UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

March 29, 2019

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

SUBJECT: GRAND GULF NUCLEAR STATION – NRC SPECIAL INSPECTION REPORT 05000416/2018050

Dear Mr. Larson:

On February 28, 2019, the Nuclear Regulatory Commission (NRC) completed a special inspection at your Grand Gulf Nuclear Station. This inspection examined activities associated with a turbine bypass valve failure resulting in operators initiating a manual reactor scram on December 12, 2018. Following the scram control room operators were initially unsuccessful establishing injection flow to the reactor and a control rod drive pump unexpectedly tripped. The NRC's initial evaluation satisfied the criteria in NRC Management Directive 8.3, "NRC Incident Investigation Program," for conducting a special inspection. The basis for initiating this special inspection is further discussed in the Charter, which is included as an attachment to this report. The determination that the inspection would be conducted was made by the NRC on December 17, 2018.

NRC inspectors documented two findings of very low safety significance (Green) in this report, one of which involved a violation of NRC requirements. The NRC is treating this violation as a non-cited violation (NCV) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest this violation or its significance, 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; and the NRC resident inspector 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region IV; and the NRC resident inspector at the Grand Gulf Nuclear Station.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Jason W. Kozal, Branch Chief
Project Branch C
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000416/2018050
w/ Attachment:
Special Inspection Charter dated
December 17, 2018 (ADAMS ML18351A001)

U.S. NUCLEAR REGULATORY COMMISSION
Inspection Report

Docket Number(s):	05000416
License Number(s):	NPF-29
Report Number(s):	05000416/2018050
Enterprise Identifier:	I-2018-050-0004
Licensee:	Entergy Operations, Inc.
Facility:	Grand Gulf Nuclear Station, Unit 1
Location:	Port Gibson, Mississippi
Inspection Dates:	December 17, 2018, to February 28, 2019
Inspectors:	C. Young, P.E., Senior Project Engineer (Team Lead) M. Chambers, P.E., Physical Security Inspector L. Newman, Project Engineer D. Loveless, Senior Reactor Analyst
Approved By:	Jason W. Kozal Chief, Project Branch C Division of Reactor Projects

Enclosure

SUMMARY

The U.S. Nuclear Regulatory Commission (NRC) continued monitoring the licensee's performance by conducting a special inspection at Grand Gulf Nuclear Station, Unit 1, in accordance with the Reactor Oversight Process. The Reactor Oversight Process is the NRC's program for overseeing the safe operation of commercial nuclear power reactors. Refer to https://www.nrc.gov/reactors/operating/oversight.html for more information. NRC-identified and self-revealed findings, violations, and additional items are summarized in the table below.

List of Findings and Violations

<table>
<tr><td colspan="4">Failure to Establish RCIC Injection Flow to the Reactor Vessel During Manual Operation</td></tr>
<tr><td>Cornerstone</td><td>Significance</td><td>Cross-cutting Aspect</td><td>Inspection Procedure</td></tr>
<tr><td>Mitigating Systems</td><td>Green
NCV 05000416/2018050-01
Closed</td><td>H.9 – Human Performance, Training</td><td>93812—Special Inspection</td></tr>
<tr><td colspan="4">A self-revealed, Green finding with an associated non-cited violation of 10 CFR 55.46(c), "Plant-referenced simulators," was identified for the licensee's failure to ensure that the simulator demonstrated expected plant response to operator input and conditions to which it has been designed to respond. Deficiencies involving simulator fidelity negatively impacted operator performance during a plant event on December 12, 2018, during which operators performed a manual actuation of the reactor core isolation cooling system and failed to establish sufficient system discharge pressure to achieve injection flow to the reactor vessel upon actuation of the system.</td></tr>
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<table>
<tr><td colspan="4">Failure to Correct a Condition Associated with Post-Scram Control Rod Drive Pump Trips</td></tr>
<tr><td>Cornerstone</td><td>Significance</td><td>Cross-cutting Aspect</td><td>Inspection Procedure</td></tr>
<tr><td>Mitigating Systems</td><td>Green
FIN 05000416/2018050-02
Closed</td><td>P.5 – PI&R, Operating Experience</td><td>93812—Special Inspection</td></tr>
<tr><td colspan="4">The inspectors identified a Green finding for the licensee's failure to address the cause and correct a condition associated with post-scram control rod drive system pump trips as required for an adverse condition by station procedure EN-LI-102, "Corrective Action Program."</td></tr>
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INSPECTION SCOPE

Inspections were conducted using the appropriate portions of the inspection procedures (IPs) in effect at the beginning of the inspection unless otherwise noted. Currently approved IPs with their attached revision histories are located on the public website at http://www.nrc.gov/reading-rm/doc-collections/insp-manual/inspection-procedure/index.html. Samples were declared complete when the IP requirements most appropriate to the inspection activity were met consistent with Inspection Manual Chapter (IMC) 2515, "Light-Water Reactor Inspection Program - Operations Phase." The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel to assess licensee performance and compliance with Commission rules and regulations, license conditions, site procedures, and standards.

OTHER ACTIVITIES – TEMPORARY INSTRUCTIONS, INFREQUENT AND ABNORMAL

93812—Special Inspection (1 Sample)

In accordance with the attached Special Inspection Team Charter, the inspection team conducted a detailed review of the turbine bypass valve failure and manual reactor scram event which occurred on December 12, 2018.

.1 Description of Event and Reactive Inspection Basis

On December 12, 2018, with the plant operating at 100 percent power, a failure began to develop in a component associated with the 'A' main turbine bypass control valve (BCV), which is expected to remain fully closed during normal full power operation. This failure resulted in erratic movement of the valve, up to approximately 10 percent open, over approximately a 90-minute time period. During this time, operators noted small increases in reactor power, as well as a reduction in generated electrical output to the grid. Operators acted to reduce reactor power on three occasions. With troubleshooting efforts underway to close the 'A' BCV, the degradation became worse and resulted in increased opening of the 'A' BCV. Operators inserted a manual reactor scram. With the 'A' BCV remaining open, operators closed all main steam isolation valves (MSIVs) to maintain reactor pressure control and limit the reactor coolant system cooldown rate.

Following the scram, control rod drive (CRD) pump 'B' unexpectedly tripped on high suction differential pressure and low suction pressure, and CRD pump 'A' was manually started. Emergency Procedure 2, "RPV Control," Revision 46, was entered due to reactor water level dropping below 11.4 inches (Level 3). Reactor pressure control was maintained by manually cycling safety relief valves (SRVs) discharging to the suppression pool. Both divisions of the residual heat removal (RHR) system were placed into suppression pool cooling mode. Emergency Procedure 3, "Containment Control," Revision 31, was entered when suppression pool temperature increased to 95 degrees. The RHR system in suppression pool cooling mode maintained pool temperature at 94 degrees.

Operators conducted a controlled manual start of the reactor core isolation cooling (RCIC) system to maintain water inventory in the reactor vessel and control reactor water level within an established control band. Injection flow from the RCIC system was not initially achieved when expected. As a result, operators manually initiated the high pressure core spray (HPCS) system to recover reactor water level. The HPCS system was operated for approximately 1 minute. Approximately 11 minutes later, reactor water level exceeded the

Level 8 setpoint, which caused an isolation of the steam supply to the RCIC system and a loss of RCIC injection flow, as designed. RCIC system operation was restored approximately 8 minutes later after reactor water level was restored within the established control band. Following the initial failure to achieve RCIC injection flow, the RCIC system was subsequently operated to maintain reactor vessel level, except for the Level 8 trip. Operators proceeded to conduct a cooldown of the plant to Mode 4.

Management Directive 8.3, "NRC Incident Investigation Program," was used to evaluate the level of NRC response for this event. Based on the deterministic criteria and risk insights related to this event, the NRC determined that the appropriate level of response was to conduct a Special Inspection. The inspectors determined that the inspection did not need to be upgraded to an Augmented Inspection Team response. This Special Inspection Team was chartered to identify the circumstances surrounding this event and review the licensee's actions to address the causes of the event.

.2 Develop a complete sequence of events related to the manual scram event on December 12, 2018.

The inspectors conducted a detailed review of the events related to the December 12, 2018, reactor scram. The team gathered information from operations logs, the plant data system computer, licensee cause evaluations and post-trip analysis, sequence of events printouts, alarm printouts, condition reports, and interviews with plant operations personnel and engineering staff to develop the following timeline of the event.

Sequence of events on December 12, 2018:

Time	Conditions and Actions
12:00 p.m.	The 'A' main turbine bypass control valve (BCV) begins to open and fluctuate in the open and closed directions, up to approximately 10 percent open. The turbine control system begins to automatically modulate main turbine control valves closed, as designed, to maintain main steam pressure.
12:12 p.m.	Operators reduced power by 1 megawatt electric (MWe) using reactor recirculation flow control valves.
12:22 p.m.	Operators reduced power by 2 MWe using reactor recirculation flow control valves.
12:29 p.m.	The operating crew entered the station's off-normal event procedure for reactor pressure control, based on an unexplained decrease in main generator output of approximately 30 MWe over the previous 20 minute time period, in addition to small increases in reactor thermal power.
12:30 p.m.	Operators logged that the 'A' BCV was observed to be 11 percent open. The licensee initiated actions to evaluate the problem and plan steps to manually close the 'A' BCV.
1:30 p.m.	The 'A' BCV position began to trend in the open direction.
1:40 p.m.	Operators performed a 10 MWe power reduction using reactor recirculation flow control valves.

Time	Conditions and Actions
1:40 p.m.	The ‘A’ BCV began to open at an increased rate.
1:51 p.m.	Operators inserted a manual reactor scram.
1:52 p.m.	Operators closed the main steam isolation valves (MSIVs) at a reactor pressure of approximately 805 psig.
1:53 p.m.	The running CRD system pump (‘B’) tripped.
1:53 p.m.	The operating crew established a reactor pressure control band of 800 psig to 1060 psig in accordance with station procedures by operating safety relief valves (SRVs) as needed to relieve steam from the reactor pressure vessel (RPV) to the suppression pool.
1:54 p.m.	Operators re-established CRD system operation using the ‘A’ pump.
1:57 p.m.	The operator assigned to control reactor pressure opened an SRV at approximately 1050 psig. Reactor pressure began lowering.
1:58 p.m.	The operating crew established a reactor water level control band of -30 inches to +50 inches in accordance with station procedures using the reactor core isolation cooling (RCIC) system to inject water to the RPV as needed.
1:59 p.m.	The operator assigned to control reactor water level initiated a manual controlled start of the RCIC system.
2:00 p.m.	The pressure control operator closed the SRV. Reactor pressure began increasing.
2:03 p.m.	The level control operator established RCIC pump speed and discharge pressure using manual control of the RCIC flow controller and attempted to initiate injection flow to the RPV from the RCIC system by opening the RCIC injection valve. No injection flow was achieved.
2:04 p.m.	The pressure control operator opened an SRV. Reactor pressure began decreasing.
2:05 p.m.	Reactor pressure decreased to less than the RCIC system discharge pressure that had been previously established by the level control operator. This resulted in the initiation of injection flow from the RCIC system to the RPV.
2:07 p.m.	RCIC system injection flow reached 771 gpm in accordance with the manual flow controller setting that had been established.
2:08 p.m.	Operators manually started the high pressure core spray (HPCS) system and initiated flow into the RPV at a reactor water level of approximately -25 inches.
2:09 p.m.	Operators secured flow from the HPCS system.
2:09 p.m.	The pressure control operator closed the SRV.

Time	Conditions and Actions
2:16 p.m.	Operators placed ‘A’ and ‘B’ residual heat removal (RHR) system pumps in suppression pool cooling mode in accordance with station emergency procedure EP-3 after suppression pool temperature increased to 95 degrees.
2:20 p.m.	The pressure control operator opened an SRV.
2:21 p.m.	Reactor water level increased to greater than +53.5 inches, which resulted in a Level 8 trip of the RCIC system and loss of injection flow to the RPV.
2:28 p.m.	Operators restarted the RCIC system and re-established injection flow to the RPV.
4:29 p.m.	At 4:29 p.m. on December 12, 2018, the licensee completed a notification to the NRC to report an actuation of the reactor protection system (RPS) and an emergency core cooling system (ECCS) discharge to the reactor coolant system.
4:34 p.m.	Operators placed the condensate system in service for RPV level control in accordance with station procedures.

.3 Review the licensee’s causal evaluations and determine if they are being conducted at a level of detail commensurate with the significance of the issues that were encountered during the event.

The inspection team reviewed the issues associated with this event that the licensee had entered into the corrective action program and had identified as subjects for causal evaluations. The team determined that the licensee’s causal evaluations were being conducted at the appropriate levels, commensurate with the significance of the associated issues. The team determined that the licensee initiated a condition report associated with the reactor scram (CR-GGN-2018-13032) and initiated an ‘A’ level root cause evaluation. The team also determined that the licensee initiated a condition report on December 13, 2018, associated with problems encountered with placing the RCIC system in service during the event (CR-GGN-2018-13050). During the inspection, the licensee elevated this issue to a ‘B’ level and initiated an apparent cause evaluation. The inspectors also noted that the licensee had initiated a condition report associated with a control rod drive pump trip that occurred following the reactor scram (CR-GGN-2018-13038). During the inspection, the licensee elevated this issue to a ‘B’ level and initiated an equipment failure evaluation.

.4 Determine the causes for the unexpected opening of a turbine bypass valve at 100 percent power.

On December 12, 2018, control room operators observed the ‘A’ main turbine bypass control valve (BCV), 1N37F001A, opening unexpectedly. The ‘A’ BCV began to slowly modulate between approximately zero to ten percent open over the course of approximately 90 minutes. After this point, the valve began to open at an increased rate, reaching approximately fifty percent open prior to operators performing a manual reactor scram. Three BCVs are used to control reactor pressure during reactor heat-up and avoid large power transients during full power operation. The BCVs are sized to allow for bypass of up to 30 percent of rated main steam flow around the main turbine to the main condenser to help mitigate large transients such as main generator load rejects. They are expected to remain fully closed during normal full power operation.

The inspectors reviewed the results of the licensee's testing and troubleshooting of the 'A' BCV, which revealed that a valve position indication coil had failed, producing an erroneously low valve position feedback signal to the control system. This failure resulted in a position error signal at the valve controller, which caused valve movement in the open direction initially, and then small valve movements in both the open and closed directions, up to approximately 10 percent open, over the course of approximately 90 minutes. Although there is a supervisory circuit which is designed to detect a failure of the Bypass Control Unit (BCU) by comparing the position signals among the three bypass control valves, the nature of this failure did not trigger the alarm until the failure resulted in more significant valve opening after the reactor scram occurred. The supervisory circuit operates by comparing valve position to the other bypass valves, and if the difference exceeds approximately 10 percent, it will disable the failed BCU controller and place the associated valve on an auxiliary controller. With the affected valve's position coil indicating a slightly less than closed output, and the other two valves remaining closed, the circuit did not sense a position feedback signal difference above the established threshold. This condition rendered the feedback coil supervisory circuit ineffective for this failure mode of the position feedback coil. Prior to the scram, there were no alarms received from the bypass control system. A bypass valve lift fault indication was received following the scram, which was confirmed by walkdowns of the BCU cabinets. Functionality of this supervisory circuit was subsequently verified via testing after the event, and the licensee replaced the associated comparator card to provide added confidence. The failed feedback coil was replaced with an installed spare, and the valve and coil were calibrated and tested satisfactory.

The inspectors reviewed previous vendor overhaul testing data for the 'A' BCV, which showed no problems with the position feedback coil. The inspectors also reviewed valve performance data for the 'B' and 'C' BCVs, with no abnormalities noted. The inspectors also reviewed industry operating experience and did not identify previous feedback coil reliability problems that caused similar failures.

To prevent recurrence of this type of failure from resulting in the need for a manual scram, the licensee added instructions to the station's off-normal event procedure for reactor pressure control malfunctions, 05-1-02-V-21, to include steps to achieve manual closure of a drifting bypass valve using controls available at a turbine control system cabinet located outside of the main control room. Specifically, the added instructions serve to disable the bypass controller and force a transfer to the auxiliary channel to close the affected valve.

.5 <u>Evaluate operator actions taken to respond to the inadvertent opening of the turbine bypass valve, including control of reactor power and reactor pressure</u>.

The inspection team reviewed data for plant operating parameters from the event, reviewed station logs and procedures, and interviewed operations and engineering personnel regarding actions that were taken in response to the conditions encountered during the event. The team determined that the operating crew was appropriately monitoring and maintaining plant parameters, including reactor power, pressure, and water level, during the time period when the plant continued to operate at power with unexpected movement of a turbine bypass valve. Reactor power, pressure and water level remained relatively stable during this time period. The turbine control system responded as expected by modulating the turbine control valves closed to maintain main steam pressure. Operators observed a corresponding decrease in main generator output, as well as small increases in reactor thermal power. Operators responded appropriately by reducing reactor power using recirculation control valves to maintain specified averages for licensed thermal power within licensed limits.

About 20 to 25 minutes after the 'A' turbine bypass valve failure began to cause unexpected movement of the valve, operators identified that this bypass valve was not in its expected closed position. The team determined that the station's off-normal event Procedure 05-1-02-V-21, "Reactor Pressure Control Malfunctions," was effectively implemented. Step 3.5 of this procedure provided directions for response to a turbine bypass valve malfunction, including monitoring condenser vacuum and reactor pressure. The licensee initiated actions to troubleshoot the condition to determine the nature of the problem and whether actions could be developed to address the condition and restore normal function of the valve. Approximately 90 minutes after the initial failure occurred, the condition became more significant and resulted in further uncontrolled opening of the affected bypass valve. Operators responded to this condition by conducting a manual reactor scram.

.6 Evaluate operator actions taken to perform a manual reactor scram and closure of MSIVs in response to the inadvertent turbine bypass valve opening.

The inspection team reviewed data for plant operating parameters, reviewed station logs and procedures, and interviewed operations and engineering personnel. The team determined that the operating crew took appropriate actions to perform a manual reactor scram and manual closure of MSIVs in response to the conditions that resulted from the turbine bypass valve failure. Shortly after performing a power reduction at 1:40 p.m. and noting the increasing trend in the 'A' turbine bypass valve position, the operating crew determined that stable control of critical plant parameters could no longer be assured and concluded that the appropriate response was to perform a manual reactor scram. The crew recognized that if the affected bypass valve continued to open, a manual closure of MSIVs would be appropriate to prevent an uncontrolled reactor depressurization and cooldown. At approximately 1:49 p.m., the crew conducted a brief for performing a scram including contingency actions for MSIV closure. At 1:51 p.m., a manual reactor scram was initiated. Within approximately 1-2 minutes following the scram, the crew appropriately diagnosed that the open bypass valve condition warranted MSIV closure, and all MSIVs were manually closed. The decrease in reactor pressure was limited to approximately 805 psig, which was above the lower end of the control band for reactor pressure that was established in accordance with station procedures.

.7 Evaluate operator actions to ensure proper decay heat removal following the scram, including control of reactor pressure vessel (RPV) pressure and inventory/level.

The inspection team reviewed data for plant operating parameters, station logs, procedures, corrective action program documentation, engineering evaluations, and interviewed operations and engineering personnel. The inspection team also observed plant simulator demonstrations that included conditions and equipment operations involved with this event. Following the scram with MSIV closure, the licensee implemented a control band of 800-1060 psig for reactor pressure using manual operation of safety relief valves (SRVs) in accordance with station procedures. The licensee also implemented suppression pool cooling using the residual heat removal (RHR) system in accordance with station procedures. Emergency Procedure 05-S-01-EP-3, "Containment Control," was implemented as required when suppression pool temperature reached 95 degrees F due to steam discharge to the pool from SRV opening as well as turbine exhaust from operation of the RCIC system.

Emergency Procedure 05-S-01-EP-2, “RPV Control,” was implemented as required when reactor water level dropped below +11.4 inches (Level 3). For reactor water level control, the licensee implemented an “expanded” level control band of -30 inches to +50 inches, in accordance with station procedures. Water level control was intended to be accomplished using the RCIC system as a source of injection to the reactor vessel. Operators attempted to perform a manual start of the RCIC system in accordance with Procedure 04-1-01-E51-1, “Reactor Core Isolation Cooling System,” Revision 139, Attachment VI; however, RCIC injection flow was not achieved due to operators establishing insufficient system discharge pressure with the flow controller in manual mode. The inspectors identified a performance deficiency associated with the failure to establish injection flow upon conducting a manual start of the RCIC system. These details associated with this finding are further described in the inspection results section below.

Injection flow from the RCIC system was only achieved when manual SRV operation resulted in a reduction reactor vessel pressure sufficiently below the RCIC discharge pressure that had been established by the operator when conducting the manual system start. As a result of the initial failure to establish RCIC injection flow, the high pressure core spray (HPCS) system was manually operated in order to maintain reactor water level within the prescribed control band. Injection flow from both the HPCS (approximately 4,300 gallons per minute) and RCIC (approximately 800 gallons per minute) systems resulted in reactor water level being established high in the prescribed control band at the time an SRV was manually opened for reactor pressure control. In this condition, the expected effect on reactor water level from manual SRV operation was not able to be accommodated, and a high reactor water level of greater than +53.5 inches (Level 8) caused an isolation of the steam supply to the RCIC system, as designed. The RCIC system was subsequently restored to operation when reactor water level was restored within the established control band. The inspectors documented an observation in the Inspection Results report section below related to the coordination of actions by the operators to control reactor vessel pressure and water level.

.8 Determine the causes associated with the failure of the RCIC system to provide the expected injection flow during the event.

The inspection team reviewed data for plant operating parameters, station logs, procedures, corrective action program documentation, engineering evaluations, and interviewed operations and engineering personnel. As discussed in the report section above, the initial failure to establish the expected injection flow from the RCIC system was due to insufficient system discharge pressure being established with the flow controller in manual mode. The RCIC system was subsequently evaluated to be in an operable condition; however, with the flow controller selected to manual mode and set to a specific governor setting, the system was in a condition where it would not provide any injection flow unless reactor pressure was sufficiently reduced by separate action.

The controlled start operating procedure for the RCIC system stated to establish a system discharge pressure greater than reactor pressure, open the injection valve, and then adjust flow as necessary with the flow controller. The operator established a RCIC pump speed and discharge pressure that was expected to result in injection flow when the RCIC injection valve was opened; however, no injection flow was observed when the RCIC injection valve was opened. A subsequent evaluation by the licensee determined that, due to the effects of elevation differences between the location of the RCIC pump and the injection point to the reactor vessel, and other system characteristics, the indication of RCIC discharge pressure available to the operators must indicate a minimum of approximately 30 psig greater than the indication of reactor pressure in order to result in the initiation of RCIC injection flow. At the time of the attempted initiation of RCIC injection flow, RCIC discharge pressure had been established approximately 23 psi higher than reactor pressure. As a result of no indication of injection flow, as well as a RCIC governor valve indication of closed (green) while the pump was running (which was determined to have been characteristic of this plant indication for a number of years), the operating crew did not proceed any further with implementing the RCIC system operating instruction (i.e., no further adjustment to the flow controller was made). This action was also based on Grand Gulf operations management expectations that operators should not proceed with an activity in the face of uncertainty.

It was determined that the plant simulator modeled the initiation of RCIC injection flow at an indicated pressure difference of approximately 10 psig, and that the plant simulator modeled the RCIC governor valve indication as intermediate (red and green) when the pump was in operation. The inspectors determined that the manual RCIC start was not successfully accomplished because operators stopped performing procedure steps when an expected system response was not observed. The expected system response was based on operating parameters established during prior successful performances of the activity in training scenarios using the existing operating procedure steps, with simulator indications. The unexpected system response led to the initial diagnosis that the system was not functioning properly. It was ultimately determined that the system was capable of functioning properly but was not operated in a way to ensure injection flow under existing plant conditions.

The licensee revised Procedure 04-1-01-E51-1, "Reactor Core Isolation Cooling System," to include guidance on selection of the quick start option for a RCIC manual start (vs. the controlled start option for a manual start). The quick start option maintains the controller in the automatic mode of operation. The licensee also added guidance to this procedure for establishing a specific range of indicated RCIC pump discharge pressure above indicated reactor pressure prior to opening the injection valve.

.9 Determine the causes for the trip of a CRD system pump during the event. Evaluate the licensee's actions to address previous similar occurrences.

During the response to the reactor scram, control rod drive (CRD) pump B unexpectedly tripped on low suction pressure, and CRD pump A was manually started in accordance with station procedures to restore the function of the CRD system as a high pressure injection source. This trip occurred due to an expected system operating characteristic where the CRD pump suction pressure decreases momentarily following a scram due to increased system flow to refill the hydraulic control unit (HCU) accumulators and due to reduced reactor pressure.

The inspectors reviewed station operating logs, corrective action program documentation and evaluations for previous similar conditions, engineering evaluations, and interviewed engineering and operations personnel. The inspectors also reviewed industry-wide as well as internal licensee operating experience involving post-scram low suction pressure CRD pump trips, and determined that the conditions that led to the occurrence of similar trips were corrected at other facilities, including other Entergy facilities, by the implementation a time delay to prevent the normal/expected low pressure transient condition resulting from the plant scram from resulting in a trip of the running CRD pump(s).

Following this December 2018 scram event, NRC inspectors noted several previous post-scram CRD low suction pressure trips having been documented in the licensee's corrective action program records and requested the licensee provide a complete list of similar previous occurrences. In the past 10 years, Grand Gulf Nuclear Station has experienced five low suction CRD pump trips involving either of the 'A' and 'B' CRD pumps coincident with a plant scram. Following the inspector's questions regarding the history of this condition occurring, the licensee initiated a 'B' level Equipment Failure Evaluation. The corrective actions associated with this evaluation included evaluating the implementation of a time delay associated with the CRD pump low suction pressure trip signal, consistent with the actions that had previously been implemented at other stations to address this condition.

The inspectors identified a performance deficiency associated with the license's failure to correct this adverse condition during previous opportunities. Further details associated with this finding are discussed in the inspection results report section below.

.10 Determine whether the licensee appropriately evaluated the operability of the RCIC system to meet technical specification requirements.

The inspection team reviewed data for plant operating parameters, station logs, procedures, corrective action program documentation, engineering evaluations, and interviewed operations and engineering personnel. The inspectors reviewed the licensee's operability determination associated with the condition described in Condition Report CR-GGN-2018-13050, which involved no injection flow being observed from the RCIC system upon implementing the manual controlled start. This condition report was generated approximately 10:00 a.m. on the day following the event, 20 hours after the event occurred. The initial evaluation of the condition was based on incomplete information that had been relayed to operations shift personnel that were not involved with the event in question. The licensee initiated Condition Report CR-GGN-2018-13160 to document this issue. As a result, the initial immediate operability review declared that the RCIC system was inoperable based on a presumed condition that the "RCIC governor was slow to respond" during system startup. This presumed condition was based in part on the observed indication that the RCIC governor valve was closed when the pump was operating at rated speed and producing approximately 1000 psig of discharge pressure.

Reviews of plant data showed that the RCIC system responded to operator inputs and functioned as designed during the event. Injection flow was not initially achieved due to insufficient system discharge pressure being established with the flow controller in manual mode. The closed governor valve indication was determined to be due to a long-standing issue associated with the configuration of the associated valve position limit switch. The inspectors noted that with the pump operating at rated speed and discharge pressure, the governor valve could not have been in a closed position. During the event, after injection flow was initiated because of lowering reactor vessel pressure from manual SRV operation, the RCIC system was subsequently operated normally. The licensee revised the associated operability evaluation to reflect a conclusion that the RCIC system was capable of performing its required safety function to meet technical specification requirements.

The inspectors reviewed previous RCIC surveillance test results from November 29, 2018, as well as RCIC post-scram operation data from the plant data system. The data and test results supported the conclusion that the RCIC system was in an operable condition. The RCIC system is designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to occur. It is designed to inject cooling water at a rate of 800 gpm against a reactor vessel pressure of 1192 psia. According to plant data and surveillance results, the RCIC system was functioning as designed and responded as designed to the operator input. The inspectors concluded that the RCIC system was capable of meeting the Technical Specification 3.5.3 requirements for operability during the December 12, 2018, scram event.

.11 Evaluate the licensee's actions to comply with reporting requirements associated with this event.

The inspection team reviewed notification requirements under 10 CFR 50.72 and 10 CFR 50.73, as well as licensee procedures EN-LI-108, "Event Notification and Reporting," and 01-S-06-5, "Reportable Events or Conditions." The inspectors determined that the licensee submitted event notification (EN) #53788 to the NRC at 4:29 p.m. on December 12, 2018, to report two 4-hour non-emergency reportable conditions associated with this event. Specifically, the actuation of the reactor protection system (RPS) while the reactor was critical was determined to be reportable under 10 CFR 50.72(b)(2)(iv)(B), and the discharge of an ECCS system to the reactor coolant system (RCS) was determined to be reportable under 10 CFR 50.72(b)(2)(iv)(A). The licensee also reported an update to EN #53788 on December 14, 2018, to indicate that an 8-hour non-emergency criterion under 10 CFR 50.72(b)(3)(iv)(A) was applicable for this event due to the actuation of the RCIC system and had not been indicated in the original event notification on December 12. The inspectors also determined that the licensee submitted licensee event report (LER) 2018-010-00 on February 8, 2019, in accordance with 10 CFR 50.73(a)(2)(iv)(A).

The inspectors developed observations, which are discussed in the next report section, regarding the licensee's notifications to the NRC associated with this event.

INSPECTION RESULTS

Failure to Establish RCIC Injection Flow to the Reactor Vessel During Manual Operation			
Cornerstone	Significance	Cross-cutting Aspect	Inspection Procedure
Mitigating Systems	Green NCV 05000416/2018050-01 Closed	H.9 – Human Performance, Training	93812 – Special Inspection
A self-revealed, Green finding with an associated non-cited violation of 10 CFR 55.46(c), "Plant-referenced simulators," was identified for the licensee's failure to ensure that the simulator demonstrated expected plant response to operator input and conditions to which it has been designed to respond. Deficiencies involving simulator fidelity negatively impacted operator performance during a plant event on December 12, 2018, during which operators performed a manual actuation of the reactor core isolation cooling system and failed to establish sufficient system discharge pressure to achieve injection flow to the reactor vessel upon actuation of the system.			

Description: On December 12, 2018, the operating crew performed a manual reactor scram and manually closed main steam isolation valves (MSIVs) due to an equipment failure that caused a turbine bypass valve to come partially open and oscillate during full power operation. To support core cooling by maintaining reactor vessel water level within the control band established in accordance with station procedures, operators performed a manual start of the reactor core isolation cooling (RCIC) system using station Procedure 04-1-01-E51-1, "Reactor Core Isolation Cooling System," Revision 139, Attachment VI. This procedure provided two options for a manual start of the RCIC system. A "quick start" involves actuating the system with the flow controller in the automatic mode of operation (which is the normal standby system configuration), whereby pump speed and discharge pressure are automatically controlled to achieve the injection flowrate that is selected on the controller. A "controlled start" involves operation of the flow controller in manual mode to control pump speed and discharge pressure. Because reactor vessel level was high in the established control band at the time, the operator chose to perform the manual "controlled start" option, which had previously been successfully implemented in the simulator. The "controlled start" procedure required the operator to establish a system discharge pressure greater than reactor pressure. The operator established a RCIC pump speed and discharge pressure that was expected to result in injection flow when the RCIC injection valve was opened; however, no injection flow was observed when the RCIC injection valve was opened.

Operators opened a safety relief valve (SRV) to relieve reactor pressure and maintain it within the desired range as established by station procedures. Injection flow from the RCIC system was subsequently initiated when, due to manual operation of the SRV, reactor pressure dropped sufficiently below the RCIC system discharge pressure that had been established by the operator. Reactor vessel level reached approximately -25 inches, and operators were uncertain of the functionality of RCIC. Therefore, in order to maintain reactor vessel level within the desired range of -30 inches to +50 inches as established by station procedures, operators manually initiated injection flow from the high pressure core spray (HPCS) system for approximately 1 minute. Approximately 11 minutes later, reactor water level exceeded the Level 8 setpoint of +53.5 inches, which resulted in an automatic closure of the RCIC steam supply valve and loss of injection flow to the reactor vessel. Operators restarted the RCIC system in accordance with station procedures approximately 8 minutes later.

The initial failure to establish injection flow from the RCIC system was because the operator established insufficient pump discharge pressure with the flow controller in the manual mode of operation. A subsequent evaluation by the licensee determined that, because of the effects of elevation differences between the location of the RCIC pump and the injection point to the reactor vessel, as well as other system characteristics, the indication of RCIC discharge pressure available to the operators must indicate a minimum of approximately 30 psig greater than the indication of reactor pressure in order to result in the initiation of RCIC injection flow. It was further determined that the plant simulator modeled the initiation of RCIC injection flow at an indicated pressure difference of approximately 10 psig. At the time of the attempted initiation of RCIC injection flow, RCIC discharge pressure had been established approximately 23 psig higher than reactor pressure. The inspectors noted that the operator established parameters that would have resulted in indication of RCIC injection flow in the simulator but did not result in RCIC injection flow in the plant. Because the expected system response (RCIC injection) was not achieved, the operating crew assessed the condition of the RCIC system for a possible system malfunction. As a result of no indication of injection flow, as well as a position indication issue that caused the RCIC governor valve to indicate a closed position while the pump was running, the operating crew did not proceed any further with implementing the RCIC system operating instruction (i.e., no further adjustment to the flow controller was made), and instead determined that use of the HPCS system was needed to recover reactor water level. RCIC injection flow was subsequently observed when reactor pressure was reduced by manual SRV operation, and the RCIC system was subsequently operated normally to control reactor vessel level as expected, except for the Level 8 trip of RCIC.

Operators received training in both the licensee's initial license training and licensed operator requalification training on the operation of systems used as reactor vessel injection sources, including the RCIC system. This training includes response to events similar to the event on December 12, which include operation of the RCIC system. The licensee's training programs include job performance measures (JPMs) and simulator evaluations with grading criteria for successful performance of RCIC system operation. The inspectors observed a manual start of the RCIC system demonstrated in the plant simulator under the conditions that existed during the plant event. The inspectors concluded that use of the RCIC system for post-scram reactor water level control should result in the ability to maintain reactor water level in accordance with station procedures without the use of the HPCS system. The operator actions to perform a manual controlled start of the RCIC system, as trained using plant simulator indications, did not result in achieving the intended system function during this event, until separate actions were taken to reduce reactor pressure. The operator stopped performing the start-up actions because the initial system response (i.e., no flow indication, as well as closed governor valve position indication) was not the expected response based on training using simulator indications.

Corrective Actions: The licensee modified the simulator model to increase the indicated pressure difference required to initiate RCIC injection flow, consistent with actual plant response. The licensee also modified the RCIC governor valve position indication in the simulator to reflect the characteristics of the indication in the plant and initiated a Work Order to adjust the valve position indication in the plant to give the expected intermediate position when operating. Procedure 04-1-01-E51-1, "Reactor Core Isolation Cooling System," was revised to include: guidance on selection of RCIC manual start option (quick start vs. controlled start), guidance on establishing a specific range of indicated RCIC pump discharge pressure above indicated reactor pressure prior to opening the injection valve, and clarification that proceeding with further controller adjustments after opening the injection valve may be necessary to establish injection flow. The licensee also issued an action to evaluate the need for a revised calibration of the RCIC pump discharge pressure indication to account for address the lack of head correction for the displayed value.

Corrective Action References: CR-GGN-2018-13050, 13142, 13206.

Performance Assessment:

Performance Deficiency: The licensee's failure to establish RCIC injection flow to the reactor vessel when performing a manual controlled start of the system, due to deficiencies involving simulator fidelity, was a performance deficiency.

Screening: The inspectors determined the performance deficiency was more than minor because it was associated with the human performance attribute of the Mitigating Systems Cornerstone, and adversely affected the objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, incorrect simulator modeling involving the parameters necessary to result in

RCIC injection flow, which was incorporated into operator training programs, contributed to a failure to establish RCIC injection to the reactor vessel when intended during manual system operation. With the flow controller in the manual mode and set to establish an insufficient discharge pressure, and without further manual adjustment, the RCIC system was rendered incapable of performing its required function unless separate actions occurred to reduce reactor vessel pressure. The initial failure to establish injection flow from the RCIC system resulted in an undue decrease in reactor vessel water level during response for a scram event with complications, as well as the need to actuate an emergency core cooling system to maintain reactor water level within the range established by station procedures for transient mitigation strategy.

Significance: The inspectors assessed the significance of the finding using Inspection Manual Chapter (IMC) 0609, Attachment 4, "Initial Characterization of Findings," and Appendix I, "Licensed Operator Requalification Significance Determination Process." The inspectors determined that the finding involved a simulator fidelity deficiency that negatively impacted operator performance in an actual plant event. The senior reactor analyst performed an assessment of the negative impact that operator performance had during the actual plant event on December 12, 2018.

Because deficiencies in the simulator modeling had provided licensed operators with unrealistic or negative training, and because this unrealistic simulator training was the primary cause of negatively impacted operator performance during the December 12, 2018, event, the analyst quantified the risk increase caused by the negative operator performance. The analyst made the following critical assumptions:

1. The Grand Gulf Station Standardized Plant Analysis Risk (SPAR) Model, Version 8.50, is the best available tool to evaluate the risk associated with the December 12, 2018, event.

2. The December 12, 2018, event is best modeled as a loss of condenser heat sink with main steam isolation valve closure and a failure to run of control rod drive hydraulics pump B.

3. The performance deficiency would only manifest itself when the RCIC system is manually initiated with the controller in "Manual Mode" (as opposed to automatic system initiation or manual initiation per procedure with the controller in automatic mode).

4. The RCIC function, during the December 12, 2018, event, would not have been significantly impacted if the high pressure core spray system was actuated or if licensed operators took manual action to depressurize the reactor coolant system, because the incorrect alignment of the RCIC system permitted injection with reactor pressure below 963.5 psig.

5. The Lo-Lo Set Mode of the safety relief valves at the Grand Gulf Station would have automatically reduced reactor pressure vessel pressure to 926 (+10) psig had operators not controlled system pressure manually.

In accordance with Assumptions 1 and 2, the analyst quantified the baseline risk for this evaluation. Using the SPAR model, the analyst determined that the conditional core damage probability for the event, assuming that the RCIC system had been properly aligned, was 1.88×10^{-6}. The analyst determined that the only applicable core damage sequence was Sequence 69, because this sequence included both a failure of the high pressure core spray system and the failure of operators to depressurize the reactor coolant system. In addition, the analyst noted that if High Pressure Core Spray actuated and injected into the core before failing, this would have resulted in the initiation of RCIC injection flow. Therefore, the analyst removed all cutsets that had the basic event HCS-MDP-FR-HPCS, “HPCS Pump Fails to Run,” from the quantification. This resulted in a baseline conditional core damage probability, that was applicable to the performance deficiency, of 1.67×10^{-6}.

To quantify the risk increase caused by the negative operator performance during the actual event, the analyst set the basic event RCI-TDP-FS-TRAIN, “RCIC Pump Fails to Start,” to a demand failure probability of 1.0, indicating that the RCIC train would always fail to start. The conditional core damage probability for the applicable cutsets from Sequence 69 was 1.18×10^{-5}. In accordance with Assumption 5, the analyst determined that with no operator action and no high pressure core spray actuation, reactor pressure vessel pressure would have increased to 1103 psig when Safety/Relief Valve B21-F051D would have opened. At this point, the Lo-Lo Set Mode of the Safety/Relief Valves would activate, and Valve B21-F051D would remain open until reactor pressure vessel pressure reached a low of 926 (+10) psig. During this time, as stated in Assumption 4, RCIC would begin injecting once reactor pressure vessel pressure went below 963.5 psig. Once Valve B21-F051D closed, pressure would increase until it reached 963.5 psig, and RCIC flow to the reactor pressure vessel would cease. This cycling of the Safety/Relief Valve would continue as long as the core was covered.

Based on the cycling of Valve B21-F051D, the analyst determined that RCIC would have been flowing to the core approximately 1/3 of the time. This flow would have extended the time to core damage and provided multiple cues to the operators to recover the system and properly control reactor vessel water level.

The analyst used the SPAR-H method described in NUREG/CR-6883, “The SPAR-H Human Reliability Analysis Method,” to determine the appropriate failure rate for failure of licensed operators to recover RCIC. The following performance shaping factors were selected:

Recovery of Reactor Core Isolation Cooling
Performance Shaping Factors

Performance Shaping Factor	Diagnosis		Action	
	PSF Level	Multiplier	PSF Level	Multiplier
Time:	Nominal	1.0	Nominal	1.0
Stress:	High	2.0	High	2.0
Complexity:	Nominal	1.0	Nominal	1.0
Experience:	High	0.5	High	0.5
Procedures:	Incomplete	20.0	Nominal	1.0
Ergonomics:	Good	0.5	Good	0.5
Fitness for Duty:	Nominal	1.0	Nominal	1.0
Work Processes:	Nominal	1.0	Nominal	1.0

The resulting nonrecovery value was 9.22×10^{-2}. By applying this nonrecovery to applicable cutsets and subtracting off the baseline event, the analyst calculated that the increase in risk

from operator performance during the actual December 12, 2018, event was 8.66×10^{-7}. Because the increase in conditional core damage frequency is less than 1×10^{-6}, according to IMC 0609, Appendix I, the performance deficiency represents a finding of very low safety significance (Green). Cross-cutting Aspect: The inspectors determined that the cause of the performance deficiency was associated with the cross-cutting aspect of training within the human performance area. The inspectors determined that the manual RCIC start was not successfully accomplished because operators stopped performing procedure steps when an expected system response was not observed. The expected system response was based on operating parameters established during prior performances of the activity in training scenarios using simulator indications. This was associated with the cross-cutting aspect that includes providing training to maintain a knowledgeable, technically competent workforce. [H.9]
Enforcement: Violation: Title 10 CFR 55.46(c)(1) requires, in part, that a plant-referenced simulator must demonstrate expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond. Contrary to the above, prior to January 17, 2019, the licensee failed to ensure that the plant-referenced simulator demonstrated expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond. Specifically, the simulator did not demonstrate the expected plant response of RCIC injection flow for operator input and system operating conditions involving the RCIC system. Enforcement Action: This violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the Enforcement Policy.

Failure to Correct a Condition Associated with Post-Scram Control Rod Drive Pump Trips			
Cornerstone	Significance	Cross-cutting Aspect	Inspection Procedure
Mitigating Systems	Green FIN 05000416/2018050-02 Closed	P.5 – PI&R, Operating Experience	93812—Special Inspection
The inspectors identified a Green finding for the licensee’s failure to address the cause and correct a condition associated with post-scram control rod drive system pump trips as required for an adverse condition by station procedure EN-LI-102, “Corrective Action Program.”			
Description: At approximately 1:51 p.m. on December 12, 2018, with the plant operating at 100 percent steady state power, the operators initiated a manual reactor scram in response to the inadvertent opening of a turbine bypass valve. Following the scram, and complicating the scram response, control rod drive (CRD) pump B unexpectedly tripped on high suction differential pressure and low suction pressure, and CRD pump A was manually started. Injection flow from the CRD system is designated as a preferred injection source for use in station emergency operating procedures. It is expected that CRD pump suction pressure decreases momentarily following a scram due to increased system flow to refill the hydraulic control unit (HCU) accumulators and due to			

reduced reactor pressure. It was identified that Grand Gulf does not have a time delay installed on the low suction pressure trip signal to prevent unwanted pump trips from occurring during this expected transient condition. A review of industry operating experience showed that a low suction pressure trip time delay had previously been installed at other BWR facilities, including other facilities operated by Entergy. This condition had also been previously identified and corrected at Pilgrim Nuclear Station (also an Entergy facility) by implementing an alternate valve lineup available to that station's specific system characteristics.

Following the December 12, 2018, scram event, the NRC resident inspector noted several previous post-scram CRD pump low suction pressure trips in the licensee's corrective action program records and requested the licensee provide a complete list of similar occurrences. It was determined that in the past 10 years, the licensee has experienced 5 low suction pressure CRD pump trips involving either the 'A' or 'B' CRD pumps coincident with a plant scram. Following one such occurrence in a scram event from 2008, the licensee performed a cause evaluation, which accurately described the momentary drops in suction pressure due to post-scram system transient flows but also attributed the cause of the pump trip to the need for more frequent cleanings of the CRD pump's suction filters. The associated corrective actions from this evaluation focused on implementing a more frequent cleaning maintenance activity for these filters.

The inspectors noted that subsequent repeat instances of post-scram CRD pump trips occurred following scram events in 2010, 2012, 2014, 2016, and 2018, and that these conditions were classified in the licensee's corrective action program as a "broke-fix" type of condition that focused on filter cleaning. The inspectors noted that no effectiveness review was performed associated with the corrective actions that involved filter cleaning from the previous 2008 occurrence. Actions were not developed to address the cause of the repeated post-scram pump trips from 2008 through 2018. Following NRC questions regarding this history of occurrences and actions taken to address the condition, the licensee increased the classification of the Condition Report CR-GGN-2018-13038 from a 'C' level "broke-fix" condition to 'B' level issue and performed an equipment failure evaluation. This cause evaluation resulted in the identification that the condition could be properly addressed by implementing a time delay modification for the CRD pump's low suction pressure trip signal, similar to actions that had been previously taken at other facilities to address the condition.

The licensee's corrective action program procedure, EN-LI-102, Revisions 14, 15, 17, 23, 25 and 35, over the previous 10-year period required licensee management to classify issues such as the repeated CRD pump trips as an adverse condition and to correct the condition and address the causes that were identified. Contrary to this, licensee management failed to provide appropriate condition report classifications and evaluation actions for five previous post-scram low suction pressure CRD pump trip condition reports to adequately correct the condition and addressing the cause.

Corrective Actions: The licensee issued an action to evaluate and implement a time delay for a low suction pressure trip signal on the CRD pumps to prevent continued undesired post-scram CRD pump trips.

Corrective Action Reference: The licensee corrective action document for this issue is GGN-2018-13038.

<u>Performance Assessment</u>: Performance Deficiency: The failure to comply with the station corrective action program procedure requirements was a performance deficiency. Screening: The finding was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective to ensure the availability reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. It adversely affected the reliability and availability of the CRD system pumps to function as a designated preferred high pressure injection source in response to an initiating event. Significance: The inspectors assessed the significance of the finding using Inspection Manual Chapter 0609, Appendix A, Exhibit 2, Section A. Since the finding did not represent a loss of system function for a significant time period, the finding was determined to be of very low safety significance (Green). Specifically, the finding did not cause a complete loss of CRD system injection flow to the reactor, due to the availability of the pump that was not running at the time of the scram to provide the function during the scram response. Cross-cutting Aspect: The finding had a cross-cutting aspect in the area of problem identification and resolution associated with operating experience. The licensee's operating experience program failed to systematically and effectively collect, evaluate, and implement relevant internal and external operating experience involving the condition associated with the CRD low suction pressure trip function in a timely manner. [P.5]
<u>Enforcement</u>: Inspectors did not identify a violation of regulatory requirements associated with this finding.

Observation	93812.7
The inspectors noted that a Level 8 trip occurred due to high reactor water level (greater than +53.5 inches) during the operating crew's response to the scram event. In accordance with station procedures 05-S-01-EP-2, "RPV Control," Revision 46, and 02-S-01-43, "Transient Mitigation Strategy", Revision 6, operators established an "expanded" control band for reactor water level during this event, due to implementing SRV operation for reactor pressure control. The normal post-scram reactor water level control band is +11.4 inches to +53.5 inches. Exceeding a reactor water level of +53.5 inches (Level 8) results in the automatic shutdown of some injection sources to the reactor vessel, including the RCIC system, and reactor feedwater pumps are automatically shut down at a reactor water level of +56 inches (Level 9). Procedure 02-S-01-43 states that attempting to maintain level greater than +11.4 inches may introduce unnecessary challenges to available injection sources in situations that include the use of a high pressure injection source (e.g., ECCS) for level control, as well as the operation of SRVs for reactor pressure control, which the procedure notes as being a cause of expected "shrink" and "swell" effects on reactor water level. This procedure states that the purpose of implementing an expanded level control band of -30 inches to +50 inches during the above situations is: "to prevent challenges to injection systems due to high level and to prevent Level 2 isolations/initiations." Additionally, the procedure states that "additional coordination between Reactor Operators to ensure that impact of one parameter on another is anticipated	

and mitigated" may be needed to ensure that prescribed control bands for reactor vessel pressure and level are maintained in situations where "maintenance of one parameter within prescribed bands conflicts with maintenance of another parameter (e.g., closing SRVs causes level to go low)."

During the crew's response to this event, a Level 8 trip was the result of reactor water level being high in the established control band, as a result of injection flow being established from both the HPCS and RCIC systems, at the time an SRV was opened for pressure control, which had the expected effect of an increase in reactor water level. Given the stated purpose of the procedure guidance referenced above, the inspectors observed that the licensee did not identify this aspect of the event as an adverse condition that would warrant further evaluation to determine whether station expectations regarding coordination of operator actions to control RPV level and pressure during a transient response were adequately implemented.

The licensee initiated Condition Report CR-GGN-2019-01558 to evaluate this issue in the corrective action program.

Minor Violation	93812.11

Minor Violation: The inspectors identified a minor violation of 10 CFR 50.72(a)(5) for the licensee's failure to identify the applicable criteria requiring the notification when making a report for a non-emergency event.

The inspectors determined that the licensee's event notification of December 12, 2018, was submitted pursuant to the applicability of two of the criteria established in 10 CFR 50.72(b)(2) for non-emergency conditions to be reported within 4 hours. Specifically, the actuation of the reactor protection system (RPS) while the reactor was critical was determined to be reportable under 10 CFR 50.72(b)(2)(iv)(B), and the discharge of an ECCS system to the reactor coolant system (RCS) was determined to be reportable under 10 CFR 50.72(b)(2)(iv)(A). The licensee submitted EN #53788 within 4 hours of these events, as required.

On December 13, 2018, NRC resident inspectors observed that the RCIC actuation that occurred during the response to the event was not included in the licensee's event notification as being an 8-hour non-emergency reportable condition per 10 CFR 50.72(b)(3)(iv)(B)(*5*). The licensee reported an update to EN #53788 on December 14, 2018, to indicate that an 8-hour non-emergency criterion under 10 CFR 50.72(b)(3)(iv)(A) was applicable for this event due to the actuation of the RCIC system and had not been identified in the original notification. The licensee's use of the RCIC system as part of the response to the event (i.e., for reactor vessel level and pressure control) was discussed in the original notification, which implied that a valid system actuation had occurred, but this was not recognized or described as being a reportable system actuation.

The inspectors concluded that the licensee's failure to recognize that an 8-hour non-emergency reportable condition had occurred did not result in a violation of 10 CFR 50.72(a)(1)(ii), since the original event notification associated with the two 4-hour reportable conditions did provide notification to the NRC of the event or condition that resulted in actuation of the RCIC system, as required by 10 CFR 50.72(b)(3)(iv)(A), within 8 hours of the event. However, the inspectors concluded that the licensee's failure to identify paragraph (b)(3) as a paragraph requiring the notification when making the non-emergency event report constituted a violation of 10 CFR 50.72(a)(5)(ii), as specified below.

10 CFR 50.72(a)(5) requires, in part, that when making a report under 10 CFR 50.72 paragraph (a)(1), the licensee shall identify paragraph (b)(1), paragraph (b)(2), or paragraph (b)(3) as the paragraph requiring notification of the non-emergency event. Contrary to the above, on December 12, 2018, the licensee made a report of a non-emergency event under 10 CFR 50.72(a)(1) and failed to identify paragraph (b)(3) as the paragraph requiring the notification.

The licensee initiated Condition Report CR-GGN-2018-13069 to document this issue in the corrective action program.

Screening: The inspectors determined that this violation did not constitute a Severity Level IV violation in accordance with NRC Enforcement Policy 6.9.d.9, since it did not represent a failure to make a required report. Therefore, the inspectors concluded that this violation was of minor significance.

Enforcement: This failure to comply with 10 CFR 50.72 constitutes a minor violation that is not subject to enforcement action in accordance with the NRC Enforcement Policy.

Observation	93812.11

The inspectors noted that licensee Procedure EN-LI-108, "Event Notification and Reporting," Revision 17, stated that NRC Form 361 "Reactor Plant Event Notification Worksheet" should be used to record information used in making NRC notifications, and should be provided to the NRC Operations Center at the time the notification is made. The inspectors determined that the licensee did use this form and did provide it to the NRC in conjunction with the notifications that were made pursuant to 10 CFR 50.72 requirements. Licensee Procedure 01-S-06-5, "Reportable Events or Conditions," Revision 112, also stated that this Event Notification Worksheet "gives guidance for providing adequate detail" when making notifications. The Event Notification Worksheet contains guidance to include an explanation in the event description for occurrences that fall into either of two categories: "Anything unusual or not understood?" or "Did all systems function as required?".

The inspectors observed that these criteria could have been applied for certain occurrences during this event that were not included in the licensee's event notification. One example is a failure to achieve RCIC injection flow to the reactor vessel upon an attempted manual start of the system. Although RCIC injection flow was later achieved because of separate action to manually depressurize the reactor vessel using an SRV, the lack of injection flow at the time the manual start procedure was being performed was an unusual occurrence, was not understood at the time, and was thought to be indicative of a system malfunction. Another example is the trip of the running CRD system pump. Although the system was promptly restored by placing the other system pump in service, there was a temporary loss of function as an injection source. The inspectors noted that the licensee's post-trip analysis characterized the CRD pump trip as being an equipment malfunction and an unexpected system response. An additional potential example of an unusual occurrence is a post-scram Level 8 trip, which resulted in a loss of injection from the RCIC system until the function was subsequently reset.

EXIT MEETINGS AND DEBRIEFS

On February 28, 2019, the inspectors presented the inspection results to Mr. E. Larson, Site Vice President, and other members of the licensee staff. Further inspection results were also presented to Mr. M. Lingenfelter, Engineering Director, on March 12, 2019. The inspectors verified no proprietary information was retained by the inspection team.

DOCUMENTS REVIEWED

Condition Reports (CR-GGN-):

2018-13125	2018-13135	2018-13142	2018-13193	2018-13206
2018-13038	2018-13042	2018-13043	2018-13050	2018-13069
2018-13020	2018-13032	2018-13035	2018-13036	2018-13037
2018-13250	2018-05286	2018-13160	2017-03711	2017-03361
2016-02970	2016-01309	2014-02825	2012-02105	2012-04259
2010-02667	2008-04790	2003-02711	2019-00358	

Work Orders

52846443	52583076	52583174	00362765	00446205	00514541	52831412

Procedures

Number	Title	Revision or Date
01-S-06-5	Reportable Events of Conditions	112
01-S-15-1	GGNS Plant Reporting Requirements	108
02-S-01-43	Transient Mitigation Strategy	006
03-1-01-4	Scram Recovery	116
03-1-01-2	Power Operations	173
04-1-01-B21-1	Nuclear Boiler System	053
04-1-01-E22-1	High Pressure Core Spray System	125
04-1-01-E51-1	Reactor Core Isolation Cooling System	139,140,141
04-1-01-N32-2	Turbine Generator Control	034
05-1-02-I-1	Reactor Scram	132
05-1-02-V-21	Reactor Pressure Control Malfunctions	003,004
05-1-02-V-5	Loss of Feedwater Heating	119
06-OP-1N32-V-0001	Turbine Stop and Control Valve Operability	121
EN-FAP-LI-001	Performance Improvement Review Group (PRG) Process	013
EN-HU-101	Human Performance Program	020
EN-LI-102	Corrective Action Program	14,15,17,23,25, 35
EN-LI-108	Event Notification and Reporting	017
EN-LI-118	Cause Evaluation Process	028
EN-OP-104	Operability Determination Process	016
EN-OP-115	Conduct of Operations	026
EN-OP-115-14	Reactivity Management	000
01-S-06-26	Post-Trip Analysis	021
05-S-01-EP-2	RPV Control	46
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Drawings: Number	Title	Revision or Date
GFIG-OPS-N3202	Main Turbine EHC Control Systems - Figures	6
M-1081B	Control Rod Drive Hydraulic System	31

Miscellaneous	Title	Revision or Date
GQC-OPS-LOQC1	Licensed Operator Qualification Card	16
GLP-OPS-E2201	High Pressure Core Spray System	13
GLP-OPS-E5100	Reactor Core Isolation Cooling	18
GLP-OPS-N1136	Main, Reheat, and Extraction Steam	11
GLP-OPS-N3201	Electro-Hydraulic Control System	16
GLP-OPS-N3202	Main Turbine ECH Control System	11
GSMS-LOR-00281	Loss of Instrument Air	01
GSMS-LOR-00295	Reactor Pressure Control Malfunction ONEP	00
GSMS-RO-DR001	RFPT/RCIC Failures	9

Engineering Changes	Title	Revision or Date
80884	Review of RCIC Response During Scram Recovery	000
80947	Review of RCIC Response During Scram Recovery	000
81267	Delta Pressure Requirements for HPCS, LPCS, RHR, and SSW to inject into Reactor Vessel	000

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

December 17, 2018

MEMORANDUM TO: Cale Young, Senior Project Engineer
Project Branch C
Division of Reactor Projects

FROM: Tony Vegel, Director ***/RA/***
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION CHARTER TO EVALUATE TURBINE BYPASS VALVE FAILURE AND SCRAM EVENT AT GRAND GULF NUCLEAR STATION

In response to a manual reactor scram event that occurred on December 12, 2018, at Grand Gulf Nuclear Station, a Special Inspection will be performed. You are hereby designated as the Special Inspection team leader. The following member is assigned to your team:

- Michael Chambers, Physical Security Inspector, Division of Reactor Safety

In addition, the following individual will accompany the team in training status to support his qualifications as a reactor inspector:

- Larry Newman, Project Engineer, Division of Reactor Projects

A. <u>Basis</u>

At approximately 1315 on December 12, 2018, with the plant at 100% steady state power, operators noted an increase in reactor power, and a decrease in generated megawatts, resulting from an undemanded opening of turbine bypass valve A. As a result, the turbine control valves modulated in the closed direction, in proper response to the increased steam flow. Operators reduced power in an attempt to close turbine bypass valve A. At approximately 1345, bypass valve A continued to open (undemanded), and the operators initiated a manual reactor scram by taking the mode switch to “Shutdown,” and all control rods fully inserted. The cause of the bypass valve opening is being investigated by the licensee. Currently, it appears to involve a failure associated with the turbine control system.

Following the scram, control rod drive (CRD) pump B unexpectedly tripped on high suction differential pressure and low suction pressure, and CRD pump A was manually started. Emergency Procedure 2, “RPV Control,” Revision 46, was entered due to reactor water level dropping below 11.4 inches (Level 3) following the scram. Bypass valve A continued opening to approximately 40% causing reactor pressure to lower. To control the reactor coolant system cooldown rate and maintain reactor pressure control operators manually closed the main steam isolation valves (MSIVs). Reactor pressure control was maintained by manually cycling safety relief valves (SRVs) discharging to the suppression pool. Both divisions of the residual heat removal (RHR) system were placed into suppression pool cooling mode. Emergency Procedure 3, “Containment Control,” Revision 31, was entered when suppression pool temperature increased to 95 degrees. The RHR system in suppression pool cooling mode maintained pool temperature at 94 degrees.

Following closure of the MSIVs and associated loss of the main feed pumps, operators prepared to use the reactor core isolation cooling (RCIC) system for reactor vessel level control. At approximately 1357 operators manually initiated RCIC, but were unsuccessful in establishing flow to the reactor. The licensee is currently evaluating whether or not both operator error and equipment deficiencies contributed to the inability to establish flow. At approximately 1407, due to continued level decrease, operators manually initiated the high pressure core spray (HPCS) system to recover reactor water level. The HPCS injection was secured at approximately 1409.

Following the initial failure of RCIC to initiate when expected, the system did subsequently function, and was used to maintain reactor vessel level. Operators proceeded to conduct a cooldown of the plant to Mode 4 using the SRVs, RCIC, and the condensate and condensate booster pumps.

Management Directive 8.3, “NRC Incident Investigation Program,” was used to evaluate the level of NRC response for this event. In evaluating the deterministic criteria of MD 8.3, it was determined that the event involved questions or concerns pertaining to licensee operational performance. The causes for the initial failure of the RCIC system to function as expected are under investigation by the licensee. Currently the licensee is evaluating if both operator error and equipment deficiencies contributed to the failure of RCIC to inject water to the reactor vessel. In evaluating the conditional risk assessment criteria of MD 8.3, the preliminary estimated incremental conditional core damage probability was determined to be 1.2×10^{-5}.

Based on the deterministic criteria and risk insights related to this event, Region IV management determined that the appropriate level of NRC response was to conduct a Special Inspection. This Special Inspection is chartered to identify the circumstances surrounding this event and review the licensee’s actions to address the causes of the event.

B. <u>Scope</u>

The inspection is expected to perform data gathering and fact-finding in order to address the following:

1. Provide a recommendation to Region IV management as to whether the inspection should be upgraded to an augmented inspection team response.

2. Develop a complete sequence of events related to the manual reactor scram event on December 12, 2018. The chronology should include the status of plant equipment and operator actions to achieve and maintain stable shutdown conditions.

3. Review the licensee's causal evaluations and determine if they are being conducted at a level of detail commensurate with the significance of the issues that were encountered during the event.

4. Determine the causes for the unexpected opening of a turbine bypass valve at 100% power.

5. Evaluate operator actions taken to respond to the inadvertent opening of the turbine bypass valve, including control of reactor power and reactor pressure.

6. Evaluate operator actions taken to perform a manual reactor scram and closure of MSIVs in response to the inadvertent turbine bypass valve opening.

7. Evaluate operator actions to ensure proper decay heat removal following the scram, including control of reactor pressure vessel (RPV) pressure and inventory/level.

8. Determine the causes associated with the failure of the RCIC system to provide the expected injection flow during the event.

9. Determine the causes for the trip of a CRD system pump during the event. Evaluate the licensee's actions to address previous similar occurrences.

10. Determine whether the licensee appropriately evaluated the operability of the RCIC system to meet technical specification requirements.

11. Evaluate the licensee's actions to comply with reporting requirements associated with this event.

12. Collect data necessary to support completion of the significance determination process, if applicable.

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the Special Inspection Team. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

You will formally begin the Special Inspection with an entrance meeting to be conducted no later than December 17, 2016. You should provide a daily briefing to Region IV management during the course of your inspections and prior to your exit meeting.

A report documenting the results of the inspection should be issued within 45 days of the completion of the inspection.

This Charter may be modified should you develop significant new information that warrants review.

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817-200-1144

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SPECIAL INSPECTION CHARTER TO EVALUATE TURBINE BYPASS VALVE FAILURE AND SCRAM EVENT AT GRAND GULF NUCLEAR STATION DATED DECEMBER 14, 2018

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