2023 TECHNICAL UPDATE

Utility Microgrid Controller Test Plan

Evaluation Method for Utility Microgrid Controllers

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ABSTRACT

The functional requirements of many microgrid controllers (MGCs) are expanding and evolving to meet growing utility and community needs. At a high level, the utility microgrid controller serves resilience and reliability use cases by coordinating transitions between grid-connected and islanded states and by managing the system during island operations. This includes control scenarios that require the microgrid controller to use flexible microgrid boundaries, maintain energy balance, coordinate with peer systems, and manage grid-forming (GFM) and grid-following (GFL) DER. In order to evaluate these functional enhancements, microgrid controller test plans must also be developed to ensure that the implemented controllers provide adequate performance. This report provides MGC test plans for both island operation and transition functions. The functions covered in this first edition report include feeder level energy management, island constraint management, secondary voltage and frequency control, black start, and synchronized reconnection.

These test cases can be applied to utility-managed microgrid controllers that exclusively manage utility-owned equipment; the tests also apply to third-party managed microgrid controllers that coordinate with utility- and customer-owned equipment. The report can also be used by technology developers and project developers in industry to evaluate control strategies and performance characteristics for community microgrid controllers.

Keywords

Microgrid Controller
Community Microgrid
Distributed Energy Resources (DER)
Distribution Islanding

EXECUTIVE SUMMARY

Deliverable Number: 3002028385

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Product Title: Utility Microgrid Controller Test Plan: Evaluation Method for Utility Microgrid Controllers

Primary Audience: Technologists and strategists working in the area of developing and evaluating distribution-scale microgrid controllers and the management of distributed energy resources (DER) for resilience

Secondary Audience: Vendors developing products and software platforms for feeder-level microgrid control and local DER management systems (DERMS)

KEY RESEARCH QUESTION

- What tests should be conducted to evaluate utility microgrid controllers?
- What scenarios and test conditions are required to test utility microgrid controls?
- What performance metrics can be used to evaluate microgrid controllers?
- What interactions are expected between the microgrid controllers, DER, and utility managed equipment during key operational scenarios?
- How to ensure that the functional requirements and specifications for a microgrid controller are effectively implemented in commercial products?

RESEARCH OVERVIEW

This report describes the foundational test cases for evaluating utility microgrid controllers that manage feeder-level island operations. These test cases build upon the community microgrid controller requirements developed in the companion report *Controller Requirements for Managing Community Microgrids*. PID: 3002025648. The objective of this research was to translate the microgrid controller functional requirements into test cases that can be used to assess the system-level control performance. These tests assume that the feeder-level microgrid has generally been designed for viable and safe operation, and that individual system components have been separately validated. The tests cases developed here focus on the microgrid controller's ability to provide system-level coordination and alignment with original site control objectives.

KEY FINDINGS

- Reference use cases and objectives for feeder-level microgrid control implementation
- Reference test cases and procedures for evaluating commercial microgrid controllers

- Illustrative diagrams to explain the complex component interactions expected throughout the control test cases
- Performance metrics for evaluating each microgrid controller function
- Guidance on test scenario implementation with a sample network and initial condition configuration

WHY THIS MATTERS

With an increasing need for distribution resilience services, many utilities are investigating and implementing feeder-level microgrid controls. This set of test plans for community microgrid controllers documents key test cases and evaluation metrics to support utility implementation of microgrid controllers. It can be used to identify gaps in commercial controller designs and improve readiness for field deployment of microgrid controllers.

HOW TO APPLY RESULTS

Utilities and product developers can use the use cases, test plans, performance metrics, and evaluation criteria defined in this report to assess their feeder-level microgrid controller implementations. These tests can be used to evaluate if a microgrid controller meets the requirements defined in the companion report *Controller Requirements for Managing Community Microgrids*. EPRI, Palo Alto, CA: 2022. 3002025648. https://www.epri.com/research/products/000000003002025648.

LEARNING AND ENGAGEMENT OPPORTUNITIES

EPRI hosts a number of interest groups and working groups through webcasts in which utility members and industry partners share experiences related to technical topics, identify gaps, prioritize research needs, and devise strategies. The SECURE Microgrid Technical Advisory Committee and contributed to this report.

- SOLACE Supplemental Group: Utilizing DER for Advanced Distribution Resiliency. EPRI. PID: 3002017800. https://www.epri.com/research/products/000000003002017800
- The Microgrid Cohort Supplemental. EPRI. PID: 3002028527. https://www.epri.com/research/products/000000003002028527

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PROGRAM: P174, Integration of DER

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1 INTRODUCTION

Increasing numbers of natural disasters causing wide-area power outages have spurred a significant interest in developing microgrids as a mechanism to improve distribution resilience and reliability. Distribution microgrid controls must consider vulnerability to systematic failures (single points of failure, e.g., communications infrastructure) and adaptability in response to changing load and resources.

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. This includes control scenarios that require the microgrid controller to manage relays and switching equipment, manage grid-forming (GFM) and grid-following (GFL) DER, and manage critical/non-critical loads. The controller is also responsible for coordinating 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 on a feeder with flexibility to expand and contract the island operation area or manage coordination with external systems. Beyond managing the DER within their own microgrid boundary, utility microgrid controllers may need to communicate with a central microgrid-managing entity or neighboring controllers to facilitate synchronizing of microgrid islands and power sharing between areas.

The functional requirements of many microgrid controllers (MGCs) are expanding and evolving to meet these broader utility and community needs. In order to evaluate these functional enhancements, microgrid controller test plans must also be developed to ensure that the implemented controllers provide adequate performance. This report provides sample test plans for evaluating a feeder-level, community microgrid controller that manages various islanded and grid-connected use cases. In the scope of this document, the term community microgrid controller applies to utility-managed microgrid controllers that exclusively manage utility-owned equipment; it also applies to third-party managed microgrid controllers that coordinate with the utility- and customer-owned equipment. An example test system is presented with related work from an EPRI-led U.S. Department of Energy Solar Energy Technologies Office Award project titled Solar Energy CommUnity Resiliency (SECURE), DE-EE0009336.

Overview of Test Plans

A summary of the utility MGC test plans covered in this report is provided in Table 1 below.

Table 1. Summary of Microgrid Controller Test Cases

Test Name	Objective
Feeder Level Energy Management	The MGC must autonomously maintain energy balance and extend operational run-time when the microgrid is isolated from the wider distribution grid. This test measures the load coverage and DER dispatch strategy provided by the microgrid controller throughout a long-duration utility outage event.
Island Constraint Management	During island operation the MGC is expected to coordinate microgrid assets (e.g., DERs, capacitor banks) to relieve thermal and voltage constraints on the feeder. This test evaluates the MGC’s ability to provide operational constraint management during island operation.
Island secondary frequency and voltage control	The goal of this test is to evaluate the MGC’s ability to provide secondary frequency and voltage control and restoration during island operation.
Black Start	Assess if the microgrid controller can safely and effectively coordinate black start sequencing. Following an outage event, the MGC is expected to autonomously execute the designed island system black start procedure from feeder outage through cold load pick-up.
Synchronized Reconnection	Evaluate the MGC’s ability to manage a non-disruptive grid-reconnection transition from an islanded state. The MGC is expected to dispatch appropriate device settings changes, and the transition should not disrupt customers or cause unacceptable grid disturbances.

Scope of Report

Testing of a microgrid system involves evaluation of many individual components and system integration in order to validate the overall readiness of the system to operate. This test plan focuses on test procedures for evaluating the *utility microgrid controller* functionality of the microgrid, as illustrated in Figure 1.

The microgrid controller plays a critical role in the coordination and dispatch of operational objectives in the microgrid. Testing the utility microgrid controller focuses on evaluating the ability of the controller to coordinate interactions between components and successfully meet the control and operational objectives of the system. These functions include dispatching DER modes and setpoints, coordinating operational sequences, and integrating into the distribution management control scheme. The viability of the microgrid design is essential to the success of the microgrid controller’s operation, however. For example, if a GFM BESS is expected to act as the black start resource, it must be capable of supplying sufficient inrush current during cold load pick-up without tripping equipment; separate test criteria may be used to evaluate such requirements[1]. The test plans in this report focus on the evaluating the MGC's ability to dispatch operational sequences and perform tertiary control.

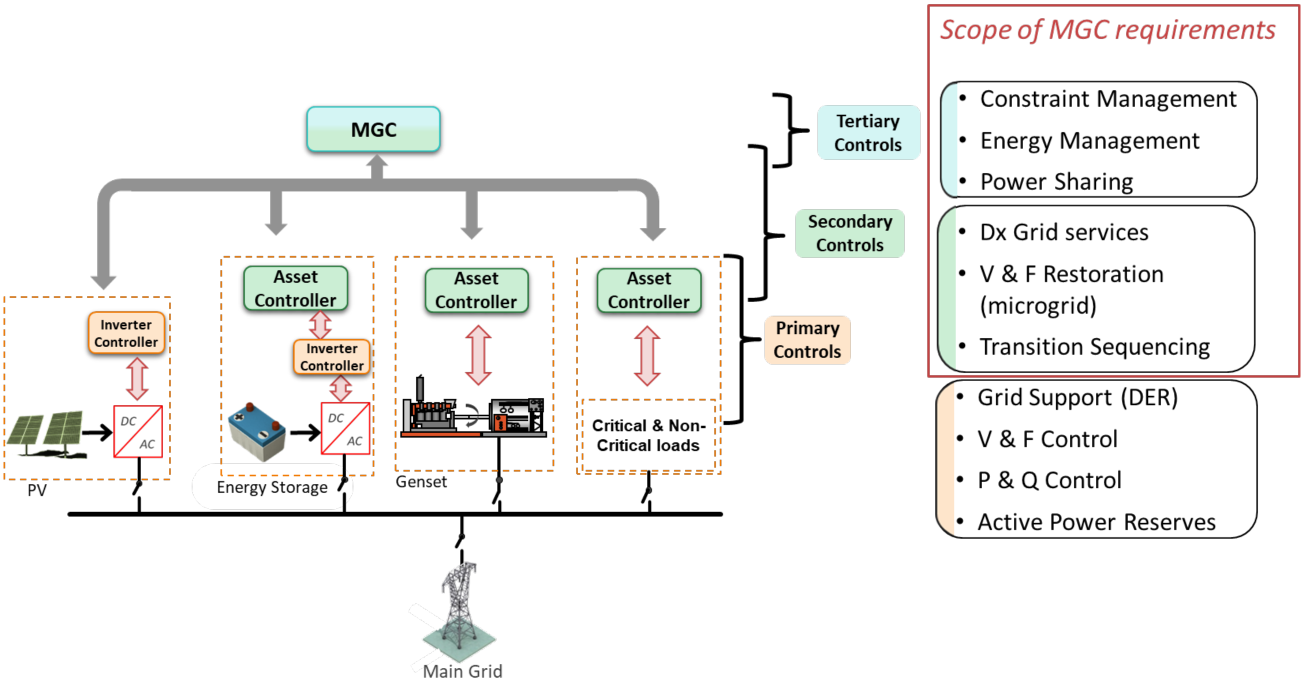

Figure 1. Illustration of microgrid system components with highlight of MGC testing scope. Adapted from Implementing Microgrid Control Strategies [1]

The functional requirements related to the tests described in this report are detailed in the companion report *Utility Microgrid Controller Requirements* [2]. Refer to the companion report for additional background information, MGC use cases, and function descriptions.

[1] See *Performance Requirements for Grid Forming Inverter Based Power Plant in Microgrid Applications* [7] for details.

2 SAMPLE TEST SYSTEM

This section describes the distribution network model selected to demonstrate the utility microgrid control functions developed in support of the SECURE project[2]. The SECURE project aims to address the key technical and business challenges impeding implementation of resilient community microgrids. This effort included adapting a sample system to develop common test plans for community microgrid controller evaluation. In this project, a variation of the Commonwealth Edison Bronzeville Community Microgrid [3] is used as the test system for the developed community control (MGC) technologies. The simplified single-line-diagram (SLD) of the adapted microgrid network is shown in Figure 2.

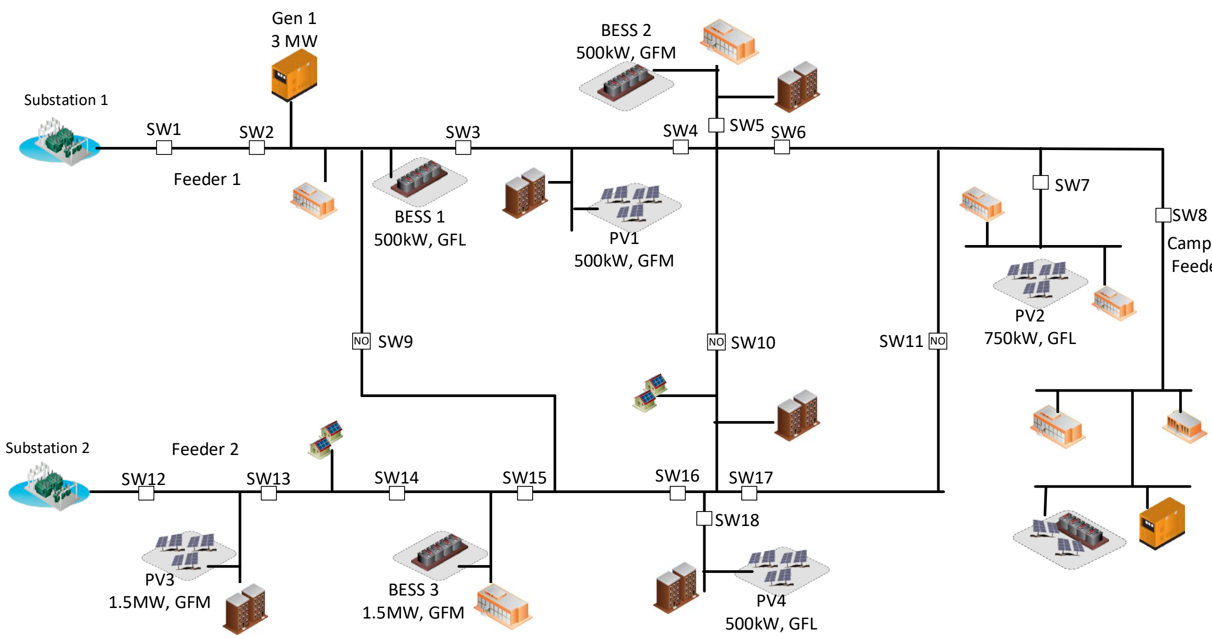

Figure 2. Simplified SLD of the microgrid system under test. Adapted from Bronzeville Community Microgrid [3]

The sample network comprises three feeders, with the Campus Feeder treated as an aggregate node that is managed by a separate, local controller. Consequently, the SECURE project's primary focus centers on Feeder 1 and Feeder 2, emphasizing power system control at the feeder level. Three tie switches, specifically Switch SW9, Switch SW10, and Switch SW11, remain in an open state when each feeder is connected to the main grid. However, when the main grid becomes unavailable and the substation switches (SW1 and SW12) are opened, Feeder 1 and Feeder 2 are transitioned to an islanded mode, and some of the mid-feeder switches (e.g., SW9, SW 11) are closed to create a multi-feeder island. In this islanded mode, the diesel generator (Gen 1) located at Feeder 1 is the primary grid-forming (GFM) source. There is a mix of legacy grid-following (GFL) photovoltaic (PV) and battery energy storage system (BESS) inverters along the feeders. The test feeder model has been augmented from the

[2] Solar Energy CommUnity Resiliency (SECURE) is supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under the Solar Energy Technologies Office Award Number DE-EE0009336.

existing Bronzeville Community Microgrid to demonstrate island operation cases with over 75% renewable penetration. Additional GFM BESS and GFM PV[3] inverters are incorporated in the test system to achieve this type of island operation.

The utility microgrid controller test plans described in this report can be applied to a variety of testing environments (e.g., software simulation, laboratory, or field testing). The test descriptions provided in this document were initially developed for a controller-hardware-in-the-loop test setting and may require minor adaptations for use in other environments.

[3] Development of GFM PV control is an additional topic under the SECURE project. For details on this technology, see *Grid-Forming PV Inverter: Technology Development and Microgrid Applications* [5].

3 TEST PLANS

Feeder Level Energy Management

Purpose

The MGC must provide coordination of power generation and consumption across the microgrid area during island operation; this function is described as feeder-level island energy management. While performing energy management, the MGC is expected to autonomously maintain energy balance and extend operational run-time when the microgrid is isolated from the wider distribution grid. Using the MGC for feeder energy management can improve the operational performance of the island by accounting for different DER characteristics, load and weather forecasts, load prioritization, power system constraints and online and offline power reserves.

The Feeder-Level Energy Management test evaluates the MGC's ability to achieve the following objectives:

- Coordinate near-term power generation and consumption during island operation
- Meet island survival (extending operational time of island based on expected outage length) performance expectations while maximizing customer reliability.

The utility MGC is expected to provide increased load coverage by more efficiently power sharing DER and expanding and contracting islanded microgrids when feasible. To demonstrate this functionality, this test measures the load coverage provided by the microgrid controller throughout a long-duration utility outage event. The test case will capture and evaluate the coverage of critical, priority, and interruptible loads compared to the microgrid baseline.

In the baseline scenario, the GFM battery inverters will be turned off and the PV inverters will be configured to operate in MPPT mode. The diesel generator will be turned on as well to operate as the isochronous frequency and voltage reference source in the islanded microgrid. No control commands will be issued from the MGC for the baseline case.

Test Overview

This test will simulate typical island conditions for a 24-hour (or longer) outage. The test duration should provide a long enough time horizon to evaluate the energy dispatch management strategy of the microgrid controller.

Test Procedure

Initial Conditions

Table 2. Initial system conditions for Feeder Level Energy Management test

	Identifier	State or Condition[4]
Load	Feeder 1 Load	[peak or low season] profiles: 24 hours start from 0am; connected
	Feeder 2 Load	[peak or low season] profiles: 24 hours start from 0am; connected
DER Status	PV1	24 hours start from 0am; cloudy day profile and sunny day profile
	PV2	24 hours start from 0am; cloudy day profile and sunny day profile
	PV3	24 hours start from 0am; cloudy day profile and sunny day profile
	PV4	24 hours start from 0am; cloudy day profile and sunny day profile
	BESS 1	Status = Online, SOC = 80%, Output = 100kW
	BESS 2	Status = Online, SOC = 80%, Output = 100kW
	BESS 3	Status = Online, SOC = 80%, Output = 100kW
	Gen 1	Status = Online, Output = 2.5MW
Island Boundary Switches	SW1	Open
	SW12	Open
Feeder Switches (internal to island boundary)	SW2	Closed
	SW3	Closed
	SW4	Closed
	SW5	Closed
	SW6	Closed
	SW7	Closed
	SW13	Closed
	SW14	Closed
	SW15	Closed
	SW16	Closed
	SW17	Closed
	SW18	Closed

[4] Sample initial conditions provided for general reference. Actual initial conditions at time of testing should be recorded.

	Identifier	State or Condition[4]
Feeder Boundary Switches	SW8	Open
	SW9	Closed
	SW10	Open
	SW11	Open
External Signals	Island Time Horizon[5]	24 hours

Execution Steps

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection)
    a. Critical loads are online
2. Monitor system conditions and microgrid controller dispatch decisions throughout island event
3. (Optional) Modify "Island Time Horizon "
    b. Observe adjustments to microgrid controller dispatch decisions
4. Test concludes at expiration of 24-hour outage event

Optional/Alternative Scenarios

- Short duration outage (hours)
- Long duration outage (multi-day)
- Outage during peak load season
- Outage during low load season

Expected Outcomes

The microgrid controller is expected to respond to system changes caused by load and irradiance variations throughout the outage simulation. When sufficient DER generating capacity is available, the controller is expected to expand and contract the energized island area to bring additional loads online in priority order (critical > priority > interruptible).

If "Island Time Horizon " is adjusted during the test, the microgrid controller is expected to update its dispatch strategy. The MGC objective should maximize the amount of load served for

[5] Expected time (in minutes, hours, or days) that microgrid will be required to stay in island mode. See *Controller Requirements for Managing Community Microgrids* [2] for details.

the remaining expected outage duration given current fuel levels, forecasted PV, and loading on the system.

Evaluation Criteria and Performance Metrics

The microgrid controller is expected to provide an energy management control dispatch strategy that increases the overall load coverage during the outage. The load coverage provided by the microgrid controllers will be compared against that in the baseline control scenario.

The performance indicators described in Table 3 can be used to measure the MGC's ability to provide Energy Management function for islanding. Metrics focused on serving critical load will be given higher priority than serving non-critical load or cost optimization.

Table 3. Performance Metrics for MGC Island Energy Management

Indicator ID	Indicator Definition	Unit	Performance Criteria
ENRGMGT:1	**<u>Percentage of Critical Load Served</u>:** The metric evaluates how MGC energy management function is able to serve the total critical load during island. The metric is defined as: $$\mathrm{Srvd}_{\mathrm{crld}} = \frac{E_{crld}^{srvd}}{E_{crld}^{req}}.100\%$$ where E_{crld}^{srvd}: the total served energy for critical load, E_{crld}^{req}: the total required critical load energy to be served during islanding time T_{island}.	%	A higher percentage of this metric denotes MGC was able to serve the critical load during island period successfully.
ENRGMGT:2	**<u>Critical Load Interruption Time</u>**: The metric evaluates MGC ability to maintain supply continuity during island for the individual critical loads. The metric is defined as: $$\mathrm{Intr}pt_{\mathrm{crld,i}} = \frac{T_{crld,i}^{shed}}{T_{island}}.100\%$$ where i: individual critical load, $T_{crld,i}^{shed}$: i^{th} critical load shedding duration, T_{island}: island duration.	%	A higher percentage of this metric denotes MGC was able to minimize the critical load interruption.
ENRGMGT:3	**<u>Percentage of Non-Critical Load Served</u>:** The metric evaluates how MGC energy management function is able to serve the total non-critical load during island. The metric is defined as: $$\mathrm{Srvd}_{noncrld} = \frac{E_{noncrld}^{srvd}}{E_{noncrld}^{req}}.100\%$$ where $E_{noncrld}^{srvd}$: the total served energy for non-critical load, $E_{noncrld}^{req}$: the total required non-critical load energy to be served during islanding time T_{island}.	%	A higher percentage of this metric denotes MGC was able to serve the non-critical load during island period successfully.
ENRGMGT:4	**<u>Non-Critical Load Interruption Time</u>**: The metric evaluates MGC ability to maintain supply continuity during island for the individual non-critical loads. The metric is defined as:	%	A higher percentage of this metric denotes MGC was able to minimize the non-

Indicator ID	Indicator Definition	Unit	Performance Criteria
	$$\mathrm{Intrpt}_{\mathrm{noncrld,j}} = \frac{T^{shed}_{noncrld,j}}{T_{island}}.100\%$$ where j: individual noncritical load, $T^{shed}_{crld,j}$: j^{th} critical load shedding duration,T_{island}: island duration.		critical load interruption.
ENRGMGT:5	**<u>Respect Load Priority</u>**: Assessment of MGC behavior in terms of maintaining the load priority while serving critical and non-critical loads during island. The metric is defined as number of times that MGC mis the priority of load dispatch during island: $$\mathrm{N_{misPriority}} = \sum_t \left[P^{req}_{crld,i}(t) - P^{srvd}_{crld,i}(t) > 0 \; and \; P^{srvd}_{noncrld,j}(t) > 0\right]$$ Where $P^{req}_{crld,i}(t)$: required capacity at time t for critical load i ,$P^{srvd}_{crld,i}(t)$: served critical load i at time t, $P^{srvd}_{noncrld,j}(t)$: served non-critical load j at the same time t.	unitless	A lower number of indicates that MGC is able to respect the load priority during island dispatching.
ENRGMGT:6	**<u>Operation Cost Minimization</u>**: this metric evaluate how MGC minimizes the generation cost while maintaining the necessary constraints. The operation cost per kWh during island is compared to a utility baseline for the 1 kWh cost during island: $$\left(\frac{\$}{kWh}\right)_{island} \leq \left(\frac{\$}{kWh}\right)_{utility_{base}}$$	%	The cost per kWh during island is better when it is lower than the utility base for $/kWh.
ENRGMGT:7	**<u>DER dispatch function control:</u>** All dispatch setpoints sent to system DER are within the pre-defined operational limits and capabilities of the DER. MGC dispatch settings respect minimum up/down time as configured.		Pass/Fail
ENRGMGT:8	**<u>Island Survival Time Report:</u>** MGC continuously updates the estimated remaining time that the microgrid can support critical loads given current DER status and forecasts		Pass/Fail
ENRGMGT:9	**<u>Available Island Capacity Report:</u>** MGC continuously updates the total remaining kWh measurement		Pass/Fail
ENRGMGT:10	**<u>Island Time Horizon Configuration:</u>** Island Energy Management dispatch plan time horizon is configurable based on an external setpoint (set manually or via HMI)		Pass/Fail

Island Constraint Management

Purpose

The goal of this test is to evaluate the MGC's ability to provide operational constraint management during island operation. The Island Constraint Management functions leverage the MGC to coordinate microgrid assets (e.g., DERs, capacitor banks) to relieve thermal and voltage constraints on the feeder during island operations. Although this functionality may normally be handled by a central distribution management system or operator, a utility MGC may be used to autonomously provide feeder constraint management when communications to the central management system are unavailable.

Commercial vendors may implement various control strategies to detect and manage thermal and voltage violations in a microgrid. This test will capture and evaluate the performance and effectiveness of the MGC's island constraint management function and compare it to a baseline case.

In the baseline scenario, the GFM battery inverters will be turned off and the PV inverters will be configured to operate in MPPT mode. The diesel generator will be turned on as well to operate as the isochronous frequency and voltage reference source in the islanded microgrid. No control commands will be issued from the MGC for the baseline case.

Test Overview

This test will simulate an overvoltage scenario during island operations over a 30-minute period. A representative day might include peak PV and low load. During the test, the MGC receives the real-time measurements from the microgrid periodically, then assigns:

- Voltage control setpoint(s) for the GFM DERs
- Active and reactive power setpoint or settings changes for GFL DERs
- Settings changes on voltage regulators, capacitor banks, tap changers (if not automated by field equipment)

Test Procedure

Initial Conditions

Table 4. Initial system conditions for Feeder Level Constraint Management test

	Identifier	State or Condition[6]
Load	Feeder 1 Load	[peak or low season] profiles: 1 hour start from 12pm; connected
	Feeder 2 Load	[peak or low season] profiles: 1 hour start from 12pm; connected
DER Status	PV1	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV2	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV3	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV4	1 hour start from 12pm; cloudy day profile and sunny day profile
	BESS 1	Status = Online, SOC = 80%, Output = 100kW
	BESS 2	Status = Online, SOC = 80%, Output = 100kW
	BESS 3	Status = Online, SOC = 80%, Output = 100kW
	Gen 1	Status = Online, Output = 2.5MW
Island Boundary Switches	SW1	Open
	SW12	Open
Feeder Switches (internal to island boundary)	SW2	Closed
	SW3	Closed
	SW4	Closed
	SW5	Closed
	SW6	Closed
	SW7	Closed
	SW13	Closed
	SW14	Closed
	SW15	Closed
	SW16	Closed
	SW17	Closed
	SW18	Closed
	SW8	Open
	SW9	Closed

[6] Sample initial conditions provided for general reference. Actual initial conditions at time of testing should be recorded.

	Identifier	State or Condition[6]
Feeder Boundary Switches	SW10	Open
	SW11	Open

Execution Steps

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection)
    a. Critical loads are online
2. Monitor system conditions and microgrid controller dispatch decisions throughout island event
3. Test concludes at expiration of 30-minute test event window

Optional/Alternative Scenarios

Additional thermal or voltage constraint scenarios may be tested with variants of load and DER profiles based on anticipated system needs and potential configurations.

Expected Outcomes

The microgrid controller is expected to respond to dispatch DER and DA equipment settings to prevent thermal or voltage constraint violations. Corrective control dispatch may also be used by the microgrid controller in response to unexpected constraint conditions. The constraint management provided by the microgrid controller will be compared against that in the baseline control scenario.

Evaluation Criteria and Performance Metrics

The following key performance indicators will be used to measure the MGC's ability to provide Constraint Management function for islanding:

Table 5. Performance Metrics for MGC Constraint Management During Island

Indicator ID	Indicator Definition	Unit	Performance Criteria
CNSTMGT:1	**Average Violation (TV):** The metric is used to evaluate the averaged constraint violation after the grid is managed under MGC. The metric is defined as: $$TV = \frac{\sum_t \sum_i max(X^t_{msd,i} - X_{lim,i}, 0)}{\sum t}$$ where i: line or node index, t: time index, $X_{msd,i}$ represents the measured constraint quantity (bus voltage or line loading), $X_{lim,i}$ represents the limit quantity (bus voltage or line loading).	Amps or Volts	A lower value of this metric denotes control was able to remove the constraints effectively.
CNSTMGT:2	**Percent Violation Reduction (PVR):** In this metric a comparison of constraint violation is considered in a grid before and after control. The metric is used to evaluate the net reduction in constraint violation after the grid is managed under MGC. $$PVR = \frac{TV\ (after\ control)}{TV\ (before\ control)} .100\ \%$$	%	A lower percentage of this metric denotes control was able to remove the constraints effectively.
CNSTMGT:3	**Maximum Magnitude of Violation:** The maximum violation observed in the grid across all nodes and lines in the feeder. The metric is used to evaluate the highest value in constraint violation after the grid is managed under MGC. $$TV_{max} = max\big(\{(X^t_{msd,i} - X_{lim,i}), 0\} \,\forall\, i, t\big)$$ where i: line or node index, t: time index, X represents the constraint quantity.	Amps or Volts	A lower value of this metric denotes control was able to reduce the severity of constraints effectively. When MMV is equal to zero that implies all the violations have been eliminated.
CNSTMGT:4	**Total Number of Violations:** This metric counts the total number of times a constraint violation occurs. This metric is used compare the grid state before and after control to analyze the efficiency of MGC.	N/A	In an ideal condition the total number of violations should go to zero after being controlled by MGC.
CNSTMGT:5	**Maximum Duration of Continuous Violation:** Maximum duration of constraint violation observed in the grid across all nodes and lines in the feeder. This metric is used to measure the temporal continuity of the violation of interest as $$\tau_{TV} = maximum\ time\big(X^t_{msd,i} - X_{lim,i}\big)$$ i: line or node index, t: time index	Min.	A lower value of this metric denotes control was able to reduce the temporal continuity of constraints effectively.
CNSTMGT:6	**Magnitude of Unnecessary DER Curtailment or Charging:** Unnecessary DER curtailment and ESS dispatch sent to the DER due to errors in state estimation of the grid.	kW	This error could occur due to underlying forecast errors and feeder model errors

Indicator ID	Indicator Definition	Unit	Performance Criteria
CNSTMGT:7	**Duration of Unnecessary DER Curtailment or Charging:** Total duration of unnecessary DER curtailment or charging commands sent to the DER due to errors in state estimation of the grid.	Min.	The ideal value of this metric is zero. Otherwise, a value closer to zero shows the better performance.
CNSTMGT:8	**Hosting Capacity:** this indicator shows how the smart action taken by MGC increased the hosing capacity as compared with the baseline scenario. The impact on the hosting capacity can be calculated as, $$\Delta HC = \frac{HC_{managed} - HC_{baseline}}{HC_{baseline}}.100$$	%	This indictor should show positive percentage, which indicate that the MGC smartly coordinated among resources.
CNSTMGT:9	**Predicted State Error:** Mean absolute difference between the actual and predicted voltage or current state quantity is given as follows $$MAE = \frac{1}{N}\sum\nolimits_{i,t}\left\|\frac{X^t_{forecasted,i} - X^t_{actual,i}}{X^t_{actual,i}}\right\|.100$$ i: constraint loc, t: time index, N: number of samples, X represents the constraint quantity	%	The ideal value of this metric is zero. Otherwise, a value closer to zero shows the better forecasting performance.

Island Voltage and Frequency Control

Purpose

The goal of this test is to evaluate the MGC's ability to provide secondary frequency and voltage control during island operation. The MGC's Secondary Frequency and Voltage control serves to provide frequency and voltage restoration across the microgrid area during island operations. An essential function of the MGC's autonomous feeder-level island control is its management of frequency and voltage stability. In an islanded microgrid with multiple GFM DER, the system frequency and voltage control can be maintained at the primary control level through droop-based load sharing. The primary controls of the GFM DER raise and lower the resources' power output in response to system frequency and voltage deviations; this dynamic control response performance should be evaluated before proceeding with the MGC testing.

The objective of the Secondary Frequency and Voltage Control use case in the MGC is to restore steady-state voltage and frequency deviations that occur during island operations. The advantage of using the MGC to provide secondary frequency and voltage control is its visibility across the islanded microgrid feeder(s), the operating state of the GFM DER, and other DER. Accordingly, the secondary frequency and voltage control communications between MGC and GFM DER will operate on the seconds-scale.

Commercial vendors may implement various strategies to control island voltage and frequency. This test will capture and evaluate the performance and effectiveness of the MGC's island secondary voltage and frequency control functions and compare it to a baseline case.

In the baseline scenario, the GFM battery inverters will be turned off and the PV inverters will be configured to operate in MPPT mode. The diesel generator will be turned on as well to operate as the isochronous frequency and voltage reference source in the islanded microgrid. No control commands will be issued from the MGC for the baseline case.

Test Overview

This test will create voltage and frequency disturbance scenarios during island operation over a 30-minute period. A representative day might include cloudy PV and peak load. During the test, the MGC receives the real-time measurements from the microgrid periodically, then adjusts frequency and voltage control setpoint(s) for the GFM DERs or active and reactive power setpoints for the GFL DER as needed to restore frequency and voltage.

Test Procedure

Initial Conditions

Table 6. Initial system conditions for Secondary Frequency and Voltage Control test

	Identifier	State or Condition[7]
Load	Feeder 1 Load	[peak or low season] profiles: 1 hour start from 12pm; connected
	Feeder 2 Load	[peak or low season] profiles: 1 hour start from 12pm; connected
DER Status	PV1	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV2	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV3	1 hour start from 12pm; cloudy day profile and sunny day profile
	PV4	1 hour start from 12pm; cloudy day profile and sunny day profile
	BESS 1	Status = Online, SOC = 80%, Output = 100kW
	BESS 2	Status = Online, SOC = 80%, Output = 100kW
	BESS 3	Status = Online, SOC = 80%, Output = 100kW
	Gen 1	Status = Online, Output = 2.5MW
Island	SW1	Open
	SW12	Open

[7] Sample initial conditions provided for general reference. Actual initial conditions at time of testing should be recorded.

	Identifier	State or Condition[7]
Boundary Switches		
Feeder Switches (internal to island boundary)	SW2	Closed
	SW3	Closed
	SW4	Closed
	SW5	Closed
	SW6	Closed
	SW7	Closed
	SW13	Closed
	SW14	Closed
	SW15	Closed
	SW16	Closed
	SW17	Closed
	SW18	Closed
Feeder Boundary Switches	SW8	Open
	SW9	Open
	SW10	Open
	SW11	Closed

Execution Steps

1. Begin with feeder-level, combined microgrid operating in stable island (no utility connection)
    a. Critical loads are online
2. Monitor system conditions and microgrid controller dispatch decisions throughout island event
3. Through MGC interface, modify Frequency Reference setpoint by 0.5%. Observe change DER dispatch and change in frequency
    a. Revert F ref to nominal and allow system to settle
4. Through MGC interface, modify Voltage Reference setpoint by 0.5%. Observe DER dispatch and change in voltage
5. Test concludes after frequency and voltage disturbances settle or expiration of 30 minute event

Optional/Alternative Scenarios

- Cloudy day island operation
- Low system load with high PV during island operation

Expected Outcomes and Sequence of Operations

The microgrid controller is expected to regulate system voltage and frequency to nominal values by dispatching available DER in the microgrid. Changes to microgrid system conditions that cause dynamic frequency and voltage excursions (within the system's anticipated design tolerance) should not cause the island to collapse. Expected events may include fluctuating irradiance due to cloud coverage or large load step changes. The MGC dispatches DER in a configuration that creates an acceptable reserve capacity to maintain transient stability between MGC dispatches. Any corrective control to frequency and voltage deviations should be slower than the primary control provided by the grid-forming or isochronous DER and not cause oscillations. The frequency and voltage control provided by the microgrid controller will be compared against that in the baseline control scenario.

Evaluation Criteria and Performance Metrics

The following performance indicators in Table 7 and Table 8 will be used to measure the MGC's ability to provide secondary frequency and voltage control during island operations:

Table 7. Performance Metrics for Secondary Frequency Control

Indicator ID	Indicator Definition	Unit	Performance Criteria
SECFC:1	**Average Frequency Deviation:** The metric is used to evaluate the average frequency violation where f_t = mean of the frequency measurements over pre-determined timestep windows; f_{set}= frequency setpoint. The frequency deviation fD is calculated in % by: $$fD_{\%} = \frac{\sqrt{\sum_t (f_t - f_{set})^2}}{f_{set}} \times 100\%$$	%	A lower value of this metric denotes control was able to remove the violation effectively.
SECFC:2	**Maximum Frequency Deviation:** this metric evaluates the behavior of the controller during the system disturbance. The maximum frequency deviation fD_{max} is calculated as: $$fD_{max} = \max_t \left(\frac{\lvert f_t - f_{set} \rvert}{f_{set}} \right) \times 100\%$$	%	A lower value indicates that the controller is able to avoid overshot due to disturbances
SECFC:3	**Average Duration of Frequency Violation:** Average duration of consecutive[8] frequency disturbances on the microgrid during an island	seconds	A lower time duration indicates better performance.

[8] Definition of consecutive disturbances and examples are provided in IEEE 1547-2018.

Indicator ID	Indicator Definition	Unit	Performance Criteria
SECFC:4	**Maximum Duration of Frequency Violation:** Longest duration of a consecutive frequency disturbance on the microgrid during an island	seconds	A lower time duration indicates better performance.
SECFC:5	**Frequency Reference Configuration:** The nominal system frequency can be configured through an external reference signal or HMI at the MGC. The MGC responds to frequency reference setting updates by modifying the respective GFM DER setpoints or a related mechanism.		Pass/Fail

Table 8. Performance Metrics for Secondary Voltage Control

Indicator ID	Indicator Definition	Unit	Performance Criteria
SECVC:1	**Average Voltage Deviation:** The metric is used to evaluate the average voltage violation where V_t = mean of the voltage measurements over pre-determined timestep windows; V_{set}= frequency setpoint. The voltage deviation VD is calculated in % by: $$VD_{\%} = \frac{\sqrt{\sum_t (V_t - V_{set})^2}}{V_{set}} \times 100\%$$	%	A lower value of this metric denotes control was able to remove the violation effectively.
SECVC:2	**Maximum Voltage Deviation:** this metric evaluates the behavior of the controller during the system disturbance. The maximum voltage deviation VD_{max} is calculated as: $$VD_{max} = \max_t \left(\frac{\lvert V_t - V_{set} \rvert}{V_{set}} \right) \times 100\%$$	%	A lower value indicates that the controller is able to avoid overshot due to disturbances
SECVC:3	**Average Duration of Voltage violation:** Average duration of consecutive[9] voltage disturbances on the microgrid during an island	seconds	A lower time duration indicates better performance.
SECVC:4	**Maximum Duration of Voltage Violation:** Longest duration of a consecutive voltage disturbance on the microgrid during an island	seconds	A lower time duration indicates better performance.
SECVC:5	**Voltage Reference Configuration:** The nominal voltage reference at selected buses can be configured through an external reference signal or HMI at the MGC. The MGC responds to voltage reference setting updates by modifying the respective GFM DER setpoints or a related mechanism.		Pass/Fail

[9] Definition of consecutive disturbances and examples are provided in IEEE 1547-2018.

Black Start – Normal Procedure

Purpose

The purpose of this test is to confirm that microgrid controller can safely and effectively coordinate black start sequencing. Following an outage event, the MGC is expected to autonomously execute the designed island system black start procedure from feeder outage through cold load pick-up. This test ensures that the MGC starts this procedure under the appropriate trigger conditions (e.g., adheres to lockout permissions) and has integrated with the DER plant controls correctly. This test assumes the designated black start plant (e.g., GFM BESS) has been previously evaluated for its ability to black start the microgrid under test[10].

Test Overview

In this test case, the system will begin in a de-energized state due to an outage condition created across the entire feeder. The MGC must assess system conditions, device availability, and coordinate DER start-up and cold-load pickup to energize the microgrid island.

Test Procedure

Initial Conditions

Table 9. Initial system conditions for Black Start, Normal Procedure test

	Identifier	State or Condition[11]
Load	Feeder 1 Load	[peak] profiles: 15 minutes start from 12pm; connected, de-energized
	Feeder 2 Load	[peak] profiles: 15 minutes start from 12pm; connected, de-energized
DER Status	PV1	15 minutes start from 12pm; sunny day profile; State = offline
	PV2	15 minutes start from 12pm; sunny day profile; State = offline
	PV3	15 minutes start from 12pm; sunny day profile; State = offline
	PV4	15 minutes start from 12pm; sunny day profile; State = offline
	BESS 1	Status = Offline, SOC = 80%
	BESS 2	Status = Offline, SOC = 80%
	BESS 3	Status = Offline, SOC = 80%
	Gen 1	Status = Offline, Output = 0MW
Island Boundary Switches	SW1	Closed, Protection relay settings = grid-connected profile
	SW12	Closed, Protection relay settings = grid-connected profile

[10] For additional information on black start DER design and testing see [7], [4], and [6].

[11] Sample initial conditions provided for general reference. Actual initial conditions at time of testing should be recorded.

	Identifier	State or Condition[11]
Feeder Switches (internal to island boundary)	SW2	Closed
	SW3	Closed
	SW4	Closed
	SW5	Closed
	SW6	Closed
	SW7	Closed
	SW13	Closed
	SW14	Closed
	SW15	Closed
	SW16	Closed
	SW17	Closed
	SW18	Closed
Feeder Boundary Switches	SW8	Closed, Protection relay settings = grid-connected profile
	SW9	Open, Protection relay settings = grid-connected profile
	SW10	Open, Protection relay settings = grid-connected profile
	SW11	Open, Protection relay settings = grid-connected profile
External Signals	Island Permission	Enabled

Execution Steps

1. Begin with de-energized system with island permission enabled. Substation power is unavailable.
    1.1. Equipment may still have grid-connected settings
2. Observe expected sequence of events managed by MGC to black start and enter island operations
    2.1. Confirm that MGC control logic bit responsible for identifying permission to island and system condition (e.g., permanent external fault) is correct
    2.2. Confirm MGC orchestrates equipment management and start up logic as expected
3. Test concludes when isolated microgrid reaches steady-state operations with GFM DER online and microgrid area energized fully.

Optional/Alternative Scenarios

The following parameter variations may warrant testing as an iteration of the above procedure.

- BESS mode (e.g., off, performing managed dispatch, idle, etc.)
- PV irradiance at peak power vs. night
- Generator unavailable
- Load level when grid connected (peak load and min load)

- Manual, operator initiated black start (e.g., for maintenance testing)

Expected Outcomes and Sequence of Operations

The following sequence of events is expected to be managed by the MGC during the black start test. The system component interactions are illustrated in Figure 3.

1) (Optional trigger of outage scenario) Low impendence fault causes Recloser 1 to trip indefinitely[12]
   a) Multiple trips may be expected before permanent fault
2) MGC checks pre-conditions to initiate black start:
   a) Islanding enabled by ADMS
   b) GFM BESS available
   c) MGC logic identifies fault as permanent and external to MG boundary
   d) All internal faults are clear (no temporary or permanent faults within the microgrid boundary)
3) Isolate microgrid area[13]; MGC checks microgrid boundary breaker status and opens breakers to isolate the island area.
   a) Open black start plant interconnection breaker (e.g., GFM inverter BESS plant interconnection breakers (BESS CB))
   b) Open all circuit breakers related to cold load pickup procedure[14]
4) MGC activates island protection settings
5) MGC sends start signal and frequency and voltage reference setpoints to black start plant (e.g., GFM inverter) in isochronous master mode
   a) GFM BESS plant controller signals individual inverters to ramp AC output voltage
      i) Inverters synch and join within plant
   b) GFM inverter BESS plant signals MGC at full voltage
6) MGC closes black start plant interconnection breaker
7) MGC continues closing breakers along feeder per cold load pickup scheme

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[12] Number of reclose events before permanent open to be determined by "Operational Philosophy " system design

[13] Some breakers may already be open from protection response to fault condition or other grid-connected configuration.

[14] Black start transient analysis should be conducted in advance of this test to determine a feasible cold load pick-up sequence. See *How to Assess Microgrid Performance* [4] for details.

8) PV along feeder may start automatically after seeing island voltage and frequency stabilize
    a) MGC sends curtailment setpoints to PV (if needed to balance microgrid system)

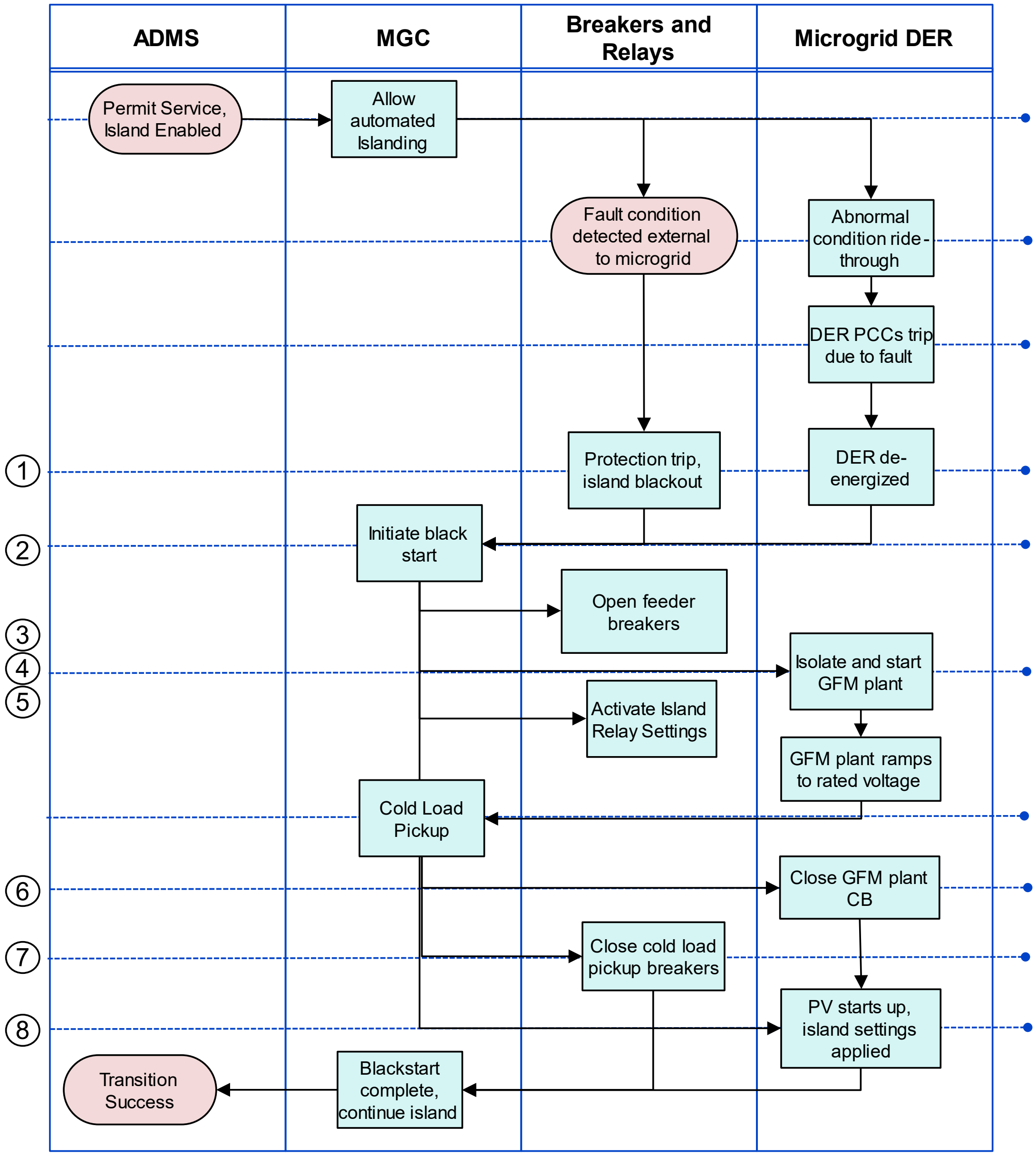

Figure 3. Microgrid component interactions during black start test

Evaluation Criteria

The evaluation criteria provided in Table 10 will be used to measure the MGC's ability to provide Black start coordination. Note that these criteria are specific to the MGC's functional requirements; a broader set of performance criteria should be applied to the overall microgrid black start design (see *How to Assess Microgrid Performance* [4] for details).

Table 10. Evaluation Criteria for MGC Black Start – Normal Procedure test

Indicator ID	Indicator Definition	Performance Criteria
MGBS:1	**Controller availability:** Following black out event and loss of normal power from substation, the MGC remains self-powered to assess system status and can initiate communications to begin dispatching the black start sequence commands to devices in the microgrid.	Pass/Fail
MGBS:2	**Permissions to island**: MGC does not execute black start without permission to island enabled; MGC checks all required device availability or connectivity status and does not attempt to black start if critical check fails.	Pass/Fail
MGBS:3	**Island settings application**: MGC updates all relay protection settings, DER settings, and Distribution Automation Equipment settings for island configuration per system design.	Pass/Fail
MGBS:4	**Isolation Check:** MGC checks status and opens all isolation switches and breakers before procedure begins	Pass/Fail
MGBS:5	**DER mode control**: MGC correctly dispatches DER modes and settings for black start and island operation	Pass/Fail
MGBS:6	**Cold load pickup order**: MGC adheres to cold load pickup order and configured timing between stages	Pass/Fail
MGBS:7	**Event logging and external communication**: MGC updates external status point changes for central monitoring throughout execution of black start sequence	Pass/Fail
MGBS:8	**System condition checks**: MGC monitors island system conditions (e.g., voltage, frequency) throughout black start sequence. If alarm conditions are raised, MGC ceases execution of black start sequence until conditions stabilize for continuation of procedure.	Pass/Fail

Synchronized Reconnection

Purpose

Closed reconnection can reduce customer interruption and outage time during reconnection and reduce grid-side cold load pickup transients. The purpose of this test is to evaluate the microgrid control system's ability to manage a non-disruptive grid-reconnection transition from an islanded state. The MGC is expected to dispatch appropriate device settings changes, and the transition should not disrupt customers or cause unacceptable grid disturbances. This test assesses if MGC is capable of coordinating active or passive synchronization for closed grid-reconnection.

- **Active synchronization**: If the microgrid voltage and frequency can be controlled sufficiently, then the MGC dispatches the GFM BESS to align the voltage and frequency to the utility power system, while a sync-check relay monitors for acceptable frequency, voltage, and phase angle conditions and closes when enabled by the MGC.

- **Passive synchronization**: The MGC enables automated resynchronization at the isolation switches without actively adjusting local voltage and frequency. The microgrid reconnects only when the two systems are within synchronization tolerance according to the sync-check relay. If the systems are badly out of sync, reconnection may not be possible with this method.

Typically, at least one interconnection breaker must have a synchronized close function to enable safe reconnection. Microgrids with multiple points of interconnection require additional sequenced coordination to implement a closed reconnection.

Test Overview

In this test case, the microgrid begins in a stable islanded operational state, then stable voltage and frequency return to the external system. The microgrid controller is expected to dispatch the DER to resynchronize to the upstream system and create a closed transition from islanded to grid-connected operation without causing disruptions. At the end of the test sequence, the microgrid should be reconnected to the main grid, with grid-connected settings applied to DER and protection equipment.

Test Procedure

Initial Conditions

Table 11. Initial system conditions for Synchronized Reconnection test

	Identifier	State or Condition[15]
Load	Feeder 1 Load	[peak] profiles: 15 minutes start from 12pm; connected, de-energized
	Feeder 2 Load	[peak] profiles: 15 minutes start from 12pm; connected, de-energized
DER Status	PV1	15 minutes start from 12pm; sunny day profile; State = online
	PV2	15 minutes start from 12pm; sunny day profile; State = online
	PV3	15 minutes start from 12pm; sunny day profile; State = online
	PV4	15 minutes start from 12pm; sunny day profile; State = online
	BESS 1	Status = Online, SOC = 40%
	BESS 2	Status = Online, SOC = 40%
	BESS 3	Status = Online, SOC = 40%
	Gen 1	Status = Online, Output = 2.0MW
Island Boundary Switches	SW1	Open, Protection relay settings = island profile
	SW12	Open, Protection relay settings = island profile

[15] Sample initial conditions provided for general reference. Actual initial conditions at time of testing should be recorded.

	Identifier	State or Condition[15]
Feeder Switches (internal to island boundary)	SW2	Closed
	SW3	Closed
	SW4	Closed
	SW5	Closed
	SW6	Closed
	SW7	Closed
	SW13	Closed
	SW14	Closed
	SW15	Closed
	SW16	Closed
	SW17	Closed
	SW18	Closed
Feeder Boundary Switches	SW8	Closed, Protection relay settings = island profile
	SW9	Closed, Protection relay settings = island profile
	SW10	Open, Protection relay settings = island profile
	SW11	Open, Protection relay settings = island profile
External Signals	Grid-Connected Permission	Enabled

Execution Steps

1) Begin test in stable, islanded operation of the microgrid
2) Grid-side voltage and frequency return to normal (via simulation or establish data feed from live grid) for at least "Enter Service Delay " amount of time. Permission to operate grid-connected signal is set to ENABLE in the microgrid controller
3) Observe autonomous sequence of events managed by MGC to dispatch DER for reconnection and transition to grid-connected operation
4) Test concludes when microgrid is connected to the grid, operating with stable steady-state conditions and grid-connected settings applied. DER remain online and microgrid area is energized fully.

Optional/Alternative Scenarios

- Operator initiated reconnection

Expected Outcomes and Sequence of Operations

The following steps describe the closed reconnection sequence from islanded to grid-connected mode. The system component interactions are illustrated in Figure 4.

1) Stable grid-side power is restored; MGC triggered to reconnect to the grid (grid-connected mode enabled)

a) MGC checks grid-side conditions are stable for at least "Enter Service Delay " time period before continuing reconnection sequence

2) MGC prepares island for reconnection

   a) Set GFM DER voltage reference setpoint to measured grid-side voltage

   b) Set GFM DER frequency reference setpoint to nominal frequency setting of grid

   c) Updates protection to grid-connected settings (if applicable)

3) MGC signals synchronizing recloser(s) at point of isolation to close

   a) Synch relay monitors grid- and microgrid-side voltage, frequency, and phase angle and waits for acceptable tolerance window to close

   b) If microgrid does not reach tolerance window, MGC adjusts microgrid-side frequency setpoint (up/down) at GFM DER to allow phase angles to overlap

   c) MGC sends close signal to second isolation breaker after first breaker closes

4) After isolation breaker(s) close, MGC changes DER modes to GFL and updates setpoints (if needed)

   a) MGC removes island-only protection settings (if applicable)

5) MGC (or ADMS) closes remaining downstream microgrid interconnection breakers (if applicable)

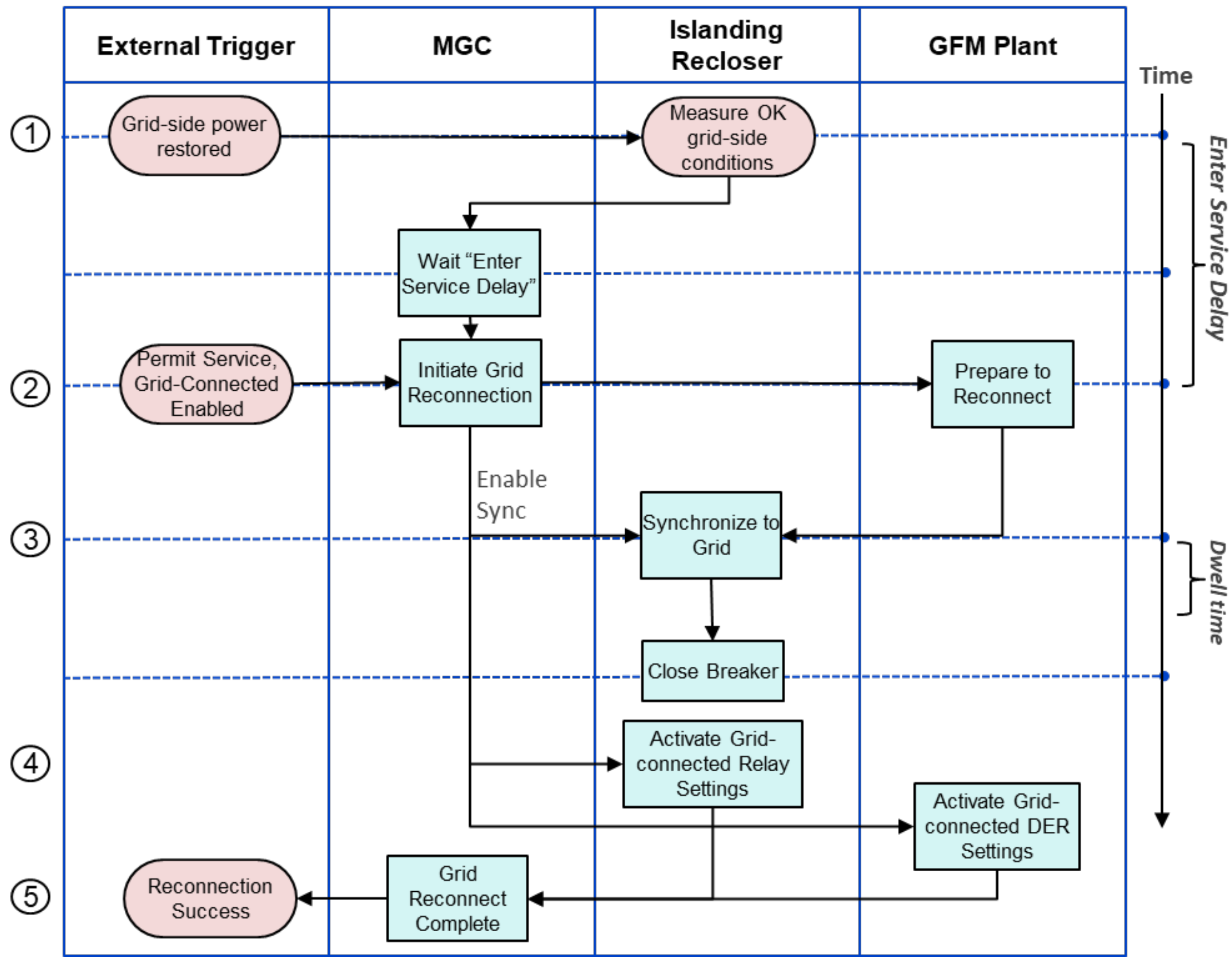

Figure 4. Microgrid component interactions during synchronized reconnection test

Evaluation Criteria

The evaluation criteria provided in Table 12 will be used to measure the MGC's ability to coordinate a non-disruptive reconnection transition. Note that these criteria are specific to the MGC's functional requirements; a broader set of performance criteria should be applied to the overall microgrid reconnection (see *How to Assess Microgrid Performance* [4] for details).

Table 12. Evaluation Criteria for MGC Synchronized Reconnection test

Indicator ID	Indicator Definition	Performance Criteria
MGSR:1	**Permissions to reconnect**: MGC does not execute reconnection procedure without permission to reconnect enabled; MGC grid-side service availability and does not attempt to reconnect before external voltage and frequency have been stable for a minimum of "Enter Service Delay " .	Pass/Fail
MGSR:2	**Grid-Connected settings application**: MGC updates all relay protection settings, DER settings, and Distribution Automation Equipment settings for grid-connected configuration per system design.	Pass/Fail
MGSR:3	**DER mode control**: MGC correctly dispatches DER modes and settings for synchronization and return to grid-connected operation	Pass/Fail
MGSR:4	**Synchronization check**: MGC does not send a close signal to the grid isolation breaker until the microgrid frequency and voltage differences from the grid-side measurements are within the allowable tolerance (e.g., $\Delta f < 0.1Hz$, $\Delta V < 3\%$, $\Delta\Phi < 10°$). Synchronization tolerance limits may be tighter or looser based on site characteristics.	Pass/Fail
MGSR:5	**Event logging and external communication**: MGC updates external status point changes for central monitoring throughout execution of reconnection sequence	Pass/Fail
MGSR:6	**System condition checks**: MGC monitors island system conditions (e.g., voltage, frequency) throughout reconnection sequence. If alarm conditions are raised, MGC ceases execution of reconnection sequence until conditions stabilize for continuation of procedure.	Pass/Fail

4 RECOMMENDED READING AND REFERENCES

Recommended Reading

IEEE Standard Association, *IEEE Std. 1547-2018. Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*. 2018.

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