STARTUP AND SHUTDOWN PLAN
MALFUNCTION ABATEMENT PLAN
COMPLIANCE ASSURANCE MONITORING PLAN

Holland Energy Park

Two (2) Natural Gas-Fired Combustion Turbines

Holland Energy Park
1 Energy Park Way
Holland, Michigan

NTH Project No. 74-210375
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NTH Consultants, Ltd.
3001 N. Coolidge, Suite 101
East Lansing, MI 48823

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Appendices

1.0 INTRODUCTION

Holland Board of Public Works (BPW) received Permit to Install (PTI) No. 107-13E for the installation and operation of a natural gas-fired combined heat and power (CHP) plant, known as Holland Energy Park (HEP), located at 1 Energy Park Way, Holland, Michigan. As of October 2021, the current air permit is identified as MI-ROP-P0465-2018; any references within this plan refer to the preceding air permit and subsequent modifications for, or renewals of, the ROP. The latest versions of the referenced manuals throughout this plan are maintained onsite and/or electronically.

MI-ROP-P0465-2018 includes requirements to maintain a Malfunction Abatement Plan (MAP) under Special Condition (SC) III.1 and a Startup and Shutdown (SUSD) plan under SC III.2 for flexible group FGCTGHRSG, which includes two (2) combined-cycle natural gas-fired combustion turbine generators (CTGs) coupled with heat recovery steam generators (HRSGs) in a 2x1 configuration with a steam turbine generator (STG). Additionally, 40 CFR Part 64 specifies that compliance assurance monitoring (CAM) be implemented for emission units meeting applicability criteria under 40 CFR §64.2(a). CAM does not apply to emissions units exempt under 40 CFR §64.2(b). The combustion turbines operating under FGCTGHRSG meet CAM criteria for emissions of volatile organic compounds (VOCs) and are controlled by oxidation catalysts; therefore, CAM requirements apply for the VOC limit of 4 ppmvd at 15% O_2 listed as special condition (SC) I.12 under FGCTGHRSG.

1.1 Process Description

Each of the two (2) natural gas-fired CTGs has a maximum design heat input rating of approximately 554 million British thermal units per hour (MMBtu/hr) and includes a HRSG to produce steam from the hot CTG exhaust gas for use in powering the steam turbine generator to provide additional electric generation and support the city of Holland with district heating. Each CTG/HRSG is equipped with dry low NO_x (DLN) combustion technology, selective catalytic reduction (SCR), and an oxidation catalyst.

In the power generation process, inlet air enters the CTG where it is compressed, mixed with natural gas, and ignited. This process causes the air to expand, creating pressure that turns the turbine blades. The spinning blades are attached to a shaft, which turns a generator to produce electricity.

The hot exhaust from each CTG (in excess of 800 °F) is routed through a HRSG where the excess exhaust heat is used to generate steam. The steam can be used to drive a steam turbine for additional electric generation, and for industrial and domestic processes that require heat. Exhaust steam leaving the steam turbine passes through a condenser where it is cooled and recovered as water for reuse in the steam cycle. Exhaust steam from the steam turbine is cooled by circulating water in the condenser.

1.2 Purpose of the Plans

The SUSD plan and MAP are used to detail procedures for operating and maintaining FGCTGHRSG during periods of startup, shutdown, and malfunction (SUSDM), and should be properly followed in order to minimize emissions during SUSDM events. The SUSD plan and MAP also detail how to implement preventative measures to guard against malfunctions and/or failures that result in pollutant emissions above permitted emission rates. Additionally, the SUSD plan and MAP present procedures for detecting and correcting these incidents, should they occur. BPW uses an oxidation catalyst for control of VOCs from FGCTGHRSG. The CAM plan details how BPW will monitor certain parameters indicative of oxidation catalyst performance to provide reasonable assurance of effective control of VOCs.

Sections 2.0 of this report details the SUSD Plan, MAP, and CAM Plan requirements. Sections 3.0 and 4.0 contain recordkeeping and reporting requirements. Sections 5.0 and 6.0 contain a list of plan revisions and referenced documents. Appendices A - H include procedures for SUSDM events, obtained from the Gas Turbine Generator System and HRSG System standard operating procedures (SOPs) listed in Section 6.0.

2.0 PLAN PROCEDURES

During SUSDM events involving FGCTGHRSG, BPW will follow the procedures in this document for proper operation in order to minimize excess emissions. The procedures in this document will be followed during periods of SUSDM. The SUSD plan and MAP are intended to provide a roadmap to plant operations and outlines procedures for operation of

FGCTGHRSG during SUSDM events. The CAM Plan specifies monitoring of performance indicators to provide reasonable assurance of compliance with the VOC limit of 4 ppmvd at 15% O_2 listed as FGCTGHRSG SC I.12; in ROP No. MI-ROP-P0465-2018. These plans will help ensure that:

- During SUSDM events, BPW operates and maintains FGCTGHRSG in a manner consistent with good air pollution control practices;
- BPW is prepared to correct malfunctions as soon as it is safe and practicable to do so, in order to minimize excess emissions of air pollutants;
- BPW meets the recordkeeping and reporting requirements associated with periods of SUSDM (including documenting corrective action taken to restore malfunctioning process and air pollution control equipment to its normal manner of operation); and
- Oxidation catalysts are operating in a manner that provides reasonable assurance of maintaining compliance with the VOC emissions limit specified under FGCTGHRSG SC I.12.

2.1 Startup and Shutdown Plan

This section provides details regarding operation of the CTG during a startup and shutdown.

Definition of Startup

Pursuant to ROP No. MI-ROP-P0465-2018, "startup for the CTGs is defined as the period of time from synchronization to the grid (generator breaker closed) until the unit reaches steady state operation (loads greater than 50 percent of design capacity)." Compliance with the CO and NO_x emission limits for operating hours during startup will be based on a 60-minute rolling average basis. This corresponds to the Minimum Emission Compliance Load (MECL). Below MECL, emissions of oxides of nitrogen (NO_x) and carbon monoxide (CO) are expected to be higher than during standard operation at operating load.

Procedures during Startup

To minimize emissions during startup, the unit should be brought to MECL as quickly as practicable. A typical startup will last between 1 to 2 hours. Detailed SOPs are located in Appendices A and B of this document (full versions of the SOPs for the CTGs and HRSGs are located in either the plant Control Room or kept electronically). Following the SOPs will help to minimize emissions during startup. Any discrepancies found during inspections will be recorded in the Operations Log, as referenced in Section 6.0 of this document.

The general procedures for CTG startup include:

1. Prior to startup of the CTGs, the pre-operation checks must first be made to verify that all required equipment is ready to start, including CTG components and monitoring equipment. A variety of equipment and system parameters associated with the CTGs will be inspected prior to startup of each unit, and adjustments will be made to equipment when necessary, as described in detail in the SOPs.
2. If there has been a loss of AC power supply, the battery status will be checked, before the CTG can be started.
3. After confirming all necessary equipment is functioning properly, the CTG can begin the startup process. During startup, proper operation of the CTG requires that Control Room Operators follow the SOPs to minimize emissions.
4. A normal start is when the CTG has no faults and that the CTG is indicating "Ready to Start."
5. Function groups for Lube Oil, Purge, Barring, Gas Fuel, Pilot Ignition, GT Room Vent, and GCB Synch/Off must be set to "Auto."
6. During startup, observe the ignition, acceleration, exhaust temp (T7), vibration displays and alarms carefully.
7. Start the lube oil and ventilation system.
8. Initiate the start order. The control and automation system will now automatically initiate the startup sequence. Before the next step, the system waits for lubricating oil to reach the right temperature and pressure.
9. The start motor begins purging, acceleration and ignition takes place, and speed increases to idle. At idle speed, automatic synchronization to the grid and closing of the generator breaker is made.

For the HRSG, the initial point of startup is when the CTG is ignited and heat input to the HRSG begins. The general procedures for HRSG startup include:

1. Prior to startup of the HRSGs, the pre-operation checks must first be made to verify that all required equipment is ready to start, including HRSG components and monitoring equipment. A variety of equipment and system parameters associated with the HRSGs will be inspected prior to startup of each unit, and adjustments will be made to equipment when necessary, as described in detail in the SOPs.
2. After confirming all necessary equipment is functioning properly, the HRSGs can begin the startup process. During startup, proper operation of the HRSGs requires that Control Room Operators follow the SOPs.
3. Verify all drums reach a constant, stable pressure. Maintain drum water levels at Normal Water Level (NWL) by feedwater controller.
4. Verify steam outlet parameters of pressure, temperature, and mass flow have reached a constant and steady measurement.
5. Open check and isolation valves in main high pressure (HP) and low pressure (LP) steam lines.
6. Fully close all startup HP and LP vent valves.
7. Supply feedwater to HP and LP steam drums with drum level control valves (CV) set to "Auto."
8. Complete intermittent HP and LP blowdown cycles, and continuous HP and LP blowdown systems should be ready for operation.
9. Set steam temperature CVs on "Auto." Isolation valves will automatically be opened prior to opening of CVs. Isolation valves in water/steam supply lines to attemperators will be operational.

Once the HRSG superheater startup vent valves are closed, and the CVs in the steam turbine bypasses take over the HP drum temperature ramp rate and superheater outlet steam pressure control, the SCR control is sequenced to startup. In order for the SCR to operate, the following conditions must be met:

- SCR inlet temperature is greater than 400 °F;
- Maximum continuous operating temperature of 750 °F;
- Maximum gas temperature imbalance of +/- 25 °F; and
- Maximum gas flow imbalance +/- 15%.

Additionally, the oxidation catalyst and DLN combustion technology startup commence automatically during the CTG startup process without operator interaction required.

Once the CTG unit reaches MECL and controls are operational, startup is complete and the CTG is now ready for the selected mode of operation, and the HRSG can supply steam to the steam turbine. Additional details on startup are provided in Appendices A and B of this document. Startup procedures in the appendix include normal startup, start by cancelling a shutdown order, and restart after shutdown. Procedures listed in Appendices A and B are obtained from the Gas Turbine Generator System and HRSG System SOPs. Additional information on startups is also found in the Siemens SGT-800_PG_B O&M Manual. These documents are referenced in Section 6.0 and are located in the plant Control Room.

Definition of Shutdown

Pursuant to ROP No. MI-ROP-P0465-2018, "shutdown is defined as that period of time from the initial lowering of the CTG output below 50 percent of full operating load, with the intent to shut the unit down, until the point at which the generator breaker opens." Compliance with the CO and NO_x emission limits for operating hours during shutdown will be based on a 60-minute rolling average basis. Emissions of NO_x and CO are expected to be higher during shutdown than at normal operating loads, so care must be taken to minimize the length of the shutdown period to the extent possible.

Procedures during Shutdown

During shutdown, BPW will follow the SOPs listed in Appendices C and D (full versions of the SOPs for the CTGs and HRSGs are located in either the plant Control Room or kept electronically) and ensure that all monitoring equipment is kept online until flameout occurs.

The general procedures for shutdown of the CTGs include:

1. When shutdown is ordered, the unit will automatically begin to decrease the load to approximately 0.5 MW. The generator breaker opens at this point and the unit shuts down (rollout).
2. At the end of the rollout period the barring (cooling) starts. The rotor is turned by the start motor during the barring (cooling down) period. A normal shutdown will take about 5 minutes to reach barring speed.
3. Note that during the cooling down period the unit can be started at any time.
4. Control Room Operators must follow the shutdown sequence to check that the barring comes in operation and that the lube oil system continues running.

The general procedures for shutdown of the HRSGs include:

1. During normal shutdown, limit the shutdown temperature ramp rate to -5°F/min until the HP drum pressure is at 0 psig.
2. For fast shutdowns, limit the shutdown temperature ramp rate to -10°F/min from maximum pressure at 100% CTG load to HP drum pressure at 0 psig.
3. Cool down the HRSGs using steam vents to reduce temperature and pressure.
4. Stop the HRSG feedwater pumps.

Additional details on shutdown are provided in Appendices C and D of this document. Shutdown procedures are listed for normal, abnormal, and emergency conditions. Procedures listed in Appendices C and D are obtained from the Gas Turbine Generator System and HRSG System SOPs. Additional information on shutdowns is also found in the Siemens SGT-800_PG_B O&M Manual. These documents are referenced in Section 6.0.

2.2 Malfunction Abatement Plan

For the purposes of this MAP, a malfunction is defined per Part 1 of the Michigan Air Pollution Control Rules:

Malfunction means any sudden, infrequent and not reasonably preventable failure of a source, process, process equipment, or air pollution control equipment to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Pursuant to Michigan Rule 911, a MAP must specify the following:

- A complete preventative maintenance program, including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
- An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
- A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

Verification that FGCTGHRSG is operating properly is important. Before CTG/HRSG startup, a number of items must be inspected as "pre-operational checks," which are fully detailed in Appendices E and F, as obtained from the Gas Turbine Generator System and HRSG System SOPs. BPW follows the startup procedures for the CTG and HRSG in the SOPs and O&M manual. Additional items to be inspected during normal operation are listed in the CTG and HRSG SOPs with inspections conducted on a daily basis as necessary and/or when alarms are triggered in the control system.

Various operating variables/parameters will be monitored continuously during operation via an automated alarm system for the CTG and HRSG system. Alarms will be triggered when a monitored parameter is outside of its normal operating range. Parameters to be monitored and set points for alarms are identified in Appendices G and H, as obtained from the Gas Turbine Generator System and HRSG System SOPs. Appendices G and H also explain the possible causes and corrective actions that should be taken to bring the associated parameters back to normal operating ranges (additional detail for normal operation of the CTG and HRSG are found in the Gas Turbine Generator System and HRSG System SOPs). Records of maintenance events, and date and time of occurrence will be properly documented in the Operations Log, as referenced in Section 6.0, by Control Room Operators. Lists of spare parts for replacement will be kept in BPW's electronic inventory system, as referenced in Section 6.0 of this document, and records of such items shall be updated and maintained as necessary by the Maintenance Supervisor.

Where operation of a CTG/HRSG must continue during a malfunction event, BPW will document reasons for continuing operation. If FGCTGHRSG shutdown due to a malfunction is necessary, follow the procedures related to abnormal or emergency shutdowns, as applicable, as listed in Appendix C (obtained from the SOPs and O&M manual).

The CTG/HRSGs and any monitoring equipment must be operated by qualified individuals. The Maintenance Supervisor will be responsible for overseeing the inspection, maintenance, and repair of the CTG/HRSGs and associated controls, and the on-going training of personnel in charge of operations and monitoring the equipment. Operating variables and ranges for varying loads will be monitored and recorded by Control Room Operators, in the Operations Log, as referenced in Section 6.0 of this document. Normal operating ranges and descriptions of monitoring methods are maintained in Appendices G and H of this document.

The DLN combustion technology and oxidation catalyst operate automatically and do not require operator interaction. Proper operation of the SCR requires conditions that must be in place prior to, and during SCR operation. These are noted in Section 2.1 above, as well as in the SOPs with additional detail. However, it is imperative to note that upon first fire of the CTG/HRSGs (i.e., initial commissioning of the units), the oxidation catalyst and SCR catalyst modules should not be loaded to allow for exhaust from the CTG/HRSGs to push any dust or particles in the system out of the stacks without fouling the catalysts. If the catalysts were to operate during first fire, it is highly likely that dust and particles in the exhaust would cause damage to the catalysts. Upon completion of commissioning of the CTG/HRSGs, catalyst modules will be engaged and the oxidation catalyst and SCR will commence operation.

BPW will keep records of each SUSDM event in accordance with Section 3.0 of this document. Records will be reported to Michigan Department of Environment, Great Lakes, and Energy (EGLE) if they cause excess emissions, as specified in Section 4.0 of this document. Excess emissions of NO_x and CO will be monitored through the CTG/HRSG unit continuous emission monitoring system and continuous emission rate monitoring system (CEMS/CERMS).

2.3 Compliance Assurance Monitoring Plan

Pursuant to 40 CFR §64.2(a), CAM applies to the VOC limit of 4 ppmvd at 15% O_2 listed as FGCTGHRSG SC I.12. FGCTGHRSG operates with oxidation catalysts to control emissions of VOCs; the CAM Plan provides for monitoring or parameters indicative of oxidation catalyst performance at a certain frequency to provide reasonable assurance of compliance with the VOC limit.

Control Technology

The oxidation catalysts contain precious metals (such as platinum, palladium, or rhodium) to treat exhaust gas from FGCTGHRSG for control of VOC emissions, as well as CO emissions. The precious metal(s) catalyze the oxidation reaction of hydrocarbons (VOCs) and CO with available oxygen to convert the compounds to carbon dioxide and water vapor. With proper operation of the oxidation catalyst, the units can achieve an emission rate of 4 ppmvd VOC at 15% O_2 (FGCTGHRSG SC I.12).

Monitoring Approach and Performance Criteria

Emissions of VOCs and CO are formed as result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Catalytic oxidation is used at FGCTGHRSG to reduce the emissions of CO and VOC resulting from the incomplete combustion of natural gas at the turbines. The emissions of CO, as measured by the CEMS/CERMS, will be monitored to provide reasonable assurance of compliance with the VOC emission limit, as described below and in Table 2-1.

Table 2-1. Oxidation Catalyst Monitoring and Performance Criteria

Parameter	CAM Criteria
Indicator	CO emissions monitored continuously at FGCTGHRSG
Indicator Range	An excursion is defined as a 24-hour average, excluding startup and shutdown, where CO emissions exceed 4 ppmvd at 15% O_2. Excursions trigger an inspection, corrective action, and the cause must be investigated.
Data representativeness	The oxidation catalyst is necessary to achieve reduction of CO and VOC emissions resulting from incomplete combustion. CO emissions data are indicative of oxidation catalyst performance.
QA/QC Practices and Criteria	The CO CEMS/CERMS will be maintained according to the requirements of Appendix A to PTI No. 107-13E
Monitoring Frequency	Continuously, excluding startup and shutdown
Data Collection	CO concentration is obtained as an hourly average, reported to the data acquisition and handling system.

Upon detecting an excursion or exceedance as outlined by performance indicators in Table 2-1, BPW will investigate the cause and initiate corrective action to the oxidation catalyst, if needed, as expeditiously as practicable and in accordance with good air pollution control practices for minimizing emissions.

Justification of Monitoring Approach and Performance Criteria

The emissions of VOCs and CO are formed as result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Incomplete combustion of the carbon-containing compounds within natural gas produces hydrocarbons (such as VOCs) and CO, contained in the exhaust gas. Oxidation catalysts contain precious metals to catalyze the oxidation reaction of carbon-containing compounds within the exhaust gas with available oxygen, producing water vapor and carbon dioxide.

The CO emissions (after the oxidation catalyst) are continuously monitored using CEMS/CERMS. Pursuant to 40 CFR §64.3(a)(1), direct or predicted emissions may be used as indicators of performance for emission controls. Emissions of CO will be used as an indicator of oxidation catalyst performance for reasonable assurance of compliance with the VOC limit.

3.0 RECORDKEEPING REQUIREMENTS

Pursuant to ROP No. MI-ROP-P0465-2018 for FGCTGHRSG under SCs III.1 and 2, BPW must maintain a SUSD plan. The SUSD plan shall incorporate procedures recommended by the equipment manufacturer, as well as incorporating standard industry practices. The MAP shall address events that meet the characteristics of a malfunction and specify information contained in Michigan Rule 911. BPW will keep current copies of the SUSD plan and MAP onsite and will maintain records of SUSDM events in the plant log books. During an abnormal startup or shutdown, records of the event shall be recorded including the time, date, probable cause(s), duration, affected equipment, emission estimates, and the corrective actions taken in response to the abnormal event. All SUSDM records shall be provided to the BPW’s Environmental Department, which will be responsible for maintaining the records in accordance with the BPW’s records retention policy. Pursuant to 40 CFR §64.9, BPW keeps records of monitoring data, monitor performance data, corrective actions taken, and other supporting information required to provide reasonable assurance of compliance with the VOC emissions limit (such as data used to document the adequacy of monitoring, or records of monitoring, maintenance, or corrective actions).

4.0 REPORTING REQUIREMENTS

This section covers various reporting requirements related to the SUSD Plan, MAP, and the CAM Plan.

4.1 Michigan Air Pollution Control Rule 912

Michigan Rule 912 requires that a facility operate its source, process, or process equipment, to the extent that is reasonably possible, in a manner consistent with good air pollution control practices for minimizing emissions during periods of abnormal conditions, startup, shutdown, and malfunctions. A source, process, or process equipment that complies with all applicable emission standards and limitations during periods of abnormal conditions, startup, shutdown, and malfunction shall be presumed to have been operated in a manner consistent with good air pollution control practices for minimizing emissions. However, there could be instances of equipment upset during a startup or shutdown, or an abnormal startup or shutdown not consistent with manufacture specifications.

BPW has permitted emission limits for the CTG/HRSGs for NO_x and CO during startup and shutdown, and separate limits for NO_x, CO, particulate matter (PM, PM_{10}, $PM_{2.5}$), volatile organic compounds (VOC) and Greenhouse Gases (GHGs) (as carbon monoxide equivalent (CO_2e)), during normal operation. Pursuant to Rule 912, BPW shall provide notice of an abnormal condition, startup, shutdown, or a malfunction that results in excess emissions of these pollutants. Excess emissions can be determined through the CEMS for NO_x and CO, and fuel usage data for other pollutants during times of SUSDM.

BPW shall provide notice and a written report of an abnormal condition, startup, shutdown, or a malfunction if it results in excess emissions above the emission limitations for the CTG/HRSGs for more than two (2) hours. The requirements for notices and written reports are as follows:

- The notices required shall be provided to EGLE as soon as reasonably possible, but not later than two (2) business days after the startup or shutdown, or after discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephone, or verbal communication.
- Written reports, if required, must be submitted to EGLE within 10 days after the startup or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal condition or malfunction, whichever is first. The truth, accuracy, and completeness of the written reports shall be certified by a responsible official in a manner consistent with the Clean Air Act. The written reports shall include all of the required information:
  - The time and date, the probable causes or reasons for, and the duration of the abnormal conditions, startup, shutdown, or malfunction.
  - An identification of the source, process, or process equipment that experienced abnormal conditions, was started up or shutdown, or which malfunctioned and all other affected process or process equipment that have emissions in excess of an applicable requirement, including a description of the type and, where known or where it is reasonably possible to estimate, the quantity or magnitude of emissions in excess of applicable requirements.
  - Information describing the measures taken and air pollution control practices followed to minimize emissions.

- For abnormal conditions and malfunctions, the report shall also include a summary of the actions taken to correct and to prevent a reoccurrence of the abnormal conditions or malfunction and the time taken to correct the malfunction.

4.2 Standards of Performance for Stationary Combustion Turbines (40 CFR 60 Subpart KKKK)

Pursuant to 40 CFR Part 60 Subpart KKKK for the CTGs, HRSGs, and monitoring systems associated with NO_x emissions from FGCTGHRSG:

- BPW shall submit excess emissions and monitor downtime in accordance with 40 CFR §60.7(c) and 40 CFR §60.4375(a) for all periods of unit operation, including periods of startup, shutdown and malfunction. The following information must be included:
  - The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess NO_x emissions. The process operating time during the reporting period.
  - Specific identification of each period of excess NO_x emissions that occurs during SUSD events of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
  - The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
  - When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
  - All reports must be postmarked by the 30th day following the end of each 6-month period.

4.3 Compliance Assurance Monitoring (40 CFR Part 64)

Pursuant to 40 CFR §64.9(a), BPW will submit semiannual CAM reports of monitoring and deviations. Each CAM report will include summary information on the number, duration, and cause of excursions or exceedances, as applicable, and the corrective action(s) taken.

Additionally, the report shall include summary information on the number, duration, and cause for monitor downtime incidents. When there are no excursions, exceedances, or downtime events in the reporting period, the CAM report will include a statement that no excursions, exceedances, or downtime events occurred.

5.0 PLAN REVISION HISTORY

The SUSD Plan, MAP, and CAM Plan will be revised to address reasonable revision requests by EGLE or as BPW determines as necessary. Revisions may be requested if it is determined that either plan:

- Does not address a SUSDM event that has occurred.
- Fails to provide operation of each CTG/HRSG unit in a manner consistent with the general duty to minimize emissions during SUSDM events.
- Inadequately addresses provisions for correcting malfunctioning process or emission control equipment.
- Does not adequately address compliance monitoring for reasonable assurance of compliance with applicable emission rates.

<u>Copies of the Written Plans</u>

A current copy of the plans shall be sent to EGLE. Another copy will be kept on file by BPW (in paper or electronic form) for the life of each CTG/HRSG unit.

Table 5-1. Revision History

Date Issued	Revision #	Revised by	Summary of Changes
11/14/2016	0	Not Applicable	Original Version
4/12/2017	1	NTH Consultants, Ltd.	Incorporation of MAP requirements
10/19/2017	2	NTH Consultants, Ltd.	Incorporation of CAM requirements
10/1/2021	3	NTH Consultants, Ltd.	Clarification of startup/shutdown emission limit applicability and compliance

6.0 REFERENCED DOCUMENTS

Table 6-1 contains a listing of documents referenced in the SUSD plan and MAP and their locations. Copies of the Siemens SGT-800_PG_B Operations and Maintenance Manual, Gas Turbine Generator System and HRSG System SOPs can be provided to EGLE upon request.

Table 6-1. Referenced Documents

Referenced Document	Location
Siemens SGT-800_PG_B Operations and Maintenance Manual	Electronic
Gas Turbine Generator System HBPW Electric Production Department Standard Operating Procedure	Control Room or electronic
HRSG System HBPW Electric Production Department Standard Operating Procedure	Control Room or electronic
Operations Log	Hard copy log in Control Room or electronic
Replacement Parts/Equipment Supply Log	Electronic Inventory System

APPENDIX A

// TURBINE STARTUP SOPS

3.0 OPERATING PROCEDURES

3.1 Startup Procedure

1. The gas turbine can be started in many different ways depending on what state the gas turbine have been in before the actually start.

Caution: **To run the generator without excitation must be avoided as far as possible! If this can't be avoided and the generator is used on idle speed without excitation when the ambient temperature is equal to or less than -15°C (+5°F), it is forbidden to run the generator unexcited for more than 15 minutes. This must be controlled by the operator so a manual stop is initiated in time.**

3.1.1 Normal start

NOTE: A normal start is when the gas turbine has no faults and that the gas turbine is indicating 'Ready to Start'.

NOTE: Supervision during startup. It is recommended to follow the startup sequence on the 01 Unit Operation and on 05 Fuel system displays. And on these displays observe the ignition, acceleration; exhaust temp (T7), vibration and alarms carefully.

1. CHECK and SET the following Function Groups to Auto:
   - A. Lube Oil
   - B. Purge
   - C. Barring
   - D. Gas Fuel
   - E. Pilot Ignition
   - F. GT Room Vent
   - G. GCB Synch/Off
2. START the FG Preparation.
   - A. This will start the lube oil and ventilation system.
3. START the FG Start/Stop. This will initiate the start order.
   - A. VERIFY that the control and automation system will now automatically initiate the startup sequence.
   - B. START lube oil.
   - C. START ventilation.

     NOTE: Before the next step starts, the system will wait for lubricating oil to reach the right temperature and pressure.
   - D. RESET safety system.
   - E. START gas turbine.
   - F. VERIFY the start motor starts purging, acceleration and ignition takes place and speed increases to idle.
     - i. Start of start motor to purge speed 1500 rpm.

ii. Wait for purge time to expire (time dependent on stack/boiler volume).

iii. At ignition, gas is fed to burner #26 where the spark plug ignites the gas. When the ignition flame is indicating, fuel is fed to the all the burners for main ignition.

iv. When main ignition is indicating, acceleration to idle speed, 6600 rpm, is started. Both the start motor and the fuel firing is contributing to the acceleration.

v. At 5600 rpm the start motor is switched off.

vi. During run-up the bleed valves will close.

G. START generator.

i. Excitation is turned ON.

ii. AVR is turned ON.

iii. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless:

- The generator is exempted by the Transmission Operator: or
- The Generator Operator has notified the Transmission Operator of one of the following:
  - That the generator is being operated in start-up, shutdown, or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator, or;
  - That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

NOTE: Startup is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

NOTE: Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

H. VERIFY that at idle speed automatic synchronization to the grid and closing of the generator breaker is made.

I. GCB synchronizing.

J. Unit in service.

K. The gas turbine is now ready for the selected mode of operation.

4. The following modes of operation are available:

A. Island mode operation (Single).

i. Frequency control mode.

ii. Load control mode.

B. Island mode operation (Parallel).

C. External mode operation (Parallel).

5. VERIFY the following occurs during continuous operation:

   A. Above 50% load, the extraction air from compressor stage 3 is no longer sub atmospheric, and the valves are therefore open. The gas turbine speed is constant independent of load and within the permitted ambient conditions there is no flat rated output. The position of the compressor inlet guide vane (IGV) at full load is dependent on ambient conditions, nominal open below +86° F and continuously closed above.

   B. The load is varied by controlling the compressor IGV, firing temperature and turbine exit temperature.

   C. The first step in load decrease is to close the compressor IGV, maintaining the firing temperature until maximal permitted turbine exit temperature is reached. At ambient above +86° F this situation occurs at full load.

   D. The next step is to continue closing the IGV until it is fully closed, maintaining the turbine exit temperature by decreasing the firing temperature.

   E. The third and final step is to further decrease the firing temperature keeping the IGV fully closed.

   F. Load increase is performed in the same way but in opposite order.

3.1.2 Start by Cancelling a Shutdown Order

1. After a stop has been initiated and load is greater than 1 MW it is possible to inhibit the shutdown order with a new start order.
2. After this, the gas turbine will start to increase the load to the previous selected load set point.
3. To give a new start order, FOLLOW section 3.1.1 steps 3 - 5.

3.1.3 Restart After Shutdown

1. A restart is possible as soon as the rotor speed is below 300 rpm and the reason behind the shutdown is investigated.
2. To give a restart order, PROCEED to section 3.1.1.

APPENDIX B

// HRSG STARTUP SOPS

3.0 OPERATING PROCEDURES

3.1 Startup Procedure

NOTE: The startup procedure outlines the required actions in order to bring the HRSG and its associated subsystems on line and to bring the HRSG to normal operation. The startup process depends on thermodynamic system characteristics and we need to consider some factors to avoid producing stresses that will have influences on the lifetime of HRSG. When the HRSG is started-up, some protection systems are important to protect HRSG to reach normal operation during startup.

NOTE: Traditionally, there is a distinction between HRSG cold (C), warm (W), and hot (H) startups. Those startups differ from each other by the time elapsed after preceding plant shutdown and, what is more important, by the initial conditions of HP steam drum water prior to the startup. We increase the HP drum pressure to reach normal operation according to maximum allowable temperature and pressure ramp curves during startup.

The consideration below is given to three basic types of startups:

- Cold (type C) – When the initial HP drum pressure: (0 psig ≤ HP Drum Pressure ≤ 200 psig);
- Warm (type W) – When the initial HP drum pressure: (200 psig < HP Drum Pressure ≤ 500 psig);
- Hot (type H) – When the initial HP drum pressure: (500 psig < HP Drum Pressure).

1. For any startup cycle the ramp in HP drum pressure should be controlled in order to produce a ramp rate of 30.6 °F/min of HP drum water temperature for cold startup, warm and hot startup.
   - A. This ramp rate must be applied to startup cycles only.
   - B. This startup ramp rate shall apply to HRSG Cycle until the Drum pressure reaches a full operational pressure at steady state conditions corresponding to CTG load.
   - C. The HP Drum ramp rate is calculated using saturation temperature corresponding to the measured saturation Drum pressure.

NOTE: For the purposes of this startup procedure, the initial point of the HRSG startup is the gas turbine ignition, when the heat input to the HRSG begins. It is understood that some preparation work needs to be done prior to this point. In the startup cycle curves of the appendices, this initial point of startup is considered time = 0 minutes.

2. At the end point of the HRSG startup the following conditions are in place:
   - A. All Drums have also reached a constant, stable pressure and the drum water levels are successfully being maintained at NWL by feedwater controller.
   - B. Steam outlet parameters of pressure, temperature, and mass flow have reached a constant and steady measurement.
   - C. Check and Isolation valves in main steam lines (HP and LP) are open. It is allowable to open the valves from the very beginning of the startup of the HRSG.
   - D. Superheated steam (HP and LP) can be piped to the STG bypasses or to the STG itself – once the corresponding system is ready.
   - E. All startup vent valves (HP and LP) are fully closed.

F. Feedwater should be supplied to steam drums (HP and LP) with drum level control valves (CV) on “Auto”.

G. Intermittent blowdown cycles (HP and LP) should be completed.

H. Continuous blowdown systems (HP and LP) should be ready for operation.

I. Isolation valves in water/steam supply lines to attemperators are operational - with steam temperature CVs on “Auto”. Isolation valves will automatically be opened prior to opening of CVs

3. VERIFY that water levels in the drums meet the permissive for gas turbine start.

A. For cold start up, initial water level is (reference to NWL):

i. HP Drum: - 8.32 inches.

ii. LP Drum: - 4.92 inches.

B. For hot and warm start up, initial water level is (reference to Normal Water Level (NWL)):

i. HP Drum: - 8.32 inches < warm, hot initial water level < 0 inch (normal water level).

ii. LP Drum: - 4.92 inches < warm, hot initial water level < 0 inch (normal water level).

4. VERIFY that during startup of the HRSG, the HP drum saturation temperature is controlled to a 30.6 °F/min ramp rate for any startup as defined in startup curve (Appendices). These curves define the most rapid time allowable to reach full plant load.

5. VERIFY that during startup, the plant condenser is on-line as soon as possible.

A. The STG bypass system and plant condenser must be online if a CTG is loaded above 25% baseload because the HP startup vent valve has not been designed to handle flows above this CTG load point.

B. Therefore, a delay in HRSG startup curve may be required when cold starting a single CTG with the STG off-line.

6. ENSURE that the main priority during the HRSG startup is the metal temperature condition in the HP drum.

A. HRSG startup is not limited by metal temperatures in the HP superheater modules. The LP sections are not a concern.

B. The HP attemperator outlet steam temperature should be maintained 50°F above saturation temperature during normal operation.

NOTE: The HRSG is equipped with inter-stage attemperators in HP SH sections to control final steam temperature to the STG. The HP inter-stage attemperator outlet steam temperature setpoint is low limited to a minimum of 50°F above the steam saturation temperature (Tsat) in order to prevent steam condensation in the steam attemperator piping. During startup, steam from the HRSG may be used to warm steam lines and the STG itself. In these situations, the final steam temperature from the HRS may greatly exceed the maximum temperature allowed for STG warming. The HRSG may not be able to adequately attemporate final steam temperature without violating the ³ Tsat+ 50°F superheat requirement. In these transient operations, it may be possible to modulate CTG load in order to produce an acceptable final steam temperature out of the HRSG and the degree of superheat downstream of attemperators can be as low as Tsat plus 30°F.

NOTE: All Economizer and Evaporator drains shall be closed. During startup, it is not recommended to open the evaporator intermittent blowdown valve (IBD) or drum continuous blowdown valve (CBD) for water purity control. However, the IBD may be used to help control drum water level during startup.

7. All HP superheater high point vents and drum vents shall remain closed during startup if the pressure prior to startup is greater than 50 psig. However if it is suspected that air may have infiltrated into the HRSG system, the high point vent should be opened to purge the steam volume. If the system pressure is less than 25 psig prior to startup, the HP SH vents and drum vents shall be kept open until the system pressure builds to over 25 psig.

8. ENSURE that the HP Steam produced can be bypassed to the condenser.

   A. Either the HP startup vent valve or the HP bypass valve shall be used to control system pressures to allow proper saturation temperature ramp rate of the HP drum.

   B. The HP steam turbine bypass control valve should be initiated as soon as possible to control HP drum temperature ramp rate.

   C. The HP steam startup vent valve will switch to Auto at 15 psig in the header.

   D. This valve will maintain warming rate until such time as the condenser is available.

NOTE: If the plant condenser is off-line prior to startup of a HRSG, any steam generated shall be vented to atmosphere by the startup vents. The main steam MOV outlet stop valve on LP and HP shall remain closed until sufficient operational margins have been established. The HRSG side main steam outlet isolation valves can be opened when the HPSH main steam pressure reaches 25 psig for HP, 15 psig for LP. The HP SH main steam isolation valve before header pipe is allowed to open when the HRSG1A HPSH steam outlet pressure is within +-20 psig of HRSG1B steam outlet pressure. HRSG1A HP steam outlet temperature is within +-30 F of HRSG1B steam outlet temperature.

Opening this valve with little or negative margins may cause undesirable chattering of the steam outlet check valve. If there is sufficient backpressure on the steam outlet stop valve (due to a hot start), or the STG bypass system is in operation, the MOV stop valve may be opened immediately after successful ignition of the CTG. In this manner, steam vented to atmosphere can be minimized.

9. ENSURE the water level in the drums (HP and LP) is at a startup level for the type of startup; hot, warm, or cold. The warm and hot startup levels in the drums (HP and LP) are based on drum pressure.

10. VERIFY the following valves are in Auto control at the DCS:

    A. HAD10AA403 HP Drum Intermittent Blowdown Valve

    B. HAD10AA404 HP Drum Intermittent Blowdown Valve

    C. HAC10AA505 HP Economizer Vent Valve

    D. LBA10AA001 HP Main Steam Outlet Isolation Valve

    E. LBA10AA002 HP Main Steam Outlet Isolation Valve

    F. LBA10AA003 HP Bypass Steam Outlet Isolation Valve

    G. LAB30AA002 HP Feedwater Isolation Valve

    H. HAD10AA502 HP Drum Vent

    I. HAD10AA402 HP Continuous Blowdown Isolation Valve

    J. HAD10AA401 HP Continuous Blowdown Control Valve

    K. HAD10AA010 HP Sparging Steam Isolation Valve

    L. HAH15AA402 HP Attemperator Inlet Drain

M. HAH10AA401 HP Superheater 2 to 3 Drain

N. HAH10AA402 HP Superheater 2 to 3 Drain

O. LBA10AA401 HP Superheated Steam Header Drain

P. LBA10AA402 HP Superheated Steam Header Drain

Q. LBA10AA101 HP Startup Vent Valve

R. LAB30AA101 HP Feedwater Regulating Valve

S. LAB30AA102 HP Feedwater Regulating Valve Bypass

T. LAE10AA001 HP Attemperator Feedwater Block Valve

U. LAE10AA101 HP Attemperator Temperature Control Valve

V. HAC50AA504 LP Economizer Vent

W. HAD50AA403 LP Drum Intermittent Blowdown Valve

X. HAD50AA404 LP Drum Intermittent Blowdown Valve

Y. LBA50AA001 LP Main Steam Isolation Valve

Z. LBA50AA002 LP Main Steam Isolation Valve

AA. LBA50AA003 LP Bypass Steam Outlet Isolation Valve

BB. HAD50AA402 LP Continuous Blowdown Isolation Valve

CC. HAD50AA101 LP Continuous Blowdown Flow Control Valve

DD. HAD50AA502 LP Drum Vent Valve

EE. LBA50AA101 LP Startup Vent Valve

FF. LBA50AA401 LP Superheated Steam Drain Valve

GG. LBA50AA402 LP Superheated Steam Drain Valve

HH. LAB50AA001 LP Feedwater Isolation Valve

II. LAB50AA003 LP Feedwater Isolation Valve

JJ. LAB50AA103 Heat Exchanger Inlet

KK. LAB50AA105 Heat Exchanger Bypass

LL. HAC50AA101 LP Drum Feedwater Regulating Valve (closed until GTG start, then Auto)

NOTE: When the drum pressure is increased, the initial startup level for warm and hot is close to “0” inches.

11. START the boiler feedwater pump using the recirculation-line available. After the boiler feedwater pump is on-line, place the water flow control valve in the recirculation-line on “Auto”.

12. When HRSG start program permissive conditions are satisfied, VERIFY the start sequence control program executes.

13. The following HRSG start permissives are interlocks for a gas turbine start:

A. HP drum level >/= -9 inches.

B. HP drum pressure is not high </=1000 psig.

C. LP drum level >/= -5 inches.

D. LP drum pressure is not high </= 85 psig.

E. HRSG duct exhaust gas pressure is not High </= 18 inches H_2O.

F. Feedwater is available.

14. OPEN the stack damper.

15. START and RAMP the CTG according to its normal startup scenario: purge, light-off, FSNL (if necessary), spinning reserve (if necessary), ramp to baseload.

16. VERIFY that feedwater quality is met.

17. MONITOR the saturation pressure and temperature ramp rate in the HP drum. These rates are prescribed by the startup curves (Appendices). Ramp rates can be maintained by modulating the HP SH steam vent control valve and HP steam turbine bypass control valve.

18. To get the steam turbine bypasses (HP and LP) on-line their corresponding pressure set points have to be equal or slightly higher than the current pressure in the upstream main steam lines. Then PLACE the pressure CVs in all Steam Turbine bypass lines should be place on “Auto”.

19. Gradually CLOSE the superheater startup vent valves. CVs in steam turbine bypasses will take over the HP drum temperature ramp rate and superheater outlet steam pressure control.

20. START the SCR as follows:

A. ENSURE the following conditions are met to operate the SCR:

i. SRC inlet temperature > 400°F.

ii. Maximum continuous operating temperature of 750°F.

iii. Maximum gas temperature imbalance +/- 25°F.

iv. Maximum gas flow unbalance +/-15%

NOTE: The control system can be set such that the ammonia shut-off valve opens as soon as startup permissives are met.

B. Prior to gas turbine startup, VERIFY that the following preparations are complete on the skid:

i. Power is available to the system.

ii. Instrument air is available to the system.

iii. All ammonia injection lines should be thoroughly drained (at first startup or after long outages).

iv. All control and monitoring instrumentation is online and calibrated.

v. Control bypass jumpers are closed

vi. All instrumentation is set at the proper set points

vii. All hand valves open in the ammonia supply line leading to the vaporizer.

viii. Both fans are in ready position.

ix. All drain valves closed.

C. VERIFY that the distribution header balancing dampers are in the fully open position, or in their normal position as determined from previous calibration.

D. As soon as the turbine is started up:

E. WARM the aqueous ammonia system (NH3 skid, header, air piping) after the startup of the gas turbine, before injecting ammonia into the vaporizer.

NOTE: It is suggested to let the skid discharge temperature reach the setpoint of 350°F before starting ammonia flow.

NOTE: Fans should be operating even if ammonia injection is not planned so as to avoid gas back flow into the skid, or plugging of the AIG nozzles due to particulate in the gas stream.

F. SELECT dilution fan “A” or “B”.

G. SELECT “AUTO” position of the dilution fan mode switch.

H. SELECT “AUTO” position of aqueous ammonia shut-off valve control switch.

CAUTION: Do not operate the skid with the ammonia shut-off valve in manual “OPEN” position; this feature is intended for testing purposes and should not be used for extended operation.

I. SELECT “ON” position of SCR system control switch.

J. VERIFY that the dilution air fan is energized immediately.

K. VERIFY that the NH3 shut-off valve is opened after the following conditions have been established:

i. NH3 adjustment header temperature “HIGH”

ii. SCR inlet gas temperature “NOT LOW”

L. CHECK the SCR outlet NOx after the plant has been in steady operation, and adjust the NH3/NOx molar ratio controller to the proper setting.

M. Once the unit is in operation, an operator should walk by the skid and check to see that all equipment is operating properly. The following items should be observed:

i. CHECK that the fan is operating properly with no abnormal noise or vibration.

ii. CHECK ammonia lines for leaks.

iii. CHECK local instrument readings

21. VERIFY proper operation of the HP economizer manifold vent valve.

NOTE: The HP Economizer manifold vent valve, HAC10AA505, is a moto-operated valve that is used to vent steam from the last economizer module to the HP Drum in the event that near steaming conditions in the economizer occur. Conditions for a potentially steaming economizer are detected by measuring the approach temperature, which is the difference between the HP drum saturation temperature and the HP economizer outlet temperature.

A. The HP economizer outlet temperature is measured by a temperature thermocouple HAC10CT001.

B. The HP Drum saturation temperature is determined in the DCS as a function of the average HP Drum saturation pressure measured by the drum pressure transmitters, HAD10CP001, HAD10CP002 & HAD10CP003.

C. If the approach temperature is less than 3°F, the HP Economizer vent valve is opened.

D. When the approach temperature is greater than 5°F the HP Economizer vent valve is closed.

E. Note that the manually operated HP Economizer module header vent valve, HAC10AA504, remains open at all times.

22. VERIFY proper operation of the LP economizer manifold vent valve.

NOTE: The LP Economizer manifold vent valve, HAC50AA504, is a motor operated valve that is used to vent steam from the last economizer module to the LP Drum in the event that near steaming conditions in the economizer occur. Conditions for a potentially steaming economizer are detected by measuring the approach temperature, which is the difference between the LP economizer outlet saturation temperature and the LP economizer outlet temperature.

A. The LP economizer outlet temperature is measured by a temperature thermocouple HAC50CT001.

B. The LP economizer outlet saturation temperature is determined in the DCS as a function of the LP economizer outlet pressure measured by the LP economizer outlet pressure transmitter, HAC50CP001.

C. If the approach temperature is less than 3°F, the LP Economizer vent valve is opened. When the approach temperature is greater than 5°F the LP Economizer vent valve is closed.

D. Note that the manually operated LP Economizer module header vent valve, HAC50AA503, remains open at all times.

23. MONITOR the HP and LP drum level.

A. The main subject of concern is the level in the HP drum.

B. If the current level position becomes too close to the “High Level Alarm” use the valves in the evaporator IBD lines to decrease the level.

i. LP – HAD50AA403/404

ii. HP – HAD10AA403/404

C. Do not use the evaporator continuous blowdown system or manually operated valves in the evaporator drain lines for this purpose.

D. The intermittent blowdown valves (HAD10(50)AA403/404), in Auto, will open at the high level alarm and close at 1 inch above NWL.

24. VERIFY that during startup, the drum levels are established by single element control.

A. As steam is generated and exits the drum, the single element control will maintain water level through drum swell and into continuous feedwater operation.

B. When the steam flow rate is greater than 30% of the full load flow rate a three element, feedforward/feedback drum level control loop is used to control drum water levels at NWL.

25. VERIFY that the heat exchanger bypass control operates to maintain LP economizer feedwater inlet temperature at 140°F by operating LAB50AA105 to prevent dewpoint corrosion on the gas side of the HRSG.

26. PLACE the HP steam attemperator into service:

A. The HP superheater inter-stage attemperator control will modulate water spray flow as required to control the HP steam terminal point temperature 978°F.

B. During startup and loading, while at minimum IGV (Inlet Guide Vane) angle position, the cylinder operated spray water block valve, LAE10AA001, is set to Auto.

C. The spray water block valve is opened when the spray water control valve LAE10AA101 open demand signal is greater than 2% and HP superheated steam output flow is greater than or equal to 12,590 lbs/hr and the HP superheated steam outlet temperature difference value between the HP superheater steam outlet temperature measurement value and the HP superheater steam outlet temperature setpoint value is less than 5°F.

D. As the CT load and exhaust gas temperature are increased, the HP superheater outlet temperature rises to its control temperature.

E. Further load increases causes the spray water temperature controller demand to increase and the spray water control valve is modulated to control superheater outlet temperature.

F. On falling spray water demand, the spray water control valve is modulated to control superheater outlet temperature.

G. If the spray water control valve open command signal is less than 2% or the HP SH steam flow rate is less than 12,590 lbs/hr, the spray water control valve is closed.

H. When the spray water control valve is closed, the spray water block valve is closed after a 30 sec time delay.

27. When the HP drum pressure is equal to or greater than the minimum “floor” pressure, PERFORM intermittent blowdown as required.

28. VERIFY that the LP superheated steam outlet pressure ramp rate compares the LP SH steam outlet pressure ramp rate to the normal LP superheated steam outlet pressure ramp rate setpoint 20 psig per minute.

A. When the LP superheated steam outlet pressure is less than 29.5 psig, the LP superheated steam outlet pressure ramp rate controller is used to control the LP superheated steam outlet pressure ramp rate at its setpoint and outputs a 0-100% signal to the LP superheated steam startup valve, LBA50AA101, until the LP superheated steam outlet pressure is reached 29.5 psig.

B. Then, the LP superheated steam outlet pressure ramp rate controller is switched to the LP superheated steam outlet pressure controller.

C. The LP superheated steam outlet pressure controller compares the LP superheated steam outlet pressure to the normal LP superheated steam outlet pressure setpoint 30 psig and outputs a 0-100% signal to the LP superheated steam startup valve, LBA50AA101, to maintain the steam outlet pressure at its setpoint.

29. SET the continuous blowdown valve as directed by water quality analysis.

30. At the end of the startup, VERIFY that all the requirements of the saturated and superheated steam quality and purity, in all HRSG pressure levels, are met. Also, VERIFY the boiler water quality in the drums. If all the requirements of the customer specification are met, it is allowable to supply steam to the STG.

APPENDIX C

// TURBINE SHUTDOWN SOPS

3.3 Shutdown

WARNING: IF THE GAS TURBINE PLANT IS SHUTDOWN AT THE SAME TIME AS THE EXTERNAL AUXILIARY POWER HAS A BLACKOUT, THE AIR CONDITIONERS OF THE LOCAL ELECTRICAL AND CONTROL MODULES WILL NOT BE WORKING. NORMALLY THIS DOES NOT LEAD TO ANY PROBLEM, BUT IF THE AMBIENT TEMPERATURE IS GREATER THAN +40°C (+104°F) THE OPERATOR HAVE TO PAY EXTRA ATTENTION TO THE TEMPERATURE INSIDE THE ELECTRICAL AND CONTROL MODULE. SHOULD THE TEMPERATURE INSIDE THE MODULES EXCEED +55°C (131°F), SPECIAL ARRANGEMENT MUST BE CARRIED OUT TO REDUCE THE TEMPERATURE. ONE SIMPLE ARRANGEMENT IS TO OPEN THE DOORS IN ORDER TO INCREASE THE NATURAL VENTILATION FLOW INSIDE THE MODULE.

Caution: If the GT ventilation fails, a temporary ventilation arrangement should be done as described in Operation Safety, chapter Operational Cautions. If a gas turbine trip is caused of high pressure in the lube oil tank the central casing must be drained before a new start.

NOTE: When shut down is ordered the unit will automatically unload to approximately 0.5 MW, then the generator breaker opens and the unit shuts down.

NOTE: At the end of the rollout period barring is started.

NOTE: The rotor is turned by the start motor during the barring (cooling down) period. This is necessary to avoid excessive temperature gradients resulting in temporarily bended rotors.

NOTE: It is also vital that the rotor bearings at all time are supplied with lubricating oil to protect the bearings from excessive temperatures.

NOTE: During the cooling down period the unit can be started at any time.

3.3.1 Normal Shutdown (Stop)

1. SELECT a stop order on the FG Start/stop.
2. VERIFY the following sequence occurs:
   A. Unit Unload
   B. Stop Generator
   C. Stop Gas Turbine
   D. Stop Ventilation
   E. Stop Lube Oil
3. VERIFY that during a normal shut down, it takes about 5 minutes to reach the barring speed.
4. When shutting down the combustor, the gas turbine speed slowly decreases until reaching the set barring speed of the electric starting motor (600 rpm).
5. Barring is then continued for 18 hours, so the gas turbine is cooled down. After this, the starting motor is stopped and the turbine is brought to standstill.

NOTE: If the barring at 600 rpm is not started due to a failure and the rpm decreases to below 50 rpm within 10 minutes the gas turbine has to cool down for 40 hours before restarting. This is known as barring block/starting block.

3.3.2 Abnormal Shutdown (Trip)

1. An abnormal shout down (trip) is when the gas turbine reaches an abnormal condition during gas turbine operation.
2. Depending on what abnormal condition that caused the trip, there are two unloading shutdowns (unload 90s or unload 30s).
3. If the abnormal condition will be cleared within the specified time the unloading will stop and the present load will be kept.

3.3.3 Emergency Stop (With and Without Blowdown)

1. USE the Emergency Stop buttons in the event of any emergency around the gas turbine or the compressor that cannot be handled in any other way.
2. When the Emergency Stop button is pressed the unit is immediately tripped without previous unloading. This will cause additive wear to the gas turbine

3.3.4 Supervision of the Gas Turbine During Shutdown

1. FOLLOW the shutdown sequence to verify that barring comes in operation and the lube oil system is still running.

3.3.5 Long Period Standstill of the Gas Turbine

1. If the gas turbine unit will be standstill for a longer time it is important to preserve the gas turbine and check that there are no other risks to resolve. How to preserve the gas turbine is described in the Maintenance Instructions.

APPENDIX D

// HRSG SHUTDOWN SOPS

3.3 Shutdown

NOTE: The maximum allowable shutdown rate for HP drum saturation temperature does not depend upon the type of startup cycle during baseload operation.

1. The HP Drum shutdown rates should follow the shutdown curves (Appendices). During normal shutdown, the limited shutdown temperature ramp rate is -5°F/min until the HP drum pressure 0 psig. The limited shutdown temperature ramp rate is -10°F/min from maximum pressure at 100% GT load to HP drum pressure 0 psig for fast shutdown.
2. The normal criterion for shutdown of the HRSG is to maintain the lowest reduction in saturation temperature from maximum pressure in the HP drum prior to shutdown. The overall ramp rate averaged between maximum drum pressure prior to shutdown and minimum drum pressure prior to re-start must not significantly exceed limited shutdown temperature ramp rate requirement. The overall ramp rate averaged between the end points (pressure to minimum drum pressure prior to re-start) must not significantly exceed the rates specified above.
3. SCR shutdown
   A. In the event of a turbine shutdown or trip, the ammonia valve should shut automatically; the blower should shut down automatically after a 5 minute delay.
   B. To shut down the skid while the turbine remains in operation, select "OFF" on the SCR Control System switch.
   C. The blower will continue to operate until it is switched off by the operator, or until the turbine is shut down.
   D. The blower should be kept in service while the turbine is operating so as to avoid plugging of the AIG nozzles and to prevent backflow of combustion gases into the skid.

3.4 Shutdown to Warm Layup Ready for Restart

Note: The following procedure describes shutting down the HRSG and leaving it prepared to go back online within 24 hours.

1. REDUCE GT load.
2. SHUTDOWN the steam turbine in accordance with steam turbine operating procedures.

NOTE: If an HRSG is still going to be in service, the steam turbine may not have to be shutdown.

3. SHUTDOWN the gas turbine in accordance with gas turbine operating procedures.
4. CLOSE chemical feed isolation valves.

5. CLOSE sample isolations.

6. STOP the boiler feedwater pump.

7. CLOSE the stack damper.

8. ALIGN all HRSG valves as required.

9. CLOSE the following valves:

   A. LAB30AA002 HP feedwater header isolation
   B. LAB30AA101 HP feedwater regulating valve
   C. LAB30AA102 HP feedwater regulating valve
   D. LBA10AA001 – HP steam header isolation
   E. LBA10AA002 – HP steam header isolation
   F. LBA10AA003 – HP steam header isolation
   G. LAB50AA001 – LP feedwater header isolation
   H. HAC50AA001 – LP feedwater regulating valve
   I. LBA50AA001 – LP steam header isolation
   J. LBA50AA002 – LP steam header isolation
   K. LBA50AA003 – LP steam header isolation

   Note: All vents and drains are to remain closed.

3.5 Shutdown

1. REDUCE GT load.

2. SHUTDOWN the steam turbine in accordance with steam turbine operating procedures.

3. SHUTDOWN the gas turbine in accordance with gas turbine operating procedures.

4. CLOSE chemical feed isolation valves.

5. CLOSE sample isolations.

6. COOL DOWN the HRSG using steam vents to reduce temperature and pressure.

7. MAINTAIN HP/LP drum levels at a sufficient level to allow for shrinking during cooldown.

8. When steam pressures and temperatures have been reduced to the appropriate point, fill the HRSG drums to just below the high level alarm.

9. When HP drum pressure falls below 25 psig, OPEN the HP saturated steam vent valves.

10. When LP drum pressure falls below 15 psig, OPEN the LP saturated steam vent valves.

11. OPEN the following drain valves when HP drum pressure reaches 25 psig.

   A. HAH10AA401

B. HAH10AA402
C. LBA10AA401
D. LBA10AA402

12. STOP the HRSG feedwater pumps.

13. When the drum pressure falls to atmospheric, the nitrogen system can be aligned to maintain a drained steam drum with 3-5 psig nitrogen blanket.

A. HAD10AA412 HP drum nitrogen supply
B. HAD50AA412 LP drum nitrogen supply

3.5.1 Gas Turbine Barring

1. If the following permissives are met, the HRSG flue gas side barring vent valve (HNA10AA501) may be opened to allow gas turbine barring for cooldown and maintenance to prevent overpressurizing the HRSG duct work with the stack damper closed.

A. GT flame NOT On; and

B. Gas turbine speed < 600 rpm; and

C. Gas turbine cooldown mode selected.

APPENDIX E

// TURBINE PRE-OPERATIONAL CHECKS

2.0 PRE-OPERATIONAL CHECKS

2.1 Precautions and Limitations

The following Precautions and Limitations apply specifically to the operation of the Gas Turbine Generator System. In addition to the items listed below, it is expected that the Operator exercise common sense, safety considerations, and industry acceptable techniques when operating plant equipment.

1. Never use the emergency stop buttons unless an emergency situation occurs, since it will cause additional wear of the gas turbine.
2. Only press the Argonite release button if fire is detected. Before using the release button, make sure there are not people inside the enclosure.
3. Personal and general public health and safety aspects must always be considered when handling Argonite. End user must assess these risks and when found necessary develop site specific safe handling and/or emergency procedures. The procedures should cover e.g. system refilling, safe venting of the protected area after a Argonite discharge, risks with low point accumulation and safe dispersion of Argonite in atmosphere. Typically the emergency procedures need to be coordinated with procedures used by the local rescue services/fire brigade.

   End user must also assess the risks with unpredictable Argonite release from the GT enclosure overpressure protection device and when found necessary develop site specific safe emergency procedures or route the outlet from the overpressure protection device to location where Argonite may safely be dispersed in atmosphere.
4. Argonite is heavier than air and may remain in lower areas.
5. When the fire detection system is indicating a possible fire, the flashing red lights are activated. Investigate the reason for the alarm and take necessary measures. These lights will flash when one detector is indicating fire. This means that there may be a fire or one of the detectors is giving a false fire indication.
6. When the siren is emitting a warning sound, immediately leave the enclosure and make sure there are not people left in the enclosure. Close the enclosure doors and unblock (reactivate) the Argonite equipment. Stay away from the enclosures and call the fire brigade.
7. Due to explosion relief of the generator terminal box there is a risk of injury when entering or approaching the generator enclosure during operation. In order to limit the risk of injury the following shall be adhered to:
   A. When entering the generator enclosure, keep the entrance door open for the duration of the stay.
   B. Keep the stay inside the enclosure as short as possible.
   C. Avoid any longer stay inside or in the immediate vicinity of the generator enclosure.
8. Operation of the Gas Turbine is only permitted to be done by authorized personnel.
9. Never block automatic shutdown devices. Manual override of signals is only allowed to be done by authorized personnel who are fully aware of the functions and are taking responsibility for any possible dangerous conditions that may arise.
10. Programming is only allowed by personnel authorized by SIT. It recommended that SIT should be consulted before any changes in the control program.
11. Be observant to control system fault alarms. Make sure that the reason of the alarm is investigated and that the fault is rectified without delay.

12. Manual synchronizing should only be carried out by authorized personnel.
13. The utmost care must be taken to prevent out-of-phase synchronization.
14. Before start up, make sure that the unit is ready for start-up after possible maintenance work.
15. Before entering the enclosure inform personnel and block the Argonite equipment.
16. When the fire suppression system is blocked, green lights will appear outside each entry door of the protected rooms.
17. Always wear eye protection, hard hat and when the GT is in operation: ear plugs - be aware of the risk of misunderstanding due to high sound level.
18. Always bring a light (explosion-proof as required by area classification), in case of loss of light.
19. Never work alone.
20. When inspecting combustion chamber flames, always wear welding goggles.
21. Do not smoke. Do not use open flames or spark producing devices unless special precautions have been taken.
22. Do not work on the gas fuel system, or weld in the enclosure if the gas fuel system is filled with gas, or the gas turbine is running. Before welding is initiated, the gas turbine has to be shut down and the gas fuel system depressurized, ventilated and flushed with nitrogen.
23. Ensure that operation of switches and valves cannot endanger personnel and/or equipment.
24. Do not step on small piping, electrical conduit or junction boxes, or use them as supports.
25. Before entering the turbine air intake/exhaust, or opening turbine inspection covers/plugs, the starter motor power supply must be switched off and tagged with "WORK IN PROGRESS - DO NOT START".
26. If possible, stay away from pressure lines and fittings during startup of equipment.
27. Always keep in mind that wet surfaces may be slippery, especially when walking on the oil tank. Eliminate any fuel or oil leaks as soon as possible.
28. Make sure that all turbine and exhaust duct inspection covers/plugs are closed before start up. Avoid breathing possible leaking exhaust gas.
29. Check for zero system pressure before disconnecting pipes/opening system components.
30. Use adequate personal protection when working with liquids such as lubricating oil, cleaning agents etc. The manufacturers/suppliers should be contacted for safety data. In case of leakage, clean up in order to prevent slip and fall accidents. Avoid breathing possible oil/solvent vapors.
31. Contact and/or inhalation of cleaning agents can involve health hazards, such as irritated skin irritation and/or breathing difficulties.
32. Contact with oil products can cause allergy and/or skin irritation.
33. Gas leakage can cause breathing difficulties, explosions and fire.
34. Gas leakage can cause an explosion in combination with static electricity. The gas pipes are therefore earthed.
35. Gas leakage in combination with smoking or any flame/spark producing device, such as welding equipment can cause explosions. Therefore such devices should never be used when the gas fuel system is in operation.
36. Contact with sections of the gas turbine without thermal insulation may cause burn injuries.

37. Contact with exhaust channels without thermal insulation may cause burn injuries.
38. Possible leakage of hot gases may cause burn injuries.
39. Make clear all washing drain valves are closed after washing. Otherwise hot gases will leak out and may cause injuries.
40. Stay clear of rotating shafts and couplings while they are running or not blocked for startup. Negligence may lead to severe injury or death.
41. Working with electrical equipment must only be performed by qualified personnel under the supervision of the authorized person responsible for electrical safety on the plant according to valid standard.
42. To prevent receiving an electrical shock when performing electrical tests, do not touch electrical components.
43. After a manual stop of any motor in the GT plant with help of Human Machine Interface on the Motor Control Center or Static Frequency Converter or with help of a safety breaker or local start/stop panel, the motor may restart automatically when the stop order is removed. This is due to automatic control and sequencing logic of the GT control system.
44. For safe work on a motor, switch off the motor from the control system, put withdrawable Motor Control Center group in disconnected position and lock with padlock. For machines breaker close to the motor also open the safety breaker and lock it with padlock.
45. When leaving the enclosure, inform the operating personnel and unblock (reactivate) the fire extinguishing system.
46. Watch the operator station start-up page for normal development of parameters and sequences and during start-up.
47. Prevent foreign matters and/or ice from entering the air inlet. Ingestion of solid matter will cause severe damage.
48. Before operating equipment, ensure that temporary covers are removed from air inlet, exhaust and vents. Ensure that these openings remain uncovered during operation.
49. Before startup, make sure that all inspection openings are closed and that all equipment is in position for startup.
50. Switch off the mobile phone. It can cause disturbance on the control system and cause a shutdown. Switch off the mobile phone before entering the enclosure. It can cause disturbance on the control system and cause a shutdown.
51. The enclosure doors shall not be left open when the enclosure ventilation is in operation. Open doors will disturb the ventilation flow and may cause excessive temperature gradients with possible wear/damage to equipment in the enclosure.
52. Ensure that you always discharge yourself before touching electronics containing ESD-electrostatic discharge sensitive components.
53. When the automatic control system has been restarted, the remaining controllers of the control network must be restarted to ensure proper function of alarm updating.
54. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode (VAR-002-4). If a generator is being started up or shutdown with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its

procedure for placing the unit into automatic voltage control mode. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

55. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility’s capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

56. When a generator’s AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

57. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

58. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

59. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change.

60. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change. If the status has been restored within the first 30 minutes, no notification is necessary.

61. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability.

2.2 Valve Lineup Checklist

The following valve list provides the position of the manual valves in preparation for performing this procedure.

NOTE: This check list can be used for either gas turbine

VERIFY or POSITION the following valves OPEN.

Check Off	Valve Number	Valve Description
		Reference P&ID
☐		All instrument root valves
☐		All instrument isolation valves
		Reference Siemens SGT800 P&ID 2913234
☐	MBL30AA020	Evaporative cooling media supply
☐	MBL31AA020	Evaporative cooling media supply
☐	MBL10AA005	Anti-icing system vent isolation
☐	MBL10AA015	Anti-icing system vent isolation
		Reference Siemens SGT800 P&ID 2913235
☐	MBP10AA005	Main gas isolation
☐	MBP60AA010	Ignition gas needle valve (Throttled)
		Reference Siemens SGT800 P&ID 2913236
☐	MBV30AA240	Cooler AC010 continuous vent isolation
☐	MBV30AA245	Cooler AC005 continuous vent isolation
☐	MBV40AA230	Lube oil filter continuous vent
☐	MBV40AA225	Lube oil filter continuous vent
		Reference Siemens SGT800 P&ID 2913210
☐	OFA20AA005	Instrument air supply

VERIFY or POSITION the following valves CLOSED.

Check Off	Valve Number	Valve Description
		Reference P&ID
☐		All system vents and drains

Check Off	Valve Number	Valve Description
		Reference Siemens SGT800 P&ID 2913235
☐	MBP10AA205	Main gas vent
☐	MBP10AA305	Gas line nitrogen purging valve
		Reference Siemens SGT800 P&ID 2913236
☐	**MBV10AA005**	Oil reservoir drain
☐	MBV30AA270	Lube oil header drain
☐	MBV30AA275	Lube oil header drain
☐	MBV30AA210	Lube oil cooler vent
☐	MBV30AA215	Lube oil cooler vent
☐	MBV30AA015	Lube oil cooler equalization valve
☐	MBV40AA215	Lube oil filter vent
☐	MBV40AA220	Lube oil filter vent
☐	MBV40AA235	Lube oil filter drain
☐	MBV40AA240	Lube oil filter drain
☐	MBV40AA030	Lube oil supply header drain
		Reference Siemens SGT800 P&ID 2913210
☐	SDB50AA236 KA01	Water wash drain (Locked Closed)
☐	SDB50AA236 KA02	Water wash drain (Locked Closed)
☐	SDB50AA236 KA03	Water wash drain (Locked Closed)
☐	SDB50AA236 KA04	Water wash drain (Locked Closed)
☐	SDB50AA236 KA05	Water wash drain (Locked Closed)
☐	SDB50AA236 KA06	Water wash drain (Locked Closed)
☐	SDB50AA236 KA07	Water wash drain (Locked Closed)
☐	SDB50AA236 KA08	Water wash drain (Locked Closed)
☐	SDB50AA236 KA09	Water wash drain needle valve (Locked Closed)

Check Off	Valve Number	Valve Description
	SDB50AA236 KA10	Water wash drain needle valve (Locked Closed)
	SDB50AA236 KA11	Water wash drain needle valve (Locked Closed)

2.3 Power Supply Lineup Checklists

Check Off	Location	Description
	480 VAC GTG MCC BFA13	SAG10AN005 GT enclosure ventilation fan #1
	480 VAC GTG MCC BFA13	SAG10AN010 GT enclosure ventilation fan #31
	480 VAC GTG MCC BFA13	MBV80AP005 Jacking oil pump
	480 VAC GTG MCC BFA13	SAE10AN005 EG enclosure ventilation inlet fan #1
	480 VAC GTG MCC BFA13	SAE10AN010 EG enclosure ventilation inlet fan #2
	480 VAC GTG MCC BFA14	MBV10AH006 Lube oil heater
	480 VAC GTG MCC BFA14	BPA12
	480 VAC GTG MCC BFA14	BFA21 240 VAC MCB Distribution Board
	480 VAC GTG MCC BFA14	BFA21 120 VAC MCB Distribution Board
	400 VAC/440 VDC BPA12	Lube oil mist fan #1
	400 VAC/440 VDC BPA12	Main lube oil pump #1
	400 VAC/440 VDC BPA12	Main lube oil pump #2
	400 VAC/440 VDC BPA12	Main lube oil pump #3
	400 VAC/440 VDC BPA12	Lube oil mist fan #2
	400 VAC/440 VDC BPA12	BPA13U1 Battery chargers
	400 VAC/440 VDC BPA12	230 V MCB Distribution Board
	400 VAC/440 VDC BPA12	BPA12U1 Battery chargers
	480 VAC MCB Distribution BFA21 F404	Low voltage distribution BJA11
	480 VAC MCB Distribution BFA21 F405	Air intake system MBL30GH005
	480 VAC MCB Distribution BFA21 F408	Ventilation control room BJC11
	480 VAC MCB Distribution BFA21 F301	Generator heater MKA10AH005

	240 VAC MCB Distribution BFA21 F201	Start motor heater MBJ10AH005
	240 VAC MCB Distribution BFA21 F203	Internal power anti-condensation heater motor
	240 VAC MCB Distribution BFA21 F204	Rotor earth fault protection
	240 VAC MCB Distribution BFA21 F205	Fuel system heat tracing MBP10AH105
	240 VAC MCB Distribution BFA21 F206	Firefighting system CYE11
	240 VAC MCB Distribution BFA21 F207	Ignition spark plug
	240 VAC MCB Distribution BFA21 F208	Cabinet vent fans
	240 VAC MCB Distribution BFA21 F209	Wall sockets
	240 VAC MCB Distribution BFA21 F210	Fuel system heat tracing MBP10AH100
	240 VAC MCB Distribution BFA21 F211	Battery module UBB10GH005
	240 VAC MCB Distribution BFA21 F212	Lube oil heat tracing MBV
	240 VAC MCB Distribution BFA21 F213	100% stator earth fault protection
	240 VAC MCB Distribution BFA21 F215	Ventilation control room BJC12
	240 VAC MCB Distribution BFA21 F216	Power supply anti-condensation heater MBV
	240 VAC MCB Distribution BFA21 F601	Internal power electrical heaters oper voltage
	120 VAC MCB Distribution BFA21 F101	Wall sockets UMB20/UMB30
	120 VAC MCB Distribution BFA21 F102	Wall sockets/lighting control module
	120 VAC MCB Distribution BFA21 F103	Wall sockets control cubicle CHA/CJD/CJP
	120 VAC MCB Distribution BFA21 F104	Wall sockets/lighting MBL30GH005
	120 VAC MCB Distribution BFA21 F105	Lighting UMB20/UMB30
	120 VAC MCB Distribution BFA21 F106	Lighting battery module UBB10CH005
	24 VDC BPA12 F1	Power supply inlet guide vane MBA10AE005
	24 VDC BPA12 F2	Emergency lighting skid UMB20
	24 VDC BPA12 F3	Operating voltage BFA
	24 VDC BPA12 F5	Power supply CPU AS1/AS2 CJD
	24 VDC BPA12 F6	Power supply 24 VDC distribution CHA
	24 VDC BPA12 F7	Power supply 24 VDC distribution CJD

	24 VDC BPA12 F8	Power supply 24 VDC distribution CJP
	24 VDC BPA12 F9	Redundant power supply 24 VDC distribution CJD
	24 VDC BPA12 F10	Redundant power supply 24 VDC distribution CHA
	24 VDC BPA12 F11	Redundant power supply CPU AS1/AS2 CJD
	24 VDC BPA12 F12	Redundant power supply 24 VDC distribution CJP
	24 VDC BPA12 F13	Lighting /Fan BPA/BPB
	480 VAC BJA11 F01	Compressor wash SDB10
	480 VAC BJA11 F02	SMA10
	480 VAC BJA11 F03	UMB20 wall socket
	480 VAC BJA11 F04	MPS10

2.4 System Startup Prerequisites

1. VERIFY that the electrical distribution system is in service.
2. VERIFY all valves are aligned to their normal operating position to establish a flow path through the system. All necessary vents and drains are closed.
3. VERIFY all instrument test connections are closed.
4. VERIFY all instrument root valves are open.
5. VERIFY all clearances are released and permission has been obtained to start the system.
6. If no work has been done to the gas turbine in any way and it is in proper condition, the gas turbine can be started without any prior checks. But in general it can be good to take a walk around check at every new start up and look for abnormal conditions or signs of machine faults, such as air, gas and temperature leakages.
7. When work has been done to gas turbine systems it must be checked so the gas turbine will be in proper condition before a new start is initiated.
8. CHECK that all work have been finalized and that no one is inside the gas turbine enclosure
9. If there has been a loss of AC power supply the battery status has to be checked, before the gas turbine can be started. The following action might be necessary to do:
   A. CHECK and RESET all alarms on the battery rectifier (BP A cubicle)
   B. When no alarms are present on the rectifier CHECK the status of the batteries. If they don't have full capacity they have to be charged for at least 12 hours before the gas turbine is restarted
   C. CHECK and RESET all other alarms that are present on the HMI.

WARNING: IF THERE HAS BEEN AN EARTHQUAKE, SIEMENS INDUSTRIAL TURBOMACHINERY MUST BE CONTACTED BEFORE STARTUP OF THE GAS TURBINE.

10. To prepare the gas turbine for a start you have to know what operation mode the gas turbine should

start with. When operation mode is chosen you can chose the proper settings for this mode of operation. Use the HMI displays 01 Unit operation, 11 Turbine Governing and 12 Generator Governing to select and change the settings and modes. For guidance refer to the Display Description and also the next section Operating the Gas Turbine from Control Station

APPENDIX F

// HRSG PRE-OPERATIONAL CHECKS

2.0 PRE-OPERATIONAL CHECKS

2.1 Precautions and Limitations

The following Precautions and Limitations apply specifically to the operation of the HRSG System. In addition to the items listed below, it is expected that the Operator exercise common sense, safety considerations, and industry acceptable techniques when operating plant equipment.

1. Maintaining proper steam drum level is critical during startup and operation of the HRSG. High water levels can cause carryover, leave deposits in the superheater, and lead to possible water damage to the steam turbine. Low water level can result in thermal damage to the evaporator tubes. A low-low level in any of the steam drums will result in an automatic trip of the CTG. A high-high level in any of the steam drums will result in an automatic trip of the STG.
2. Thermal stresses are induced in the HRSG during startup and shutdown. The greater the rate of change during these periods, the greater the stress. If ignored, these stresses can cause fatigue and premature mechanical problems.
3. It is preferable to start the gas turbine with the HRSG temperature as hot as possible. Hot starts induce lower stresses in the HRSG than cold starts.
4. During HRSG startup, the loading rate of the gas turbine and modulation of the steam vent and bypass valves should be adjusted to keep the ramp rate within manufacturers recommendations.
5. During base load operation, the exhaust gas pressure at the inlet of the HRSG should not exceed 18 inches H_2O. An abnormally high reading indicates an obstruction through the HRSG, at which time the gas turbine must be shutdown. Operation with exhaust gas pressures above design values may damage expansion joints, coil support structures, or other HRSG components.
6. In the event of attemperator failure, the gas turbine load must be limited so that design temperatures remain within the limits.
7. The HRSG Superheater LP Superheater coils are NOT designed for ‘Dry Run’ operation. Lack of steam flow can result in short term overheating and subsequent tube failure.
8. The reliability of the steam drum level transmitters should be periodically checked against the actual level using the corresponding gauge glass.
9. All gauge glasses must be periodically blown down to prevent the accumulation of contaminates and sludge.
10. Never operate the HRSG without all of the Safety Valves in place, calibrated, and in good working condition.
11. If the HRSG has been drained due to maintenance, water must be added to HRSG to establish drum levels prior to startup. When filling the HRSG water circuits, the high point vents of the economizers and steam drums must be opened to allow air to escape. Once complete, the vents must be closed.
12. When filling the HRSG, temperature differentials between the fill water and metal of the drum or economizer should be minimized and must be below 50°F.
13. Proper Boiler Water Chemistry must be maintained at all times. Improper chemistry can lead to fouling or corrosion of internal surfaces, reduced unit efficiency, and possible damage and/or failure of the boiler tubes. Adhere to all water chemistry guidelines.
14. If solids carryover is being caused by excessive boiler water solids concentration, adjustment of the continuous blowdown valve may be required.
15. Prior to initial operation, the HRSG blowdown and superheater blowdown tanks must be filled with

water to form a water seal between the upper portion of the tank and the outlet pipe. Failure to fill the tank will result in undue stress on the tank and the associated piping.

16. All economizer manual vents should be closed except for those listed as normally open on the P&ID drawings. The economizer vent header pipe MOV shall be in “Auto” and will open when steaming conditions are measured in the economizer section.
17. No manual blowdown valves of drum level gauges shall be opened during startup. No chemical feed valves shall admit flow into any drum during startup.
18. HP superheater drains under DCS control should be set to “Auto” and automatically open to drain any condensate formed prior to startup. All LP superheater low point drains should be opened automatically to drain any condensate which may be present. Automatic drain pot valve downstream of the HP attemperator is used to prevent condensation from damaging the HP Superheater during startup and/or upset conditions.
19. All HP Superheater attemperator loop is equipped with condensate pots. They should automatically open to drain any condensate formed prior to startup.

2.2 Valve Lineup Checklist

The following valve list provides the position of the manual valves in preparation for performing this procedure.

NOTE: These lists can be used for either HRSG, unit 10 or unit 11.

VERIFY or POSITION the following valves OPEN.

Check Off	Valve Number	Valve Description
☐		All instrument root and isolation valves are open.
		Reference Vogt Power P&ID V17486-ICND-0004
☐	HAC50AA004	LP economizer outlet to HPFW isolation valve
☐	HAD50AA601	Chemical feed to LP drum valve
☐	HAD50AA501	LP drum vent valve
☐	LAB50AA002	LPSH outlet steam stop valve
☐	LAB50AA001	LPSH outlet steam stop valve
☐	QUB50AA601	LPSH outlet steam to sample isolation
☐	QUB50AA602	LPSH outlet steam to sample isolation
☐	LBA50AA503	LP SH steam startup vent isolation
☐	HAD50AA401	LP drum to blowdown tank isolation
☐	QUA50AA601	LP drum outlet steam to sample
☐	QUA50AA602	LP drum outlet steam to sample

Check Off	Valve Number	Valve Description
	HAC50AA503	LP economizer LPEC 1 vent
	HAC50AA001	LPEC 2 to heat exchanger isolation
	LAB50AA005	LP feedwater inlet and outlet to heat exchanger isolation
	LAB50AA006	LP feedwater inlet and outlet to heat exchanger isolation
	HAC50AA002	Heat exchanger to LPEC 1 isolation
	LAB50AA004	LP feedwater isolation
	LBA50AA304	LPSH outlet drip leg level column isolation
	LBA50AA305	LPSH outlet drip leg level column isolation
	HAD50AA307	LP drum level transmitter isolation
	HAD50AA308	LP drum level transmitter isolation
	HAD50AA301	LP drum level column isolation
	HAD50AA302	LP drum level column isolation
	HAD50AA303	LP drum level transmitter isolation
	HAD50AA304	LP drum level transmitter isolation
	HAD50AA305	LP drum level transmitter isolation
	HAD50AA306	LP drum level transmitter isolation

Reference Vogt Power P&ID V17486-ICND-0003

	HAD10AA501	HP steam drum vent
	HAH15AA401	HP SH attemperator outlet line drain
	QUA12AA601	HP drum to sample isolation
	QUA12AA602	HP drum to sample isolation
	HAD10AA401	HP drum to sample isolation
	QUB10AA601	HP SH outlet steam to sample system isolation
	QUB10AA602	HP SH outlet steam to sample system isolation
	HAD10AA602	Chemical feed line to HP drum stop
	HAC10AA504	HP economizer HPEC #1 vent
	LBA10AA501	HPSH outlet startup vent

Check Off	Valve Number	Valve Description
	LAE10AA002	HP interstage attemperator spray stop
	LBA10AA003	HPSH steam outlet bypass isolation
	LBA10AA002	HPSH steam outlet isolation
	LBA10AA001	HPSH steam outlet isolation
	LBA10AA304	HP SH outlet drain pot level column isolation
	LBA10AA305	HP SH outlet drain pot level column isolation
	LBA10AA306	HP SH outlet drain pot level column isolation
	LBA10AA307	HP SH outlet drain pot level column isolation
	HAH10AA301	HP SH3 outlet drain pot level column isolation
	HAH10AA302	HP SH3 outlet drain pot level column isolation
	HAH10AA303	HP SH3 outlet drain pot level column isolation
	HAH10AA304	HP SH3 outlet drain pot level column isolation
	HAD10AA313	HP drum level transmitter isolation
	HAD10AA314	HP drum level transmitter isolation
	HAD10AA315	HP drum level transmitter isolation
	HAD10AA316	HP drum level transmitter isolation
	HAD10AA301	HP drum level column isolation
	HAD10AA302	HP drum level column isolation
	HAD10AA303	HP drum level column isolation
	HAD10AA304	HP drum level column isolation
	HAD10AA305	HP drum level transmitter isolation
	HAD10AA306	HP drum level transmitter isolation
	HAD10AA307	HP drum level transmitter isolation
	HAD10AA308	HP drum level transmitter isolation
	HAD10AA309	HP drum level transmitter isolation
	HAD10AA310	HP drum level transmitter isolation
	HAD10AA311	HP drum level transmitter isolation

Check Off	Valve Number	Valve Description
☐	HAD10AA312	HP drum level transmitter isolation
☐	HAD10AA409	HP drum intermittent blowdown isolation
		Reference Vogt Power P&ID V17486-ICND-0005
☐	LBH10AA301	Superheater drain tank level column isolation
☐	LBH10AA302	Superheater drain tank level column isolation
		Reference Vogt Power P&ID V17486-ICND-0002
☐	HNE10AA401	Stack drain

VERIFY or POSITION the following valves CLOSED.

Check Off	Valve Number	Valve Description
☐		All system vents and drains
		Reference Vogt Power P&ID V17486-ICND-0004
☐	LAB50AA401	LP feedwater inlet pipe drain
☐	LAB50AA402	LP feedwater inlet pipe drain
☐	LAB50AA403	LP feedwater inlet pipe drain
☐	LAB50AA404	LP feedwater inlet pipe drain
☐	LAB50AA405	LP feedwater inlet pipe drain
☐	LAB50AA406	LP feedwater inlet pipe drain
☐	HAD50AA405	LP drum water column drain
☐	HAD50AA406	LP drum water column drain
☐	HAD50AA407	LP drum water column drain
☐	HAC50AA401	LP economizer LPEC 1 drain
☐	HAC50AA402	LP economizer LPEC 1 drain
☐	HAC50AA403	LP economizer LPEC 1 drain
☐	HAC50AA404	LP economizer LPEC 1 drain
☐	HAC50AA405	LP economizer drain valve

Check Off	Valve Number	Valve Description
	HAC50AA406	LP economizer drain valve
	LBA50AA003	LPSH outlet steam bypass stop valve
	HAD50AA412	Nitrogen system to LP drum isolation
	HAC50AA501	LP economizer LPEC 3 & 4 vent
	HAC50AA502	LP economizer LPEC 2 vent
	HAC50AA003	LPEC 2 to LPEC 1 bypass isolation
	LBA50AA403	LPSH outlet drip leg level column drain
	LBA50AA404	LPSH outlet drip leg level column drain
	HAC50AA410	Feedwater inlet to drum drain
	HAC50AA411	Feedwater inlet to drum drain

Reference Vogt Power P&ID V17486-ICND-0003

	LAB30AA401	HP feedwater inlet pipe drain
	LAB30AA402	HP feedwater inlet pipe drain
	LAB30AA403	HP feedwater inlet pipe drain
	LAB30AA404	HP feedwater inlet pipe drain
	LAB30AA405	HP feedwater inlet pipe drain
	LAB30AA406	HP feedwater inlet pipe drain
	HAC10AA404	HPEC 1 module drain
	HAC10AA403	HPEC 2 module drain
	HAC10AA402	HPEC 3 module drain
	HAC10AA401	HPEC 4 module drain
	HAC10AA405	HPEC module drain
	HAC10AA406	HPEC module drain
	LBA10AA405	HPSH outlet line freeblow drain isolation
	LBA10AA406	HPSH outlet line freeblow drain isolation
	LBA10AA403	HP SH outlet drain pot line valve
	LBA10AA404	HP SH outlet drain pot line valve

Check Off	Valve Number	Valve Description
	HAH10AA403	HPSH cross module #2 and module #3 drain pot line valve
	HAH10AA404	HPSH cross module #2 and module #3 drain pot line valve
	HAD10AA405	HP water column drain
	HAD10AA406	HP water column drain
	HAD10AA407	HP water column drain
	LAE10AA401	HP feedwater to attemperator spray water line drain
	LAE10AA402	HP feedwater to attemperator spray water line drain
	HAD10AA412	Nitrogen system to HP drum isolation
	HAC10AA501	HP economizer HPEC #4 vent
	HAC10AA502	HP economizer HPEC #3 vent
	HAC10AA503	HP economizer HPEC #2 vent
	HAH15AA503	HP attemperator outlet vent
	HAH15AA504	HP attemperator outlet vent
	HAH15AA501	HPSH 2 outlet vent
	HAH15AA502	HPSH 2 outlet vent
	HAH10AA501	HP drum steam outlet header vent
	HAH10AA502	HP drum steam outlet header vent
	HAD10AA415	HP drum sparging steam supply drain
	HAD10AA416	HP drum sparging steam supply drain

Reference Vogt Power P&ID V17486-ICND-0005

	LBH10AA410	Cooling water to blowdown tank control valve
	LBH10AA411	Cooling water to blowdown tank control valve
	LBH10AA401	Superheater tank water column drain
	LBH10AA402	Superheater tank water column drain
	LBH10AA403	Superheater tank water column drain

2.3 Power Supply Lineup Checklists

Check Off	Location	Description
	Unit 10	
	10ANA00MC020 480 VAC 10 BOP/HRSG MCC-20	Unit 10 HRSG superheater drain tank pump 1
	10ANA00MC020 480 VAC 10 BOP/HRSG MCC-20	Unit 10 HRSG superheater drain tank pump 2
	00BRA00PN001 208/120 VAC UPS Panel bkr 17	Steam outlet drain pot level switches 10-LBA-10-CL-001/2/3/4
	00BRA00PN001 208/120 VAC UPS Panel bkr 19	HPSH3 drain pot level switches 10-HAH-10-CL-001/2
	00BRA00PN001 208/120 VAC UPS Panel bkr 23	Drum level indicator ECU 10-HAD-10-CL-004
	00BRA00PN001 208/120 VAC UPS Panel bkr 26	Bi-color level gauge 10-HAD-10-CL-501
	00BRA00PN001 208/120 VAC UPS Panel bkr 52	Drum level indicator ECU 10-HAD-50-CL-004
	00BRA00PN001 208/120 VAC UPS Panel bkr 56	Drum level indicator 10-HAD-50-CL-501
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A25/27/29	10 LP Economizer crossover block valve 10HAD50AA504
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A31/33/35	10 HP continuous blowdown block valve 10HAD10AA402
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A37/39/41	10 HP intermittent blowdown block valve 10HAD10AA404
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A20/22/24	10 HP economizer crossover block valve 10HAC10AA505
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A26/28/30	10 HP sparging steam block valve 10HAD10AA010
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A32/34/36	10 HP intermittent blowdown block valve 10HAD10AA403
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A38/40/42	10 HP nitrogen block valve 10HAD10AA412
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A43/45/47	10 HP drum vent valve 10HAD10AA502
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B1/3/5	10 LP intermittent blowdown block valve 10HAD50AA403
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B7/9/11	10 LP N2 Block valve 10HAD50AA412

Check Off	Location	Description
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B13/15/17	10 FG stack damper 10HNE10DM001
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B19/21/23	10 LP feedwater block valve 10LAB50AA001
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B25/27/29	10 HRSG superheater outlet MOV 10 LBA01AA010
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B31/33/35	10 HP main steam outlet block valve 10LBA10AA002
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts A44/46/48	10 LP continuous blowdown block valve 10HAD50AA402
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B2/4/6	10 LP intermittent blowdown block valve 10HAD50AA404
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B8/10/12	10 LP drum vent valve 10HAD50AA502
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B14/16/18	10 HP economizer inlet block valve 10LAB30AA002
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B20/22/24	10 LP economizer inlet block valve 10LAB50AA003
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B26/28/30	10 HP main steam check valve 10LBA10AA001
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B32/34/36	10 HP main steam outlet block valve bypass 10LBA10AA003
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B43/45/47	10 LP main steam outlet block valve 10LBA50AA002
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B49/51/53	10 HRSG LP steam outlet MOV 10LBL02AA002
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B38/40/42	10 LP main steam check valve 10LBA50AA001
	10HAX00PN010 480 VAC Distribution Panel Board Unit 10 ckts B44/46/48	10 LP main steam outlet bypass block valve 10LBA50AA003

Unit 11

Check Off	Location	Description
	11ANA00MC021 480 VAC 11 BOP/HRSG MCC-21	Unit 11 HRSG superheater drain tank pump 1
	11ANA00MC021 480 VAC 11 BOP/HRSG MCC-21	Unit 11 HRSG superheater drain tank pump 2

Check Off	Location	Description
	00BRA00PN001 208/120 VAC UPS Panel bkr 18	Steam outlet drain pot level switches 11-LBA-10-CL-001/2/3/4
	00BRA00PN001 208/120 VAC UPS Panel bkr 21	HPSH3 drain pot level switches 11-HAH-10-CL-001/2/3/4
	00BRA00PN001 208/120 VAC UPS Panel bkr 24	Drum level indicator ECU 11-HAD-10-CL-004
	00BRA00PN001 208/120 VAC UPS Panel bkr 28	Bi-color level gauge 11-HAD-10-CL-501
	00BRA00PN001 208/120 VAC UPS Panel bkr 55	Bi-color level gauge 11-HAD-50-CL-501
	00BRA00PN001 208/120 VAC UPS Panel bkr 54	Drum level indicator 11-HAD-50-CL-504
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A33/34/36	11 LP Economizer crossover block valve 11HAC50AA504
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A38/40/42	11 HP continuous blowdown block valve 11HAD10AA402
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A44/46/48	11 HP intermittent blowdown block valve 11HAD10AA404
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A31/33/35	11 HP economizer crossover block valve 11HAC10AA505
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A37/39/41	11 HP sparging steam block valve 11HAD10AA010
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts A43/45/47	11 HP intermittent blowdown block valve 11HAD10AA403
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B1/3/5	11 HP nitrogen block valve 11HAD10AA412
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B2/4/6	11 HP drum vent valve 11HAD10AA502
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B8/10/12	11 LP intermittent blowdown block valve 11HAD50AA403
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B14/16/18	11 LP N2 Block valve 11HAD50AA412
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B20/22/24	11 FG stack damper 11HNE10DM001
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B26/28/30	11 LP feedwater block valve 11LAB50AA001
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B32/34/36	11 HRSG superheater outlet MOV 11LBA01AA010

Check Off	Location	Description
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B38/40/42	11 HP main steam outlet block valve 11LBA10AA002
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B7/9/11	11 LP continuous blowdown block valve 11HAD50AA402
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B13/15/17	11 LP intermittent blowdown block valve 11HAD50AA404
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B19/21/23	11 LP drum vent valve 11HAD50AA502
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B25/27/29	11 HP economizer inlet block valve 11LAB30AA002
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B31/33/35	11 LP economizer inlet block valve 11LAB50AA003
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B37/39/41	11 HP main steam check valve 11LBA10AA001
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B43/45/47	11 HP main steam outlet block valve bypass 11LBA10AA003
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B49/51/53	11 LP main steam outlet block valve 11LBA50AA002
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B55/57/59	11 HRSG LP steam outlet MOV 11LBL02AA002
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B44/46/48	11 LP main steam check valve 11LBA50AA001
	11HAX00PN011 480 VAC Distribution Panel Board Unit 11 ckts B50/52/54	11 LP main steam outlet bypass block valve 11LBA50AA003

2.4 System Startup Prerequisites

1. VERIFY that the electrical distribution system is in service.
2. ENSURE all valves are aligned to their normal operating position to establish a flowpath through the system. All necessary vents and drains are closed.
3. CHECK all instrument test connections are closed.
4. CHECK all instrument root valves are open.
5. ENSURE all clearances are released and permission has been obtained to start the system.
6. VERIFY that the gas turbine is ready for operation.
7. VERIFY that the condensate system is ready for operation.
8. VERIFY that the feedwater system is ready for operation.

9. VERIFY that the blowdown and waste water system is ready for operation.
10. VERIFY that the SCR and ammonia systems are ready for operation.

APPENDIX G

// TURBINE OPERATING VARIABLES, ALARMS AND CORRECTIVE ACTIONS

4.0 ALARM RESPONSE

The following chart is provided to assist an experienced Operator in identifying and resolving abnormal conditions associated with the Gas Turbine Generator System. It is not intended as a substitute for a thorough understanding of the system equipment, common sense, and safe operating practices and techniques.

Condition	Setpoint	Effect	Possible Cause	Action
Fire	Smoke Detector Flame/Temp Detection in GT Room One Detector Two Detectors	Alarm Alarm Alarm Trip	• Detector failure • Actual fire	1. In case of a fire, when the Argonite system is released it is important to call the local fire dept, to verify that fire is totally extinguished before anyone enters the protected rooms. 2. There is always a small risk of re-ignition of fire. 3. When fire is totally extinguished: a. Open the shut-off dampers before entering the enclosure b. Restart the ventilation. c. Acknowledge the alarm and block the Argonite equipment. d. Wait at least 3 minutes before entering the enclosure after starting the ventilation. e. Refill aragonite bottles and restart fire detection system and extinguishing system before starting gas turbine.

Condition	Setpoint	Effect	Possible Cause	Action
High Gas Levels	Alarm @ 5% LEL Trip @ 10% LEL	Possible fire or explosion	• Detector failure. • Actual gas leak.	1. Acknowledge the alarm. 2. Use a portable gas detector and locate the leak. 3. Decide if the gas turbine operation can continue without any risk or if the turbine has to be shutdown to seal the leakage. 4. If trip occurs, ensure that no one is in the enclosure and doors are shut. 5. Acknowledge the trip. 6. Verify ventilation system is in operation. 7. When no gas is detected in the enclosure, the doors can be opened and you may enter the enclosure after blocking the suppression system. 8. Repair or replace defective components.
Ventilation Failure		High enclosure temperatures. Gas turbine trip. Buildup of combustible gases.	• Fan failure. • Loss of power. • Damper failure.	1. When there is ventilation failure in the gas turbine enclosure, the unit will trip and the temperature will rise to above 140°F. 2. Temporary ventilation is recommended by opening the enclosure doors. 3. Block the Argonite-equipment and arrange for manual fire supervision. 4. If the ventilation failure is longer than 15 minutes, then barring blockage will occur in order to prevent possible wear/damage to equipment in the enclosure. 5. When the enclosure ventilation is restarted, all doors should be closed as soon as possible and the fire suppression-equipment reactivated.

Condition	Setpoint	Effect	Possible Cause	Action
Axial Displacement High/Low	+/- 0.01 inches @ +/- 0.02 inches	Alarm Trip	• Instrument failure • Actual excessive movement in turbine	1. Reset the trip. 2. Check cables and transducer for failure.
Exhaust Differential Pressure High	PDAH @ 0.58 psid PDAHH @ 0.73 psi	Alarm Trip	• Instrument failure. • High back pressure.	1. Compare local indications to remote. 2. Reset a trip. 3. Check for possible causes.
High Surge Protection Differential Pressure	PDAH @ 0.07 psi	Trip	• Surging occurs when the differential pressure over the compressor is too low in relation to the rotating speed.	1. Check the function and the control loop for bleed valves #1 and #2 as well as the control drive. 2. Check the function for bleed valve #1 and #2 as well as the control drive. 3. Check the function of the control loop for the inlet guide vane as well as the control drive. 4. Check the function of the pressure switch.
Inlet Air Differential Pressure High	PDAH @ 0.28 psi PDAHH @ 0.36 psi	Alarm Trip	• Instrument failure. • Clogged or dirty filters. • Mechanical filter damage.	1. Unload the unit manually in order to decrease differential pressure. 2. At standstill, check the air filters. 3. Check the air intake for mechanical damage
Flame Failure		Trip	• Insufficient fuel supply. • Malfunction in the instrument loop. • Dirty sight glass/lens.	1. Acknowledge the alarm. 2. Check fuel supply. 3. Check all instrumentation. 4. Clean flame detector lens when possible. 5. If failure occurred during startup, make another start attempt.

Condition	Setpoint	Effect	Possible Cause	Action
Overspeed	6946 rpm 7277 rpm 6284 rpm	Alarm Trip Trip after 5 second time delay after trip of GCB	• Turbine governor fault. • Measurement fault of the transducer. • Loss of generator load.	1. Acknowledge the alarm. 2. Investigate to see if there has been a load rejection. 3. Contact the technician. 4. Check the actual speed measurement works properly. 5. Check if the turbine governor is working properly.
Radial Bearing 1 / Thrust Bearing Temperature High	TAH @ 212°F TAHH @ 230°F	Alarm Alarm	• Instrument failure. • High oil temperature. • Bearing failure. • Loss of lube oil.	1. Acknowledge the alarm. 2. Reduce load. 3. Shutdown the turbine. 4. Check the lube oil temperature after the lube oil cooler. 5. Check the lube oil pressure.
Temperature Outside Turbine Stator High	TAH @ 662°F	Alarm	• Instrument failure. • Ventilation failure. • Mechanical problem.	1. Compare local indications to remote. 2. Visually inspect enclosure for abnormal indications. 3. Check ventilation system operation. 4. Shutdown and inspect turbine stator area.
Radial Bearing 2 Temperature High	TAH @ 212°F TAHH @ 232°F	Alarm Trip	• Instrument failure. • High oil temperature. • Bearing failure. • Loss of lube oil.	1. Acknowledge the alarm. 2. Reduce load. 3. Shutdown the turbine. 4. Check the lube oil temperature after the lube oil cooler. 5. Check the lube oil pressure.

Condition	Setpoint	Effect	Possible Cause	Action
Bearing 1 Vibration High	VAH @ 0.28 inches (<4500/> 6500 rpm) VAH @ 0.47 inches (4500-6500 rpm) VAHH @ 0.47 inches while turbine in service VAHH @ 0.59 inches	Alarm Alarm Trip Trip	• Instrument failure. • Loss of lube oil. • Bearing damage. • Turbine and compressor blade damage.	1. Check the lube oil pressure. 2. Check the lube oil temperature. 3. Perform compressor washing according to instruction. 4. Check the vibration by using a portable vibration instrument. 5. Check bearing temperatures.
Bearing 2 Vibration High	VAH @ 0.28 inches VAHH @ 0.47 inches VAHHH @ 0.59 inches	Alarm Unloaded shutdown Trip	• Instrument failure. • Loss of lube oil. • Bearing damage. • Turbine and compressor blade damage.	1. Check the lube oil pressure. 2. Check the lube oil temperature. 3. Perform compressor washing according to instruction. 4. Check the vibration by using a portable vibration instrument. 5. Check bearing temperatures.
Calculated Mass Flow Compressor Inlet	FAH @ +/- 2.9 psi	Alarm	• Control system malfunction • Compressor damage. • Instrument failure.	1. Compare local indications to remote. 2. Check the compressor for vibration or damage. 3. Check inlet filter differential pressure.
Calculated Compressor Outlet Temperature High/Low	TAH/TAL @ +/- 27°F	Alarm	• Control system malfunction • Compressor damage. • Instrument failure.	1. Compare local indications to remote. 2. Check the compressor for vibration or damage.
Bleed Valve Position Fault		Alarm/Shutdown	• Failing instrument air supply. • Solenoid valve malfunction. • Position feedback malfunction. • Broken valve stem.	1. Acknowledge the shutdown alarm. 2. Reset the safety system. 3. Check the air supply. 4. Check the valve for damage.

Condition	Setpoint	Effect	Possible Cause	Action
Lube Oil Reservoir Level Low	Low alarm @ 24 inches Low-low alarm @ 17.7 inches	Minimum operating level Locks out reservoir heater	• Instrumentation failure. • Oil leaks • Improper valve lineup, drain open.	1. Compare local indications to remote. 2. Inspect the system for indication of leaks. 3. Check the drain closed.
Lube Oil Reservoir Level High	LAH @ 26.8 inches operating LAH @ 31.5 inches shutdown	Alarm Alarm	• Instrumentation failure. • Leakage of water from lube oil cooler	1. Compare local indications to remote. 2. Inspect the oil for indications of water leakage. 3. If water leakage is cause switch operating lube oil coolers.
Lube Oil Reservoir Pressure High	LAH @ -0.12 psi LAHH @ -0.06 psi	Alarm Trip	• Clogged oil mist filter. • Malfunction with the L/O fan (incl. SFC). • Malfunction in the instrument loop.	1. Compare local indications to remote. 2. Check the oil mist filter for cleanliness. 3. Check the operation of the fan.
Lube Oil Reservoir Temperature Low	TAL @ 114.8°F Low-low alarm @ 68°F	Locks out pumps	• Instrument failure. • Malfunction in the temperature control valve. • Clogged lube oil cooler. • Malfunction of cooling water. • Malfunction of the lube oil heaters.	1. Compare local indications to remote. 2. Check operation of the lube oil coolers and their cooling water supply. 3. Verify operation of the lube oil tank heater.
Lube Oil Reservoir Temperature High	TAH @ 122°F TAHH @ 176°F	Turns off heaters Alarm	• Instrument failure. • Malfunction in the temperature control valve. • Clogged lube oil cooler. • Malfunction of cooling water. • Malfunction of the lube oil heaters.	1. Compare local indications to remote. 2. Check operation of the lube oil coolers and their cooling water supply. 3. Verify lube oil tank heater if off.

Condition	Setpoint	Effect	Possible Cause	Action
Lube Oil Pressure Low	PAL @ 7.25	Alarm and starts standby pump.	• Clogged lube oil supply filter. • Malfunction with the lube oil pumps (incl. SFC). • Malfunction in the pressure control valve. • Manual valves before/after pump are closed. • Malfunction in the instrument loop.	1. Acknowledge the shutdown alarm. 2. Reset the safety system. 3. Check the pressure trend. 4. Inspect pumps and pressure control valves for proper operation. 5. Look for system leaks. 6. Verify proper valve lineup. 7. Check filter differential pressure.
Lube Oil Filter Differential Pressure High	PDAH @ 15.95	Alarm	• Instrument failure. • Clogged or dirty filters.	1. Compare local indications to remote. 2. Check filters for cleanliness. 3. Place standby filter into service.
Lube Oil Supply Pressure Low	PAL @ 20.31 psig PALL @ 15.95 psig	Alarm Trip	• Clogged lube oil supply filter. • Malfunction with the lube oil pumps (incl. SFC). • Malfunction in the pressure control valve. • Manual valves before/after pump are closed. • Malfunction in the instrument loop.	1. Acknowledge the shutdown alarm. 2. Reset the safety system. 3. Check the pressure trend. 4. Inspect pumps and pressure control valves for proper operation. 5. Look for system leaks. 6. Verify proper valve lineup. 7. Check filter differential pressure.
Lube Oil Supply Temperature High	TAH @ 131°F TAHH @ 140°F	Alarm Trip	• Instrument failure. • Improper cooler operation.	1. Compare local indications to remote. 2. Check operation of lube oil coolers and cooling water supply.
Lube Oil Supply Temperature Low	TAL @ 95°F TALL @ 77°F	Alarm Interlocks out start motor	• Instrument failure. • Improper cooler operation.	1. Compare local indications to remote. 2. Verify tank heaters are on. 3. Check operation of lube oil coolers.

Condition	Setpoint	Effect	Possible Cause	Action
Starting Motor Winding Phase 1/2/3 High Temperature	TAH @ 329°F TAHH @ 347°F	Alarm Start Abort	• Instrument failure. • Cooling fan failure. • Clogged air filters. • Motor failure or damage.	1. Check start motor cooling fan function. 2. Check if cooling fan motor is running. 3. Inspect starting motor for damage. 4. Contact the technician. 5. Avoid new start attempt until motor temperature is below alarm level.
Starting Motor Failure		The start motor has not started within 1 minute from the start motor order It has been stopped for more than 10 minutes during cooling down time.	• Motor damage. • Electrical fault. • Coupling fault. • Loss of lube oil. • Bad bearing	1. Acknowledge the alarm. 2. Check if there is any other start motor alarm. 3. Contact the technician. Check for electrical faults. 4. Check the lube oil pressure. 5. Check the SSS coupling function by manual barring.
Gear Reducer Temperature High	TAH @ 212°F TAHH @ 230°F	Alarm Alarm	• Instrument failure. • High oil temperature. • Bearing failure. • Loss of lube oil.	1. Acknowledge the alarm. 2. Reduce load. 3. Shutdown the turbine. 4. Check the lube oil temperature after the lube oil cooler. 5. Check the lube oil pressure.
Gear Reducer Casing Vibration High	VAH @ 0.18 in/sec VAHH @ 0.28 in/sec VAHHH @ 0.31 in/sec	Alarm Unloading Trip Trip	• Instrument failure. • Loss of lube oil. • Coupling failure. • Gas turbine vibration. • Bearing failure.	1. Compare local indications to remote. 2. Check the lube oil pressure. 3. Check the lube oil temperature. 4. Perform compressor washing according to instruction. 5. Check the vibration by using a portable vibration instrument. 6. Check bearing temperature
Static Pre-Filter Differential Pressure High	PDAH @ 0.0653 psi	Alarm	• Instrument failure. • Dirty or clogged filters.	1. Compare local indications to remote. 2. Inspect filters for cleanliness.

Condition	Setpoint	Effect	Possible Cause	Action
Second Stage Filter Differential Pressure High	PDAH 0.087 psi	Alarm	• Instrument failure. • Dirty or clogged filters.	1. Compare local indications to remote. 2. Inspect the filters for damage, cleanliness and clogging.
Evaporative Cooler High Water Level	LAH @	Alarm	• Drain valve not opening. • Supply valve failed open	1. Compare local indications to remote. 2. Inspect the filters for damage, cleanliness and clogging.
Air Intake Differential Pressure	PDAH @0.189 psid PDAHH @ 0.218 psid	Alarm Trip	• Instrument failure. • Dirty or clogged filters.	1. Compare local indications to remote. 2. Check the trend curve. 3. Change clogged filter stage no. 2 only at standstill. 4. If filter stage no. 1 is close to clogging change also these at same time. 5. Make sure that all filter cassettes are locked tight through. 6. Look for leakage.
Evaporative Cooling Conductivity High	High @ 750 µS/cm HH @ 950 µS/cm	Alarm Trip	• Instrument failure. • Water exchange failure.	1. Compare local indications to remote. 2. Take manual sample. 3. Check that makeup water is available and operating and blowdown is operating.
Natural Gas Pressure High	PAH @ 406 psig PAHH @435.1 psig	Alarm Alarm	• Instrument failure. • High supply pressure.	1. Compare local indications to remote. 2. Check that the gas supply pressure is properly regulated.
Natural Gas Pressure Low	PAL @ 319 psig PALL @ 290 psig PALLL @ 232 psig	Alarm Unloading Trip Trip	• Clogged filter. • Manual valves not opened. • Malfunction in pneumatic valves. • Malfunction in the instrument loop. • External gas fuel pressure wrong	1. Compare local indications to remote. 2. Check valve lineup. 3. Check operation of gas supply valve. 4. Verify normal gas supply pressure.

Condition	Setpoint	Effect	Possible Cause	Action
Natural Gas Temperature High/Low	TAH @ 302°F TAL @ 37°F above dewpoint TALL @ 28°F above dewpoint TALLL @ 19°F above dewpoint	Alarm Alarm Alarm Trip	• Malfunction in the instrument loop. • External gas fuel temperature is wrong.	1. Compare local indications to remote. 2. Verify that gas supply is not high or low pressure. 3. Check operation of dewpoint heater.
Fuel Gas Strainer Differential Pressure	PDAH @ 10.2 psid PDAHH @ 14.5 psid	Alarm Alarm	• Instrument failure. • Clogged or dirty strainer.	1. Compare local indications to remote. 2. Check strainer cleanliness.
Central Gas Pressure High	PAH @ 14.5 psig	Abort Start	• Instrument failure. • High supply pressure.	1. Compare local indications to remote. 2. Check that the gas supply pressure is properly regulated.
Generator Cooling Water Leak		Alarm	• Instrument failure. • Actual closed cooling water leak into generator.	1. Inspect generator for indications of leakage. 2. If leak confirmed, generator must be shutdown and isolated for repairs.
Generator Bearing Temperature High	TAH @ 185°F TAHH @ 203°F	Alarm Alarm	• High bearing temperature. • High lube oil temperature. • Low lube oil pressure. • High vibration level. • Malfunction in the instrument loop.	1. Compare local indications to remote. 2. Check operation of the lube oil system and lube oil coolers. 3. Inspect generator bearings for indication of abnormal operation.

Condition	Setpoint	Effect	Possible Cause	Action
Generator Cool Air Temperature	TAH @ 131°F	Alarm	• High cooling air/cooling water temperature. • High generator load. • Malfunction in the instrument loop.	1. Acknowledge the alarm. 2. Compare local indications to remote. 3. Check the supply temperature and flow of cooling water. 4. If possible reduce the reactive power output. 5. Unload the turbine manually and wait for the temperature to decrease.
Generator Stator Temperature High	TAH @ 230°F TAHH @ 248°F TAHHH @ 248°F after 5 minutes	Alarm Alarm Trip	• High cooling air/cooling water temperature. • High generator load. • Malfunction in the instrument loop.	1. Compare local indications to remote. 2. Check generator loading. 3. Check operation of cooling water supply and temperature. 4. Reduce load.
Generator Bearing Oil Outlet Temperature High	TAH @ 176°F	Alarm	• Instrument failure. • High oil supply temperature. • Low oil flow. • Bearing damage.	1. Compare local indications to remote. 2. Check the oil supply temperature and pressure. 3. Inspect sightglass for proper oil flow. 4. Inspect generator for high vibration or other indication of damage.
Generator Bearing Vibration High	VAH @ 0.18 in/sec VAH @ 0.27 in/sec after 1 second VAHH @ 0.31 in/sec after 0.1 second	Alarm Trip Trip	• Instrument failure. • Loss of lube oil. • Turbine/ compressor vibration.	1. Check the lube oil pressure. 2. Check the lube oil temperature. 3. Perform compressor washing according to instruction. 4. Check the vibration by using a portable vibration instrument. 5. Check bearing temperature.
Drying Air Temperature High	TAH @ 257°F	Trip	• Instrument failure. • Excessive load.	1. Compare local indications to remote. 2. Check air supply.

Condition	Setpoint	Effect	Possible Cause	Action
Electrical Room Ventilation Differential Pressure Low	PAL @ 0.0218 psi	Alarm	• Instrument failure. • Fan failure. • Inadequate flow path.	1. Compare local indications to remote. 2. Check fan operation. 3. Verify a flow path exists for air flow.
Electrical Room Ventilation Temperature High	TAH @ 149°F	Alarm	• Instrument failure. • Fan failure. • Inadequate flow path. • High ambient temperatures.	1. Compare local indications to remote. 2. Check fan operation. 3. Verify a flow path exists for air flow.
Gas Turbine Room Differential Pressure High/Low	PDAH @ 0.0363 psid PDAL @ 0.0073 psid	Alarm Alarm	• Clogged air filter. • Wrong position of the shutters in the ventilation channels. • Malfunction in the instrument loop.	1. Make sure that no one is inside the enclosure (door is hard to open at high differential pressure). 2. Acknowledge the alarm. 3. Compare local indications to remote. 4. Check air filters for clogging. 5. Check shutter positions.
Differential Pressure Over Fan Low	PDAL @0.0290 psid PDALL 0.0145 psid	Alarm Trip	• Clogged air filter. • Wrong position of the shutters in the ventilation channels. • Malfunction in the instrument loop.	1. Make sure that no one is inside the enclosure (door is hard to open at high differential pressure). 2. Acknowledge the alarm. 3. Compare local indications to remote. 4. Check air filters for clogging. 5. Check shutter positions.
Gas Turbine Ventilation Inlet Temperature High	TAH @ 131°F	Alarm	• Malfunction of the ventilation air inlet heater. • Malfunction of the ventilation fan. • Malfunction in the instrument loop.	1. Compare local indications to remote. 2. Check fan operation. 3. Verify a flow path exists for air flow.

Condition	Setpoint	Effect	Possible Cause	Action
Gas Turbine Ventilation Temperature Low	TAL @ 6.8°F after 10 minute time delay at start TALL @ 5°F after 60 minute time delay during operation	Alarm Trip	• Instrument failure. • Inadequate inlet air heating. • Very low ambient temperatures.	1. Compare local indications to remote. 2. Check operation of the inlet air heating system.

APPENDIX H

// HRSG OPERATING VARIABLES, ALARMS AND CORRECTIVE ACTIONS

4.0 ALARM RESPONSE

The following chart is provided to assist an experienced Operator in identifying and resolving abnormal conditions associated with the HRSG System. It is not intended as a substitute for a thorough understanding of the system equipment, common sense, and safe operating practices and techniques.

Condition	Setpoint	Effect	Possible Cause	Action
HP Drum Level High	High-High-High @ +7 inches High-High @ +6 inches High @ +5 inches	HHH - ST Trip & CT Trip HH & H - alarm	• Sudden loss of steam header pressure. • Level control valve malfunction or incorrect setpoint • Swelling of water during startup.	1. Check the HP steam header pressure. 2. Verify the HRSG HP steam header vent valves are not open while the unit is online. 3. Verify the DCS “Drives” the Drum Level Control Valves to the CLOSED position 4. Remove water from the drum through the Intermittent Blowoff drain valves. 5. Check the Level Controller for failure. If controller fails to operate in AUTO, place in MANUAL and control level as necessary. 6. Troubleshoot and correct source of problem. 7. Verify that GT protective load shedding occurs. 8. Restore drum level. Recover from steam turbine trip.

Condition	Setpoint	Effect	Possible Cause	Action
HP Drum Level Low	Low-Low-Low Alarm @ -35 inches Low-Low alarm @ -21 inches Low @ -6 inches	LLL – CT Trip LL – CT Runback L - Alarm	• Level control valve malfunction or incorrect setpoint. • Loss of Makeup	1. Verify the Drum Level Controller is in AUTO with the correct setpoint. 2. Verify makeup water flow to the HP steam drum. 3. Test the Drum Level Controller for response. If controller fails to operate in AUTO, place in MANUAL and control level as necessary. 4. Verify instrument air is available to Level Control Valve. Valves fail closed on loss air. 5. Check the Level Control Valve for possible binding; i.e., stuck in position. 6. Check level transmitter signal quality. Compare remote level indications against the local sight glass. 7. Verify the HP intermittent blow drain valves are CLOSED. 8. If level continues to decrease, CLOSE the HP drum continuous blowdown and intermittent blowoff valves. 9. Make all efforts to restore drum water level to normal. Continued reduction of water level may result in a unit trip. 10. Troubleshoot and correct source of problem.

Condition	Setpoint	Effect	Possible Cause	Action
LP Drum Level High	High-High-High @ +7 inches High-High @ + 6 inches High @ +5 inches	HHH - ST Trip & CT Trip HH - alarm H - alarm	• Level control valve malfunction or incorrect setpoint. • Sudden decrease in LP steam header pressure.	1. Verify the DCS “Drives” the Drum Level Control Valve and block valve to the CLOSED position. 2. Remove water from the drum through the Intermittent Blowoff drain valves. 3. Check the Level Controller for failure. If controller fails to operate in AUTO, place in MANUAL and control level as necessary. 4. Troubleshoot and correct source of problem. 5. Re-establish normal drum water level and control.
LP Drum Level Low	Low-Low-Low @ -19 inches Low-Low @ -13 inches Low @ -6 inches	LLL – CT Trip LL – CT Runback L - Alarm	• Level control valve malfunction or incorrect setpoint. • Loss of Makeup	1. Verify the Drum Level Controller is in AUTO with the correct setpoint. 2. Verify condensate makeup water flow to the LP steam drum. 3. Test the Drum Level Controller for response. If controller fails to operate in AUTO, place in MANUAL and control level as necessary. 4. Verify instrument air is available to Level Control Valve. Valves fail closed on loss air. 5. Check the Level Control Valve for possible binding; i.e., stuck in position. 6. Check level transmitter signal quality. Compare remote level indications against the local sight glass. 7. Make all efforts to restore drum water level to normal. Continued reduction of water level may result in a unit trip.

Condition	Setpoint	Effect	Possible Cause	Action
HP Drum Pressure High	High-High-High @ 1100 psig High-High @ 1040 psig High @ 1000 psig	HHH – CT Trip HH – CT Runback H - alarm	• Excessive firing of gas turbine. • Loss of steam flow from HRSG. • Instrument failure.	1. Compare local indications to remote. 2. Ensure a flow path for steam to the turbine or condenser is available and not restricted. 3. Reduce gas turbine firing rate to reduce system pressure.
HP Steam Output Temperature High	High-High-High @ 1003°F High-High @ 998°F High @ 988°F	HHH – CT Trip HH – CT Runback H - alarm	• Instrument failure. • Excessive firing of gas turbine. • Improper or inadequate attemperator operation.	1. Compare local indications to remote. 2. Check the operation of the attemperator temperature control valve and block valve. Take manual control of valve if required. 3. Verify feedwater is available to attemperator. 4. Check valve lineup for feedwater. 5. Reduce gas turbine firing.
HP Superheater Outlet Pressure High	High-High @ 1010 psig High @ 980 psig	HH – CT Runback H - alarm	• Excessive firing of gas turbine. • Loss of steam flow from HRSG. • Instrument failure.	1. Compare local indications to remote. 2. Ensure a flow path for steam to the turbine or condenser is available and not restricted. 3. Reduce gas turbine firing rate to reduce system pressure.
LP Drum Pressure High	High-High-High @ 127 psig High-High @ 100 psig High @ 85 psig	HHH – CT Trip HH – CT Runback H - alarm	• Excessive firing of gas turbine. • Loss of steam flow from HRSG. • Instrument failure.	1. Compare local indications to remote. 2. Ensure a flow path for steam to the turbine or condenser is available and not restricted. 3. Reduce gas turbine firing rate to reduce system pressure.
LP Superheater Outlet Pressure High	High-High @ 100 psig High @ 85 psig	HH – CT Runback H - alarm	• Excessive firing of gas turbine. • Loss of steam flow from HRSG. • Instrument failure.	1. Compare local indications to remote. 2. Ensure a flow path for steam to the turbine or condenser is available and not restricted. 3. Reduce gas turbine firing rate to reduce system pressure.

Condition	Setpoint	Effect	Possible Cause	Action
Measurement Fault in HP Drum Level, Pressure or Temperature		CT Trip	• Instrument failure.	1. Compare local indications to remote. 2. Repair or replace defective components.
Measurement Fault in LP Drum Level, Pressure or Temperature		CT Trip	• Instrument failure.	1. Compare local indications to remote. 2. Repair or replace defective components.
HRSG Duct Exhaust Pressure High	High-High @ 19.5 in. H_2O High @ 18 in. H_2O	HH - CT Trip H - alarm	• Instrument failure. • Stack damper closed. • Obstruction in flue gas path. • Tube leak.	1. Compare local indications to remote. 2. Check that stack damper is full open. 3. Inspect to determine if there is a flow obstruction. 4. Check HRSG for tube leak that could be flooding HRSG with steam. Check stack drain for water output.
HRSG Duct Exhaust Pressure Measurement Fault		CT Trip	• Instrument failure.	1. Compare local indications to remote. 2. Repair or replace defective components.
LP Economizer Inlet Pressure High	High @ 365 psig	Alarm	• Instrument failure. • Improper valve lineup. • Flashing of condensate.	1. Compare local indications to remote. 2. Verify proper valve lineup. 3. Ensure economizer vent is operating properly. 4. Inspect system for indications of high temperature.
Heat Exchanger Inlet Cold Water Line Pressure High	365 psig	Alarm	• Instrument failure. • Improper valve lineup. • Flashing of condensate.	1. Compare local indications to remote. 2. Verify proper valve lineup. 3. Ensure economizer vent is operating properly. 4. Inspect system for indications of high temperature.

Condition	Setpoint	Effect	Possible Cause	Action
Heat Exchanger Outlet Hot Water Line Pressure High	365 psig	Alarm	• Instrument failure. • Improper valve lineup. • Flashing of condensate.	1. Compare local indications to remote. 2. Verify proper valve lineup. 3. Ensure economizer vent is operating properly. 4. Inspect system for indications of high temperature.
LP Steam Output Temperature High	High-High-High @ 434.13°F High-High @ 429.13°F High @ 419.13°F	Alarm	• Low LP steam flow through system. • Instrument failure. • Excessive firing rate.	1. Compare local indications to remote. 2. Check the gas turbine firing rate. 3. Verify that sufficient steam flow exists through the LP system to cool the LP superheater.