately -9.9 psig on December 13, 2013. All systems performed per design during the reactor startups with the RPV pressure below 0 psig during the past 3 years.

The cause of not entering LCO 3.4.11 was the condition was procedurally allowed and aligned with operator training. Corrective actions included revising station procedures

and training documents. The licensee also performed an apparent cause evaluation (ACE) and developed corrective actions based on the findings of the ACE. The inspectors reviewed the ACE and associated corrective actions and determined the licensee's conclusions and course of action were reasonable. The enforcement aspects of this event were discussed in NRC Inspection Report 05000416/2013005 in Section 1R20. Documents reviewed as part of this inspection are listed in the attachment.

These activities constitute completion of one event follow-up sample, as defined in Inspection Procedure 71153.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report 05000416/2013-006-00: "Primary Containment Inoperable Due to an Inadequate Surveillance Procedure Resulting in a Loss of Safety Function"

a. Inspection Scope

On December 17, 2013, at approximately 1:22 p.m., with the plant operating in Mode 1 at 100 percent thermal power, Grand Gulf Nuclear Station personnel utilized a procedure that was incorrectly revised. The event was identified at 2:15 p.m. during the performance of the surveillance when valve E51-F063, reactor core isolation cooling (RCIC) steam line drywell inboard isolation valve, was observed unexpectedly going closed when a test signal was applied. This action resulted in the inoperability of primary containment and the RCIC system. The operators immediately halted the surveillance and began troubleshooting the cause of the valve closure. The operators restored RCIC system operability at 2:35 p.m. when valve E51-F063 was reopened. Primary containment operability was restored at 2:37 p.m. by restoring power to the containment isolation valve (valve E51F064).

The cause of this event was an improper procedure revision that resulted in an inadequate procedure. Corrective actions included restoring the operability of primary containment isolation and the RCIC system. Other corrective actions included correcting the procedural deficiency, performing reviews of other procedures that were recently revised, and conducting a root cause evaluation of the event. The inspectors reviewed the root cause as well as the associated corrective actions and determined the actions taken by the licensee were reasonable. The enforcement aspects of this event were discussed in NRC Inspection Report 05000416/2013005 in Section 1R22. Documents reviewed as part of this inspection are listed in the attachment.

These activities constitute completion of one event follow-up sample, as defined in Inspection Procedure 71153.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 Follow-up on Traditional Enforcement Actions Including Violations, Deviations, Confirmatory Action Letters, Confirmatory Orders, and Alternative Dispute Resolution Confirmatory Orders (IP 92702)

a. Background:

On August 24, 2011, the NRC issued a Confirmatory Order (EA-11-096) to Entergy Operations, Inc., and Entergy Nuclear Operations, Inc. (collectively referred to as Entergy). The Confirmatory Order actions were agreed upon by Entergy and the NRC during an alternative dispute resolution session held on July 18, 2011, to resolve NRC concerns regarding an apparent violation of employee protection requirements at the River Bend Station. The actions focused on reorganizing the Quality Control reporting relationships, ensuring adequate training of 10 CFR 50.7, “Employee Protection,” and performing an effectiveness review of the Employee Concerns Program procedures at all Entergy facilities.

By letter dated August 23, 2012, Entergy notified the NRC of the actions that had been taken in response to the requirements imposed by the Confirmatory Order. Accordingly, during the week of April 29, 2013, NRC staff from the Office of Enforcement and Region IV performed an inspection at the River Bend Station to assess the specific actions identified in Entergy’s response letter. NRC staff also verified implementation of the remaining actions required to satisfy the conditions set forth in the Confirmatory Order, for all Entergy sites. Subsequent to this inspection, NRC staff continued to interact with Entergy regarding the adequacy of the corrective and preventive actions related to the underlying discriminatory issue.

b. Findings and Observation:

During the follow-up inspection, the NRC staff reviewed Entergy’s Employee Concerns Program supervisory training and general employee training documents, the relevant “lessons learned” from the facts of this matter and the fleet-wide written communication reinforcing Entergy’s commitment to maintaining a safety-conscious work environment.

The NRC staff also reviewed the General Employee Training and Supervisory Training modules. Based on these reviews, it was determined that these training modules adequately addressed employee protection and included insights from the underlying discriminatory matter. The NRC staff determined that the supervisory training module appeared complete and included case studies as well as the specific elements from the underlying § 50.7, “Employee Protection,” violation. However, it was noted that although employees receive General Employee Training on an annual basis, Entergy does not require supervisors to take employee protection refresher training on a recurring basis as a means to reinforce these standards.

Additionally, NRC staff evaluated the results of Entergy’s effectiveness review of Employee Concerns Program (ECP) enhancements and the associated training that arose from the corrective actions taken to address this matter. Based on the results of this evaluation, it was determined that Entergy had performed the requisite reviews at each station, including examination of selected ECP Case Files, Records Retention,

Concerned Individual follow-up, and ECP Coordinator training. Within the areas examined, no findings were identified and in general it was determined that Entergy had adequately performed the effectiveness review of ECP procedural enhancements and the ECP training related to this matter.

During the follow-up review of the Quality Control/Quality Assurance reporting relationship, it was determined that Entergy's response did not ensure that persons performing the quality assurance function of receipt inspection reported to a management level sufficient to maintain organizational freedom and independence from cost and schedule are maintained. Subsequent to the identification of this performance issue, which affected the implementation of the QA program at all nine Entergy sites, the condition was entered into the licensee's corrective action program as Condition Report CR-HQN-2013-00466.

Following the identification of this issue, additional discussions were held between NRC and Entergy to clarify the intent of the settlement agreement and subsequent Confirmatory Order stemming from the earlier alternate dispute resolution mediation. As a result of these discussions, Entergy's Corporate Licensing organization developed a fleet reconciliation plan to modify Entergy's Quality Assurance Program Manual to require that individuals performing inspections in accordance with Quality Assurance Program Manual, Section B.12, "Inspection," functionally report to the associated manager responsible for Quality Assurance. As described in the corrective actions associated with Condition Report CR-HQN-2013-00466, the affected individuals were those requiring certification in accordance with Quality Assurance Program Manual, Table 1, Regulatory Commitments, Section G, Regulatory Guide 1.58, Revision 1, "Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel," dated September 1980. In addition to revising the applicable provisions in the Quality Assurance Program Manual, corrective actions were initiated to revise implementing procedures to reflect the change in reporting relationship during the performance of required inspections as well as providing training to the affected individuals. The NRC staff confirmed that the remaining conditions of the Confirmatory Order were adequately addressed.

c. Conclusion:

Based on the above reviews, the NRC determined that Entergy properly implemented the conditions specified in the Confirmatory Order and the associated actions were adequately implemented.

d. Findings:

No findings were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On July 17, 2014, the inspectors presented the inspection results to Mr. K. Mulligan, Site Vice President of Operations, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of the NRC Enforcement Policy for being dispositioned as a non-cited violation.

- Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," states, in part, activities affecting quality shall be prescribed by documented procedures, of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Contrary to the above, the licensee failed to assure that activities affecting quality were prescribed by documented instructions of a type appropriate to the circumstances. Specifically, the licensee failed to meet the requirements of Electrical Standard ES03, "Electrical Standard for Installation of Cables," Revision 1, in that Chico A potting compound was not used to seal the drywell electrical penetration. As immediate corrective actions, the licensee removed the instrument cables and sealed the penetration. The licensee entered this issue in the corrective action program under Condition Report CR-GGN-2014-02141. Furthermore, the licensee evaluated the potential impact the open 4-inch penetration would have on the suppression pool's suppression capability and determined that having an open 4-inch diameter penetration in the drywell did not cause the drywell bypass leakage criteria to be exceeded. Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," June 19, 2012, Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," the inspectors determined this issue affected the Barrier Integrity Cornerstone. Using Manual Chapter 0609, Appendix A, "Significance Determination Process (SDP) for Findings at Power," June 19, 2012, Exhibit 3, "Barrier Integrity Screening Questions," the inspectors determined that this finding represented an actual open pathway in the physical integrity of reactor containment (valves, airlocks, etc.), containment isolation system (logic and instrumentation), and heat removal components. Using Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," dated May 6, 2004, the inspectors determined that this finding would not influence the likelihood of accidents leading to core damage. However, since this finding involved components significant to suppression pool integrity/scrubbing that are important to LERF, the inspectors determined a detail risk analysis needed to be performed by a senior risk analyst. The senior risk analyst performed a detailed risk evaluation and determined that since the function of the systems/components did not fail, even with the failed penetration, and there was no failure of the safety function. Therefore, this finding is of very low safety significance (Green).

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

C. Beschett, Manager, Nuclear Oversight
T. Coutu, Director, Regulatory Compliance and Performance Improvement
J. Dorsey, Security Manager
H. Farris, Assistant Operations Manager
J. Gerard, Manager, Operations
M. Godwin, Assistant Operations Manager
G. Hawkins, Manager, Site Projects
J. Miller, General Manager Plant Operations
R. Miller, Manager, Radiation Protection
M. Milly, Manger, Maintenance
K. Mulligan, Site Vice President
J. Nadeau, Manager, Regulatory Assurance and Performance Improvement
R. Scarbrough, Senior Regulatory Engineer, Licensing
T. Thornton, Manager, Design Engineering
D. Wiles, Director, Engineering

NRC Personnel

D. Loveless, Senior Reactor Analyst
G. Replogle, Senior Reactor Analyst

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000416/2014003-01	NCV	Failure to Promptly Reinstate an Essential-Critical Preventative Maintenance Task for a High-Critical Component (Section 1R15)

Closed

05000416/2013-005-00	LER	Reactor Pressure Vessel Steam Pressure Less than 0 psig During Six Plant Startups Resulting in a Violation of Technical Specification 3.4.11, RCS Pressure and Temperature (P/T) Limits (Section 4OA3)
05000416/2013-006-00	LER	Primary Containment Inoperable Due to an Inadequate Surveillance Procedure Resulting in a Loss of Safety Function (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures

Number	Title	Revision Date
06-TE-1000-V-0001	Culvert No. 1 Embankment Stability Inspection/Survey	101
05-1-02-VI-2	Off-Normal Event Procedure Hurricanes, Tornados, and Severe Weather	127
ENS-PL-150	Switchyard and Transmission Interface Requirements	3
ENS-DC-201	ENS Transmission Grid Monitoring	6
ENS-DC-199	Off Site Power Supply Design Requirements Nuclear Plant Interface Requirements	8
EN-LI-113, Attachment 9.1	LBDCR Form #2013-007	February 22, 2013
ENS-DC-201	ENS Transmission Grid Monitoring	6
ENS-PL-158	Switchyard and Transmission Interface Requirements	3
ENS-DC-199	Off Site Power Supply Design Requirements Nuclear Plant Interface Requirements	8
05-1-02-I-4	Off-Normal Event Procedure Loss of SC Power	46
EN-AD-101, Attachment 9.1	NMM Review and Approval Form (RAF): Off Site Power Supply Design Requirements Nuclear Plant Interface Requirements	8

Other Documents

Title	Date
GGNS Due Work	
Switchyard Work	March & April 2014

Condition Reports

CR-GGN-2014-03621	CR-GGN-2014-03681	CR-GGN-2014-03794
CR-GGN-2014-03618	CR-GGN-2014-03083	

Engineering Change	Revision
EC 29705	0

Work Orders

WO 51558126 01	WO 52300427 01

Section 1R04: Equipment Alignment

Procedures

Number	Title	Revision
04-1-01-T48-1	Standby Gas Treatment	35
04-1-01-E51-1	Reactor Core Isolation Cooling	132
02-S-01-2	Control and Use of Operations Section Directives	52
04-1-03-A30-3	Locked Valve Checks	12
04-S-01-Z51-1	Control Room HVAC System	56
04-1-01-E22-1	High Pressure Core Spray System	119
04-1-01-P75-1, Attachment IA	Standby Diesel Generator System	101

Condition Reports

CR-GGN-2013-02030	CR-GGN-2013-02447	CR-GGN-2013-02820
CR-GGN-2013-02825	CR-GGN-2013-02914	CR-GGN-2013-03142
CR-GGN-2013-05848	CR-GGN-2014-00028	CR-GGN-2014-03470
CR-GGN-2011-04663	CR-GGN-2012-08175	CR-GGN-2013-02486
CR-GGN-2011-04953	CR-GGN-2012-08403	CR-GGN-2013-02617
CR-GGN-2011-06073	CR-GGN-2012-08404	CR-GGN-2013-03242
CR-GGN-2011-06461	CR-GGN-2012-09700	CR-GGN-2013-03243
CR-GGN-2012-03263	CR-GGN-2012-09718	CR-GGN-2013-03668
CR-GGN-2012-03280	CR-GGN-2012-09745	CR-GGN-2013-04427
CR-GGN-2012-04445	CR-GGN-2012-10021	CR-GGN-2013-04538
CR-GGN-2012-04938	CR-GGN-2012-10536	CR-GGN-2013-04539
CR-GGN-2012-05334	CR-GGN-2012-10934	CR-GGN-2013-04776
CR-GGN-2012-05384	CR-GGN-2012-13125	CR-GGN-2013-04969
CR-GGN-2012-05444	CR-GGN-2013-00674	CR-GGN-2013-05140
CR-GGN-2012-05541	CR-GGN-2013-00688	CR-GGN-2013-05162
CR-GGN-2012-05577	CR-GGN-2013-00689	CR-GGN-2013-05163
CR-GGN-2012-05678	CR-GGN-2013-00696	CR-GGN-2013-05280

CR-GGN-2012-05845	CR-GGN-2013-00736	CR-GGN-2013-05511
CR-GGN-2012-05980	CR-GGN-2013-00739	CR-GGN-2013-05634
CR-GGN-2012-06052	CR-GGN-2013-00765	CR-GGN-2013-05669
CR-GGN-2012-06240	CR-GGN-2013-00767	CR-GGN-2013-06785
CR-GGN-2012-06248	CR-GGN-2013-00769	CR-GGN-2013-06839
CR-GGN-2012-06270	CR-GGN-2013-00772	CR-GGN-2013-07296
CR-GGN-2012-06289	CR-GGN-2013-00776	CR-GGN-2014-00041
CR-GGN-2012-06292	CR-GGN-2013-00796	CR-GGN-2014-00146
CR-GGN-2012-06375	CR-GGN-2013-01021	CR-GGN-2014-00305
CR-GGN-2012-06505	CR-GGN-2013-01115	CR-GGN-2014-00371
CR-GGN-2012-06590	CR-GGN-2013-01304	CR-GGN-2014-00372
CR-GGN-2012-06631	CR-GGN-2013-01881	CR-GGN-2014-00855
CR-GGN-2012-06661	CR-GGN-2013-01944	CR-GGN-2014-00859
CR-GGN-2012-08170	CR-GGN-2013-01945	CR-GGN-2014-02045
CR-GGN-2012-08171	CR-GGN-2013-01962	CR-GGN-2014-02933
CR-GGN-2012-08173	CR-GGN-2013-02028	CR-GGN-2014-02934
CR-GGN-2012-08174	CR-GGN-2013-02052	CR-GGN-2014-03326
CR-GGN-2011-04750	CR-GGN-2014-04090	CR-GGN-2014-04091
CR-GGN-2014-04093	CR-GGN-2014-04094	

Work Orders

WO 52472663 01	WO 00302776	WO 52466308

Section 1R05: Fire Protection

Calculations

Number	Title	Revision
MC-QSP64-86058	Combustible Heat Load Calculations	59

Other Documents

Number	Title	Revision
Fire Pre-Plan A-25	Electrical SWGR Room, Room 1A309, Area 7, Elevation 139	2

Other Documents

Number	Title	Revision
Fire Pre-Plan A-24	Electrical SWGR Room, Room 1A308, Area 8, Elevation 139	1
Fire Pre-Plan A-16	Electrical SWGR Room 1A219 and 1A221, Area 10-9, Elevation 119’	2
GG UFSAR	9A.5.9 Fire Area 9	
Fire Pre-Plan DG-03	Division 2 Diesel Generator Room 1D303, Area 12, Elevation 133	5

Section 1R06: Flood Protection Measures

Procedures

Number	Title	Revision
05-1-02-VI-1	Off-Normal Event Procedure Flooding	110

Drawings

Number	Title	Revision
A-0647	Unite 1 - Turbine Bldg. Fire Protection FL. Plan at EL. 166’-0” & 186’-3”	1
A-0646	Unit 1 – Turbine Bldg. Fire Protection FL. Plan at EL. 133’-0”	0
A-0645	Unit 1 – Turbine Bldg. Fire Protection FL. Plan at EL. 113’-0”	0
A-0644	Unit 1 – Turbine Bldg. Fire Protection FL. Plan at EL. 93’-0”	0
J-15030	Instrument Location Turbine Building Plan at EL. 133’-0”	1
M-1268	Area Piping Composite Auxiliary Building EL. 139’-0” Area 7	6
M-1264	Area Piping Composite Auxiliary Building EL. 119’-0” Area 7 Unit 1	3
M-1273	Area Piping Composite Auxiliary Building EL. 166’-0” Area 8 Unit 1	0
M-1272	Area Piping Composite Auxiliary Building EL. 166’-0” Area 7 Unit 1	2
M-1260	Area Piping Composite Auxiliary Building EL. 93’-0” Area 7 Unit 1	4
M-1265	Area Piping Composite Auxiliary Building EL. 119’-0” Area 8 Unit 1	5
M-1269	Area Piping Composite Auxiliary Building EL. 139’-0” Area 8	8

Drawings

Number	Title	Revision
J-1504F	Instrument Location Turbine Building Plan at EL. 166’-0”	1
J-1502F	Instrument Location Turbine Building Plan (Area 6) at EL. 113’-0”	0
J-1504C	Instrument Location Turbine Building Plan at EL. 166’-0” Unit 1	0
J-1503F	Instrument Location Turbine Building Plan at EL. 133’-0” Unit 1	0

Other Documents

Number	Title	Revision
GGNS-91-0045	Engineering Report for IPE: Internal Flooding Analysis Notebook	0
GGNS-CS-05	Standard for Erection of Scaffolding in Seismic Category I Buildings	3

Engineering Changes	Revision
EC 20952	0
EC 20952	1
EC 41149	0

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance

Procedures

Number	Title	Revision
EN-OP-115	Conduct of Operations	14
02-S-01-27	Operation’s Philosophy	58
GSMS-LOR-WEX01	Licensed Operator Requalification Training	26

Other Documents

Title	Revision Date
Operations Continuing Training 2014 Cycle 4	March 24, 2014
2014 Cycle 4 Licensed Operator Requal Simulator Training Plan Simulator Differences	0

Section 1R12: Maintenance Effectiveness

Procedures

Number	Title	Revision Date
EN-LI-119-01, Attachment 9.1	Equipment Failure Evaluation Template: CR-GGN-2012-8367	2
EN-DC-205, Attachment 9.1	Maintenance Rule Functional Failure Evaluation Template: CR-GGN-2012-09786	August 9, 2012
EN-DC-205, Attachment 9.1	Maintenance Rule Functional Failure Evaluation Template: CR-GGN-2013-22 CA-50	March 22, 2013
EN-DC-205, Attachment 9.1	Maintenance Rule Functional Failure Evaluation Template: CR-GGN-2012-8367	June 17, 2012
EN-DC-205, Attachment 9.1	Maintenance Rule Functional Failure Evaluation Template: CR-GGN-2012-9612	August 2, 2012
EN-DC-205, Attachment 9.1	Maintenance Rule Functional Failure Evaluation Template: CR-GGN-2012-10335	August 30, 2012
06-ME-1M10-O-0002	Containment Integrated Leak Rate Test	108
06-ME-1M10-O-0003	Drywell Bypass Leakage Rate	105
EN-DC-203	Maintenance Rule Program	2
EN-DC-204	Maintenance Rule Scope and Basis	3
EN-DC-205	Maintenance Rule Monitoring	5
EN-DC-206	Maintenance Rule (a)(1) Process	3

Calculations

Number	Title	Revision
MC-Q1M24-99004	Drywell Bypass Leakage For Failed Drywell Penetrations 331, 348, 349, & 364 Due to Overpressurization	0
MC-Q1111-97001	Generic Letter 96-06 Evaluation of Drywell and Containment Penetrations	0
MC-Q1M24-08008	Drywell Bypass Pressure Drop Test	1
MC-Q1M24-99004	Drywell Maximum Allowable Leak Rate	

Other Documents

Number	Title	Revision Date
99/0001	ES-03 Electrical Standard for Installation of Cables	1
2010-031	Change wording to Technical Specification Bases 3.6.5.1.1 to reflect actual requirement as stated in 06-ME-1M10-O-0003	September 8, 2010

Condition Reports

CR-GGN-2012-08367	CR-GGN-2012-10335	CR-GGN-2013-05848
CR-GGN-2012-08605	CR-GGN-2013-02030	CR-GGN-2014-00028
CR-GGN-2012-09353	CR-GGN-2013-02447	CR-GGN-2014-03381
CR-GGN-2012-09612	CR-GGN-2013-02820	CR-GGN-2014-03434
CR-GGN-2012-09674	CR-GGN-2013-02825	CR-GGN-2012-09786
CR-GGN-2012-09680	CR-GGN-2013-02914	CR-GGN-2013-03142
CR-GGN-2012-09742	CR-GGN-2013-06562	CR-GGN-2014-00412
CR-GGN-2012-00303	CR-GGN-2014-00725	CR-GGN-2012-05355
CR-GGN-2012-00723	CR-GGN-2014-00762	CR-GGN-2012-05391
CR-GGN-2012-00827	CR-GGN-2014-00858	CR-GGN-2012-05444
CR-GGN-2012-00966	CR-GGN-2014-01147	CR-GGN-2012-05514
CR-GGN-2012-02038	CR-GGN-2014-01161	CR-GGN-2012-05735
CR-GGN-2012-02065	CR-GGN-2014-01245	CR-GGN-2012-05839
CR-GGN-2012-02157	CR-GGN-2014-01300	CR-GGN-2012-05896
CR-GGN-2012-02218	CR-GGN-2014-01321	CR-GGN-2012-05947
CR-GGN-2012-02368	CR-GGN-2014-01349	CR-GGN-2012-05996
CR-GGN-2012-02500	CR-GGN-2014-01412	CR-GGN-2012-06021
CR-GGN-2012-03038	CR-GGN-2014-01440	CR-GGN-2012-06109
CR-GGN-2012-03044	CR-GGN-2014-01445	CR-GGN-2012-06191
CR-GGN-2012-03068	CR-GGN-2014-01531	CR-GGN-2012-06315
CR-GGN-2012-03180	CR-GGN-2014-01583	CR-GGN-2012-06940
CR-GGN-2012-03263	CR-GGN-2014-01597	CR-GGN-2012-06991
CR-GGN-2012-03301	CR-GGN-2014-01667	CR-GGN-2012-07172
CR-GGN-2012-03305	CR-GGN-2014-01705	CR-GGN-2012-07341
CR-GGN-2012-03367	CR-GGN-2014-01706	CR-GGN-2012-08749

CR-GGN-2012-03416
CR-GGN-2012-03557
CR-GGN-2012-03941
CR-GGN-2012-03975
CR-GGN-2012-03977
CR-GGN-2012-04223
CR-GGN-2012-04292
CR-GGN-2012-04339
CR-GGN-2012-04348
CR-GGN-2012-04357
CR-GGN-2012-04358
CR-GGN-2012-04478
CR-GGN-2012-04521
CR-GGN-2012-04565
CR-GGN-2012-04584
CR-GGN-2012-04654
CR-GGN-2012-04684
CR-GGN-2012-04817
CR-GGN-2012-04976
CR-GGN-2013-07409
CR-GGN-2013-07733
CR-GGN-2013-07734
CR-GGN-2013-07807
CR-GGN-2014-00004
CR-GGN-2014-03455
CR-GGN-2014-01882
CR-GGN-2014-01953
CR-GGN-2014-01960
CR-GGN-2014-02012
CR-GGN-2014-02191
CR-GGN-2014-02200
CR-GGN-2014-02207
CR-GGN-2014-02232
CR-GGN-2014-02293
CR-GGN-2014-02358
CR-GGN-2014-02376
CR-GGN-2014-02394
CR-GGN-2014-02437
CR-GGN-2014-02578
CR-GGN-2014-02952
CR-GGN-2014-02959
CR-GGN-2014-03001
CR-GGN-2014-03256
CR-GGN-2014-03337
CR-GGN-2013-04748
CR-GGN-2013-05661
CR-GGN-2013-05827
CR-GGN-2013-06044
CR-GGN-2013-06190
CR-GGN-2012-09438
CR-GGN-2012-11109
CR-GGN-2013-00022
CR-GGN-2013-00405
CR-GGN-2013-00696
CR-GGN-2013-01527
CR-GGN-2013-01595
CR-GGN-2013-01749
CR-GGN-2013-01882
CR-GGN-2013-01974
CR-GGN-2013-02167
CR-GGN-2013-02357
CR-GGN-2013-02407
CR-GGN-2013-02588
CR-GGN-2013-02633
CR-GGN-2013-02660
CR-GGN-2013-02675
CR-GGN-2013-02719
CR-GGN-2013-02783
CR-GGN-2013-03285
CR-GGN-2013-03358
CR-GGN-2013-03726
CR-GGN-2013-03867
CR-GGN-2012-10397

Engineering Changes
EC 0000034734

Work Orders
WO 00150146 01
WO 52399863 01

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision Date
05-1-02-VI-2	Off-Normal Event Procedure Hurricanes, Tornados, and Severe Weather: April 4, 2014	127
05-1-02-VI-2	Off-Normal Event Procedure Hurricanes, Tornados, and Severe Weather: April 6, 2014	127
05-1-02-VI-2	Off-Normal Event Procedure Hurricanes, Tornados, and Severe Weather: April 14, 2014	127
EN-OP-115-03	Shift Turnover and Relief	0
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52540497	April 29, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52541251	April 25, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52428357	April 28, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 348190-06	April 28, 2014
05-1-02-VI-2	Hurricanes, Tornadoes, and Severe Weather for April 28, 2014	127
05-1-02-VI-2	Hurricanes, Tornadoes, and Severe Weather for April 29, 2014	127
05-1-02-III-3	Reduction in Recirculation System Flow rate	112
01-S-18-6	Risk Assessment of Maintenance Activities	13
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52541825-01	May 14, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WOs 52554730, 52515000, 52481030, 52550280, 52550095, 52554864, 52464433, 52554728, 52554729, 358752, 52464909, 52550096, 52541620, 52543888, & 380062	May 18, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52549292	May 18, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 217852	May 18, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WOs 273034-01, 378900-01, & 378900-02	May 19, 2014

Procedures

Number	Title	Revision Date
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52555501	May 23, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52549292	May 22, 2014
EN-WM-101, Attachment 9.1	Online Emergent Work Add/Delete Approval Form: WO 52421737	May 23, 2014
02-S-01-41	On Line Risk Assessment	11
02-S-01-41, Attachment IV	Risk Activity Evaluation Check sheet	11
EN-HU-102	Human Performance Traps & Tools	13
EN-WM-104	On Line Risk Assessment	9

Drawings

Number	Title	Revision
M-1850	Wall & Floor Penetration Schedule Auxiliary Bldg. El. 119’-0” Unit 1	12
M-1850	Wall & Floor Penetration Schedule Auxiliary Bldg. El. 119’-0” Unit 1	17
M-08000	Electrical Penetration Closures Notes and Details Units 1 & 2	17
M-1858	Blockouts & Penetrations Auxiliary Building El. 119’-0” Area 10, Unit-1	16

Other Documents

Number	Title	Date
	Wind Information On Site from 3 am on April 14, 2014, through 9 pm on April 14, 2014, Instrument C84J009	April 14, 2014
	Grand Gulf Line Load	

Condition Reports

CR-GGN-2014-03571 CR-GGN-2014-03329

Section 1R15: Operability Determinations and Functionality Assessments

Procedures

Number	Title	Revision
EN-OP-104	Operability Determination Process: CR-GGN-2013-6504	7
EN-OP-104	Operability Determination Process	7
EN-OP-104	Operability Determination Process: CR-GGN-2014-03960	7
EN-LI-108	Event Notification and Reporting	9

Calculations

Number	Title	Revision
CC-Q1111-94004	Probabilistic Evaluation of Tornado Missile Strike for IPEEE Study	1
C-C941	SSW Cooling Tower Fan Stack Tornado Missile Protection	0
MC-Q1111-05004	Maximum Expected Differential Pressure (MEDP) of various AOVs	0
PC-Q1P11-02045	Calculation of the Maximum Expected Differential Pressure for Air Operated Valve 1P11F075 for the GGNS AOV Program	0
PC-Q1P11-02125	Calculation of the required operating Thrust/torque, actuator output capability, and availability actuator capability margin for Air Operated Valve 1P11F062	0
PC-Q1P11-02196	Calculation of the required operating thrust/torque, actuator output capability, and available actuator capability margin of the Air Operated Valve 1P11F063	1

Drawings

Number	Title	Revision
SFD-1065	System Flow Diagram Condensate & Refueling Water Storage & Transfer System	6

Other Documents

Number	Title	Date
GNRI-2004/00013	GGNS, Unit 1 – Issuance of Amendment RE: One-Time Extension of the Integrated Leak Rate Test And Drywell Bypass Test Interval (TAC No. MB8940)	January 28, 2004
46000182	RCIC Pump Drive for Terry Steam Turbine	

Condition Reports

CR-GGN-2014-03320	CR-GGN-2007-00291	CR-GGN-2014-03765
CR-GGN-2014-03960	CR-GGN-2014-04140	

Work Orders

WO 52400215 01

Section 1R18: Plant Modifications

Engineering Changes	Revision
EC 49880, 0	0

Section 1R19: Post-Maintenance Testing

Procedures

Number	Title	Revision
06-OP-SZ51-M-0002, Attachment I	Control Room Standby Fresh Air Unit B Blower Test	108
06-RE-1C51-W-0001	APRM Gain Adjustment – Automatic Method	106
06-OP-1E51-Q-0002	RCIC System Quarterly Valve Operability Test	114

Other Documents

Number	Title	Date
STI Procedure	RCIC In-Service Testing using Handheld Tachometer Test #1a	
STI Procedure	RCIC In-Service Testing using Handheld Tachometer Test #1b	
WO 314640	Change Request # 01	May 12, 2014

Condition Reports

CR-GGN-2014-04125	CR-GGN-2014-04126	CR-GGN-2014-04133
CR-GGN-2014-04134	CR-GGN-2014-04141	CR-GGN-2014-04142
CR-GGN-2014-04120		

Work Orders

WO 00372970 01	WO 00318613 01	WO 00318611 01
WO 00281003 01	WO 00280997 01	WO 00281000 01
WO 00376526 01	WO 00376523 01	WO 00360397 04

WO 52474471 05	WO 00379858 03	WO 00362573
WO 52474117	WO 00355810 01	WO 00355810 02
WO 52476249 01	WO 52476249 05	WO 52541466
WO 52541466 04	WO 52474471 07	WO 00345861 01
WO 00366904 01	WO 00364953	WO 52553930
WO 52489079	WO 00360211 01	WO 00360211 08
WO 00314640	WO 00361191	WO 00348903 01
WO 00348903 05	WO 00326462 01	WO 00326462 05
WO 00340850 01	WO 00340850 02	WO 00340850 01

Section 1R22: Surveillance Testing

Procedures

Number	Title	Revision
06-EL-1L11-W-0001	125-Volt Battery Bank Pilot Cell Check	104
06-0P-1E12-Q-0005	LPCI/RHR Subsystem A MOV Functional Test, Technical Specification: SR 3.6.1.3.4, SR 3.6.4.2.2, 5.5.6, and TRM 7.6.3.3	114
06-0P-1E12-Q-0005	LPCI/RHR Subsystem A MOV Functional Test	114
EN-DC-311	MOV Periodic Verification	4
EN-DC-312	MOV Test Data Review	3
EN-DC-331	MOV Program	4
EN-DC-332	Inservice Testing Duties and Responsibilities	2
06-EL-1R21-M-0001	4.16KV Degraded Voltage Functional Test and Calibration	105
06-IC-1B21-Q-2008, Attachment I	Drywell High Pressure (ECCS) Functional Test Channel A	103
04-S-03-P64-20	Transformer Deluge Functional and full Flow Test (ESF Transformer 12 Deluge D119)	6

Calculations

Number	Title	Date
MPL-5645-M-650.0-NSP64DII9-B.0-1-1	Hydraulic Calculations “Automatic” Sprinkler Corporation of America	February 28, 1978

Drawings

Number	Title
MPL-9645-M-6500-NSP64DII9-13-1-2	Middle South Energy, Inc. Mississippi Power & Light Co. Grand Gulf Nuclear Station Unit 1 Grand Gulf, Miss.

Other Documents

Number	Title	Revision Date
Specification No. 9645-M-650.0	Technical Specification for Deluge and Sprinkler Systems	18
NFPA 803	National Fire Codes, Volume 11	June 6, 1978
NFPA 15	Standard for Water Spray and Fixed Systems for Fire Protection	1996 Edition

Condition Reports

CR-GGN-2014-03349

Work Orders

WO 52536633 01	WO 52536430 01	WO 52529095 01
WO 52529099 01	WO 52529100 01	WO 52553762

Section 1EP6: Drill Evaluation

Other Documents

Title	Date
GGNS Emergency Plan Drill Scenario: Blue Team	May 2014
Grand Gulf Emergency Notification Form #1 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #2 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #3 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #4 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #5 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #6 for Drill	May 7, 2014

Other Documents

Title	Date
Grand Gulf Emergency Notification Form #7 for Drill	May 7, 2014
Grand Gulf Emergency Notification Form #8 for Drill	May 7, 2014
Response Team Predispatch Requirements (Loss if division 1 Buss)	May 7, 2014
Response Team Predispatch Requirements (Search and Rescue Team)	May 7, 2014
Response Team Predispatch Requirements (Open G41F002 normal makeup to spent fuel	May 7, 2014
Response Team Predispatch Requirements (185' and 205' Aux/Brief Team to Evaluate Damage to Spent Fuel Pool)	May 7, 2014
Response Team Predispatch Requirements (166' Aux & 185' Aux/Brief Team to Inject Water into Spent Fuel Pool to Maintain Water Level)	May 7, 2014
Response Team Predispatch Requirements (Close 1A319, Install Flood Plug 5)	May 7, 2014
Response Team Predispatch Requirements (166' Provide Support to Assist Ops Restoring Fuel Pool Cooling	May 7, 2014
Press Release, Entergy GGNS	May 7, 2014 at 9:43 am
News Release, Entergy GGNS	May 7, 2014 at 11:39 am
GGNS 2014 May 7 Site Blue Team Drill Emergency Facility Log EOF	

Condition Reports

CR-GGN-2014-04068	CR-GGN-2014-04069	CR-GGN-2014-04070
CR-GGN-2014-04071	CR-GGN-2014-04073	CR-GGN-2014-04074
CR-GGN-2014-04075	CR-GGN-2014-04076	CR-GGN-2014-04077
CR-GGN-2014-04089	CR-GGN-2014-04040	CR-GGN-2014-04042
CR-GGN-2014-04043	CR-GGN-2014-04044	

Section 4OA1: Performance Indicator Verification

Procedures

Number	Title	Revision
EN-LI-114	Performance Indicator Process, 1st Qtr 2014	6
EN-LI-114	Performance Indicator Process, 1st Qtr 2013	6
06-OP-1000-D-0001, Attachment I	Daily Operator Logs 12-HR Requirements, Due 8 am	143

Procedures

Number	Title	Revision
06-OP-1000-D-0001, Attachment I	Daily Operator Logs 12-HR Requirements, Due 8 pm	143
06-CH-1B21-W-0008	Reactor Coolant Dose Equivalent Iodine	105

Other Documents

Number	Title	Date
	Monthly Summaries for Drywell Total Leakage	April 2013 – March 2014

Work Orders

WO 52454795	WO 52455797	WO 52456976
WO 52458164	WO 52459414	WO 52460655
WO 52461617	WO 52462716	WO 52464091
WO 52465480	WO 52467132	WO 52468729
WO 52470341	WO 52471808	WO 52473355
WO 52474742	WO 52476121	WO 52477565
WO 52478759	WO 52480542	WO 00359843
WO 52481840	WO 52483552	WO 52484755
WO 52485975	WO 52487295	WO 52488861
WO 52490186	WO 52491483	WO 52492728
WO 52494093	WO 52495415	WO 52496704
WO 52498002	WO 52499212	WO 52500566
WO 52502093	WO 52503923	WO 52506054
WO 52507563	WO 52511033	WO 52512872
WO 52514559	WO 52515970	WO 52517541
WO 52519104	WO 52520572	WO 52521682
WO 52522834	WO 52524050	WO 52525447
WO 52526784	WO 52527938	

Section 4OA2: Problem Identification and Resolution

Procedures

Number	Title	Revision
06-IC-1B21-R-2012	Reactor Vessel Water Level (HPCS) Calibration	104
05-S-02-VI-3	Off-Normal Event Procedure Earthquake	110
EN-LI-121	Trending and Performance Review Process	15
EN-LI-121-01	Trend Codes	6

Calculations

Number	Title	Revision
JC-01B21-N674-1	Level 8 Wide Range HPCS Injection Valve Closure	0
JC-Q1111-09017	Drift Calculation for Rosemount Range Codes 4-7 Differential Pressure Transmitters	0
JC-Q1B21-N682-1	Level 2 Setpoint Calculation	1
JC-01B21-N674-1	Level 8 Wide Range HPCS Injection Valve Closure	1

Other Documents

Number	Title	Revision Date
460000047	Instruction & Service Manual for Rosemount Trip/Calibration System Model 510DU	
TSTF-09-29	Transmittal of Revised TSTF-493, Revision 4	January 5, 2010
NEDC-31336P-A	General Electric Instrument Setpoint Methodology	September 1996
ANSI/ISA-67.04.01-2006	Setpoints for Nuclear Safety-Related Instrumentation	October 13, 2011
GGNS-JS-09	Methodology for the Generation of Instrument Loop Uncertainty & Setpoint Calculations	1
2014 Technical Report	Electric Power Research: Guidelines for Instrument Calibration Extension/Reduction	2
	System Health Report DIV 1 & 2 Emergency Diesel Generators Q1-2014	May 21, 2014
GGNS-MS-37	GGNS Mechanical Standard for the division I and 2 Diesel Generator Maintenance	6

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CR-GGN-2013-00371	CR-GGN-2012-00821	CR-GGN-2012-09399
CR-GGN-2012-11068	CR-GGN-2012-11841	CR-GGN-2013-04384
CR-GGN-2013-04919	CR-GGN-2014-03397	CR-GGN-2013-07859
CR-GGN-2011-04010	CR-GGN-2012-10054	CR-GGN-2014-00284
CR-GGN-2011-05338	CR-GGN-2013-04063	CR-GGN-2014-00387
CR-GGN-2011-05387	CR-GGN-2013-04325	CR-GGN-2014-00519
CR-GGN-2012-01744	CR-GGN-2013-04358	CR-GGN-2014-01798
CR-GGN-2012-05560	CR-GGN-2013-04361	CR-GGN-2014-02119
CR-GGN-2012-06138	CR-GGN-2013-04718	CR-GGN-2014-03883
CR-GGN-2012-07028	CR-GGN-2013-05535	CR-GGN-2014-04159
CR-GGN-2012-08906	CR-GGN-2013-05651	CR-GGN-2014-04163
CR-GGN-2014-03006	CR-GGN-2013-07616	CR-GGN-2012-0055
CR-GGN-2012-9193	CR-GGN-2012-9507	CR-GGN-2012-9842
CR-GGN-2012-0447	CR-GGN-2013-2666	CR-GGN-2013-2707
CR-GGN-2013-5223	CR-GGN-2013-5275	CR-GGN-2013-6441
CR-GGN-2013-6651	CR-GGN-2014-515	CR-GGN-2014-516
CR-GGN-2014-694	CR-GGN-2014-2124	CR-GGN-2014-3793
CR-GGN-2014-3870	CR-GGN-2014-3909	CR-GGN-2014-3314
CR-GGN-2012-8896	CR-GGN-2012-9028	CR-GGN-2012-0365
CR-GGN-2012-0372	CR-GGN-2013-1582	CR-GGN-2012-9808
CR-GGN-2013-4366	CR-GGN-2012-08436	CR-GGN-2013-03639
CR-GGN-2013-04831	CR-GGN-2013-07575	CR-GGN-2014-00468
CR-GGN-2012-00273	CR-GGN-2013-07616	

Engineering Changes	Revision
EC 39554	0
EC 39605	0

Work Orders

WO 00270690 01	WO 00280303 01	WO 00285844 01
WO 00311413 01	WO 00370679 01	WO 00372688 01

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures

Number	Title	Revision
EN-LI-118-08, Attachment 9.2	Failure Mode Analysis Worksheet CR-2014-3131	1
01-S-06-28	Post-Trip Analysis GGNS Unit 1, Scram No. 135	21
EN-DC-115	Engineering Change Process	16
EN-DC-134	Design Verification	5
EN-DC-141	Design Inputs	14
EN-HU-104	Engineering Task Risk & Rigor	4

Other Documents

Number	Title	Date
RMP-GG-20-004	Gen Sync to 1st Suppressed Pattern	April 2014
	GGNS Load Reject Trip for SCRAM on March 29, 2014	
49972	Event Notification Report	March 29, 2014
GGNS LER 2013-006-00	Primary Containment Inoperable Due to an Inadequate Surveillance Procedure Resulting in a Loss of Safety Function	February 15, 2014
Red Memo	Steam Leak on Main Steam Line resulting in Scram 134 (CR-GGN-2014-02824)	April 23, 2014
Root Cause Evaluation (RCE) Attachment 9.6	Steam Leak on Main Steam Line resulting in Scram 134	April 15, 2014
GGNS LER 2013-005-00	Reactor Pressure Vessel steam pressure less than 0 psig during six plant startups resulting in a violation of Technical Specification 3.4.11, RCS Pressure and Temperature (Pff) Limits.	February 5, 2014
GGNS LER 2014-002-00	Manual actuation of the Reactor Protection System due to Steam Leak with Reactor Core Isolation Cooling manual initiation	May 15, 2014

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CR-GGN-2013-07021	CR-GGN-2013-07734

Section 4OA5 Other Activities

Safety Culture Assessment Documents

Title	Revision/Date
Entergy Nuclear Lesson Plan FCBT-GET-PATSS	16
Entergy Nuclear Safety Culture Assessment 2012 Survey	April 30, 2013

Procedures

Number	Title	Revision
EN-MP-120	Material Receipt	7
EN-MP-121	Materials, Purchasing and Contracts Indoctrination &Training	5
EN-MP-138	Commercial Grade Dedication Lab Conduct of Operation	1
EN-QV-100	Conduct of Nuclear Oversight	9
EN-QV-111	Training and Certification of Inspection/Verification and Examination Personnel	13

Condition Reports

CR-HQN-2013-00466 CR-HQN-2011-00979

Licensing Documents

Title	Revision
Entergy Quality Assurance Program Manual	25

Section 4OA7: Licensee-Identified Violations

Condition Reports

CR-GGNS-2014-02141

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Sincerely,

/RA/

Don Allen, Branch Chief
Project Branch C
Division of Reactor Projects

Docket No.: 50-416
License No.: NPF-29

Enclosure:
Inspection Report 05000416/2014003
w/Attachment: Supplemental Information

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Subject: GRAND GULF NUCLEAR STATION – NRC INSPECTION REPORT 05000416/ 2014003

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