UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

May 30, 2003

George A. Williams, Acting Vice President,
Operations - Grand Gulf Nuclear Station
Entergy Operations, Inc.
P.O. Box 756
Port Gibson, Mississippi 39150

SUBJECT: GRAND GULF NUCLEAR STATION – NRC SPECIAL TEAM INSPECTION REPORT 50-416/03-07

Dear Mr. Williams:

On May 9, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed a special team inspection at your Grand Gulf Nuclear Station. The enclosed report documents the inspection findings, which were discussed with you and other members of your staff on May 9, 2003.

The inspection examined the details of the automatic scram which occurred on April 24, 2003. In particular, an extensive review of the causes of the scram, partial loss of offsite power, and loss of instrument air were performed as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspection consisted of an examination of procedures and records and interviews with station personnel.

This report documents one finding of very low safety significance (Green) which was determined to involve a violation of your Technical Specifications. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this finding as a noncited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, 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, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Grand Gulf Nuclear Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

William D. Johnson, Chief
Project Branch A
Division of Reactor Projects

Docket: 50-416
License: NPF-29

Enclosure:
NRC Inspection Report
50-416/03-07
w/attachments:
1. Supplemental Information
2. Special Inspection Team Charter
3. GGNS Electrical Distribution Drawing

cc w/enclosure:
Executive Vice President
and Chief Operating Officer
Entergy Operations, Inc.
P.O. Box 31995
Jackson, Mississippi 39286-1995

Wise, Carter, Child & Caraway
P.O. Box 651
Jackson, Mississippi 39205

Winston & Strawn
1400 L Street, N.W. - 12th Floor
Washington, DC 20005-3502

Jay Barkley, Chief
Energy & Transportation Branch
Environmental Compliance and
Enforcement Division
Mississippi Department of
Environmental Quality
P.O. Box 10385
Jackson, Mississippi 39289-0385

President, District 1
Claiborne County Board of Supervisors
P.O. Box 339
Port Gibson, Mississippi 39150

General Manager
Grand Gulf Nuclear Station
Entergy Operations, Inc.
P.O. Box 756
Port Gibson, Mississippi 39150

The Honorable Richard Ieyoub
Attorney General
Department of Justice
State of Louisiana
P.O. Box 94005
Baton Rouge, Louisiana 70804-9005

Office of the Governor
State of Mississippi
Jackson, Mississippi 39201

Mike Moore, Attorney General
Frank Spencer, Asst. Attorney General
State of Mississippi
P.O. Box 22947
Jackson, Mississippi 39225

Dr. Brian W. Amy
State Health Officer
State Board of Health
P.O. Box 1700
Jackson, Mississippi 39215

Robert W. Goff, Program Director
Division of Radiological Health
Mississippi Dept. of Health
P.O. Box 1700
Jackson, Mississippi 39215-1700

Vice President
Operations Support
Entergy Operations, Inc.
P.O. Box 31995
Jackson, Mississippi 39286-1995

Director, Nuclear Safety
and Regulatory Affairs
Entergy Operations, Inc.
P.O. Box 756
Port Gibson, Mississippi 39150

Electronic distribution by RIV:
Regional Administrator **(EWM)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Senior Resident Inspector **(TLH4)**
Branch Chief, DRP/A **(WDJ)**
Senior Project Engineer, DRP/A **(TRF)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(NBH)**
Mel Fields **(MBF1)**
GG Site Secretary **(MJS)**
Dale Thatcher **(DFT)**

ADAMS: **X** Yes ☐ No Initials: **wdj**
X Publicly Available ☐ Non-Publicly Available ☐ Sensitive **X** Non-Sensitive

R:_GG\2003\GG2003-07RP-TLH.wpd

RIV:SRI:DRP/A	RI:DRP/A	C:DRP/A		
TLHoeg	RWDeese	WDJohnson		
T - WDJohnson	***T - WDJohnson***	***/RA/***		
5/30/03	5/30/03	5/30/03		

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-416
License:	NPF-29
Report:	50-416/03-07
Licensee:	Entergy Operations, Inc.
Facility:	Grand Gulf Nuclear Station
Location:	Waterloo Road Port Gibson, Mississippi 39150
Dates:	May 5-9, 2003
Inspectors:	T. L. Hoeg, Team Leader, Senior Resident Inspector, Grand Gulf R. W. Deese, Resident Inspector, Grand Gulf
Approved By:	W. D. Johnson, Chief Project Branch A Division of Reactor Projects

Attachment 1: Supplemental Information
Attachment 2: Special Inspection Team Charter
Attachment 3: GGNS Electrical Distribution Drawing

SUMMARY OF FINDINGS

IR 05000416/2003-007; 5/5/03 - 5/9/03; Grand Gulf Nuclear Station; Special Inspection Report; Procedures.

The report covered a one-week special inspection by one senior resident inspector and one resident inspector who assessed the licensee and reactor plant response to an automatic reactor scram resulting from a partial loss of offsite power. The scram recovery was complicated due to a loss of instrument air and the power conversion system. One Green noncited violation was identified. The significance of any findings is indicated by the color (Green, White, Yellow, or Red) assigned using IMC 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Inspector Identified and Self-Revealing Finding

Cornerstone: Mitigating Systems

Green. The team identified a noncited violation of Technical Specification 5.4.1 and Regulatory Guide 1.33, Section 6.b, for the failure of Grand Gulf Nuclear Station personnel to provide an adequate procedure for restoring the instrument air system following a loss of instrument air. The procedure failed to provide instructions on how to provide seal air and control air to the instrument air compressor from a temporary source. This resulted in operation of the unit one instrument air compressor in an abnormal configuration, which caused damage to its inlet valve and the licensee's inability to restore instrument air header pressure with that compressor. This issue was documented in the licensee's corrective action program as Condition Report 2003-1347.

This finding was evaluated using the Significance Determination Process and determined to be of very low safety significance. The finding is greater than minor because it affected the mitigating systems cornerstone objective as described in NRC Manual Chapter 0612 involving the ability to ensure the availability, reliability, and capability of systems that respond to initiating events. The finding was of very low safety significance because, although the recovery of instrument air was delayed, all mitigating safety system functions remained available (Section 3.4).

CONTENTS

REPORT DETAILS

1. SPECIAL INSPECTION ACTIVITIES

The NRC conducted this special inspection to better understand the circumstances surrounding the automatic scram which occurred on April 24, 2003. The events causing and following the scram resulted in a partial loss of offsite power, loss of instrument air pressure, and loss of the power conversion system.

The Special Inspection Team, or team, evaluated the potential safety implications related to the cause of the scram and the resulting loss of system safety functions associated with the loss of instrument air. The inspectors used NRC Inspection Procedure 93812, "Special Inspection," to conduct the inspection. The team reviewed procedures, operator logs, corrective action documents, a posttrip review report, and design and maintenance records for equipment of concern. The team interviewed key station personnel regarding the scram event and attempts to restore instrument air and the power conversion system. The team performed a walkdown of the instrument air compressor area to visualize the control air piping configuration for temporary hookup of control air following a loss of instrument air pressure. Attachment 2 is the charter for the team, which describes the inspection scope in greater detail. Attachment 3 is a Grand Gulf Nuclear Station (GGNS) switchyard electrical distribution drawing.

2. DESCRIPTION OF EVENT AND CHRONOLOGY

2.1 System Descriptions

GGNS Electrical Distribution System

The GGNS 500 kilovolt (kV) switchyard is the receiving location for 500 kV offsite power from the Baxter Wilson and Franklin lines which are part of the Entergy electrical grid system. The GGNS 500 kV switchyard also serves as the transmission system for electrical power generated by the site's main generator, which exits the switchyard through the same Baxter Wilson and Franklin lines when the plant is operating. The GGNS switchyard consists of two buses, the 500 kV east bus and the 500 kV west bus, each of which is normally energized and synchronized. All breakers in the switchyard are electrically isolable by two disconnect switches on either side of the breakers.

Power to GGNS electrical equipment is normally supplied from the GGNS 500 kV switchyard through Service Transformers 11 and 21 and their associated load centers and motor control centers. Included in this electrical equipment is the engineered safety features (ESF) electrical equipment powered through electrical Buses 15AA, 16AB, and 17AC for Divisions I, II, and III, respectively. If offsite power to these ESF buses is degraded or isolated, emergency diesel generators (EDG) will start automatically and begin powering the ESF electrical equipment. Power is also available in an emergency to the ESF buses from offsite via a normally unused 115 kV line from Port Gibson which is independent of the switchyard.

Instrument Air System

The instrument air system is a nonsafety related system which provides a safety-related function to provide clean, dry, oil-free, compressed air to the main steam line isolation valve accumulators and the automatic depressurization system accumulators. In addition, the system provides air to various plant instrumentation, air-operated valves, and control devices.

The instrument air system consists of two 100 percent capacity centrifugal type compressors designated as the Unit 1 instrument air compressor (IAC) and Unit 2 IAC. Unit 1 IAC is powered from the Division II ESF bus, and the Unit 2 IAC is powered from a nonvital balance of plant (BOP) electrical bus. The instrument air system can be cross-connected with the service air system. The service air system is arranged to automatically provide a backup supply to instrument air through a control valve that opens upon reduced air pressure in the instrument air header. The service air system also has two 100 percent capacity centrifugal type compressors which are both powered from nonvital BOP busses.

Cooling water to the IACs is provided by the turbine building cooling water (TBCW) system, which is powered from nonvital BOP electrical busses. The safety related standby service water (SSW) system may be manually aligned to provide cooling water to the IACs as needed. Control air and seal air for compressor operation is normally provided from the instrument air header through separate pressure regulators. Seal air is used to separate lubricating oil from the compressed air within the compressor. The TBCW system and the seal air system both have a pressure interlock relay associated with the compressor motor control logic. The TBCW setpoint is approximately 19 psig and the seal air pressure interlock is set at approximately 6 psig. The compressor motor will not start when in standby and will trip off when running if these pressure interlocks are not met.

2.2 Event Summary

On April 14, 2003, Entergy Mississippi removed 500 kv Breaker J5204 from service in the switchyard at GGNS by opening Disconnects J5203 and J5205 in order to repair an internal gas leak. On the morning of April 24, 2003, work was continuing on Breaker J5204 when strong winds and rain entered the Port Gibson, Mississippi, area at which time the workers in the switchyard took shelter in the switchyard relay house. At 9:48 a.m., Disconnect J5205 inadvertently closed, creating a line-to-ground fault, which isolated all incoming 500 kv power to Service Transformer 21 (ST21). Loss of ST21 resulted in a bus undervoltage on the Divisions II and III ESF busses, causing an autostart of the Divisions II and III EDGs which energized their respective busses.

At this same time, failures in the Entergy Mississippi carrier transmission fault relaying system caused both normal 500 kV power sources from the Baxter Wilson Station and Franklin Station switchyards to be isolated from the GGNS switchyard. The Grand Gulf generator remained on the 500 kV east bus powering ST11. Because of this 500 kV power grid transient, the GGNS turbine generator control system sensed a load reject producing a turbine control valve fast closure and subsequent automatic reactor scram. All control rods inserted and the reactor was shut down. Approximately 74 seconds later, the main generator output breaker opened on a volts-to-hertz ratio trip, resulting in a loss of 500kV power to ST11 and the Division I ESF bus. The Division I EDG autostarted on bus undervoltage and supplied power to its ESF bus. At that time all three EDGs were running, supplying power to the three safety-related vital busses. In addition, at about the same time, the 500 kV Franklin and Baxter Wilson line feeder breakers closed and restored power to the GGNS 500 kV switchyard.

The scram was complicated due to a loss of instrument air pressure and closure of the main steam isolation valves, resulting in loss of the power conversion system. When ST21 was lost, the running Unit 2 IAC lost its power and tripped off. Instrument air and service air cross-connected and the operating service air compressor tripped off as expected upon loss of ST11. As a result, instrument air header pressure dropped approximately 5 psig per minute, until it was totally lost in approximately 20 minutes. Both of the reactor protection system motor generators tripped on loss of the STs, resulting in a reactor protection system main steam isolation valve closure and loss of the normal heat removal path using the power conversion system. Reactor safety relief valves were manually operated for reactor pressure control until shutdown cooling was established almost 19 hours later.

2.3 Preliminary Risk Significance of Event

Following the automatic reactor scram complicated by a partial loss of offsite power, the NRC performed an evaluation of the preliminary risk significance in terms of conditional core damage probability (CCDP). The CCDP is the probability of core damage over a period of time given a specific plant condition. The CCDP analysis represented the loss of offsite power with a resulting turbine/reactor trip, loss of the power conversion system (PCS), and a loss of instrument air. The NRC senior reactor analyst determined the upper bound for risk to be from the loss of instrument air because its recovery was beyond what was proceduralized and greatly reduced the ability to recover the plant's PCS. As a result, the lower bound for risk was the loss of the PCS. The CCDP was calculated to be on the order of 6.9 E-6 and 3.3 E-5. NRC Management Directive 8.3, "NRC Incident Investigation Program," requires the consideration of a special inspection when the estimated CCDP is greater than or equal to 1 E-6. The NRC determined that a Special Inspection Team would assess the cause of the scram; assess the licensee's ability to restore offsite power, instrument air, and the power conversion system; and evaluate the licensee's coordination of risk activities for performing switchyard work. The NRC's decision to perform a special inspection was based on the circumstances of the scram event, including the partial loss of offsite power driven by an external event such as high winds and the fact that a performance deficiency may have resulted in the loss of instrument air.

2.4 Sequence of Events

The team developed a detailed sequence of events following the partial loss of offsite power and automatic reactor scram. The timeline included applicable events and actions before, during, and following the scram. The time line was generated from operator logs, written records, GGNS plant data system printouts, a posttrip review report, and interviews with members of the licensee's staff. This activity satisfied Special Inspection Team Charter Scope Item 1.

(All times are given in Central Daylight Time)

April 10, 2003

Entergy Mississippi removed 500 kV BreakerJ5204 from service in the switchyard at the GGNS by opening Disconnects J5203 and J5205 in order to repair an internal gas leak.

April 24, 2003

Time (Military hours)	Description
0948:34	500 kV Breaker J5204 Disconnect J5205 closed, causing a line-to-ground fault
0948:34	ST21 Lockout Trip, Breakers J5208 and J1652 Open, ST21 Lost Breakers J2425, J2420 Open, Franklin 500 kV Line De-energized Breakers J2240, J2244 Open, Baxter Wilson 500kV Line De-energized West Bus Lockout, Breakers J5228, J5240, J5216 Open
0948:34	Load reject relay actuates, turbine control valve fast closure, reactor scram
0948:34	Condensate Booster Pump C and Condensate Pumps B and C tripped
0948:37	Division II EDG started and powered its ESF Bus
0948:37	Division III EDG started and powered its ESF bus
0948:38	Turbine trip, turbine stop valve closure
0948:41	Unit 2 instrument air compressor tripped
0948:42	Safety relief valve auto actuation, two valves open for approximately 1 minute and begin to cycle

0948:46	Condensate Booster Pump A tripped
0948:50	Condensate Booster Pump B tripped
0948:53	Manual scram, mode selector switch placed in shutdown
0949:15	Main steam line isolation valves closed
0949:20	Condensate Pump A tripped
0949:36	Reactor Feed Pumps A and B tripped
0949:47	Main generator lockout relay, volts-to-hertz ratio
0949:48	Generator output breaker opened, generator off-line, East 500 kV line de-energized
0949:49	Breaker J2425 closes, Franklin 500kV line re-energizes
0949:51	Breaker J2240 closes, Baxter Wilson 500 kV line re-energizes
0949:53	Division I EDG started and powered its ESF bus
0950:05	Service air and instrument air auto cross-connect at ~90 psig
0956:02	Reactor vessel water reached Level 2
0956:07	High pressure core spray (HPCS) and reactor core isolation cooling (RCIC) systems autoinitiated and injected into the core
0958:40	HPCS pump secured by control room operator
0958	Control room operators established pressure and level control with manual operation of safety relief valves and RCIC
0959:41	Unit 1 instrument air compressor auto started
1018:29	Unit 1 instrument air compressor tripped due to loss of seal air pressure
1020:51	Started suppression pool cooling with Residual Heat Removal System (RHR) A
1025:28	Started suppression pool cooling with RHR B

1025 Unit 1 instrument air compressor restarted and secured several times while attempting to provide temporary control air. Instrument air header pressure was not restored.

1058 Restored offsite power to ST21

1108 Abnormal sounds and vibration reported by eyewitnesses at the Unit 1 IAC

1145 Unit 2 IAC started using appropriate fittings and regulators

1150 Suspended attempts to restore Unit 1 IAC

1151 Unit 2 IAC restored header pressure

1438 Condensate Pump A started

1453 Restored power to Division III ESF bus from offsite power source; secured Division III EDG

1530 Condensate Booster Pump C started

1537 Restored power to Division II ESF bus from offsite power source; secured Division II EDG

1600 Restored power to Division I ESF bus from offsite power source; secured Division I EDG

1700 Placed feedwater system on startup water level control

2202 Restored fuel pool cooling

2325 Main steam isolation valves re-opened; unable to recover condenser due to mechanical vacuum pump tag out

April 25, 2003

0515 Started RHR B in shutdown cooling
0635 Reactor plant in Mode 4, reactor plant temperature less than 200°F

2.5 Coordination of Risk Activities

a. Inspection Scope

The team reviewed the licensee’s action to evaluate the risk associated with the switchyard work on April 24, 2003, for any needed corrective actions. Similarly, the team reviewed the licensee's assessment of risk for the combined switchyard and other ongoing plant activities. These inspection activities included the team performing an independent risk calculation and interviewing licensee risk experts. This activity satisfied Special Inspection Team Charter Scope Item 4.

b. Findings and Observations

The team determined that the licensee properly applied their risk analysis model for Breaker J5204 maintenance by taking the breaker out of service on their Equipment Out Of Service (EOOS) model. The team also verified that the licensee captured the aggregate risk of all maintenance activities for that day listed on the Plan of the Day Report in their EOOS calculation. The team also interviewed operations personnel to determine why the severe weather penalty was not taken against their EOOS value for that day since this was a weather related event. The team determined that, despite the nature of the initiating event, the weather did not meet any of the licensee's criteria for taking this penalty since no National Weather Service warnings were in effect at the time. The team determined that these licensee actions required no corrective actions.

After reviewing the licensee's procedure for applying the switchyard maintenance penalty factor in Procedure EDP-045, "GGNS EOOS Risk Monitor Users' Guide," Revision 1, the team questioned the licensee on how they applied the switchyard maintenance penalty factor against their EOOS value. The team determined that the guidance was vague and that licensee personnel normally called the licensee's risk analyst for clarification whenever switchyard work arose. The team discussed this practice with licensee representatives and they wrote Condition Report GGN-2003-1513 to remove subjectivity from the EOOS modeling process for entering the switchyard penalty factor.

3. OVERALL PLANT RESPONSE

3.1 Loss of 500 kV West Bus

a. Inspection Scope

The team examined the response of the 500 kV switchyard breakers and their associated relaying following the unplanned closure of Disconnect J5205. The team examined plant computer system traces and event logs, interviewed licensee personnel, and reviewed GGNS switchyard electrical distribution diagrams. This activity satisfied Special Inspection Team Charter Scope Item 2.

b. Findings and Observations

The team interviewed licensee personnel to discuss which breakers actuated in the GGNS 500 kV switchyard in response to Disconnect J5205 inadvertently closing. Breaker J5204 had a gas leak which necessitated removing it from service April 10, 2003, to repair the leak. The breaker was electrically isolated by open Disconnects J5203 and J5205. Breaker J5204 was also equipped with grounding straps on both sides of each of its three phases as a standard maintenance practice. At the time of the disconnect closure, maintenance personnel had Breaker J5204 closed, which allowed the fault current which passed through Disconnect J5205 to flow to ground on both sides of the breaker.

The first path was through Disconnect J5205 from the 500 kV line and then through the installed grounding strap to ground. The team determined that this first current path served to isolate ST21 as expected. The ground fault conditions actuated relays for differential current on all three phases of both the primary and backup detection circuits, which triggered the ST21 primary and backup lockout relay trips. These trips fed logic to open Breakers J1652, isolating ST21 from the GGNS, and J5208, isolating ST21 from the east bus and completely electrically isolating ST21 and clearing the electrical fault from the 500 kV system. The team determined that the ST21 isolation was per design.

The second path for current was through Disconnect J5205 and Breaker J5204, then through the grounding strap on Disconnect J5203 of the breaker-to-ground. The second current path served to isolate the west 500 kV bus. The fault conditions actuated relays for differential current on Phase C of both the primary and backup detection circuits, which triggered the west bus primary and backup lockout relay trips. These trips fed logic to open Breakers J5216, J5228, and J5240, which isolated the west GGNS 500 kV bus from the remainder of the incoming 500 kV grid and GGNS. The team determined that the west bus isolation was per design for the ground fault in the switchyard.

3.2 Loss of 500 kV East Bus

a. Inspection Scope

The team examined the response of the switchyard breakers and relaying given the failures of the Entergy Mississippi pilot relaying system. This response included a loss of 500 kV power to the GGNS switchyard. The team examined plant computer system traces and event logs, interviewed licensee personnel, and reviewed switchyard GGNS electrical distribution diagrams. The team reviewed the cause of the momentary loss of offsite power to the switchyard after the scram and the subsequent response of the main generator and the Division I EDG. This activity satisfied Special Inspection Team Charter Scope Item 3.

The team also reviewed the licensee’s ability to utilize the 115 kV Port Gibson offsite power supply line for offsite power recovery. In this effort, the team reviewed licensee procedures which controlled the use of the 115 kV Port Gibson offsite power supply, interviewed operators on their knowledge and ability to implement these procedures, and reviewed the capability of the line to supply power that day. This activity satisfied Special Inspection Team Charter Scope Item 5.

b. Findings and Observations

The team determined that failures in the carrier blocking network between the GGNS switchyard and both the Baxter Wilson and Franklin switchyards led to isolation of power to the GGNS 500 kV switchyard. The carrier blocking system was designed to give time for local breakers to isolate faults before more distant breakers isolated larger portions of the grid. Specifically for these cases, this carrier blocking system should have acted to block the trips of the Baxter Wilson and Franklin switchyard breakers feeding the GGNS 500 kV switchyard for 34 cycles (about 0.5 seconds), giving time for the fault to be cleared by breakers in the GGNS 500 kV switchyard. Malfunctions of the carrier blocking systems prevented these blocking signals from occurring, allowing the Baxter Wilson and Franklin breakers to trip and isolate 500 kV power to the GGNS switchyard.

First, the team determined that one of the blocking signals from GGNS was not received in the Baxter Wilson switchyard by its carrier receiver, allowing the Baxter Wilson feeder breakers to the GGNS switchyard to open immediately. If this signal had been received, the trip logic for the Baxter Wilson to GGNS breakers would have been delayed long enough for the GGNS switchyard fault to clear, which would have allowed Baxter Wilson to supply power to the GGNS switchyard. Next, the team determined that the carrier signals for the trip relays were received in the Franklin switchyard, but a failed auxiliary relay in the Franklin switchyard carrier receiver prevented the blocking function. This failure of the blocking function allowed the Franklin feeder breakers to GGNS to open and isolated that 500 kV power supply to the GGNS switchyard.

Overall, had either one of these carrier blocking systems worked, an offsite source of 500 kV power would have remained to the GGNS switchyard and the division one ESF bus would never have been affected by the disconnect failure. The team determined that, except for the failures of the Entergy Mississippi relaying logics, the response of the switchyard was as designed.

During this loss of offsite power, the Baxter Wilson and Franklin 500 kV feeders were electrically isolated from the GGNS 500 kV switchyard and the GGNS main generator was the only power source remaining to the GGNS switchyard powering some balance-of-plant and Division I ESF loads. This load reduction from 1350 megawatts to approximately 20 megawatts caused a load reject on the GGNS main generator, which actuated a turbine control valve fast closure and subsequent scram of the reactor. After the scram the turbine tripped, shutting the turbine stop valves, and the generator began slowly coasting down with a limited amount of residual steam in the main steam piping available to generate electricity to GGNS loads. Approximately 40 seconds into this coast-down, the power supply breakers for the only remaining channels of reactor protective system logic tripped on under-frequency, initiating a main steam isolation valve (MSIV) closure signal and causing all MSIVs to close. Eventually, the generator output breaker tripped upon sensing a volts-to-hertz mismatch, thereby isolating electrical power to the Division I ESF bus. A bus undervoltage condition signaled the Division I EDG to start and re-power the Division I ESF bus. This bus undervoltage condition also cleared the trip signals on the Baxter Wilson and Franklin feeder breakers to the GGNS 500 kV switchyard, thereby allowing those breakers to close, restoring 500 kV power to the GGNS switchyard. The team reviewed this response and determined that it was per design.

The licensee lost all offsite 500 kV power for approximately 74 seconds, but still had one available offsite source available in the Port Gibson 115 kV line. The team interviewed operators to determine their knowledge and proficiency in use of the Port Gibson 115 kV line. The team determined that the operators received adequate training prior to this scram on connecting this power supply in a proper and safe manner. The team also reviewed Off-Normal Event Procedure (ONEP) 05-1-02-I-4, “Loss of AC Power,” Revision 29; System Operating Instruction 04-1-01-R21-15, “ESF Bus 15AA, Safety Related,” Revision 13; System Operating Instruction 04-1-01-R21-16, “ESF Bus 16AB, Safety Related,” Revision 17; System Operating Instruction 04-1-01-R21-17, “ESF Bus 17AC, Safety Related,” Revision 7; system operating instruction 04-S-01-R27-1, “500/115 kV System, Non-safety Related,” Revision 26; and integrated operating instruction 03-1-01-1, “Cold Shutdown to Generator Carrying Minimum Load,” Revision 124, and found that the licensee’s procedures for using the Port Gibson 115 kV line were adequate.

Finally the team questioned licensee personnel on the capability of the Port Gibson 115 kV line that day. The team questioned the licensee on their load flow studies for electrical power supply availability of the Port Gibson 115 kV line and concluded that, due to the light electrical power needed for the scram event on April 24, 2003, the line was ready for offsite power recovery at all times.

3.3 Reactor Power, Pressure, and Level Control

a. Inspection Scope

The team evaluated the reactor plant response following the scram, including automatic control rod insertion, automatic injection of the RCIC and HPCS systems, and control room operator actions to control reactor vessel pressure and level. The team also interviewed control room operators and other licensee staff involved in these activities. This activity satisfied portions of Special Inspection Team Charter Scope Items 2, 7, and 9.

b. Findings and Observations

The team determined that, immediately following the reactor scram (Section 3.1), all control rods were automatically inserted and the reactor was shut down. The operators placed the reactor mode switch in shutdown as required by ONEP 05-1-02-I-1, "Reactor Scram, " Revision 110. The loss of STs 11 and 21 eliminated power to the balance-of-plant loads, including condensate and condensate booster pumps, which caused a loss of feedwater flow to the reactor vessel.

Reactor vessel level decreased for several minutes before reaching a reactor protection system (RPS) trip setpoint (Level 2) for reactor vessel water level, which started both the HPCS system and RCIC systems automatically injecting into the core, restoring reactor vessel level. The RPS Level 2 trip setpoint satisfactorily isolated the containment, auxiliary building, and containment building as designed. The team observed the control room operators taking manual control of the HPCS and RCIC systems per Procedures 04-1-01-E22-1,"HPCS Operation," Revision 105, and 04-1-01-E51-1, "RCIC Operation," Revision 118, respectively. Operator action to maintain reactor vessel level was deliberate, in accordance with procedures, and effectively communicated between control room operators. The licensed operators appropriately secured the HPCS system and controlled reactor vessel water level with the RCIC system.

The team determined that following the scram a MSIV closure (Section 3.2) occurred, eliminating the condenser as an available heat sink. The recovery of the condenser was further complicated due to the unavailability of the mechanical vacuum pump system, which was tagged out for planned maintenance and could not be realigned in a timely manner. Without the available condenser for reactor decay heat removal, reactor vessel pressure was controlled by manual operation of safety relief valves. The team observed the control room operators take manual control of the safety relief valves per Procedure 04-1-01-B21-1, "Nuclear Boiler System," Revision 45, to maintain reactor pressure within an established pressure band. Operator action to maintain reactor vessel pressure was deliberate, in accordance with procedures, and effectively communicated between control room operators.

The automatic RPS trip setpoint logic and system operation associated with reactor pressure and level control was determined by the inspectors to be per design. Control room operator actions following the scram and automatic RPS initiations were found to be in accordance with applicable procedures and training.

3.4 Loss of Instrument Air Pressure

a. Inspection Scope

The team reviewed the conditions which existed following the scram and partial loss of offsite power which required manual actions in order to restore instrument air header pressure. The team also reviewed actions taken by licensee personnel in their attempt to restore instrument air header pressure with the Units 1 and 2 IACs. Additionally, the team reviewed applicable procedures related to the operation of instrument air and interviewed licensee personnel who were involved in the recovery of the instrument air system. This activity satisfied portions of Special Inspection Team Charter Scope Items 6, 8, and 10.

b. Findings

Background

The team determined that, upon the loss of ST21 and ST11 (Sections 3.1 and 3.2), the running Unit 2 IAC, the running service air compressor, and the TBCW pump all tripped due to loss of power. Instrument air header pressure is normally maintained at approximately 115 psig. As instrument air header pressure began to lower, the service air system cross-connect valve opened as designed and pressure stabilized only momentarily. Since the service air compressor was not running, instrument air header pressure continued to lower and an automatic start signal was received to the Unit 1 IAC, but it did not start because of a low TBCW pressure interlock relay which remained open while the operators restored TBCW with SSW. Almost 10 minutes after the partial loss of offsite power, TBCW was restored with SSW, and the Unit 1 IAC TBCW pressure interlock relay closed and the compressor started, but instrument air header pressure had lowered to about 40 psig and was unable to provide enough pneumatic energy and motive force to modulate the compressor's inlet control Valve 1P53-FCV-F511 and unload control Valve 1P53-FCV-F520. As a result, the control valves remained in an unloaded condition with the inlet valve closed and the unloading valve open, which rendered the machine unable to produce adequate discharge pressure. Instrument air header pressure continued to lower and the Unit 1 IAC continued to run until its seal air pressure interlock relay opened and it tripped off on low seal air pressure. The team determined that the appropriate alarms and annunciators were received in the control room and the instrument air system control logic operated as designed. Total instrument air header pressure was lost approximately 35 minutes after the scram.

The team reviewed operator actions as they attempted to restore the instrument air header pressure following the partial loss of offsite power. The control room operators clearly understood the consequences of losing instrument air header pressure and responded appropriately by entering ONEP 05-1-02-V-9, "Loss of Instrument Air," Revision 30. They verified the automatic service air crosstie valve opened and observed that instrument air header pressure continued to lower. The operators realized both running compressors had tripped following the loss of ST21 and ST11. They dispatched a building operator to the instrument air compressor location to inspect the system. The operator noted the Unit 1 IAC was running but header pressure was not increasing as expected. The control room then dispatched engineering and maintenance personnel to the area to assist the operator.

When engineering and maintenance personnel arrived, the building operator was attempting to use a portable air compressor with a temporary air hose held in place to the compressor's control air connection to assist starting. The team determined from interviews and document reviews that there was no written guidance or specific instructions on how to start a compressor upon a loss of air pressure. The team found there was confusion among the operators and other site personnel as to what equipment was necessary and how to provide a temporary source of air. The team also determined that the licensee staff did not understand how the compressor control valves operated on a loss of air pressure. Several attempts were made by the licensee to provide temporary control air without mechanical fittings by holding and duct taping the hose to the control air connection while the seal air trip relay was overridden by manually holding closed its contacts. The operators assumed the inlet control valve was open and the unloading control valve was closed. Their assumptions were incorrect. After multiple failed attempts to pressurize the air header, the operators noted the unloading control valve was open so they decided to manually actuate the unloading valve closed by use of an air jumper directly to the valve actuator. The operators then restarted the Unit 1 IAC for the fifth time and header pressure began to increase slower than expected and reached no more than 65 psig. At this same time, eyewitnesses noted loud mechanical metal-to-metal type sounds and high vibrations coming from the inlet control valve area of the machine. The operators continued to run the Unit 1 IAC for about 45 minutes while continuing to troubleshoot with no success before shutting down the machine. It was later determined that the prolonged operation of the Unit 1 IAC without an adequate supply of control air caused the inlet control valve to flutter, creating high stresses and vibration on the roll pin that holds the inlet control valve disk to the valve actuator stem. Visual inspection of the pin showed axial scratch marks on the pin, indicating it backed out of its hole, creating a shear stress on the pin where it remained in contact with the valve disk and valve stem. The fluttering action of the valve caused a hammering effect at this shear stress region where the pin became overloaded and sheared off in three pieces. The team concluded the pin failure was the result of operation of the compressor without adequate control air pressure.

In parallel with running and troubleshooting the Unit 1 IAC, a second group of licensee personnel were successful in attempting to restart the Unit 2 IAC with the proper mechanical fittings and regulators to provide the required control air pressure. Instrument air header pressure was restored 2 hours after the scram using the Unit 2 IAC.

ONEP 05-1-02-V-9, "Loss of Instrument Air," Revision 30, Section 3.11, refers to the use of compressed air or nitrogen to be used for seal air to restart the compressors but provides no other information. System Operating Instruction 04-1-01-P53-1, "Instrument Air System," Revision 56, Prerequisite 4.1.1.a, refers to the use of compressed air or nitrogen to be used for seal air and control air to restart the compressors but provides no other information. The team determined that the procedural guidance provided to restart a compressor following a loss of header pressure was inadequate.

Introduction. A Green NCV was identified for failure to provide an adequate procedure to restart and restore IAC operation following a loss of instrument air pressure as required by Technical Specification 5.4.1.

Description. The team identified that on April 24, 2003, during recovery of the instrument air system following a scram and partial loss of offsite power, the licensee failed to provide instructions on how to provide seal air and control air to the IACs from a temporary source. This resulted in operation of the Unit 1 IAC outside of its normal configuration which caused damage to its inlet valve and the licensee's inability to restore instrument air header pressure as described in the background section above.

Analysis. This finding was determined to be more than minor because it affected the mitigating systems cornerstone objective as described in NRC Manual Chapter 0612 involving the ability to ensure the availability, reliability, and capability of systems that respond to initiating events. The finding was assessed in accordance with NRC Inspection Manual Chapter 0609, Significance Determination Process," Phase 1 and 2. Based on the phase two analysis, the finding was of very low safety significance because, although recovery of instrument air was delayed, all mitigating safety system functions remained available.

Enforcement. GGNS Technical Specification Section 5.4.1, "Procedures," states that written procedures shall be established, implemented, and maintained that are recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, February 1978 , Section 6.b, states that safety related activities such as those for combating emergencies and other significant events such as a loss of instrument air should be covered by procedures. GGNS ONEP 05-1-02-V-9, "Loss of Instrument Air," Revision 30, did not provide guidance on how to provide temporary control air and seal air to the compressors following a loss of instrument air. Because this failure to provide an adequate procedure is of very low safety significance and has been entered into the licensee's corrective action system as Condition Report 2003-1347, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-416/03-07-01, Failure to Provide an Adequate Procedure to Restore Instrument Following a Loss of the Instrument Air System.

4 CORRECTIVE ACTIONS

4.1 Causal Analysis

a. Inspection Scope

Partial Loss of Offsite Power

The team reviewed the licensee’s apparent and root causes for the unplanned closure of Disconnect J5205 and the failures of the 500 KV carrier blocking system. The team interviewed licensee personnel, reviewed condition reports, studied plant computer trends and events logs, and toured the GGNS 500 kV switchyard area. The team reviewed these activities for independence, completeness, accuracy, and associated corrective actions. This activity satisfied portions of Special Inspection Team Charter Scope Items 8, 9, and10.

Loss of Instrument Air System

The team reviewed the licensee's preliminary root cause evaluation report for loss of the instrument air system. The team performed a field inspection of the Unit 1 IAC, interviewed licensee personnel, and reviewed condition reports, system engineer logs, vendor manuals, plant computer trends, operator logs, and metallurgical analysis of the broken roll pin. The team reviewed these activities for independence, completeness, accuracy, and associated corrective actions. This activity satisfied portions of Special Inspection Team Charter Scope Items 8, 9 and 10.

b. Findings and Observations

Partial Loss of Offsite Power

A priority corrective action from Condition Report 2003-1340 was written by the licensee to perform a significant event review team (SERT) investigation to determine the cause of the scram on April 24, 2003. The SERT issued a preliminary report which was not finalized at the time of the inspection. The team interviewed three members of the SERT, including the SERT leader. The SERT established that the scram was caused by the electrical transient initiated by the unplanned closure of Disconnect J5205. The NRC team also concluded this to be the apparent cause of the scram.

The team concurred with the licensee's assertion that the unplanned closure of Disconnect J5205 was assisted by the wind. The team confirmed that winds measured at the meteorological tower one quarter mile away at the time of the event were varying from 25 to 35 miles per hour and that the wind direction was from 340 degrees, which would have tended to force the disconnect in the closed direction. The disconnect was equipped with a spring counterbalance assembly whose design was to keep the disconnect open against 77 mile per hour winds. Since the winds apparently did not exceed the design specification for wind speed, the team questioned the integrity of the counterbalance assembly.

An externally mounted motor disengagement locking collar was padlocked in the disengaged position for the breaker maintenance. Following the event, the locking device was found broken. The cast aluminum device had cracked and disconnected from its locked position. The initial investigation into the apparent cause of the disconnect failure focused on the locking device, which was replaced and analyzed for its failure mechanism. Several days into the SERT evaluation, the licensee was informed by Entergy Mississippi, which owns, operates, and maintains the disconnect devices, that the probable cause of the device closing was due to a spring counter balance assembly and not the locking collar device. It was not until after ST21 was returned to service that the condition of the Disconnect J5205 spring counterbalance assembly was questioned. Since further investigation of the assembly required ST21 to be de-energized, the licensee used engineering judgement in considering failure of the counterbalance assembly as an apparent cause until further investigation of the disconnect counterbalance assembly is performed. These disconnects only use the counterbalance assembly when they are opened and the licensee and Entergy Mississippi have taken compensatory measures to chain open disconnects as a further means of securing disconnects until the exact cause of the unplanned disconnect closure is determined. There were no disconnects in the GGNS switchyard in the open position at the conclusion of this inspection. Corrective actions are discussed in more detail in Section 4.3 of this report.

The team determined that one of the carrier blocking signals from GGNS was not received in the Baxter Wilson switchyard, allowing the Baxter Wilson feeder breakers to GGNS to open. The cause was later found to be a weak feedback signal originating from the GGNS switchyard. The carrier blocking logic device in the GGNS switchyard required an adjustment to strengthen its signal. The channel was taken to trip and then properly adjusted. If the signal had been received, the trip of the Baxter Wilson feeder breakers to the GGNS switchyard would have been inhibited long enough for the fault and its associated trip signal to clear. With the Baxter Wilson feeder supplying uninterrupted power to the Grand Gulf switchyard, the east 500 kV bus would have not been de-energized and the Division I ESF bus would have never been affected by the unplanned disconnect closure.

The team determined that, while the signals for the trip relays were received in the Franklin switchyard, a failed auxiliary relay in the Franklin switchyard carrier receiver logic prevented the blocking function. This failure of the blocking function allowed the Franklin feeder breakers to the GGNS switchyard to open and isolated this 500 kV power source to the GGNS switchyard. A properly functioning relay would have kept power to the GGNS switchyard and the Franklin 500 kV power supply to the GGNS switchyard east 500 kV bus and the Division I ESF bus would have never been affected by the disconnect failure.

Overall, the team determined that had either one of these Entergy Mississippi carrier blocking signal systems worked as designed, the east 500 kV bus and the Division I ESF bus would have never been affected by the unplanned disconnect closure.

<u>Loss of Instrument Air</u>

The team determined the root cause of the loss of instrument air to be a lack of procedural guidance or instruction to provide temporary control air and seal air to the compressors following a loss of instrument air header pressure (Section 3.4).

Secondly, the team determined a contributing cause to be from the inherent design of the compressor cooling water configuration. When the normal source of TBCW is lost, as occurred during this event, it takes several minutes to restore cooling water with the backup SSW system in order to clear the cooling water pressure interlock. By the time the autostart relay (~90 psig) picked up, cooling water pressure had not been restored; therefore, the compressor did not start (Section 3.4). By the time cooling water was restored, air header pressure had dropped below what is required for control air pressure in order to modulate the control valves and pressure could not be restored.

4.2 Extent of Conditions

a. Inspection Scope

Partial Loss of Offsite Power

The team reviewed the causes for the unplanned closure of Disconnect J5205 and the loss of 500 kV power to the Grand Gulf switchyard. The team reviewed condition reports, interviewed personnel, and reviewed switchyard diagrams in this effort. This activity satisfied portions of Special Inspection Team Charter Items 8 and 10.

Loss of Instrument Air Pressure

The team reviewed the contributing causes for the loss of the instrument air system and reviewed the licensee's corrective action data base to determine if similar events had taken place in the past. The team also reviewed plant historical records, including design modifications, operating procedures, and system drawings to better understand the background of the instrument air system and the overall extent of the loss of air event and its contributing causes. This activity satisfied portions of Special Inspection Team Charter Scope Items 6, 8, and 10.

b. Findings and Observations

Partial Loss of Offsite Power

The team determined that the inspection of Disconnect J5205 to discover its root cause failure mechanism associated with the spring counterbalance assembly must be completed when ST21 was electrically isolated from the plant. The licensee will have to schedule an ST21 outage to determine the root cause of the disconnect failure and then, based on their findings, begin an extent of condition determination. The team concluded that the licensee will not be able to perform this determination on other disconnect assemblies without de-energizing significant portions of the GGNS switchyard. The inspectors concluded that the compensatory measures described in Section 4.1 of this report that have been established by the licensee and Entergy Mississippi are adequate when applied to similar switchyard disconnects until the extent of condition can be established. There were no disconnects in the GGNS switchyard in the open position at the conclusion of this inspection.

The carrier blocking system signal components which were found to be defective were repaired. Since failures occurred on the only two feeder supplies into the GGNS 500 kV switchyard, the extent of this condition of having inoperative carrier blocking systems was covered by the event. Entergy Mississippi had to troubleshoot the two subsystems making up the pilot relying system in order to return them to service. The team therefore determined that the extent of condition for the carrier blocking system failures was properly addressed during the corrective actions for the system failures.

Loss of Instrument Air Pressure

The team determined the causes for the loss of the instrument air system as described in Section 4.1. The team determined that the lack of procedural guidance to restore seal air and control air to compressors affected the instrument and service air compressors. The team found that some of the more experienced maintenance personnel were aware of the need for special fittings and regulators to provide the required volume and pressure for temporary instrument air. The licensee group that restarted the Unit 2 IAC utilized their experience and the required hardware to successfully start the compressor and did not experience any unusual noises or vibration while running the machine to restore air header pressure.

The team concluded that this was the first time a loss of instrument air occurred at GGNS where the licensee was unable to routinely restore pressure to the system. The Unit 1 IAC was operated beyond its normal design configuration, which resulted in damage to the compressor's inlet control valve. The Unit 2 IAC was restored with the proper fittings and regulators and no abnormal sounds or vibrations were noted when it was operated.

4.3 Corrective Actions

a. Inspection Scope

The team reviewed the corrective actions proposed and implemented by the licensee. This included corrective actions from the licensee’s SERT reports, condition reports generated after the scram, and maintenance action items generated after the scram. The team reviewed these documents to determine whether the actions proposed were thorough, addressed the extent of the condition, and solved the proper problem. This activity satisfied Special Inspection Team Charter Scope Item 10.

b. Findings and Observations

Partial Loss of Offsite Power

Upon discovery, the licensee took action to chain Disconnect J5205 in the open position to ensure further unplanned closures would be prevented even under high wind conditions. The licensee extended this practice for future openings of disconnects until the root cause was firmly established and understood. The team concluded that no other immediate action is currently needed because all disconnects in the switchyard are in their normally closed position. An ST21 outage will be needed to investigate the root cause and generate any further corrective action.

Breaker J5204 and Disconnect J5205, along with all of the other 500 kV switchyard equipment, did not suffer any significant damage. The team concurred with the licensee’s assessment that no corrective actions were needed as a result of the event to return these components to service. However, minor damage was found on the Disconnect J5205 side of Breaker J5204. A temporary maintenance grounding strap showed signs of excessive current and heat damage and was replaced so safe maintenance on Breaker J5204 could resume after the event. The corona ball on the end of the Phase C disconnect pole showed signs of electrical arc damage resulting in a throughwall hole approximately one inch in diameter. Entergy Mississippi evaluated the corona ball condition, concluded that the damage was minor, and plans to replace the device at the next opportunity.

After discovery that the carrier blocking system malfunctioned during the event, each of the faulty channels was taken to trip. This action would ensure that the faulty equipment would not hamper the intended operation of the carrier blocking system until specific failures could be determined.

Investigation by Entergy Mississippi personnel uncovered a failed auxiliary relay in the Franklin yard carrier receiver which prevented the blocking function. This relay was replaced and the Grand Gulf-to-Franklin carrier blocking system was returned to full service. Additional investigation determined the cause of the Baxter Wilson carrier blocking system failure to be a weak signal originating from the Grand Gulf switchyard. The signal was adjusted so that it could be received at Baxter Wilson for any future electrical system faults.

Loss of Instrument Air Pressure

The team determined that the licensee's immediate corrective action for the loss of instrument air was to properly connect a temporary air supply to the Unit 2 IAC and pressurize the instrument air header. The licensee inspected and repaired the unit one IAC inlet control valve under Maintenance Action Item 332119. The licensee performed analysis on the broken roll pin described in Section 3.4 and documented it in licensee laboratory Report L20324. The licensee concluded that the failure of the inlet control valve was caused by the abnormal operation of the compressor which caused excessive loadings on the roll pin and ultimately failure from brittle fracture.

GGNS performed a root cause analysis on the loss of instrument air. GGNS determined that: (1) their instrument air system operating procedure did not provide the necessary instructional information for supplying temporary air when starting the IACs; and (2) that the IAC's cooling water system requires time consuming manual restoration following a partial loss of offsite power as described in Section 3.4. GGNS long-term corrective actions included revising procedures to include specific instructions for use of temporary air to the compressors and providing a temporary source of air located at the compressor skids with the appropriate tools and fittings. GGNS determined that Item (2) is within the design basis of the plant and any corrective action to change its operation would be an enhancement to the plant and would be addressed by their plant projects and not the corrective action program. The team concluded that the licensee's corrective actions were adequate.

5. EXIT MEETING SUMMARY

On May 9, 2003, the team presented the inspection results to Mr. George Williams and other members of his staff. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Barfield, Manager, System Engineering
T. Barnett, Electrical Design Engineer
C. Bottemiller, Manager, Plant Licensing
R. Brinkman, Operations Senior Reactor Operator
L. Buffkin, Operations Reactor Operator
R. Burditt, Operations Reactor Operator
R. Collins, Partial Loss of Offsite Power SERT Leader
D. Cotton, Supervisor, Radiation Protection
J. Edwards, General Manager, Plant Operations
C. Ellsaesser, Manager, Corrective Action and Assessment
M. Guynn, Manager, Emergency Preparedness
E. Hester, Electrical Design Engineer
S. Humphries, Shift Manager, Operations
G. Ingram, Licensing Specialist
R. Ingram, Operations Shift Supervisor
E. Langley, Supervisor, Planning and Scheduling
M. Larson, Senior Licensing Specialist
D. McDirmid, System Engineer
J. O'Neil, Operations Reactor Operator
W. Parman, Electrical Maintenance Supervisor
R. Patterson, Senior Reactor Operator, Operations
T. Powell, Operations Control Room Supervisor
J. Roberts, Director, Nuclear Safety Assurance
C. Rogers, Operations Reactor Operator
G. Smith, Senior Staff Engineer, Design Engineering
G. Sparks, Manager, Operations
T. Thornton, Engineering Supervisor, System Engineering
F. Weaver, Operations Shift Manager
D. Wiles, Director, Engineering
H. Yeldell, Manager, Design Engineering

NRC

D. Loveless, Senior Reactor Analyst
T. Farnholtz, Senior Project Engineer

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000416/0307-01	NCV	Failure to Provide an Adequate Procedure to Restore Instrument Air Following a Loss of the Instrument Air System (Section 3.4)

LIST OF DOCUMENTS REVIEWED

Procedures:

03-1-01-1, "Cold Shutdown to Generator Carrying Minimum Load," Revision 124
04-1-01-R21-15, "System Operating Instruction - ESF Bus 15AA," Revision 13
04-1-01-R21-16, "System Operating Instruction - ESF Bus 16AB," Revision 17
04-1-01-R21-17, "System Operating Instruction - ESF Bus 17AC," Revision 7
04-1-01-R27-1, "System Operating Instruction - 500/115 kV System," Revision 26
04-S-01-P52-1, "Service Air System Electrical Lineup," Revision 28
05-1-02-I-1, "Reactor Scram, " Revision 110
05-1-02-I-4, "Loss of AC Power," Revision 29
05-1-02-V-9, "Loss of Instrument Air," Revision 30
05-1-02-111-2, "Loss of Both RPS Busses," Revision 20
05-1-02-I-2, "Turbine and Generator Trips," Revision 23
05-1-02-V-2, "Loss of Turbine Building Cooling Water," Revision 19
05-1-02-V-7, "Loss of Feedwater Flow," Revision 20
05-1-02-V-8, "Loss of Condenser vacuum," Revision 18
04-1-01-E51-1, "RCIC Operation," Revision 118
04-1-01-B21-1, "Nuclear Boiler System," Revision 45
05-5-01-EP-2, "EP2," Revision 34
05-5-01-EP-3, "EP3," Revision 26
05-S-01-EP-2, "RPV Control," Revision 34
05-S-01-EP-3, "Containment Control," Revision 26
05-S-01-EP-4, "Auxiliary Building Control," Revision 25
06-OP-1R20-W-0001, "Plant AC/DC Electrical Power Distribution Weekly Lineup," Revision 104

Condition Reports:

CR-GGN-2001-1309	CR-GGN-2003-1350	CR-GGN-2003-1371
CR-GGN-2002-2420	CR-GGN-2003-1351	CR-GGN-2003-1382
CR-GGN-2002-2426	CR-GGN-2003-1352	CR-GGN-2003-1391
CR-GGN-2003-1339	CR-GGN-2003-1353	CR-GGN-2003-1421

CR-GGN-2003-1340	CR-GGN-2003-1355	CR-GGN-2003-1422
CR-GGN-2003-1341	CR-GGN-2003-1357	CR-GGN-2003-1428
CR-GGN-2003-1345	CR-GGN-2003-1364	CR-GGN-2003-1471
CR-GGN-2003-1346	CR-GGN-2003-1365	CR-GGN-2003-1513
CR-GGN-2003-1347	CR-GGN-2003-1372	CR-GGN-2003-1534
CR-GGN-2003-1349		

Maintenance Action Items:

332099	332129	332141	332147
332116	332130	332143	332180
332117	332131	332145	332183
332118	332132	332146	323882
332119	332140		

Other Documents:

Entergy Mississippi April 24, 2003 GGNS 500 kV Switchyard Inspection Results
Entergy Mississippi Transmission Group Safety Alert for 500 kV Disconnects
Entergy Transmission Relay Operations Point Paper
GGNS Control Room Supervisor Turnover Sheet for April 24, 2003
GGNS Electrical Distribution Drawing, Revision Date 4/4/02
GGNS EOOS Risk Monitor Users' Guide, Revision 1
GGNS Operators' Logs for April 24-25, 2003
GGNS Plan of the Day Report for April 24, 2003
GGNS Shift Manager's Report for April 24, 2003
Grand Gulf Nuclear Station Lesson Plan, GG-1-LP-RO-P5300
Grand Gulf Nuclear Station Red Tag number GG-03-0338 - Mechanical Vacuum Pump C
P53 (Instrument Air) System Engineer Log Notes, dated 5/5/03
Plant Data System Computer Traces
Radiation Protection Log for April 25, 2003
System Description P53, Instrument Air System
Scram Number 107, Analysis Report, dated 4/25/03
Tracking LCO Report 02-0655 for 115 kV Line Offsite Feeder

LIST OF ACRONYMS USED

BOP	balance of plant
CCDP	conditional core damage probability
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
EOOS	equipment out of service model
ESF	engineered safety features
GGNS	Grand Gulf Nuclear Station
HPCS	high pressure core spray
IAC	instrument air compressor
kV	kilovolt
MSIV	main steam isolation valve
ST	service transformer
NCV	noncited violation
NRC	Nuclear Regulatory Commission
ONEP	off-normal event procedure
PCS	power conversion system
RCIC	reactor core isolation cooling
RHR	residual heat removal
RPS	reactor protection system
SDP	significance determination process
SERT	significant event review team
SSW	standby service water
ST	service transformer
TBCW	turbine building cooling water
psig	pounds per square inch (gauge)

ATTACHMENT 2

CHARTER FOR THE SPECIAL INSPECTION TEAM
AT THE GRAND GULF NUCLEAR STATION

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

May 2, 2003

MEMORANDUM FOR: Timothy L. Hoeg, Senior Resident Inspector, Grand Gulf Nuclear Station

FROM: Arthur T. Howell III, Director, Division of Reactor Projects ***/RA/ 5/2/03***

SUBJECT: SPECIAL INSPECTION TEAM AT GRAND GULF NUCLEAR STATION

In response to our initial evaluation of the causes and impact of the automatic reactor scram on April 24, 2003, which also involved a loss of offsite power, loss of instrument air, and the unavailability of the power conversion system for several hours, a Special Inspection Team is being chartered. You are hereby designated as the Special Inspection Team leader.

A. Basis

On April 24, 2003, during strong winds and a thunderstorm, a locked open 500 kV disconnect switch associated with a breaker which was out of service for maintenance closed, causing a severe ground (short circuit) through a temporary grounding strap which dropped out station Transformer 21 and locked out the west 500 kV offsite power source, resulting in a partial loss of offsite power. The east 500 kV switchyard bus was deenergized when the main generator tripped but was immediately reenergized from offsite power. Instrument air was lost following the loss of power. Instrument air was restored after about 2 hours. The initial CCDP for this event is in the range of 6.9E-06 to 3.3E-05.

A Special Inspection Team will be dispatched to better understand the cause of the automatic scram, system and component responses, and operator actions following the event. The team is also tasked with gaining a better understanding of the licensee's posttrip review analysis and root cause investigations. The team is expected to perform data gathering and fact-finding in order to address the following items.

B. Scope

1. Develop a complete sequence of events related to the reactor scram.

2. Review the plant response to the scram and verify it was as per design.

Attachment 2

3. Review the failure and/or site specific design that resulted in the loss of the east switchyard bus.

4. Evaluate the licensee's coordination of risk activities with the ongoing switchyard work.

5. Evaluate the licensee's procedures and readiness to use the alternative power source for offsite power recovery.

6. Evaluate the conditions that caused a loss of instrument air following the loss of secondary power, including their likelihood.

7. Evaluate the licensee's ability to recover the power conversion system following the event, including an estimate of the time range to recovery.

8. Review the licensee's root cause determinations for independence, completeness, and accuracy, including risk analysis of the event.

9. Review the overall adequacy of the licensee's response to the scram, including operator actions, problem identification, and immediate and long-term corrective actions associated with identified deficiencies.

10. Review and assess the corrective actions proposed by the licensee.

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the Special Inspection Team.

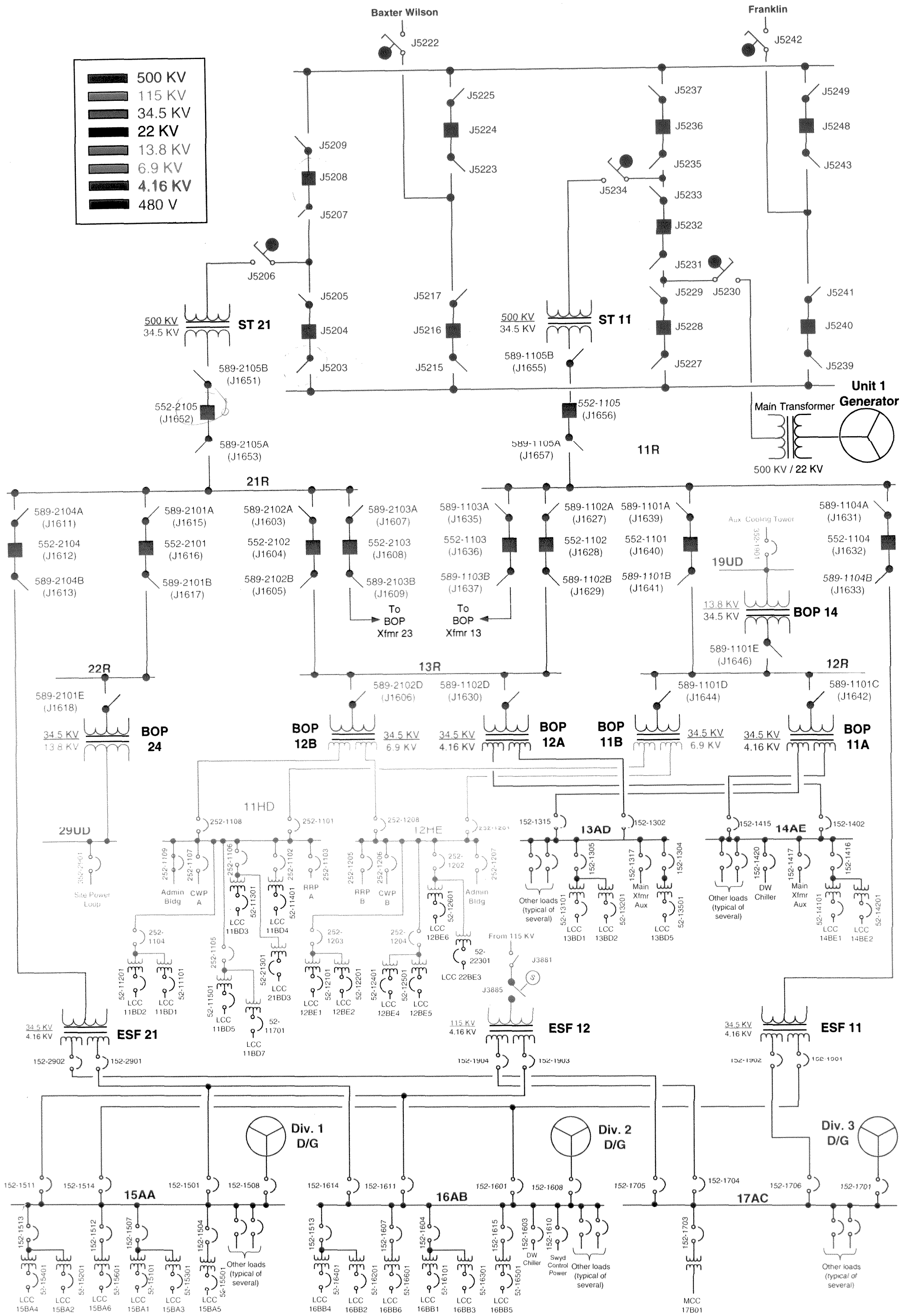
This memorandum designates you as the Special Inspection Team leader. Your duties will be as described in Inspection Procedure 93812. The team will include the Grand Gulf resident inspector. The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not 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.

The Team will report to the site, conduct an entrance, and begin inspection on Monday, May 5, 2003. Tentatively, the inspection should be completed by close of business May 9, with a report documenting the results of the inspection issued within 30 days of the completion of the inspection. While the team is on site, you will provide daily status briefings to Region IV management.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact me at (817) 860-8248.

ATTACHMENT 3

<u>GGNS SWITCHYARD ELECTRICAL DISTRIBUTION DRAWING</u>



GGNS ELECTRICAL DISTRIBUTION

FOR INFORMATION ONLY

Revision Date:
4/4/02