

# Case Study: Turbine Load-Sharing and Load-Shedding System for an Australian LNG Facility

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# CASE STUDY: TURBINE LOAD-SHARING AND LOAD-SHEDDING SYSTEM FOR AN AUSTRALIAN LNG FACILITY

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**Abstract**—This paper presents a turbine load-sharing and load-shedding system for an islanded liquefied natural gas facility in Australia. The system includes three independent and redundant load-shedding schemes: process-based contingency load shedding with predefined load group and load pairs, high-speed underfrequency-based load shedding, and progressive overload shedding with system frequency supervision. In addition to the load-shedding schemes, the site includes a generation control system with frequency control, voltage control, automatic synchronization, and turbine load-sharing schemes. A breaker-and-a-half configuration complicates the fast load-shedding scheme. Results from hardware-in-the-loop testing are shared.

**Index Terms**—Power management, generation control, fast load shedding, autosynchronization, power system modeling.

## I. INTRODUCTION

A power management system (PMS) is a collection of hardware and software components configured to provide intelligent automatic load reduction in response to predetermined contingencies, in addition to maintaining frequency and voltage within an island [1] [2]. This paper describes a PMS implemented at an islanded liquefied natural gas (LNG) facility in Australia, including system design and hardware-in-the-loop testing results.

The PMS at the LNG facility automatically adjusts the system loading and generator set points to account for operational changes made within the electrical grid. The PMS also provides load shedding to recover after a major instability develops, such as a sudden loss of generation. The load-shedding system (LSS) includes three schemes for determining the amount of load to shed. The primary scheme is contingency-based, while the secondary (backup) scheme is underfrequency-based [3]. Both schemes run on independent, dual redundant processors supplied from redundant direct current (dc) supplies. The third load-shedding scheme is progressive overload shedding (PLS), which is an overload scheme that protects generators from overload.

The LSS at the LNG facility is deployed on two pairs of dual modular redundant (DMR) LSS controllers. A DMR design is a

reliability engineering technique in which both appliances in a pair receive data, run logic, and operate simultaneously. This technique is proven to be vastly more reliable than hot- or warm-standby redundancy configurations used elsewhere. In a DMR system, a pair of controllers is used for fast and proactive load shedding, while another pair is used for underfrequency load shedding.

The PMS generation control system (GCS) includes an automatic generation control (AGC) system, a voltage control system (VCS), and an island control system (ICS). The hardware uses PMS controllers that gather data from the relays installed throughout the LNG facility.

The PMS GCS controls both active and reactive power dispatch and sharing of generators. More challenges can be introduced to the system if the PMS is required to coordinate with steam production, which can impact the generator production [4]. In this project, two steam expander turbines are running in the system; however, they are not controlled by the PMS. The PMS is only controlling the gas turbines. In addition, the GCS actively controls system voltage and frequency. Also, any number of system islands can be simultaneously handled. The hardware for this hot-standby redundant system is loaded with the GCS image. At all times, the GCS maintains the voltage and frequency at normal values [5] [6].

Generation control at the LNG facility is accomplished with two GCS controllers. The two GCS controllers operate in a hot-standby mode. Hot-standby redundancy occurs when one controller is constantly operating as the master controller. The second controller will take over if the master fails or is not in perfect operating condition. This strategy is well suited for the slow control behavior of the GCS.

## II. LNG FACILITY POWER SYSTEM OVERVIEW

The Australian LNG facility downstream power system is sourced by four 36 MW gas turbine generators (GTGs) connected to a main substation (see Fig. 1), and two 9 MW steam expander cogenerators. The LNG facility is not connected to the utility; therefore, onsite generation is the only power source. The power system typically operates as a single island. The main gas-insulated switchgear incorporates a breaker-and-a-half scheme.

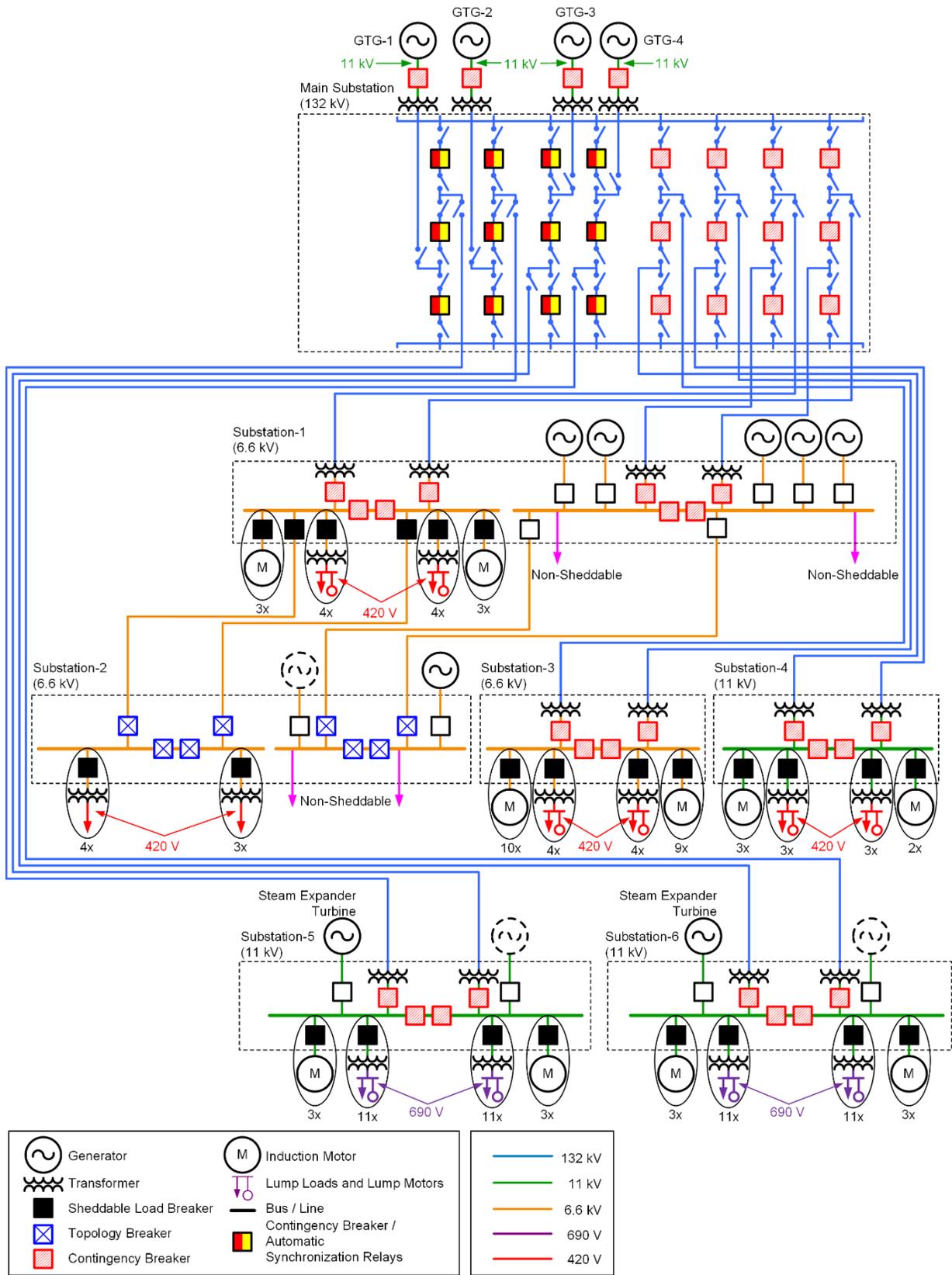


Fig. 1 Simplified One-Line Diagram

The main substation provides power to six other substations. The main feeders at the substations employ a main-tie-tie-main scheme with the ties in a normally closed position, as shown in Fig. 1. The LNG facility has over 100 loads that can be shed.

### III. GENERATION CONTROL SYSTEM

This section provides a functional description of the GCS applied at the LNG facility. Generators are controlled by the GCS to maintain system frequency and voltage at the 132 kV buses. Both bus voltage and frequency are critical data to the GCS, especially in an islanded system. Active and reactive power flows throughout the primary buses are monitored to facilitate properly executed controls. Voltage and frequency are maintained across the primary generation substations. Fig. 2 shows a simplified one-line diagram related to the GCS control.

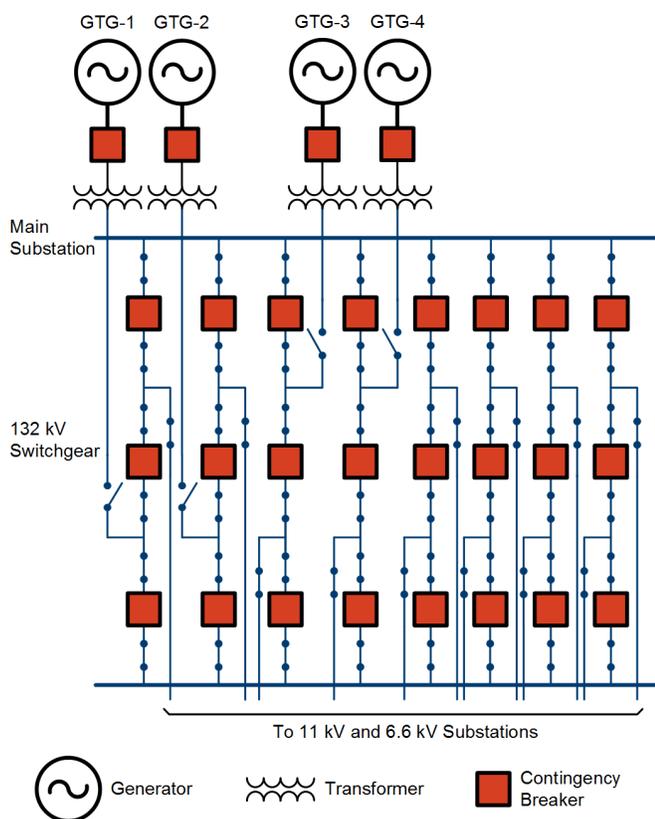


Fig. 2 GCS Simplified One-Line Diagram

#### A. Generation Control System Control Philosophy

The general requirements of the AGC system and VCS are as follows:

1. Share the MW/MVAR contribution between GTGs; this function is also commonly called load sharing.
2. Continuously regulate the busbar frequency to 50 Hz for single- and multiple-island operations; this is an AGC system function.

3. Continuously regulate the busbar voltage at the generation bus for single- and multiple-island operations; this is a VCS function.
4. Participate in automatic synchronization.

#### 1) Bringing a Generator Online

Each generator at the LNG facility can be brought online manually by the operator at the generator control panel or initiated from the PMS human-machine interface (HMI). In both scenarios, the generator manufacturer is responsible for matching the actual frequency and voltage to the system.

To initiate automatic synchronization from the PMS HMI, the operator must put the governor in external load control mode and the exciter in remote mode. While in remote mode, the PMS will not issue lower and raise pulses until the generator breaker is closed.

If the unit is not in external load mode, the GCS will not include this generator in its MW and MVAR sharing algorithms and will simply keep the remaining generators equally sharing the load.

#### 2) Generator Loading Modes

Three modes of operation are used by the AGC system and VCS to facilitate commissioning in this project, as well as the different types of generator operating constraints. These modes will generally be entered into the system before the generator is brought online (although, they can be changed afterward). The modes are:

1. Disabled
2. Maintained MW/MVAR
3. Maintained MW/MVAR with regulation

##### a) Disabled mode

The disabled mode removes the GTG from all control routines within the PMS and prevents noncommissioned GTGs from affecting the portion of the system that has already been commissioned.

The AGC system and VCS do not send any up or down controls to the generator governor. The GTG is treated by the AGC system and VCS as though it is still in local mode. With the generator in local mode, the PMS should not control the generator; instead, it must be controlled by the operator.

##### b) Maintained MW/MVAR mode

This mode is used primarily for commissioning. The unit output is controlled to the load set point, which is only displayed on the GTG dialog box; whereas, the AGC system and VCS maintain the generator at a constant power output.

The maintained MW mode can be used to maintain the units at a constant power output only when the governors are in droop mode. The generator still reacts to any sudden load change in the system. Similar to the other generators, it will still throttle up or down quickly in response to the step-load change, based on its droop characteristic. However, this mode will not be operational if the GTG is in isochronous (ISOC) mode.

##### c) Maintained MW/MVAR with regulation

In normal operation, this is the recommended mode for all generators. The unit output is biased toward the base set point; however, it is not constrained to it. Rather than attempting to

maintain each generator at a specific set point, the bias point is used to weigh the relative load sharing of each generator as a percentage of generator capacity. If all generators are set with the same percentage of rated power, all generators will be biased equally and will share the load equally.

When all generators have the same capacity, upper limit, lower limit, and MW/MVAR bias point, the result of the MW/MVAR sharing algorithm is intuitive. For example, if two 100 MW/MVAR capacity generators are online, their bias points will be 50 MW/MVAR. Additionally, if there is a requirement of 100 MW/MVAR, each generator will run at its bias point of 50 MW/MVAR and each generator will be exactly at its MW/MVAR set point. If the load increases to 125 MW/MVAR, then both generators will pick up an equal share (12.5 MW/MVAR) and run at 62.5 MW/MVAR each. The calculation for this load-sharing bias allows for differentiated loading, actual generator capacity considerations, and artificial loading boundaries.

Maintained MW with regulation mode will not be operational if the GTG is in ISOC mode.

### 3) Capability Curve and Regulation Limits

The capability of generators is important information for the GCS. Reserve margins (RMs) for real and reactive power are calculated based on the present operating temperature and power output. Given the real and reactive power and the operating temperature, the actual operating point along with a dynamic capability curve can be determined. The capability of the GTG is usually limited more strictly by other factors or bounds, such as the operator-entered limits or the manufacturer's control system.

The bounds set by the capability curve and the operator-entered regulation limits determine the ultimate margins used within the GCS. These margins are aggregated for each bus and analyzed for any electrical island that is created to facilitate calculating the percentage of real (P) and reactive (Q) power on each island, which can be used in generation control. The margins bound by both the capability curve and the regulation limits are visually represented in Fig. 3.

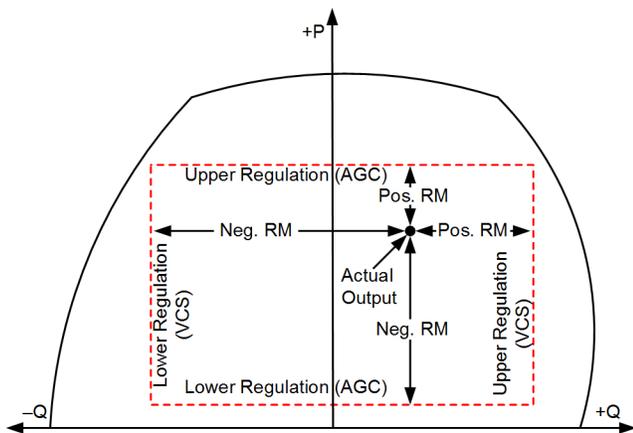


Fig. 3 Final Reserve Margins in the GCS

Calculated and selected RMs, shown in Fig. 3, are used internally during the aggregation and allocation process for island control. Regulation limits create a box, as shown in the

figure; however, the limits may be entered such that the box exceeds the capability curve. In this case, the RMs would be bound by the capability curve. A selection process is executed in the logic to use a specific boundary for the calculated reserves to represent reality.

The generator spinning reserve measurement is available to the GCS as an input from the turbine manufacturer. The GCS will calculate the turbine limit as the sum of the present active power and the spinning reserve. The GCS will then calculate the maximum capacity of each generator as the minimum between the operator-entered upper regulation limit and the turbine limit.

### 4) Load-Sharing Calculations

The equal percentage loading for the AGC system and VCS is calculated using the following equations:

$$\text{Total\_Capacity} = \sum_{i=1}^n \text{Generator\_Capacity}_{\text{GEN}_i} \quad (1)$$

Total capacity, as shown in (1), is equal to the summation of all generator capacity, where the generator capacity is the least of the following factors:

1. Operator-entered upper regulation limit
2. Generator capability curve
3. Turbine capability in MW sharing only

$$\% \text{Deviation} = \frac{\text{System\_Load} - \sum_{i=1}^n \text{Bias\_Point}_{\text{GEN}_i}}{\text{Total\_Capacity} - \sum_{i=1}^n \text{Bias\_Point}_{\text{GEN}_i}} \quad (2)$$

$$\text{Deviation}_{\text{GEN}_i} = \% \text{Deviation} \cdot (\text{Generator\_Capacity}_{\text{GEN}_i} - \text{Bias\_Point}_{\text{GEN}_i}) \quad (3)$$

$$\text{Power\_Request}_{\text{GEN}_i} = \text{Bias\_Point}_{\text{GEN}_i} + \text{Deviation}_{\text{GEN}_i} \quad (4)$$

where:

System\_Load is the total MW load of the facility.

Bias\_Point is the HMI operator-defined MW/MVAR set point.

From the previous equations, it is clear that the percentage of load sharing depends on the generator capacity and the MW/MVAR set point entered by the operator on the PMS HMI.

The AGC system and VCS automatically create new control arrangements for multiple-islanded systems. For example, if two islands exist, two completely autonomous solutions are required for active AGC/VCS control.

### 5) Generation Control System Functional Overview

The PMS GCS performs the following functions:

1. Supervises all signals with communications-quality indications.
2. Regulates the active and reactive power output of the generators to maintain the system frequency at nominal.
3. Remains operational and dynamically recalculates control set points under all system bus configurations.

4. Reselects the data source dynamically. The system will automatically select the most reliable data source for control.
5. Controls generation with an adaptive algorithm in response to all topologies related to its control.
6. Allows the control mode of each generator to be operator-selectable between disabled, maintained, and regulated.

#### *B. Frequency Control Philosophy*

Depending on the combination of breakers and switches, the system in the LNG facility can form individual islands. The frequency control philosophy depends on the number of generators in an electrical island. The governor will set the GTG units to droop mode before putting them in external load mode. The AGC system can control the frequency by keeping all generators in droop mode, or one of the generators can be manually placed in ISOC mode and the AGC system will control the remaining droop units to load-share with the ISOC unit.

The AGC system performs active power sharing among the droop units, taking into consideration the ISOC unit loading, to provide enough headroom to the ISOC unit for maximum disturbance rejection. This is accomplished by sending raise and lower power set-point commands to the GTGs in droop mode. Because the power output of the ISOC unit cannot be controlled directly, the AGC system will directly control the droop units, which indirectly maintains the output of the ISOC unit at an equal percentage loading or a lower percentage with the droop units. Keeping the ISOC unit near its optimal maintained set point maximizes the disturbance rejection abilities. This allows the governor of one unit to control the system frequency at exactly 50 Hz. Simultaneously, the droop units will share the remaining load as close as possible to the bias points set by the HMI. This is realistic because the droop units are not responsible for the final frequency control.

If all units are running in droop, the algorithm will monitor the frequency of the system. An increase in load causes a slight drop in frequency. This frequency decline will be arrested by the droop characteristic of the individual turbine governor, which dictates that the lower the frequency, the higher the power output. This causes the system to settle at a slightly lower frequency than nominal. As soon as the frequency declines, the PMS will begin to send raise signals to each generator; therefore, the droop line is biased to a higher power output for a given frequency and the system operates again at nominal frequency.

#### *C. Voltage Control System Philosophy*

The normal operating mode for the system is to set all generator exciters in the system to voltage control mode. The PMS HMI is set with each generator in regulated mode. This configuration allows the generation bus voltage to be completely controlled by the VCS. The VCS sends voltage raise and lower commands to each of the generation units, allowing each unit to maintain the 132 kV bus voltage while sharing 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, change the terminal

voltage on the generator and change MVARs through the generator step-up transformer. Therefore, what is interpreted by the exciter as a terminal voltage command to maintain the 132 kV will also share the MVAR output of the generator. The equitable sharing of MVARs is accomplished by setting each of the units with the same MVAR set points in the HMI. If one generator has a higher unit set point, it will share a larger percentage of the MVAR support than it would at a lower set point.

The VCS automatically creates new control arrangements for multiple-island systems. For example, if two islands exist, two completely autonomous solutions are required for active VCS control.

#### *D. Island Control System Functional Overview*

The PMS ICS performs the following functions:

1. Supervises all signals with communications-quality indications.
2. Detects electrical islands created by breaker and/or switch openings. The ICS successfully operates with any combination of generators connected to all combinations of the generation bus connections.
3. Shows in the HMI the total percent loading of all generators on that island.
4. Sends control operation messages that include information redundancy and shifting to provide data security and prevent false operations.

#### *E. Generation Control System Error Handling*

Several different types of failures are accounted for within the GCS. It is important to note that the GCS is designed so that it does not need to control every generator in the system to function. If a generator is unresponsive or has a loss of communication, the PMS GCS is limited in its capability to maintain the system. However, the GCS will continue to manage all remaining units under its control while maintaining the system integrity at the set parameters. The details of the different error compensation methods used by the GCS are outlined in the following subsections.

##### *1) Communications*

The PMS GCS dynamically tracks the health and communications status of all front-end processors, as well as the enabled status of the individual intelligent electronic devices (IEDs) to which they are connected. The GCS immediately recognizes a communications or equipment failure and sends an alarm to the HMI screen. The adaptive algorithm monitors the health of the IEDs used for data acquisition and control and reconfigures its solutions to account for the failure.

##### *2) Unresponsive Generator*

Expected system responses are monitored by the GCS. If the GCS does not detect the expected results or if the mode for the governor or exciter is not the expected mode, the system will flag that generator as unresponsive and display an error alarm. The alarm will also be automatically raised if the governor or exciter is in a different mode than expected. Once a generator has been flagged as unresponsive, it is removed

from the load-balancing algorithms by disabling either the AGC system or the VCS.

### 3) Data Acquisition Device Failure

Redundant gateways send the voltage and frequencies. If either gateway experiences a communications failure, or any other failure, the alarm signal will cause the GCS to automatically switch to the alternate gateway for both its frequency and its voltage source. A similar redundancy is used to receive the 52A and 52B contacts from the relays. A communications failure will cause the binary inputs of the other device to be used. If no frequency (AGC system) or voltage (VCS) from the generation busbar is present, the respective control will turn off.

### 4) Insufficient Capacity Warning

The ICS screen shows the total percent loading of all generators on an island. This must be monitored to ensure that the loading of the island does not become excessive and that an adequate margin is maintained. The ICS will generate an alarm if there is insufficient power to maintain frequency or insufficient MVARs to support voltage. If a generator has run out of capacity in either direction, the At Max Capacity alarm on the AGC system and VCS will illuminate.

### 5) Frequency and Voltage Warning

The frequency warning indicates when the steady-state frequency of the system falls below 49 Hz or rises above 51 Hz for a certain time. The voltage warning indicates when the steady-state voltage of the system falls below 0.9 per unit or goes above 1.1 per unit for a certain time. This alarm occurs when the MW/MVAR reserve margin for the island is completely used up and as a result, the frequency and voltage begin to fall.

### 6) Generation Control System Failure Indication

The input/output (I/O) modules at the generators each have an A-type contact (open in the quiescent state) that is held closed under normal operations. The health of the GCS is monitored, and the contact is opened if it detects a GCS failure. These contacts, which are wired in parallel between the redundant GTG interface, function such that if both I/O modules fail or communication from the GCS to both I/O modules fails, it will cause the contacts to open. Then, an input monitoring these contacts in parallel detects a control system failure to that specific GTG when both contacts open (the input wired to these contacts will be normally high and will alarm when low). These contacts are wired in parallel because the loss of a single I/O module GTG interface does not constitute a loss of control.

### F. Automatic Synchronization

This section describes the automatic synchronizer that was developed to synchronize islands formed in the LNG facility system. A total of 12 relays were used for automatic synchronization as shown in Fig. 1. The relay used for this application was programmed to perform the automatic synchronization via the synchronization logic (synchronizing/synchronism-check device [25A]) elements in the relay. The controls included local and remote initialization

of the automatic synchronization process and monitoring for alarms.

The automatic synchronization relay was used to track phase rotation, phase angle, frequency, and the voltage of one power system and to compare them to the frequency and voltage of another power system before allowing the circuit breaker to be closed.

The automatic synchronization relay system can also perform the following functions:

1. Inform the GCS about the status of the 25A (i.e., initiated, paused, aborted, or failed).
2. Display frequency angle margin, voltage magnitude difference, and frequency magnitude difference acceptance criteria for automatic close.
3. Provide a close fail alarm and indication if the controlled circuit breaker fails to close within an operator-settable time.
4. Provide a close lockout alarm and indication if the controlled circuit breaker opens within a specified time after a close.
5. Allow either bus to be the controlling unit depending on which units are in service. All voltage and frequency matching controls originate from the GCS.
6. Use two series relays for sync-check (25A) to increase the security of automatic synchronization. The automatic synchronization relay and supervisory relay are shown in Fig. 4.

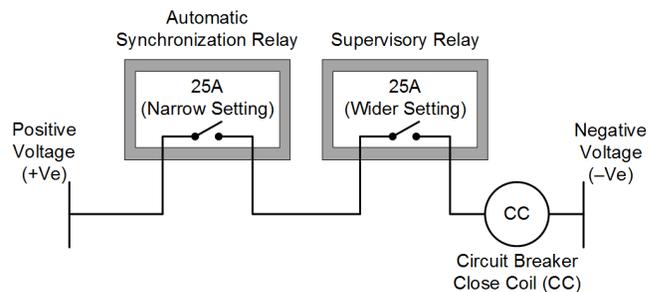


Fig. 4 Two Sync-Check Relays in Series

## IV. POWER MANAGEMENT SYSTEM LOAD-SHEDDING SYSTEM

After industrial systems are islanded from the utility, they will have a small inertia. Based on the system inertia and the response by the governor to arrest the frequency, the frequency decay might be very high and the protection for the generators might trip the generators before any underfrequency causes the necessary loads to shed.

The typical scenarios that might lead to underfrequency in the system include opening a generator, utility lines, or power-wheeling circuit breakers. Opening any of these breakers will create a power mismatch between the electrical power and the mechanical power. If the system loses its source of power, the frequency will start to go down and loads must be shed to balance the system again. The faster the load is shed, the faster the system will regain its balance [5].

The following subsections explain the different methods of load shedding that have been used in the LNG facility to rebalance the mismatch between the electrical and mechanical power within the system after disturbances. The section concludes with a summary of the technical and economic benefits of the load-shedding system.

#### *A. Contingency Load-Shedding (CLS) System*

CLS is the primary scheme that sheds load based on a predicted power deficit when a contingency occurs. Contingencies are defined as the opening of breakers that cause the loss of one or more power sources. This scheme sheds the total facility load to less than the calculated available capacity, based on the measured capacity. The calculation is done before a contingency occurs and includes the sum of the incremental RM (IRM) of the power sources in the remaining generators. This scheme only operates when a contingency breaker is opened under load.

The amount of load selected to shed is based on the system IRM. The IRM factor, in units of MW/Hz, is the amount of step-change in load required to result in a specific frequency change in the system.

For every scenario, the system predetermines the amount of load to shed. Calculations take into account the bus topology and available power that can be supplied from various sources. When the amount of load to shed is determined, loads (or load groups) are automatically selected for shedding based on bus connection and an operator-defined priority list. If the system detects an event requiring load shedding, load is shed according to the preselection logic. Load is shed via high-speed outputs from I/O modules wired directly to breaker trip coils. After a system event, logic will dictate how the system responds to subsequent contingency triggers.

#### *B. Underfrequency Load Shedding*

This scheme sheds load based on underfrequency thresholds. It sheds the amount of load predicted to correspond with levels of frequency excursion. This scheme backs up the primary load-shedding scheme by detecting frequency decay that would be caused by a contingency breaker opening and the CLS system failing to operate.

The underfrequency scheme is considered to be a centralized underfrequency LSS. This centralized style of load shedding serves to correct all known weak points of traditional underfrequency systems. These centralized schemes still shed load based on several underfrequency thresholds; however, the signals are sent from remote devices to a centralized processor.

Generator protection relays use the frequency relay (81) elements to advise the underfrequency-based load-shedding (UFLS) controllers when underfrequency thresholds have been crossed. The UFLS controller then declares an underfrequency event and selects an amount of load to shed based on the frequency response characteristic of the system. Each underfrequency level progressively sheds more load. If the system fails to recover and the next level is triggered via threshold detection, more loads are shed based on the set point.

This application runs on its own dedicated hardware. It serves as a backup for the contingency-based system in scenarios that involve a breaker opening without sending the system a trigger input (such as equipment failures, broken wiring, or shorted current transformer windings). There are many failures modes that might not be detected by the CLS system, such as a contingency in alarm, a GTG beginning to lose its output power due to bad quality natural gas, or a generator cool shutdown initiated.

Based on these issues, to protect the system it is recommended to always have another scheme that is based on the power system behavior (frequency based) as a backup scheme.

The UFLS accesses the same operator-defined priority list as the CLS system to dynamically select loads or generators that must be shed to equalize the generation to load balance. The UFLS also tracks the bus configuration to select loads associated with the underfrequency bus in advance of the contingency. If loads are triggered to be shed on the CLS system, an indication that these loads are already being shed will be sent to the UFLS; therefore, they are masked from selection in both controllers.

Power system real-time simulations are used to find the Level-1 and Level-2 pickup setting values to determine the underfrequency pickup and time-delay values used to initiate underfrequency contingencies. Power system simulations indicate the amount of load reduction required for each underfrequency contingency.

#### *C. Progressive Overload Shedding*

The PLS portion of the LSS code is treated as an overload contingency within the LNG facility system, similar to a contingency breaker being tripped [2]. However, instead of monitoring the breaker state, this contingency is asserted when the PLS integrator value exceeds an operator-settable value.

The PLS pickup starts when the power produced by a generator is higher than an operator-settable percentage of the individual generator capacity, which is referred to as excess load threshold. The PLS pickup time is proportional to the difference between this operator-settable threshold and the present output of the unit. The PLS also has a drop-down timer, so that a brief power output lower than the operator-defined set point will not cause the integrator to reset immediately. For example, a single generator rated at 36.4 MW at 27.3°C from the factory may be slightly derated because of ambient temperature; therefore, the actual capacity might be 34.00 MW. If the operator enters a value of 95 percent, the integrator will begin integrating when this single generator exceeds 32.3 MW of load. The lowest PLS setting will be coordinated with the GCS upper-limit setting. The PLS is supervised with underfrequency.

#### *D. Load Priorities Group and Load Pairs*

Priorities are set for each load by entering it into a specific load-shedding group. The operator can also assign priorities to the load-shedding groups. Once all loads within a load-shedding group have been selected to be shed for a specific contingency, the loads listed for the next sequential group will

be selected until the calculated power deficit is satisfied. In this case, loads can be grouped by priority such that the loads on the first action table will be the first to be shed. When no more loads can be selected from that list, the system begins selecting loads from the second list, and so on. These action tables allow the operator to have complete flexibility in defining the priority and grouping of loads to be shed; yet, provide optimal levels for selection of load shedding. The system at the LNG facility has a maximum of ten configurable action tables. Within the group, the operator can assign the same priority to different loads; therefore, loads with the same priority will be shed together.

An example load priority table is shown in Fig. 5. Note that the group load-shedding option priorities are limited to Numbers 1 through 10. Hence, each load-shedding option must have a unique, non-zero priority ranging from 1 through 10. The LSS sheds load with the smallest priority first. For example, a load set to Priority 1 will be shed first when compared to a load set to Priority 2, if both are available for shedding. If a load-shedding priority is set to zero, the load will be inhibited from being shed. Fig. 6 shows the flowchart for the LSS used in the LNG facility project.

Low-voltage switchgear is sourced from transformers that are connected to outgoing feeders in the medium-voltage switchgear. Low-voltage switchgear include a main-tie-main circuit arrangement with an automatic transfer scheme (ATS) functionality. The LSS is configured to always shed both medium-voltage breakers that are feeding a low-voltage switchboard. This ensures that the ATS does not cancel out the LSS action by bringing the shed loads back online.

Load-Shedding Group	Load	Load-Shedding Priority	Load 1	Load 2	Load 3	Load 4	Load 5	Load 6	Load 7	Load 8	Load 9	Load 10
LS 1	Load Group 1	1			1	1						
LS 2	Load Group 2	2	1	2								
LS 3	Load Group 3	3					1	2	2			
LS 4	Load Group 4	4										
LS 5	Load Group 5	5										
LS 6	Load Group 6	6										
LS 7	Load Group 7	7										
LS 8	Load Group 8	8										
LS 9	Load Group 9	9								1	2	
LS 10	Load Group 10	10										1

Fig. 5 Example of a Load Priority Table

**E. Variable-Frequency Drive Starting Inhibit**

At the LNG facility, starting inhibit logic was implemented for the variable-frequency drive (VFD) feeders at Substation-4 (see Fig. 1). The LSS calculates the effects of the export compressor VFDs that are added to the system. This is accomplished by comparing the rated MW value of these loads to the total spinning reserve available on the island to which they connect. If a load is rated higher than the total spinning reserve of the island that it will be connected to, the load inhibit signal is sent to the process controls system.

An override control button is provided on the HMI to override the inhibit signal from the PMS. If the motor does not start after 15 minutes, the override command automatically resets.

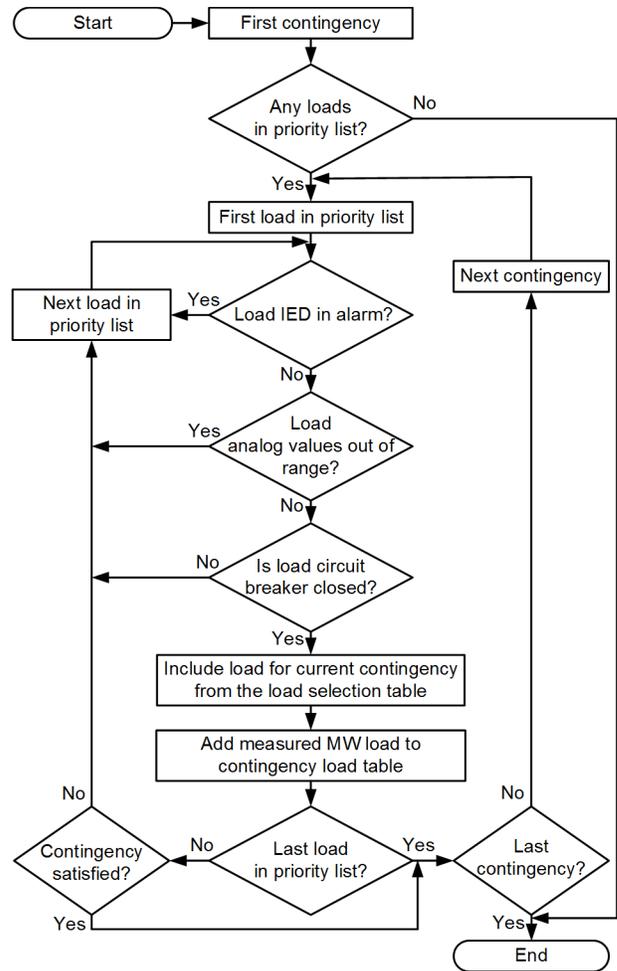


Fig. 6 LSS Selection Algorithm

**F. Summary of Technical and Economic Benefits**

Load-shedding schemes were incorporated in this LNG facility because they possess the following technical and economic benefits:

1. Maintain the island stability during any contingency event by fast CLS and with the backup UFLS scheme.
2. Prevent generators from overloading by using a PLS scheme, which also protects the assets by shedding loads.
3. Execute process-based priority shedding by load-shedding groups, in addition to different load pairs.
4. Track the topology of the system in real time to provide the correct load shedding in multiple islands.
5. Handle simultaneous or closely timed contingency events to reduce system blackouts.
6. Provide more reliability to the system by using a redundant controller.
7. Provide event reports for post-event analysis.

## V. REAL-TIME SYSTEM MODELING AND VALIDATION

Hardware-in-the-loop testing, using a real-time power system simulator [7], was adapted to test the PMS for the LNG facility. The real-time simulator was connected to the PMS controllers to form the hardware in the loop. The closed-loop validation of the PMS was accomplished during factory acceptance testing for the LNG facility project.

Fig. 7 shows two different scenarios for a GTG response to one expander generator tripping and the Underfrequency Level-1 being triggered. In both cases, two GTGs are running at 30 MW and the expander generator is running at 9 MW. The expander generator is tripped and the frequency response of the GTG is shown in Fig. 7. The first scenario occurred when one GTG was running in ISOC mode and the other was running in droop mode. The second scenario occurred when both GTGs were running in droop mode.

Underfrequency Level-1 was triggered at 47.5 Hz after 100 milliseconds. Approximately 20 MW was shed, and the ISOC unit controlled the frequency back to 50 Hz. There was no significant difference in either overshoot or undershoot for both curves.

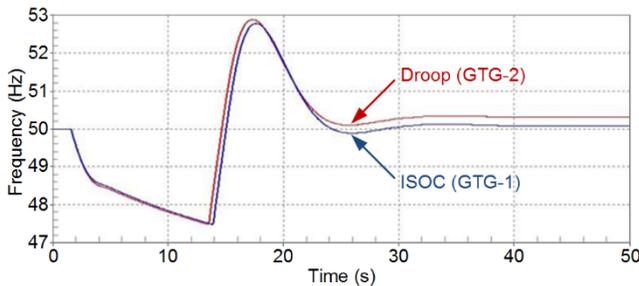


Fig. 7 Comparison of Droop Versus ISOC Response for Loss of 9 MW Expander Generator

Fig. 8 shows the electrical power response of the ISOC GTG-1 unit compared to the droop GTG-2 unit when a 9 MW expander generator was tripped and Underfrequency Level-1 was triggered.

The dynamic electrical power responses for both units are very similar. However, the steady-state settling power to the units is different. The droop unit returned to the original power set point, while the ISOC unit backed off to maintain the frequency.

An important note is that the expander generator was not part of the CLS system; therefore, the CLS system did not take any action for the event. The GCS redispatched the droop unit to an equal share with the ISOC unit, and after a few minutes, both units were sharing equally.

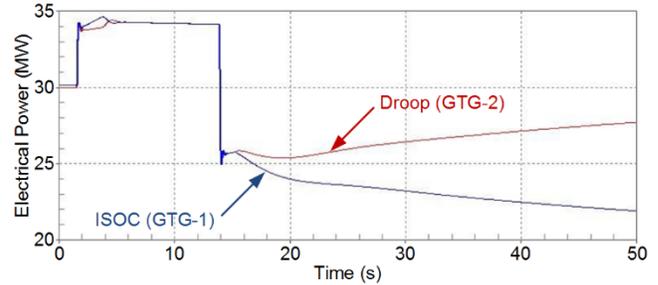


Fig. 8 Electrical Power Comparison of GTG-1 Unit Versus GTG-2 Unit for Loss of 9 MW Expander Generator and Level-1 Underfrequency

## VI. CONCLUSIONS

The PMS of an islanded system has many critical functions that protect the system and increase the reliability of the electric power system.

This project required a series of customizations of the CLS load group implementation and low-voltage ATS pair load shedding in addition to VFD start inhibit.

The GCS must maintain the voltage and frequency at all times at normal values. The GCS allows the LNG facility to operate using one ISOC unit or all droop units, based on the operator's selection. The modes of operation for the GTGs are implemented to provide flexibility to meet the characteristics of the LNG facility loads. The automatic synchronization system was also designed to synchronize all generators across the breaker-and-a-half scheme.

Hardware-in-the-loop simulation and testing were crucial methods to assess the PMS functionalities because the facility was a greenfield; therefore, it was impossible to perform any testing in the greenfield. The results of the hardware-in-the-loop simulation provided great confidence to the operators and engineers of the working PMS.

## VII. NOMENCLATURE

25A	Synchronizing/synchronism-check device.
81	Frequency relay.
P	Real power.
Q	Reactive power.
-Ve	Negative voltage.
+Ve	Positive voltage.

## VIII. ACKNOWLEDGEMENT

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