Ushering in a New Era of Power Management for a Centenarian Oil Field

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USHERING IN A NEW ERA OF POWER MANAGEMENT FOR A CENTENARIAN OIL FIELD

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Abstract—This paper presents a state-of-the-art power management system that was commissioned for an energy corporation at its central California oil field. This field consists of several reclosers dispersed over a wide geographic area. The electrical power requirements of the plant are met by 3 cogeneration plants, comprising 8 generators with a total installed capacity of around 25 MW and 1 utility tie-line connection. In the event of a disruptive blackout, the consequent downtime results in the loss of critical production and revenue, which necessitates a solution involving a smart and high-speed power management system. The power management system solution consists of load-shedding schemes that are contingency-based, underfrequency-based, progressive-based, and wireless radio-based. The solution also includes systems for supervisory control and data acquisition, automatic generation control, voltage control, islanding control, tie-line control, and advanced automatic synchronization. Additionally, there is a high-speed generation-shedding system that sheds excess generation to prevent generators from dropping under the environmental (NO_x) emissions limit. This power management system has been commissioned successfully and has been in service since September 2019.

This paper discusses different power management system capabilities, design philosophy, communications architecture, data flow, hardware-in-the-loop testing using a real-time, transient-level computer model of the power system, onsite lessons learned, field implementation, and real-time events that have occurred since the commissioning of this system.

Index Terms—HIL, load-shedding system, simulation, generation control system, commissioning, generation-shedding system.

I. INTRODUCTION

An energy corporation is managing several oil fields in California to meet the energy demands of the state. One field has been in service for more than 100 years and stood to vastly benefit from modernization of its power management system (PMS) via smart grid technologies. The energy corporation wanted to transition this field to a modern state-of-the-art PMS which can provide uninterrupted features, such as central human-machine interface (HMI)-enabled supervisory control and data acquisition (SCADA), high-resolution power monitoring, high-speed load shedding, high-speed generation shedding, a generation control system, autosynchronization (25A), and automatic import and export tie-line control. These PMS functionalities are supported by a resilient network backbone. Fig. 1 represents the one-line diagram of the oil field. Typically, the field is connected to the 115 kV utility tie line via Breaker 2 (Breaker 3 is normally open) and is usually exporting power to the utility's grid [1]. There are 3 cogeneration substations comprising 8 generators, each unit producing around 2.9 MW. When the system is connected to the utility, all the generators operate in droop mode, but when it is islanded from the utility, G1 through G4 operate in droop mode and G5 through G8 operate in isochronous mode. The electrical power is distributed from the generation to the loads via reclosers, which do not perform traditional reclosing but instead operate like circuit breakers with relay protection functionality and receive commands for high-speed load shedding from the PMS controllers.

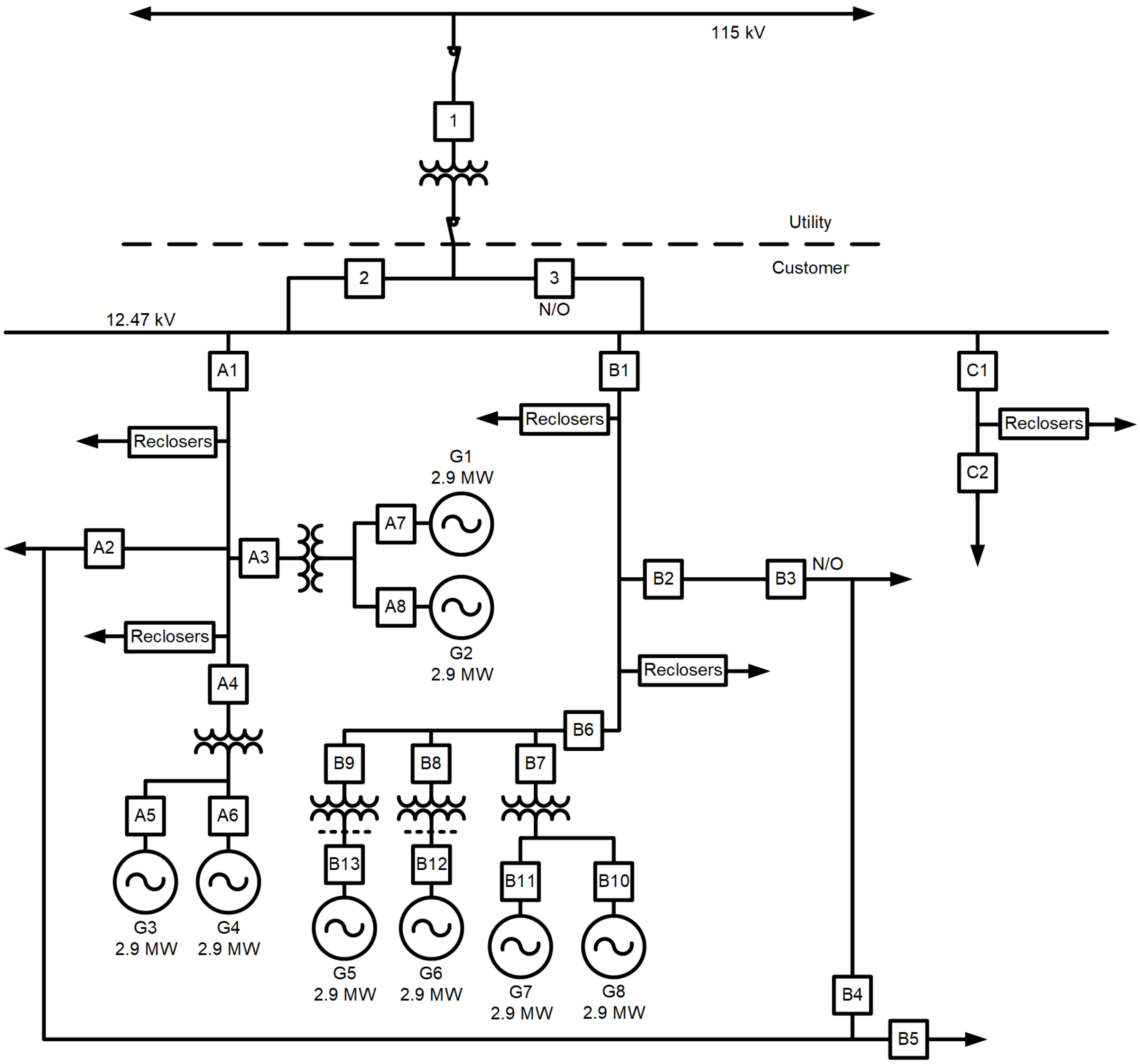

Fig. 1 One-Line Diagram

II. COMMUNICATION OVERVIEW

As mentioned earlier, a robust network is necessary to enable the several PMS functionalities that protect this power system. The flexibility of Ethernet networks was leveraged, and several protocols, such as IEC 61850 Generic Object-Oriented Substation Event (GOOSE), Network Global Variable List User Datagram Protocol, Mirrored Bits communications, Distributed Network Protocol (DNP3), and Modbus, were implemented to enable the different types of data transfer across different devices. This is illustrated in Fig. 2. These protocols can be separated into high speed and slow speed based on their application. High-speed protocols were implemented exclusively for load-shedding purposes, whereas slow-speed protocols were implemented for SCADA monitoring and control [2].

A. High-Speed Protocols (Load Shedding)

1. IEC 61850 GOOSE was used between the substation data concentrators and the input/output (I/O) modules and reclosers in the field.
2. Mirrored Bits communications was used between the data concentrators and the serial radio reclosers. (Radios installed in this field along with Mirrored Bits protocol helped minimize the cost of laying fiber across large distances.)
3. The Network Global Variable List was used between the controllers and data concentrators.

B. Slow-Speed Protocols (SCADA)

1. DNP3 was used between the substation data concentrators and the I/O modules, relays, and reclosers in the field.
2. Modbus was used between the substation data concentrator and the generator programmable logic controllers.

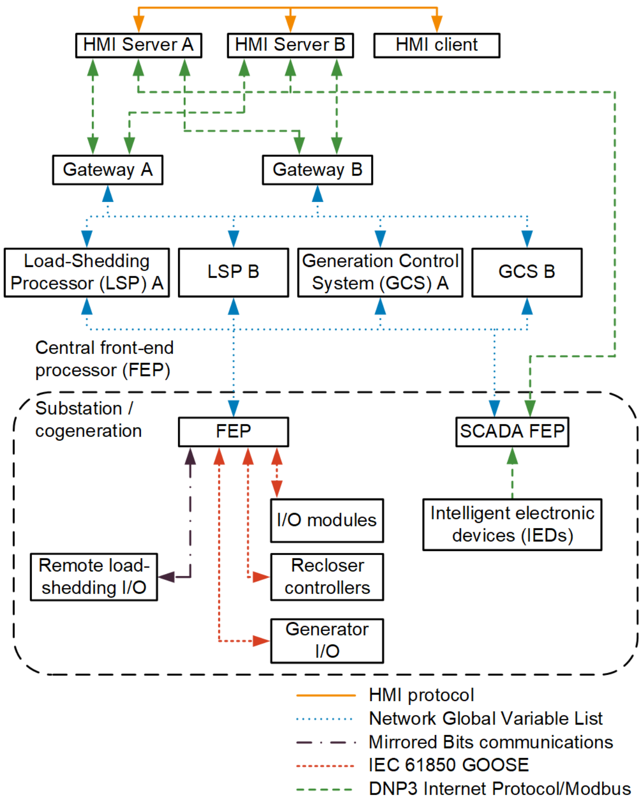

Fig. 2 Data Flow Diagram

III. LOAD SHEDDING

Prior to PMS installation, this site had existing power system protection in place, to protect its individual assets, such as generators and transformers, and trip breakers when needed. But these protection philosophies are not sufficient to prevent potential scenarios that result in a system-wide blackout. This necessitates a secondary level of protection that steps in after the primary protection has acted. High-speed load shedding is one such example.

Whenever a power system protection event trips open a generator or a utility breaker serving power to an electrical island, the PMS detects that event (also defined as a contingency) and immediately trips sheddable load breakers (in order of defined priorities) within the same island as the contingency, thereby correcting the electrical generation-load imbalance to restore the nominal frequency. There are three different types of contingencies handled by the three different algorithms in the PMS controller. The algorithms serve different purposes (explained in detail in the following paragraphs) but have a common goal of achieving power system stability via load shedding.

A. Contingency-Based Load Shedding (CLS)

This is the primary form of load shedding in the PMS controller, and this algorithm defines a contingency as the opening of any power-wheeling breaker. The deficit calculation to rebalance the plant load and available generation capacity is performed before the contingency occurs. To minimize the total amount of load to shed, this calculation includes the sum of all the applicable incremental reserve margin (IRM) from remaining power sources (generators or utility tie), which can instantaneously contribute to the loss of power.

Since the controller runs these calculations before the event occurs, the operators can always see if there is sufficient load, as well as which loads the controller has selected on a priority basis. If there is not sufficient plant load to balance the loss of power, an alarm indication will be raised on the HMI. This allows operators to take corrective action as needed and prevent continued operation in a state that could potentially cause a blackout. Table I lists all the CLS contingencies that were defined for the oil field.

TABLE I
CLS CONTINGENCIES

Contingency Number	Breaker Type	Breaker Number
1	Generator	A5
2	Generator	A6
3	Generator	A7
4	Generator	A8
5	Generator	B10
6	Generator	B11
7	Generator	B12
8	Generator	B13
9	Utility tie	2
10	Utility tie	3
11	Bus coupler	B9
12	Bus coupler	B8
13	Bus coupler	A1
14	Bus coupler	B1
15	Bus coupler	C1
16	Bus coupler	A3
17	Bus coupler	A4
18	Bus coupler	B7
19	Bus coupler	B6

NOTE: This table includes critical contingency breakers, such as B6, the tripping of which can cause the loss of an entire cogeneration substation.

B. Underfrequency-Based Load Shedding (UFLS)

The UFLS contingency is defined as an underfrequency trigger that is generated due to a drop in power system frequency. The relays that monitor the bus frequency trigger load shedding when the frequency falls below set thresholds for a predetermined time period. These underfrequency levels indicate system instability due to a mismatch between load and generation, resulting in the need to shed load.

This type of load shedding only occurs when the electrical system is islanded from the utility. This scheme also acts as a backup to the primary CLS scheme, which might be ineffective due to wiring issues, field alarms, incorrect HMI set points, disabling of controller, etc.

Table II lists UFLS contingencies that are set up for this field.

TABLE II
UFLS CONTINGENCIES

UFLS Contingency	Generator	Levels
1	G1	L1, L2
2	G2	L1, L2
3	G3	L1, L2
4	G4	L1, L2
5	G5	L1, L2
6	G6	L1, L2
7	G7	L1, L2
8	G8	L1, L2

C. *Progressive-Based Load Shedding (PLS)*

While the CLS and UFLS schemes are implemented to quickly respond to a load-generation imbalance, the PLS is set up differently. The PLS scheme responds when an asset exceeds its currently defined power threshold limit.

This can be applicable to either a utility breaker that has import limits in place or a generator breaker with a limit on its production.

This scheme is based on an integration function that works like an inverse overprotection curve, wherein the time it takes between the firing of the contingency and the shedding of the load is inversely proportional to the amount by which the asset is overloaded [3].

The equation for seconds to shed is as follows:

$$\text{Seconds to shed} = \frac{\text{Integrator threshold}}{\left(\dfrac{\text{Present power}}{\text{Base power}} - \dfrac{\text{Integration pickup}}{100}\right)} \quad (1)$$

Table III lists PLS contingencies that are set up for this oil field.

TABLE III
PLS CONTINGENCIES

PLS Contingency	Breaker Type	Asset
1	Generator	G1
2	Generator	G2
3	Generator	G3
4	Generator	G4
5	Generator	G5
6	Generator	G6
7	Generator	G7
8	Generator	G8
9	Utility breaker	2
10	Utility breaker	3

D. *Load-Shedding Priority-Based Selection*

All load-shedding actions within the PMS controller use a priority-based selection. Loads that have their priorities set to zero are inhibited from shedding. Loads with lower numerical priorities are selected for shedding first, beginning with one and proceeding until the total amount of load selected for shedding is greater than or equal to the amount of load needed for shedding [4].

IV. GENERATION SHEDDING

The primary purpose for a generation-shedding algorithm is to maintain the unit output at a greater level than the minimum threshold after a contingency. The minimum unit threshold for the generators at this field is around 800 kW and is based on environmental NO_x relay protection limits that are factored into the generator relays. By keeping the power above this limit, generators can be kept online after islanding and thus prevent system-wide outages (blackouts).

The secondary goal of this system is to minimize high-frequency disturbances to generation after islanding because of excessive generation compared to the loads in the island during these shedding events.

Table IV lists generation-shedding scheme (GSS) contingencies that are set up for this field.

TABLE IV
GSS CONTINGENCIES

GSS Contingency	Asset Type	Breaker Number
1	Utility tie	2
2	Utility tie	3
3	Bus coupler	A1
4	Bus coupler	B1
5	Bus coupler	C1
6	Generator underloading	G1–G4
7	Generator underloading	G5–G8

Fig. 3 shows a high-level flow chart depicting the GSS algorithm in the controller.

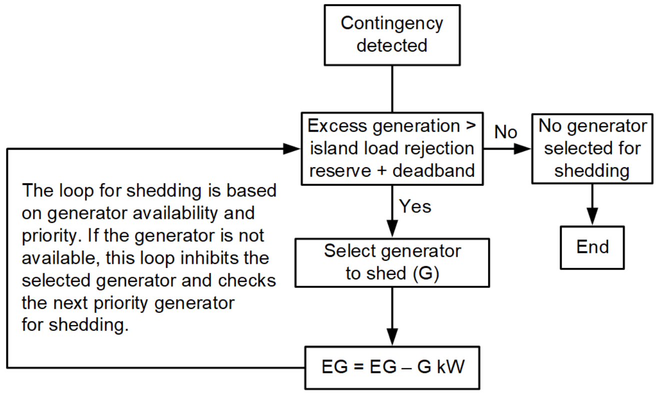

Fig. 3 Generation-Shedding Logic Flow Chart

NOTE: While the first five GSS contingencies listed in Table IV are triggered upon opening of the breaker, the last two contingencies are triggered as soon as the electrical loading on the island approaches the total sum of the minimum generation within a predefined threshold.

V. GENERATION CONTROL SYSTEM

While the load-shedding system is called into action primarily whenever a contingency happens, the generation control system is constantly monitoring the field and sending digital raise and lower pulses to all the participating generation units to actively support different functionalities, such as voltage and frequency control, 25A, utility tie-line control. These different components are listed in detail in this section.

A. Island Control System (ICS) Modes of Operation

The ICS detects if the field has been disconnected from the utility. If it has been disconnected, the ICS instantly sends a control command to the affected generation units, changing their modes and enabling seamless operation. The ICS is also able to detect the different electrical islands that might have been created across the field and maintain the nominal frequency and voltage in those islands by pulsing only those generation units accordingly.

There are three scenarios with different modes of operation for this system, as illustrated in Table V.

TABLE V
MODES OF OPERATION

Asset	Utility Connected	No Utility Connected (2 Islands Scenario)	No Utility Connected and Autosync Initiated
Governors G1–G4	Droop mode	Droop mode	Droop mode
Exciters G1–G4	Power factor (PF) set point	Voltage mode	Voltage mode
Governors G5–G8	Droop mode	Isochronous sharing	Isochronous sharing
Exciters G5–G8	PF set point	Voltage mode	Voltage mode

NOTE: When the oil field is islanded from the utility, there are two possibilities.

1. If G1–G4 and G5–G8 are electrically connected, then the frequency of the island is maintained by G5–G8 units in isochronous sharing mode.
2. If they are in separate islands, the PMS controller maintains the frequency for the G1–G4 island and G5–G8 remain in isochronous mode, maintaining the frequency on their island.

B. Automatic Generation Control (AGC)

The AGC algorithm dispatches the governor of the generating units by sending digital pulses and takes care of the following functionalities:

1. Controls real power flow (kW) across the utility tie
2. Dispatches the frequency set point to chosen generators during 25A
3. Dispatches raise and lower pulses to governors in droop mode to perform load sharing and maintain nominal frequency
4. Dispatches raise and lower pulses to governors in isochronous mode during 25A

C. Voltage Control System (VCS)

The VCS algorithm dispatches the exciter of the generating units by sending digital pulses and takes care of the following functionalities:

1. Controls reactive power flow (kVAR) across the utility
2. Dispatches voltage raise and lower pulses to chosen generators during 25A
3. Dispatches raise and lower pulses to exciters in droop mode for load sharing and maintaining nominal value within a plant-specified deadband
4. Dispatches the PF set point to the generators in grid-connected operation

D. 25A System

As the name indicates, the 25A system helps automatically synchronize different electrical islands to each other or automatically synchronize the whole field as an island to the utility. Whenever 25A is initiated across the chosen breaker, the controller measures the frequency, voltage, and angle across the two islands on either side of the breaker and sends correction pulses to the governor and exciters of the participating generators, thereby actively reducing the slip. The synchronization criteria are as follows:

1. Angle difference: ±10 degrees
2. Voltage difference: 0 to 5 percent
3. Slip: ±0.05 Hz

Once the power system parameters come within the synchronization window, the relay closes the sync contact and breaker close is achieved. This is an efficient, unattended, and safe way to synchronize across different electrical islands [5].

Table VI lists the four breakers that were chosen for the 25A system in this project.

TABLE VI
25A BREAKERS

25A Breaker No.	Breaker Type	Breaker No.
1	Utility tie	2
2	Utility tie	3
3	Bus coupler	A1
4	Bus coupler	B1

There are four possible operating 25A scenarios, as shown in Fig. 4, Fig. 5, Fig. 6, and Fig. 7. Open breakers are shown as solid green breakers and closed breakers are shown as striped red breakers. The following figures do not show the full system (which can be found in Fig. 1). They show only the relevant aspects of the system.

1) Field Islanded From Utility—Breaker 2 Synchronization

Preconditions: Breakers 2 and 3 are open. Breakers A1 and B1 are closed and connected to each other, as shown in Fig. 4. G1–G4 units are in droop mode. G5–G8 units are in isochronous mode.

Scenario: When 25A is initiated across Breaker 2, the PMS controls the G1–G4 units in droop mode as well as the G5–G8 isochronous units to match the voltage and frequency of the utility. Once Breaker 2 is closed, the G5–G8 units are dispatched to droop mode.

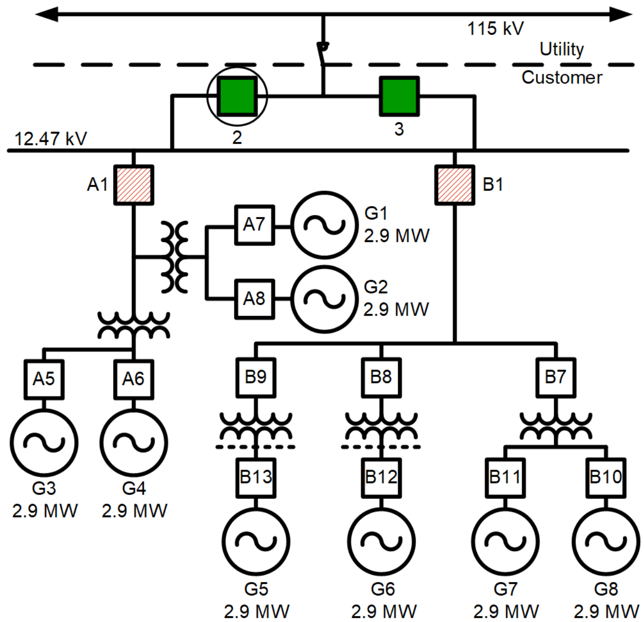

Fig. 4 25A Across Breaker 2

2) Field Islanded From Utility—Breaker A1 Synchronization

Preconditions: Breakers 2 and 3 are open. Breaker A1 is open. G1–G4 units are in droop mode. G5–G8 units are in isochronous mode, as shown in Fig. 5.

Scenario: When 25A is initiated across the A1 breaker, the 25A system controls the available G1–G4 droop units to match the voltage and frequency of the B1 isochronous island. Once Breaker A1 is closed, G1–G4 stay in droop mode and G5–G8 remain in isochronous mode and maintain the island frequency.

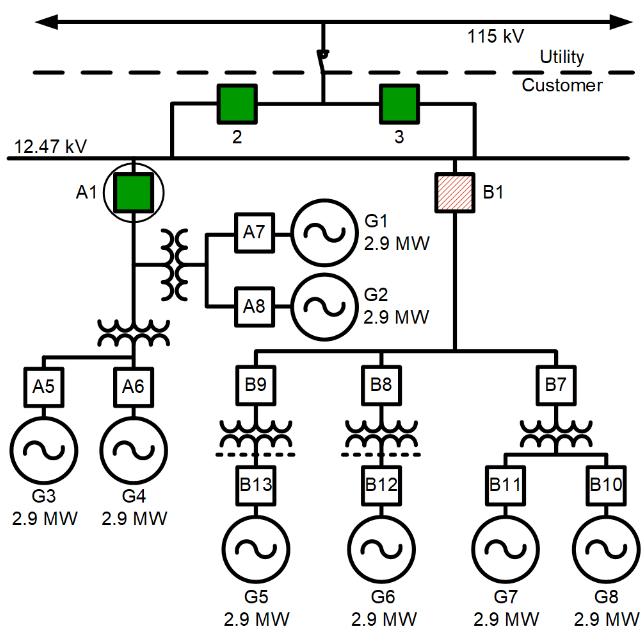

Fig. 5 25A Across Breaker A1

3) Field Connected to Utility—Breaker A1 Synchronization

Preconditions: Breaker 2 is closed. Breaker A1 is open. Breaker B1 is closed to the utility, as shown in Fig. 6.

Scenario: When 25A is initiated across the A1 breaker, the controller controls the available G1–G4 droop units to match the voltage and frequency of the utility.

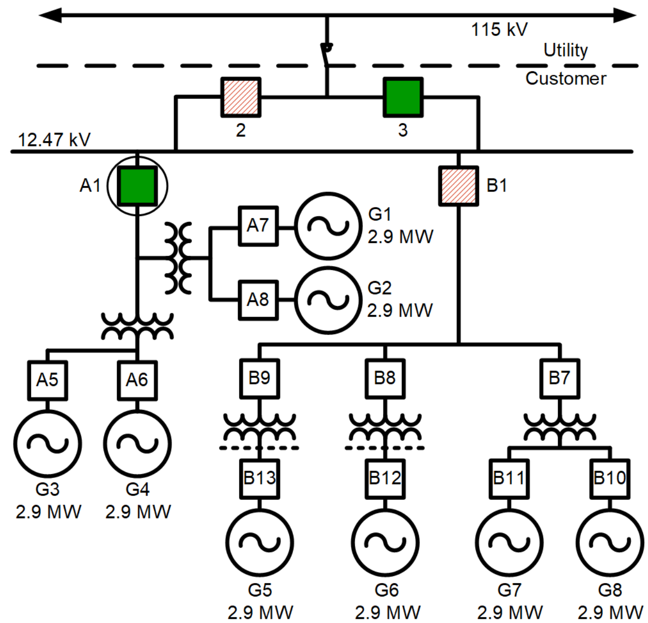

Fig. 6 25A Across Breaker A1

4) Field Connected to Utility—Breaker B1 Synchronization

Preconditions: Breaker 2 is closed. Breaker A1 is closed to the utility, as shown in Fig. 7. Breaker B1 is open.

Scenario: When 25A is initiated across the B1 breaker, the controller controls the available G5–G8 isochronous units to match the voltage and frequency of the utility. Once Breaker B1 is closed, the G4–G8 units are dispatched to droop mode.

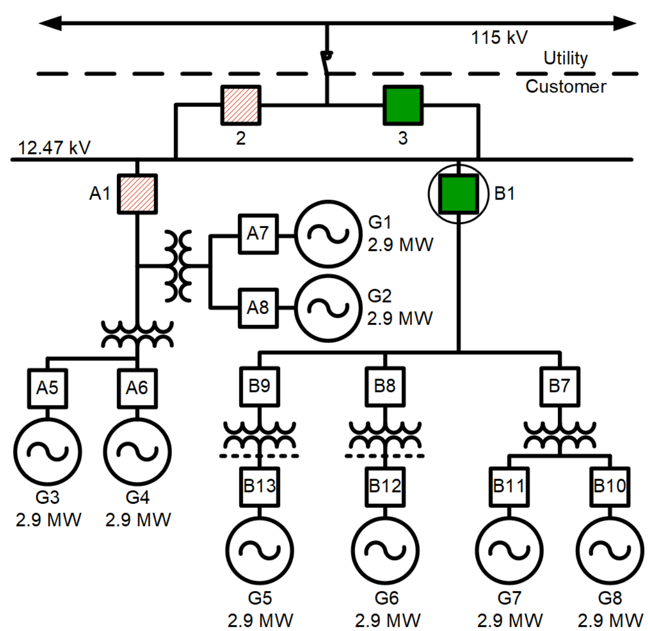

Fig. 7 25A Across Breaker B1

TABLE VII
UTILITY EXPORT AND IMPORT CONTROL

	Status						Set Points			
Tie Breaker	**Breaker Status**	**kW Control Mode**	**kVAR Control Mode**	**Real Power (kW)**	**Reactive Power (kVAR)**	**Selected Set Point**	**Peak (kW)**	**Off Peak (kW)**	**Partial Peak (kW)**	**Super Off Peak (kW)**
Circuit Breaker 2/3	Closed	Enabled	Disabled	1,000	–500	1,000	1,000	1,200	800	1,400

E. Export and Import Control

Based on the date and time of day, the controller automatically selects the kW and kVAR set point from the HMI and sends raise and lower pulses to the participating generators, which brings the utility import and export power values to within an acceptable range of the user-defined set point.

A day is divided into four periods with varying rates for buying and selling power: peak demand, partial peak, off peak, and super off peak. The controller factors in these different time periods and changes the set points automatically, which helps lower the annual utility bills for the field by buying and selling power when it is most economically feasible.

Table VII depicts the different set points and statuses.

VI. REAL-TIME DIGITAL SIMULATION

The PMS controller has been tested via a hardware-in-the-loop (HIL) setup using a real-time digital simulator (RTDS). HIL is the best platform to test control systems, such as PMS, which can encounter critical scenarios that are difficult to replicate and test in an existing operational oil field [6]. HIL is the key to reducing the inherent risks of operating an oil field by testing all possible cases in a lab environment. The following cases and associated plots demonstrate the importance of PMS and the system response when subjected to contingency events.

A. Case 1: CLS Versus UFLS

This case demonstrates the power system response when CLS and UFLS individually respond to the loss of utility connection when importing power.

Preconditions: The field is importing 3.3 MW from the utility via Breaker 2 and six generators are in operation (G1 and G3 are out of service). The frequency of the island is at nominal 60 Hz. The total sum of IRM from the six generators equals 0.8 MW. Hence the load Required to Shed (RTS) for a Breaker 2 contingency is RTS = Import MW – IRM = 3.3 – 0.8 = 2.5 MW.

Scenario: When the utility breaker opens, the CLS instantaneously trips four loads (based on priorities 1–4) with Selected to Shed (STS) totaling 3.9 MW. The system prevents a blackout with the frequency dipping only to 59.24 Hz. When the same scenario is repeated with CLS disabled (to mimic conditions such as alarmed breaker, communications issue, etc.), the UFLS is triggered once the frequency hits Levels 1 and 2 and sheds loads as per predetermined RTS values of 0.5 MW and 1 MW for Levels 1 and 2, respectively. The STS values are 1 MW and 1.5 MW. The total loads shed are Loads 1 through 4, which are the same loads shed using CLS.

It is clear from Fig. 8 that the frequency response of CLS is much faster than UFLS scheme. The minimum frequency that the power system dipped to and the round-trip times (including 5-cycle breaker operation) are listed in Table VIII. Note that this figure demonstrates the difference between having a CLS versus not having a CLS. This might not be the exact frequency response in the field since this RTDS model was developed using a generic governor and exciter. (Replicating the actual governor and exciter model from the field was outside the scope of this project.)

TABLE VIII
FREQUENCY AND ROUND-TRIP TIME COMPARISON

	Minimum Frequency (Hz)	Load Trip Time (ms)	Level 1 Load Trip (ms)	Level 2 Load Trip (ms)
CLS	59.24	111	—	—
UFLS	57.57	—	465	849

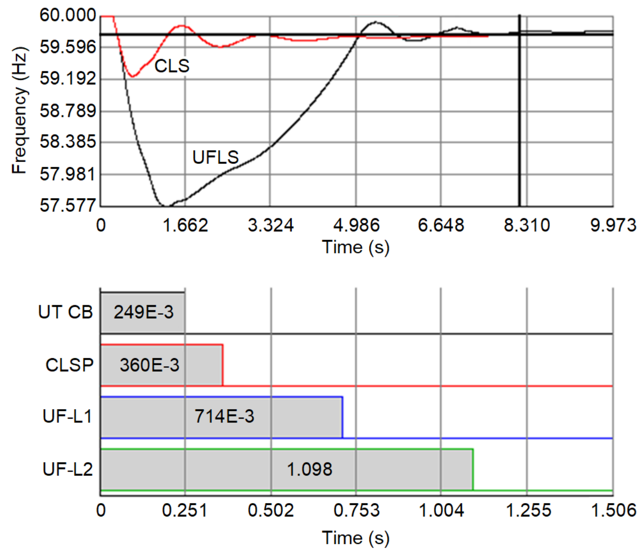

Fig. 8 Frequency Response of CLS Versus UFLS

B. Case 2: GSS

This case demonstrates the power system response when GSS responds to a trip of the A1 breaker when it is exporting 6.4 MW.

Preconditions: The electrical power system is exporting 6.4 MW across A1, and G1–G4 are producing 2.7 MW each and are programmed with the same droop value. The generators have a minimum power output set by environmental requirements to stay above 1.2 MW. In the absence of GSS, if A1 were to open, each generator's power output would dip to 1.1 MW equally (2.7 – 6.4 / 4), which is shown in Fig. 9, and instantly trip due to environmental limit-based protection settings.

Scenario: When A1 opens, GSS sheds G1 (as per priority) instantaneously and helps the power system prevent a blackout. The GSS calculation is as follows:

Reserve available from each generator = 2.7 – 1.2 = 1.5 MW.

Total reserve = 1.5 • 4 = 6 MW.

Since this is less than the current export of 6.4 MW, the GSS selects one generator (G1) to trip and has a 4.5 MW margin from the remaining three units (1.5 • 3).

Now RTS = 6.4 – 4.5 = 1.9 MW and STS = 2.7 MW.

The power left after shedding one generator = 6.4 – 2.7 = 3.7 MW, which is split equally between the remaining three generators; they run at 1.47 MW each (2.7 – 3.7 / 3), which is shown in Fig. 9.

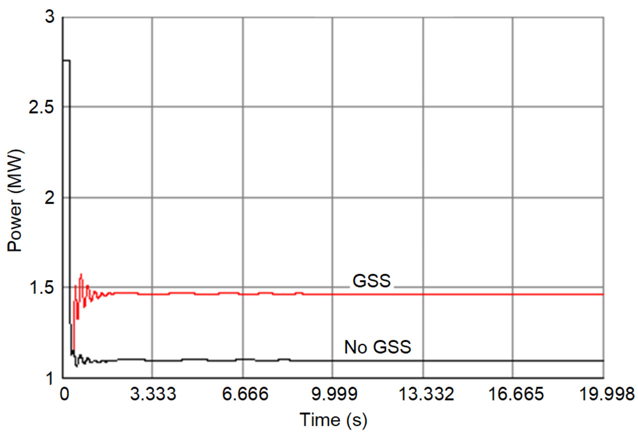

Fig. 9 Generator Output With GSS Versus Without GSS

In addition to preventing a blackout caused by environmental limit protection settings, GSS also helps with stabilizing overall island frequency after A1 opens (as seen in Fig. 10). The maximum frequency excursion without GSS is 66.26 Hz, and with GSS, it is 64.58 Hz. Note that this figure demonstrates the difference between having a GSS versus not having a GSS. This might not be the exact frequency response in the field since this RTDS model was developed using a generic governor and exciter. (Replicating the actual governor and exciter model from the field was outside the scope of this project.)

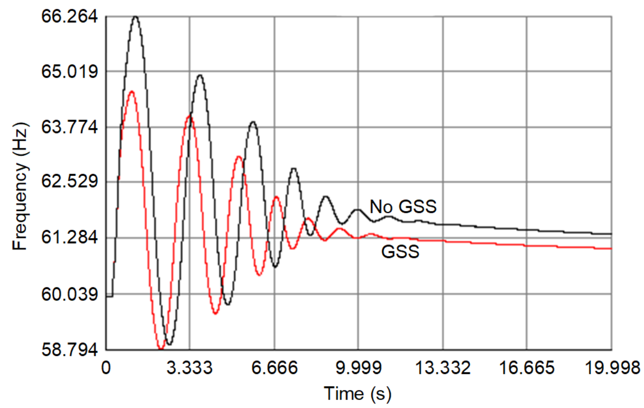

Fig. 10 Generator Frequency With GSS Versus Without GSS

VII. SYSTEM PERFORMANCE (INSIGHTS FROM THE FIELD)

The PMS was commissioned successfully and placed in service on September 30th, 2019. This technology has not only modernized the existing power system, but with minimal training for operations personnel, it has made daily work activities much more efficient and optimized. Some of the observed tangible and intangible benefits are listed as follows.

A. Reduction in Power Restoration Time

This oil field consists of several overhead medium-voltage lines that all together are hundreds of miles long and associated equipment, which incur some expected challenges and issues. There are, on average, 12 power outages each year, which result in substantial lost production. Most of these outages are due to factors, such as weather, fauna, and old infrastructure, which are outside of the operator's realm of control. While these outages are hard to prevent, the ability to respond to these outages was greatly improved with the PMS. Statistical data showed that the power restoration time dropped by 60 percent after this PMS was commissioned, as shown in Fig. 11. This, in turn, translated to a considerable reduction in lost production associated with such outages.

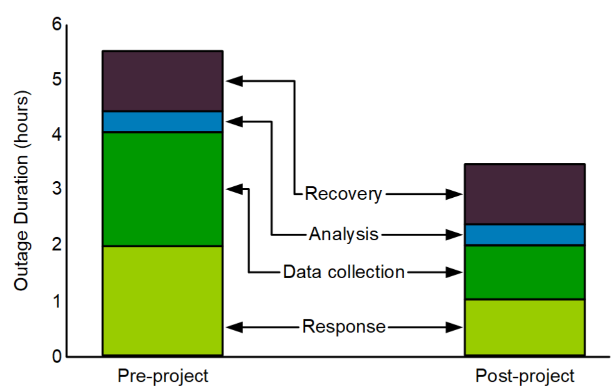

Fig. 11 Outage Composition Times Pre- and Postcommissioning

B. Scalability With Implementing Add-On Features and Schemes

After the PMS was commissioned, updates were performed at different time intervals to implement new features with rapid deployment time. A typical implementation for some of these features, which might have taken 6 months in the past, was now deployed within 30 days, utilizing the existing infrastructure backbone in place. Some examples of the functionalities added in this manner are listed as follows:

1. Spill prevention schemes
2. System health monitoring
3. Automatic transfer schemes

C. Separation and Synchronization to Grid

The PMS makes separation and resynchronization to the utility (traditionally intense activities) easy, efficient, and secure. Before separation, the operator can first ensure minimal power flow across the utility breaker by using the export or import functionality and then resynchronizing at any time using the 25A functionality on the HMI. The total time pertaining to grid synchronization was reduced from hours to seconds, roughly translating to a 75 percent reduction in mobilization and manpower requirement for such synchronization activities.

D. Data Collection

The PMS has enabled access to thousands of data points across the field, which provide insight into the whole electrical system. With these data, operators can go the extra mile in understanding the electrical system and better maintain the field in myriad ways:

1. Find bottlenecks and impending failure points in the system.
2. Enhance proactive maintenance, such as critical dc system health monitoring and circuit overloading creep alarms.
3. Analyze power quality.
4. Derate and visualize real-time generation capability.
5. Monitor breaker wear.

E. Workflow Optimization

This system helped the energy corporation optimize their existing manpower and operating workflow by offering intangible benefits, such as:

1. Remote operation, which enables a reduction in manpower and creates a safer workplace by minimizing personnel contact with energized equipment.
2. Cogeneration controls available from a centralized location.
3. A reduction in labor time associated with routine inspection of assets.
4. The automation of real and reactive power tie-line export control.

F. Success Stories

1. The remote monitoring capability allowed an offsite protection specialist to spot an anomaly in the sync-check system during a system inspection performed in the 25A procedure. If it had not been spotted, it could have potentially resulted in an out-of-sync breaker closure for eight gas turbine generators and damage to equipment.
2. Online dissolved gas analysis (DGA) monitoring of a key power transformer (which was integrated along with the SCADA monitoring and control as referenced in Fig. 2) helped system owners catch the sudden creep of transformer oil gas within a week’s time frame. This would not have been possible with the regular annual, manual DGA sampling and analysis.
3. An accurate generator response capability was developed using a high-speed real-time data sampling system to fine-tune the load-shedding system. This is not possible with old systems that have few documents and little data associated with them.

VIII. CONCLUSIONS

This paper describes the different components of PMS, which were implemented to modernize an existing oil field, and the testing setup that was used to validate these schemes across different possible scenarios. The RTDS plots also demonstrate the importance of multiple algorithms working in synergy to not only avoid a blackout but to do so with minimal interruptions to the process. While the CLS, UFLS, PLS, and GSS are programmed to respond to critical contingencies that might threaten a blackout, the generation control system, on the other hand, constantly maintains the voltage and frequency of the plant while also assisting with different 25A scenarios and utility tie-line import and export requirements. The PMS was successfully commissioned, and over the past three years of being in service, it has proven itself several times, as evidenced by data validation from the end user site, including metrics that show the difference that PMS has brought to the oil field.

IX. ACKNOWLEDGEMENTS

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