Power Management System for a 4 GW Integrated Gasification Combined-Cycle Generation Facility

Dr. Abdel Rahman Khatib
Schweitzer Engineering Laboratories, Inc.

© 2024 IEEE. Personal use of this material is permitted. Permission from IEEE must be obtained for all other uses, in any current or future media, including reprinting/ republishing this material for advertising or promotional purposes, creating new collective works, for resale or redistribution to servers or lists, or reuse of any copyrighted component of this work in other works.

This paper was presented at the 71st Annual Petroleum and Chemical Industry Technical Conference and can be accessed at https://doi.org/10.1109/PCIC47799.2024.10832277.

For the complete history of this paper, refer to the next page.

Presented at the
71st Annual IEEE IAS Petroleum and Chemical Industry
Technical Conference (PCIC)
Orlando, Florida
September 11–14, 2024

POWER MANAGEMENT SYSTEM FOR A 4 GW INTEGRATED GASIFICATION COMBINED-CYCLE GENERATION FACILITY

Copyright Material IEEE

Dr. Abdel Rahman Khatib, P.E.
Senior Member, IEEE
Schweitzer Engineering Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
akhatib@selinc.com

Abstract—This paper presents the design of a power management system (PMS) for a 4 gigawatt (GW) integrated gasification combined-cycle power plant and refinery. The facility is comprised of 5 combined-cycle power blocks, 800 MW each. The combined-cycle block consists of two gas turbines and one steam turbine. The gas turbine is one of the largest in the world that runs on synthesis gas (syngas). The facility is designed to export 2.4 GW to support the local utility, with the remaining power feeding the refinery and internal loads.

The paper discusses the islanding impact on the refinery and how the fast generation-shedding and runback solution maintains power system stability after islanding. Automatic synchronization for the facility to connect back to the local utility at a 380 kV level is also covered in the paper. It also discusses a tie-flow control scheme for active and reactive power at the point of common coupling, dispatched by the local utility or plant operation. This scheme allows utility operators to control demand output at the power block level.

The paper covers the automatic black start and load restoration sequence for the facility, a critical requirement and automated within the capabilities of the PMS. Contingency-based load shedding and underfrequency-based load shedding are implemented for the black start substation to ensure the reliability of the black start sequence.

The electrical power system, including the syngas turbine challenging modeling, has been tested and validated using hardware-in-the-loop (HIL) simulation.

Index Terms—power management system (PMS), synthesis gas generator, voltage control, frequency control, hardware-in-the-loop.

NOMENCLATURE

AGC	automatic generation control
AO	analog output
ASU	air separation unit
AutoSynch	automatic synchronization
BPD	barrels per day
CGT	combustion gas turbine
CIT	compressor inlet temperature
CLS	contingency-based load shedding
DCS	distributed control system
EDG	essential diesel generator
GIS	gas insulated substation
GSS	generation-shedding system
GPF	global power failure
GW	gigawatt
HIL	hardware-in-the-loop
ICS	island and tie line control system
IGCC	integrated gasification combined-cycle
ISO	isochronous
LRS	load restoration system
LTC	load tap changer
MMm^3/hr	million cubic meters per hour
OHTL	overhead transmission lines
PB	power blocks
PF	power factor
PMS	power management system
SLD	single-line diagram
STG	steam turbine generator
Syngas	synthesis gas
TPD	tons per day
UFLS	underfrequency-based load shedding
UT	utility
VCS	voltage control system

I. INTRODUCTION

This paper describes the power management system (PMS) of the largest integrated gasification combined-cycle (IGCC) system in the world and capable of producing up to 4 GW of power. This is enough to exceed the energy demands of the plant itself, and also to support power to nearby communities.

The main aspects of the IGCC refinery design and operation are reducing carbon emissions and increasing efficiency and sustainability, while also transforming waste leftover products into valuable end-products [1]. For instance, the dry ash produced will be processed through a special operation to separate the metal residue (nickel and vanadium). About 7,200 tons per year of nickel and vanadium are estimated to be extracted from the refinery ash. Nickel can be used for batteries, coins, and steel strengthener. Vanadium can be used for jet engines, machine components, and automotive parts.

The vacuum residue is the heaviest of the distillation cuts. It is cut from the vacuum distillation tower. Vacuum residue from the refinery is supplied to the IGCC complex for gasification.

The gasification unit is supplied with oxygen generated by the air separation unit (ASU) to produce hydrogen and syngas. Vacuum residue is the substance which is obtained by vacuum distillation. The vacuum residue elements' composition is carbon (88.7 to 90 percent), oxygen (5.7 to 15.80 percent), sulfur (1.4 to 3.5 percent), and aluminum (0.1 to 0.3 percent) [2].

The gasification unit is designed to deliver up to 2.11 million cubic meters per hour (MMm^3/hr) of syngas (which consists of 30 percent hydrogen), which will be used for power generation by the combined-cycle facility. The entire facility is estimated to produce about 585,000 tons of steam and 184,000 cubic meters of hydrogen per hour [3].

In this process, syngas is produced, then treated to remove impurities, to create hydrogen gas. This pure hydrogen product is then utilized in the desulfurization of refinery products, resulting in the creation of lower-sulfur fuels, such as ultra-low-sulfur diesel and gasoline. Fig. 1 shows a simplified block diagram of the IGCC plant.

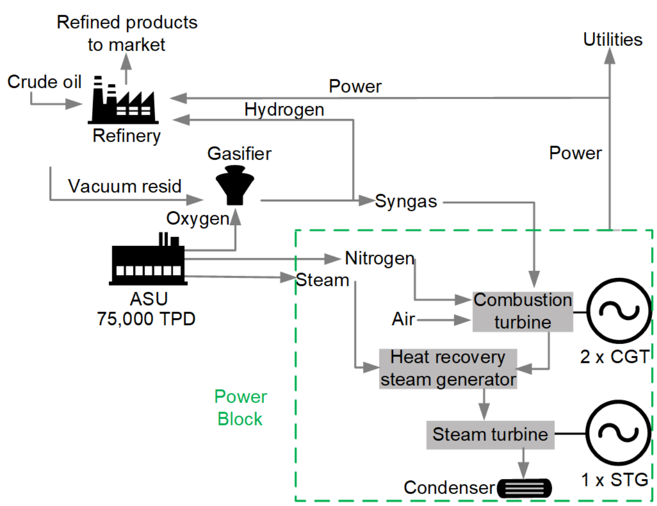

Fig. 1 A simplified block diagram of the IGCC power plant.

The PMS covered in this paper contains the main algorithms:

- Automatic generation control (AGC)
- Voltage control system (VCS)
- Generation shedding and runback
- Island and Tie Line Control System (ICS)
- Automatic synchronization between utility and IGCC system
- Load shedding for the Essential Substation
- Black start and load restoration for the Essential Substation
- Main challenges required to model syngas combustion gas turbine (CGT)
- Hardware-in-the-loop (HIL) [4] for individual CGTs and system performance during islanding with a large export

II. OVERVIEW OF THE ELECTRICAL SYSTEM NETWORK

A simplified single-line diagram of the system under study is shown in Fig. 2. Utility Substation 1 Gas Insulated Substation (GIS) connects with five other 380 kV utility substations. Substation 2 GIS connects with the five power blocks (PBs), the Refinery Substation, the 132 kV Main Substation, and the 230 kV ASU Substation.

Furthermore, each PB is consists of

- Two gas turbines 288 MVA, 18 kV, inertia 5.28 MWs/MVA
- One steam turbine 382 MVA, 23 kV, inertia 6.76 MWs/MVA

The 132 kV Main Substation is feeding the Essential Substation at 13.8 kV. The Essential Substation has essential feeders that can be used to feed the essential load in case of blackout.

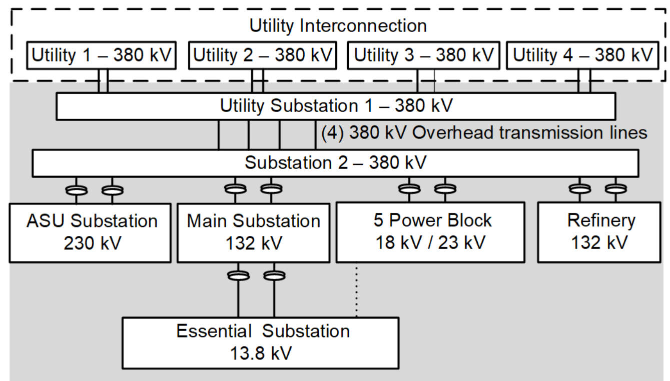

Fig. 2 Overall single-line diagram.

A. Utility Substation 1 and Substation 2

Utility Substation 1 GIS connects with four other 380 kV utility substations through double circuit (one future) overhead transmission lines (OHTLs). The length of these lines varies from short to long, with an average length of 150 km. Substation 2 GIS is connected to Substation 1 through four short OHTLs, each with line capacity of 1,200 MVA, for total capacity of 4,800 MVA that can support export of up to 4 GW.

B. Refinery Substation

The 400 MW refinery with capacity of up to 400,000 barrels per day (BPD), is intended to create a varied range of products, which includes benzene, paraxylene, gasoline, and ultra-light sulfur diesel. It is expected to provide vacuum residue feedstock for the IGCC plant, which generates power and industrial gases [5].

C. Power Generation Block

Each of the five 800 MW blocks includes two dual-fuel gas turbines and their generators, two dual-pressure, duct-fired heat recovery steam generators, and one steam turbine and its generator. Syngas from gasification is the primary and high-sulfur fuel oil is the secondary fuel. The PB rating is 958 MVA /

800 MW. A gasification facility using vacuum residue from the refinery is the main source of syngas for CGTs.

D. ASU Substation

The ASU Substation is built of six air separation units [6] that are estimated to supply approximately 75,000 tons per day (TPD) of oxygen and nitrogen to the IGCC power station and the refinery.

E. Main Substation

The Main Substation is built to distribute power to many substations that are outside the scope of the work of this paper, except for Essential / Black Start. Other substations include Gasification Units, Acid Gas Removal, Sulfur Recovery Units, Essential / Black Start Power Systems, Utility Wastewater Treatment, Sea Water Systems, Tank Farm, and Administration Buildings.

F. Essential / Black Start Substation

This substation is mainly connected to the Main Substation and feeds essential loads. Each essential load has double feed sources: one is from the Essential Substation that is normally fed from the Main Substation. The second source, in case of blackout, are essential diesel generators that energize this substation and feed all essential loads. The load-shedding system and black start have been implemented for this substation as part of the PMS and will be explained in Section VIII.

III. TYPICAL POWER FLOW OF IGCC POWER SYSTEM

The IGCC power system typically generates 3.3 GW and total loads of 1.46 GW that includes 100 MW PB auxiliaries. The system typically exports 1,840 MW to the utility through four OHTLs with each line carrying 460 MW. Two OHTLs, out of four lines, can carry the full export capability of the system. At normal operation, the essential diesel generators do not run and only start if there is a global power failure (GPF) blackout. Fig. 3 shows the typical power flow for the IGCC power system.

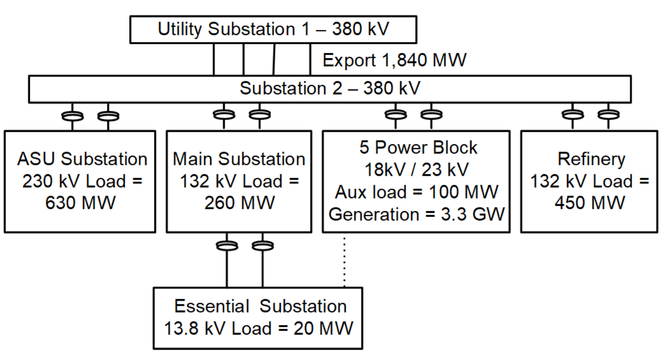

Fig. 3 A typical power flow for an IGCC power system.

IV. AGC/VCS MAIN FUNCTIONALITY SCOPE

In an IGCC system, when generators are connected to the utility, the PMS sends the MW demand set point analog output (AO) for each PB to the respective distributed control system (DCS) interface. The DCS dispatches the set point among individual generators. All generators operate in droop mode when connected to the utility. If a generator is found in isochronous (ISO) mode, the PMS sends a droop-enable command to switch the generator to droop mode.

When generators are islanded from the utility, the PMS sends the MW demand set point AO for each combustion gas turbine (CGT) to the respective CGT controller. The same signal is also used for the island/runback set point if runback is enabled and is overwritten by the runback set point for the duration of runback enabled.

Runback might not be a common term among generator manufacturers. Runback is fast load rejection to the governor. It is designed to bypass some rate limiters and to be immune against flaming out and generator tripping. The governor needs to be equipped with runback capability. The PMS feeds the analog MW for generator target runback and digital signal for enabling runback.

In a normal scenario, the MW dispatch required by the PMS, based on frequency control and equal-percentage MW sharing, is sent to the CGTs. There is no MW control for steam turbine generators (STGs) through the PMS. If the generator is in ISO mode and autosynchronization is initiated, the PMS can send speed raise and lower pulses to the CGT operating in ISO mode.

When generators are connected or islanded from the utility, the PMS can send volt/VAR raise and lower pulses to the CGT and STG exciter. The same signal is also used during autosynchronization. In addition, based on the user selection, the PMS can send power factor (PF) or MVAR analog set points to the generator exciter.

A. PMS AGC/VCS Common Functionalities

The PMS AGC/VCS performs the following common functions:

- Tracks all system islands and assigned generators and loads to each island.
- Designates buses based on system topology to AGC and VCS control loops so that utility-connected generators will be controlled for maintaining utility MW and MVAR/voltage and islanded generators are controlled for island frequency and voltage control.
- Allocates the available spinning reserves (MVAR and MW) of generators to islands and tie lines.
- Displays voltage and frequency measurements for all system islands.
- Dispatches droop and ISO control mode enable signals to the governor based on the operating scenario.
- Dispatches volt, VAR, or PF control mode enable signals to the exciter based on the operating scenario.
- Includes time-stamped PMS Sequential Events Recorder records for all alarm conditions.

- Generates a voltage alarm, frequency alarm, or MVAR/MW maximum capacity alarm when the measurements go outside the defined limits.

B. PMS AGC Main Functionalities

The PMS AGC performs the following functions:

- Dispatches turbine generator governor set points for equal-percentage MW load sharing in an islanded scenario.
- Controls the system frequency of each islanded section of the plant.
- Dispatches MW set points for each power block when connected to the UT.
- Controls the MW flow across the tie lines according to user-entered set points.

C. PMS VCS Main Functionalities

The PMS VCS performs the following functions:

- Dispatches exciter set points for equal-percentage reactive power load sharing within plant generators.
- Controls the generators terminal voltage to maintain the bus voltage at nominal on each plant.
- Controls transformer load tap changer (LTC) in parallel with generator excitation to maintain the generator terminal voltage.

D. AGC and VCS Control Modes

The PMS AGC and VCS operate in either of the following three modes, one at a time, whichever mode is selected.

- Under PMS control
- Under DCS control
- Under utility (UT) control

The PMS uses the set point selected by the system operator (PMS / DCS / UT) to dispatch the generators. The default mode is PMS. When in PMS mode, the operator has complete control of the generator dispatch.

If the DCS wants to take control of the utility export set point, the operator must enable DCS mode control from the DCS. The DCS can set the following set points:

- MVAR export/import from the UT.
- MW export from the UT.
- 380 kV bus voltage set point from the UT.

If the UT wants to take control of the IGCC export or generator set points, the UT operator must send the request for UT Mode Enable control. The PMS operator is then prompted to give control to the UT. The UT can set the following set points and controls:

- MVAR and PF dispatch set points for each generator, including the STGs.
- MW dispatch set points for each CGT.
- MW, MVAR, and PF set points for each power block.
- MW, MVAR, and PF dispatch set points for overall utility export/import between the IGCC and the UT.
- Voltage set point for the 380 kV bus.
- MW mode selection:
  - Utility Plant Export Set Point (overall export)
  - Individual CGT MW Set Point
  - PB MW Set Point
- MVAR/Exciter mode selection:
  - Utility/IGCC Bus Voltage Set Point
  - Overall export/import MVAR Utility
  - Individual Generator PF Set Point
  - Individual Generator MVAR Set Point
  - Power Block PF Set Point
  - Power Block MVAR Set Point

E. AGC and VCS Control Strategy

CGTs can operate on two different fuel types, syngas and liquid (oil) fuel. The PMS AGC is designed to operate efficiently considering the type of fuel. Based on the fuel type status received by the AGC from the DCS interface, the AGC dynamically calculates the capability and spinning reserve of the machine and dispatches the MW demand output accordingly.

However, the spinning reserve is interlocked with the MW load capability analog input to the PMS from the turbine. The PMS uses this value all the time except when it is not available (communication alarm, etc.). The dynamic capability calculation is based on a manufacturer-provided capability curve.

The VCS sends voltage raise and lower commands to each of the generation units so that each unit shares an equal portion of the MVAR, as a percent of available capacity for each generator. The voltage raise and lower signals, which are sent from the VCS, will raise the terminal voltage on the generator and push more MVARs through the generator step-up transformer. Simultaneously if the generator terminal voltage exceeds +/- 5 percent, the PMS controls the transformer LTC by sending tap raise or lower commands to the LTC to bring the voltage between ± 5 percent.

V. UTILITY TIE LINE CONTROL

In the IGCC system, four utility tie lines can be controlled for active power flow by the PMS. The PMS sends the PB MW dispatch set point to DCS interfaces, and the DCS dispatches it among generators within PBs. The PMS calculates the PB MW dispatch set point based on the tie MW set point by the operator (IGCC/UT) and, accordingly, demands the PB to produce MW based on the set point, ensuring the MW percent load sharing between the PB connected to the utility.

In this case, if one or two transmission lines trip, the overall set point remains applicable since the two lines are capable of handling the complete export flow. If only one line remains, the generation-shedding system (GSS) needs to take an action and tie flow will be disabled.

Tie line control is for active power MW and reactive power MVAR/PF/voltage set point; therefore, all the alarms, including voltage high/low limits and MVAR maximum capacity, are considered for system stability. The thermal stability limit alarm is also considered. The thermal stability limit MW alarm is triggered when the tie MW flow reaches a certain MW on a single line; the tie control is stopped automatically on all the alarms. After the stopped tie flow on alarm initiation, the PMS waits for the user to enter a different MW set point before disabling tie control.

Tie-flow control for reactive power is only enabled when the VCS is in Voltage/MVAR mode. If the VCS is utility-connected, it can run in six different modes as shown in Table I. In the first two modes, volt mode and volt/MVAR mode, the PMS controls all generators to maintain the voltage/MVAR. Any time the terminal voltage goes outside that five percent range, the PMS is controlling the transformer LTC to keep the generator terminal voltage within five percent. The four other modes are passthrough modes to either PB or an individual generator; in these four modes, the PMS is not controlling the voltage nor the LTC.

TABLE I
VCS UTILITY-CONNECTED CONTROL MODE SUMMARY

VCS mode	Exciter mode	VCS control summary
Volt mode	Voltage	Maintains UT dispatch voltage. Uses transformer LTC to maintain generator voltage.
MVAR mode	Voltage	Maintains UT dispatch MVAR. Uses transformer LTC to maintain generator voltage.
PB PF mode	PF	Distributes PB PF to each generator. No voltage / transformer control.
Gen PF mode	PF	Sends individually entered PF set point to each generator. No voltage / transformer control.
PB MVAR mode	VAR	Distributes PB MVAR set point to each generator. No voltage/ transformer control.
Gen VAR mode	VAR	Sends individually entered VAR set point to each generator. No voltage/ transformer control.

VI. AUTOSYNCHRONIZATION SYSTEM

This section describes the redundant automatic synchronization (AutoSynch) system, which is part of the PMS. This AutoSynch system is used to synchronize eight breakers (in a breaker-and-a-half scheme substation), connecting four transmission lines between UT Substation 1 and Substation 2. Two dedicated autosynchronization system relays are installed on all eight breakers. AutoSynch has been placed only in Substation 2, not Substation 1.

When the IGCC is islanded from the UT and synchronization is initiated on any of the eight breakers, the PMS sends an analog set point to all connected generators to match the UT frequency and voltage raise/lower pulses to all generators to match the UT voltage. Once all the synchronization parameters are within the breaker closing window, a relay will close the breaker.

The AutoSynch [7] [8] uses advanced angle technology that considers the slip rate and the breaker closing mechanism delay setting to cause closure to occur at zero degrees.

VII. GENERATION-SHEDDING AND RUNBACK SYSTEM

The primary goal of this system is to keep the frequency of the IGCC power system in a stable range during major disturbances since the system is exporting up to 2.4 GW and the CGT runs on syngas, which has lower energy content compared to natural gas. Major disturbances can be utility lines tripping or losing the major load substations. By keeping the frequency in a stable range after major disturbances, the generation control system corrects the frequency and brings it back to steady-state normal frequency.

There are 15 generators (STGs and CGTs) on the IGCC system that can be shed and 10 CGTs that can be run back, if required. These generators shed or run back based on the priorities set by the operator on the PMS. Different interlocks can be set up for setting priorities in the PMS based on operational requirements. CGT runback is used to quickly reduce the generator output to bring the system frequency back to nominal. The generation runback characteristics are typically faster than the generator load-rejection characteristics. If a CGT is selected for shedding and the STG of the same PB is still running, the coupling effect of the tripped CGT on STG output has an effect in about ten minutes. During this time, the AGC MW set point to the other CGTs can be increased more quickly to compensate for the STG load drop. The CGT can raise 13 to 14 MW per minute.

A. Islanding and Runback Scenarios

There are three different types of contingency events in terms of how the PMS uses islanding digital (latch), runback digital, runback set point, AGC generator set point, and AGC PB set point. There are multiple scenarios within each type, as explained next.

1) Utility-Connected GSS Contingency Trigger

In this scenario, two or three utility lines trip or the refinery trips while the IGCC is still utility-connected. Generation shedding is the only option in this case and no runback is allowed since the generators are still connected to the utility (per the CGT manufacturer), the GSS sends a PB set point to the DCS interface. The PMS will perform generation shedding only, based on excess generation if required.

2) Islanded Runback Utility Disconnected

In this scenario, the IGCC is islanded from the utility. An islanded latch signal and analog runback set point are sent to the turbine interface. An analog runback set point is sent for a certain duration, and the AGC analog set point takes over once the generator settles down to runback set point.

3) Islanded Runback Already Utility Disconnected

In this scenario, the IGCC is already islanded from the utility and then an additional contingency is triggered, such as a refinery trip, and excess generation occurs on an island. An islanded latch signal is already high since the IGCC is already islanded. Another runback digital output and analog runback set point will now be sent to the CGTs for a certain duration. The AGC analog set point will take over once the generator settles down to runback set point.

VIII. ESSENTIAL SUBSTATION LOAD SHEDDING AND LOAD RESTORATION

A. Simplified Single-Line Diagram (SLD) for Essential Substation

Fig. 4 shows an SLD simplified for the Essential Substation. The substation consists of eight essential diesel generators (EDGs), two incomers, and one bus intertie. The Essential Substation back feeds PB-1 for black start. The two incomers are fed from the Main Substation.

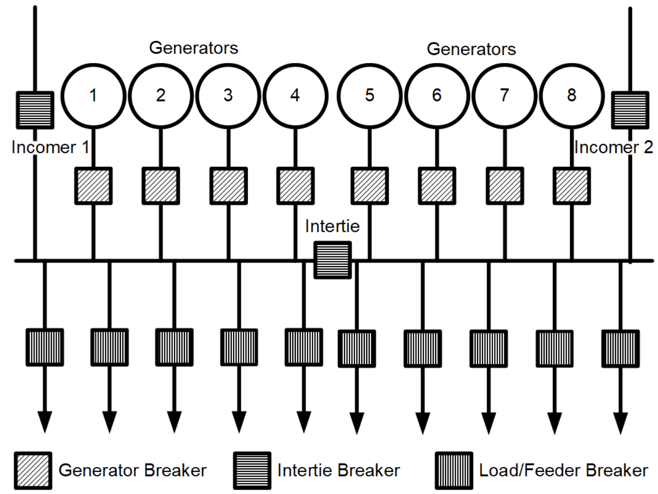

Fig. 4 SLD of the Essential Substation.

B. GPF and Load Shedding Enable

GPF is defined as the IGCC being islanded from the utility with ten CGTs in the IGCC facility tripped. The logic diagram to determine a blackout and assert GPF signal is shown in Fig. 5.

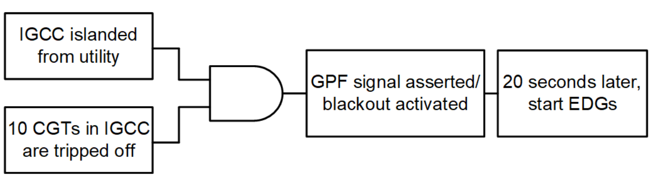

Fig. 5 Logic diagram to assert GPF and start EDGs.

The load shedding is enabled only when the following condition is satisfied, as shown in Fig. 6.

- Two incomer breakers are opened.
- IGCC has GPF.
- Essential Substation is not back feeding PB 1.

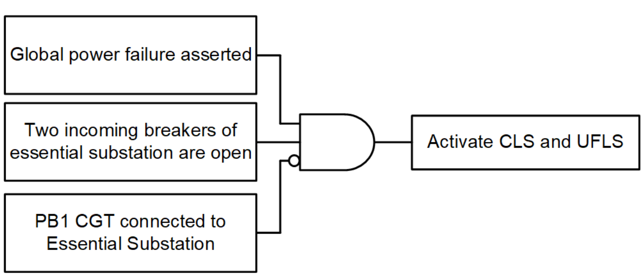

Fig. 6 Logic diagram to activate CLS and UFLS.

Contingency-based load shedding (CLS) and underfrequency-based load shedding (UFLS) are implemented to protect the system if any of the generators or the intertie trip during a black start. For detailed information for CLS and UFLS refer to [9] [10] [11].

C. Black Start and Load Restoration System (LRS)

A black start and load restoration sequence can be summarized as shown in Fig. 7 as follows.

- Once a GPF is detected, open all outgoing feeders and the incomer breakers.
- The PMS sends a close command to the intertie breaker dead bus closing.
- The PMS sends a start command to the EDG controller.
- The EDG controller starts all eight EDGs after receiving the command from the PMS controller.
- The PMS opens all the incomer PBs.
- The PMS begins closing the outgoing load feeders one by one, according to operator priority.
- For the load breakers feeding PBs, the PMS sends the close command to the load feeder and to the corresponding incomer breaker and tiebreaker PBs to energize PB auxiliaries.
- Outgoing feeders are restored based on two parameters: restoration priority and available generation.
  - Priorities for load restoration are separate from those used for load shedding.
  - Available generation is calculated based on the number of generators that have started and connected to the essential switchgear and the loads that have been restored.
- The power value for outgoing feeders is the expected power consumption entered by operators. If the actual load is more than the operator-entered value, then the PMS will consider the actual load when calculating the spinning reserve.

IX. POWER SYSTEM MODELING CHALLENGING

The main challenge of this power system model is the government mode of the syngas CGT. Since the energy content of syngas is less than natural gas, a standard governor model cannot be used because it is based on high-energy content fuel. A modified version of the GGOV1 governor has been used and validated with the governor manufacturer. The details of the syngas governor model are out of the scope of this paper. The summary of these modifications as follows.

- When the gas turbine generator (CGT) is switched to ISO mode, the output of the governor proportional integral derivative controller will be reset to the value corresponding to ISO target MW.
- The fuel control to the governor passes through a rate limiter that is able to provide an 8 percent instantaneous increase, followed by an 8.4 percent per minute ramp-up rate. This fuel control is due to the energy content of the syngas for pickup load. The

simulation results in the next section will demonstrate that limitation.

- Modified droop function logic allows 10 percent instantaneous droop MW increase followed by a 30 MW per minute increase rate. For the same reason explained previously.
- The governor model is equipped with underfrequency protection logic. The logic is based on CIT. When the speed drops below the limit, an underfrequency trigger is activated. The loading above maximum MW is reduced if the underfrequency trigger signal is active. The maximum MW of gas turbine loading is related to CIT. More details will be explained next.

A. Governor Underfrequency Protection Logic

The chemical composition of syngas varies based on the raw materials and processes used to make it; however, in general it has less energy density than natural gas.

Due to that fact, when operating in syngas, if the system frequency decays, the maximum capability limit of CGT will be reduced.

- The underfrequency protection trigger (Hz) is a function of the compressor inlet temperature (CIT).
- The maximum capability protection limit (measured in MW) is a function of the CIT as well.

For example:

- For CIT 48 degrees C → underfrequency protection is 59.61 Hz.
- For CIT 48 degrees C → CGT rejects any loads above 164.3 MW.

A realistic example for this scenario is when the IGCC is islanded from the utility and operating with ISO and Droop machines in the system. If only the ISO machine reaches the MW turbine limit (maxed-out) and is unable to correct the frequency to nominal 60 Hz, CGT underfrequency is triggered. If the droop generators still have MW reserve, the PMS will update the turbine maximum limit of all machines in the island. Accordingly, the PMS demands that the droop machines increase MW out, which will eventually reduce MW on the ISO machine and help in correcting the frequency.

For example, one ISO machine is operating at 230 MW. Three droop machines are operating at 100 MW. The maximum MW limit of all the machines is 250 MW. A load of 117.5 MW is increased on the system. The ISO can only pick up 20 MW, so the remaining 97.5 MW is picked up by three droop units. ISO is unable to correct the frequency so underfrequency is triggered at 59.61 MW at 48 degrees C, which reduces the maximum MW limit to 164.3 MW for all the generators.

ISO machine MW rejection = 250 – 164.3 = 85.7 MW
Total Droop MW pick = 97.5 + 85.7 = 183.2 MW
MW Droop units reserve = 3 • (164.3 – 100) = 192.9 MW

Because droop units have enough MW reserve, the PMS will be able to increase the droop machines' MW output and correct the frequency.

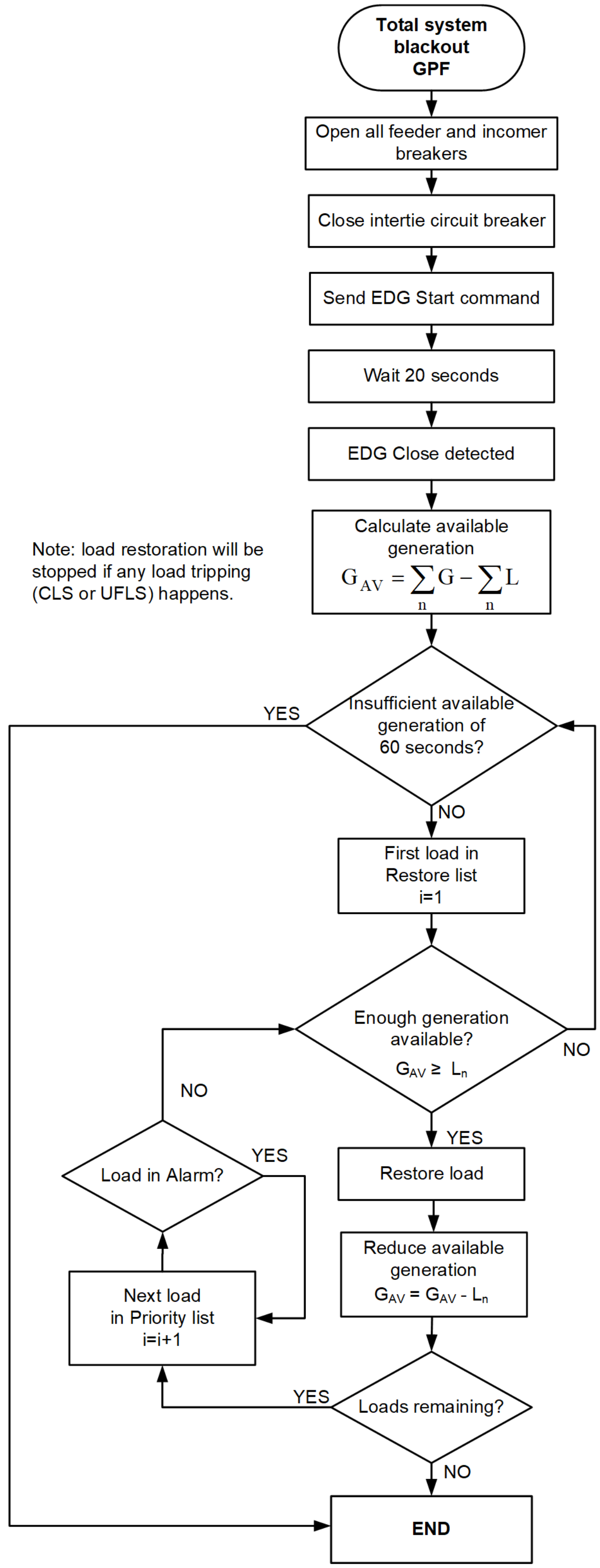

Fig. 7 Simplified LRS logic diagram.

X. HIL SIMULATED CASES

A. Load Acceptance of CGT

The first test is performed by adding loads to the single islanded CGT when the CGT is running in droop and ISO mode, respectively. Fig. 8 shows the frequency response for different load acceptance with different governor modes.

The response of a single CGT with the GGOV1 governor was analyzed. For the load acceptance test when the CGT was in droop/ISO mode, one load is always connected to the CGT and absorbs 180 MW. The load acceptance for Load 2 is switched in after one second for the following four scenarios:

- Droop mode 15 MW
- Droop mode 18 MW
- ISO mode 18 MW
- ISO mode 30 MW

The bus-frequency response of the test is shown in Fig. 8. Note that the CGT in Droop mode cannot accept much load.

- For CGT in Droop mode, 18 MW load acceptance in a single CGT test brings the frequency down to 56.7 Hz.
- For CGT in ISO mode, 30 MW load acceptance in a single CGT test brings the frequency down to 57.9 Hz.

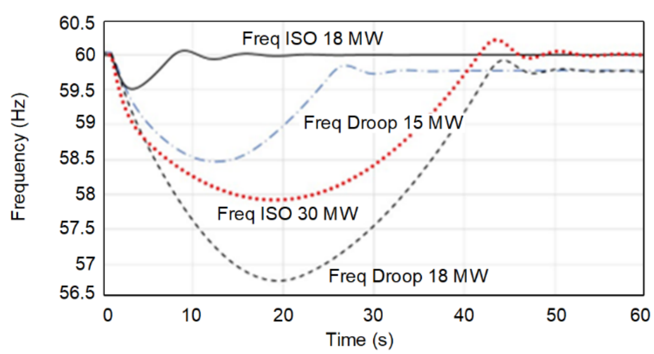

Fig. 8 Load acceptance for CGT ISO/Droop.

B. Test 2: Load Rejection of CGT With Runback

This test of individual CGT 120 MW load rejection with runback is enabled. The test is performed with ISO and Droop modes of CGT. Fig. 9 shows the frequency reponse of load rejection with runback.

- Maximum and minimum frequency of droop mode is 62.5 Hz and 59.9 Hz.
- Maximum and minimum frequency of ISO mode is 62.3Hz and 58.8 Hz.

Maximum frequencies for both ISO and Droop are close to each other for the runback test, and ISO mode has under damped response and frequency reach to 58.8 Hz, which might not be a perfect scenario considering the underfrequency protection logic explained previously. The final mode of operation will be decided during system commissioning.

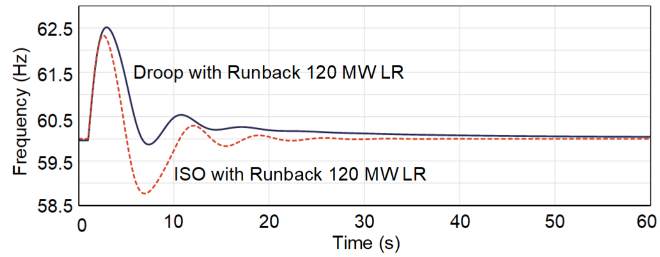

Fig. 9 Frequency response for 120 MW load rejection with runback.

C. Test 3: Load Rejection of CGT Without Runback

Performing load rejection without runback has an unacceptable behavior for the CGT frequency response. Fig. 10 shows a frequency response for 60 MW load rejection.

As explained from the previous test, ISO mode has under damped behavior and, for this test, it has a frequency collapse. For the droop mode, the frequency behavior is also not acceptable and the minimum frequncy is 52.9 Hz.

Enabling runback is a critical function for the PMS, and without it the islanding will fail.

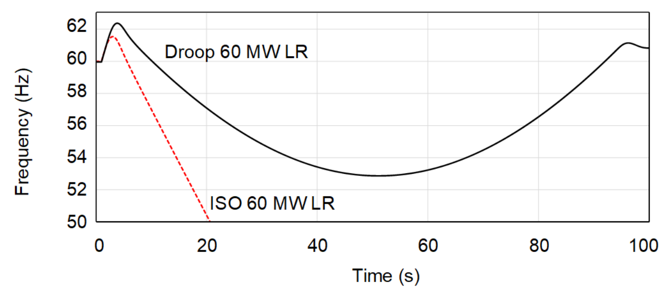

Fig. 10 Frequency response for 60 MW load rejection without runback.

D. Test 4: IGCC Island With Export 2,335 MW

This test demonstrates an islanded scenario with export of 2,335 MW to the UT. The island load is 841 MW, as shown in Fig. 11.

- Four PBs with eight CGTs and four STGs.
- Each CGT producing 240 MW and each STG producing 314 MW.
- Total generation is 3.176 GW.

After the island PMS performs the following actions, shown in Fig. 12.

- Two full PBs consisting of four CGTs and two STGs (1.588 GW) are tripped after a 200 ms delay (worst expected delay).
- The other four CGTs are running back to 53.3 MW after a 200 ms delay.
- Two remaining STGs assumed are constant MW.
- One CGT is switched to ISO mode after islanding.
- Island load is 841 MW.

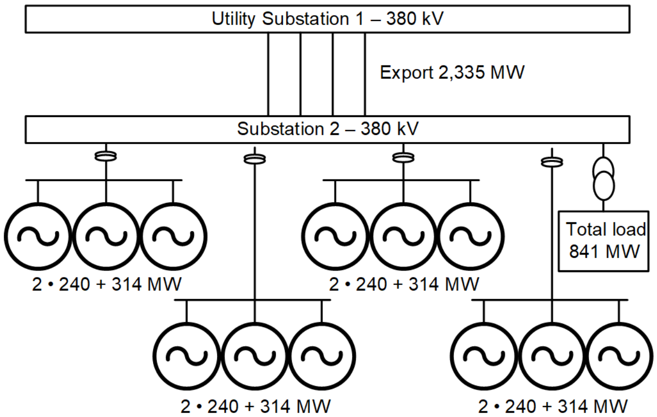

Fig. 11 Loading for Test 4 precontingency.

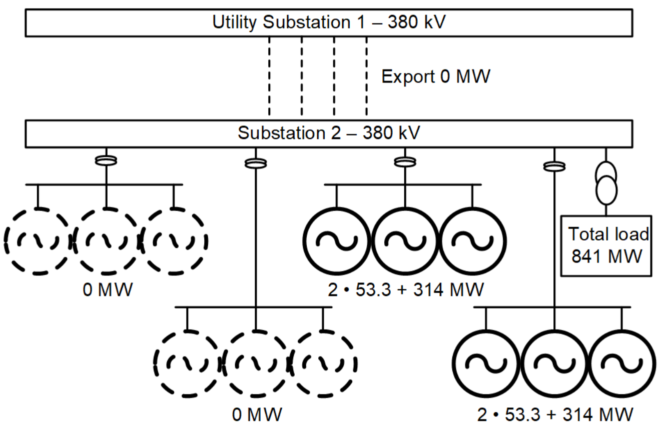

Fig. 12 Loading for Test 4 postcontingency.

The same test has been repeated with the unlocked STG. Since the STG is coupled with the CGT, the output of the STG is reduced over time with runback; the STG and the ISO CGT will compensate for that. The frequency response of lock and unlocked STG is shown in Fig. 13.

The maximum frequency that the island hits is 62.6 Hz with a locked STG and 62.2 with an unlocked STG. These frequencies are within the acceptable range with over 2 GW export level.

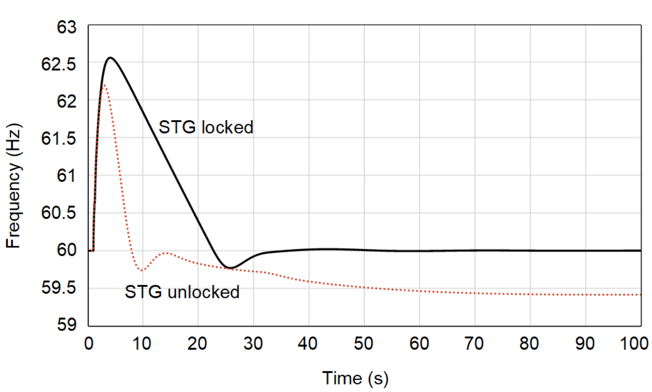

Fig. 13 Frequency response for Test 4.

XI. CONCLUSIONS

This paper presents a PMS that has been designed for an IGCC system that can export up to 2.5 GW. The main objective of the PMS is maintaining the stability of the refinery after islanding, which is a great challenge particularly because syngas is the main fuel of the CGTs. While the IGCC is utility-connected, the PMS maintains the tie-flow active and reactive power and voltage across the utility. The PMS has multi-agent tie-flow control that can be controlled from the utility, DCS, and local operators in multiple different mode of operations, such as PB level, individual generator level, or IGCC level.

The PMS leads the black start and load restoration in the essential substations with a load-shedding system running in the background to prevent the Essential Substation from blackout again during a black start operation.

Optimal selecting for shedding and/or runback generators has been achieved using HIL modeling and testing. The best combination of shedding and runback has been tested and evaluated with an HIL test environment.

The paper highlights the main challenge of modeling syngas CGTs and shows some key generator and system tests that explain the special behavior of syngas CGTs.

XII. ACKNOWLEDGMENTS

The author gratefully acknowledges the contributions of Maaz Kazmi and Dr. Niannian Cai for their work during project design and development efforts. The author acknowledges Mohammed Ruwajli (Saudi Aramco) for coordinating all discussions and project execution.

XIII. REFERENCES

[1] A. Gray, "Jazan – Our New Smart Self-Powering Refinery," *Elements Magazine*, Aramco, Nov. 14, 2022. Available: aramco.com/en/magazine/elements/2022/jazan-complex.

[2] A. C. Sánchez Berna, V. Camacho Moran, E. T. Romero Guzmá, and M. José Yacamán, "Asphaltene Aggregation from Vacuum Residue and Its Content of Inorganic Particles" *Petroleum Science and Technology*, 24: pp.1055–1066, 2006.

[3] NS Energy, "Jizan Integrated Gasification Combined-Cycle Power Project." Available: nsenergybusiness.com/projects/jizan-integrated-gasification-combined-cycle-power-project/.

[4] S. Manson, A. R. Khatib, N. Cai, and S. S. Rajan, "Advantages of Real-Time Closed-Loop Simulation," *2021 IEEE IAS Petroleum and Chemical Industry Technical Conference (PCIC)*, San Antonio, TX, September 2021, pp. 47–56.

[5] Air Products, "Jazan Industrial Gas Complex." Available: airproducts.com/campaigns/jazan-industrial-gas-complex.

[6] Air Products, "Delivering World-Scale Air Separation Plants." Available: airproducts.com/company/innovation/air-separation.

[7] S. Manson, A. Upreti, and M. J. Thompson, “Case Study: Smart Automatic Synchronization in Islanded Power Systems,” *IEEE Transactions on Industry Applications, 52*, pp. 1241–1249.

[8] T. Foxcroft and M. Thompson, “Advanced Synchronizing System Provides Flexibility for Complex Bus Arrangement,” *42nd Annual Western Protective Relay Conference*, Spokane, WA, October 2015.

[9] S. Manson, M. Checksfield, P. Duffield, and A. R. Khatib, “Case Study: Simultaneous Optimization of Electrical Grid Stability and Steam Production,” *2014 IEEE Petroleum and Chemical Industry Technical Conference (PCIC)*, San Francisco, CA, September 2014, pp. 389–397.

[10] G. M. Asim Akhtar, M. W. Ahmed, W. Allen, P. Zhang, K. Jensen, and S. Dasgupta, “Fast and Reliable Load-Shedding Scheme for Wastewater Treatment Plant – A Case Study,” *2022 IEEE Electrical Power and Energy Conference (EPEC)*, December 2022, pp. 149–156.

[11] K. Hao, A. R. Khatib, N. Herbert, and N. Shah, “Case Study: Integrating the Power Management System of an Existing Oil Production Field,” *2016 Petroleum and Chemical Industry Technical Conference (PCIC)*, Philadelphia, PA, September 2016, pp. 1–9.

XIV. VITAE

Abdel Rahman Khatib, PE (M 1999, SM 2007), is a principal engineer at SEL Engineering Services, Inc. (SEL ES), a subsidiary of Schweitzer Engineering Laboratories, Inc. (SEL). He joined SEL in 2010. He received his BS and MS in electrical power engineering from Military Technical College in Cairo, Egypt. He received his PhD in electrical engineering from Virginia Tech in 2002. He executes and consults on projects that focus on power management system design, testing, and commissioning for the petrochemical and oil industries, data centers, microgrids, and remedial action schemes. His current research interests are power system modeling, power system load flow and dynamic stability, smart grid control systems, and power system protection. He has 12 years of university teaching experience in Egypt, the United States, and Saudi Arabia. He is a senior member of the IEEE Power Engineering Society, and is a registered professional engineer in Washington, California, Indiana, Montana, and Texas.

Previously presented at the 2024 IEEE IAS Petroleum and Chemical Industry Technical Conference (PCIC), Orlando, Florida, September 2024.
© 2024 IEEE – All rights reserved.
20240430 • TP7094