Microgrid Control System Protects University Campus From Grid Blackouts

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***Abstract*—Today's microgrid controls are designed to maximize generation availability, preserve critical loads, and ensure system stability. Microgrids are also capable of autonomous operation during a loss of utility or intentional islanding during grid disturbances. Such autonomous operation requires sources that can provide primary frequency and voltage regulation within the microgrid system. Additional controls also use optimization algorithms for saving costs, improving efficiency, and maximizing green energy usage. The University of California San Diego (UC San Diego) is a world-class research university with an advanced campus electrical utility system. The university's microgrid system consists of a diverse generation and load portfolio. This paper discusses details of microgrid monitoring and control system (MMCS) components implemented for UC San Diego, such as contingency-based load shedding, frequency-based load shedding, peak shavings, synchrophasor-based islanding detection and decoupling, high-speed generator switching, adaptive protection systems, and automatic synchronization with an overview of the overall system architecture. The paper also presents the dynamic performance of the MMCS during hardware-in-the-loop (HIL) testing with a real-time and dynamic digital simulator, and how the MMCS protects the UC San Diego system from blackouts, supports the islanded operation, and performs resynchronization to the grid.**

The paper also presents the efforts put into the modeling and simulation of the campus microgrid, its benefits for system validation, and commissioning using HIL testing and the commissioning results.

This MMCS is currently in operation.

I. Introduction

One important function of a microgrid monitoring and control system (MMCS) is its ability to perform high-speed control of the electrical system to preserve frequency and voltage stability. With the fast development of microgrids around the world, several new control systems and techniques are being designed to better monitor, operate, and protect the microgrid systems. This paper discusses a reliable, high-speed control system that protects the University of California San Diego (UC San Diego) microgrid at wide-area speeds of less than 25 milliseconds.

The sustainable energy project started in the wake of the 2011 Southwest blackout. When the power outage disrupted critical operations, campus officials recognized the need for an islanded system. Today, onsite generation at UC San Diego covers approximately 85 percent of the campus annual load and 75 percent of peak demand—a total of approximately 50 MW. The remainder is imported from the San Diego Gas & Electric (SDG&E) grid. UC San Diego's diverse portfolio includes a 2.8 MW fuel cell, a 2.2 MW solar network, a 30 MW gas-turbine cogeneration plant, a 2.5 MW energy storage system, and a chiller plant. UC San Diego has centers for science, engineering, and medicine; the campus is required to ensure a reliable source of energy and prevent a power supply disruption.

This facility has three utility ties, which can split into multiple power islands for continued system operation. The MMCS has been designed to track all such possible islands and provide simultaneous control. Fig. 1 represents the simplified microgrid power system.

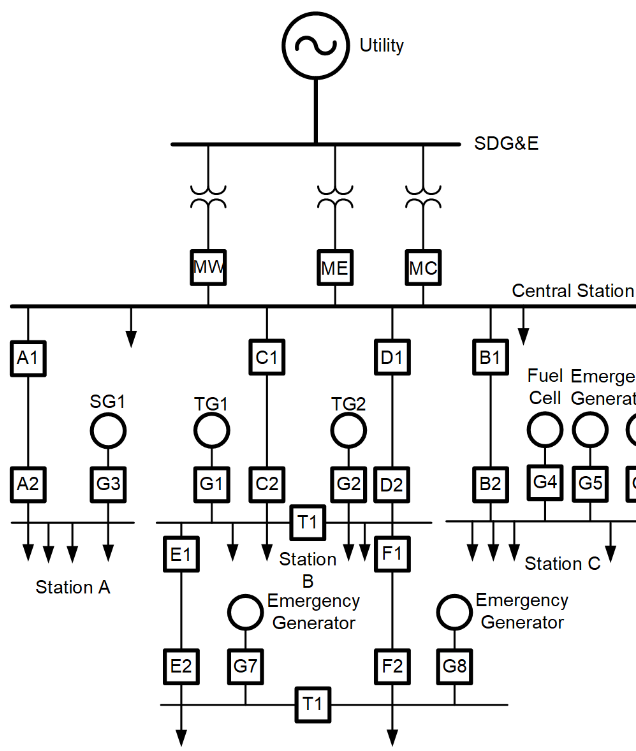

Fig. 1. UC San Diego Simplified One-Line Diagram

II. Microgrids

Microgrids are capable of autonomous operation during loss of utility caused by grid disturbances. Such autonomous operation requires sources that can provide primary frequency and voltage regulation within the microgrid. To effectively manage these sources for smooth islanded operation, the

MMCS interfaces with all assets. Some examples of such assets include diesel generators, photovoltaic sources, wind sources, and fuel cells. The MMCS components include islanding detection and decoupling systems [1], primary and backup load-shedding systems [2], slow- and high-speed generation control systems [3], adaptive protection systems, peak shaving, energy source optimization, and other analytical and control functions.

Unlike traditional sources, power electronic-based renewable sources (found typically in microgrids) are not so predictable. Concerns such as intermittency and reduced inertia can have a large impact on power system dynamics as the installed capacity of distributed generation increases. Such concerns warrant the need for fast-acting control systems that can potentially avoid situations that could destabilize the microgrid power system. In addition, turning radial distribution configurations into meshed configurations may require changes in the distribution protection philosophy and adaptive protection schemes. Fig. 2 shows a simplified system architecture of the MMCS used to protect and control the electrical network shown in Fig. 1.

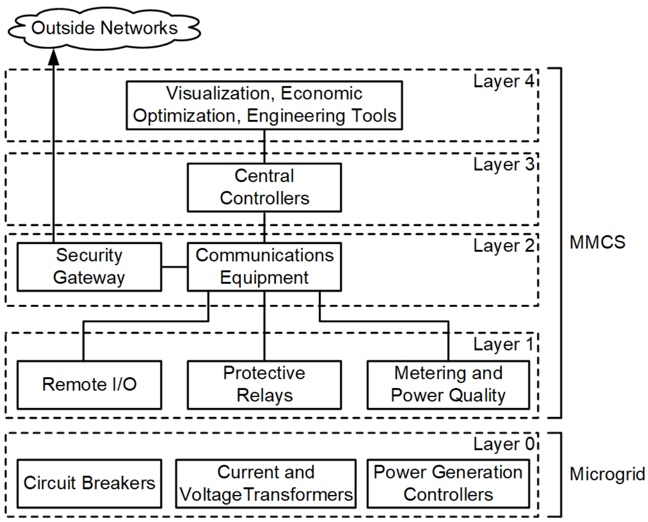

Fig. 2. High-Level Microgrid Architecture

III. UC San Diego System Overview

The UC San Diego microgrid as shown in Fig. 1 is connected to the SDG&E utility via three 28 MVA step-down transformers. The SDG&E utility tie is rated at 69 kV and feeds the 12 kV Central Station. Central Station acts as a power-wheeling bus and connects to Station A, Station B, and Station C with some sheddable and non-sheddable loads connected. Station C has two generators, Station C G1 and Station C G2, and a fuel-cell generator (FC).

Station A is connected to Central Station through the incoming feeder breakers and has a sheddable load. Station B is connected to Central Station through incoming feeder breakers and has one generator (PG1). The largest source of generation inside the UC San Diego microgrid is at Station B. Station B has emergency diesel generators, two gas generators (TG1 and TG2), and one steam generator (SG1).

IV. Communications and Network Architecture

Modern-day electrical control systems rely significantly upon analog and digital communications [4]. Most of the newer systems use various forms of communication mediums such as radio, copper, and fiber. These mediums enable connections between microprocessor-based programmable logic controllers (PLCs), computers, intelligent electronic devices (IEDs), and several other devices that are normally found on the power grid. The application of monitoring, controlling, and managing microgrids is no different. The MMCS uses a wide range of electronic devices and industry standard communications protocols such as DNP3, Modbus, Inter Control Center Communications Protocol (ICCP), Network Global Variable List (NGVL), IEC 61850, and IEEE C37.118. Communications protocols are mainly classified into high- and slow-speed protocols.

High-speed protocols are often used in situations where speed matters. For example, applying IEC 61850 GOOSE for high-speed breaker tripping can be commonly found in load-shedding applications. On the contrary, slow-speed protocols work great for interfacing with microgrid assets, moving data between the human-machine interface (HMI) and storage systems, and other functions.

Depending on the application criticality, it is very important to identify and segregate communication networks to guarantee dedicated bandwidth and network latency. A good design stage activity is to identify all the input/output (I/O) signals required for the monitoring and control functions. Using the I/O list, network calculations should be performed to calculate the required bandwidth and the type of communications.

Fig. 3 shows the Ethernet network connections between the multiple data concentrators located at various substations on the UC San Diego campus. The network communications allowed for the monitoring of system parameters along with microgrid management.

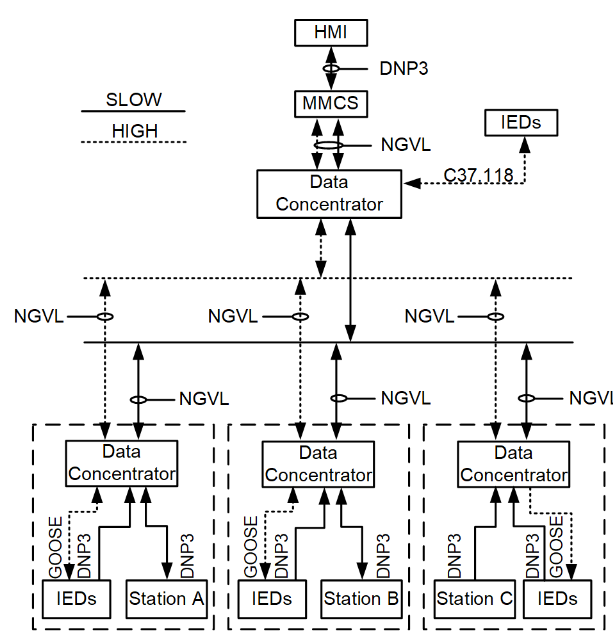

Fig. 3. Microgrid Communications Network

V. MICROGRID MONITORING AND CONTROL SYSTEMS

A. Load-Shedding Systems

Historically, power systems have implemented load-shedding systems to keep the steady-state frequency close to nominal during major loss of generation capacity (contingency). The typical contingencies include loss of utility interconnection or generators. In addition, the load-shedding system minimizes the disturbance toward sensitive critical loads and prevents system-wide blackouts.

Load-shedding systems can be mainly classified into two types: primary contingency-based load shedding (CBLS) systems and backup frequency-based load shedding (FBLS) systems. The CBLS is much faster and more accurate compared to an FBLS. The CBLS is an independent control system that makes decisions based on topology, contingency, and load calculations from field IED data. Because of its high-speed nature, the CBLS comes pre-armed for load-shedding events and provides a fast response in a range of milliseconds. In addition, the CBLS tracks the entire system's topology and sheds sufficient load to limit any power and frequency oscillations, as shown in Fig. 4. The fundamental principle of a CBLS is to maintain the power balance equation by shedding load before the frequency starts to decay. Finally, the CBLS dynamically tracks the various system islands to avoid shedding on different islands and prevent unnecessary tripping.

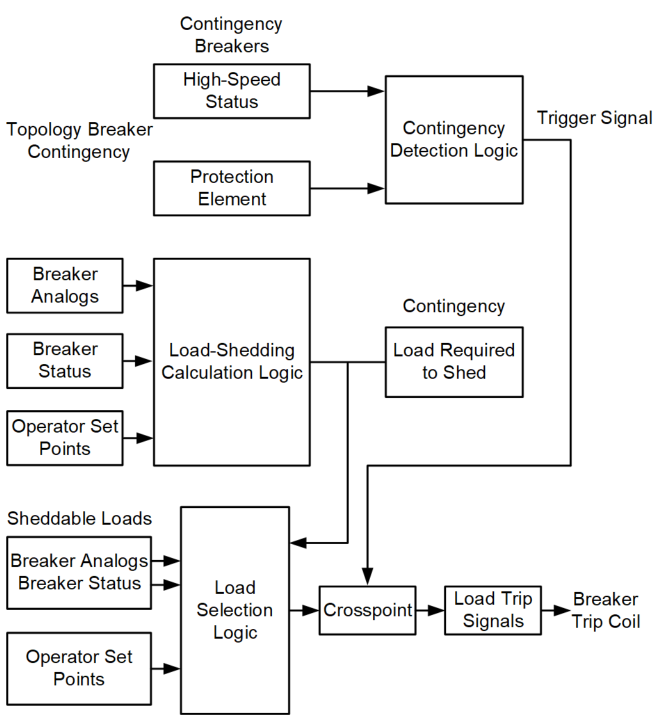

Fig. 4. Contingency-Based Load-Shedding Algorithm

Both the CBLS and the FBLS are implemented in the UC San Diego MMCS.

The amount of load to be shed is the difference between the amount of source power lost and the sum of the instantaneous power that can be supplied by the remaining sources, as described in the following equation. The equation is performed for each island on the system, meaning that the terms of the load, power disparity, and incremental reserve margin (IRM) [2] are all specific to individual islands.

$$L_n = P_n - \sum_{g=1}^{m} IRM_g$$

where:

n = contingency event number

m = number of sources connected to the affected island after n event

g = generator number, 1 through m

L_n = amount of load selected for n event (MW)

P_n = power disparity caused by n event (MW)

IRM_g = incremental reserve margin of all sources after n event (MW)

Fig. 5 shows the load-selection logic. Additional loads are selected until the required-to-shed calculation is met. The Hysteresis algorithm was added for the UC San Diego CBLS and the FBLS to keep the discrepancy between the required-to-shed and the selected-to-shed calculations minimal and to preserve system stability.

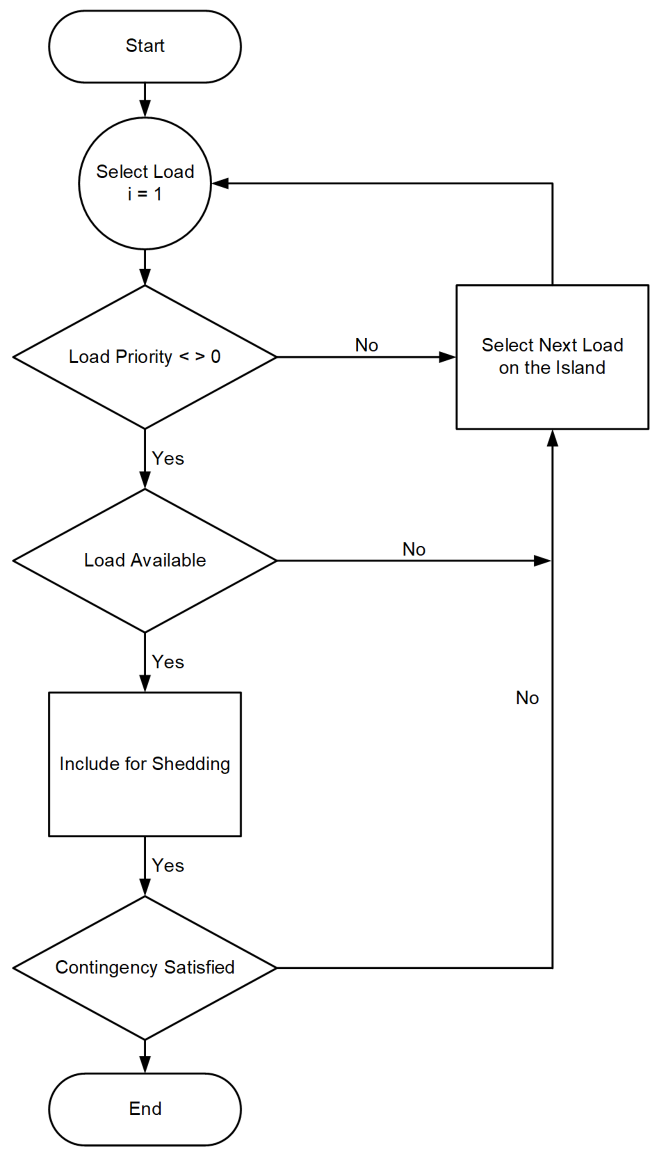

Fig. 5. Load-Selection Logic

The FBLS operates as a backup to the CBLS. Underfrequency triggers are generated from the IEDs located at Station B. Two levels of underfrequency thresholds were selected as indicated in the frequency line diagram in Fig. 6. A frequency line diagram provides a visual indication of major frequency dependencies in a power system and allows coordination between different asset protection schemes to be seen. MMCS decoupling and FBLS underfrequency triggers are supervised with voltage and communications qualifications. The frequency for the underfrequency was coordinated along with generator protection set points and decoupling set points. The underfrequency operation for load selection is similar to the CBLS system except that the required-to-shed calculation is based on the island, topology status, and user-settable inputs. This testing was validated using hardware-in-the-loop (HIL) testing [5].

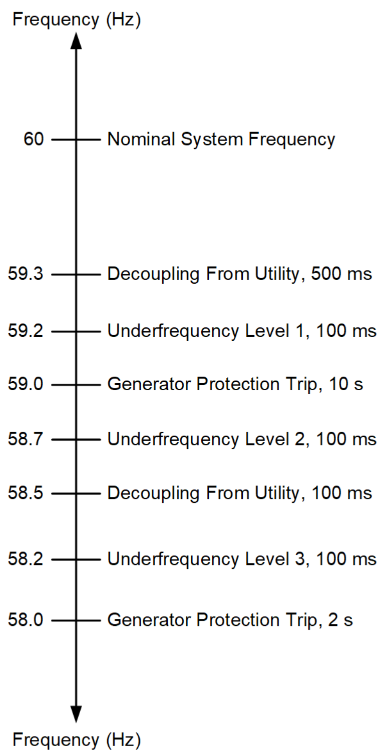

Fig. 6. Frequency Line Diagram

B. *Generation Control Systems*

When the utility is connected, microgrid generators are paralleled with the utility using droop characteristics. Under such situations, an important function of a generation control system is a slow-speed rebalancing act to share load proportionally in terms of real and reactive power. Typical functions that are active during this time include the automatic generation control (AGC) and volt/volt-ampere reactive (VAR) control system.

When disconnected from the utility, generation control systems should validate the microgrid separation from the utility and change speed control modes on governors (from droop to isochronous). For systems that allow isochronous load sharing, multiple governors can be set to isochronous speed control mode.

An MMCS is programmed to track the internal islands of the system when disconnected from the utility. This allows for simultaneous voltage and frequency control of the islands with available generation capacity.

Such high-speed generator mode switching combined with a fast load-shedding, generation-shedding, or runback system stabilizes the power system response during high import or export conditions. A simplified generation control system (GCS) and an automatic synchronization system [6] were provided for the UC San Diego MMCS. During islanding conditions, the modes of the generators were switched to isochronous and back during automatic synchronization for the TG1 and TG2 at Station B.

C. *Islanding Detection System and Decoupling System*

When the utility is connected, the MMCS should be able to detect utility disturbances and decouple. It should also detect a loss of utility for local or remote breaker openings. This can be achieved via status-based and analog-based measurements. The status-based schemes typically rely on breaker-open conditions for several points of common coupling breakers. The analog-based measurements include local and wide-area methods. Local methods employ voltage- and frequency-based schemes, whereas wide-area schemes can use angle difference-based schemes [1].

An islanding detection and decoupling system (IDDS) was provided as a part of the UC San Diego MMCS. The main purpose of this IDDS was to detect any utility disturbance and decouple in case the disturbance had a negative impact on the system stability and reliability of the UC San Diego power system. The wide-area-based system islanding detection monitoring scheme was implemented; this wide-area scheme is currently in the monitoring state.

1) *Local-Based IDDS Scheme*

The local-based scheme uses standard frequency- and voltage-based elements, such as 81 O/U and 27/59, along with advanced 81RF functionality. The protective relay at the local utility performs this function. Fig. 7 demonstrates the functionality.

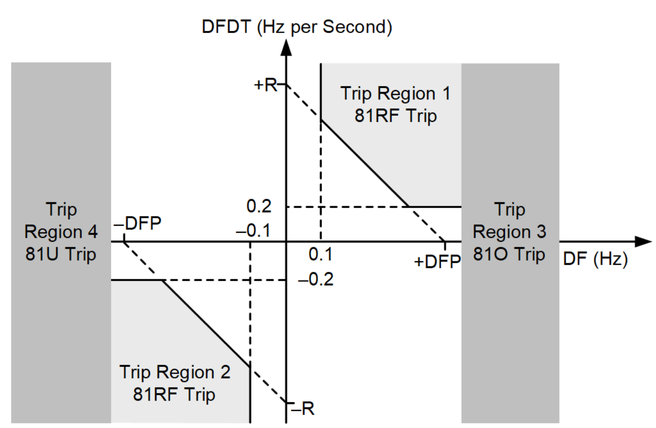

Fig. 7. Decoupling Scheme Characteristics

2) Wide-Area-Based IDDS Scheme

An angle difference-based wide-area scheme (see Fig. 8) uses positive-sequence voltage angles between two locations (local and remote) to determine islanding conditions, as shown in Fig. 9. For the UC San Diego system, angle differences between the measurements from the phasor measurement units (PMUs) on the 69 kV yard and 12 kV switchgear are compared. The angle-difference element operates if the phase angle difference between the positive-sequence voltage phasors at the two locations exceeds a programmable threshold for a specified duration.

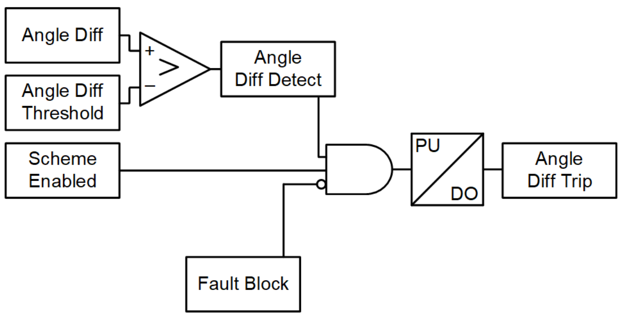

Fig. 8. Wide-Area Angle-Based Detection

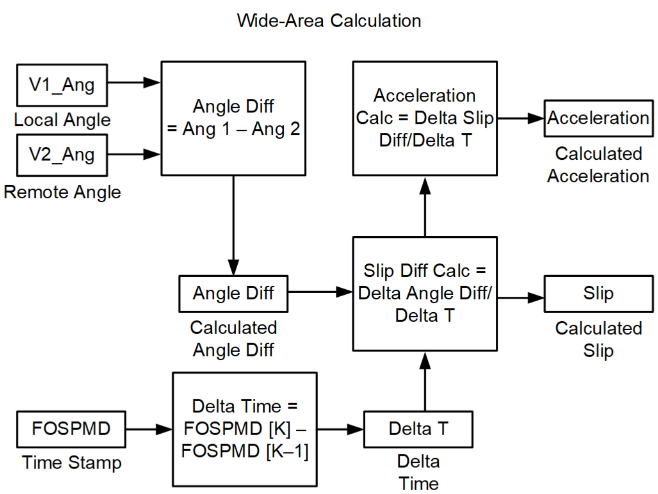

Fig. 9. Wide-Area Parameter Calculation

When the utility is connected, the MMCS should be able to detect a loss of utility for a local or remote breaker opening. This can be achieved via status-based and analog-based measurements. The status-based schemes typically rely on a breaker-open condition for several points of common coupling breakers. The analog-based measurements include local and wide-area methods. Local methods employ voltage- and frequency-based schemes, whereas wide-area schemes can use angle-difference-based schemes [1]. The UC San Diego MMCS currently employs a status-based and local analog-based scheme along with a wide-area-based scheme.

The slip- and acceleration-based scheme, as shown in Fig. 10, was implemented to detect the islanding condition for the UC San Diego system.

When the system is interconnected, the operating point is at the origin of the slip acceleration characteristic. Once the systems separate, the operating point starts to move from the restrain region to the operate region. The unshaded area represents the thresholds that are selected for security. The out-of-step detection (OOSD) declares an islanding condition and/or grid disturbance when the operating point stays in the operate region for a specified duration.

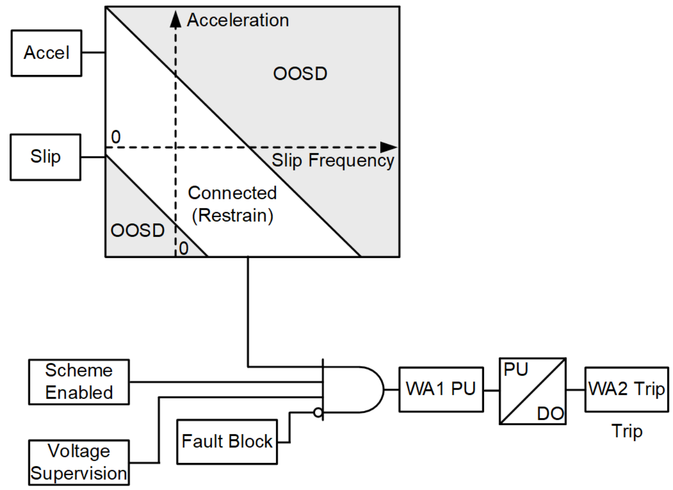

Fig. 10. Slip- and Acceleration-Based Wide-Area Scheme

D. *Human-Machine Interface*

The MMCS at UC San Diego also has an HMI for remote monitoring and control of the MMCS. The front panel of the protective relays and control devices was replicated in the HMI for system monitoring and control. The load-shedding system cross-point matrix, load status, and contingency status were also displayed in the HMI.

The HMI also provides alarms regarding the communication failures, incongruence of the breaker status, close failures, voltage transformer (VT) failures, and islanding detection and trips.

VI. System Validation

Prior to installation of the MMCS at UC San Diego, complete testing was performed at the laboratory. A real-time digital simulator (RTDS) model capable of continuous real-time operation was developed to validate the functionality of the MMCS.

This section describes the UC San Diego microgrid power system, simulation environment, and dynamic simulation results.

A. *Simulation Environment and Test Setup*

The hardware-based Electromagnetic Transients Program (EMTP) simulation environment was modeled in the RTDS. The RTDS model based on the electrical configuration of the UC San Diego power system, as described previously, was specifically developed to validate the microgrid control functionality.

The RTDS model of the UC San Diego power system was developed to run a simulation for evaluating potential interaction of the load-shedding controller, asset controller, and protective devices. Each component of the model was validated and tested to determine asset performance when subjected to system disturbances. Logic to transition the Station B generators from droop mode to isochronous mode during a loss of utility connection was also implemented. The model was built to study the dynamic response of the system in tandem with controller action to a wide range of electrical network transients and faults. To mimic field setup, the load-shedding controllers were connected in a closed loop with the UC San Diego power system model. A data concentrator was programmed to collect analog measurements and the digital status of contingency breakers. Simulating field IEDs, the interaction between the UC San Diego RTDS model and the microgrid controller was established using various communications protocols. For high-speed control, an action-like load trip was implemented. Along with data concentrators, relays were hardwired to simulate and test the performance of the IDDS logic. The closed-loop capability provided a test bed to investigate vulnerabilities of the controller and its response to simulated continency events. The closed-loop setup designed for the UC San Diego test bed is shown in Fig. 11.

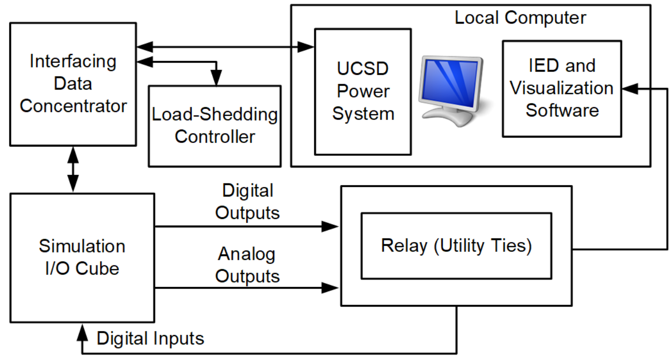

Fig. 11. RTDS Closed-Loop Interface

The model was primarily developed to test the performance of the primary contingency load shedding and backup underfrequency load shedding, and to provide frequency coordination settings among underfrequency controller triggers, decoupling relays, and generator frequency-based protection.

A list of system-wide events was simulated to study the load-shedding controller actions. Critical parameters such as system-wide frequency, voltage, and breaker status were monitored to study and ensure system stability after a controller action. A set of tests that were conducted as part of a factory acceptance test is presented in Table I.

TABLE I
SIMULATED SYSTEM EVENTS

Case	System Event	Precondition	Operation	Pass/ Fail
A	Decouple of UC San Diego due to frequency disturbance (decay rate 2.5 Hz/s).	• Utility ties MW and MC are closed. • MW is importing 3.69 MW. • MC is importing 3.6 MW. • TG1 and TG2 are running at 13.5 MW. • SG1 is running at 2.8 MW. • FC is running at 2.5 MW. • Emergency diesel and pharmacy are running at a total of 12.27 MW. • All bus couplers are closed.	Primary contingency-based load shedding.	Pass
B	Loss of generation at Station B (TG2).	• Two out of three utility tie breakers are open. • MW breaker is importing 17.83 MW into UC San Diego. • TG1 and TG2 are running at 13.5 MW. • SG1 is running at 1 MW. • FC is running at 2.5 MW. • All bus couplers are closed. • Other emergency generators are offline.	Primary contingency-based load shedding.	Pass
C	Island-based load shedding (loss of intertie breakers and loss of generation at Station B).	• Utility ties MW and MC are closed. • MW is importing 12.07 MW. • MC is importing 11.98 MW. • TG1 and TG2 are running at 10.88 MW. • FC is running at 2.5 MW. • All bus couplers are closed. • Other emergency generators are offline.	Primary contingency-based load shedding.	Pass
D	Three-phase fault on utility tie and loss of generation.	• Utility ties MW and MC are closed. • MW is importing 8.92 MW. • MC is importing 8.85 MW. • TG1 and TG2 are running at 13.5 MW. • SG1 is running at 1 MW. • FC is running at 2.5 MW. • All bus couplers are closed. • Other emergency generators are offline.	Primary contingency-based load shedding.	Pass

1) Case A: Decouple of UC San Diego due to Frequency Disturbance (Decay Rate 2.5 Hz/s)

The goal of this test was to demonstrate the operation and coordination between the different components of the MMCS. The components of interest include the IDDS scheme, CBLS, and FBLS. In this test, grid frequency disturbance was simulated with a decay rate of 2.5 Hz/s. As the frequency decayed past the threshold indicated in Fig. 12, the UC San Diego decoupled from SDG&E. The disconnection initiated CBLS action. A total of 5.35 MW of load was shed.

This testing demonstrated UC San Diego's capability of islanding from the utility during grid disturbance and successfully operating in islanded mode. During this test, the TG1 and TG2 generator modes were also switched from droop to isochronous.

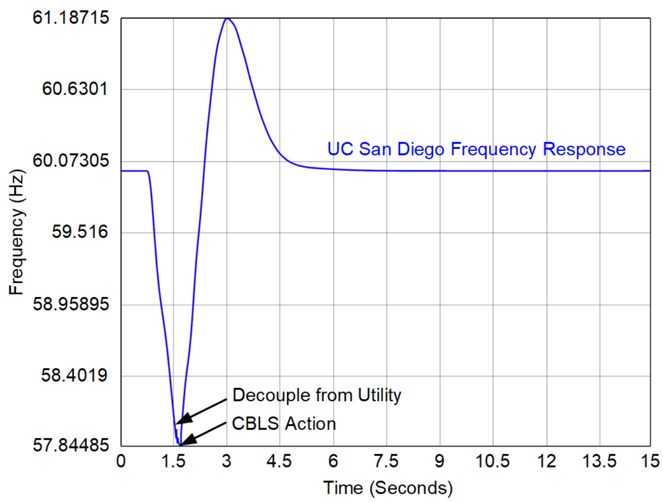

Fig. 12. Case A: Islanding for Grid Disturbance

2) Case B: Loss of Generation at Station B (TG2)

The goal of this test was to demonstrate how the CBLS would prevent overloading and tripping of the utility transformer tie using the IRM threshold during internal loss of generation within UC San Diego. The IRM set points can be used to restrict the utility tie from becoming overloaded via a user-operated HMI.

Prior to simulating the event, the loads in the UC San Diego system were fed through the utility breaker MC along with local generation within the UC San Diego plant. To simulate the contingency event, generator breaker TG2 was tripped. Tripping TG2 caused the power flow to increase to 31.33 MW on the utility breaker incomer, as shown in Fig. 13.

As the normal power rating is set at 22 MW, the CBLS shed 10.41 MW of loads (the amount required to shed was reported as 9.33 MW). Fig. 14 shows the frequency response post-CBLS action.

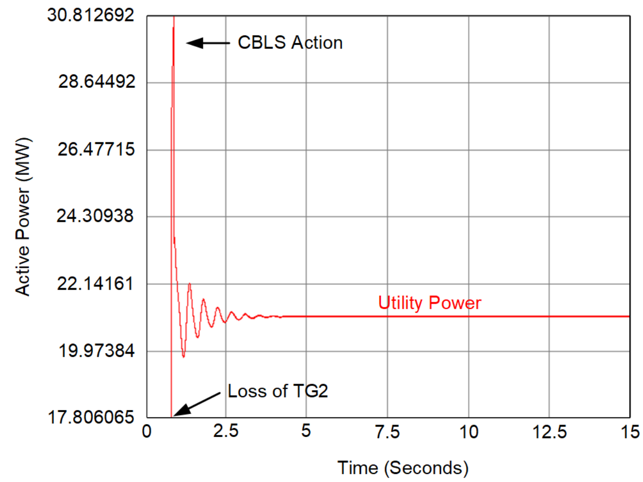

Fig. 13. Power Flow Across the Utility

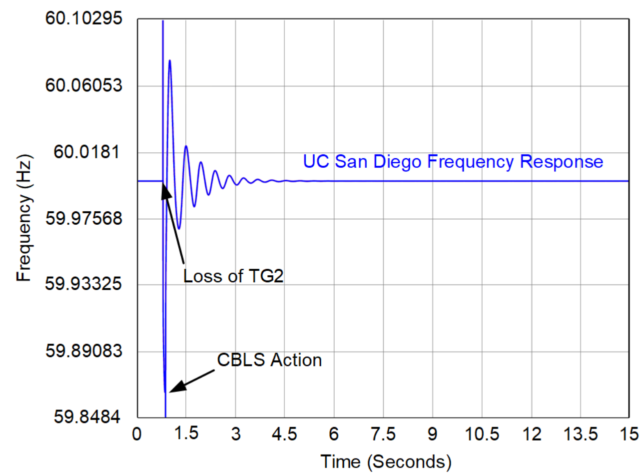

Fig. 14. Case B: Loss of Generation at Station B

3) Case C: Island-Based Load Shedding (Loss of Intertie Breakers and Loss of Generation at Station B)

The goal of this test was to demonstrate how load selection is based on islanding by splitting the system into two islands. Island 1 consisted of Station B. Island 2 consisted of Station A and Station C with a connection to the grid.

To demonstrate load selection based on islanding, TG2 was tripped under load, causing a contingency event. The CBLS detected the loss of TG2; based on the available IRM set point of TG1, the CBLS selected loads in Island 1 for load shedding. The CBLS selected loads based on the available priority in Island 1 and shed the loads accordingly. Proper topology tracking and priority-based load shedding functionality were validated. This also proved UC San Diego's capability of forming and maintaining a small island within the UC San Diego electrical network. Fig. 15 shows the frequency response of Island 1.

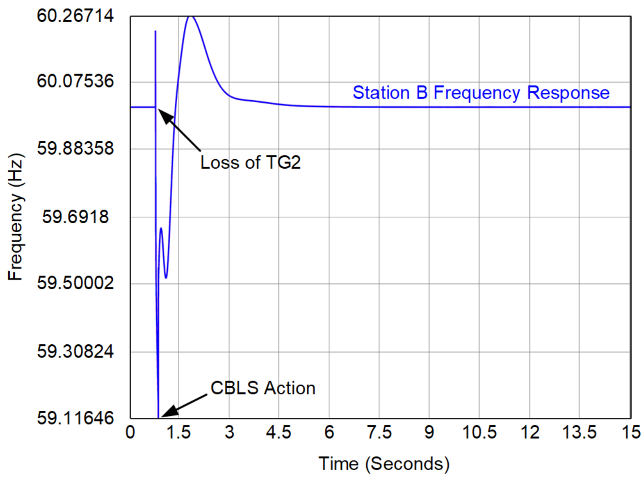

Fig. 15. Case C

4) *Case D: Three-Phase Fault on Utility Tie and Loss of Generation*

The goal of this test was to demonstrate the functionality of the CBLS regarding simultaneous and closely timed contingencies. In this case, a fault was simulated that tripped the utility breakers simultaneously, followed immediately by the tripping of six breakers in close succession.

- Event 1: Trip utility tie MC, MW, and ME.
- Event 2: Within 10 s of Event 1, trip fuel cell.
- Event 3: Within 10 s of Event 2, trip SG1.
- Event 4: Within 10 s of Event 3, trip TG2.

The tripping of the utility tie, fuel cell, SG1, and TG2 in sequence caused load shedding as the system did not have enough IRM to account for the loss of utility. Fig. 16 shows the system frequency response during this sequential event. The system stabilized and continued to operate as an island.

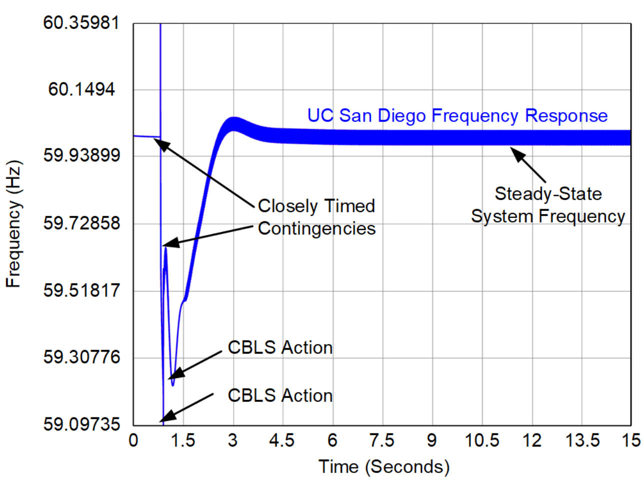

Fig. 16. Case D

VII. Conclusion

This paper demonstrates the design, development, and validation testing of the UC San Diego MMCS using an HIL testing method. Each function of the UC San Diego MMCS was tested prior to running system-wide tests to validate integrated operation. Since then, the system at the UC San Diego campus has been commissioned and is in service. This project augmented the UC San Diego goal of resiliency, reliability, and survivability during grid disturbances. The goal to preserve the UC San Diego critical loads from blackout during utility disturbance by islanding and prevent system blackouts using load-shedding schemes was met.

VIII. Acknowledgment

The authors gratefully acknowledge the contributions of Tyler McCoy and Nathan Bridges for their work on the development, testing, validation, and commissioning for this MMCS.

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X. VII. Biographies

John Dilliot, PE, is an Associate Director of Energy and Utilities at the University of California San Diego.

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