

FINAL REPORT

Modular Control Architecture for Scalable Resilient, and Cybersecure Microgrids

Jacqueline Baum
Arindam Maitra
Mike Simpson
Y. Ma
Electric Power Research Institute, Inc.

Sigfredo Gonzalez
J. Flicker
A. Summer
Sandia National Laboratories

P. Curtiss
S&C Electric Company

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TABLE OF CONTENTS

	Page
ABSTRACT	IX
EXECUTIVE SUMMARY	ES-1
1.0 INTRODUCTION	1
1.1 TEST PLAN BACKGROUND	1
2.0 MICROGRID CONTROLLER	2
2.1 BANSHEE NETWORK AND DEMONSTRATION MODEL BACKGROUND	2
2.2 DEMONSTRATION SYSTEM CONTROL BOUNDARIES AND LOAD PRIORITY	3
2.3 OPERATIONAL STRATEGY	4
2.3.1 N reliability	4
2.3.2 N+1 reliability	4
3.0 HIL CONFIGURATION	5
3.1 EPRI CONTROLLER-HARDWARE-IN-THE-LOOP TESTBED	5
3.1.1 Microgrid CHIL Testbed Components	5
3.1.2 Test Environment	5
3.1.3 Microgrid Network and DER Simulation	6
3.2 SANDIA POWER-HARDWARE-IN-THE-LOOP TESTBED	7
3.3 PURPOSE OF CHIL AND PHIL TESTING	9
4.0 PERFORMANCE OBJECTIVES	11
4.1.1 SUMMARY OF PERFORMANCE OBJECTIVES	11
4.1.2 Performance Objectives Descriptions	12
5.0 HIL INTEGRATION AND INITIAL TESTING	16
5.1 COMMUNICATION AND CONTROLS INTERFACE	16
6.0 CHIL PERFORMANCE TESTING	16
6.1 TEST CASE 1: DEMONSTRATE OUTAGE RECOVERY FOR RESILIENCE	17
6.1.1 Purpose	17
6.1.2 Test Scenario	18
6.1.3 Test Approach / Narrative	18
6.1.4 Evaluation Criteria	20
6.1.5 Test Results	21
6.2 TEST CASE 2: DEMONSTRATE INCREASED LOAD COVERAGE	28
6.2.1 Purpose	28
6.2.2 Test Scenario	28

TABLE OF CONTENTS (Continued)

	Page
6.2.3 Test Approach / Narrative.....	29
6.2.4 Evaluation Criteria	29
6.2.5 Test Results	29
6.3 TEST CASE 3: INCREASED RELIABILITY, LOSS OF PV SCENARIO	34
6.3.1 Purpose.....	34
6.3.2 Test Scenario.....	35
6.3.3 Test Approach / Narrative.....	35
6.3.4 Evaluation Criteria	35
6.3.5 Test Results	35
6.4 TEST CASE 4: INCREASED RELIABILITY, LOW ESS SOC SCENARIO.....	39
6.4.1 Purpose.....	39
6.4.2 Test Scenario.....	39
6.4.3 Test Approach / Narrative.....	40
6.4.4 Evaluation Criteria	40
6.4.5 Test Results	40
6.5 TEST CASE 5: INCREASED RELIABILITY, LOSS OF GENERATOR SCENARIO.....	45
6.5.1 Purpose.....	45
6.5.2 Test Scenario.....	45
6.5.3 Test Approach / Narrative.....	46
6.5.4 Evaluation Criteria	46
6.5.5 Test Results	46
6.6 TEST CASE 6: INCREASED RELIABILITY, LOSS OF MICROGRID CONTROLLER SCENARIO	50
6.6.1 Purpose.....	51
6.6.2 Test Scenario.....	51
6.6.3 Test Approach / Narrative.....	51
6.6.4 Evaluation Criteria	51
6.6.5 Test Results	52
6.7 TEST CASE 7: DEMONSTRATE OPERATIONS FOR ECONOMIC BENEFITS.....	56
6.7.1 Purpose.....	56
6.7.2 Test Scenario(s)	57
6.7.3 Test Approach / Narrative.....	57
6.7.4 Evaluation Criteria	57
6.7.5 Test Results	57
7.0 PHIL PERFORMANCE TESTING	62
7.1 PHIL PERFORMANCE TESTING	62
7.1.1 Test Case 1: Demonstrate Outage Recovery for Resilience	62
8.0 PERFORMANCE ASSESSMENT	70
8.1 FEEDER BUS VOLTAGE.....	70

TABLE OF CONTENTS (Continued)

	Page
8.2 FEEDER FREQUENCY	71
8.2.1 Synchronization Tolerance	72
8.2.2 Black start automation	73
8.2.3 Load Outage Duration.....	74
8.2.4 Load Coverage	75
8.2.5 Controller Coordination – Economic dispatch.....	77
8.3 PERFORMANCE ASSESSMENT CONCLUSIONS	78
9.0 COST ASSESSMENT	80
9.1 COST MODEL	80
9.1.1 Cost Elements	80
9.2 COST DRIVERS	83
10.0 IMPLEMENTATION ISSUES	84
11.0 REFERENCES	86
APPENDIX A SANDIA NATIONAL LABORATORIES PHIL TESTBED DETAILS.....	A-1
APPENDIX B POINTS OF CONTACT	B-1

LIST OF FIGURES

	Page
Figure ES-1. Networked Microgrid Demonstration System	ES-3
Figure ES-2. EPRI Microgrid Controller-hardware-in-the-loop Testbed Setup	ES-4
Figure ES-3. Test Environment for PHIL Demonstration; Hardware Buses Are Highlighted	ES-4
Figure 2-1. Networked Microgrid Demonstration System	2
Figure 3-1. Microgrid Controller-hardware-in-the-loop Testbed Setup	6
Figure 3-2. Networked Microgrid Demonstration System for PHIL Testing	7
Figure 3-3. Test Environment for PHIL Demonstration; Hardware Buses Are Highlighted	8
Figure 5-1. Networked Microgrid Controller Device Connectivity	16
Figure 6-1. Test Case Demonstration of Individual Microgrid Control Areas Synchronizing to One Combined Microgrid	18
Figure 6-2. Microgrid Synchronization Interaction Details During Black Start	20
Figure 6-3. Black Start Process with 4pm Profile N Strategy	23
Figure 6-4. Black Start Process with 8pm Profile N+1 Strategy	24
Figure 6-5. Blackstart Process with 4pm Profile Separated Microgrids	25
Figure 6-6. Join Process of Two Transformer Level Microgrids	26
Figure 6-7. 24h Islanded Operation with Cloudy Day Profile Separated Microgrids	31
Figure 6-8. 24h Islanded Operation with Sunny Profile N Strategy	32
Figure 6-9. 24h Islanded Operation with Cloudy Profile N+1 Strategy	33
Figure 6-10. Microgrid Reaction to Loss of PV with 4pm Profile Separated Microgrids	37
Figure 6-11. Microgrid Reaction to Loss of PV with 12pm Profile N+1 Strategy	38
Figure 6-12. Microgrid Reaction to Low ESS SOC with 0am Profile Separated Microgrids	42
Figure 6-13. Microgrid Reaction to Low ESS SOC with 0am Profile N Strategy	43
Figure 6-14. Microgrid Reaction to Low ESS SOC with 0am Profile N+1 Strategy	44
Figure 6-15. Generator 2 Loss at 2400 s with 8pm Profile Separated Microgrids	48
Figure 6-16. Generator 2 Loss at 2400 s with 8pm Profile N+1 Strategy	49
Figure 6-17. Microgrid Reaction to Loss of Microgrid Controller with N+1 Strategy	54
Figure 6-18. Microgrid Reaction to Loss of Microgrid Controller with Separated Microgrids	55
Figure 6-19. Economic Dispatch Test Run Scenario Results Sample from a Summer Weekday Run	59
Figure 6-20. Bus Voltages Across the Feeder during the Grid-connected, Economic Dispatch Test	61
Figure 7-1. Test Case Demonstration of Individual Microgrid Control Areas Synchronizing to One Combined Microgrid	63
Figure 7-2. Reactive Power Flowing through CB-M1, which Contains a Simulated 100kW BESS, PV Inverter, and a Resistive Load	65
Figure 7-3. Active Power Flow through CB-M1	66
Figure 7-4. Frequency of MGC-1 before CB- 106 Closure	66

LIST OF FIGURES

	Page
Figure 7-5. MGC-1 and MGC-2 Voltages Are Adjusted to Be Comparable, Once CB106 Closes Voltages Match.....	67
Figure 7-6. SEL-351 Phasor Diagrams.....	67
Figure 7-7. (a) CB-106 Closes when Black Trace Goes High, (b) CB-106 opens when Black Trace Goes Low	68
Figure 7-8. DETL Data Acquisition Data for MGC-1	68
Figure 7-9. DETL Aata Acquisition Data for MGC-2	69
Figure 8-1. SEL-351 Phasor Diagrams.....	73

LIST OF TABLES

	Page
Table ES-1. Summary of Performance Objectives for Evaluating Networked Microgrid Controllers	ES-5
Table ES-2. Cost Model for Modular Microgrid Controller	ES-7
Table 2-1. Adapted Banshee Model Equipment Ratings.....	3
Table 3-1. Components of the EPRI CHIL Microgrid Testbed.....	5
Table 3-2. Adapted Banshee Model Equipment Ratings for PHIL Testing	8
Table 3-3. Sandia Lab Power Hardware Equipment and Scaled Ratings in Feeder Model	9
Table 4-1. Performance Objectives for Black Start Outage Recovery	11
Table 4-2. Performance Objectives for Island Operations	12
Table 4-3. Performance Objectives for Grid-Connected Operations	12
Table 4-4. ANSI C84.1 Voltage Magnitude Limits.....	13
Table 4-5. Allowable Range for Frequency Readings within the Microgrid throughout Testing	13
Table 4-6. Synchronization Parameter Limits for Joining Networked Microgrids; Adapted from IEEE 1547-2018 [4]	14
Table 6-1. Performance Metrics of Black Start Test	22
Table 6-2. Performance Metrics of 24h Islanded Test.....	30
Table 6-3. Performance Metrics of Loss of PV Tests.....	36
Table 6-4. Performance Metrics of Low ESS SoC Scenario	41
Table 6-5. Performance Metrics of Loss of Generator Tests.....	47
Table 6-6. Performance Metrics of Loss of Microgrid Controller Tests	53
Table 6-7. Utility Rate Structure Used to Analyze Economic Dispatch Performance	58
Table 6-8. Daily Billing Results for Summer, Weekday Test Runs.....	59
Table 6-9. Economic Dispatch Test Results Extrapolated to a 30-day Billing Period.....	59
Table 8-1. Summary of Feeder Bus Voltages Captured during Testing.....	70
Table 8-2. Summary of Feeder Frequency Ranges Captured during Testing	71
Table 8-3. Summary of Load Outage Duration Change from Baseline to Networked Microgrid Configuration Across Test Scenarios for Each Load Type.....	74
Table 8-4. Summary of Average Load Coverage Change from Separated to Networked Microgrid Configurations Across Test Scenarios for Each Load Type	76
Table 8-5. Economic Dispatch Test Results Extrapolated to a 30-day Billing Period.....	77
Table 9-1. Cost Model for Modular Microgrid Controller	80
Table 9-2. Utility Rate Structure Used to Analyze Economic Dispatch Performance	82

ACRONYMS AND ABBREVIATIONS

CHIL	Controller-hardware-in-the-loop
DER	Distributed Energy Resources
DNP3	Distributed Network Protocol 3
ESS	Energy Storage System
GCB	Generator circuit breaker
GFM	Grid-Forming
IPC	Intelligent Power Controller, the base unit of the GridMaster
kW	kilowatt
MW	megawatt
OPC	Open Platform Communications
PCC	Point of Common Coupling
PHIL	Power-hardware-in-the-loop
PV	Photovoltaic
RMS	Root mean square
SCADA	Supervisory Control and Data Acquisition
SNL	Sandia National Laboratories
SoC	State of charge

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Electric Power Research Institute (EPRI)

Principal Investigators

J. Baum

Y. Ma

A. Maitra

A. Renjit

S&C Electric Company

Principal Investigators

P. Curtiss

S. Roberts

J. Gehring

Sandia National Laboratories

Principal Investigators

S. Gonzalez

J. Flicker

A. Summer

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ABSTRACT

INTRODUCTION AND OBJECTIVES

With increasing numbers of microgrid developments, networked microgrids present an opportunity to improve distribution feeder resilience and reliability. Networked microgrids are physically interconnected microgrid areas with controller interoperability that enables multi-island synchronization and coordinated power sharing. This project aims to demonstrate a solution that reduce the time and cost of designing and implementing microgrids in military installations. EPRI partnered with a commercial microgrid controls vendor (S&C Electric Company) and Sandia National Laboratories to design and test a networked microgrid controller. Key concepts of DER power sharing, multilayer network redundancy, sequenced outage recovery, coordinated system protection, and cyber-secure communications were demonstrated. This report captures the executed test plan, results, and performance analysis of the networked microgrid controls.

TECHNOLOGY DESCRIPTION

The microgrid controller technology developed in this project aimed to implement a generic process for joining and separating individual microgrids into larger grid sections. Variations on this have been demonstrated previously, but these solutions have been customized to the specific equipment and requirements of the installations. In this project, the S&C GridMaster controller design focused on developing a modular solution that can be adapted to any given configuration of microgrids with minimal setup time and configuration efforts. The tested controller hardware solution is capable of managing various DER combinations and communicating between the controllers and reclosers to join and separate microgrid areas.

PERFORMANCE AND COST ASSESSMENT

The networked microgrid controller concept was capable of meeting minimum performance requirements for the operation of joined microgrids. Across all test scenarios, the joined microgrids operated within acceptable frequency and voltage limits, and the island synchronization process did not cause adverse system conditions. The ability to safely black start, synchronize, and operate joined microgrid islands as a feeder-level island was confirmed in both CHIL and PHIL test environments. The operational cost savings observed during the grid-connected test scenarios appear to provide a net benefit but can vary based on local electricity tariffs. Key cost drivers include control complexity, potential upgrades to enable remote control and paralleling of legacy DER, and interconnection assessment.

IMPLEMENTATION ISSUES

One of the anticipated benefits of joining microgrids was the ability to share DER output to increase high-priority load coverage across the joined areas during island. The test network and system conditions simulated in this project phase failed to meet the load coverage performance objectives. However, using the data gathered throughout the testing process, the project team identified several design variables that could be adjusted to improve the joined microgrid performance. In addition, the benefits of power sharing control are expected to be more pronounced under system conditions with higher penetrations of PV and larger DER-to-load ratios.

PUBLICATIONS

Test Plan for a Networked Microgrid Controller. EPRI, Palo Alto, CA: 2021. 3002021861.

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EXECUTIVE SUMMARY

INTRODUCTION

Increasing numbers of natural disasters causing wide-area power outages have spurred a significant interest in microgrid development, and the landscape of microgrid types is evolving to meet broader end-user needs. Networked microgrid controllers can further enhance the reliability and resilience provided by microgrids. Most current microgrid designs rely upon centralized controls architectures with vulnerability to systematic failures (single points of failure, e.g., communications infrastructure) and limited adaptability in response to changing load and resources. Advancements in distributed controllers, next-generation distributed network architecture design, and recent iterations of communications protocols can address these challenges and enable the cost-effective and resilient deployment of scalable and repeatable networked microgrids.

Networked microgrids are physically interconnected microgrid areas with controller interoperability that enables multi-island synchronization and coordinated power sharing. As part of a DoD ESTCP award in 2020, EPRI began a project to demonstrate innovative solutions that reduce the time and cost of designing and implementing microgrids in military installations. To address this challenge, EPRI partnered with a commercial microgrid controls vendor (S&C Electric Company) and Sandia National Laboratories to design and test a networked microgrid controller. Key concepts of DER power sharing, multilayer network redundancy, sequenced outage recovery, coordinated system protection, and cyber-secure communications were demonstrated. This report captures the executed test plan, results, and performance analysis of the networked microgrid controls.

OBJECTIVES

The core concepts in this project involve demonstrating, through rigorous testing, a decentralized control architecture that will allow implementation of multiple networked microgrids that cost-effectively employ a combination of legacy generation assets, building loads, and DER assets. The key beneficial goals include the following:

- Integrate combinations of legacy generation assets and DER for utilization as capacity resources in lieu of large-scale centralized resources.
- Enable DER power sharing, meet reliability targets, and increase robustness to localized failures.
- Facilitate operation of multiple independent microgrids within a military site.
- Expedite the installation and commissioning of networked microgrids, simplification of component and systems integration, and sequencing or intelligent phasing of modular expansions across a military installation over time while addressing the expected business and financial constraints of microgrid design-builds.

TECHNOLOGY DESCRIPTION

The microgrid controller technology developed in this project aimed to implement a generic process for joining and separating individual microgrids into larger grid sections. Variations on this have been demonstrated previously, but these solutions have been customized to the specific equipment and requirements of the installations. In this project, the S&C GridMaster controller

design focused on developing a modular solution that can be adapted to any given configuration of microgrids with minimal setup time and configuration efforts. The tested controller hardware solution is capable of managing various DER combinations (inverter based, synchronous generation, load controls, etc.) and communicating between the controllers and reclosers to join and separate microgrid areas.

Role of the Microgrid Controller

A microgrid control system is responsible for managing the DER within its boundary during both grid-connected and islanded operations. Perhaps most critically, it must manage the transitions between those operational states. In the islanded mode, when load or renewable generation conditions change, the microgrid controller must respond and dispatch available devices to maintain voltage, frequency, and power balances across the microgrid area. The controller is also responsible for managing the black start sequencing of an islanded microgrid. For many small, behind-the-meter facility microgrids, the microgrid controls logic may be deterministically programmed into fast-acting relays and single-master, grid-forming DER. However, larger microgrids with more DER and protection devices likely require a dedicated microgrid controller.

The responsibility of the microgrid controller further increases when operating within a network of microgrids. Beyond managing the DER within their own microgrids, networked microgrid controllers must communicate with each other (or a central microgrid-managing entity) to facilitate synchronizing of microgrid islands and power sharing between areas. Allowing microgrids to join and operate as a larger island system requires clear definition and testing of the interaction between the networked microgrid controllers. Coordination of networked microgrids must consider the following:

- Control objectives of each microgrid area (e.g., wider load coverage in the short term versus long-term critical load coverage)
- Available control modes of individual DER within each microgrid (e.g., whether the grid-forming devices are isochronous only or droop capable)
- Type and frequency of information passed between controllers
- Synchronization capabilities at microgrid boundaries (passive or active synchronization and related communication pathways)
- Joint control objectives of the networked microgrid area (e.g., N versus N+1 operations, load priority)
- Coordination and sequencing of transition events (e.g., black start, grid reconnection)
- Response to faults, unexpected system conditions

Banshee Network and Demonstration Model Background

To demonstrate the networked microgrid controller concept, the project team selected the Banshee distribution network system¹ to benchmark the microgrid controller capabilities. The Banshee

¹ R. Salcedo, E. Corbett and C. Smith, "Banshee distribution network benchmark and prototyping platform for hardware-in-the-loop integration of microgrid and device controllers," *IET Journals*, 2018.

system is a publicly available power distribution test network with detailed device models that have been validated for stability and accuracy. Using the Banshee model, the commercial microgrid controller's performance can be more directly compared to the performance of other commercial microgrid controllers and system management strategies. Adaptations were made to the model to allow for more focused testing of distributed controller coordination and conforms to the computing and power hardware equipment constraints of the controller-hardware-in-the-loop (CHIL) and PHIL laboratory environments.

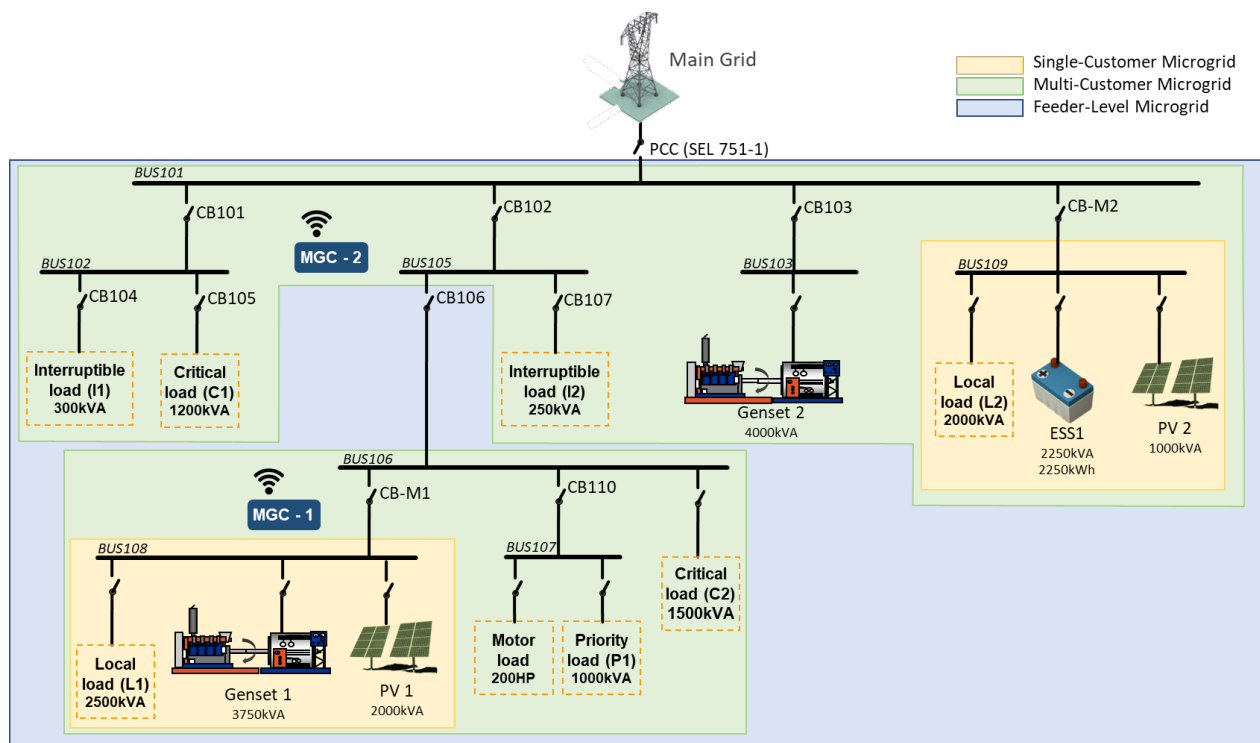


Figure ES-1. Networked Microgrid Demonstration System (Adapted from Banshee Benchmark Model); Distributed Microgrid Controllers Manage Multi-customer Areas, Shown in Green.

Test Environment

Multiple test environments (CHIL and PHIL) were developed to evaluate a broad set of test scenarios while also assessing key scenarios with higher fidelity emulation.

EPRI's co-simulation platform was utilized for microgrid controller-hardware-in-the-loop (CHIL) testing of the microgrid system integrated with the S&C GridMaster control system. The testbed is comprised of circuit models, detailed (dynamic) DER models, standards-based communications protocols, and advanced analysis and visualization techniques to simulate field conditions in a real-world microgrid.

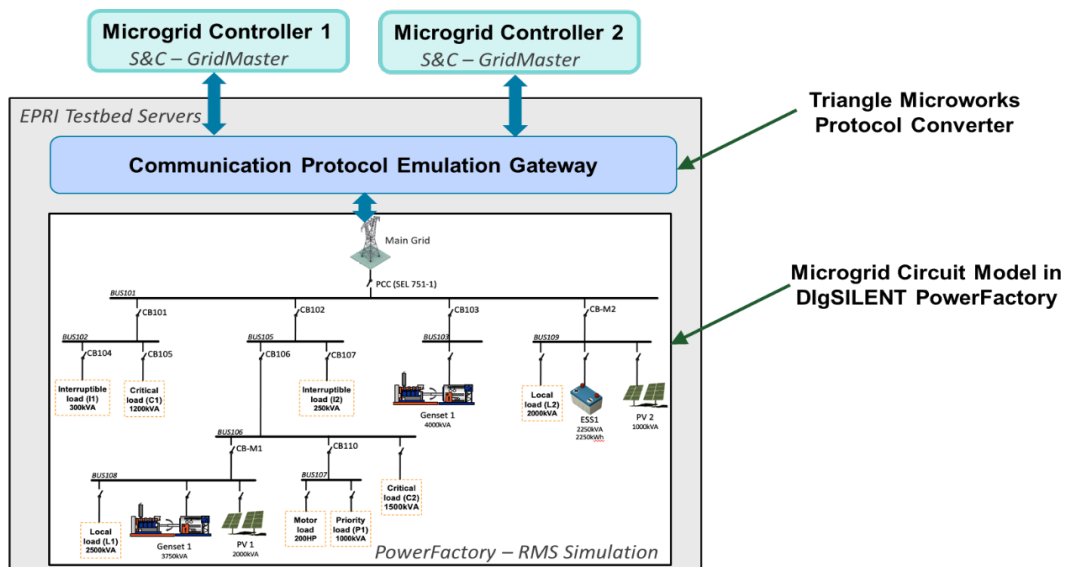


Figure ES-2. EPRI Microgrid Controller-hardware-in-the-loop Testbed Setup

The second stage of testing included a power-hardware-in-the-loop (PHIL) testbed hosted at Sandia National Lab's Distributed Energy Technology Laboratory. This testbed connects the microgrid controller hardware to a hybrid power hardware and an Opal-RT simulation feeder model.

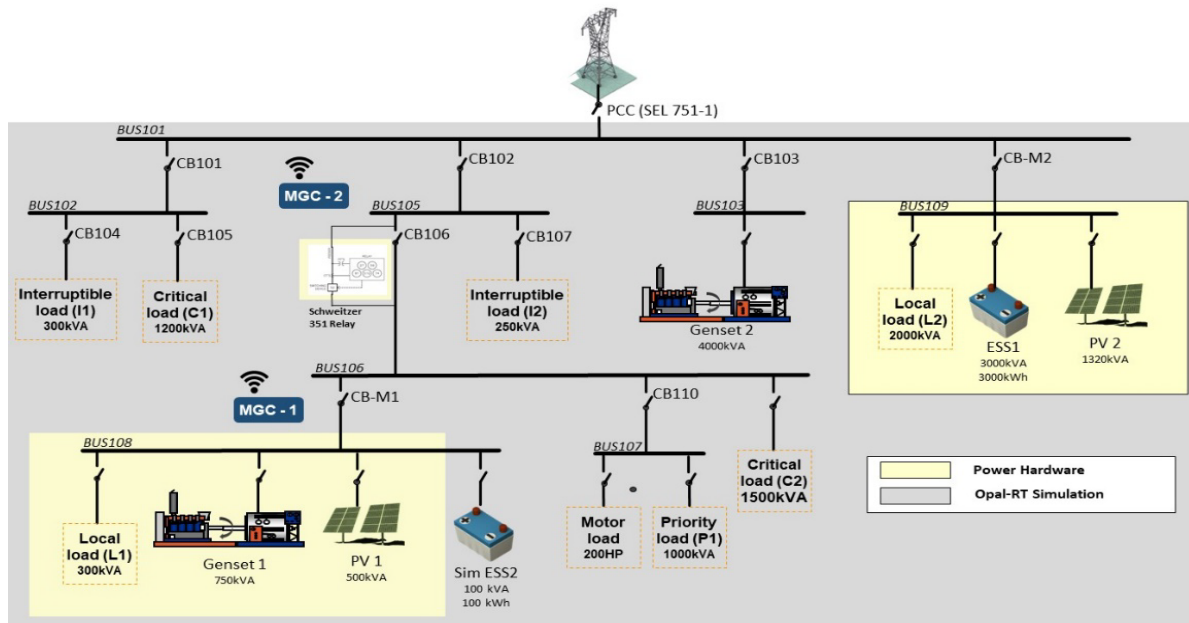


Figure ES-3. Test Environment for PHIL Demonstration; Hardware Buses Are Highlighted

Communication and Controls Interface

The benchmark distribution network was controlled by two S&C GridMaster Intelligent Power Controllers (IPCs). The CHIL and PHIL testbeds each used standard monitoring and control interfaces (e.g., SunSpec Modbus) for communicating with equipment in the distribution system.

The GridMaster IPCs share network connectivity with each other, as well as with individual DER and controllable breakers within their respective multi-customer microgrid areas. The report details the static and dynamic external interface points required by the GridMaster controllers to manage equipment in the networked microgrids.

PERFORMANCE

Performance Objectives

The following performance objectives were used to evaluate the microgrid controller throughout testing. These objectives have been selected to measure the outage recovery for resilience, increased redundancy for reliability, and operations for economic benefit of the networked microgrid controllers while complying with applicable microgrid interconnection and interoperability standards (e.g., IEEE 1547-2018, IEEE 2030.8).

Table ES-1. Summary of Performance Objectives for Evaluating Networked Microgrid Controllers

Performance Objective	Metric	Success Criteria
Local Load Outage duration	Local load outage duration during test	% decrease in outage duration observed with networked controllers vs baseline
Critical Load Outage duration	Critical load outage duration during test	% decrease in outage duration observed with networked controllers vs baseline
Priority Load Outage duration	Priority load outage duration during test	% decrease in outage duration observed with networked controllers vs baseline
Interruptible Load Outage duration	Interruptible load outage duration during test	% decrease in outage duration observed with networked controllers vs baseline
Black start automation	Time to energize and synchronize networked microgrids	Distributed controllers automatically initiate isolation switching and black start sub-microgrids within 10 minutes of grid loss
Feeder voltage	Magnitude voltage excursion during sub-feeder microgrid reconnection	All voltage readings remain within ANSI C84.1 limits during black start
Feeder frequency	Magnitude frequency excursion during sub-feeder microgrid reconnection	All frequency readings remain within IEEE 1547-2018 ride-through Hz limits during black start
Local Load Coverage	Local load served during outage	Local load remains 100% covered during outage (no difference from baseline)
Critical Load Coverage	Critical load served during outage	Critical load coverage during outage increases compared to baseline
Priority Load Coverage	Priority load served during outage	Priority load coverage during outage increases compared to baseline
Interruptible Load Coverage	Interruptible load served during outage	Interruptible load coverage during outage increases compared to baseline
Controller Coordination, economic dispatch	Operational Cost	Distributed controllers coordinate available DER generation to reduce operational costs compared to baseline

Performance Assessment

Overall, the networked microgrid controller concept was capable of meeting minimum performance requirements for the operation of joined microgrids. Across all test scenarios, the joined microgrids operated within acceptable frequency and voltage limits, and the island synchronization process did not cause adverse system conditions. The ability to safely black start, synchronize, and operate joined microgrid islands as a feeder-level island was confirmed in both CHIL and PHIL test environments.

One of the anticipated benefits of joining microgrids was the ability to share DER output to increase high priority load coverage across the joined areas during island. The test network and system conditions simulated in this project phase failed to meet the load coverage performance objectives. However, using the data gathered throughout the testing process, the project team identified several design variables that could be adjusted to improve the joined microgrid performance. Additionally, the benefits of power sharing control are expected to be more pronounced under system conditions with higher penetrations of PV and larger DER to load ratios.

Summarized results related to key performance metrics are as follows:

Feeder Voltage:

Overall, the networked microgrid configuration was able to maintain feeder voltages within acceptable operational range throughout each testing scenario. There were temporary excursions into ANSI Range B during the microgrid black start process; while this behavior is common during the energization of most microgrids, it may have an impact on undervoltage protection tripping coordination. Because this transient excursion was related to the generator equipment sizing and black start capability used in the demonstration—not the networked microgrid control design—it was not considered a failure of the controllers.

Feeder Frequency:

Overall, the networked microgrid configuration was able to maintain feeder frequency within acceptable operational range throughout each testing scenario. The maximum and minimum frequencies observed in the joined microgrid cases are related to load shedding and restoration. The system frequency is mostly within the default IEEE 1547-2018 mandatory operation range. The excursions observed beyond the default IEEE 1547-2018 frequency ride-through ranges were still within the allowable ride-through settings ranges defined in the standard. This indicates that the microgrid protection design may require frequency ride-through settings that are wider than default, regardless of the separated or networked microgrid configuration. The networked microgrid configuration, however, experienced shorter duration and magnitude frequency excursions outside the default ride-through range.

Outage Duration and Load Coverage:

The objective of the outage duration metric was to measure whether the networked microgrid controller configuration was capable of decreasing the outage duration experienced across the microgrids. The controllers were expected to prioritize loads served based on their priority assignment (Local > Critical > Priority > Interruptible). The networked microgrid controls had mixed performance across the variety of test cases. In all cases, the controllers passed the key

requirement of keeping local load online as highest priority, showing equal or reduced outage duration compared to the baseline cases. The results appear strongest for the shorter duration test scenarios; the longer duration test, Low SOC, and loss of controller scenarios did not show an improvement over the baseline for reducing load outage duration.

The load coverage in joined microgrid is worse than the baseline result across most test cases. Multiple factors may have contributed to this result based on the project team's analysis: non-ideal control logic when ESS's SOC drop to a low threshold, insufficient communication of data between the microgrid controllers, and lack of a forecast-based planning algorithm for long-term island operations. In most cases, the SOC is depleted during the night covering the lower priority loads. A reliability-based dispatch algorithm may be helpful to reserve the capacity of the battery if longer period of islanded operation is foreseeable.

COST ASSESSMENT

A cost model for implementing a networked microgrid control system is provided in Table 9-1 below. The data identified in this model reflects the microgrid controller element costs and additional upgrades necessary to enable networked microgrid operation. The costs in the table do not reflect the total cost of implementing a microgrid (individual or multiple), such as DER installation and commissioning costs.

Table ES-2. Cost Model for Modular Microgrid Controller

Cost Element	Data Tracked During the Demonstration	Estimated Costs
Hardware capital costs	Estimates made based on component costs for demonstration	\$75K for control hardware (\$25k per control unit)
		\$50K for managed network switches and dedicated fiber
		Additional costs may be incurred to add remote operation functionality to generators, switchgear.
Installation costs	Labor and material required to install	\$30K
Consumables	Fuel cost used during demonstration	Diesel at \$3 / gallon. Estimated using market price at time of simulation tests.
Facility operational costs	Reduction in energy required vs. baseline data	Savings (%)
		Energy Total 0.57%
		Energy Billed Cost 13.65%
		Demand Charge 24.59%
Maintenance	- Frequency of required maintenance - Labor and material per maintenance action	10% annually of initial capital costs
		Assume generator maintenance cost of \$0.01 per kWh produced
Hardware lifetime	Estimate based on components degradation during demonstration	Assume replacement of controller hardware every 7 years
		Assume replacement of battery packs every 5 years
Operator training	Estimate of training costs	\$6K (Assume 1 person week for training every five years)

IMPLEMENTATION ISSUES

End-users and those considering a networked microgrid control solution implementation may consider further investigating the following factors in more depth as part of their assessment of whether this type of control is best for their system needs.

- Assess the data exchanged between controllers when joint area control decisions are made.
- DER mix in test system: Consider whether the microgrid is dominated by inverter-based resources – such as renewables and energy storage – to better understand how such devices would impact black start and accommodation of sudden load changes.
- Higher ratio of DER to load: Proportion of variable DER or a different ratio of inverter vs synchronous generation-based DER and total load in the system. Performance may also vary based on ratios of different load priorities.
- Performance comparisons to a single, centralized controller vs the networked, distributed controls should be performed to better quantify how the microgrid would respond to loss of communications between components and to quantify a level of complexity at which distributed controls are more advantageous than a central control despite the added complexity of the system.
- Consider the impact of equipment protection and ability to adjust settings based on the various networked microgrid configurations.
- Mixed duration outage testing: compare the performance of the networked controls during short-term versus long-term outages. Include forecasted energy reserves into the design performance criteria of the controller interactions.
- Consider designing for the ability to pick up non-microgrid loads in the event of widespread utility outages.

Procurement of a commercialized system may be challenging. The evaluated controls were developed on commercial off-the-shelf equipment but programmed with prototype software. This type of software control is in the newly commercialized stage and vendor claims should be carefully evaluated during procurement.

1.0 INTRODUCTION

As part of a DoD ESTCP award in 2020, EPRI began a project to demonstrate “innovative solutions that reduce the time and cost of designing and implementing microgrids in military installations.” To address this challenge, EPRI worked with a commercial microgrid controls vendor (S&C Electric Company) and Sandia National Laboratories to design and test a networked microgrid controller. Key concepts of DER power sharing, multilayer network redundancy, sequenced outage recovery, coordinated system protection, and cyber-secure communications were demonstrated. This report captures the executed test plan, results, and performance analysis of the networked microgrid controls.

1.1 TEST PLAN BACKGROUND

EPRI’s co-simulation platform (detailed in the [CHIL Configuration section](#)) was utilized for microgrid controller-hardware-in-the-loop (CHIL) testing of the microgrid system integrated with the S&C GridMaster control system. The testbed is comprised of circuit models, detailed (dynamic) DER models, standards-based communications protocols, and advanced analysis and visualization techniques to simulate field conditions in a real-world microgrid. The second stage of testing includes a power-hardware-in-the-loop (PHIL) testbed hosted at Sandia National Lab’s Distributed Energy Technology Laboratory. This testbed connects the microgrid controller hardware to a hybrid power hardware and an Opal-RT simulation feeder model (detailed in the [PHIL Testbed section](#)). The test cases defined in the test plan will be executed, and the results will be documented based on predefined performance criteria.

The core concepts in this project involve demonstrating, through rigorous testing, a decentralized control architecture that will allow implementation of multiple networked microgrids that cost-effectively employ a combination of legacy generation assets, building loads, and DER assets. The key beneficial goals include the following:

- Integrate combinations of legacy generation assets and DER for utilization as capacity resources in lieu of large-scale centralized resources.
- Enable DER power sharing, meet reliability targets, and increase robustness to localized failures.
- Facilitate operation of multiple independent microgrids within a military site.
- Expedite the installation and commissioning of networked microgrids, simplification of component and systems integration, and sequencing or intelligent phasing of modular expansions across a military installation over time while addressing the expected business and financial constraints of microgrid design-builds.

2.0 MICROGRID CONTROLLER

2.1 BANSHEE NETWORK AND DEMONSTRATION MODEL BACKGROUND

To demonstrate the networked microgrid controller concept, the project team selected the Banshee distribution network system [1] to benchmark the microgrid controller capabilities. The Banshee system is a publicly available power distribution test network with detailed device models that have been validated for stability and accuracy. Using the Banshee model, the commercial microgrid controller's performance can be more directly compared to the performance of other commercial microgrid controllers and system management strategies. A reduced version of the Banshee model will be used for this demonstration project, as shown in Figure 2-1. The adapted model uses Feeder 1 from the original model with four additional DER and two additional loads and adds passive synchronization capabilities to circuit breaker (CB)-106. Devices on the additional buses, 108 and 109, are based on actual power hardware equipment that were used during power-hardware-in-the-loop (PHIL) testing at Sandia National Laboratories. This adaptation allows for more focused testing of distributed controller coordination and conforms to the computing and power hardware equipment constraints of the controller-hardware-in-the-loop (CHIL) and PHIL laboratory environments. Details on the test system configuration are provided in [Section 3.0 HIL Configuration](#) of this report; equipment ratings are provided in Figure 2-1 and Table 2-1.

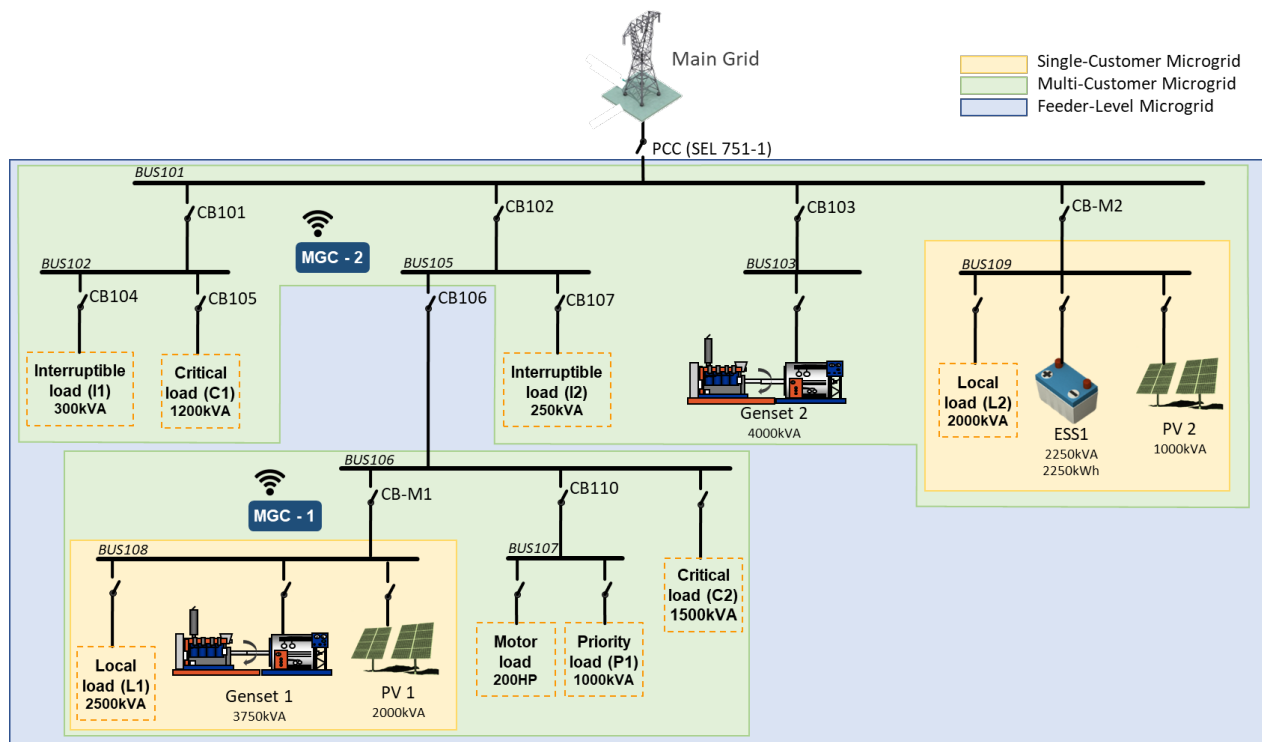


Figure 2-1. Networked Microgrid Demonstration System (adapted from Banshee benchmark model); Distributed Microgrid Controllers Manage Multi-customer Areas, Shown in Green.

Table 2-1. Adapted Banshee Model Equipment Ratings

	Bus	Element	Rating (MW)	Rating (MVA)
MGC-1	Bus 108, PHIL 1	Diesel Genset 1	3	3.75
		PV Inverter 1	2	2
		Local Load 1	2	2.5
	Bus 106	Load C2 (Critical)	1.2	1.5
	Bus 107	Load P1 (Priority)	0.8	1
		Motor Load (Interruptible)	0.15	0.16
MGC-2	Bus 109, PHIL 2	ESS Grid Forming Inverter 1	2.25 (2.25 MWh)	2.25
		PV Inverter 2	1	1
		Local Load 2	1.6	2
	Bus 103	Diesel Genset 2	3.2	4
	Bus 102	Load I1 (Interruptible)	0.24	0.3
		Load C1 (Critical)	0.96	1.2
	Bus 105	Load I2 (Interruptible)	0.2	0.25

2.2 DEMONSTRATION SYSTEM CONTROL BOUNDARIES AND LOAD PRIORITY

To demonstrate the multi-level, distributed microgrid controller architecture concept, the adapted Banshee system is divided into predefined microgrid boundaries, as shown in Figure 2-1 above. Two distributed GridMaster microgrid controllers each manage a separate area of the feeder. Each controller can independently operate a single- or multi-customer microgrid in isolation from other portions of the feeder; it has visibility and control of devices within and on the perimeter of its boundary. The two controllers are connected through a common communications network and can coordinate to synchronize their respective microgrid areas and form a single, feeder-level microgrid.

These microgrid configuration levels can be defined as follows:

- *Single-customer* microgrid (yellow regions in Figure 2-1): The smallest microgrid boundary area that can operate in isolation from the feeder; contains at least one grid-forming DER and a critical load, and is managed by one controller
- *Multi-customer* microgrid (green+yellow regions in Figure 2-1): An extended microgrid boundary area that operates in isolation from part of the feeder, contains at least one grid-forming DER and multiple priority load types with controllable breakers, and is managed by one controller

- *Feeder-level* microgrid (blue+yellow+green regions in Figure 2-1): Microgrid boundary area that includes the entire feeder and operates in isolation from the utility grid; multiple controllers manage a single island

When the substation feeder breaker (PCC [SEL 751-1] in Figure 2-1) is closed, the microgrid controllers continue to manage their respective microgrid areas. In this case, the controllers will manage the DER with grid-connected objectives.

With the new local loads added to the demonstration model, the microgrid controllers must consider four tiers of load levels when determining black start and load shed order. The controllers are configured to manage loads in the following order:

1. Local load (highest priority)
2. Critical load
3. Priority load
4. Interruptible load (lowest priority)

2.3 OPERATIONAL STRATEGY

This section describes the various strategies used to dispatch and curtail power sources. The concept of N reliability refers to having as many sources available as necessary to satisfy the electrical demand but no more, while N+1 reliability refers to having one extra source available such that you can unexpectedly lose the largest operating power source and still have sufficient on-line capacity to avoid an outage. Further details on the controller operational strategies and modes are provided in the S&C Microgrid Architecture Report [2].

2.3.1 N reliability

Reserve values are calculated using all spinning reliable sources (i.e., those that are available and not in error). Renewables are assumed to trip off with the failure of the first source. Thus, the reserves do not include any renewable capacity.

2.3.2 N+1 reliability

N+1 operation strives to keep enough reliable sources online that should any single fail, the remainder can hold up the island. This N+1 criterion is a short-term consideration since in the long-term another source can be brought online and/or loads can be curtailed. Therefore, multiple short-term reserve values are calculated, each with a different source removed from the spinning sources. The reserve is the minimum value produced from those and from the N based long-term calculation. This strategy requires that 2 reliable sources are running in island mode.

Renewables are assumed to trip off with the failure of the first source. Thus, the reserves do not include any renewable capacity.

3.0 HIL CONFIGURATION

3.1 EPRI CONTROLLER-HARDWARE-IN-THE-LOOP TESTBED

3.1.1 Microgrid CHIL Testbed Components

The EPRI CHIL testbed is designed to validate the performance of the designed microgrid controller against a balanced RMS network simulation. The equipment and software components used in the testbed are listed in Table 3-1.

Table 3-1. Components of the EPRI CHIL Microgrid Testbed

Testbed Component	Vendor and Application	Notes
Power System Simulation	DIgSILENT PowerFactory	Dynamic RMS simulation with DER-level controls and system monitoring via OPC.
Communication Gateway	Triangle Microworks SCADA Data Gateway	Protocol conversion interface between power system simulation and microgrid controller. Emulates vendor-specific DER interface. Handles OPC, DNP3, Modbus TCP/IP, etc.
Microgrid Controller	S&C GridMaster Intelligent Power Controllers	Microgrid controller. Testbed setup includes off-the-shelf controller hardware provided by S&C. https://www.sandc.com/en/products--services/products/gridmaster-microgrid-control-system/

3.1.2 Test Environment

The microgrid controller hardware-in-the-loop testbed will run in the EPRI Knoxville lab on two Windows server machines, networked with two commercial microgrid controllers.

The SCADA (supervisory control and data acquisition) Gateway component of the CHIL testbed models the communication interface of individual DER as seen by the microgrid controller. The gateway will be configured to resemble the field interface of DER in order to best evaluate the performance of the microgrid controller without field-specific alterations.

The PowerFactory model includes an OPC interface allowing external monitoring and control communications with the microgrid controller via the SCADA Gateway. The SCADA Data Gateway mapping provides a conversion from OPC to Modbus TCP/IP; its configuration includes individual device IDs and replicates commercial communication interface mapping for the DER and controllable breakers. The GridMaster controllers pass control signals by communicating with the gateway over Modbus TCP/IP. See Figure 3-1 for a generator testbed layout diagram.

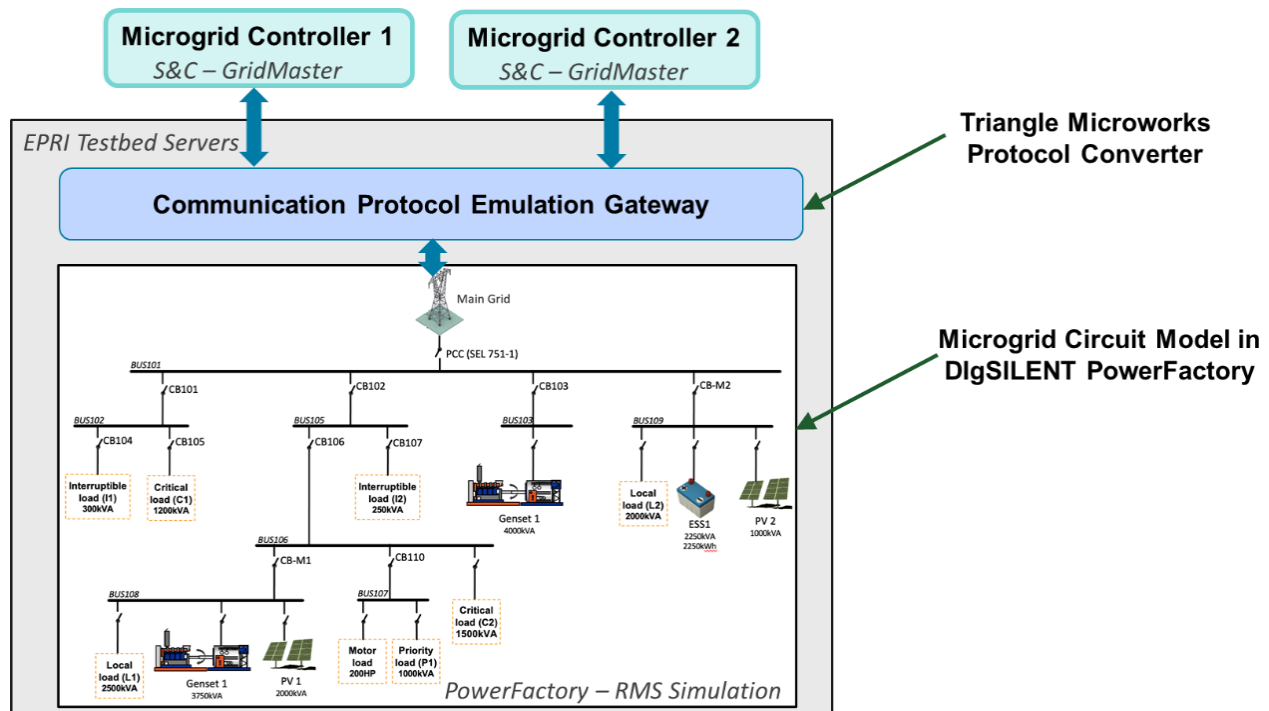


Figure 3-1. Microgrid Controller-hardware-in-the-loop Testbed Setup

The GridMaster controllers are designed to manage the distribution system autonomously. While the controllers include an operator interface for configuration and manual intervention, this interface will not be used for testing purposes beyond commissioning configuration and troubleshooting of individual device communications and refining of functional interfaces.

External monitoring and control point availability are based on the dynamic data stream interfaces specified in the detailed project test plan report [3].

3.1.3 Microgrid Network and DER Simulation

DlgSILENT PowerFactory is used to model and simulate the power system dynamics of the feeder microgrid and its electrical components. The RMS simulation tool in PowerFactory can analyze balanced and unbalanced transient conditions triggered by internally programmed or externally controlled events. The DlgSILENT Simulation Language enables the real-time simulation to include DER model definitions to enable dynamic responses and common control functions from an external controller. The microgrid network model will only be programmed to simulate responses of the power system dynamics and individual DER controllability. High-level microgrid controls (e.g., coordinated island transitioning, peak load reduction, diesel fuel limiting) will be managed by the external microgrid controller system, shown as IPC-1 and IPC-2 in Figure 5-1.

For each test case, the distribution network simulation contains an automated series of events designed to trigger a control response from the external controller hardware. The microgrid controllers are expected to manage the system conditions by dispatching available DER output and reconfiguring system switches to meet the performance objective of the respective test.

Load and generation profiles have been adapted from the DOE Smart Inverter Project: Haverhill, with permission from EPRI.

3.2 SANDIA POWER-HARDWARE-IN-THE-LOOP TESTBED

The second stage of testing includes a PHIL testbed hosted at Sandia National Lab's Distributed Energy Technology Laboratory. This testbed connects the microgrid controller hardware to a hybrid power hardware and an Opal-RT simulation feeder model. For this evaluation, the IPCs automatic features were not enabled and the IPCs were utilized in manual mode and were used to enable PV1 and PV2 inverters and sets the operating modes and power levels of ESS-1 and Genset 1. The customer-level microgrids (yellow boxed equipment in Figure 3-2) where both exercised, and both worked well. The initial sequence for black start suggested the customer-microgrid start-up and then close CB-M1 or CB-M2 and energize the multi-customer microgrid portion. This however can't be accomplished without large perturbations or tripping the ac simulator because of energizing a dead bus. Instead, to demonstrate black-start capabilities, the multi-customer microgrids were first energized, which is accomplished by starting-up Genset 2 in MGC-2 and then the customer-microgrids were energized. For MGC-1, there wasn't a generation source, so a 100kVA ESS-BESS device (Sim-ESS-2) was inserted onto BUS 108. The IPCs are used to enable ESS1 and can bias the frequency and voltage to adjust the active and reactive power generation of ESS-1, see Figure 3-2 for reference.

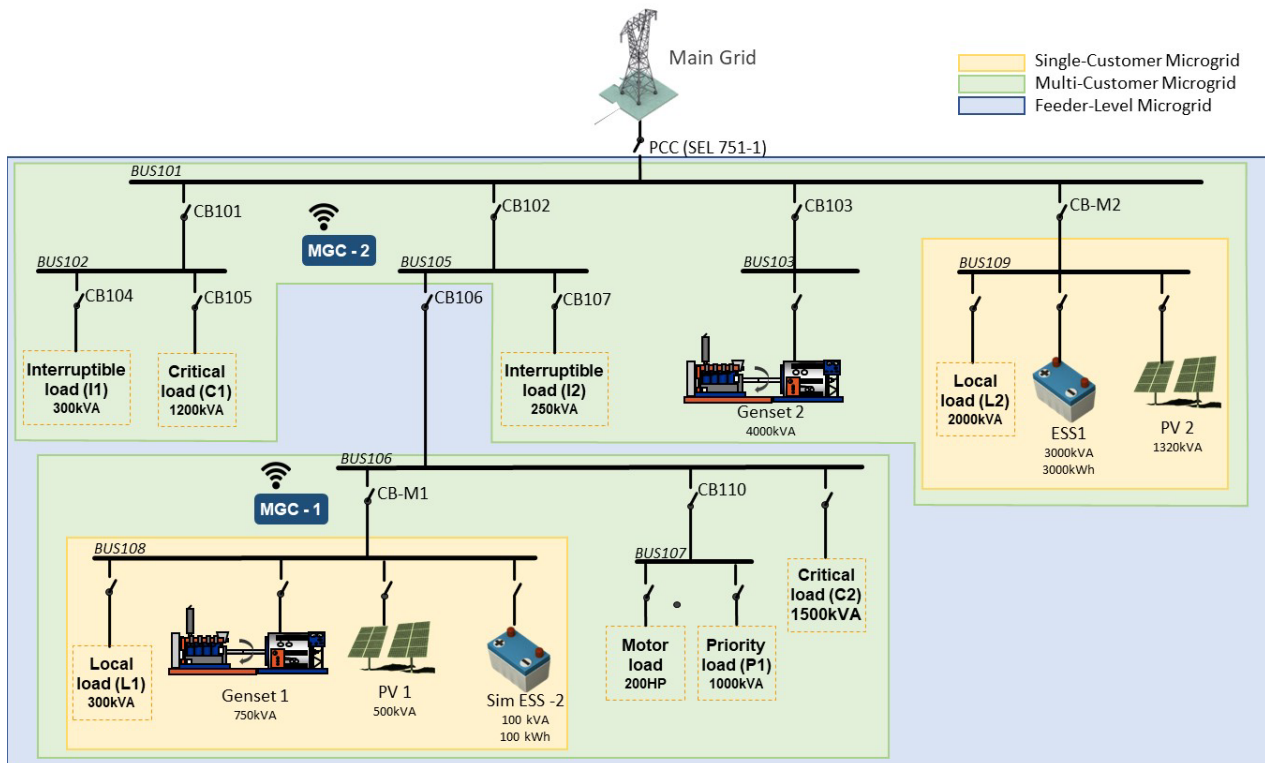


Figure 3-2. Networked Microgrid Demonstration System for PHIL Testing (Adapted from Banshee Benchmark Model); Distributed Microgrid Controllers Manage Multi-customer Areas, Shown in Green.

Table 3-2. Adapted Banshee Model Equipment Ratings for PHIL Testing

	Bus		Element	Rating (kW)	Rating (kVA)
MGC-1	Bus 108	PHIL 1	Diesel Genset 1	750	750
			PV Inverter 1	500	500
			Local Load 1	300	300
		Opal-RT	Simulated GFM ESS	100 (100 kWh)	100
	Bus 106		Load C2 (Critical)	1200	1500
	Bus 107	Load P1 (Priority)	800	1000	
		Motor Load (Interruptible)	150	160	
MGC-2	Bus 109, PHIL 2		ESS Grid Forming Inverter 1	3000 (3000 kWh)	3000
			PV Inverter 2	1320	1320
			Local Load 2	2000	2000
	Bus 103		Diesel Genset 2	3200	4000
	Bus 102	Load I1 (Interruptible)	2400	3000	
		Load C1 (Critical)	960	1200	
	Bus 105		Load I2 (Interruptible)	200	250

The separation between hardware and simulated network components is shown in Figure 3-3. Each power hardware bus is connected to the Opal-RT feeder model through a 90-kVA Ametek Grid Simulator. The Opal-RT simulation scales the inputs from each Grid Simulator to proportionately tie the power hardware buses into the adapted Banshee model. The equipment types, real ratings, and scaled equivalent ratings in simulation on each bus are provided in Table 3-3.

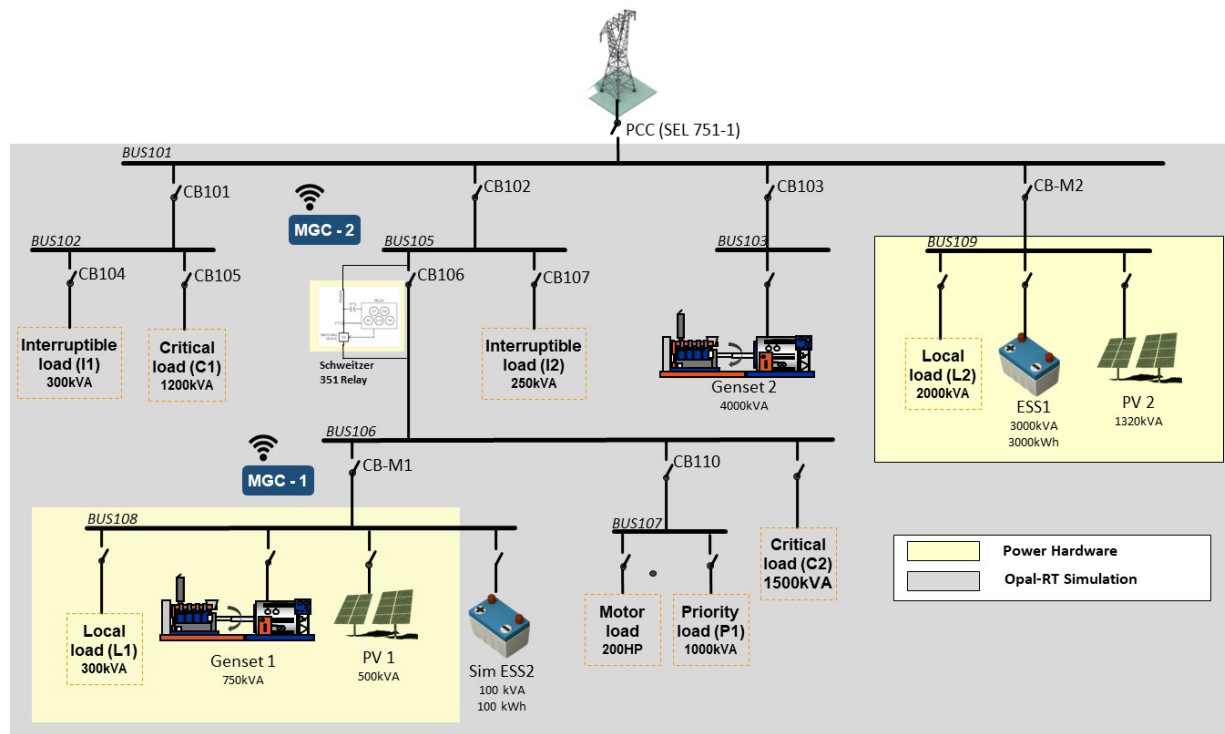


Figure 3-3. Test Environment for PHIL Demonstration; Hardware Buses Are Highlighted

Table 3-3. Sandia Lab Power Hardware Equipment and Scaled Ratings in Feeder Model

	Element	Device Model	Sandia Power Hardware	Simulation Rating
Bus 108, PHIL 1	Diesel Genset 1	CAT Diesel Generator with Woodward Controller	75 kW	750 kVA
	PV Inverter 1	SMA Tripower Core 1	50 kW	500 kW
	DC PV 1	YL300P-35b		
	Local Load 1	Avtron Spirit Manual Control Load Bank	50 kW	500 kVA
Bus 109, PHIL 2	ESS Inverter 1	ABB PCS100 ESS	75 kVA	3.0 MVA
	DC Battery Sim 1		75 kWh (configurable)	3.0 MWh
	PV Inverter 2	SMA Tripower Core 1	33kW	1.32 MW
	DC PV Sim 2			
	Local Load 2	ASCO Programmable RLC Load Bank	50 kW	2 MVA
	CB-106	Schweitzer 351 synchronizing relay	SEL-351 Synchronizing Relay	CB106

Each PHIL bus will be managed by a separate microgrid controller; the distributed microgrid controllers can independently isolate and black start their respective PHIL buses in parallel. The microgrid controllers will also be connected to the digital simulation. During various test scenarios, the PHIL buses will be synchronized through one common Opal-RT simulation. The Grid Simulator on each PHIL bus converts the analog output of each bus to a digital power output flowing into the system simulation. The synchronizing breaker, CB-106 between Bus 105 and Bus 106, will also incorporate a CHIL component. The Schweitzer 351 synchronizing relay will be connected to the Opal-RT simulation to emulate the synchronization check and send a close breaker signal to the simulation. When the microgrid controllers initiate a “synchronize microgrids” step, they will directly communicate with the physical synch relay to initiate the synch check and breaker close process.

Incorporating real, grid-forming DER into the PHIL testbed environment increases the test fidelity of the demonstration. The duration and scope of certain tests will be constrained within the safe operational procedures of Sandia’s lab environment. However, using separate power hardware buses with real DER that can operate independently and are synchronized through simulation will provide critical insight into the stability of the networked microgrid controllers.

Additional data from the PHIL testbed configuration is provided in [Appendix A](#).

3.3 PURPOSE OF CHIL AND PHIL TESTING

The purpose of the CHIL test is to evaluate the performance of the networked microgrid controller across all test conditions described in the [CHIL Performance Testing section](#). Using a simulation-based testbed with controller hardware in the loop allows for a broader range of test scenarios for the demonstration project. The CHIL system supports multi-day test duration and edge cases that must be limited in the power-hardware-in-the-loop environment. The CHIL test bed also provides

a lower cost testing environment, allowing communications interfaces and key control testing to be completed before moving into the more expensive PHIL test environment. This stage of testing will also enable the test team to tune the microgrid controller algorithms before beginning PHIL testing.

The purpose of the PHIL testing is similarly to evaluate the performance of the networked microgrid controllers. The primary differentiator of the PHIL environment is the ability to use commercially available DER power hardware in the loop with the simulated test network. This increases the fidelity of the overall test simulation and provides valuable information about the control interactions, both with communications interoperability and dynamic coordination between the variety of equipment controllers. However, the cost of running each PHIL test is much higher than in the CHIL environment, and there are more limitations to the boundary conditions and edge cases that can be safely tested on physical power equipment. That limited the PHIL testing to covering only 1 of the 7 total test cases.

Overall the combination of testing the same network feeder in different CHIL and PHIL environments allowed the networked microgrid controllers to be evaluated against a broader range of test cases while also assessing key scenarios with higher fidelity emulation.

4.0 PERFORMANCE OBJECTIVES

The following section provides the controller performance objectives that will be used to evaluate the microgrid controller throughout testing. These objectives have been selected to measure the outage recovery for resilience, increased redundancy for reliability, and operations for economic benefit of the networked microgrid controllers. Specifically, the metrics will quantify the microgrid controller's ability to reduce customer outage duration and expand island load coverage, while complying with applicable microgrid interconnection and interoperability standards (e.g., IEEE 1547-2018, IEEE 2030.8).

4.1.1 SUMMARY OF PERFORMANCE OBJECTIVES

Table 4-1, Table 4-2, and Table 4-3 present a summary of the performance objectives that will be used in the networked microgrid controller tests. Each table corresponds to one of the key demonstration goals: provide outage recovery, redundancy, and economic dispatch services.

Table 4-1. Performance Objectives for Black Start Outage Recovery

Performance Objective	Metric	Data Requirements	Success Criteria
Black Start (Grid to Feeder Island Transition)			
Local Load Outage duration	Local load outage duration during black start	Meter readings of local loads on feeder	% decrease in outage duration observed with networked controllers vs baseline
Critical Load Outage duration	Critical load outage duration during black start	Meter readings of critical loads on feeder	% decrease in outage duration observed with networked controllers vs baseline
Priority Load Outage duration	Priority load outage duration during black start	Meter readings of priority loads on feeder	% decrease in outage duration observed with networked controllers vs baseline
Local and Critical Load Coverage	Local and Critical load interruption time during synchronization of multiple microgrids	Meter readings on local and critical loads	All local and critical loads remain online and uninterrupted during island synchronization
Black start automation	Time to energize and synchronize networked microgrids	Meter readings from microgrids, utility-side PCC, and IPC control signals	Distributed controllers automatically initiate isolation switching and black start sub-microgrids within 10 minutes of grid loss
Feeder voltage	Magnitude voltage excursion during sub-feeder microgrid reconnection	Bus voltages at each microgrid, branch recloser, and feeder PCC	All voltage readings remain within ANSI C84.1 limits during black start
Feeder frequency	Magnitude frequency excursion during sub-feeder microgrid reconnection	Frequency at each microgrid, branch recloser, and feeder PCC	All frequency readings remain within IEEE 1547-2018 ride-through Hz limits during black start

Table 4-2. Performance Objectives for Island Operations

Performance Objective	Metric	Data Requirements	Success Criteria
Island Operations (Reliability Tests)			
Local Load Coverage	Local load served during outage	Meter readings on local loads throughout outage	Local load remains 100% covered during outage (no difference from baseline)
Critical Load Coverage	Critical load served during outage	Meter readings on critical loads throughout outage	Critical load coverage during outage increases compared to baseline
Priority Load Coverage	Priority load served during outage	Meter readings on priority loads throughout outage	Priority load coverage during outage increases compared to baseline
Interruptible Load Coverage	Interruptible load served during outage	Meter readings on interruptible loads throughout outage	Interruptible load coverage during outage increases compared to baseline
Feeder voltage	Magnitude voltage excursion during sub-feeder microgrid reconnection	Bus voltages at each microgrid, branch recloser, and feeder PCC	All voltage readings remain within ANSI C84.1 limits during island operations
Feeder frequency	Magnitude frequency excursion during sub-feeder microgrid reconnection	Frequency at each microgrid, branch recloser, and feeder PCC	All frequency readings remain within IEEE 1547-2018 ride-through Hz limits during island operations

Table 4-3. Performance Objectives for Grid-Connected Operations

Performance Objective	Metric	Data Requirements	Success Criteria
Grid Connected Operations (Economic Benefit Tests)			
Controller Coordination, economic dispatch	Operational Cost	Meter readings from microgrids, utility-side PCC, DER, and S&C control signals	Distributed controllers coordinate available DER generation to reduce operational costs compared to baseline
Feeder voltage	Magnitude voltage excursion during event	Bus voltages at each microgrid, branch recloser, and feeder PCC	All voltage readings remain within ANSI C84.1 limits during event

4.1.2 Performance Objectives Descriptions

4.1.2.1 Feeder Bus Voltage

- Feeder Bus Voltage: bus voltages (in per unit) across the test feeder
- Purpose: Networked microgrids typically operate across multiple customer meters, and thus should remain within grid-connected interconnection voltage tolerance ranges when islanded as a joint network of microgrids.

- Metric: Magnitude of bus voltage excursions (in p.u.) throughout the test sequence
- Data: Bus voltages at each microgrid, branch recloser, and feeder PCC. Per the Equipment Interface section details, each breaker and DER will provide voltage readings for post-analysis.
- Success Criteria: In all test cases, the voltage readings in the network are expected to remain within ANSI C84.1 short-term and long-term ranges (as referenced in IEEE 1547-2018 and IEEE 2030.8). These are provided below in Table 4-4 for reference.

Table 4-4. ANSI C84.1 Voltage Magnitude Limits

ANSI C84.1	Range A (long-term)	Range B (short-term)
Minimum	0.95	0.917
Maximum	1.05	1.058

4.1.2.2 Feeder Frequency

- Feeder Bus Frequency: bus and DER frequency (in Hz) across the test network
- Purpose: Networked microgrids typically operate across multiple customer meters, and thus should remain within grid-connected interconnection frequency tolerance ranges when islanded as a joint network of microgrids.
- Metric: Frequency reading (in Hz) throughout the test sequence.
- Data: Frequency measurement at each microgrid, branch recloser, and feeder PCC. Per the Equipment Interface section details, each breaker and DER will provide frequency readings for post-analysis.
- Success Criteria: In all test cases, the frequency readings in the network are expected to remain within IEEE 1547-2018 default “Continuous Operation” or “Mandatory Operation” frequency ranges. These allowable operational frequency ranges are provided in Table 4-5 for reference.

Table 4-5. Allowable Range for Frequency Readings within the Microgrid throughout Testing; Adapted from IEEE 1547-2018 DER Ride-through Requirements

Frequency Range (Hz)	Maximum frequency deviation time allowance	Operating state
$f > 62.0$	0.16 s	DER expected to trip
$61.2 < f \leq 61.8$	300 s	Mandatory Operation
$58.8 \leq f \leq 61.2$	Infinite	Continuous Operation
$57.0 \leq f < 58.8$	300 s	Mandatory Operation
$f < 57.0$	0.16 s	DER expected to trip

4.1.2.3 Synchronization Tolerance

- Synchronization Tolerance: Voltage and frequency differences between sub-microgrids when microgrid controllers coordinate to form a feeder-level microgrid.

- Purpose: The microgrid controllers are expected to manage the individual microgrid areas' voltage and frequency to enable synchronization and joining of multiple microgrids.
- Metric: This PO will use the difference between feeder frequency and voltage measurements in microgrid 1 and 2 as described in the respective POs above.
- Data: see data collection for Feeder Frequency and Feeder Bus Voltage objectives above.
- Success Criteria: The networked microgrid controllers must not send a close signal to the synchronization relay if the sub-microgrid frequency and voltage differences are larger than the allowable difference specified in Table 4-6 below. This table from IEEE 1574-2018 is used as a reference for synchronization tolerance limits in evaluating this networked microgrid function.

**Table 4-6. Synchronization Parameter Limits for Joining Networked Microgrids;
Adapted from IEEE 1547-2018 [4]**

Frequency difference (Δf , Hz)	Voltage difference (ΔV , %)
0.1	3

4.1.2.4 Black start automation

- Black start automation: The automated process of black starting the full feeder-level networked microgrid following a utility grid outage.
- Purpose: The networked microgrid controllers are expected to provide faster and wider outage recovery. This performance objective measures the speed of this automated black start process.
- Metric: Time to energize and synchronize networked microgrids (in minutes)
- Data: Meter readings from microgrids, utility-side PCC, and IPC control signals
- Success Criteria: Distributed controllers automatically initiate isolation switching and black start sub-microgrids within 10 minutes of grid loss.

4.1.2.5 Load Outage Duration

- Load Outage Duration: The total elapsed time between a utility outage and re-energization of the load by the microgrid black start.
- Purpose: The microgrid controllers are expected to minimize outage duration for loads along priority order (Local > Critical > Priority > Interruptible). This performance objective measures the customer outage length during respective tests for comparison against a baseline scenario.
- Metric: Duration of load outage (in minutes) by type of load.
- Data: Timestamped meter readings at each load in the test feeder. Load outage duration will be calculated as the total time elapsed between the start of the grid black-out and when the respective load is brought online again. This outage duration will be calculated separately for each type of load (local, critical, priority, and interruptible).

- Success Criteria: Decrease in outage duration observed with networked microgrid controllers compared to baseline setup described in respective test cases. A separate performance objective will be calculated for each load type. Performance improvements are expected to align with load priority order (Local > Critical > Priority > Interruptible).

4.1.2.6 Load Coverage

- Name and Definition: Load coverage is quantified as the total energy served by the microgrid DER during an island event.
- Purpose: The networked microgrid controllers are expected to increase load coverage for loads along priority order (Local > Critical > Priority > Interruptible). This performance objective measures the total power served during respective tests for comparison against a baseline scenario.
- Metric: Total energy (in kWh) consumed by respective load types on the test feeder. This coverage should be calculated separately for each type of load (local, critical, priority, and interruptible).
- Data: Timestamped meter readings at each load in the test feeder. Load coverage will be calculated as the total energy served by the microgrid DER during an island event. This coverage metric will be calculated separately for each type of load (local, critical, priority, and interruptible).
- Success Criteria: The microgrid controllers are expected to improve coverage for the highest priority loads during islanding. A separate performance objective will be calculated for each load type. Performance improvements are expected to align with load priority order (Local > Critical > Priority > Interruptible).

4.1.2.7 Controller Coordination – Economic dispatch

- Economic Dispatch: The ability of the microgrid controllers to provide economic benefit (e.g., utility bill reduction) by coordinating DER dispatch during grid-connected state.
- Purpose: The controllers are designed to provide economic benefits during grid-connected operations (with substation feeder recloser and sub-microgrid isolation breaker closed). The sub-microgrid controllers are expected to coordinate to operate the system in least-cost mode.
- Metric: Operational cost (in \$) of running the microgrid (equivalent utility bill over duration of test sequence plus fuel costs)
- Data: Power readings (in kW) collected from all microgrid loads and DER outputs. Total utility bill cost will be calculated by using common military base utility rates, including a monthly fixed charge, Summer On-/mid-/off-peak charges in \$/kWh, Winter Mid-/off-peak charges in \$/kWh, Monthly Peak Demand charges in \$/kW, and other fees. Diesel fuel price will be considered in \$/gallon along with the heat rate of the diesel gensets in Btu/kWh.
- Success Criteria: The microgrid controllers reduce the total utility bill while grid-connected compared to a baseline without microgrid control.

5.0 HIL INTEGRATION AND INITIAL TESTING

5.1 COMMUNICATION AND CONTROLS INTERFACE

The benchmark distribution network will be controlled by two S&C GridMaster Intelligent Power Controllers (IPCs). The CHIL and PHIL testbeds will provide common monitoring and control interfaces for equipment in the distribution system. The GridMaster IPCs share network connectivity with each other, as well as with individual DER and controllable breakers within their respective multi-customer microgrid areas. This section details the static and dynamic external interface points required by the GridMaster controllers to manage equipment in the networked microgrids.

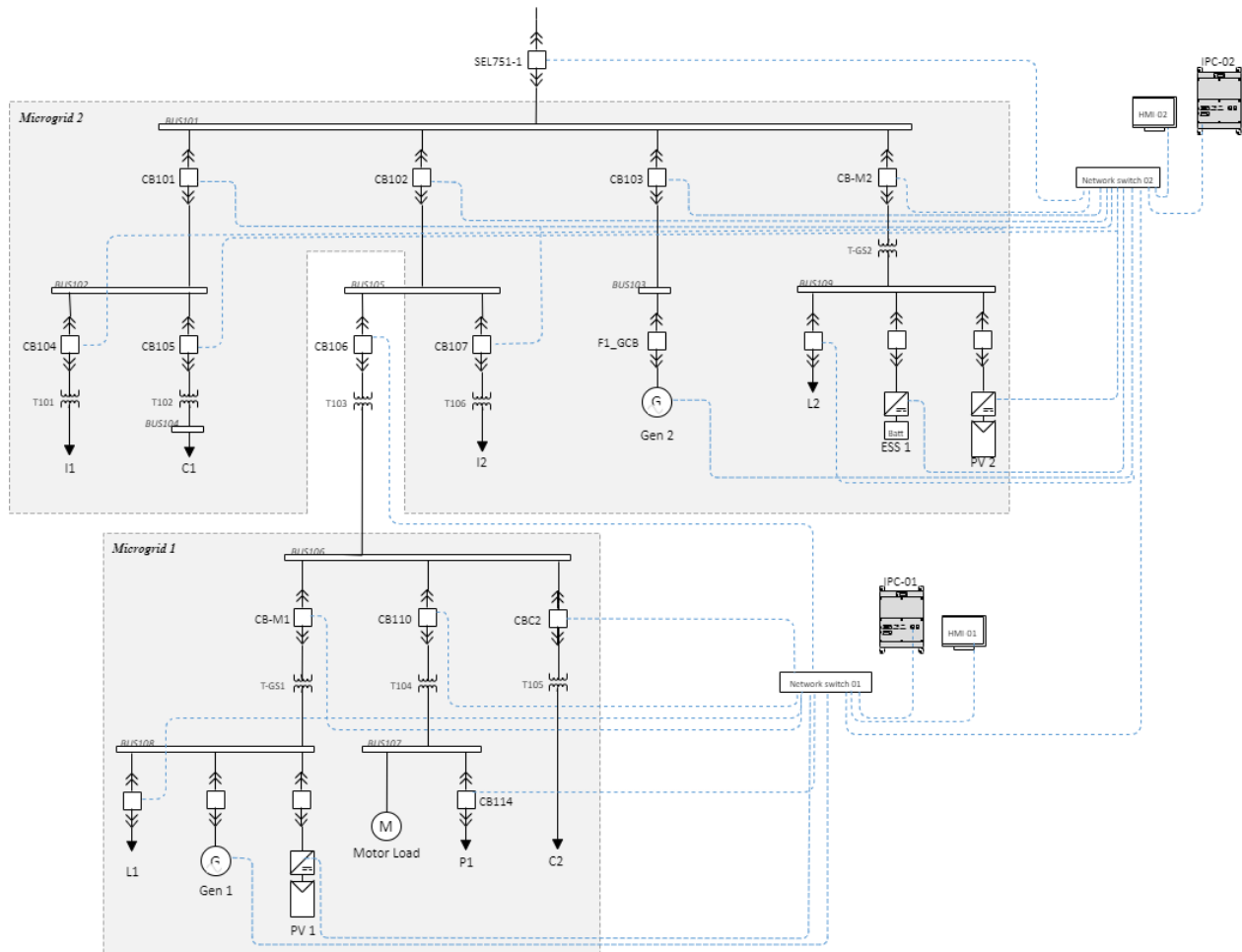


Figure 5-1. Networked Microgrid Controller Device Connectivity

6.0 CHIL PERFORMANCE TESTING

This section presents system procedures, results, and analysis of testing conducted in the EPRI CHIL test environment. The test case descriptions detail initial conditions and generalized steps that were used to execute the tests. The [Performance Objectives](#) were used to evaluate the microgrid controller's performance.

6.1 TEST CASE 1: DEMONSTRATE OUTAGE RECOVERY FOR RESILIENCE

This case is designed to evaluate the following:

- How do networked microgrid controllers coordinate to provide feeder-level outage recovery?
- Can the outage recovery sequencing (black start) of islanded, networked microgrids be managed by commercially available microgrid controllers?
- Can the synchronization of islanded microgrids be managed by commercially available microgrid controllers?
- Will the combination of shared droop control and microgrid controller management be sufficient to prevent voltage and frequency excursions that would trip protection equipment or harm the system?

6.1.1 Purpose

A defining component of grid resilience is the ability to recover rapidly from changing conditions and disruptions. Networked microgrid controllers are expected to improve this aspect of resilience by bringing the combined microgrid areas online faster than a centralized controller or manually sequenced, independent microgrid controllers. To demonstrate and evaluate outage recovery performance, this test will require the controllers to execute an island black start and connect the islanded microgrid areas as a single, networked island.

When independent microgrids synchronize and reconnect to the grid, the utility grid provides a relatively stiff voltage and frequency source that can absorb the transient effects of the microgrid island reconnection. When networked microgrids join together to form a larger island, the voltage and frequency stability of the system depends on an adequate design (selection) of grid-forming DER and microgrid controller management. A key function of networked microgrid controllers is the ability to synchronize single microgrids operating in island mode and connect them to create a larger island. This function (detailed in [2]) is essential to coordinating multi-microgrid outage recovery and providing wider outage coverage. It allows the individual microgrid controllers to simultaneously manage critical load restoration within their local microgrid boundary, then join to create wider areas of load coverage as a networked group. In order for this synchronization process to be successful, the microgrid controllers must ensure that the DER are positioned for the transition to minimize voltage and frequency disturbances that might otherwise cause another black out.

The test case will capture and evaluate:

- Outage recovery sequencing (black start process from utility outage to energized, connected networked island)
- Outage duration of critical and priority loads
- Networked microgrid controller capability to manage the joining of two microgrids into a single, islanded microgrid
- Transient effects of island synchronization on voltage and frequency when transitioning from separate to joint microgrids

- The following baseline cases will be considered for comparison against the networked microgrid outage recovery performance:
- No ability to network and combine islanded microgrids. Controllers and pre-defined microgrid boundaries remain isolated and cannot share resources during event. Independent microgrid controllers can black start single-customer portions of the feeder only.
- No microgrid controller is available to manage black start of the island. In this case, the outage duration is equivalent to the expected length of the utility outage.

6.1.2 Test Scenario

1. Planned/Unplanned utility outage—black start function

- Black start single-customer microgrids 1 and 2 (left frame in Figure 6-1)
- Create multi-customer microgrids 1 and 2 (bring lower priority loads online, if possible, middle frame in Figure 6-1)
- Create feeder-level microgrid (synchronize and connect multi-customer microgrids 1 and 2, right frame in Figure 6-1)

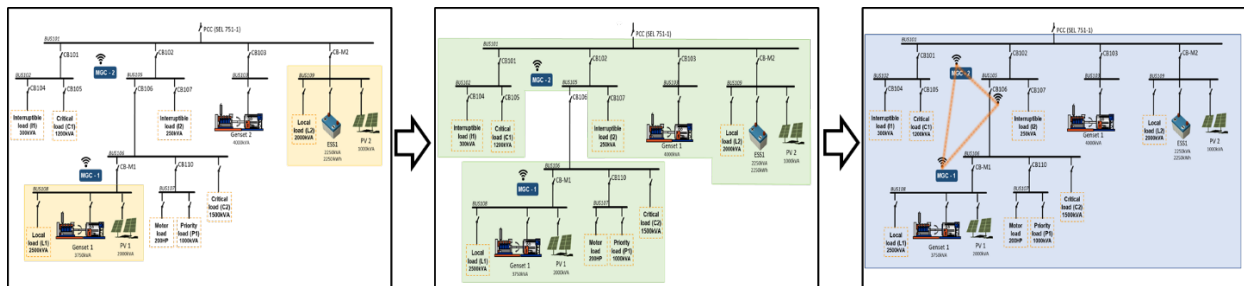


Figure 6-1. Test Case Demonstration of Individual Microgrid Control Areas Synchronizing to One Combined Microgrid

6.1.2.1 Baseline Scenario(s)

- Planned/Unplanned utility outage—black start with independent controllers
 - No communication link between microgrid controllers

6.1.3 Test Approach / Narrative

- Normal, utility-connected system operations observed

Utility outage event occurs (triggered in simulation by SEL751-1 trip)

- Feeder-wide blackout, DER trip
- Microgrid controllers open load and microgrid boundary switches as needed to isolate and safely black start respective areas

Microgrid controllers initiate outage recovery sequence for critical loads

- a. Black start customer-level microgrid 1 (sequenced in parallel to customer-level microgrid 2 start):
 - i. Confirm isolation, CB-M1 verified open
 - ii. IPC-1 starts diesel generator in customer-level microgrid 1
 - iii. Bus 108 load served
 - b. Black start customer-level microgrid 2 (sequenced in parallel to customer-level microgrid 1 start)
 - i. Confirm isolation, CB-M2 verified open
 - ii. IPC-2 starts ESS grid-forming inverter in customer-level microgrid 2
 - iii. Bus 109 load served
3. Microgrid controllers initiate recovery of additional loads within multi-customer microgrid boundaries²
- a. Expand microgrid 1 to multi-customer boundaries
 - i. Confirm isolation from multi-customer microgrid 2, CB-106 verified open, CB-110 open
 - ii. IPC-1 closes CB-M1; bus 106 load served
 - iii. If adequate DER generation available, IPC-1 closes CB-110, brings bus 107 online
 - b. Expand microgrid 2 to multi-customer boundaries
 - i. Confirm isolation from substation and multi-customer microgrid 1, SEL751-1 and CB-106 open, CB-101 and CB-102 open
 - ii. IPC-2 closes CB-M2 and CB-101 to serve bus 102 loads
 - iii. IPC-2 brings generator 2 online
 - iv. If adequate DER generation available, IPC-1 closes CB-102, brings bus 105 online
4. Microgrid controllers (IPC-1 and IPC-2) coordinate to synchronize microgrid (MG)-1 and MG-2 to form feeder-level microgrid (see test case 2 for evaluation of microgrid performance during synchronization)
- a. MG-1 and MG-2 are online and stable; IPC-1 and IPC-2 communicate to confirm readiness to form feeder-level microgrid
 - b. Microgrid controllers send bias signal to generator and ESS to bring ΔV and $\Delta \theta$ within acceptable synchronization tolerance
 - c. IPC-1 or IPC-2 sends close command to CB-106 (synchronizing recloser)
 - i. CB-106 monitors voltage and phase angles of MG-1 and MG-2
 - ii. CB-106 closes when voltages of separate microgrids are within tolerance
 - d. Primary droop response of diesel generator and ESS is expected to maintain feeder-level microgrid stability following CB-106 close

² Autonomous decision making of the IPCs to connect multi-customer microgrids and bring additional loads online depends on the N versus N+1 operational reliability strategy and available DER capacity in real time. Details on this function are provided in [Section 2.3 Operational Strategy](#).

- e. IPC-1 and IPC-2 controllers continue to coordinate and manage DER setpoints for single feeder-level microgrid

IPC-1 and IPC-2 bring PVs online and ramp up PV output to its maximum power point. In the meantime, IPCs adjust frequency setpoints of BESS and generators for frequency regulation

Test concludes when entire feeder-level microgrid is live, all loads are online,³ and grid-forming DER are coordinated by S&C GridMaster controllers to share load and maintain voltage and frequency within operational limits.

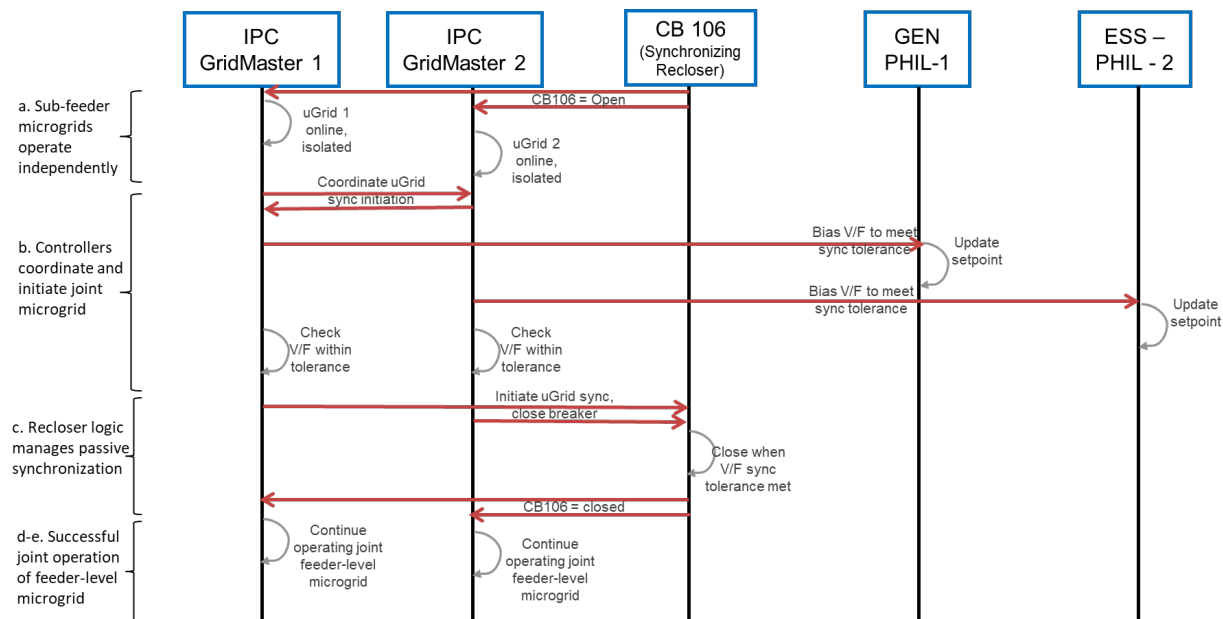


Figure 6-2. Microgrid Synchronization Interaction Details During Black Start

6.1.4 Evaluation Criteria

To successfully demonstrate the improved outage recovery capability, the networked microgrids are expected to complete the island energization and synchronization within 10 minutes of a utility outage. This expected recovery time will vary based on characteristics of DER in the microgrids (e.g., generator start-up time, PV reconnection configuration). The capability and speed of outage recovery will also be evaluated by comparing the load outage duration during this black start period to the baseline black start scenarios. Voltage and frequency measurements on the feeder must remain within acceptable short-term grid tolerance. To successfully demonstrate this function, the microgrid synchronization step should occur without critical load loss or DER tripping throughout the transition. Transients caused by the synchronization process should not cause protection equipment to trip. Specific metrics are provided in Table 6-1.

³ All critical loads must be online; additional priority and interruptible loads should be brought online based on real-time available generating capacity of DER in the microgrid. See [2] for expected behavior and reserve margin calculations.

6.1.5 Test Results

Total simulation run time: 30 minutes

6.1.5.1 *PowerFactory simulation configuration*

- Selected load and PV profiles: 0am, 8am, 12pm, 4pm, 8pm
- SEL-751-1 Status: closed at start
- BESS SOC at initialization: 50%

6.1.5.2 *Baseline configuration conditions*

GridMaster IPC Configuration:

- Operational strategy⁴ for both IPC1 and IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids
- Configured date/time of day at test start: 0am, 12pm, 4pm, 8pm

6.1.5.3 *Black start test run configuration*

GridMaster IPC Configuration:

- Operational strategy for both IPC1 and IPC2: [N] and [N+1]
- Unavailable devices: [none]
- Configured date/time of day at test start: 0am, 12pm, 4pm, 8pm

⁴ See Section 2 – Operational Strategy for definitions of these objectives.

Table 6-1. Performance Metrics of Black Start Test

Performance Metrics	0am			12pm			4pm			8pm			Average of [N]	Variation from baseline	Average of [N+1]	Variation from baseline
	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs				
Critical Load 1 Outage duration (s)	389.7	1414.7	387.7	336.4	1305.7	353.3	346.2	1260.2	350.4	361.7	1384.6	389.7	358.52	-3.18%	1341.29	262.23%
Critical Load 2 Outage duration (s)	218.5	419.8	261.8	246.8	1139.3	215.6	255.9	1250.1	250.8	1795.0	1314.4	1795.0	629.02	-0.28%	1030.89	63.42%
Interruptible Load 1 Outage duration (s)	504.5	1538.2	505.5	430.9	1024.2	456.0	441.8	586.5	443.0	970.3	662.9	460.1	586.85	25.90%	952.93	104.43%
Interruptible Load 2 Outage duration (s)	616.3	767.9	581.0	528.5	858.5	551.6	538.3	837.3	539.7	806.1	842.0	565.8	622.30	11.22%	826.44	47.71%
Priority Load 1 Outage duration (s)	301.1	1478.7	342.4	735.1	1011.5	1795.0	1795.0	1095.3	1795.0	444.5	1795.0	234.8	818.94	-21.39%	1345.11	29.11%
Motor Load outage duration (s)	287.0	390.2	331.3	316.2	444.1	275.9	481.1	469.9	362.5	221.9	500.1	221.7	326.53	9.63%	451.06	51.45%
Local Load 1 Outage duration (s)	83.7	182.0	117.1	87.8	112.6	82.8	98.9	118.9	89.8	81.3	180.1	97.9	87.93	-9.24%	148.40	53.17%
Local Load 2 Outage duration (s)	81.9	108.8	92.0	76.9	163.7	82.9	74.8	70.8	85.9	87.5	108.8	89.0	80.27	-8.22%	113.02	29.22%
All Critical Loads Outage duration (s)	608.2	1834.5	649.6	583.1	2444.9	568.9	602.1	2510.3	601.3	2156.7	2699.0	2184.7	987.54	-1.35%	2372.18	136.96%
All Local Loads Outage duration (s)	165.7	290.8	209.1	164.7	276.3	165.7	173.7	189.7	175.8	168.8	288.9	186.8	168.20	-8.76%	261.42	41.81%
All Priority Loads outage duration (s)	301.1	1478.7	342.4	735.1	1011.5	1795.0	1795.0	1095.3	1795.0	444.5	1795.0	234.8	818.94	-21.39%	1345.11	29.11%
All Interruptible Load outage duration (s)	1407.7	2696.2	1417.8	1275.6	2326.7	1283.4	1461.2	1893.7	1345.1	1998.2	2005.0	1247.6	1535.68	16.03%	2230.43	68.53%
All Critical Load coverage (MWh)	0.513	0.320	0.505	0.641	0.251	0.647	0.705	0.250	0.705	0.352	0.194	0.344	0.55	0.44%	0.25	-53.80%
All Local Load coverage (MWh)	0.990	0.960	0.978	1.235	1.198	1.237	1.357	1.358	1.355	1.601	1.201	1.592	1.30	0.42%	1.18	-8.61%
All Interruptible load coverage (MWh)	0.148	0.100	0.148	0.175	0.129	0.175	0.180	0.160	0.184	0.166	0.145	0.209	0.17	-6.72%	0.13	-25.46%
Total Critical Load disruptions	0	2	0	0	2	0	0	2	0	0	2	0	0.00	0	2.00	-2.00
Total Local Load disruptions	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0	0.00	0
Total Interruptible Load disruptions	0	2	0	0	3	0	0	3	0	2	3	0	0.50	-0.5	2.75	-2.75
Black start automation time (s)	748.9	682.1	n/a	536.4	857.7	n/a	731.6	770.2	n/a	975.2	743.2	n/a	748.02	n/a	763.32	n/a
Maximum voltage (p.u.)	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	0.10%	1.01	0.01%
Minimum voltage (p.u.)	0.93	0.93	0.93	0.87	0.92	0.92	0.92	0.92	0.92	0.93	0.93	0.92	0.91	-1.46%	0.93	0.18%
Maximum frequency (Hz)	63.24	60.84	63.35	63.10	63.09	63.24	63.42	63.35	63.24	63.28	60.99	63.24	63.26	-0.01%	62.07	-1.90%
Minimum frequency (Hz)	57.18	55.67	56.80	57.98	55.85	56.90	55.81	55.82	55.71	56.04	55.46	54.92	56.75	1.19%	55.70	-0.69%
Sync tolerance at join (Yes/No)	Yes	Yes	n/a	Yes	Yes	n/a	Yes	Yes	n/a	Yes	Yes	n/a				

Performance Metric notes:

1. Black start automation time: Elapsed time between grid outage (SEL751 open, dead feeder) to microgrids joined (CB 106 closed, voltage and frequency within acceptable steady state limits)
2. Minimum and Maximum Voltage and Frequency: ignores dead bus conditions
3. Sync tolerance at join: Indicates whether the microgrids were within acceptable synchronization tolerance range when the IPCs sent a join request.

Figure 6-3 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages during the black start process, with 4pm profile and N strategy. The process can be divided into 4 major steps:

1. Preparation: After detection of grid isolation, the IPCs started to prepare for black start, by opening the load switches and setting up the droop commands.
2. Start-up transformer level microgrids: In this step after preparation completed, the IPCs started up sources and loads one by one, while maintaining frequency and voltage stable in steady state.
3. Join microgrids: After loads are picked up, the IPCs started the join process after the frequency and voltage difference across CB106 is within the threshold. More detailed results are shown in Figure 6-6.
4. Islanded operation: After system is stabilized, IPCs started to ramp up PV. The loads remain online.



Figure 6-3. Black Start Process with 4pm Profile N Strategy

Figure 6-4 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages during the black start process, with 8pm profile and N+1 strategy. There are 4 major steps. The first 3 steps are the same as the previous case with N strategy. The IPCs prepared, black started, and joined the two transformer level microgrids. In step 4 Islanded operation, because N+1 strategy is used, IPCs readjust the load served, to ensure the system stability if one of sources fails. The critical loads and interruptible loads are disconnected to allow more generation headroom. Then, smaller loads (motor load, I1, and I2) are added back shortly after.

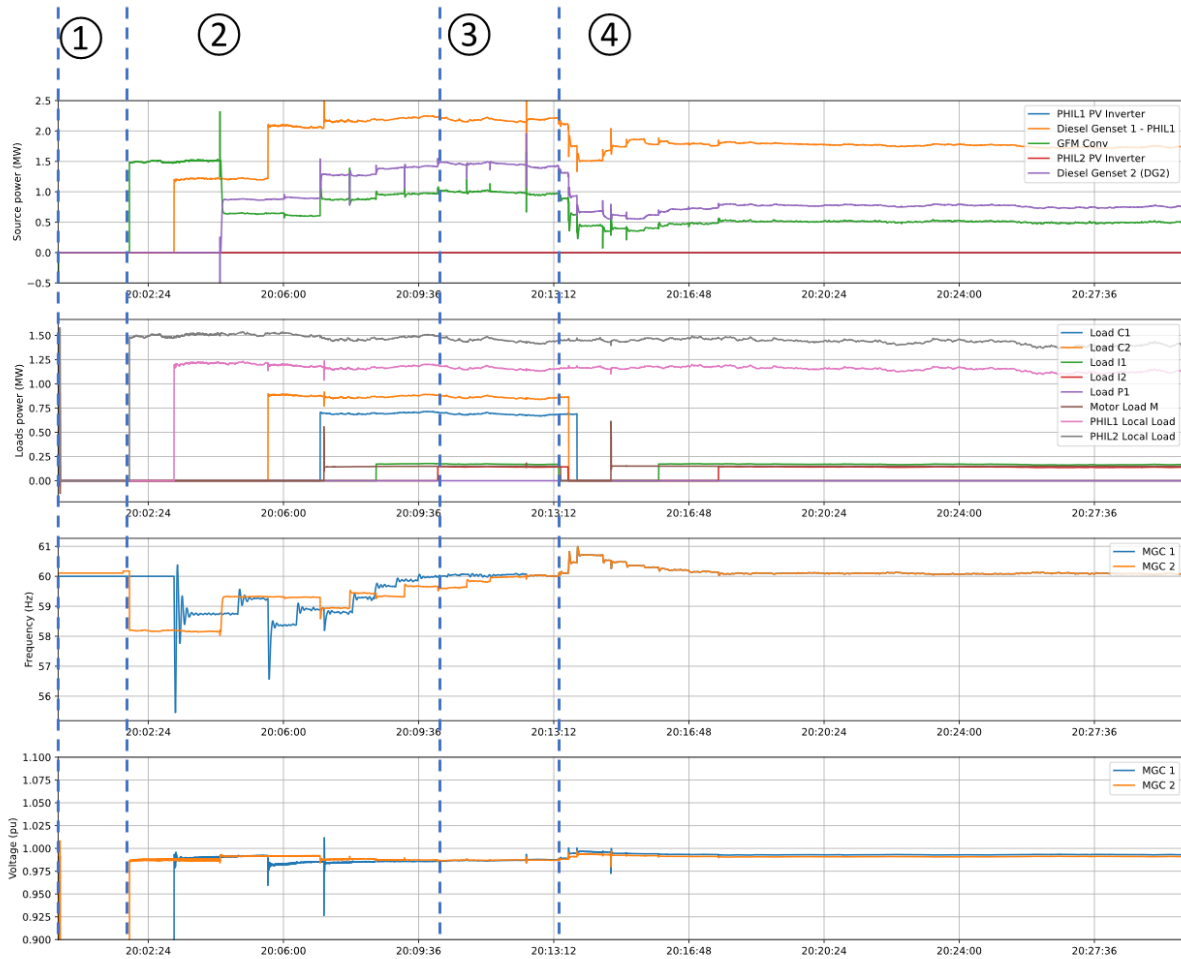


Figure 6-4. Black Start Process with 8pm Profile N+1 Strategy

Figure 6-5 shows the baseline case of separated microgrids black starting during the 4pm profile. The output power of the sources, load power consumptions, microgrid frequencies and voltages during the black start process are shown. The test was conducted by marking CB106 unavailable in the IPCs. The black start process stops after all loads are picked up in step 2 and PV ramped up in step 3.



Figure 6-5. Blackstart Process with 4pm Profile Separated Microgrids

Figure 6-6 shows the join process of the two transformer-level microgrids. This example event is captured using 8pm profile and N+1 strategy. Before the join process, IPCs for the two microgrids adjusted frequencies to be around 60 Hz. At 815 s, one of the two IPCs sent out the join command, when the frequency difference is less than 0.1 Hz and voltage difference is less than 0.002 pu. The sync relay CB106 receives the command and closes at 829 s when the angle difference is less than 10 degrees.

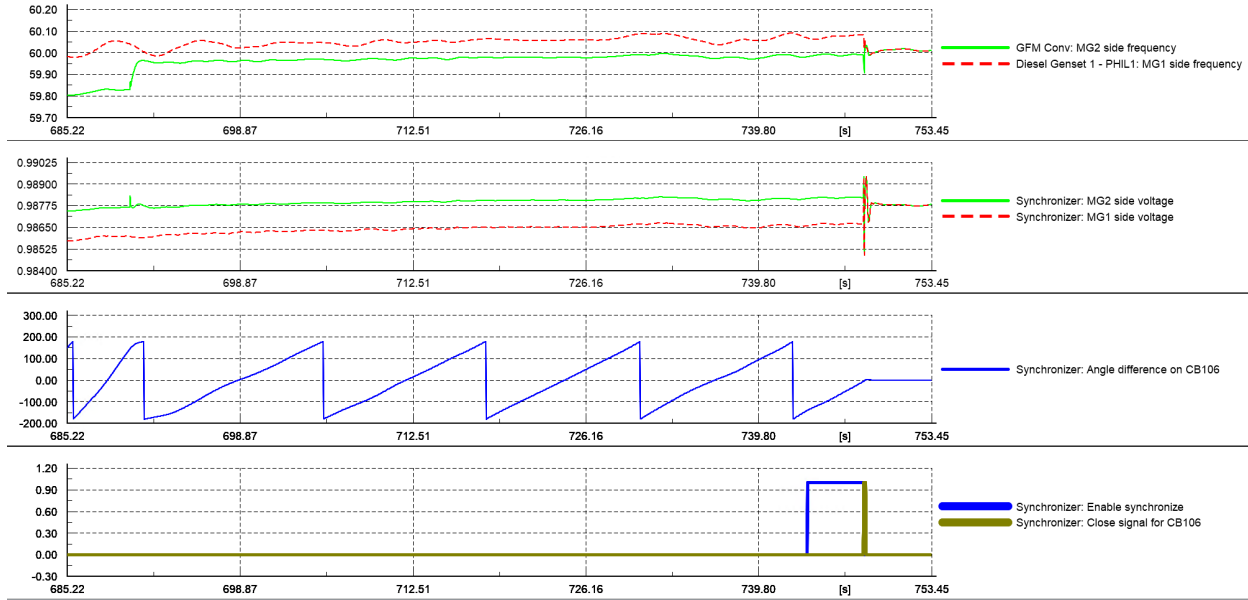


Figure 6-6. Join Process of Two Transformer Level Microgrids

6.1.5.4 Results analysis and baseline comparison:

The purpose of this test was to evaluate how the networked microgrid controllers manage black start sequencing to reduce outage duration and understand the transient effects of sub-feeder island synchronization.

6.1.5.5 Performance objective 1: Decrease Outage Duration

If the operational strategy is [N], the outage durations of local loads, critical loads, and priority loads are decreased. These loads have a higher priority. The results demonstrate that by having a joined feeder level microgrid, the resources can be shared to reduce the outage time of the important loads. However, the interruptible loads have an increased outage time because the shared generation capacity is allocated to higher priority loads first.

If the operational strategy is [N+1], the outage durations for all the loads are decreased. Since the [N+1] strategy is developed to reserve more power to be able to maintain system stability if one major resource fails, it is expected to have an increased outage duration in normal operation. This is partially due to the limited number of GFM DER within the test system. Because MG-1 only includes 1 GFM DER, it is impossible to run MG-1 independently in [N+1] strategy mode, thus there is no true baseline case for comparison to this strategy for the combined microgrid operations. To further evaluate the [N+1], a larger test network with multiple GFM DER in each microgrid should be used.

Also, it is noticed that in [N+1] strategy, the black start process has a delayed starting time, compared with the baseline case and the case when [N] strategy is activated. The delayed starting time range from 10 s to 90 s. This contributes to a longer outage duration for the local loads, which were not disconnected otherwise. The reason is unknown. One hypothesis for the difference is that the [N+1] control results in less loads added during black start, causing the separated microgrids to initialize further from 60 Hz. This could result in the controllers spending more time bringing the separated grids within an acceptable frequency difference. Further testing is needed to confirm this theory.

6.1.5.6 Performance objective 2: Increase Load Coverage

Similar to the discussion on outage duration, if the operational strategy is [N], the joined feeder microgrid offers an increased load coverage for the local loads, critical loads, and priority loads, while have a reduced load coverage for interruptible loads. If the operational strategy is [N+1], the load coverage is reduced compared with the base case.

6.1.5.7 Performance objective 3: “Black start automation”/ Feeder-level join time

The average join time for all tests conducted for both N and N+1 strategy is 755 seconds, which is longer than the 10-minute target.

The main reason identified is because the end-to-end communication delay between the simulation platform and IPCs is around 6 seconds. The delay is longer than the expected communication delay for field devices, which is assumed to be less than 1 second when developing the target. The time delay includes: (1) the Modbus communication delay between IPCs and Triangle Microworks SCADA Gateway (TMW), (2) the processing delay to convert Modbus to OPC communication in TMW, (3) the OPC communication delay between TWM and PowerFactory circuit simulation. The time delay cannot be further reduced in this simulation environment; however, it can be reduced in a field installation with direct communication networking. This delay was not seen in the PHIL test environment.

6.1.5.8 Performance objective 4: Feeder voltage deviation

The maximum and minimum voltages reported in Table 6-1 occurred when the two transformer level microgrids were picking up the motor loads, which was before the joined feeder level microgrid. Other than the voltage transient due to motor load start, the system voltage is regulated well for all tests, and remain within the ANSI C84.1 recommended ranges. It is not obvious that the joined feeder level microgrid can improve this performance in normal operations.

6.1.5.9 Performance objective 5: Feeder frequency deviation

The maximum and minimum frequencies reported in Table 6-1 occurred during the start-up process of the generator at microgrid 1. Most of the frequency disturbances are caused by the load restorations, which happens mostly before the joined feeder level microgrid. Overall, in normal operation, the system frequencies are within the IEEE 1547-2018 mandatory operation ranges for DER.

As demonstrated in Figure 6-5, if separated, the microgrid 1 may experience slightly more severe frequency fluctuations due to load variation, since the frequency is regulated by a synchronous generator. If joined, shown in Figure 6-3 and Figure 6-4, the frequency fluctuations in the feeder level microgrid are reduced.

6.1.5.10 Performance objective 6: Synchronization tolerance

The IPCs are designed to only initiate microgrid joining when the voltage and frequency differences between the two transformer level microgrids are within tolerance. Figure 6-6 has demonstrated that the join command is issued when the voltage and frequency differences have reached within the acceptable range

6.2 TEST CASE 2: DEMONSTRATE INCREASED LOAD COVERAGE

This test case is designed to evaluate the following research question related to networked microgrid controllers:

Can networked microgrid controllers improve load coverage following a utility outage?

6.2.1 Purpose

A key advantage of networked microgrid controllers is the ability to provide increased load coverage by power sharing DER between islanded microgrids. To demonstrate this capability, this test measures the load coverage provided by the networked microgrids throughout a long-duration utility outage event. The test case will capture and evaluate:

- Coverage of critical, priority, and interruptible loads compared to an independent, isolated microgrids baseline

The following baseline case will be considered for load coverage performance comparison:

- No ability to connect islanded microgrids; controllers and microgrids with predefined boundaries remain isolated and cannot share resources during outage

6.2.2 Test Scenario

1. Long-duration outage—increase networked microgrid load coverage by power sharing during islanded operation
 - a. Execute utility outage simulation for 24 hours

6.2.2.1 Baseline Scenario

1. Long-duration utility outage without ability to connect microgrids
 - a. Microgrid controllers have no communication link
 - b. Test begins with independent microgrids online and isolated from each other
 - c. Execute utility outage simulation for 24 hours; various combinations of load and solar profile time series will be used

6.2.3 Test Approach / Narrative

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection, CB-106 closed)
 - a. Critical loads are online
2. Microgrid controllers are expected to respond to load and PV profile variations throughout the outage simulation
 - a. When sufficient DER generating capacity is available, controllers are expected to bring additional loads online in priority order (local > critical > priority > interruptible)

6.2.4 Evaluation Criteria

The networked microgrid controllers are expected to provide power sharing that increases the overall load coverage during the outage. The load coverage provided by the networked microgrid controllers will be compared against that in a baseline test in which the controllers are unable to communicate and must maintain separate, isolated islands without power sharing. Specific metrics are provided in Table 4-2.

6.2.5 Test Results

Total simulation run time: 24 hours

6.2.5.1 *PowerFactory simulation configuration*

- Selected load profiles: 24 hours start from 0am
- Selected PV profiles: 24 hours start from 0am, cloudy day profile and sunny day profile
- SEL-751-1 Status: open at start (stable island)
- BESS SOC at initialization: 80%

6.2.5.2 *Baseline configuration conditions*

GridMaster IPC Configuration:

- Operational strategy IPC1: [N]
- Operational strategy IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids
- Configured date/time of day at test start: 0am

6.2.5.3 *“Increased load coverage” long-run test configuration*

GridMaster IPC Configuration:

- Operational strategy IPC1: [N], [N+1]
- Operational strategy IPC2: [N], [N+1]

- Unavailable devices: [none]
- Configured date/time of day at test start: 0am

Table 6-2. Performance Metrics of 24h Islanded Test

Performance Metrics	Sunny Day Profile			Cloudy Day Profile		
	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs
All Critical Loads Outage duration (s)	101275.1	132186.4	20316.97	62126.94	142543.9	20328.61
All Local Loads Outage duration (s)	0	0	0	0	0	0
All Priority Loads outage duration (s)	62572.46	63434.91	59292.11	42808.67	64076.91	59308.65
All Interruptible Load outage duration (s)	153346.3	110291.6	63140.11	97193.02	178617.9	63177.22
All Critical Load coverage (MWh)	12.17457	7.34478	31.2919	20.40445	4.878387	31.27077
All Local Load coverage (MWh)	60.80986	60.8781	60.44283	60.56678	61.10907	60.39617
All Priority Loads coverage (MWh)	2.548598	2.557275	3.018342	5.688012	2.357919	3.015491
All Interruptible load coverage (MWh)	3.815912	5.729524	7.653663	6.17399	2.679512	7.644761
Total Critical Load disruptions	4	2	1	3	1	1
Total Local Load disruptions	0	0	0	0	0	0
Total Priority Load disruptions	2	10	1	2	2	1
Total Interruptible Load disruptions	6	16	3	7	6	3
Maximum voltage (p.u.)	0.995816	0.999098	1.0126	0.997666	0.998789	1.012404
Minimum voltage (p.u.)	0.974859	0.976908	0.923478	0.973796	0.97985	0.923103
Maximum frequency (Hz)	61.69676	60.94858	61.48476	61.54053	60.78449	62.16505
Minimum frequency (Hz)	59.2852	59.4795	58.48278	59.65647	59.55365	58.08362

Figure 6-7 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages during the 24-hour islanded operation, using a cloudy day profile, separated microgrids.

In the morning around 1:30 am, IPC2 turned off Generator 2, possibly because of a low load consumption, which may be more economical with only BESS supplying the load. The generator is turned back on afterwards. Additional load shedding was triggered when load consumption gets higher in the middle of the day and during the nights.

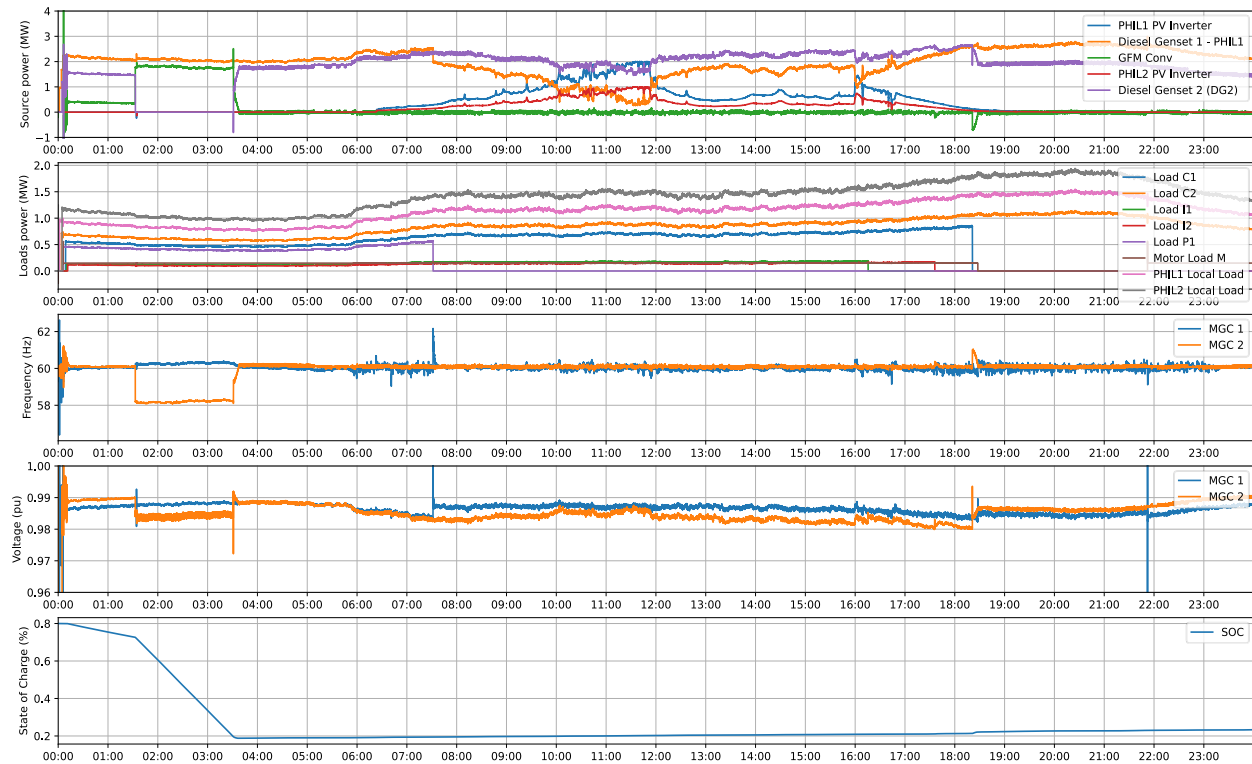


Figure 6-7. 24h Islanded Operation with Cloudy Day Profile Separated Microgrids

Figure 6-8 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages, and battery State of charge (SOC) during the 24h islanded operation, using a sunny day profile and N strategy. When battery SOC dropped to 20% at around 6:30am, IPCs no longer consider ESS as a reliable source, and start to shed load. During middle of the day, the additional PV power charges the battery. When battery SOC rose to 30% at around 12pm, IPCs restored some high priority loads until SOC depleted again. The behavior of low ESS SOC scenario is explained in [Test Case 4](#) in more detail.

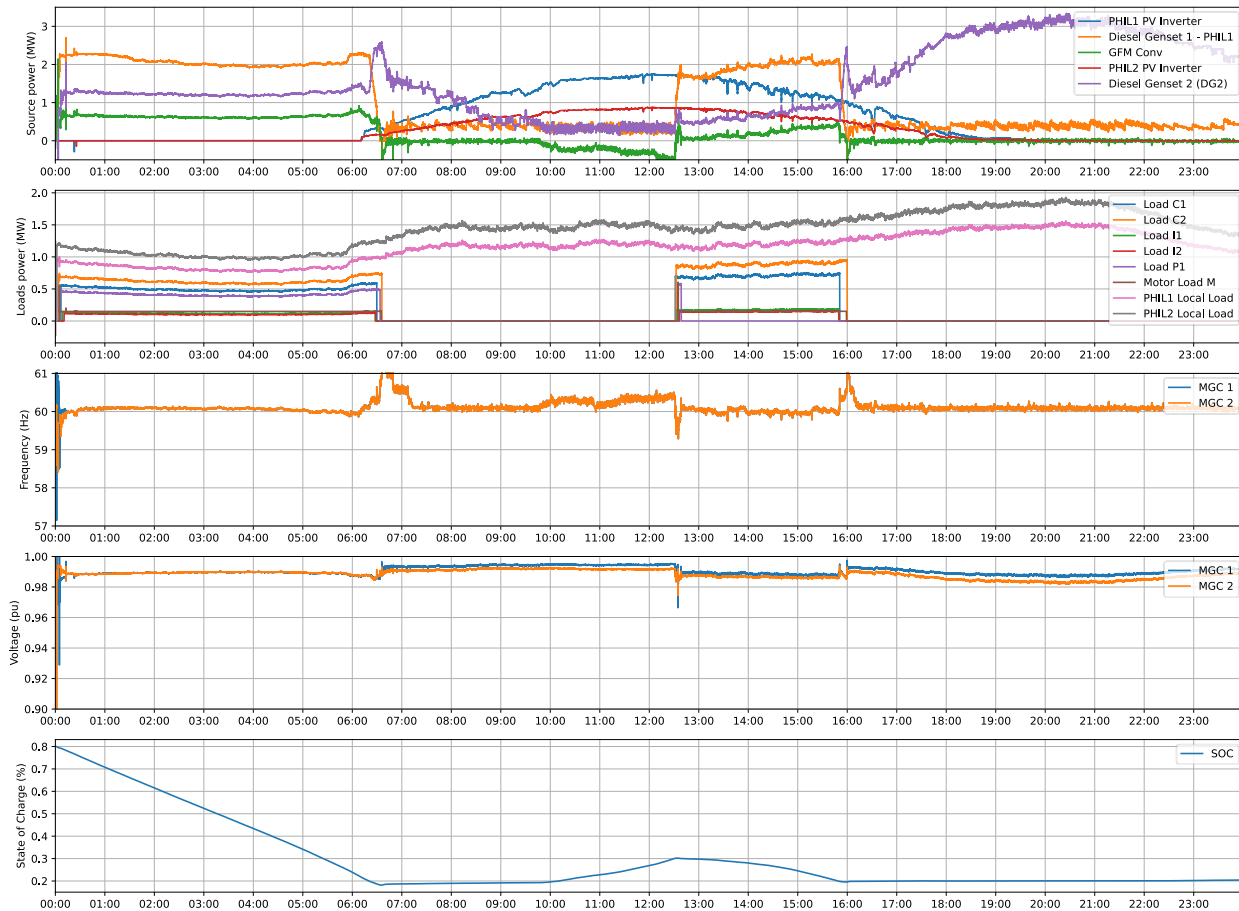


Figure 6-8. 24h Islanded Operation with Sunny Profile N Strategy

Figure 6-9 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages, and battery SOC during the 24h islanded operation, using a cloudy day profile. Less loads are served in this case because N+1 strategy is activated. The same as the previous case, when ESS SOC dropped to 20%, the loads are disconnected to allow more headroom.

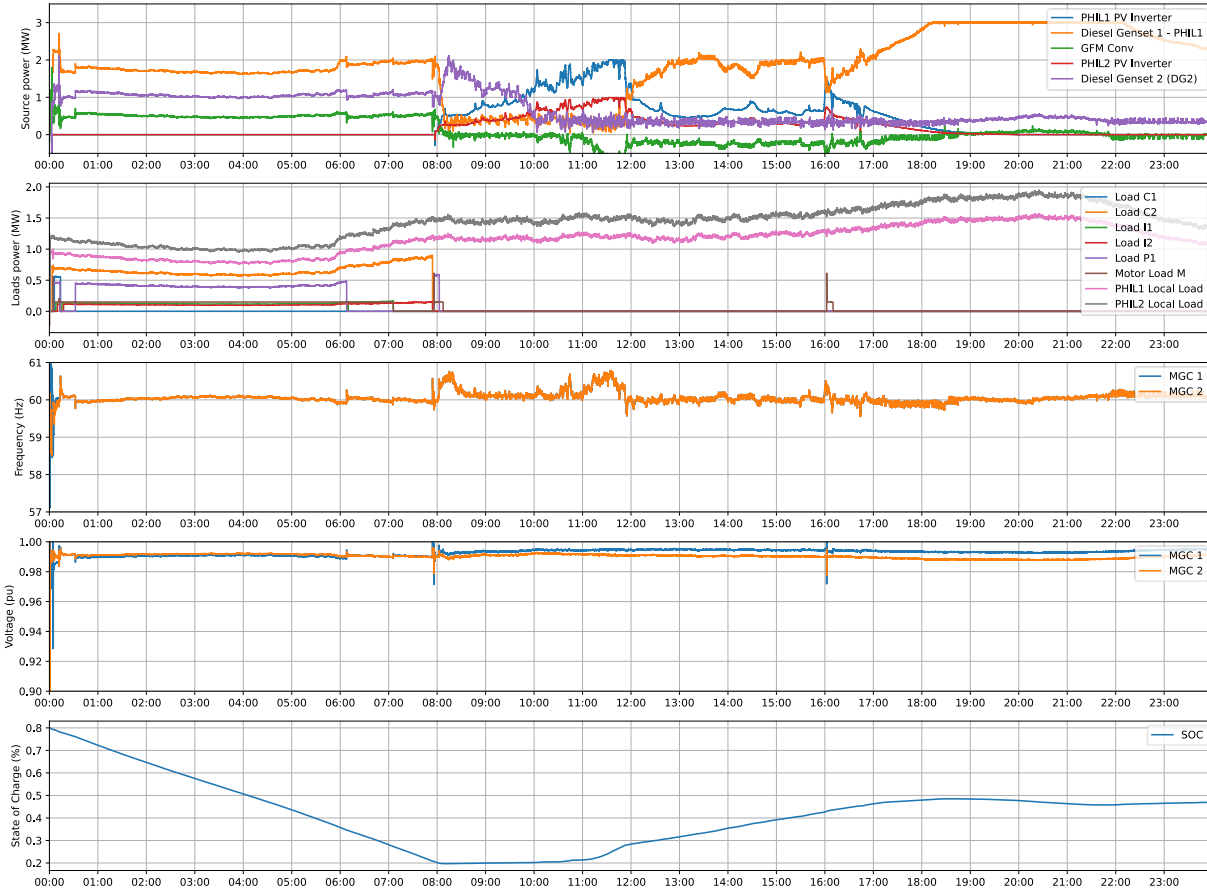


Figure 6-9. 24h Islanded Operation with Cloudy Profile N+1 Strategy

6.2.5.4 Results analysis and baseline comparison:

The purpose of this test was to evaluate if the networked microgrid controllers provide increased load coverage by power sharing DER across the feeder during island operations.

6.2.5.5 Performance objective 1: Increase Load Coverage

The load coverage in joined microgrid is worse than the baseline result. One reason identified is because of the non-ideal control logic when ESS's SOC drop to 20%. It appears that the IPC2 ramps up generator 2 to reduce the output of ESS, which causes frequency rise in the joined microgrid, which causes IPC1 to ramp down generator 1 for frequency regulation. More detailed results will be discussed in Test case 4.

In addition, it appears that currently the communication between IPCs does not provide optimal load sharing between the sources in the two microgrids, which may hinder the load restoration even though there is enough power available from other sources from the other microgrid. Notice that in Figure 6-8, generator 1 produces much more power than generator 2 during the evening. But in Figure 6-9, it is the opposite that generator 2 produces much more power than generator 1 during the evening. If the two microgrids join with their sources at different enough frequency offsets then one microgrid's sources will generally handle more of the load than the other. This results in a lower overall reserve as those sources are closer to their maximums than if they were balanced. While the joined grid is near 60 Hz and DER are operating within their operational limits, neither microgrid will further adjust the respective frequency droop offsets. Recommendations for improving this performance are discussed in the final chapter of this report.

The final reason which may have impacted the load coverage is that the IPCs do not plan around ESS's SOC for longer period operations. In most cases, the SOC is depleted during the night covering the lower priority loads. A reliability-based dispatch algorithm may be helpful to reserve the capacity of the battery if longer period of islanded operation is foreseeable.

6.2.5.6 Performance objective 2: Feeder voltage deviation

The maximum and minimum voltages in the 24h islanded operation usually associate with load restoration, especially the motor load start-up process. With joined microgrid, feeder voltage is regulated within the ANSI long-term range, better than separated transformer level microgrids.

6.2.5.7 Performance objective 3: Feeder frequency deviation

The maximum and minimum frequency observed in joined microgrid cases are related to load shedding and restoration. The system frequency is mostly within the IEEE 1547-2018 mandatory operation range.

On the other hand, the minimum frequency observed in separated microgrid base case is during the morning when only ESS is supporting the entire microgrid 2. The measured frequency is around 58.5 Hz for around an hour, which is outside of allowable range shown in Table 4-5.

6.3 TEST CASE 3: INCREASED RELIABILITY, LOSS OF PV SCENARIO

This case is designed to evaluate the following research questions related to networked microgrid controllers:

- How much can networked microgrid controllers improve island load coverage during a cloudy day PV scenario during island operations?
- How will networked microgrid controllers mitigate the transient effects of intermittent DER during island operations?

6.3.1 Purpose

By power sharing DER between microgrids during islanding, networked microgrids can increase load coverage when PV output is variable. To demonstrate this capability, this test measures the load coverage and transient stability provided by the networked during a cloudy day that limits PV production. The test case will capture and evaluate:

- Coverage of critical, priority, and interruptible loads compared to an independent, isolated microgrids baseline
- Voltage and frequency transient stability during cloudy day PV output

The following baseline case will be considered for load coverage performance comparison:

- No ability to connect islanded microgrids. Controllers and pre-defined microgrid boundaries remain isolated and cannot share resources during intermittent PV day.

6.3.2 Test Scenario

1. Reliable Feeder Microgrid Operations—maintain service by power sharing during individual DER or controller outages in islanded operation including:
 - a. Worst case cloudy day PV, sudden loss of PV supply; various load profile conditions will be used

6.3.2.1 Baseline Scenario

1. Long duration utility outage without ability to connect microgrids
 - a. No communication link between microgrid controllers
 - b. Test begins with independent microgrids online and isolated from each other
 - c. During generator loss, MGC1 and MGC2 are unable to share power resources

6.3.3 Test Approach / Narrative

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection, CB 106 = closed)
2. Shutdown one PV plant to observe multi-controller response to microgrid condition
3. Load shedding priority should be interruptible – priority – critical – local
4. Test concludes when the system reaches steady-state for configured profile duration.

6.3.4 Evaluation Criteria

The outcome of this test case should demonstrate the improved reliability provided by networked microgrid controllers coordinating power sharing. The shared response of multiple grid-forming DERs across the networked microgrids is expected to reduce voltage and frequency fluctuations and load shedding when PV output is variable. During the intermittent PV availability event, the networked microgrid must remain online and continue serving loads in priority order. Non-critical load shedding is acceptable if inadequate DER are available. Feeder-microgrid voltage and frequency should not exceed short-term excursion limits throughout the duration of the test. Specific metrics are provided in Table 4-2.

6.3.5 Test Results

Total simulation run time: [60 minutes]

6.3.5.1 PowerFactory simulation configuration:

- Selected load profiles: 12pm, 4pm
- Selected PV profiles: 12pm, 4pm sunny day profile
- SEL-751-1 Status: open at start (stable island)
- BESS SOC at initialization: 80%
- Time of PV plant shutdown: 40 min

6.3.5.2 Baseline configuration conditions:

GridMaster IPC Configuration:

- Operational strategy IPC1: [N]
- Operational strategy IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids
- Configured date/time of day at test start: 12pm, 4pm

6.3.5.3 “Loss of PV” test configuration:

GridMaster IPC Configuration:

- Operational strategy IPC1: [N], [N+1]
- Operational strategy IPC2: [N], [N+1]
- Unavailable devices: [none]
- Configured date/time of day at test start: 12pm, 4pm

Table 6-3. Performance Metrics of Loss of PV Tests

Performance Metrics	12pm (Loss of PV1)			4pm (Loss of PV2)		
	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs
All Critical Loads Outage duration (s)	0.0	1936.6	0.0	0.0	2398.0	0.0
All Local Loads Outage duration (s)	0.0	0.0	0.0	0.0	0.0	0.0
All Priority Loads outage duration (s)	0.0	0.0	1199.0	1199.0	0.0	1199.0
All Interruptible Load outage duration (s)	0.0	0.0	0.0	0.0	0.0	0.0
All Critical Load coverage (MWh)	0.504	0.085	0.506	0.576	0.000	0.575
All Local Load coverage (MWh)	0.851	0.858	0.854	0.972	0.977	0.971
All Priority Loads coverage (MWh)	0.187	0.189	0.000	0.000	0.215	0.000
All Interruptible load coverage (MWh)	0.152	0.153	0.152	0.166	0.167	0.166
Total Critical Load disruptions	0	0	0	0	0	0
Total Local Load disruptions	0	0	0	0	0	0
Total Priority Load disruptions	0	0	0	0	0	0
Total Interruptible Load disruptions	0	0	0	0	0	0
Maximum voltage (p.u.)	0.987	0.993	0.998	0.988	0.991	0.987
Minimum voltage (p.u.)	0.982	0.985	0.969	0.986	0.989	0.984
Maximum frequency (Hz)	60.189	60.356	60.406	60.109	60.096	60.185
Minimum frequency (Hz)	59.292	58.790	56.100	59.843	59.834	59.741

Figure 6-10 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages during a PV loss event, with 4pm profile and separated microgrids (baseline scenario). Because PV is not considered as a reliable source by IPC, there is no load interruptions afterwards.

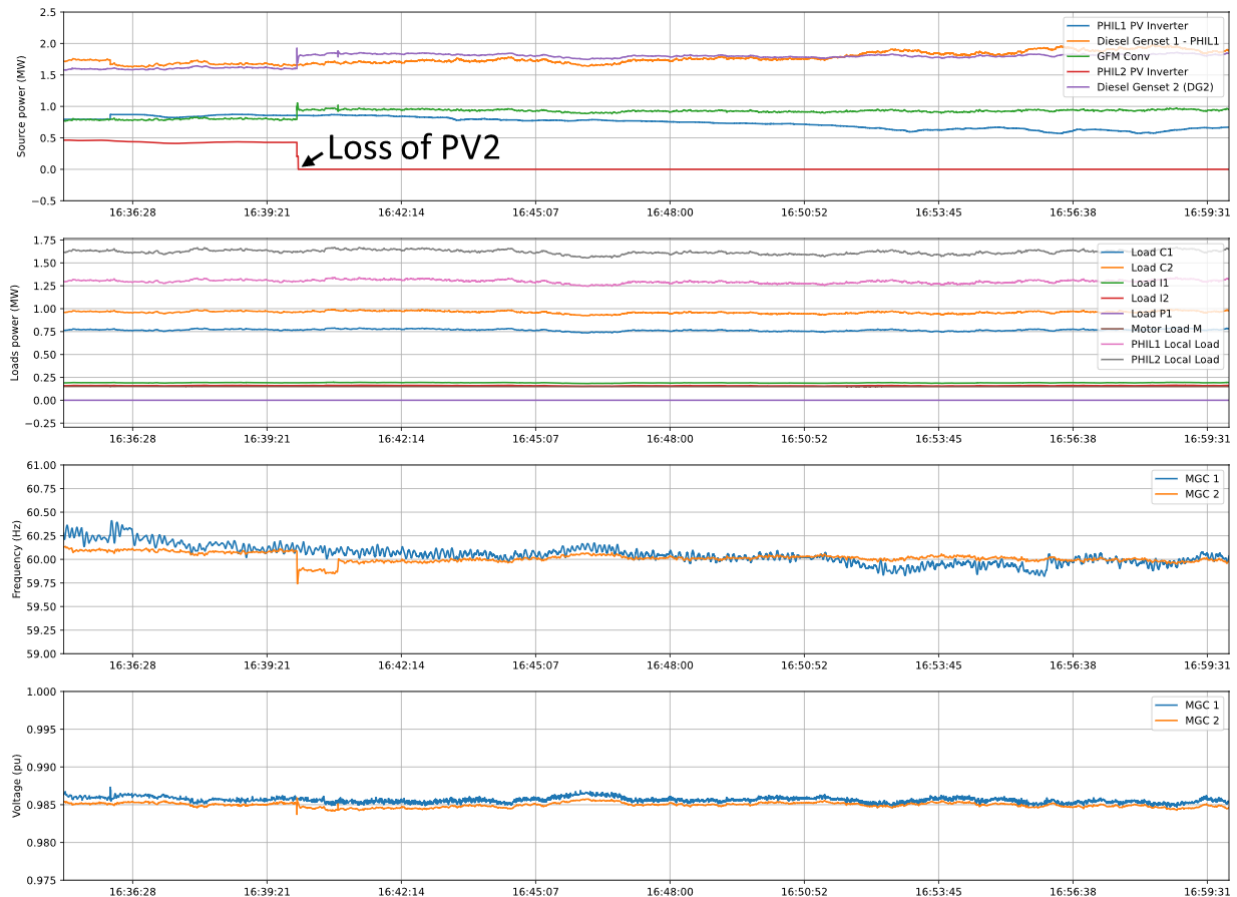


Figure 6-10. Microgrid Reaction to Loss of PV with 4pm Profile Separated Microgrids

Figure 6-11 shows the output power of the sources, load power consumptions, microgrid frequencies and voltages of a PV loss event, with 12pm profile and N+1 strategy. Similarly, there are no load interruptions afterwards. Instead, reduction in the load consumption profile triggered IPC1 to restore Interruptible load 2.

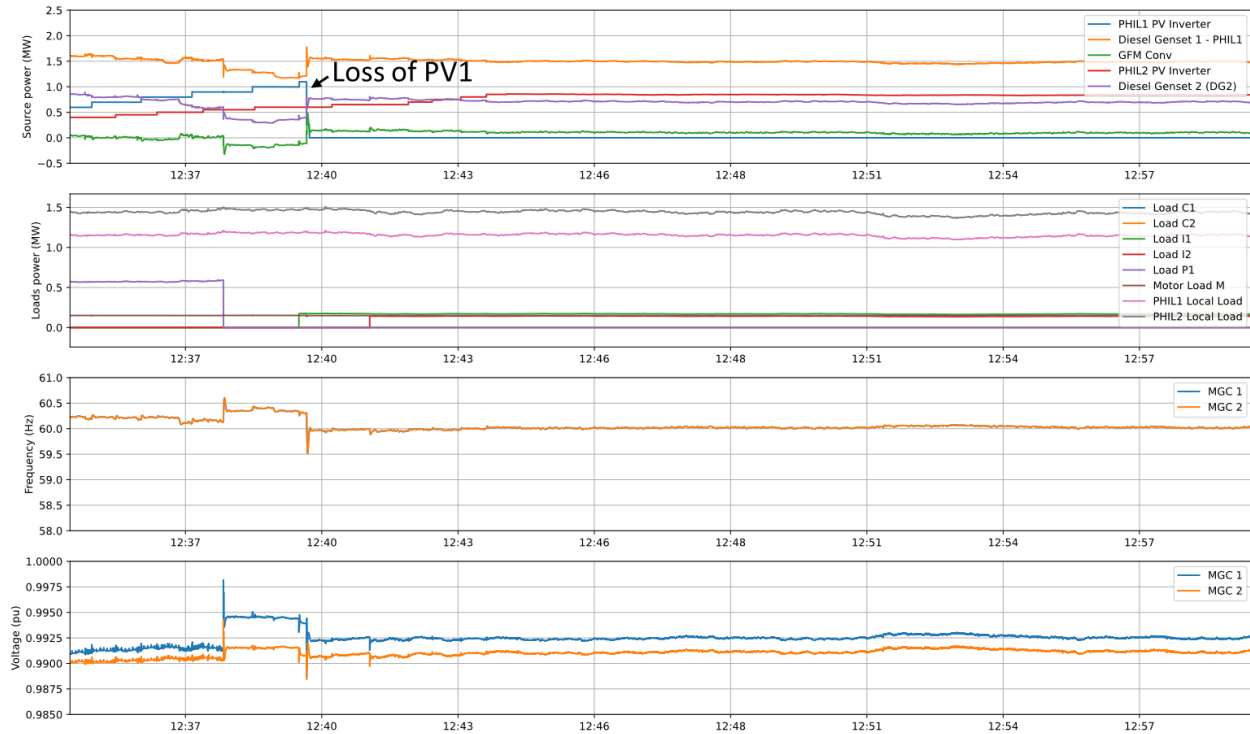


Figure 6-11. Microgrid Reaction to Loss of PV with 12pm Profile N+1 Strategy

6.3.5.4 Results analysis and baseline comparison

The purpose of this test was to evaluate if the networked microgrid controllers provide increased load coverage by power sharing DER across the feeder during island operations.

6.3.5.5 Performance objective 1: Increase Load Coverage

Since PV does not count as a reliable source by IPC, the PV loss event does not impact load coverage. The load coverage performance is purely determined by N or N+1 strategy.

For N strategy, since the joined microgrid is able to serve the priority loads, the system load coverage is improved.

However, for N+1 strategy, since the joined microgrid reserved more headroom for potential loss-of-source event, less load is served, indicating lesser load coverage than baseline cases.

6.3.5.6 Performance objective 2: Feeder voltage deviation

Joined microgrids provide better voltage regulation in a loss of PV event. The maximum and minimum voltages are within ANSI C84.1 long term ranges for all cases, including the baseline cases. However, in joined microgrids, the voltages are more bounded with smaller variations.

The performance increase is more noticeable with PV1 loss than PV2 loss. It is because microgrid 1 is powered only by a generator, which has weaker voltage regulation capability than microgrid 2, which is powered by a generator and a droop-controlled GFM ESS.

6.3.5.7 Performance objective 3: Feeder frequency deviation

Joined microgrids provide better frequency regulation in a loss of PV event. The maximum and minimum frequencies are within IEEE 1547-2018 DER mandatory ranges for all joined microgrid cases.

The minimum frequency drops to 56.1 Hz during PV1 loss event in separated microgrid case, which may lead to DER trip.

6.4 TEST CASE 4: INCREASED RELIABILITY, LOW ESS SOC SCENARIO

This case is designed to evaluate the following research question related to networked microgrid controllers:

- How much can networked microgrid controllers improve island load coverage when battery storage DER have low SOC?

6.4.1 Purpose

By power sharing DER between microgrids during islanding, networked microgrids can increase load coverage when resources are limited. To demonstrate this capability, this test measures the load coverage provided by the networked microgrids when the MGC2 ESS reaches a low state of charge. The test case will capture and evaluate:

- Coverage of critical, priority, and interruptible loads compared to an independent, isolated microgrids baseline

The following baseline case will be considered for load coverage performance comparison:

- No ability to connect islanded microgrids. Controllers and pre-defined microgrid boundaries remain isolated and cannot share resources during event.

6.4.2 Test Scenario

1. Reliable Feeder Microgrid Operations—maintain service by power sharing during individual DER or controller outages in islanded operation including:
 - a. Low battery SoC, charge ESS when PV is sufficient; various combinations of load and solar profile time series will be used

6.4.2.1 Baseline Scenario

Separate controllers, MGC2 is unable to receive power from MGC1 when ESS SOC is low

1. Long duration utility outage without ability to connect microgrids
 - a. No communication link between microgrid controllers

- b. Test begins with independent microgrids online and isolated from each other
- c. ESS in MGC2 has low SOC, MGC1 is unable to share DER power

6.4.3 Test Approach / Narrative

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection, CB 106 = closed), available solar is below (total load – minimum generator operating point)
 - a. ESS is discharging and reaches low SOC level (20%)
 - b. Observe multi-controller response to microgrid condition
 - c. Microgrid controller should control Diesel gensets to inject more power or shed loads
 - d. SOC level of ESS should not go below 10% (or configured minimum)
 - e. Test concludes when the system reaches steady-state for configured profile duration.

6.4.4 Evaluation Criteria

The outcome of this test case should demonstrate the improved reliability provided by networked microgrid controllers coordinating power sharing. During the low SOC event, the networked microgrid must remain online and continue serving loads in priority order. Non-critical load shedding is acceptable if inadequate DERs are available. Feeder-microgrid voltage and frequency should not exceed short-term excursion limits throughout the duration of the test. Specific metrics are provided in Table 6-4.

6.4.5 Test Results

Total simulation run time: [60 minutes]

6.4.5.1 *PowerFactory simulation configuration*

- Selected PV and load profiles: 0am
- SEL-751-1 Status: open at start (stable island)
- BESS SOC at initialization: 80%,
- BESS SOC sudden change to 20% at 40 min

6.4.5.2 *Baseline configuration conditions*

GridMaster IPC Configuration:

- Operational strategy IPC1: [N]
- Operational strategy IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids
- Configured date/time of day at test start: 0am

6.4.5.3 “Low ESS SOC” test configuration

GridMaster IPC Configuration:

- Operational strategy IPC1: [N], [N+1]
- Operational strategy IPC2: [N], [N+1]
- Unavailable devices: [none]
- Configured date/time of day at test start: 0am

Table 6-4. Performance Metrics of Low ESS SoC Scenario

Performance Metrics	0am		
	[N]	[N+1]	Sep. MGs
All Critical Loads Outage duration (s)	577.2	2021.6	0.0
All Local Loads Outage duration (s)	0.0	0.0	0.0
All Priority Loads outage duration (s)	440.2	1199.0	0.0
All Interruptible Load outage duration (s)	1336.9	3143.0	0.0
All Critical Load coverage (MWh)	0.312	0.070	0.395
All Local Load coverage (MWh)	0.665	0.671	0.664
All Priority Loads coverage (MWh)	0.093	0.000	0.146
All Interruptible load coverage (MWh)	0.086	0.015	0.130
Total Critical Load disruptions	1	1	0
Total Local Load disruptions	0	0	0
Total Priority Load disruptions	1	0	0
Total Interruptible Load disruptions	2	3	0
Maximum voltage (p.u.)	0.992	0.997	0.990
Minimum voltage (p.u.)	0.986	0.991	0.985
Maximum frequency (Hz)	60.779	60.86	60.970
Minimum frequency (Hz)	59.984	59.99	59.783

Figure 6-12 shows the output power of the sources, load power consumptions, and ESS SOS of a Low ESS SOC event, with 0am profile and separated microgrids. The event was triggered by manually set the SOC to 20% at 2400s. After Low SOC was detected, IPC2 started to ramp up generator 2 and ramp down the ESS to avoid deep discharging the ESS. All loads are kept served by the separated microgrids without interruptions.

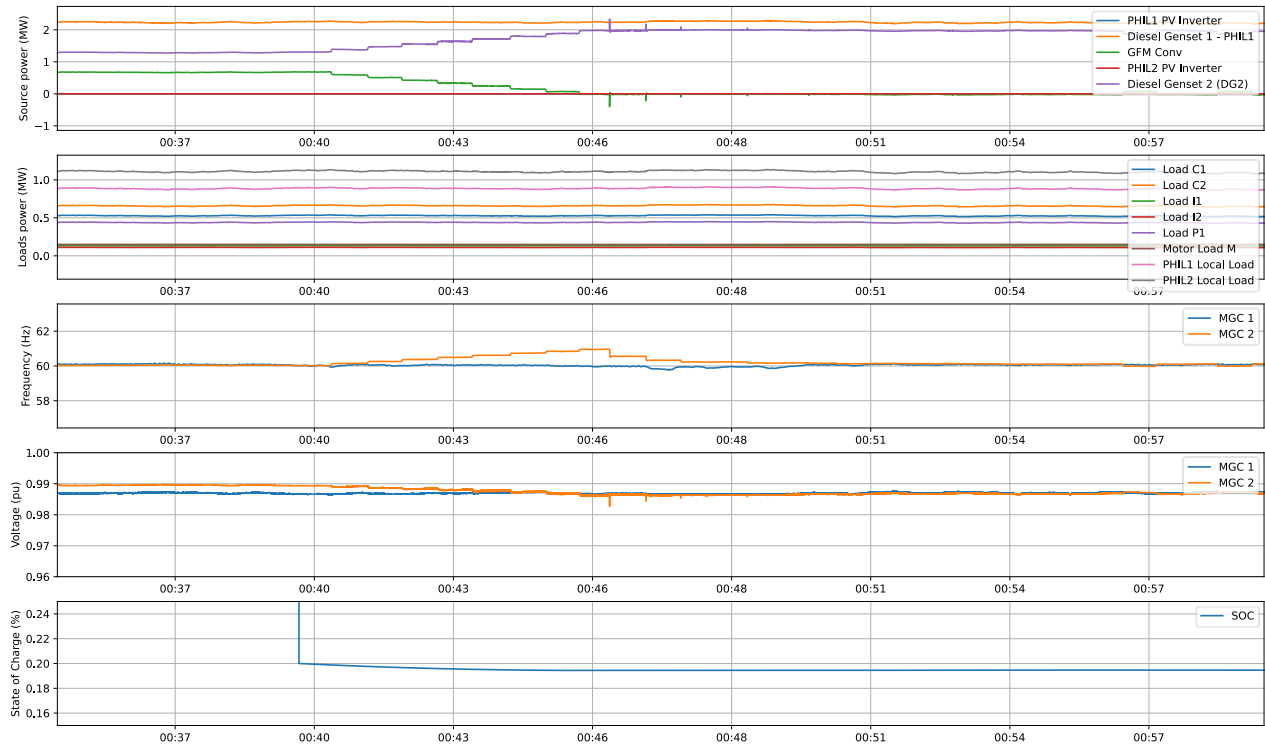


Figure 6-12. Microgrid Reaction to Low ESS SOC with 0am Profile Separated Microgrids

Figure 6-13 shows the output power of the sources, load power consumptions, and ESS SOS of a Low ESS SOC event, with 0am profile and N strategy. Similarly, IPC2 started to ramp up generator 2 and ramp down the ESS to avoid deep discharging. However, this creates frequency rise, which in turn causes IPC1 to ramp down generator 1 for frequency regulation. This eventually caused unnecessary load shedding. Figure 6-14 shows similar results with 0am profile and N+1 strategy.

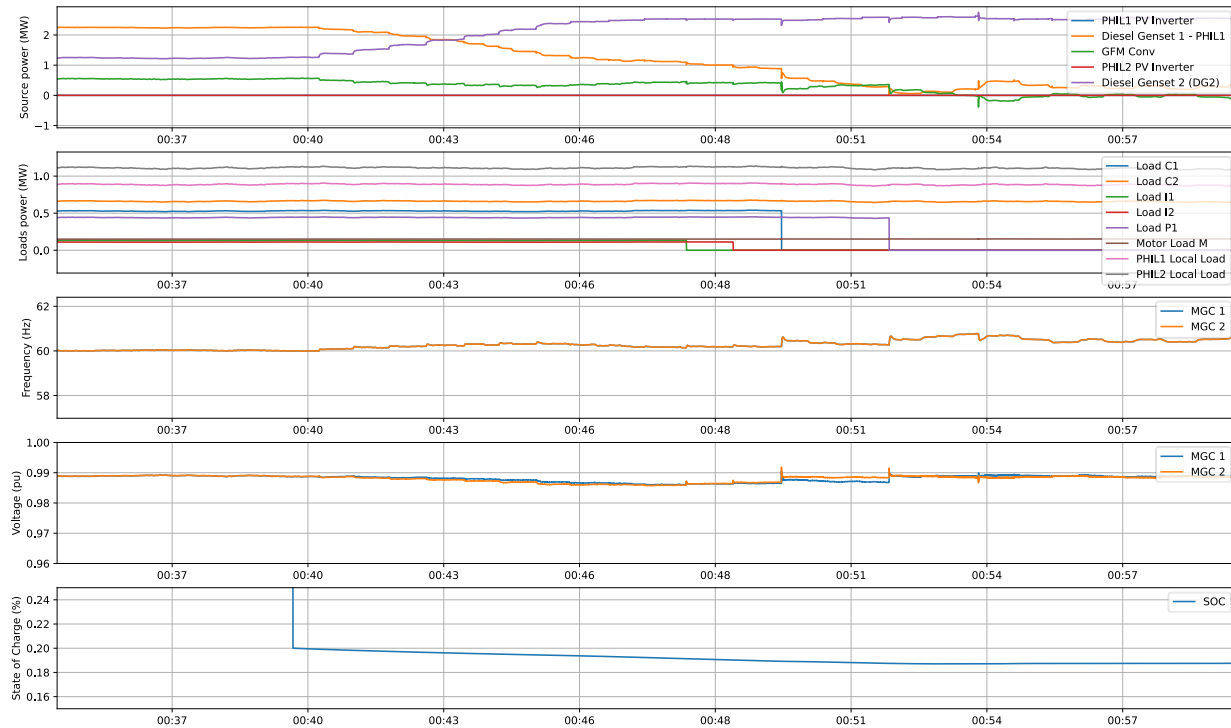


Figure 6-13. Microgrid Reaction to Low ESS SOC with 0am Profile N Strategy

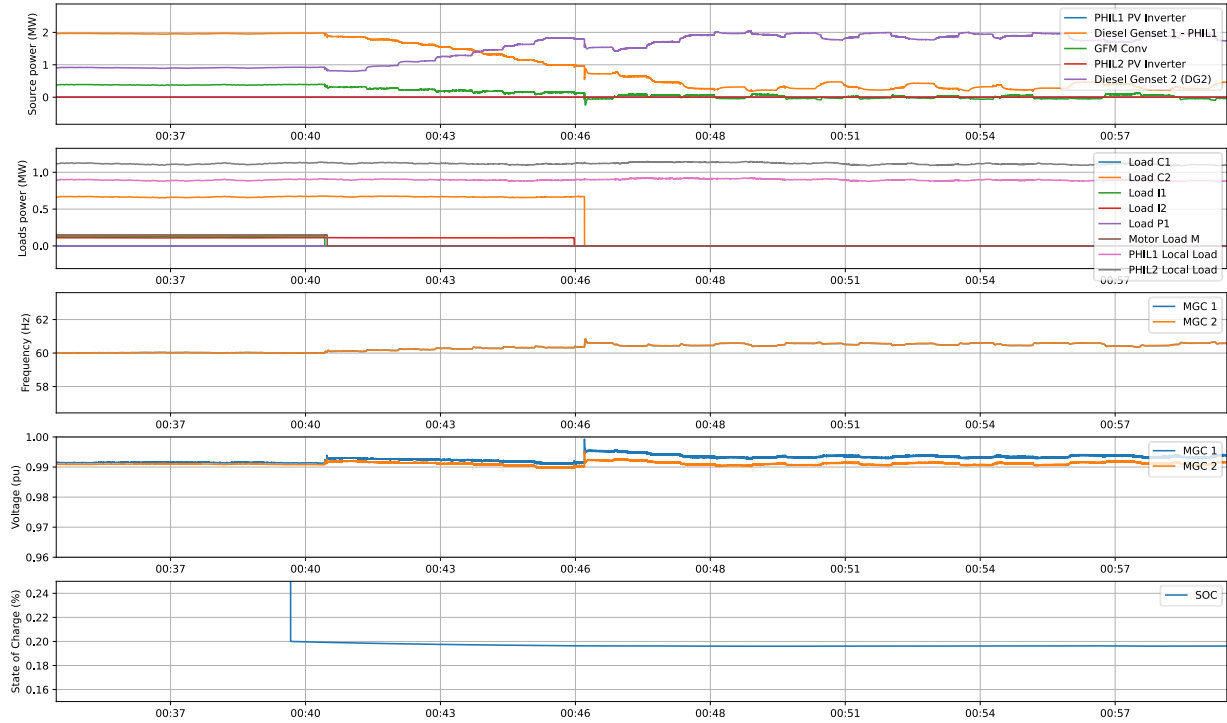


Figure 6-14. Microgrid Reaction to Low ESS SOC with 0am Profile N+1 Strategy

6.4.5.4 Results analysis and baseline comparison:

The purpose of this test was to evaluate if the networked microgrid controllers provide increased load coverage by power sharing DER across the feeder during island operations when ESS reaches low SOC.

6.4.5.5 Performance objective 1: Increase Load Coverage

The load coverage in joined microgrid is worse than the baseline result (as shown in Table 6-4). It appears that the IPC control of the two joined microgrids are not coordinated well when ESS's SOC drop to 20%. The frequency restoration adjustments made to the diesel generators to compensate for the low ESS SOC appears to counteract the intended load sharing effect of power sharing between the microgrids.

This also contributed to the decreased load coverage in 24h islanded operation in test case 2.

6.4.5.6 Performance objective 2: Feeder voltage deviation

Joined microgrid shows slightly better voltage regulation than the separated microgrid base case. The system voltages are within ANSI C84.1 long term range for all test cases.

However, control algorithm improvement may be made in future to resolve load coverage issue, which may lead to different voltage deviation results that require further analysis.

6.4.5.7 Performance objective 3: Feeder frequency deviation

Joined microgrid shows slightly better frequency regulation than the separated microgrid base case. The system voltages are within IEEE 1547-2018 DER mandatory operating range for all test cases.

However, control algorithm improvement may be made in future to resolve load coverage issue. Although a more coordinated approach to frequency restoration could improve the load coverage issue, it may lead to different frequency deviation results that require further analysis.

6.5 TEST CASE 5: INCREASED RELIABILITY, LOSS OF GENERATOR SCENARIO

This case is designed to evaluate the following research questions related to networked microgrid controllers:

- How much can networked microgrid controllers improve island load coverage during a loss of generation source scenario during island operations?
- How will networked microgrid controllers mitigate the transient effects of a loss of generation source scenario during island operations?

6.5.1 Purpose

By power sharing DER between microgrids during islanding, networked microgrids can increase load coverage when resources are limited or unexpectedly lost. To demonstrate this capability, this test measures the load coverage and transient stability provided by the networked microgrids when a generation resource is tripped offline. The test case will capture and evaluate:

- Coverage of local, critical, priority, and interruptible loads compared to an independent, isolated microgrids baseline
- Voltage and frequency transient stability during a loss of generator event

The following baseline case will be considered for load coverage performance comparison:

- No ability to connect islanded microgrids. Controllers and pre-defined microgrid boundaries remain isolated and cannot share resources during event.

6.5.2 Test Scenario

1. Reliable Feeder Microgrid Operations—maintain service by power sharing during individual DER or controller outages in islanded operation including:
 - a. Sudden DER supply loss (Gen 1 or Gen 2 trip); various combinations of load and solar profile time series will be used

6.5.2.1 Baseline Scenario

1. Long duration utility outage without ability to connect microgrids
 - a. No communication link between microgrid controllers

- b. Test begins with independent microgrids online and isolated from each other
- c. During generator loss, MGC1 and MGC2 are unable to share power resources

6.5.3 Test Approach / Narrative

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection, CB 106 = closed), BESS SOC is set to 80%, sunny day solar availability
 - a. Generator 1 or Generator 2 trips offline
 - b. Observe multi-controller response to microgrid condition
 - c. Load shedding priority should be interruptible < priority < critical < local
 - d. Test concludes when the system reaches steady-state for configured profile duration.

6.5.4 Evaluation Criteria

The outcome of this test case should demonstrate the improved reliability provided by networked microgrid controllers coordinating power sharing. During the loss of generator event, the networked microgrid must remain online and continue serving loads in priority order. Non-critical load shedding is acceptable if inadequate DERs are available. Feeder-microgrid voltage and frequency should not exceed short-term excursion limits throughout the duration of the test. Specific metrics are provided in Table 6-5.

6.5.5 Test Results

Total simulation run time: [60 minutes]

6.5.5.1 PowerFactory simulation configuration

- Selected PV and load profiles: 0am, 8pm
- SEL-751-1 Status: open at start (stable island)
- BESS SOC at initialization: 80%
- Time of generator trip/failure: 40 min

6.5.5.2 Baseline configuration conditions

GridMaster IPC Configuration:

- Operational strategy IPC1: [N]
- Operational strategy IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids
- Configured date/time of day at test start: 0am, 8pm

6.5.5.3 “Loss of Gen” test configuration

GridMaster IPC Configuration:

- Operational strategy IPC1: [N], [N+1]
- Operational strategy IPC2: [N], [N+1]
- Unavailable devices: [none]
- Configured date/time of day at test start: 0am, 8pm

Table 6-5. Performance Metrics of Loss of Generator Tests

Performance Metrics	0am (Loss of Gen1)			8pm (Loss of Gen2)		
	[N]	[N+1]	Sep. MGs	[N]	[N+1]	Sep. MGs
All Critical Loads Outage duration (s)	0.0	2094.4	1198.5	2334.3	2398.0	2321.4
All Local Loads Outage duration (s)	0.0	0.0	1198.5	0.0	0.0	0.0
All Priority Loads outage duration (s)	0.0	1199.0	1198.6	1161.5	1199.0	0.0
All Interruptible Load outage duration (s)	0.0	3274.0	1198.5	2462.2	3078.3	2295.1
All Critical Load coverage (MWh)	0.380	0.054	0.177	0.015	0.000	0.018
All Local Load coverage (MWh)	0.642	0.662	0.372	1.113	0.859	1.108
All Interruptible load coverage (MWh)	0.139	0.000	0.000	0.008	0.000	0.244
Total Critical Load disruptions	0.128	0.013	0.081	0.049	0.022	0.055
Total Critical Load disruptions	0	1	1	1	0	1
Total Local Load disruptions	0	0	1	0	0	0
Total Priority Load disruptions	0	0	1	1	0	0
Total Interruptible Load disruptions	0	2	0	4	3	2
Maximum voltage (p.u.)	0.989	0.994	Outage in MG1	0.993	0.993	0.986
Minimum voltage (p.u.)	0.957	0.973	Outage in MG1	0.970	0.984	0.971
Maximum frequency (Hz)	60.178	60.666	Outage in MG1	60.269	60.200	60.489
Minimum frequency (Hz)	57.750	58.148	Outage in MG1	58.089	59.241	57.564

Figure 6-15 shows the simulation results of sources output power, load consumption, voltage and frequency of the microgrids, with 8pm profile separated microgrids. In this simulation case, generator 2 trips at 2400 s. Due to the generator loss, BESS served all the 3 MW loads that were online before the event. As the BESS is only sized 2.25MW; in this case, it is assumed the BESS did not trip due to its overload capability. The system frequency drops below 58 Hz for almost 1 minute until loads are shed to keep the BESS operating within its nameplate rating.

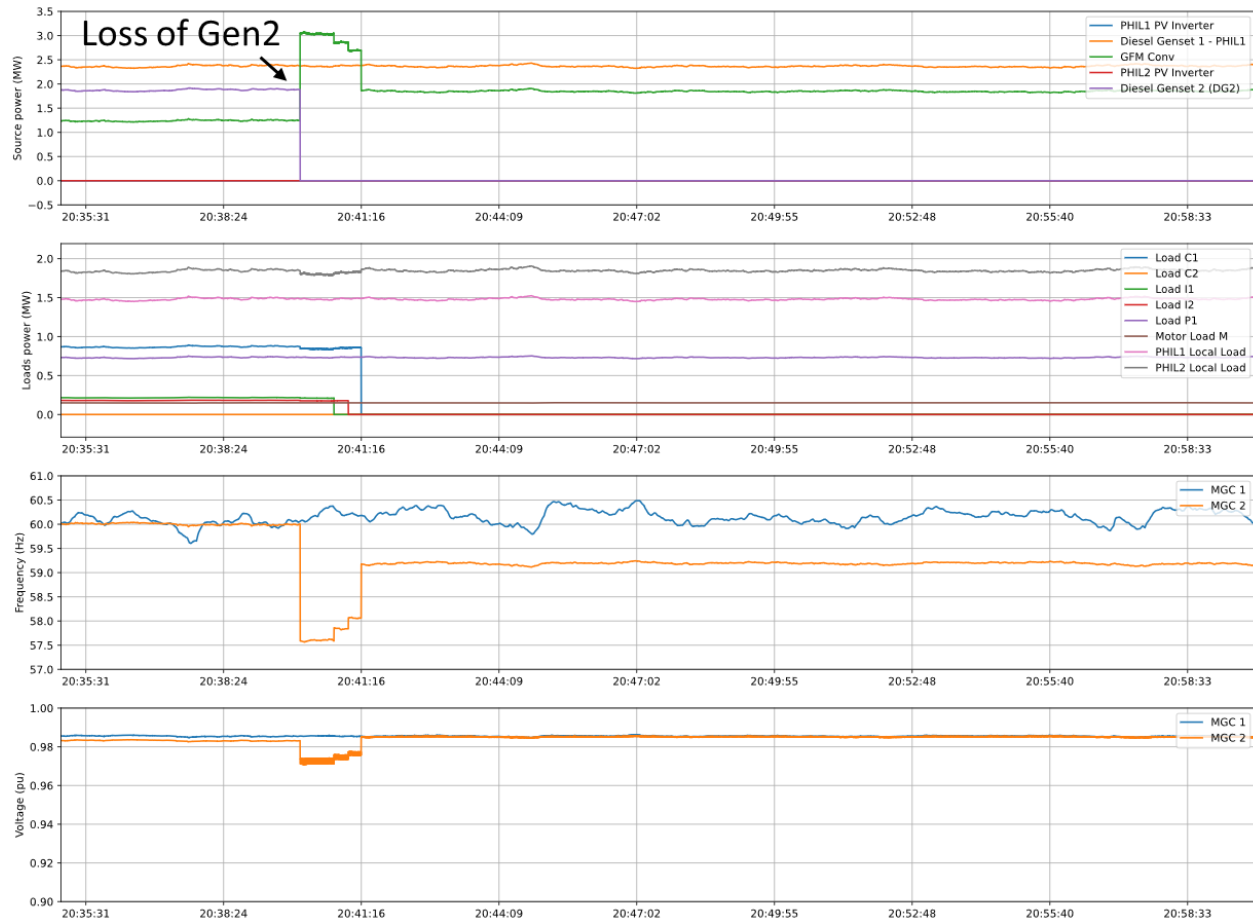


Figure 6-15. Generator 2 Loss at 2400 s with 8pm Profile Separated Microgrids

Figure 6-16 shows the simulation results of sources output power, load consumption, voltage and frequency of the microgrids, with 8pm profile N+1 strategy. In this simulation case, generator 2 trips at 2400 s. The motor loads and interruptible loads are shed soon after the loss-of-generator event. The system frequency and voltages are maintained well within the mandatory operation range.

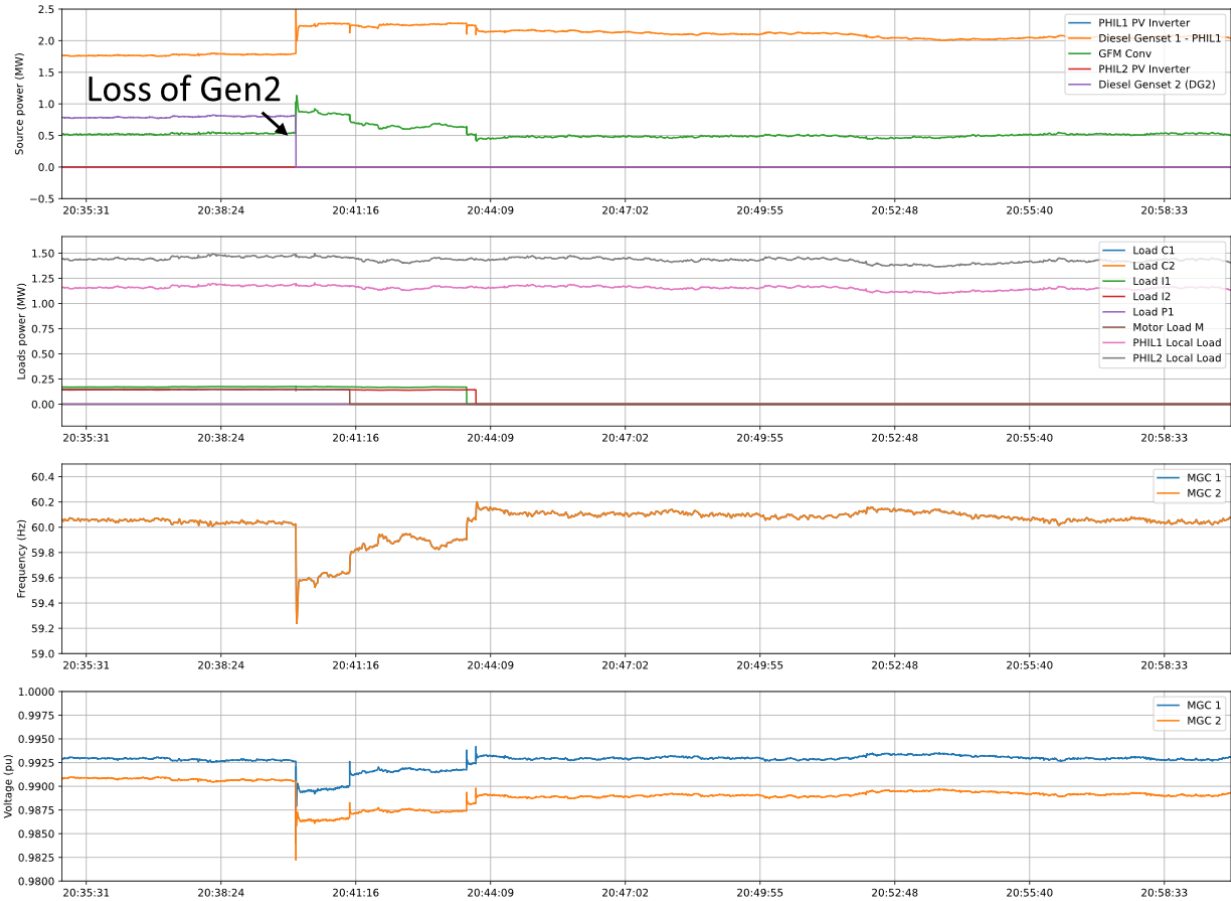


Figure 6-16. Generator 2 Loss at 2400 s with 8pm Profile N+1 Strategy

6.5.5.4 Results analysis and baseline comparison

The purpose of this test was to evaluate if the networked microgrid controllers provide increased load coverage during a loss of generator event by power sharing DER across the feeder during island operations.

6.5.5.5 Performance objective 1: Increase Load Coverage

If the only generator at MG1 fails, the joined microgrid provides increased load coverage. The resources at MG2 can be used to serve the loads in MG1.

However, if the generator at MG2 fails, the tests do not indicate an increased load coverage in response to a sudden generator loss under the assumption that the BESS has the capability to overload for a short duration. Otherwise, the BESS may also trip immediately after the loss of generator 2 due to overload.

This is generally consistent with the expectation that separate microgrids with only one voltage and frequency controlling DER each will see reliability benefits from a networked microgrid configuration because the joined microgrids provide voltage and frequency control source redundancy.

6.5.5.6 Performance objective 2: Feeder voltage deviation

The joined microgrids in both the N and N+1 operational strategies meet the voltage deviation performance objective—no voltage violations were seen in the joined microgrid with loss of generator test scenarios. The joined microgrid configuration does prevent voltage collapse compared to separate microgrids with only one DER providing voltage control (e.g., Gen-1 loss in MG1). The joined microgrid does not provide significantly better performance in terms of voltage regulation in case of loss-of-generator event compared to a separate microgrid with multiple DER that provide voltage control (e.g., Gen-2 loss in MG2).

6.5.5.7 Performance objective 3: Feeder frequency deviation

The joined microgrids in both the N and N+1 operational strategies meet the frequency deviation performance objective—no frequency violations were seen in the joined microgrid with loss of generator test scenarios. The joined microgrid configuration prevents frequency collapse compared to separate microgrids with only one DER providing frequency control (e.g., Gen-1 loss in MG1).

The joined microgrid also provides better performance in terms of frequency regulation in case of loss-of-generator event compared to a separate microgrid with multiple DER that provide frequency control (e.g., Gen-2 loss in MG2). In the separated baseline case shown in Figure 6-15, the MG2 loss of generator event caused a short-term frequency drop into the IEEE 1547-2018 “Mandatory Operation” range while the ESS droop response prevents a collapse. Non-critical loads are shed by the IPC before the frequency returns to acceptable “Continuous Operation” range. The joined microgrid case shown in Figure 6-16 improves the frequency regulation performance; the feeder frequency remains within the “Continuous Operation” range following the loss of Gen-2 event.

6.6 TEST CASE 6: INCREASED RELIABILITY, LOSS OF MICROGRID CONTROLLER SCENARIO

This case is designed to evaluate the following research questions related to networked microgrid controllers:

- How much can networked microgrid controllers improve island load coverage when one controller fails during island operations?
- Can networked microgrid controllers improve the reliability of an island during a utility outage?

6.6.1 Purpose

The distributed controller architecture of networked microgrids allows sub-microgrids to continue operating when one controller fails. This modularity is expected to improve reliability as compared to a single, centralized controller (which causes an island-wide power loss upon failure). To demonstrate this reliability improvement, this test measures the load coverage and transient stability provided by the networked microgrids when one of the microgrid controllers fails. The test case will capture and evaluate:

- Coverage of critical, priority, and interruptible loads compared to a centralized controller baseline
- Voltage and frequency transient stability during a loss of microgrid controller event

The following baseline case will be considered for load coverage performance comparison:

- No ability to connect islanded microgrids. Controllers and pre-defined microgrid boundaries remain isolated and cannot share resources during event.

6.6.2 Test Scenario

1. Reliable Feeder Microgrid Operations—maintain service by power sharing during controller outages in islanded operation including:
 - a. Recovery of a sub-microgrid in the case of loss of controller to controller communications; various combinations of load and solar profile time series will be used.

6.6.2.1 Baseline Scenario

1. Long duration utility outage—no ability to connect islanded microgrids
 - a. Microgrid controllers have no communication link
 - b. Loss of controller results in separate island shutdown

6.6.3 Test Approach / Narrative

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection, CB 106 = closed), sunny day solar availability
 - a. GridMaster Controller 1 or 2 becomes unavailable, loses connectivity. DER remain online and serving load
 - b. Observe single controller response to loss of other Microgrid controller
 - c. Expect remaining microgrid controller to remain online, safely separate the microgrids, and continue serving its local critical loads

6.6.4 Evaluation Criteria

The outcome of this test case should demonstrate the improved reliability provided by the distributed microgrid controller architecture. During the loss of microgrid controller event, the remaining microgrid controller must remain online and continue serving local loads in priority

order. Non-critical load shedding is acceptable if inadequate DERs are available. The voltage and frequency of the microgrid area that remains online should not exceed short-term excursion limits throughout the duration of the test. DERs under the failed microgrid controller should safely shut down as a result of lost communications. Specific metrics are provided in Table 6-6.

6.6.5 Test Results

Total simulation run time: [24 hours]

6.6.5.1 *PowerFactory simulation configuration*

- Selected load profiles: 24 hours start from 0 am
- Selected PV profiles: Sunny day profile
- SEL-751-1 Status: open at start (stable island)
- BESS SOC at initialization: 80%

6.6.5.2 *Baseline configuration conditions*

GridMaster IPC Configuration:

- Operational strategy IPC1: [N]
- Operational strategy IPC2: [N]
- Unavailable devices: IPCs configured to prevent closing [CB-106], thus preventing joined microgrids; IPC-1 is shutdown during the test.
- Configured date/time of day at test start: 0am
- Time of IPC-1“loss”: 12pm

6.6.5.3 *“Loss of Controller” test configuration*

GridMaster IPC Configuration:

- Operational strategy IPC1: [N+1]
- Operational strategy IPC2: [N+1]
- Unavailable devices: [none]
- Configured date/time of day at test start: 0am
- Time of single controller “loss”: 12pm

Table 6-6. Performance Metrics of Loss of Microgrid Controller Tests

Performance Metrics	[N]	[N+1]	Sep. MGs
All Critical Loads Outage duration (s)	144859.5	150961.4	20885.89
All Local Loads Outage duration (s)	0	0	0
All Priority Loads outage duration (s)	72563.68	73545.59	59300.63
All Interruptible Load outage duration (s)	190780	208847.7	50940.97
All Critical Load coverage (MWh)	4.33909	2.886264	31.14896
All Local Load coverage (MWh)	60.92271	60.95583	60.43179
All Interruptible load coverage (MWh)	1.338001	1.267851	3.017122
Total Critical Load disruptions	2.34764	1.757679	8.030779
Total Critical Load disruptions	2	3	1
Total Local Load disruptions	0	0	0
Total Priority Load disruptions	1	2	1
Total Interruptible Load disruptions	5	5	2
Maximum voltage (p.u.)	0.996899	0.99729	1.003461
Minimum voltage (p.u.)	0.984836	0.977851	0.967595
Maximum frequency (Hz)	60.96658	61.37638	61.47467
Minimum frequency (Hz)	59.49849	59.67643	54.82367

Figure 6-17 shows the output power of the sources, load power consumptions, and microgrid frequencies and voltages during the 24h islanded operation, using a sunny day profile and N+1 strategy.

IPC1 is turned off at around 12pm, such that MG1 equipment cannot be controlled afterwards. Since the frequency and voltage setpoints of generator 1 cannot be adjusted after 12pm, only generator 2 and BESS can regulate the system voltage and frequency. After the BESS energy is depleted around 19:00, generator 2 takes over all active power demands in the microgrid by raising its frequency setpoint. The system frequency is around 61.2 Hz around the period, slightly above the default DER over-frequency trip setting 1. System voltage is maintained well within the ANSI C84.1 requirements.

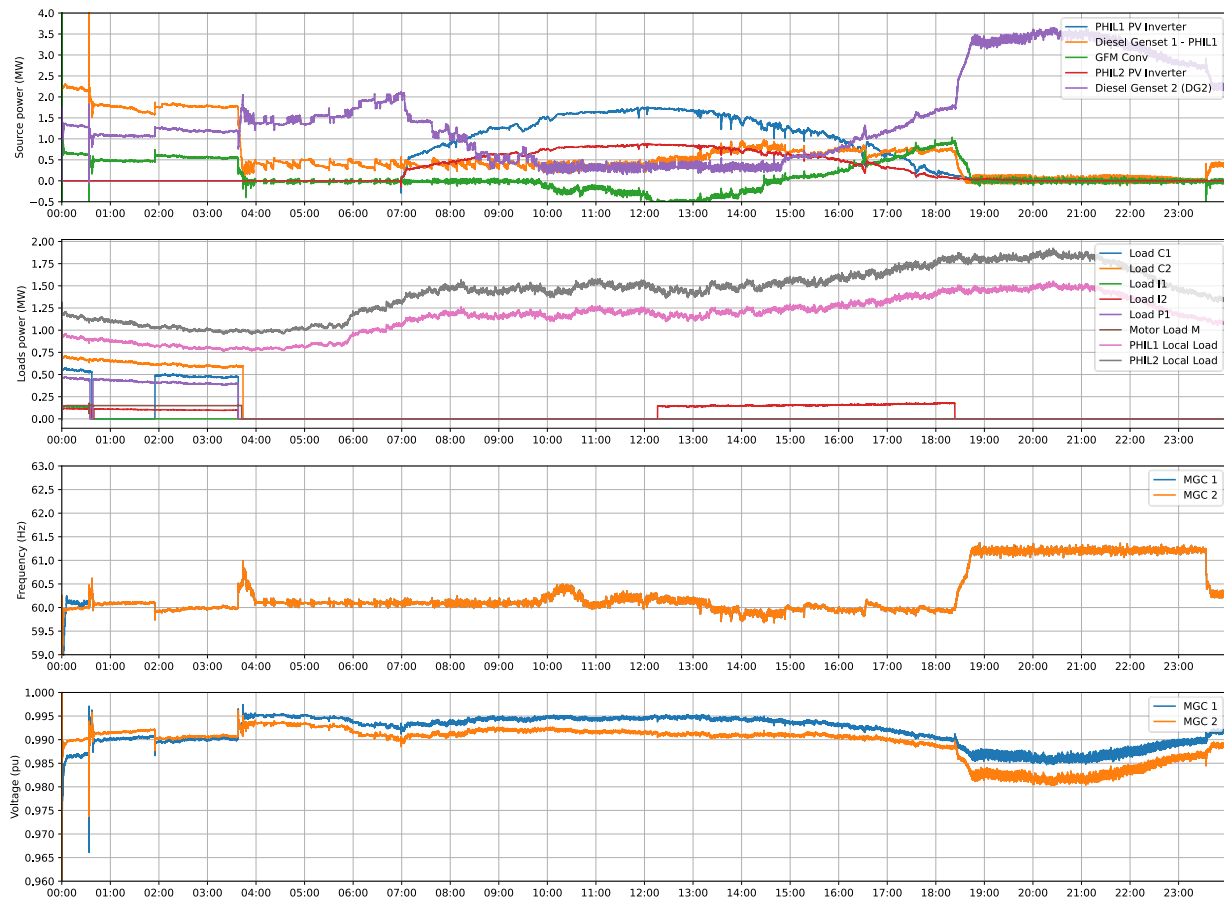


Figure 6-17. Microgrid Reaction to Loss of Microgrid Controller with N+1 Strategy

Simulated failure of IPC1 occurs at 12:00.

Figure 6-18 shows the output power of the sources, load power consumptions, and microgrid frequencies and voltages during the 24h islanded operation, using a sunny day profile and separated microgrids.

Again, IPC1 is turned off at around 12pm, such that MG1 equipment cannot be controlled afterwards. In separated microgrids, the voltage and frequency in MG1 remains unregulated. During the evening, the frequency at MG1 drops to around 55 Hz, lower than the default DER under-frequency trip setting 2. System voltage is still within the ANSI C84.1 requirement.

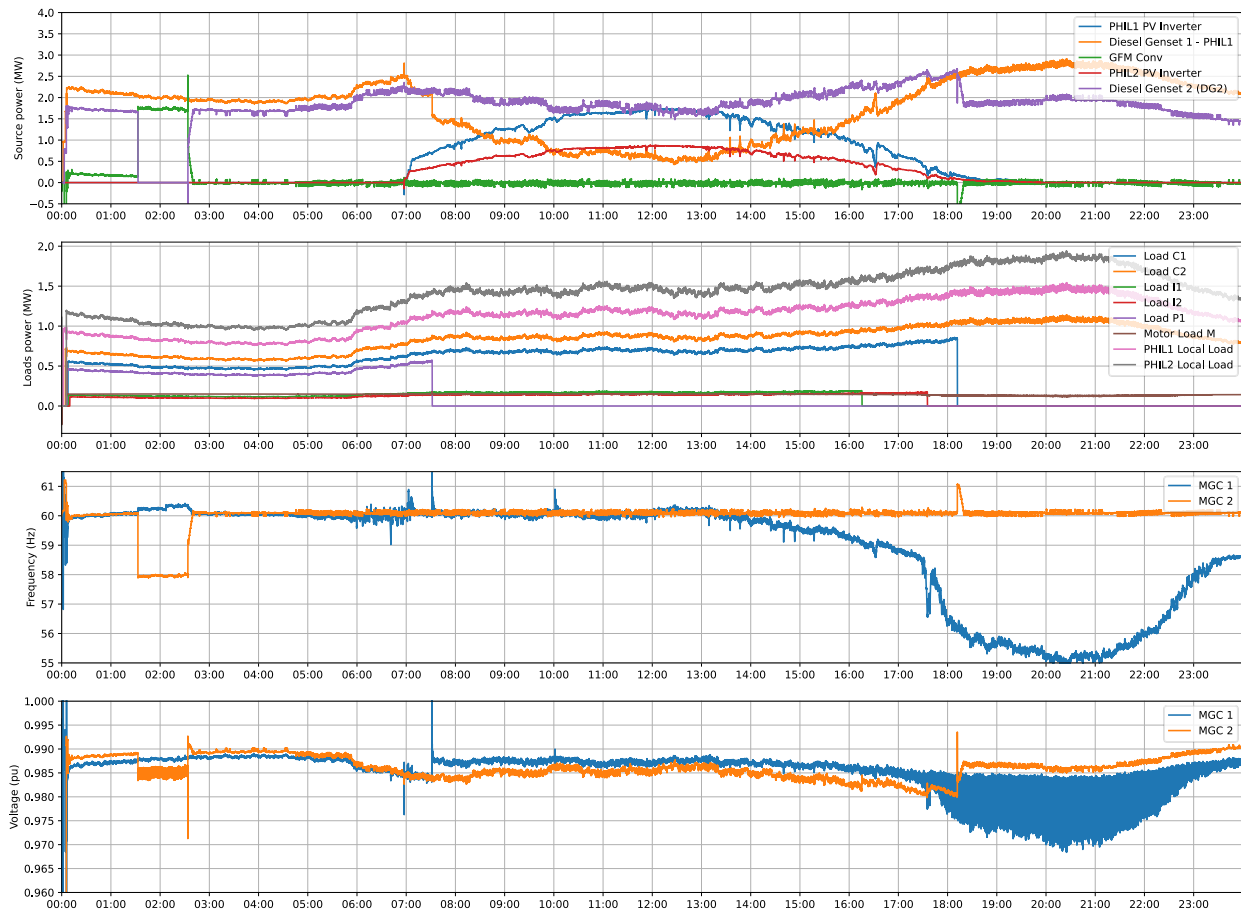


Figure 6-18. Microgrid Reaction to Loss of Microgrid Controller with Separated Microgrids.

Simulated failure of IPC1 occurs at 12:00.

6.6.5.4 Results analysis and baseline comparison

The purpose of this test was to evaluate if the networked microgrid controllers can provide increased reliability in a loss of controller scenario during island operations.

To focus on examining the influence of the networked microgrid controllers in this scenario, the DER and controllable breakers in the simulated feeder were modeled to continue operating at their last known setpoint in the event of a loss of master controller. Certain site installations may require

DER or specific reclosers to trip for safety under a loss of control master state; that type of equipment shutdown response would likely decrease the total load coverage captured in these scenarios.

6.6.5.5 Performance objective 1: Increase Load Coverage

The joined microgrid configurations have worse load coverage in this test case, mainly due to the system response in normal condition (before controller loss). It is identified earlier that the IPC control of the two joined microgrids lack sufficient coordination to improve high priority load coverage, especially after ESS's SOC drop to 20%. More details are discussed in test case 2 and test case 5.

6.6.5.6 Performance objective 2: Feeder voltage deviation

The joined microgrids show improved voltage regulation in both N and N+1 control strategies. both Joined microgrids has slightly better system voltage regulation. Although MG1 does not technically violate the ANSI C84.1 voltage limits in the separated controller case, the bus voltage oscillation following the simulated controller failure may trigger equipment trips in a physical system.

6.6.5.7 Performance objective 3: Feeder frequency deviation

The joined microgrids show improved frequency control in both N and N+1 control strategies compared to the separated case. The joined microgrids in the N control strategy are able to continue operations with both microgrids in acceptable frequency limits. The baseline separated controller configuration fails to meet the performance requirements due to the significant frequency deviation in MG1 during the evening peak. The joined microgrids in the N+1 control strategy do exceed the long-term over frequency limit (61.2 Hz) during the evening load peak (after IPC1 is simulated to fail).

Ultimately, the simulated load coverage captured in the loss of controller scenarios may not be achievable under field conditions due to protection elements tripping during the noted frequency excursions.

6.7 TEST CASE 7: DEMONSTRATE OPERATIONS FOR ECONOMIC BENEFITS

This case is designed to evaluate the following research question related to networked microgrid controllers:

- Can networked microgrid controllers provide economic benefit when grid-connected?

6.7.1 Purpose

This test case is designed to demonstrate the economic benefits of networked microgrid controllers during grid-connected operations (substation feeder recloser and sub-microgrid isolation breaker are closed). The scenario will run over multiple days to capture typical utility bill charges and varied load profiles. The sub-microgrid controllers are expected to coordinate to operate the system at least cost mode. A baseline operational case will be created by running the scenario without active microgrid controllers (e.g., only uncontrolled PV active). The baseline will be compared to two conditions:

- Distributed microgrid controllers active, without controller-to-controller communication
- Distributed microgrid controllers active, with controller-to-controller communication

The cases with active microgrid controllers are expected to reduce the total operational cost of the system; the case with controller-to-controller communication should further reduce the operational cost over the duration of the scenario.

6.7.2 Test Scenario(s)

1. Utility connected, multi-day microgrid operations for economic benefit; various combinations of load and solar profile time series will be used.

6.7.2.1 Baseline Scenario(s)

- Utility connected, multi-day operations, no microgrid controls activated

6.7.3 Test Approach / Narrative

1. While operating grid connected, feeder-level microgrid in steady state conditions, measure normal operational cost over 1-2 day profile; no controller managing DER
 - a. Utility bill, fuel costs
 - b. Repeat initial conditions and rerun load/PV profiles with economic benefit control functions activated in separate microgrid controllers (IPC-1 and IPC-2), but no communication between the controllers
 - c. Repeat initial conditions and rerun load/PV profiles with economic benefit control functions activated in both microgrid controllers (IPC-1 and IPC-2), including coordinated communication between the controllers
 - d. Measure utility bill and fuel costs
 - e. These tests must run for at least one day.

6.7.4 Evaluation Criteria

Reduced operational costs when microgrid controller is enabled (step 2). Operational costs should reduce further when both controllers are enabled to communicate with each other and coordinate power sharing across the feeder. The outcome of this test case is expected to demonstrate improved economic benefit through distributed microgrid controller coordination. This benefit is measured by comparing system operational cost between baseline test and active controller tests. Specific metrics are provided in Table 6-7.

6.7.5 Test Results

Total simulation run time: 24 hr

6.7.5.1 PowerFactory simulation configuration

- Selected load profiles: 0am
- Selected PV profiles: 0am

- SEL-751-1 Status: closed
- BESS SOC at initialization: 50%

Utility rate structure:

Table 6-7. Utility Rate Structure Used to Analyze Economic Dispatch Performance

Bill Component	Price
Monthly Fixed Charges	\$2,110.04
Distribution Energy Charges (\$/kWh)	\$0.02651
Summer On-Peak Generation Charges (\$/kWh)	\$0.30144
Summer Mid-Peak Generation Charges (\$/kWh)	\$0.08113
Summer Off-Peak Generation Charges (\$/kWh)	\$0.03562
Winter Mid-Peak Generation Charges (\$/kWh)	\$0.05148
Winter Off-Peak Generation Charges (\$/kWh)	\$0.04116
Monthly Peak Demand Charges (\$/kW)	\$8.77
Aggregate Taxes and Other Fees	0.0%
Diesel Fuel Price (\$/gallon)	\$2.97
Heat Rate of Diesel Gensets (Btu/kWh)	12,040

Utility Rate Notes:

1. Billing components here are adapted from the Southern California Edison TOU-8 Option A Schedule
2. Summer is June through September, and winter is October through May.
3. The on-peak period is 12pm-6pm on summer weekdays except holidays.
4. The mid-peak period is 8am-12pm and 6pm-11pm on summer weekdays except holidays, and 8am-9pm on winter weekdays except holidays.
5. The off-peak period is all hours except on-peak and mid-peak hours.
6. Distribution energy charges apply to all consumption volumes.

6.7.5.2 Baseline configuration conditions

GridMaster IPC Configuration: Disabled. To establish a baseline, the original total feeder load net PV output was used to calculate the baseline bill.

A sample of the economic dispatch test scenario is plotted in Figure 6-19 below. In this test run, IPC-2 dispatches the battery at 12:00 to reduce the power imported at the PCC; the diesel gensets are dispatched between 17:00-22:30 to reduce the peak demand on the feeder.

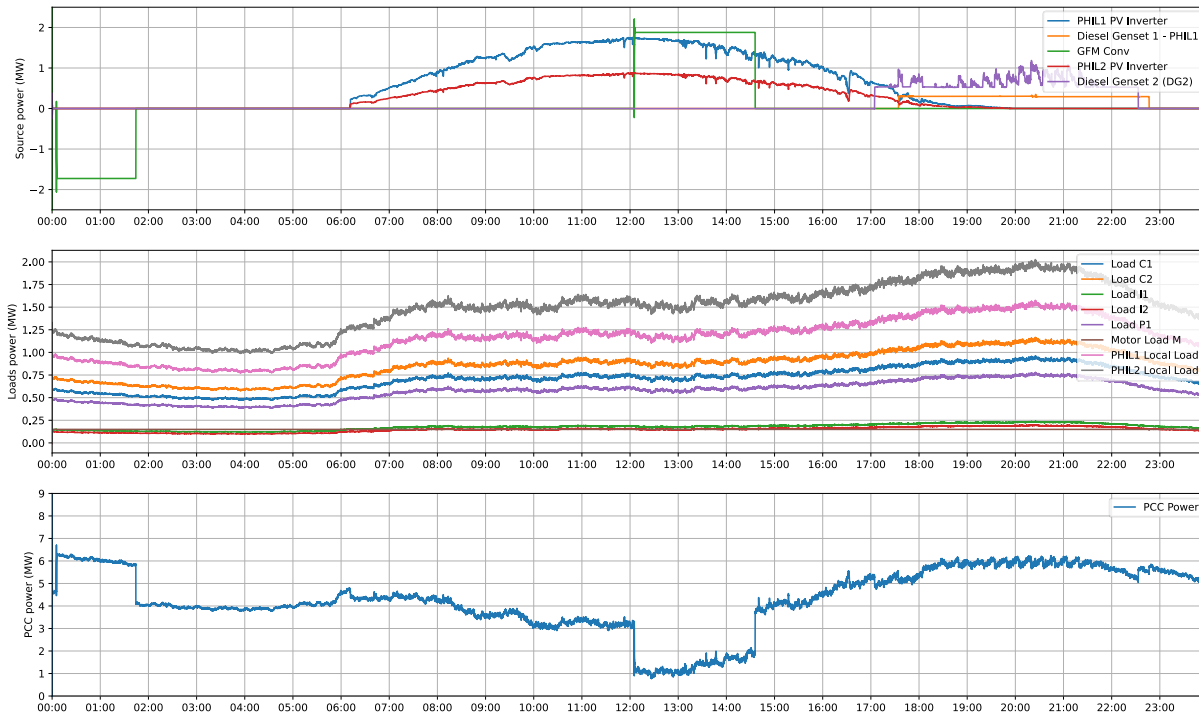


Figure 6-19. Economic Dispatch Test Run Scenario Results Sample from a Summer Weekday Run.

6.7.5.3 Results analysis and baseline comparison

The purpose of this test was to evaluate if the networked microgrid controllers provide increased economic value during grid-connected operations. Overall, the microgrid controllers do provide a net economic benefit based on the calculated billing savings shown in Table 6-8 and Table 6-9.

Table 6-8. Daily Billing Results for Summer, Weekday Test Runs

	Test Day 1		Test Day 2		Test Day 3	
	Active Control	Baseline	Active Control	Baseline	Active Control	Baseline
Daily Energy Total	\$ 15,629.15	\$ 15,683.66	\$ 15,265.25	\$ 15,376.33	\$ 15,600.75	\$ 15,701.88
Energy Billed Cost	\$ 13,449.87	\$ 15,683.66	\$ 13,301.29	\$ 15,376.33	\$ 13,628.66	\$ 15,701.88
Fuel Cost	\$ 2,179.28	0	\$ 1,963.96	0	\$ 1,972.09	0
Demand Charge	\$ 56,005.22	\$ 74,264.36	\$ 55,961.37	\$ 63,906.99	\$ 55,373.78	\$ 64,301.64
Total with Demand Charge	\$ 71,634.37	\$ 89,948.02	\$ 71,226.62	\$ 79,283.32	\$ 70,974.53	\$ 80,003.52

Table 6-9. Economic Dispatch Test Results Extrapolated to a 30-day Billing Period

	Active Control	Baseline	Savings (%)	Savings (\$)
Energy Total	\$ 464,951.44	\$ 467,618.64	0.57%	\$ 2,667.20

Energy Billed Cost	\$ 403,798.13	\$ 467,618.64	13.65%	\$ 63,820.51
Fuel Cost	\$ 61,153.31	\$ -	-	\$ (61,153.31)
Demand Charge	\$ 56,005.22	\$ 74,264.36	24.59%	\$ 18,259.14
Billing Total	\$ 520,956.66	\$ 541,883.00	3.86%	\$ 20,926.34

6.7.5.4 Performance objective 1: Economic dispatch

To measure the success of the economic dispatch algorithm in the networked microgrid controllers, the combined feeder-level microgrid area was treated as a single billed customer at the TOU billing rate provided in Table 6-7. The results of three 24-hr economic dispatch test cycles are provided in Table 6-8. The “Energy Total” cost shows the combined energy charges (kWh from the utility) and fuel cost. The “Demand Charge” is calculated using the peak demand from the feeder during the respective 24-hr test cycle.

The data from the 3 days of testing were extrapolated to a 30-day billing cycle to estimate monthly performance in Table 6-9. The monthly “Demand Charge” is taken from the peak demand across the 3 days of testing (all taken from the same month). The results show an estimated 3.86% savings on the monthly summer bill. This performance meets the defined success criteria that the microgrid controllers should reduce the total utility bill while grid-connected compared to a baseline without microgrid control.

The IPC architecture (documented in *GridMaster Decentralized Control Architecture and Functionality* [2]) notes that the economic dispatch algorithms use historical data from the site to continuously improve the economic dispatch performance. Given the limited grid-connected run-time in the test setup and lack of historical feeder data, it is expected that the economic dispatch performance could be improved by initializing the IPC with more load data.

Note, the economic savings due to PV production are not calculated in the savings shown in Table 6-9. While the PV production does provide billing savings, the PV output was not changed in either the baseline or active controls test scenarios. To measure the economic dispatch impact of PV control in future test scenarios, the test network should include a higher ratio of installed PV to load.

6.7.5.5 Performance objective 2: Feeder voltage deviation

No abnormal voltage conditions were seen during the economic dispatch tests. A sample of the bus voltages during an economic dispatch test run is shown in Figure 6-20. All sampled voltages remain within ANSI C84.1 Range A (normal operations) limits as described in the Performance Objectives section.

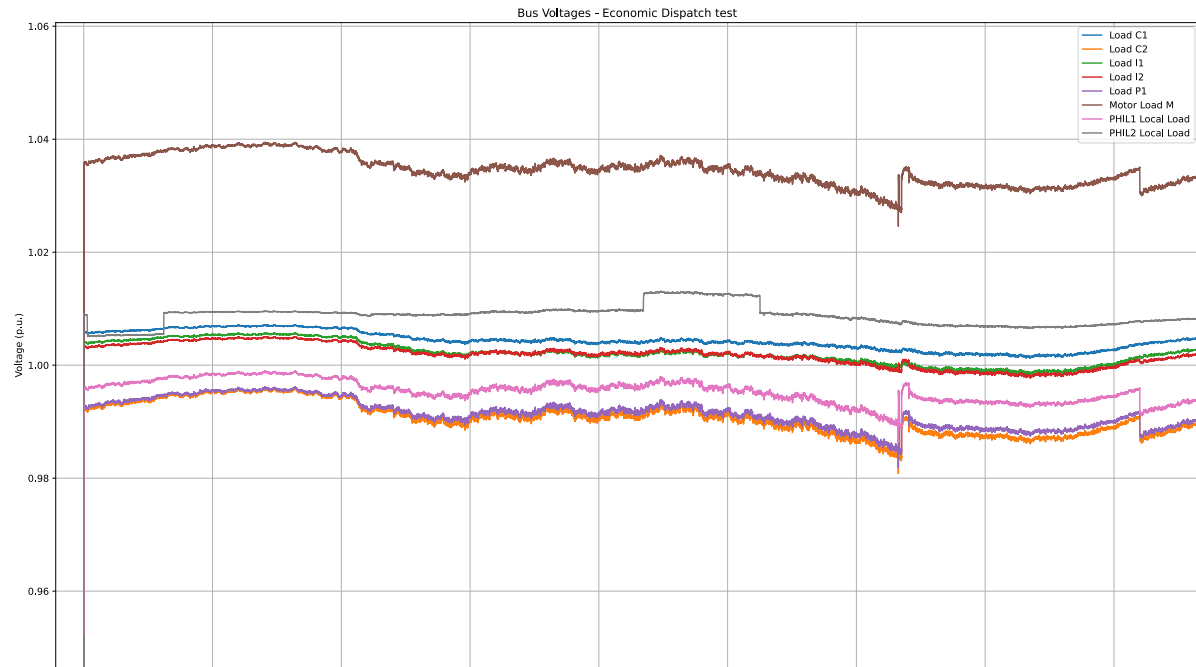


Figure 6-20. Bus Voltages Across the Feeder during the Grid-connected, Economic Dispatch Test

7.0 PHIL PERFORMANCE TESTING

7.1 PHIL PERFORMANCE TESTING

This section presents system test procedures and results from the PHIL testing conducted at Sandia National Lab.

7.1.1 Test Case 1: Demonstrate Outage Recovery for Resilience

This case is designed to evaluate the following:

How do networked microgrid controllers coordinate to provide feeder-level outage recovery?

Can the outage recovery sequencing (black start) of islanded, networked microgrids be managed by commercially available microgrid controllers?

Can the synchronization of islanded microgrids be managed by commercially available microgrid controllers?

Will the combination of shared droop control and microgrid controller management be sufficient to prevent voltage and frequency excursions that would trip protection equipment or harm the system?

Purpose

A defining component of grid resilience is the ability to recover rapidly from changing conditions and disruptions. Networked microgrid controllers are expected to improve this aspect of resilience by bringing the combined microgrid areas online faster than a centralized controller or manually sequenced, independent microgrid controllers. To demonstrate and evaluate outage recovery performance, this test will require the controllers to execute an island black start and connect the islanded microgrid areas as a single, networked island.

When independent microgrids synchronize and reconnect to the grid, the utility grid provides a relatively stiff voltage and frequency source that can absorb the transient effects of the microgrid island reconnection. When networked microgrids join together to form a larger island, the voltage and frequency stability of the system depends on an adequate design (selection) of grid-forming DER and microgrid controller management. A key function of networked microgrid controllers is the ability to synchronize single microgrids operating in island mode and connect them to create a larger island. This function (detailed in [2]) is essential to coordinating multi-microgrid outage recovery and providing wider outage coverage. It allows the individual microgrid controllers to simultaneously manage critical load restoration within their local microgrid boundary, then join to create wider areas of load coverage as a networked group. In order for this synchronization process to be successful, the microgrid controllers must ensure that the DER are positioned for the transition to minimize voltage and frequency disturbances that might otherwise cause another black out.

The test case will capture and evaluate:

Outage recovery sequencing (black start process from utility outage to energized, connected networked island)

Transient effects of island synchronization on voltage and frequency when transitioning from separate to joint microgrids

Test Scenario

1. Planned/Unplanned utility outage—black start function
 - a. Black start multi-customer microgrids 1 and 2 (left frame in Figure 7-1)
 - b. Create multi-customer microgrids 1 and 2 (bring single-customer on-line, bring lower priority loads online, if possible, middle frame in Figure 7-1)
 - c. Create feeder-level microgrid (synchronize and connect multi-customer microgrids 1 and 2, right frame in Figure 7-1)

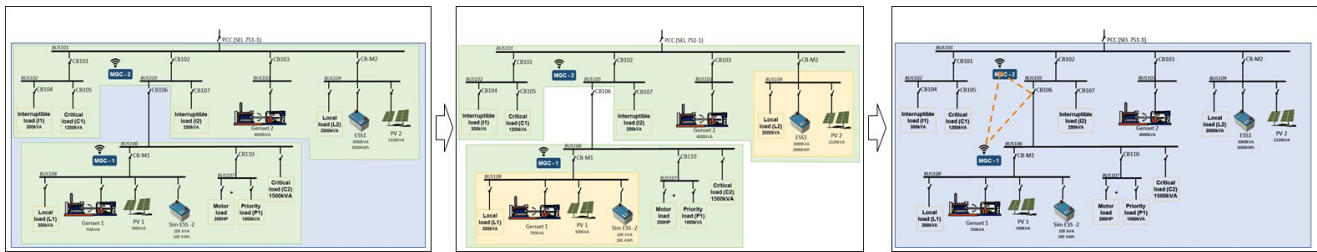


Figure 7-1. Test Case Demonstration of Individual Microgrid Control Areas Synchronizing to One Combined Microgrid

Test Approach / Narrative

1. Normal, utility-connected system operations observed
2. Utility outage event occurs (triggered in simulation by SEL751-1 trip)
 - a. Feeder-wide blackout, DER trip
3. Microgrid controllers open load and microgrid boundary switches as needed to isolate and safely black start respective areas—for these test evaluations the IPCs were used in manual modes and all CBs were either opened or closed manually.
4. Microgrid controllers initiate outage recovery sequence for critical loads
 - a. Black start customer-level microgrid 1 (sequenced in parallel to customer-level microgrid 2 start):
 - i. Confirm isolation, CB-M1 verified open
 - ii. IPC-1 starts simulated 100kVA BESS in customer-level microgrid 1. Since BUS106 nor BUS108 doesn't contain any simulated generation sources, initial attempts to energize the dead bus via the ABB resulted in transients that would trip ac simulator. Therefore, a 100kW simulated BESS was implemented on BUS108.
 - iii. Bus 108 load served
 - iv. PV-1 starts after bus 108 has stable voltage for approximately 2 minutes

- iv. Black start microgrid 2. Confirm isolation, CB-M2 verified open
 - v. IPC-2 starts Genset-2, multi-customer microgrid 2 is served
 - vi. Bus 101 is served—loads are served
 - vii. IPC-2 starts ESS1 grid-forming inverter in customer-level microgrid 2
 - viii. Bus 109 load served
 - ix. PV-2 starts after bus 109 has stable voltage for approximately 2 minutes
5. Microgrid controllers initiate recovery of additional loads within multi-customer microgrid boundaries. For these evaluations the IPCs were used in manual mode
- a. Expand microgrid 1 to multi-customer boundaries
 - i. Confirm isolation from multi-customer microgrid 2, CB-106 verified open, CB-110 open
 - ii. IPC-1 closes CB-M1; bus 106 load served
 - iii. If adequate DER generation available, IPC-1 closes CB-110, brings bus 107 online
 - b. Expand microgrid 2 to multi-customer boundaries
 - i. Confirm isolation from substation and multi-customer microgrid 1, SEL751-1 and CB-106 open, CB-101 and CB-102 open
 - ii. IPC-2 closes CB-M2 and CB-101 to serve bus 102 loads
 - iii. If adequate DER generation available, IPC-1 closes CB-102, brings bus 105 online
6. Microgrid controllers (IPC-1 and IPC-2) coordinate to synchronize microgrid (MG)-1 and MG-2 to form feeder-level microgrid (see test case 2 for evaluation of microgrid performance during synchronization)
- a. MG-1 and MG-2 are online and stable; IPC-1 and IPC-2 communicate to confirm readiness to form feeder-level microgrid
 - b. Microgrid controllers send bias signal to generator and ESS to bring ΔV and $\Delta \theta$ within acceptable synchronization tolerance
 - c. IPC-1 or IPC-2 sends close command to CB-106 (synchronizing recloser, which is realized with the use of the Schweitzer 351 synchronizing relay)
 - i. CB-106 monitors voltage and phase angles of MG-1 and MG-2
 - ii. CB-106 closes when separate microgrids are within tolerance
 - d. Primary droop response of diesel generator and ESS is expected to maintain feeder-level microgrid stability following CB-106 close. Instead of diesel generator, a simulated BESS operating in V/F droop mode fulfills this requirement. This was originally introduced because energizing MG1 simulated dead bus could not be accomplished without creating large transients.
 - e. IPC-1 and IPC-2 controllers continue to coordinate and manage DER setpoints for single feeder-level microgrid
7. Test concludes when entire feeder-level microgrid is live, all loads are online, and grid-forming DER are coordinated manually through the S&C GridMaster controllers to share load and maintain voltage and frequency within operational limits.

The results to test sequence 1 are shown below. These tests were conducted at Sandia National Laboratories Distributed Energy Technology Laboratory (DETL) facility. The PV power in MG1 is provided by a PV array and dynamic irradiance conditions can be seen in the data presented. The PV power in MG2 is provided by a PV simulator and steady irradiance conditions were programmed into the PV simulator, however in the Sandia data, the PV power is not shown because it is paralleled after the monitoring transducers and doesn't get monitored and the IPC-2 didn't capture the data because of a memory overrun.

1. Start Sim
2. Simulated Diesel Start
3. Simulated BESS on
4. Close CBs
 1. IPC1 (11:12)
 2. IPC2 (11:12)
5. Turn on MG1
 1. PV on (11:14)
 2. Load on 15kW (11:15)
 3. Scale MG1 to 10 (11:15)
6. Turn on MG2
 1. PV on (11:18)
 2. Load on 30kW (11:19)
 3. ABB on (11:20)
7. CB106 Close (11:26)
8. Increase Load on MG1 to 15 → 25kW
9. Curtail PV MG2 to 50% (11:28)
10. Decrease load on MG1 (30 → 10 kW) (11:29)
11. PV MG2 off (11:30)
12. PV MG2 100% (11:31)
13. Decrease load on MG1 (25 → 15 kW) (11:32)
14. Open CB106
15. Load off MG1 (11:34)
16. PV off MG1 (11:34)
17. ABB off
18. Load MG2 off (11:35)
19. MG2 off
20. Sim Stop (11:36)

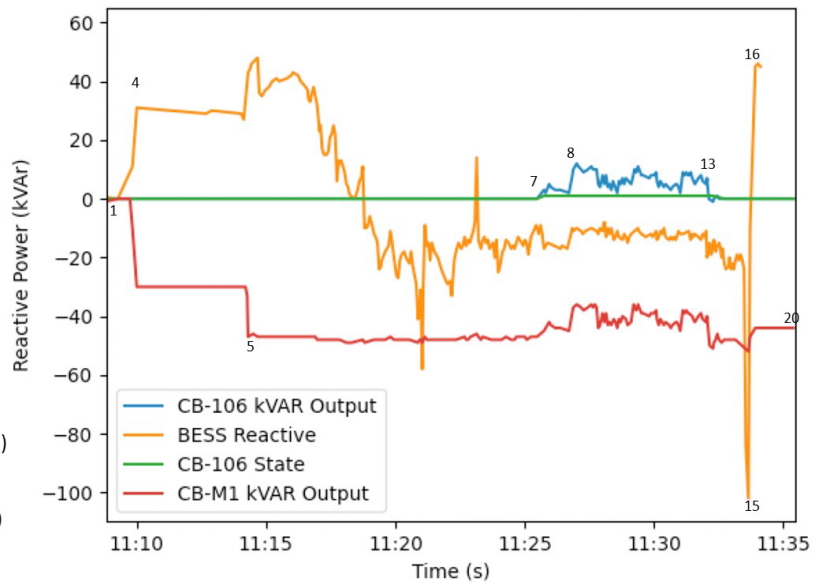


Figure 7-2. Reactive Power Flowing through CB-M1, which Contains a Simulated 100kW BESS, PV Inverter, and a Resistive Load

1. Start Sim
2. Simulated Diesel Start
3. Simulated BESS on
4. Close CBs
 1. IPC1 (11:12)
 2. IPC2 (11:12)
5. Turn on MG1
 1. PV on (11:14)
 2. Load on 15kW (11:15)
 3. Scale MG1 to 10 (11:15)
6. Turn on MG2
 1. PV on (11:18)
 2. Load on 30kW (11:19)
 3. ABB on (11:20)
7. CB106 Close (11:26)
8. Increase Load on MG1 to 15 → 25kW
9. Curtail PV MG2 to 50% (11:28)
10. Decrease load on MG1 (30 → 10 kW) (11:29)
11. PV MG2 off (11:30)
12. PV MG2 100% (11:31)
13. Decrease load on MG1 (25 → 15 kW) (11:32)
14. Open CB106
15. Load off MG1 (11:34)
16. PV off MG1 (11:34)
17. ABB off
18. Load MG2 off (11:35)
19. MG2 off
20. Sim Stop (11:36)

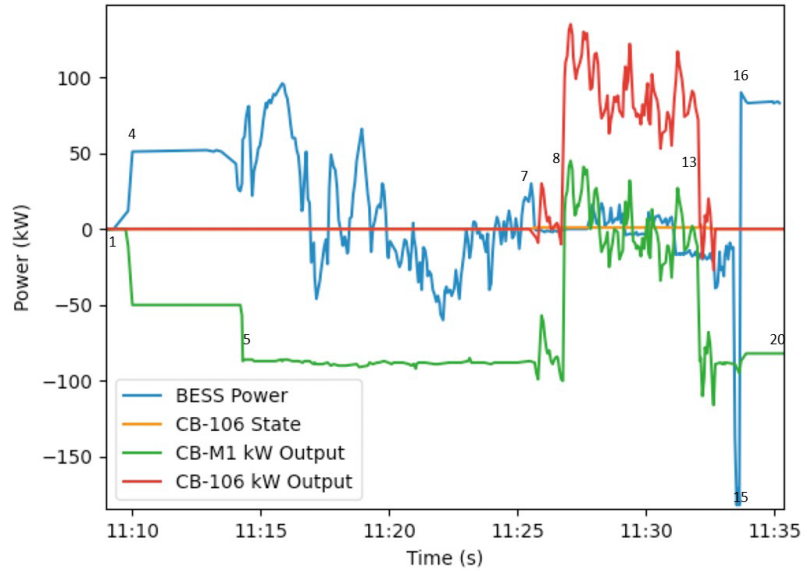


Figure 7-3 Active Power Flow through CB-M1

1. Start Sim
2. Simulated Diesel Start
3. Simulated BESS on
4. Close CBs
 1. IPC1 (11:12)
 2. IPC2 (11:12)
5. Turn on MG1
 1. PV on (11:14)
 2. Load on 15kW (11:15)
 3. Scale MG1 to 10 (11:15)
6. Turn on MG2
 1. PV on (11:18)
 2. Load on 30kW (11:19)
 3. ABB on (11:20)
7. CB106 Close (11:26)
8. Increase Load on MG1 to 15 → 25kW
9. Curtail PV MG2 to 50% (11:28)
10. Decrease load on MG1 (30 → 10 kW) (11:29)
11. PV MG2 off (11:30)
12. PV MG2 100% (11:31)
13. Decrease load on MG1 (25 → 15 kW) (11:32)
14. Open CB106
15. Load off MG1 (11:34)
16. PV off MG1 (11:34)
17. ABB off
18. Load MG2 off (11:35)
19. MG2 off
20. Sim Stop (11:36)

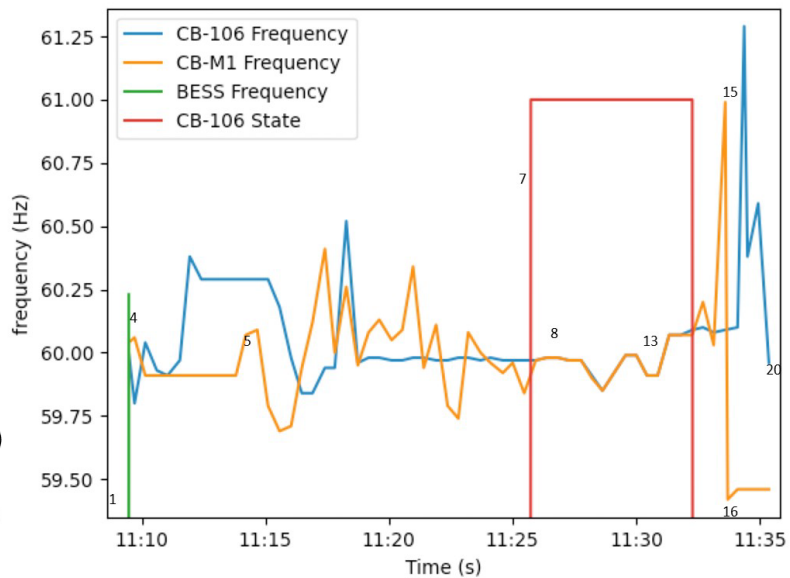


Figure 7-4. Frequency of MGC-1 before CB- 106 Closure

MGC-1 and MGC-2 synchronized and CB-106 closes at about 11:25:30 and at this point frequencies from MGC-1 and 2 are matched

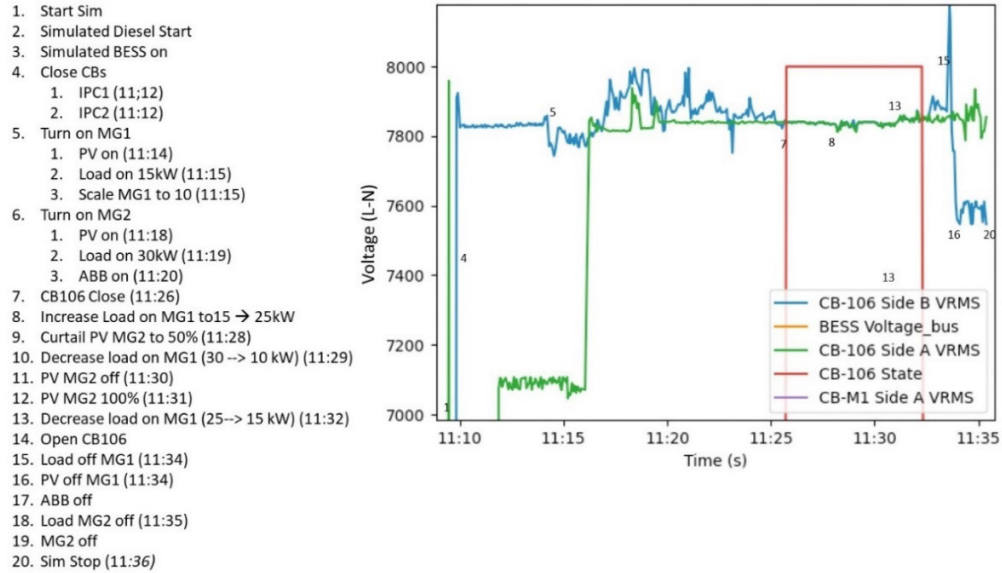


Figure 7-5. MGC-1 and MGC-2 Voltages Are Adjusted to Be Comparable, Once CB106 Closes Voltages Match

The following plots show the Schweitzer 351 synchronizing relay synch-scope for a pre-synch condition and a synchronized condition, where the two dials are at the same position. The varying PV (dynamic irradiance conditions) in MGC-1 made it somewhat difficult to synchronize the two microgrids. The SEL relay sends a permissive signal to the IPCs to close CB-106 when the phase angle is within 3° .

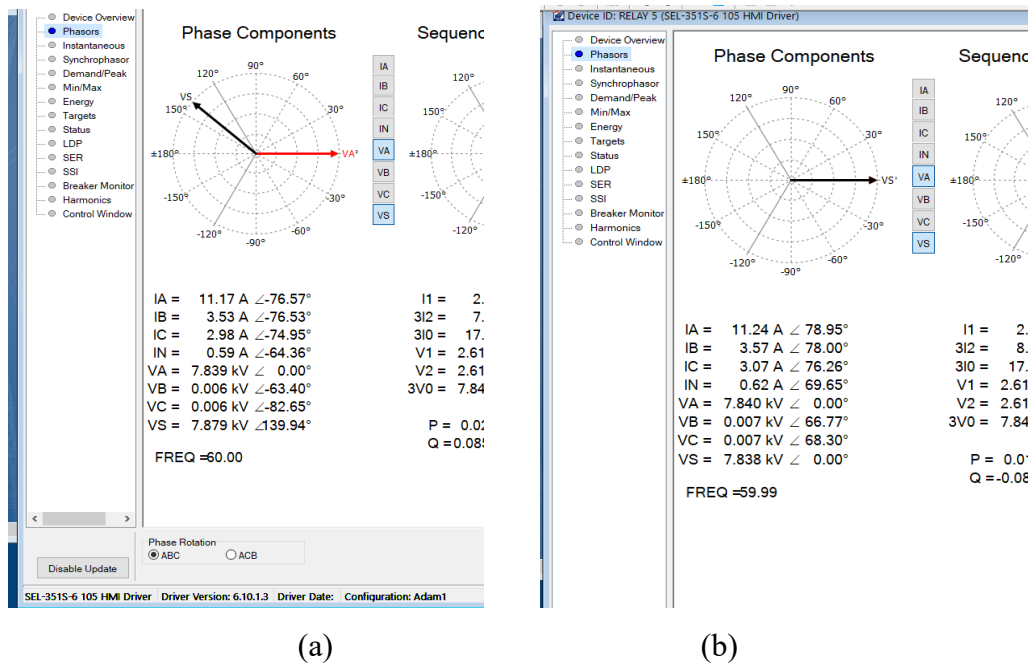


Figure 7-6. SEL-351 Phasor Diagrams (a) Shows a Pre-synch State, with Phase Angle at About 140° , (b) Shows the Synchronized State and Both Microgrids Connected and In-phase

During the closing of CB-106 relay, the Opal-RT simulator captured the voltage and current waveform data at CB-106 the moment the two microgrids are interconnected. Since the voltage amplitudes are closely matched and the phase-angles are closely matched prior to closing CB-106, the current transient during the interconnection is minimal. Figure 7-7 shows the voltage and current waveforms, plus a signal trace indicating when the relay closes and opens.

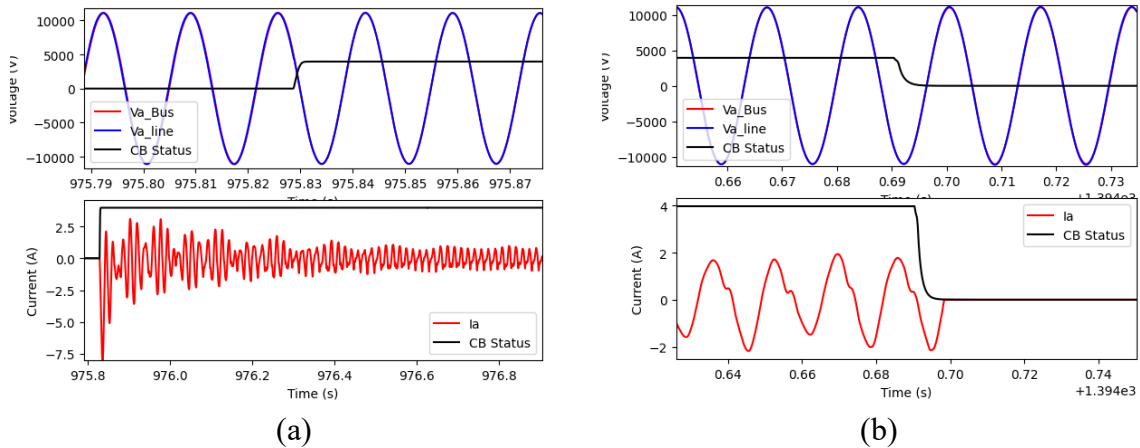


Figure 7-7. (a) CB-106 Closes when Black Trace Goes High, (b) CB-106 opens when Black Trace Goes Low

The following two plots were captured on DETL's LabView based data acquisition system. As mentioned above, the second plot doesn't display the PV power because PV is paralleled after monitoring system.

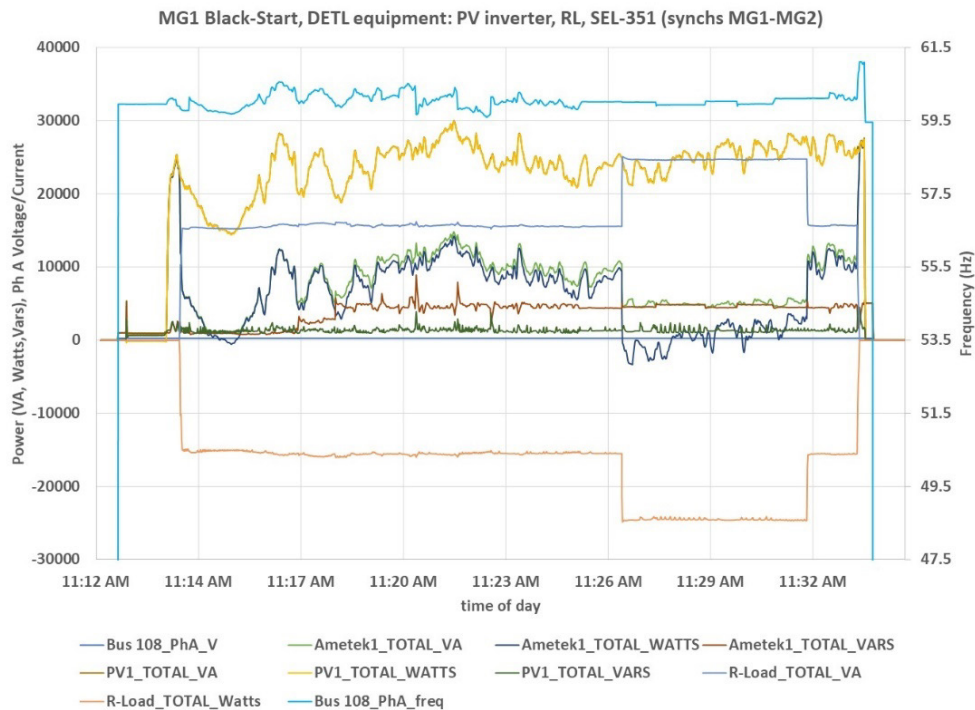


Figure 7-8. DETL Data Acquisition Data for MGC-1

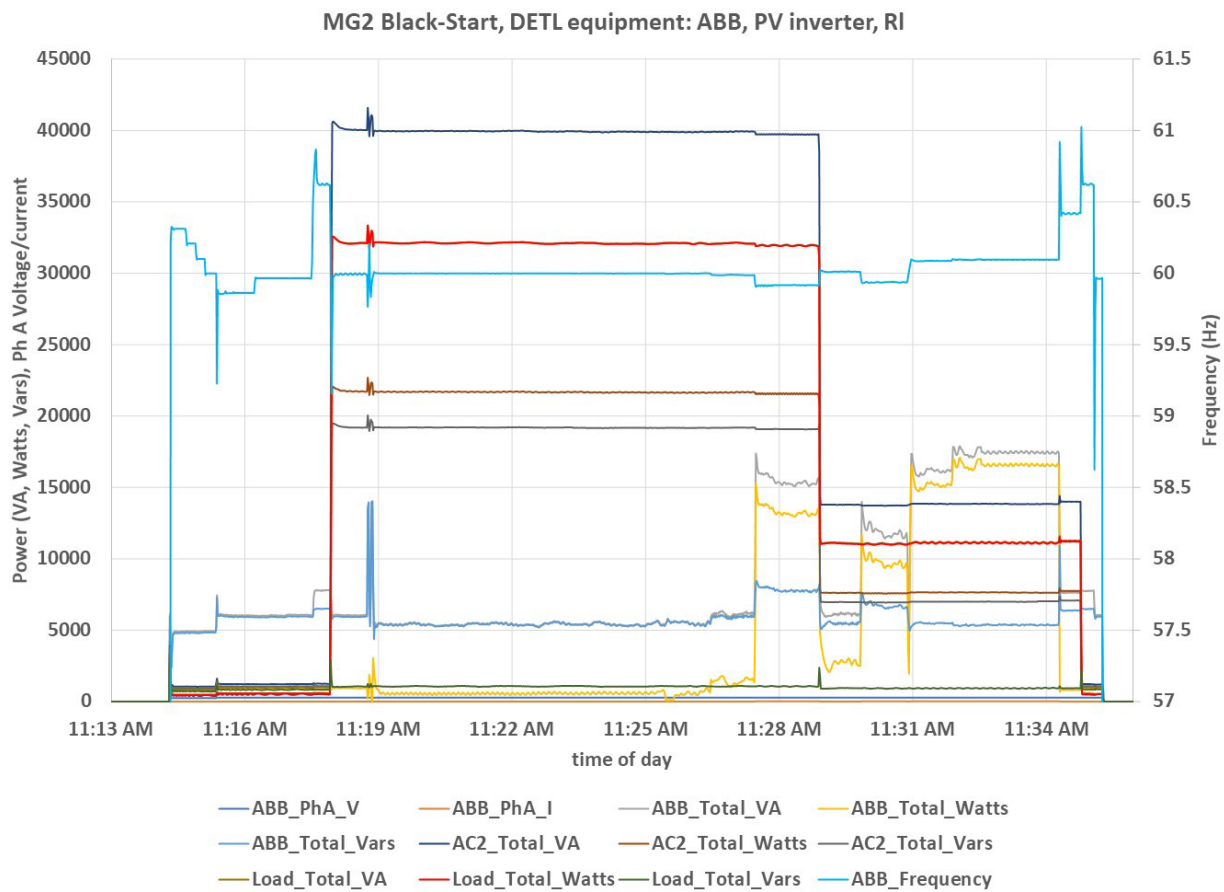


Figure 7-9. DETL Aata Acquisition Data for MGC-2

8.0 PERFORMANCE ASSESSMENT

This section presents a summary of the testing analysis from results presented above in [CHIL PERFORMANCE TESTING](#) and [PHIL PERFORMANCE TESTING](#). The detailed [Performance Objectives](#) that were used to evaluate the microgrid controller's performance and complete this analysis are provided in Chapter 4.0.

8.1 FEEDER BUS VOLTAGE

- **Feeder Bus Voltage:** bus voltages (in per unit) across the test feeder
- **Purpose:** Networked microgrids typically operate across multiple customer meters, and thus should remain within grid-connected interconnection voltage tolerance ranges when islanded as a joint network of microgrids.
- **Metric:** Magnitude of bus voltage excursions (in p.u.) throughout the test sequence
- **Data:** Bus voltages at each microgrid, branch recloser, and feeder PCC. Per the Equipment Interface section details, each breaker and DER will provide voltage readings for post-analysis.
- **Success Criteria:** In all test cases, the voltage readings in the network are expected to remain within ANSI C84.1 short-term and long-term ranges (as referenced in IEEE 1547-2018 and IEEE 2030.8). These are provided below in Table 8-1 for reference.

Table 8-1. Summary of Feeder Bus Voltages Captured during Testing

Test Case	Voltage Min (p.u.)	Voltage Max (p.u.)
1: Outage Recovery and Synchronization	0.91	1.01
2: Long Duration Island	0.974	0.995
3: Loss of PV	0.982	0.988
4: Low ESS SOC	0.986	0.992
5: Loss of Generator	0.957	0.993
6: Loss of Microgrid Controller	0.977	0.997
7: Grid-Connected Economic Benefit	0.985	1.039

Overall, the networked microgrid configuration was able to maintain feeder voltages within acceptable operational range throughout each testing scenario. There were temporary excursions into ANSI Range B during the microgrid black start process; while this behavior is common during the energization of most microgrids, it may have an impact on undervoltage protection tripping coordination. Because this transient excursion was related to the generator equipment sizing and black start capability used in the demonstration—not the networked microgrid control design—it was not considered a failure of the controllers.

Black start results:

The maximum and minimum voltages reported in Table 8-1 occurred when the two transformer-level microgrids were picking up the motor loads, which was before the joined feeder-level microgrid.

Other than the voltage transient due to motor load start, the system voltage is regulated well for all tests and remains within the ANSI C84.1 recommended ranges. It is not obvious that the joined feeder-level microgrid can improve this performance in normal operations.

Long duration island results:

The maximum and minimum voltages in the 24-hour islanded operation are usually associated with load restoration, especially the motor load start-up process. With joined microgrid operation, feeder voltage is regulated within the ANSI long-term range, better than separated transformer level microgrids.

8.2 FEEDER FREQUENCY

- Feeder Bus Frequency: bus and DER frequency (in Hz) across the test network
- Purpose: Networked microgrids typically operate across multiple customer meters, and thus should remain within grid-connected interconnection frequency tolerance ranges when islanded as a joint network of microgrids.
- Metric: Frequency reading (in Hz) throughout the test sequence.
- Data: Frequency measurement at each microgrid, branch recloser, and feeder PCC. Per the Equipment Interface section details, each breaker and DER will provide frequency readings for post-analysis.
- Success Criteria: In all test cases, the frequency readings in the network are expected to remain within IEEE 1547-2018 default “Continuous Operation” or “Mandatory Operation” frequency ranges. These allowable operational frequency ranges are provided in Table 8-2 for reference.

Table 8-2. Summary of Feeder Frequency Ranges Captured during Testing

Test Case	Frequency Min (Hz)	Frequency Max (Hz)
1: Outage Recovery and Synchronization	56.750	63.260
2: Long Duration Island	59.285	61.696
3: Loss of PV	59.292	60.189
4: Low ESS SOC	59.984	60.779
5: Loss of Generator	57.750	60.178
6: Loss of Microgrid Controller	59.498	60.966

Performance Assessment: Feeder frequency deviation

Black start results:

The maximum and minimum frequencies reported in Table 6-1 occurred during the start-up process of the generator at microgrid 1. Most of the frequency disturbances are caused by the load restorations, which happens mostly before the joined feeder level microgrid. Overall, in normal operation, the system frequencies are within the IEEE 1547-2018 mandatory operation ranges for DER.

As demonstrated in Figure 6-5, if separated, the microgrid 1 may experience slightly more severe frequency fluctuations due to load variation, since the frequency is regulated by a synchronous generator. If joined, shown in Figure 6-3 and Figure 6-4, the frequency fluctuations in the feeder level microgrid are reduced.

Long duration island results:

The maximum and minimum frequencies observed in the joined microgrid cases are related to load shedding and restoration. The system frequency is mostly within the default IEEE 1547-2018 mandatory operation range.

The excursions observed beyond the default IEEE 1547-2018 frequency ride-through ranges were still within the allowable ride-through settings ranges defined in the standard. This indicates that the microgrid protection design may require frequency ride-through settings that are wider than default, regardless of the separated or networked microgrid configuration. The networked microgrid configuration, however, experienced shorter duration and magnitude frequency excursions outside the default ride-through range.

8.2.1 Synchronization Tolerance

- Synchronization Tolerance: Voltage and frequency differences between sub-microgrids when microgrid controllers coordinate to form a feeder-level microgrid.
- Purpose: The microgrid controllers are expected to manage the individual microgrid areas' voltage and frequency to enable synchronization and joining of multiple microgrids.
- Metric: This PO will use the difference between feeder frequency and voltage measurements in microgrid 1 and 2 as described in the respective POs above.
- Data: see data collection for Feeder Frequency and Feeder Bus Voltage objectives above.
- Success Criteria: The networked microgrid controllers must not send a close signal to the synchronization relay if the sub-microgrid frequency and voltage differences are larger than the allowable difference specified in Table 4-6. This table from IEEE 1574-2018 is used as a reference for synchronization tolerance limits in evaluating this networked microgrid function.

Synchronization tolerance performance assessment

The IPCs are designed to only initiate microgrid joining when the voltage and frequency differences between the two transformer level microgrids are within tolerance. Figure 6-6 from Test Case 1 has demonstrated that the join command is issued only when the voltage and frequency differences have reached within the acceptable range.

Notable results from PHIL synchronization testing

The following plots show the Schweitzer 351 synchronizing relay synch-scope for a pre-synch condition and a synchronized condition, where the two dials are at the same position. The varying PV (dynamic irradiance conditions) in MGC-1 made it somewhat difficult to synchronize the two microgrids. The SEL relay sends a permissive signal to the IPCs to close CB-106 when the phase-angle is within 3° .

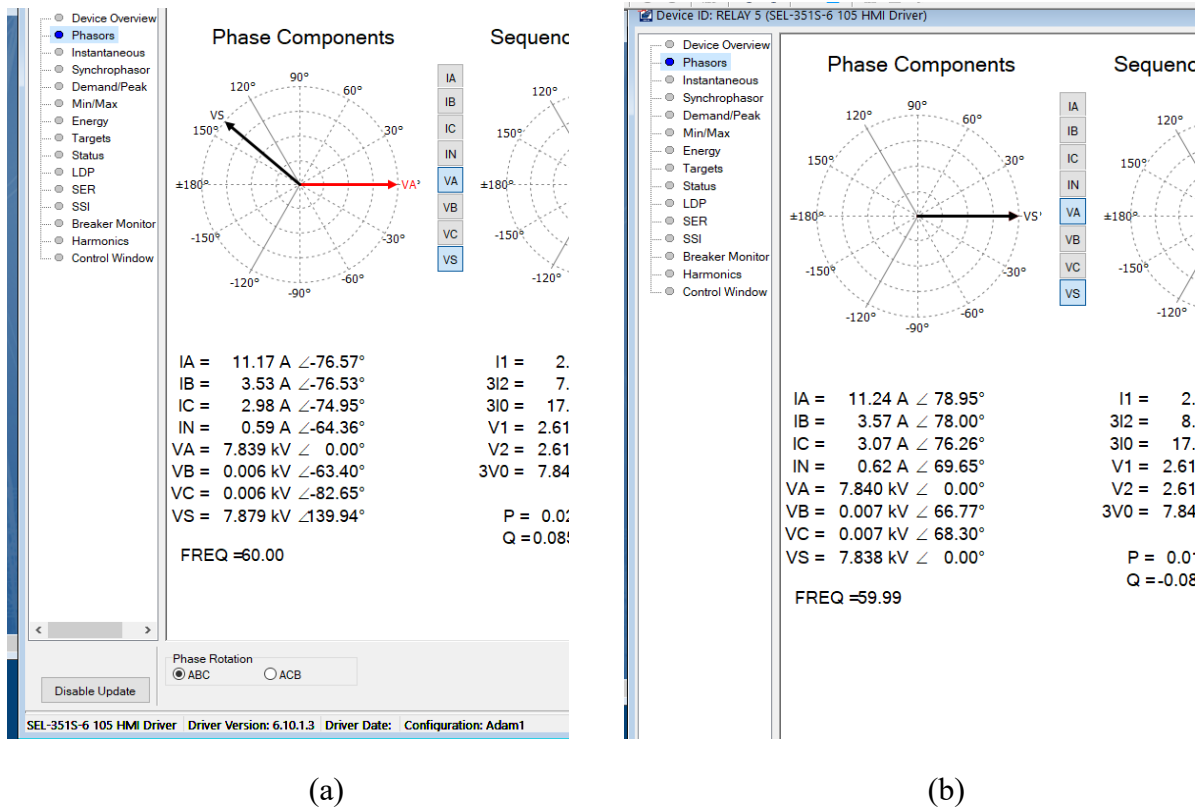


Figure 8-1. SEL-351 Phasor Diagrams (a) Shows a Pre-synch State, with Phase Angle at About 140°, (b) Shows the Synchronized State and Both Microgrids Connected and In-phase

8.2.2 Black start automation

- **Black start automation:** The automated process of black starting the full feeder-level networked microgrid following a utility grid outage.
- **Purpose:** The networked microgrid controllers are expected to provide faster and wider outage recovery. This performance objective measures the speed of this automated black start process.
- **Metric:** Time to energize and synchronize networked microgrids (in minutes)
- **Data:** Meter readings from microgrids, utility-side PCC, and IPC control signals
- **Success Criteria:** Distributed controllers automatically initiate isolation switching and black start sub-microgrids within 10 minutes of grid loss.

Performance Assessment for “Black start automation”/ Feeder-level join time

The average join time for all tests conducted for both N and N+1 strategy is 755 seconds, which is longer than the 10 minute target.

The main reason identified is because the end-to-end communication delay between the simulation platform and IPCs is around 6 seconds. The delay is longer than the expected communication delay for field devices, which is assumed to be less than 1 second when developing the target. The time delay includes: (1) the Modbus communication delay between IPCs and Triangle Microworks SCADA Gateway (TMW), (2) the processing delay to convert Modbus to OPC communication in TMW, (3) the OPC communication delay between TWM and PowerFactory circuit simulation. The time delay cannot be further reduced in this simulation environment; however, it can be reduced in a field installation with direct communication networking. This delay was not seen in the PHIL test environment.

8.2.3 Load Outage Duration

- **Load Outage Duration:** The total elapsed time between a utility outage and re-energization of the load by the microgrid black start.
- **Purpose:** The microgrid controllers are expected to minimize outage duration for loads along priority order (Local > Critical > Priority > Interruptible). This performance objective measures the customer outage length during respective tests for comparison against a baseline scenario.
- **Metric:** Duration of load outage (measured in total seconds of outage elapsed throughout the test case) by type of load.
- **Data:** Timestamped meter readings at each load in the test feeder. Load outage duration will be calculated as the total time elapsed between the start of the test scenario and when the respective load is brought online again. This outage duration will be calculated separately for each type of load (local, critical, priority, and interruptible).
- **Success Criteria:** Decrease in outage duration observed with networked microgrid controllers compared to baseline setup described in respective test cases. A separate performance objective will be calculated for each load type. Performance improvements are expected to align with load priority order (Local > Critical > Priority > Interruptible).

Table 8-3. Summary of Load Outage Duration Change from Baseline to Networked Microgrid Configuration Across Test Scenarios for Each Load Type

Test Case	Load Outage Duration (% change from baseline)			
	Local	Critical	Priority	Interruptible
1: Outage Recovery and Synchronization	-8.76%	-1.35%	-21.39%	16.03%
2: Long Duration Island	0% ⁵	302%	-11%	98%
3: Loss of PV	0%	0%	-50%	0%
4: Low ESS SOC	0%	Inf	Inf	Inf
5: Loss of Generator	-50%	-50%	-50%	3.5%
6: Loss of Microgrid Controller	0%	594%	22%	275%

⁵ All local load (highest priority) was served through the 24 hour island test case for both the baseline and networked microgrid configurations.

Performance Assessment: Decrease Outage Duration

The objective of the outage duration metric was to measure whether the networked microgrid controller configuration was capable of decreasing the outage duration experienced across the microgrids. The controllers were expected to prioritize loads served based on their priority assignment (Local > Critical > Priority > Interruptible). As shown in Table 8-3, the networked microgrid controls had mixed performance across the variety of test cases. In all cases, the controllers passed the key requirement of keeping local load online as highest priority, showing equal or reduced outage duration compared to the baseline cases. The results appear strongest for the shorter duration test scenarios; the longer duration test, Low SOC, and loss of controller scenarios did not show an improvement over the baseline for reducing load outage duration.

One of the anticipated benefits of joining microgrids was the ability to share DER output to reduce load outage duration across the joined areas during island. The test network and system conditions simulated in this project phase failed to meet this performance objective. However, using the data gathered throughout the testing process, the project team identified several design variables that could be adjusted to improve the joined microgrid performance. Additionally, the benefits of power sharing control are expected to be more pronounced under system conditions with higher penetrations of PV and larger DER to load ratios. Additional discussion on this behavior seen within the individual test cases is provided in the respective Test Results section of Chapter 6.0.

8.2.4 Load Coverage

- Name and Definition: Load coverage is quantified as the total energy served by the microgrid DER during an island event.
- Purpose: The networked microgrid controllers are expected to increase load coverage for loads along priority order (Local > Critical > Priority > Interruptible). This performance objective measures the total power served during respective tests for comparison against a baseline scenario.
- Metric: Total energy (in kWh) consumed by respective load types on the test feeder. This coverage should be calculated separately for each type of load (local, critical, priority, and interruptible).
- Data: Timestamped meter readings at each load in the test feeder. Load coverage will be calculated as the total energy served by the microgrid DER during an island event. This coverage metric will be calculated separately for each type of load (local, critical, priority, and interruptible).
- Success Criteria: The microgrid controllers are expected to improve coverage for the highest priority loads during islanding. A separate performance objective will be calculated for each load type. Performance improvements are expected to align with load priority order (Local > Critical > Priority > Interruptible).

Table 8-4. Summary of Average Load Coverage Change from Separated to Networked Microgrid Configurations Across Test Scenarios for Each Load Type

Test Case	Average Load Coverage change from baseline			
	Local	Critical	Priority	Interruptible
1: Outage Recovery and Synchronization	0.42%	0.44%		-6.72%
2: Long Duration Island	0%	-48%	37%	-35%
3: Loss of PV	0%	0%	50%	0%
4: Low ESS SOC	0%	-21%	-36%	-34%
5: Loss of Generator	37%	50%	Inf	23%
6: Loss of Microgrid Controller	1%	-86%		-56%

Performance Assessment: Increase Load Coverage

Long duration island performance

The load coverage in joined microgrid is worse than the baseline result. One reason identified is because of the non-ideal control logic when ESS's SOC drop to 20%. It appears that the IPC2 ramps up generator 2 to reduce the output of ESS, which causes frequency rise in the joined microgrid, which causes IPC1 to ramp down generator 1 for frequency regulation. More detailed results will be discussed in Test case 4.

In addition, it appears that currently the communication between IPCs does not provide optimal load sharing between the sources in the two microgrids, which may hinder the load restoration even though there is enough power available from other sources from the other microgrid. Notice that in Figure 6-8, generator 1 produces much more power than generator 2 during the evening. But in Figure 6-9, it is the opposite that generator 2 produces much more power than generator 1 during the evening. If the two microgrids join with their sources at different enough frequency offsets then one microgrid's sources will generally handle more of the load than the other. This results in a lower overall reserve as those sources are closer to their maximums than if they were balanced. While the joined grid is near 60 Hz and DER are operating within their operational limits, neither microgrid will further adjust the respective frequency droop offsets.

The final reason which may have impacted the load coverage is that the IPCs do not plan around ESS's SOC for longer period operations. In most cases, the SOC is depleted during the night covering the lower priority loads. A reliability-based dispatch algorithm may be helpful to reserve the capacity of the battery if longer period of islanded operation is foreseeable.

Loss of Generator performance

If the only generator at MG1 fails, the joined microgrid provides increased load coverage. The resources at MG2 can be used to serve the loads in MG1.

However, if the generator at MG2 fails, the tests do not indicate an increased load coverage in response to a sudden generator loss under the assumption that the BESS has the capability to overload for a short duration. Otherwise, the BESS may also trip immediately after the loss of generator 2 due to overload.

This is generally consistent with the expectation that separate microgrids with only one voltage and frequency controlling DER each will see reliability benefits from a networked microgrid configuration because the joined microgrids provide voltage and frequency control source redundancy.

8.2.5 Controller Coordination – Economic dispatch

- Economic Dispatch: The ability of the microgrid controllers to provide economic benefit (e.g., utility bill reduction) by coordinating DER dispatch during grid-connected state.
- Purpose: The controllers are designed to provide economic benefits during grid-connected operations (with substation feeder recloser and sub-microgrid isolation breaker closed). The sub-microgrid controllers are expected to coordinate to operate the system in least-cost mode.
- Metric: Operational cost (in \$) of running the microgrid (equivalent utility bill over duration of test sequence plus fuel costs)
- Data: Power readings (in kW) collected from all microgrid loads and DER outputs. Total utility bill cost will be calculated by using common military base utility rates, including a monthly fixed charge, Summer On-/mid-/off-peak charges in \$/kWh, Winter Mid-/off-peak charges in \$/kWh, Monthly Peak Demand charges in \$/kW, and other fees. Diesel fuel price will be considered in \$/gallon along with the heat rate of the diesel gensets in Btu/kWh.
- Success Criteria: The microgrid controllers reduce the total utility bill while grid-connected compared to a baseline without microgrid control.

Table 8-5. Economic Dispatch Test Results Extrapolated to a 30-day Billing Period

	Active Control	Baseline	Savings (%)	Savings (\$)
Energy Total	\$ 464,951.44	\$ 467,618.64	0.57%	\$ 2,667.20
Energy Billed Cost	\$ 403,798.13	\$ 467,618.64	13.65%	\$ 63,820.51
Fuel Cost	\$ 61,153.31	\$ -	-	\$ (61,153.31)
Demand Charge	\$ 56,005.22	\$ 74,264.36	24.59%	\$ 18,259.14
Billing Total	\$ 520,956.66	\$ 541,883.00	3.86%	\$ 20,926.34

Performance Assessment: Economic dispatch

To measure the success of the economic dispatch algorithm in the networked microgrid controllers, the combined feeder-level microgrid area was treated as a single billed customer at the TOU billing rate provided in Table 6-7. The results of three 24-hr economic dispatch test cycles are provided in Table 6-8. The “Energy Total” cost shows the combined energy charges (kWh from the utility) and fuel cost. The “Demand Charge” is calculated using the peak demand from the feeder during the respective 24-hr test cycle.

The data from the 3 days of testing were extrapolated to a 30-day billing cycle to estimate monthly performance in Table 8-5. The monthly “Demand Charge” is taken from the peak demand across the 3 days of testing (all taken from the same month). The results show an estimated 3.86% savings on the monthly summer bill. This performance meets the defined success criteria that the microgrid controllers should reduce the total utility bill while grid-connected compared to a baseline without microgrid control.

The IPC architecture (documented in *GridMaster Decentralized Control Architecture and Functionality* [2]) notes that the economic dispatch algorithms use historical data from the site to continuously improve the economic dispatch performance. Given the limited grid-connected run-time in the test setup and lack of historical feeder data, it is expected that the economic dispatch performance could be improved by initializing the IPC with more load data.

Note, the economic savings due to PV production are not calculated in the savings shown in Table 8-5. While the PV production does provide billing savings, the PV output was not changed in either the baseline or active controls test scenarios. To measure the economic dispatch impact of PV control in future test scenarios, the test network should include a higher ratio of installed PV to load.

8.3 PERFORMANCE ASSESSMENT CONCLUSIONS

Overall, the networked microgrid controller concept was capable of meeting minimum performance requirements for the operation of joined microgrids. Across all test scenarios the joined microgrids operated within acceptable frequency and voltage limits, and the island synchronization process did not cause adverse system conditions. The ability to safely black start, synchronize, and operate joined microgrid islands as a feeder-level island was confirmed in both CHIL and PHIL test environments.

One of the anticipated benefits of joining microgrids was the ability to share DER output to increase high priority load coverage across the joined areas during island. The test network and system conditions simulated in this project phase failed to meet the load coverage performance objectives. However, using the data gathered throughout the testing process, the project team identified several design variables that could be adjusted to improve the joined microgrid performance. Additionally, the benefits of power sharing control are expected to be more pronounced under system conditions with higher penetrations of PV and larger DER to load ratios.

The following design variables should be considered for further testing and analysis of the networked microgrid controller capabilities:

- Expanded interface between the controllers: The results indicate that power sharing performance would be improved if the microgrid controllers incorporated more data (e.g., load priority, solar PV availability, fuel level) into their data exchange to make joint area control decisions. This could also be corrected with another process to adjust the microgrids closer to the same overall power load ratio.
- DER mix in test system: The control strategy should be evaluated against microgrids with more controllable DER (i.e., to measure the N+1 control decision performance). This mix should also consider microgrids dominated by inverter-based resources – such as renewables and energy storage – to better understand how such devices would impact black start and accommodation of sudden load changes.

- Higher ratio of DER to load: Networked controls did not have a noticeable impact on voltage deviation in the test system. This impact should be evaluated in a microgrid configuration with higher penetration of variable DER or a different ratio of inverter vs synchronous generation-based DER.
- Loss of generator event scenarios: extend test cases to evaluate response during high PV, including ride-through response (tests covered in this report were conducted using 0am and 8pm profiles, i.e., no PV).
- Performance comparisons to a single, centralized controller vs the networked, distributed controls should be performed to better quantify how the microgrid would respond to loss of communications between components and to quantify a level of complexity at which distributed controls are more advantageous than a central control despite the added complexity of the system.
- Investigate the impact of different equipment protection settings and run tests again to compare load coverage response.
- Loss of controller scenarios: reconsider expected control behavior during loss of controller scenario. Protection and tripping elements may be expected to alter the load coverage during long-term frequency deviations.
- Mixed duration outage testing: compare the performance of the networked controls during short-term versus long-term outages. Include forecasted energy reserves into the design performance criteria of the controller interactions.
- Generalize the communication exchange protocols that would allow multiple microgrids on a given feeder to coordinate and operate in tandem to increase power reliability for customers. This would expand the developed algorithms to consider adjacent microgrids with customer loads between them and allow microgrids on a given feeder to share power and pick up non-microgrid loads in the event of widespread utility outages.

9.0 COST ASSESSMENT

9.1 COST MODEL

A cost model for implementing a networked microgrid control system is provided in Table 9-1 below. The data identified in this model reflects the microgrid controller element costs and additional upgrades necessary to enable networked microgrid operation. The costs in the table do not reflect the total cost of implementing a microgrid (individual or multiple), such as DER installation and commissioning costs.

Table 9-1. Cost Model for Modular Microgrid Controller

Cost Element	Data Tracked During the Demonstration	Estimated Costs
Hardware capital costs	Estimates made based on component costs for demonstration	\$75K for control hardware (\$25k per control unit)
		\$50K for managed network switches and dedicated fiber
		Additional costs may be incurred to add remote operation functionality to generators, switchgear.
Installation costs	Labor and material required to install	\$30K
Consumables	Fuel cost used during demonstration	Diesel at \$3 / gallon. Estimated using market price at time of simulation tests.
Facility operational costs	Reduction in energy required vs. baseline data ⁶	Savings (%)
		Energy Total 0.57%
		Energy Billed Cost 13.65%
		Demand Charge 24.59%
Maintenance	- Frequency of required maintenance - Labor and material per maintenance action	10% annually of initial capital costs Assume generator maintenance cost of \$0.01 per kWh produced
Hardware lifetime	Estimate based on components degradation during demonstration	Assume replacement of controller hardware every 7 years Assume replacement of battery packs every 5 years
Operator training	Estimate of training costs	\$6K (Assume 1 person week for training every five years)

9.1.1 Cost Elements

Details on the purpose and scaling behind each cost element are as follows:

9.1.1.1 Hardware Capital Costs:

Microgrid Controller Unit:

The microgrid controller is the primary hardware component that enables the networked microgrid operation. It coordinates the DER and breakers in the system to enable the microgrid functions.

⁶ The baseline energy tariff used to estimate grid-connected operational costs is provided in the sample rate below

Each individual microgrid area is managed by (1) microgrid controller unit. This testing demonstration used (2) controller units to demonstrate the networked concept. The modular networked microgrid design scales linearly, so each new microgrid “area” integrated into a larger networked microgrid requires a hardware control unit.

Managed Network Switches and Dedicated Fiber:

In order to enable the networked microgrid operation, the microgrid control units must be capable of communicating with each other. Using managed network switches and dedicated fiber provides the highest security and connectivity between controllers. The cost of these network switches and fiber routing is most dependent on the physical layout of the microgrid areas.

Device Controller Hardware upgrades:

Legacy DER may require additional local controller hardware upgrades in order to be controlled remotely and parallel within the networked microgrid region. These costs are likely to be site and vendor specific. Integrating higher amounts of legacy equipment from a wider variety of vendors will increase the costs incurred by this component. These additional costs can be reduced as more DER interconnections comply with standard remote interfaces and control capabilities, such as defined in IEEE 1547-2018.

9.1.1.2 Installation Costs:

Installation costs include the installation of the controller hardware, as well as the required interface integration between the microgrid and DER control units. The per-unit cost can reduce at scale with the use of standard DER protocols and repeated vendor implementation.

9.1.1.3 Consumables

The primary consumable that must be accounted for in the networked microgrid implementation is fuel consumption. The controller dispatch algorithm will change the baseline fuel consumption used by an individual microgrid. This cost is dependent on market rates for fuel at the time of use.

9.1.1.4 Facility Operational Costs

The facility operational costs represent the cost of electricity for the facility loads served by the networked microgrids. As a baseline, this cost typically includes the utility billing structure and operating fees incurred by the facilities. Networked microgrid controls can reduce the total electricity bill. The scalability of this operational cost depends on the microgrid DER sizing (ratio of kW/kWh to net microgrid load profile), as well as the local billing structure.

To measure the success of the economic dispatch algorithm in the networked microgrid controllers, the combined feeder-level microgrid area was treated as a single billed customer at the TOU billing rate provided in the table below.

Utility rate structure sample:

Table 9-2. Utility Rate Structure Used to Analyze Economic Dispatch Performance

Bill Component	Price
Monthly Fixed Charges	\$2,110.04
Distribution Energy Charges (\$/kWh)	\$0.02651
Summer On-Peak Generation Charges (\$/kWh)	\$0.30144
Summer Mid-Peak Generation Charges (\$/kWh)	\$0.08113
Summer Off-Peak Generation Charges (\$/kWh)	\$0.03562
Winter Mid-Peak Generation Charges (\$/kWh)	\$0.05148
Winter Off-Peak Generation Charges (\$/kWh)	\$0.04116
Monthly Peak Demand Charges (\$/kW)	\$8.77
Aggregate Taxes and Other Fees	0.0%
Diesel Fuel Price (\$/gallon)	\$2.97
Heat Rate of Diesel Gensets (Btu/kWh)	12,040

Utility Rate Notes:

1. Billing components here are adapted from the Southern California Edison TOU-8 Option A Schedule
2. Summer is June through September, and winter is October through May.

9.1.1.5 Maintenance

Maintenance costs on the microgrid controllers includes regular software upgrades to incorporate user-identified bug fixes and required cybersecurity patches that may be identified throughout the lifetime of the equipment.

The DER may incur additional maintenance costs directly based on kWh produced. This cost will vary based on individual site characteristics, grid-side outage occurrences, and customer demand, however the algorithms in the networked microgrid controllers should reduce DER maintenance cost as compared to the operation of the DER in separate, individual microgrids.

9.1.1.6 Hardware Lifetime

The microgrid controls may increase the utilization of the DER in the system, thus requiring earlier replacement. The total lifetime of the DER is type, vendor, and use dependent. The microgrid controller should track the utilization of the DER (e.g., cycling rate) to monitor state of health and replacement needs. The controller hardware lifetime estimates are based on commercial hardware that is already produced at scale.

9.1.1.7 Operator Training

Operator costs are incorporated to ensure that operators are familiarized with the capabilities of the networked microgrid controllers and expected behavior during normal and emergency operation of the system. The cost of creating site-specific training materials and procedures will be highest. Once developed the majority of the training cost is the employee time to complete the training, plus the time of the facilitator.

9.2 COST DRIVERS

The major cost drivers that may impact the overall cost of implementing networked microgrids are related to control implementation and interfaces and potential interconnection costs for operation across utility-owned equipment. The primary drivers are as follows:

- *Total cost of controller implementation* – As described above, this cost may increase based on the operational objectives of the site and complexity of control. If similar sub microgrids exist across the larger area, the modular approach may work well.
- *Asset upgrades for controls* – Integrating legacy equipment often requires upgrading the device’s local control interface to enable paralleling operation with other DER. This cost is vendor and implementation dependent. In some cases, custom PLC logic may have been implemented on the legacy equipment controls, requiring a complete overhaul of the controls panel if the original program cannot be modified. In other cases, if the same legacy equipment was used in multiple locations across the wider area, the same updated interface can be applied to simplify this effort.
- *Evaluating networked operation for protection coordination* – The scope of this project focused on the microgrid control implementation, however, operating networked microgrids will also require a protection coordination evaluation to ensure that the networked operating configuration still supplies anticipated fault current levels and has sufficient equipment protection. Due to the nascent nature of these types of microgrid configurations, studies may be more expensive because they require more in-depth review. This cost is expected to reduce as networked and flexible microgrids become more common.
- *Additional study costs for obtaining interconnection approval* – Some networked microgrids may operate across utility-owned distribution equipment to connect neighboring customer-owned systems. This will require additional studies by the interconnecting utility to provide permission to operate the microgrids in the networked configuration. Similar to the protection studies component, this cost may be expensive because of a lack of current utility experience with studying this type of system. This cost is expected to reduce as networked and flexible microgrids become more common.

10.0 IMPLEMENTATION ISSUES

The following factors were considered as potential areas for future development in the networked microgrid controller implementation. End-users and those considering this type of control implementation may consider further investigating these factors in more depth as part of their assessment of whether this solution is best for their system needs.

- Expanded interface between the controllers: Assess the data exchanged between controllers when joint area control decisions are made.
- DER mix in test system: Consider whether the microgrid is dominated by inverter-based resources – such as renewables and energy storage – to better understand how such devices would impact black start and accommodation of sudden load changes.
- Higher ratio of DER to load: Proportion of variable DER or a different ratio of inverter vs synchronous generation-based DER and total load in the system. Performance may also vary based on ratios of different load priorities.
- Performance comparisons to a single, centralized controller vs the networked, distributed controls should be performed to better quantify how the microgrid would respond to loss of communications between components and to quantify a level of complexity at which distributed controls are more advantageous than a central control despite the added complexity of the system.
- Consider the impact of equipment protection and ability to adjust settings based on the various networked microgrid configurations.
- Mixed duration outage testing: compare the performance of the networked controls during short-term versus long-term outages. Include forecasted energy reserves into the design performance criteria of the controller interactions.
- Consider designing for the ability to pick up non-microgrid loads in the event of widespread utility outages.

Procurement of a commercialized system may be challenging. The evaluated controls were developed on commercial off-the-shelf equipment but programmed with prototype software. This type of software control is in the newly commercialized stage and vendor claims should be carefully evaluated during procurement.

Operating networked microgrids can face regulatory barriers when utility-owned distribution equipment is involved. In general, if the entire networked microgrid system is independently owned and operated, the regulatory barriers are similar to those of individual microgrids (namely, grid-connected interconnection costs and limitations). Islanded operation that involves utility-owned distribution equipment typically requires in-depth review by the operating electric utility. Cybersecurity regulations may need to be aligned between the electric utility and microgrid equipment owners in the event that data (e.g., utility-owned recloser state, DER operating settings) must be shared during real-time operations.

The following references may provide useful guidance during implementation:

- *How to Assess Microgrid Performance*. EPRI, Palo Alto, CA: 2022. 3002024584. <https://www.epri.com/research/products/000000003002024584>
- Maitra et al., “Expanding the Role of Microgrid Controllers and Evaluating Their Performance,” *IEEE Power and Energy Magazine*. Vol. 25, No. 4, pp. 41–49 (2017).
- Pacific Gas & Electric, "Community Microgrid Technical Best Practices Guide," 2023. [Online]. Available: https://www.pge.com/pge_global/common/pdfs/residential/in-your-community/community-microgrid/pge-community-microgrid-technical-best-practices-guide.pdf
- *A Smart and Flexible Community Microgrid with Dynamic Boundary*. EPRI, Palo Alto, CA: 2020. 3002020212. <https://www.epri.com/research/products/000000003002020212>.

11.0 REFERENCES

- [1] R. Salcedo, E. Corbett and C. Smith, "Banshee distribution network benchmark and prototyping platform for hardware-in-the-loop integration of microgrid and device controllers," *IET Journals*, 2018.
- [2] S&C Electric Company, "GridMaster Decentralized Control Architecture and Functionality," 2021.
- [3] EPRI, S&C Electric Company and Sandia National Laboratory, "MODULAR CONTROL ARCHITECTURE FOR SCALABLE, RESILIENT, AND CYBERSECURE MICROGRIDS TEST PLAN," 2021.
- [4] IEEE Standard Association, *IEEE Std. 1547-2018. Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*. 2018.

APPENDIX A SANDIA NATIONAL LABORATORIES PHIL TESTBED DETAILS

Notes:

- PV Inverters:
 - PV 1 – The 50kVA inverter will be on real PV that has an STC rating of 42kW, so power will fluctuate according to weather conditions
 - PV 2 - The 33kVA inverter will be operated via PV simulator, so we can implement a solar profile
- Loads: PHIL bus loads will be static and resistive only
- Generation:
 - Caterpillar Diesel Generator—313kVA, 250kW @ 0.8PF
 - Energy Storage Inverter—ABB PCS100 100kVA, V/F mode @ 2% frequency droop and 5% voltage droop

The two multi-customer microgrid MGC-1 and MGC-2 contain DETL hardware generation resources and the following provides data of the DETL hardware generation resources of MGC-1, which is a Caterpillar Diesel genset and can operate as needed for this project. The genset at Sandia's DETL initially underwent a high level of qualifications, since the genset is required to operate in droop mode. The generator doesn't have the ability to operate in full droop V/F mode, but the frequency can be biased to deliver the required active and reactive power that the local power system or microgrid require. The generator can deliver the desired active and reactive power within its specifications and can automatically adjust active and reactive power in relation to the frequency and voltage deviation from nominal conditions.

The diesel genset underwent several laboratory tests to document the ability of the genset. Figure A-1 shows the diesel generator sourcing 50kVA/50kW to the utility, then by adjusting the frequency bias, the export is lowered to 42kW and held for over 10 min. The ability to adjust the power delivery was again shown by adjusting the generation back to original 50kW and then increasing to 58kW and held for about 10 min before returning to 50kW and then commanding a shutdown.

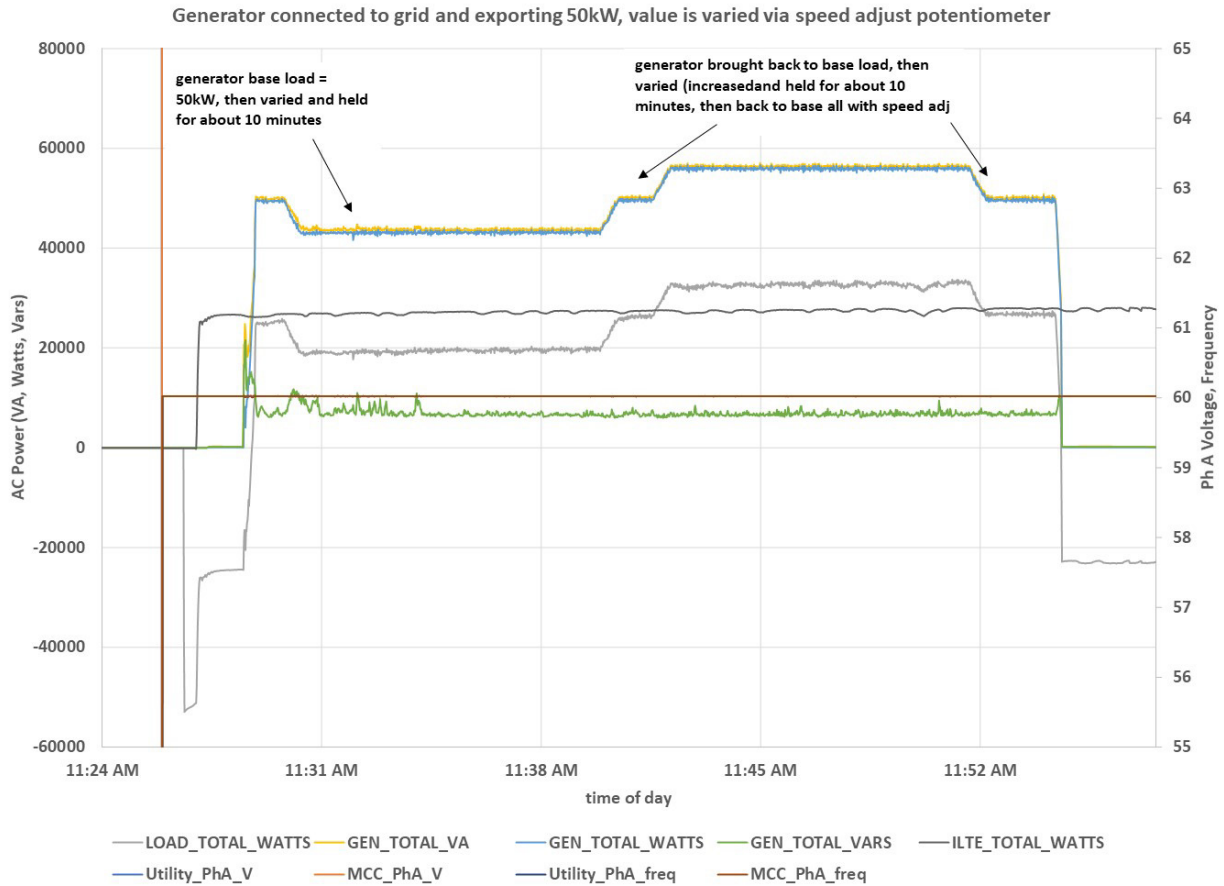


Figure A-1 Diesel Generator Frequency Bias Capabilities

In figure A-2, the generator's capability is shown operating in parallel with another ac source (ac simulator) and the profile was implemented that caused the frequency to be ramped from nominal 60 Hz to ± 0.4 Hz and capture the response of the generator. The configuration is much like the hardware configuration for MGC-1 and includes the diesel generator, PV inverter, and the resistive load. For the test, the generator synchs to the ac source and starts exporting is programmed 50kW to the simulated utility. When the frequency varies from 60 Hz, the generator export varies depending on the frequency, as expected and required for this project.

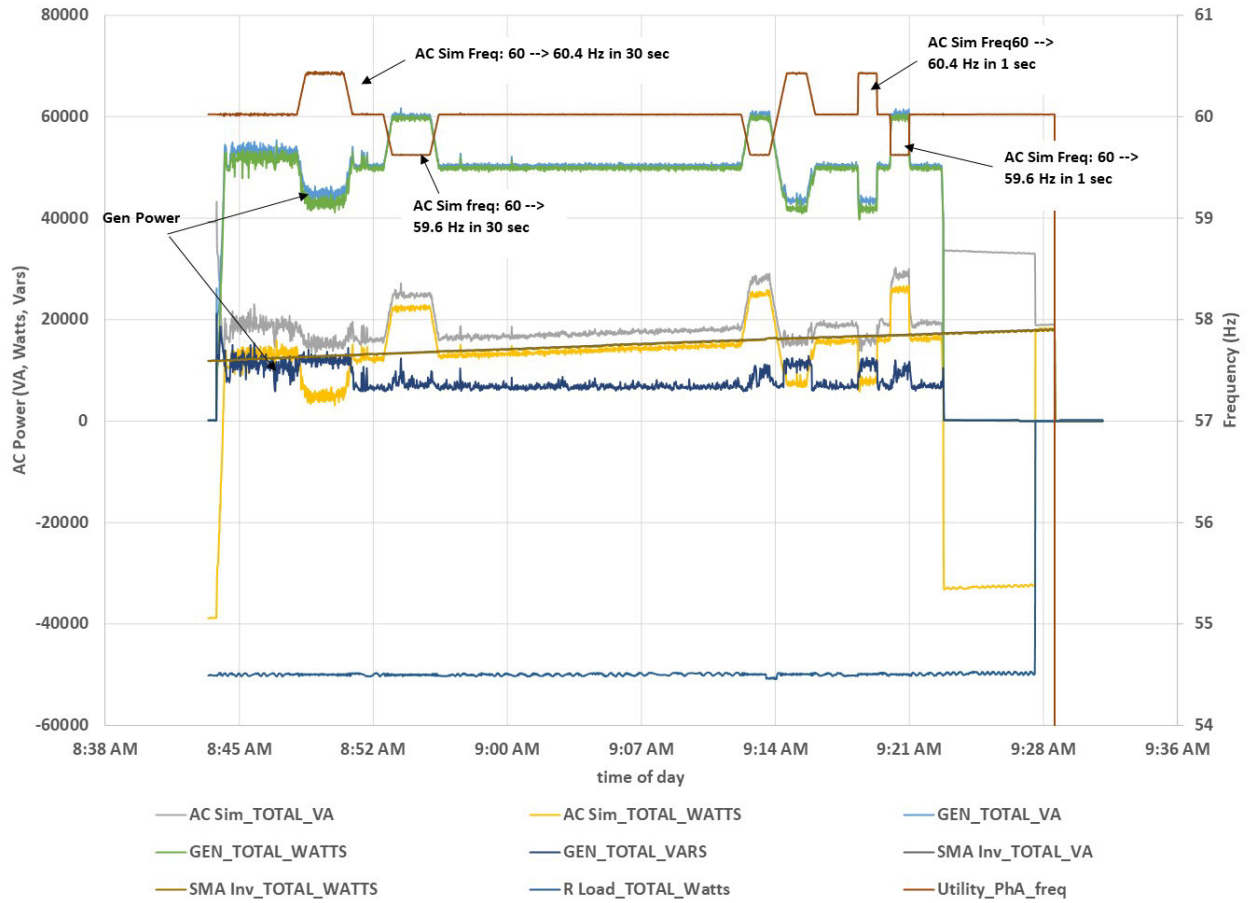


Figure A-2 Diesel Generator Frequency Droop Characteristic

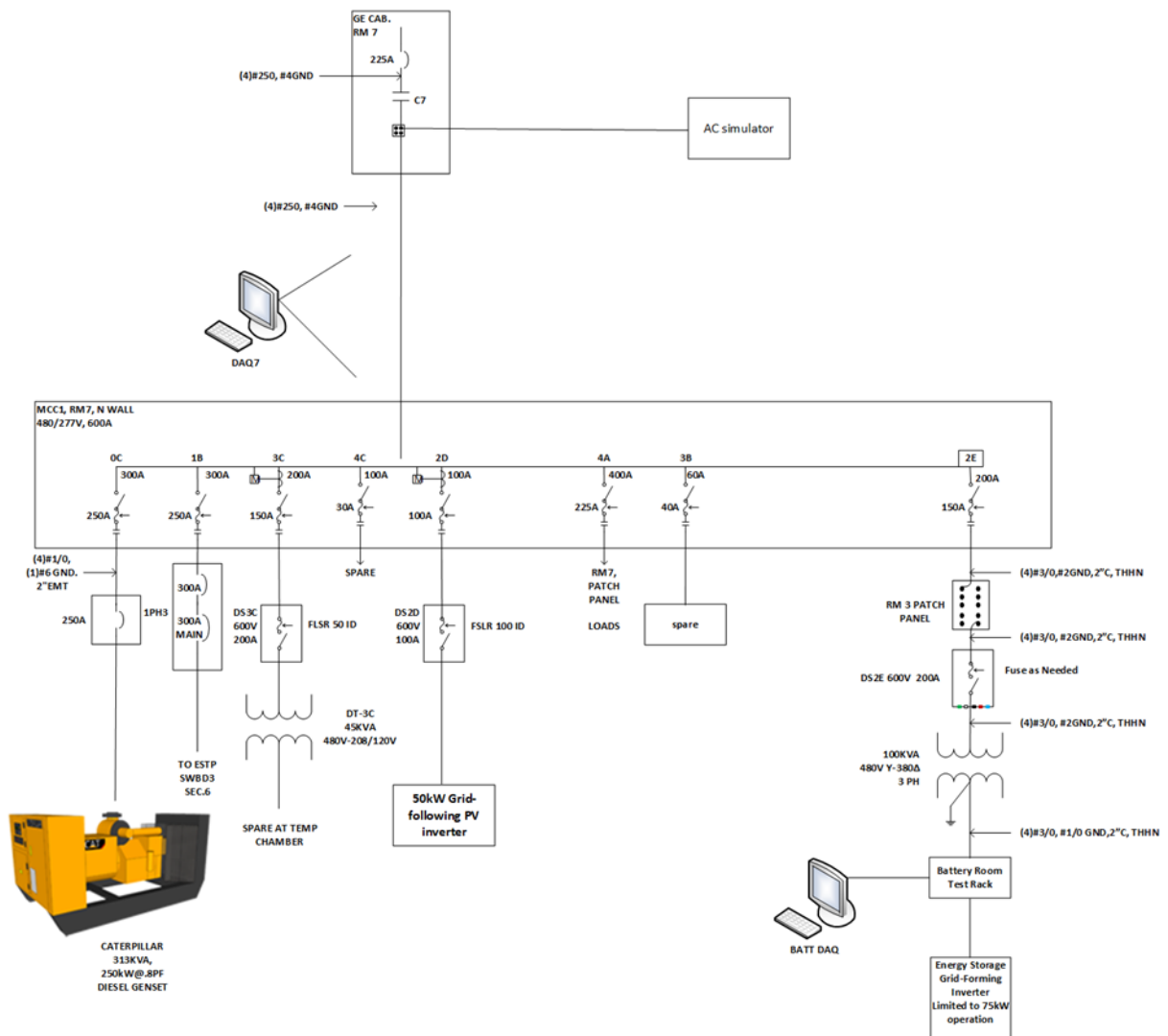


Figure A-3 DETL Oneline Provided by SNL

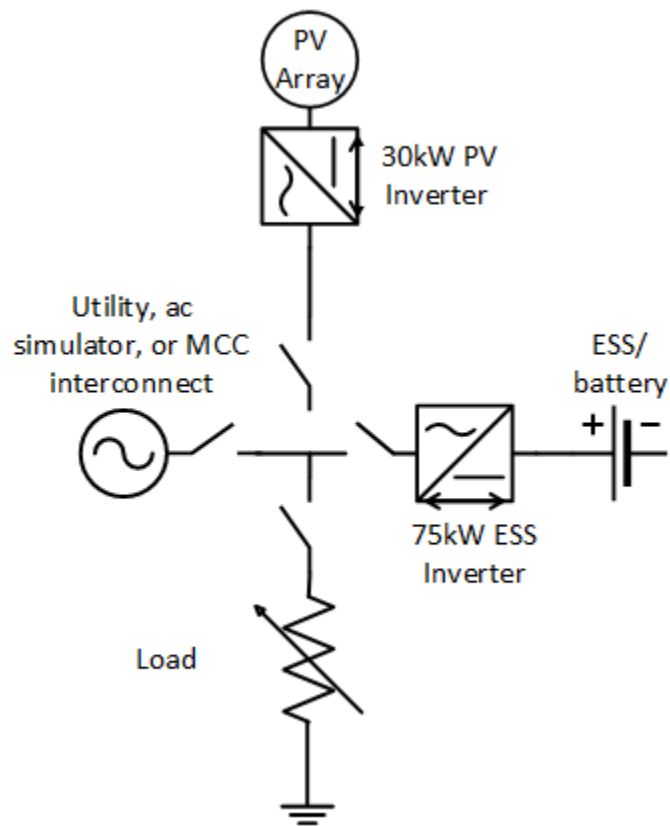


Figure A-4 Proposed Microgrid 2 PHIL Bus Provided by SNL

APPENDIX B POINTS OF CONTACT

POINT OF CONTACT Name	ORGANIZATION Name Address	Phone Fax E-mail	Role in Project
Jacqueline Baum	EPRI	jbaum@epri.com	Principal Investigator
Peter Curtiss	S&C Electric	peter.curtiss@sandc.com	Controller Lead
Sig Gonzales	Sandia National Lab	sgonza@sandia.gov	PHIL Lead