Hardware in the Loop Microgrid Controller Information Packet

V1.4

July 29, 2016

LINCOLN LABORATORY
MASSACHUSETTS INSTITUTE OF TECHNOLOGY
244 Wood Street, Lexington, MA 02420-9108

This work is sponsored by the Department of Energy, Office of Electricity Delivery and Energy Reliability under Air Force Contract #FA8721-05-C-0002. Opinions, interpretations, conclusions and recommendations are those of the author and are not necessarily endorsed by the United States Government.

Revision History

Rev	Date	Description	Editor
0.1	4/11/2016	First version based on updates to 2015 system	Limpaecher
0.2	4/12/2016	Added thermal control diagram Updated IP addresses	Corbett Rekha
0.3	4/20/2016	Updated from team review: merged NG/diesel section, merged power converter section, removed reference to load metering	Limpaecher
0.4	4/21/2016	Updated dates (Sec. 3), removed fuel curves, added EPC CANBUS link	Limpaecher
0.5	4/21/2016	Added content to Table 4, added paragraph at bottom of p. 12, added row to bottom of Table 6, provided text for Section 7 and content for Table 7	Corbett
0.6	4/22/2016	Updated tables 3 and 6. Added content for sections 8, 8.1, and 8.2. Updated tables 8 and 9. Added current Modbus register list, and added notes and references.	Nowocin
0.7	4/27/2016	Copy editing; added distribution statement & sponsor info	Limpaehcer
0.8	5/17/2016	Edited CHP model, Figure 3; edited Section 7 and added proposed energy optimization metric	Corbett
0.9	5/27/2016	1. Updated section "10. Simulated Generic Relays"; added decription and changes to: model, multiple protection groups, multiple TCC, register list 2. Updated section 4.1 Modbus Device Address Map; Added key relay's description, renamed column Modbus Address to Feeder Location ID, assigned relays to corresponding feeders based on line-diagram 3. Updated Section 5 Control capabilities; removed V/F control from PV 4. Updated section 3.2. Device Integration Test; terminology of relay, software vs hardware	Salcedo
1.0	6/27/2016	1. Replaced one-line diagram with updated version including more information. 2. Revised details and requirements of load categories – see Table 12 3. Included a table summarizing the load demand sizes and the feeders serving those loads 4. Added a description of the microgrid system – see 3.4.1	Salcedo
1.1	7/8/2016	Added steam transport delay to CHP model, Figure 3; added content to Section 6.2; updated Section 7 text and Table 7.	Corbett
1.2	7/8/2016	Added HILLEN diagram and firewall description	Rekha

1.3	7/8/2016	Added test plan and test plan metrics (key performance parameters)	Backes
1.4	7/8/2016	Updated table 3, added Modbus registers for controlling generator operation, and added inverter Modbus reference specification (SunSpec)	Nowocin
1.4	7/27/2016	Updated table 12 to include SAIDI metric for critical load. Updated table 2 with correct relay names for each feeder and the IP addresses. Added link to security gateway. Added updated oneline and fast load shedding diagram. Added cybersecurity test plan.	Backes

File path: \\202 Standard Microgrid Controls\12 Interface Control Document\

Table of Contents

1 Introduction

Microgrids can be used to decrease customer energy costs while increasing resiliency to power grid outages, but the design and construction of these systems is often too expensive. The microgrid controller stands out as one component with widely varying capabilities, levels of maturity, and project-specific integration costs among different vendors. Incompatibility between components and vendors is another concern.

In October 2015, MassCEC, MIT Lincoln Laboratory (MIT-LL), and government sponsors held a Microgrid Controller Symposium. The centerpiece of the Symposium was live operation of microgrid controllers from two commercial vendors. This was enabled by a real-time hardware-in-the-loop (HIL) power systems simulation platform developed by MIT-LL. The Department of Energy (DOE) Office of Electricity is interested in addressing these challenges by further developing the HIL platform for the following purposes:

Objective 1: Provide a **Development Platform** for microgrid controller vendors to build new capabilities and showcase them to entities considering the deployment of microgrids – utility companies, project developers, and systems integrators – at the second Microgrid and DER Controller Symposium in Boston.

Objective 2: Provide a **Deployment Platform** for systems integration and pre-commissioning testing of actual microgrid deployments. The HIL system will integrate the site's actual device controllers, enable utility risk reduction commissioning, and provide test coverage of edge conditions and dangerous fault conditions, thereby reducing eventual hardware commissioning time.

Objective 3: Provide a **Validation Platform** for vendors, test labs, and utilities to verify conformance with IEEE P2030.7 and P2030.8 microgrid controller functional and test standards once they are completed.

For objective 1, DOE is hosting the next Microgrid and DER Controller Symposium, held at MIT in Cambridge. Major investor-owned utilities, microgrid project developers, regulators, and systems integrators will be in attendance. The centerpiece of this Symposium will be live operational demonstrations of commercial microgrid controllers running in real time.

These controllers will be showcased at the Symposium in through operational demonstrations, interaction by attendees, and an anonymized performance analysis illustrating the current state-of-practice of the microgrid industry.

This document outlines the microgrid HIL system, its interfaces, and functional demonstration scenarios. This information packet will continue to be updated as the design is refined.

2 Test System Diagrams

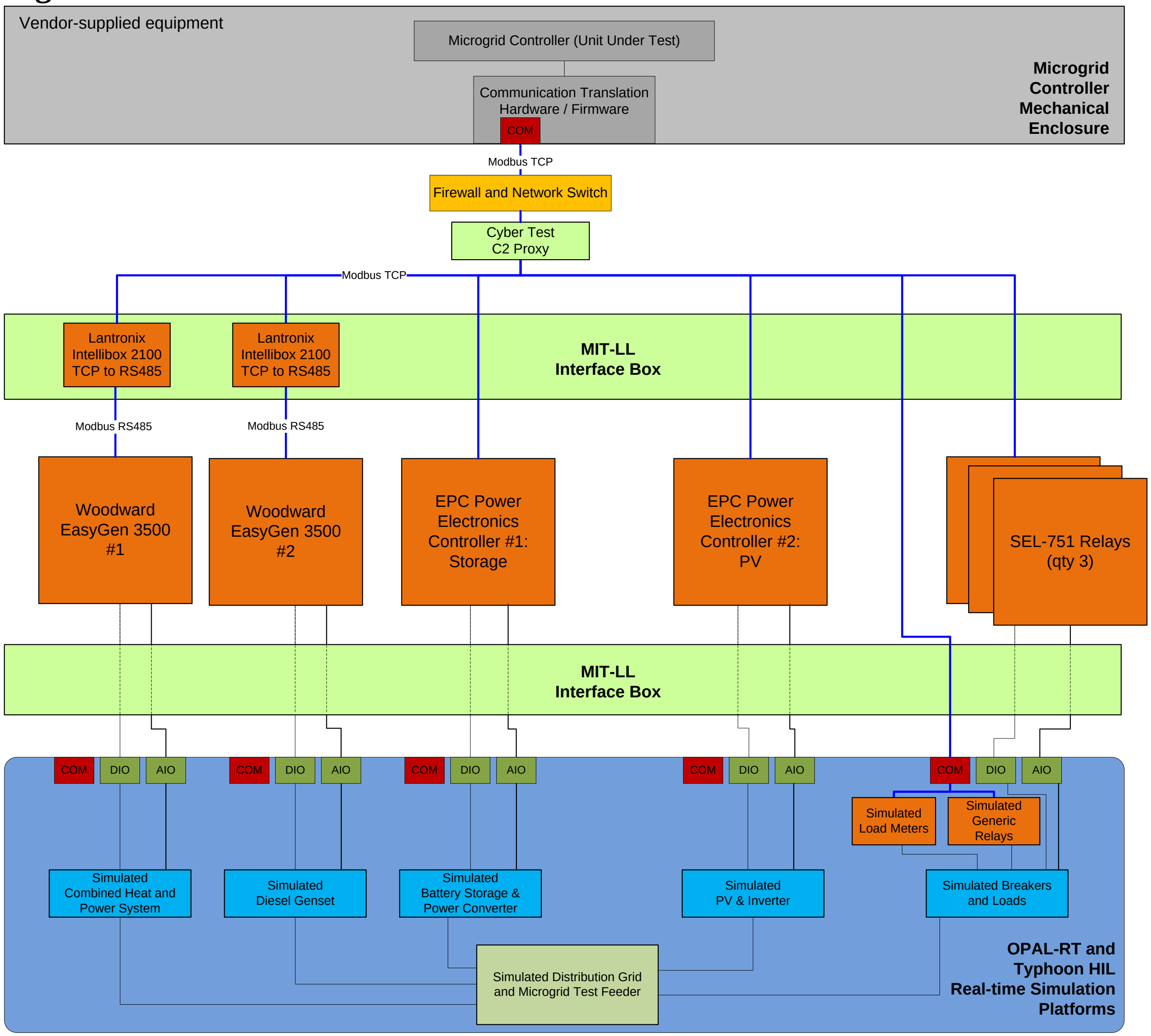

Figure 1. HIL demonstration testbed components and interfaces

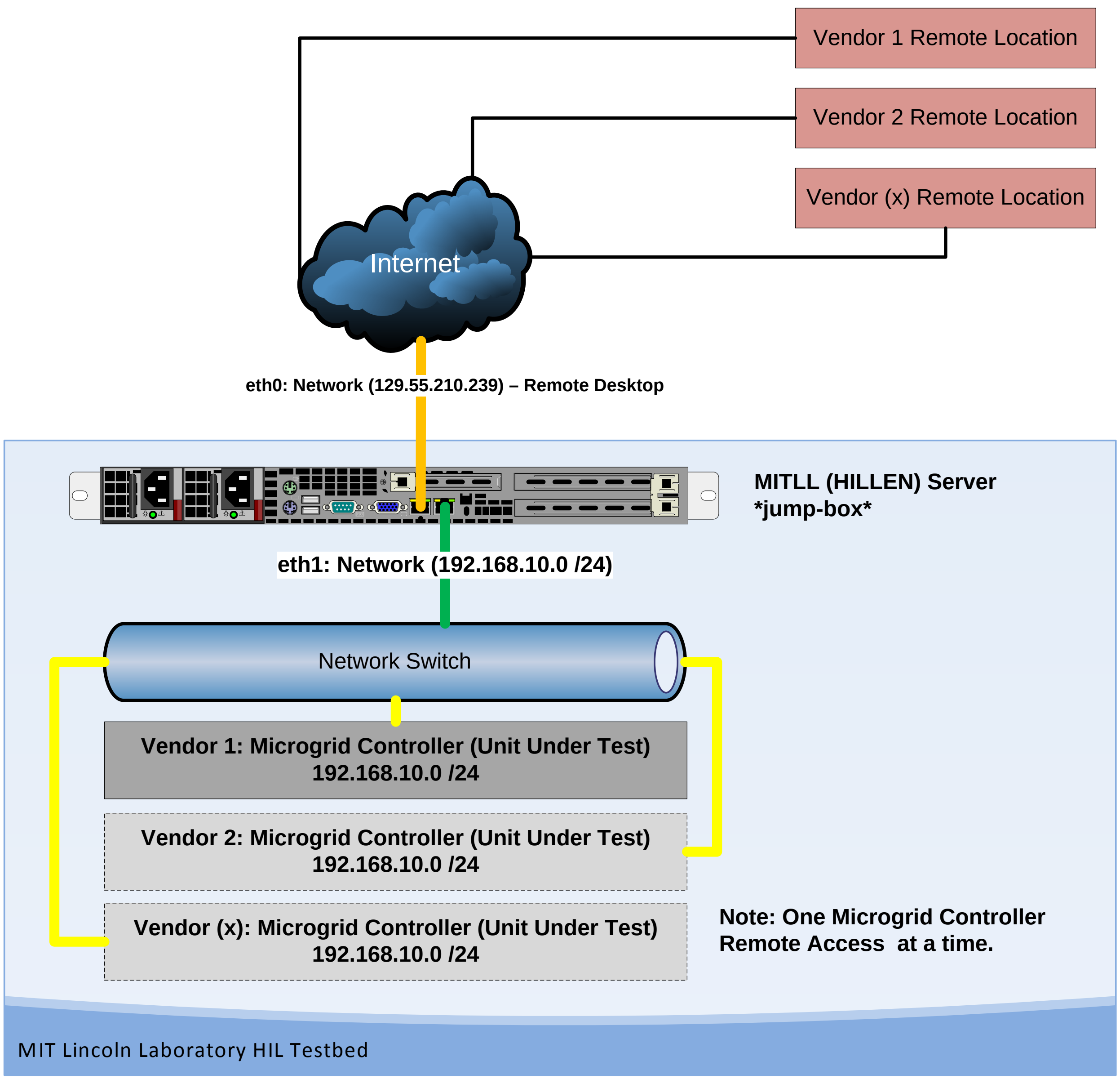

Figure 1b. Remote Vendor Access for Microgrid Controller Testing

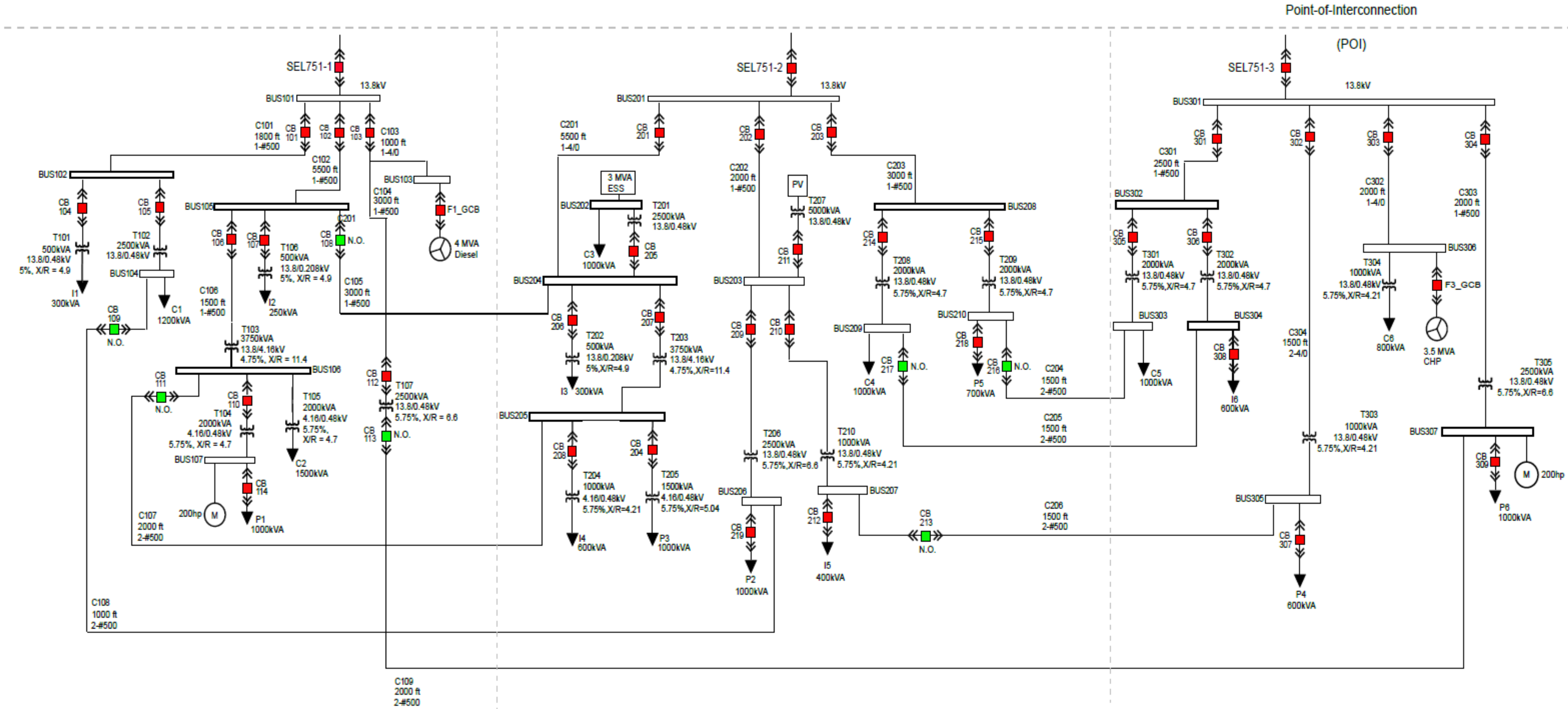

Figure 2. Test feeder electrical one-line diagram

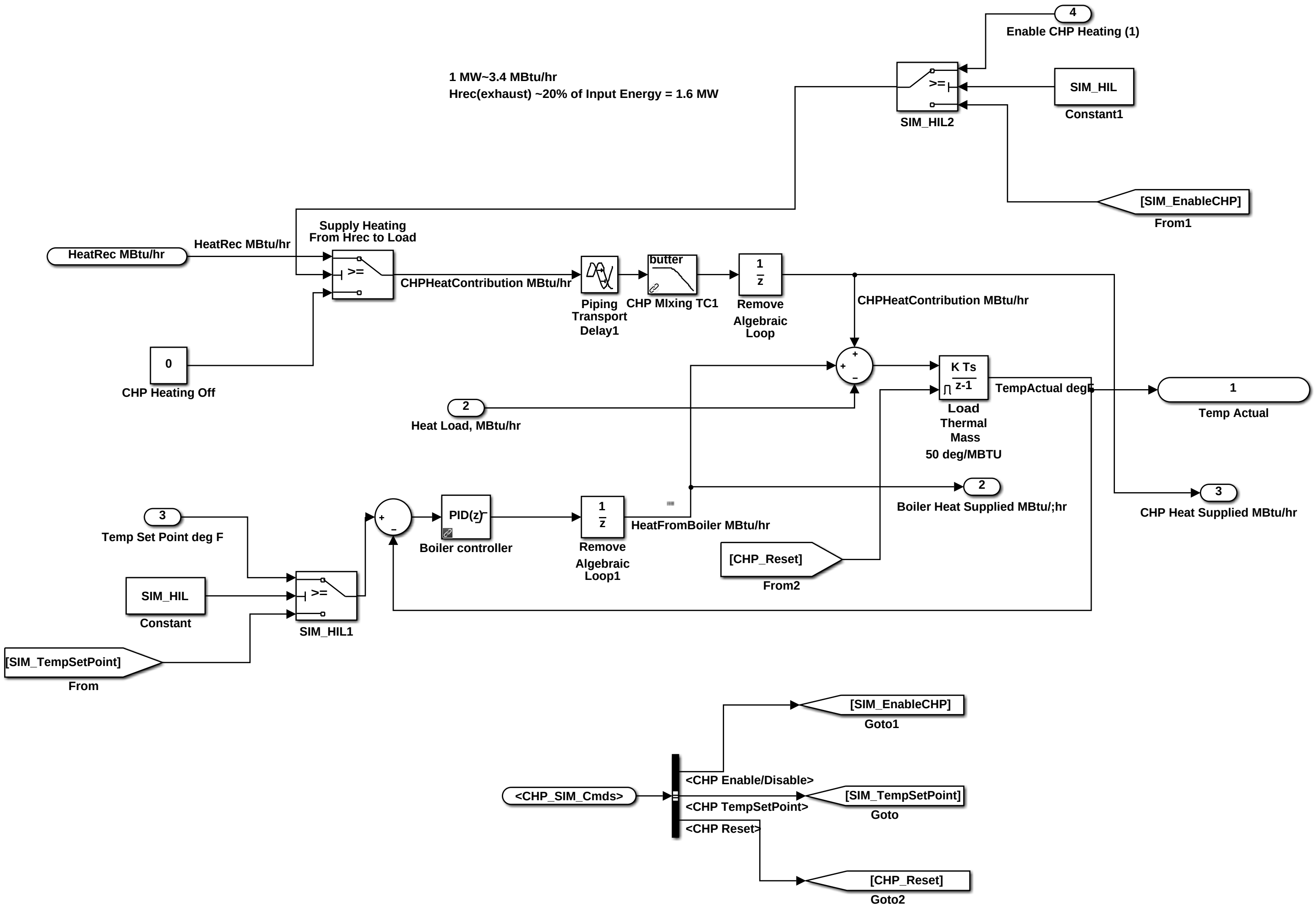

Figure 3. System thermal control diagram

3 Microgrid Controller Integration and Testing

MIT-LL will develop five separate tests – described below – to support the integration of vendors' microgrid controllers and the demonstrations at the Symposium. Three of these tests involve only MIT-LL staff. Two of the tests will involve the microgrid controller vendors' staff.

3.1 Unit Tests (Apr - Aug / MIT-LL only)

These tests, done internally at MIT-LL, will ensure the proper operation of each of the distributed energy resources, relays, and other testbed elements.

3.2 Device Integration Test (Sep - Oct / with vendors)

Before integrating their microgrid controllers with the full test feeder, vendors will be given the opportunity to test their communications with each device operating as part of a standalone test model.

The Device Integration Test model will consist of the five standalone sets of sources and loads outlined below:

	Unit Test	Notes
1	NG Gen→ Software Relay→Load Relay→Load	
2	PV→ Software Relay→Constant P Load	Constant irradiance, matching PV generation to load
3	BES→ Software Relay→ Software Relay→ Load (P&Q) → Software Relay→Motor Load	Variable load
4	CHP→ Software Relay→Electrical Load →Thermal Sensor→Thermal Load	
5	Grid→MID*→Feeder Sect. Switch→ →MID →Feeder Sect. Switch→Bus Tie Sw. →2-4 Loads	

Table 1: List of the device integration test models

*MID: Microgrid Interconnection Device (i.e. hardware relay controlling the breaker at POI)

3.3 System Integration Test (Nov - Dec / with vendors)

The system integration test will use the full test feeder. The test scripts will exercise the microgrid controller under a wide range of conditions, summarized below, to identify any remaining integration problems and give the vendors confidence in the reliable operation of the system.

- Steady-state conditions – to confirm optimization performance, controls for ancillary services, data collection, performance analysis post-processing, and intentional islanding events
- Worst-case ramping conditions – to allow vendors to exercise their stability and dispatching controls

- Faults – to allow vendors to exercise their load shedding and microgrid reconfiguration controls
- Unintentional islanding – to allow vendors to exercise their recovery and microgrid black start controls

3.4 Performance Evaluation Test (Jan / MIT-LL only)

This test will use the final test feeder model. The test script will be between 30 minutes and 4 hours long and will not be shared with vendors. It is intended to test under realistic conditions experienced by the microgrid after the microgrid controller's final deployment and commissioning.

No human intervention by the vendors will be allowed. MIT-LL does, however, want vendors to successfully complete the test run. Time permitting, MIT-LL will notify vendors of integration bugs that are encountered, to enable vendors to fix these bugs prior to a retest.

The performance results from these tests will be anonymized and presented during the Symposium. The goal of presenting the results is to illustrate the current state-of-practice within the microgrid industry, not to advocate for or penalize individual vendors.

3.4.1 Microgrid System Description

The Radial distribution systems are widely implemented due to their simplicity and relatively low cost. The feeders leave a substation and distribute electrical power in the designated zone without connections to other points of supply. This configuration is popular in rural areas with long feeders supplying remote loads. To increase reliability, damaged parts of the feeders may be isolated and alternative power sources (i.e. nearby substations or local generation) can be connected by means of manual or automatic tie switches.

The system modelled for this microgrid controller symposium consists of three radial feeders supplying a real-life industrial park, yet presenting challenges that will be found in a community microgrid. After the point-of-interconnection (POI), all cables are underground. The overall electrical demand of the feeders ranges from 5 MW to 14 MW for minimum and maximum load, respectively. The system is rated for a medium voltage of 13.8 kV and low voltages of 4.16 kV, 480 V, and 208 V. There are 18 loads continuously supplied by the feeders (6 critical, 6 priority, and 6 interruptible). Critical loads are categorized by the high requirements of continuous electrical service, power quality, and reliability (i.e. sensitive equipment labs, etc.). Priority loads are buildings that ideally are always served, but in case of contingencies, or islanding with lack of generation, may be disconnected. Interruptible loads are buildings not necessarily required to be served during contingencies or islanded conditions. Furthermore, there are two large induction motor of 200 horsepower, one of the largest sizes recommended by the 2011 National Electric Code (NEC) for full voltage start-up.

Each of the system loads is modelled as a time-varying dynamic load based on electrical demand profiles extracted from smart metering equipment. The generation assets consists of a 4000 kVA diesel generator and a 3500 kVA natural gas-fired combined heat-and-power (CHP) system. Both units are controlled and protected using the commercially available Woodward EasYgen 3500 generator controllers and operate at a 13.8 kV nominal voltage. During simulations, the Woodward controllers are entirely controlled by the microgrid controllers without operator intervention unless the alarms deem necessary. The system also includes a simulated 5000 kW PV and a 2000 kVA battery energy storage (BES), see section 8 for more details. Both the PV inverter and the BES power converter are controlled by commercially available EPC MG-LC 12/6 power module controllers. The PV system will be supplied with a varying irradiance profile matching a defined test sequence. The BES is fully controlled by the microgrid controller enabling the evaluation of power factor correction, peak shaving/smoothing, and possibly power export. The total system demand, and the available generation and storage will be sized to evaluate the microgrid controller's ability to perform smart load shedding prior and during islanded conditions.

The point-of-interconnection between the utility-grid and the test system is controlled and protected by the microgrid controller and three hardware Schweitzer SEL-751 relays. Internal system fault protection is provided by simulated relays. These units can be remotely actuated by the microgrid controller, and provide sensor values. The simulated relay functions are the following: synchronizing or synchronism-check (ANSI Std. Dev. No. 25), phase instantaneous overcurrent (ANSI Std. Dev. No. 50P), AC inverse time overcurrent (ANSI Std. Dev. No. 51P), undervoltage relay (ANSI Std. Dev. No. 27), and overvoltage relay (ANSI Std. Dev. No. 59). Addition of other relay functions may be a topic for future development.

3.4.2 Fast Load Shedding Capability

The testbed is being evaluated to support fast load shedding capabilities via interfacing with digital I/O on the OPAL-RT. It is likely this expansion will be available before the device integration test. Figure 4 illustrates the components and interfaces provided to enable fast load shedding. The next ICD release will provide further details on this feature.

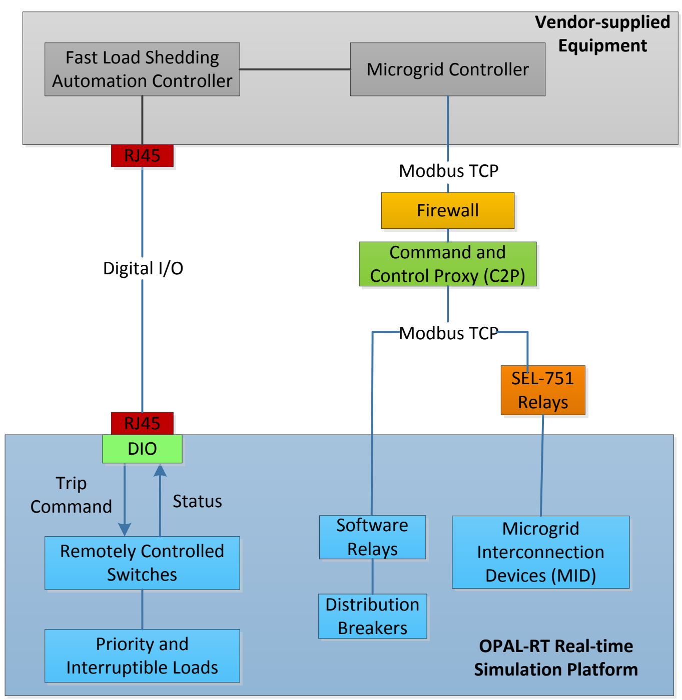

Figure 4. Fast load shedding components and interfaces

3.4.3 Test Plan

3.4.3.1 Baseline Test Plan – generation with no microgrid controller

This rest will run grid-connected test cases with all generation assets available, but with no microgrid controller active.

3.4.3.2 Test Plan Framework

This section shows the framework behind enumerating the possible testing conditions. There are four core components to this list: initial conditions, dispatch objectives, POI dispatch orders, and disturbances. The flow diagram shows a conceptual representation of the test framework combining all possible events without explicitly calling the evaluated action.

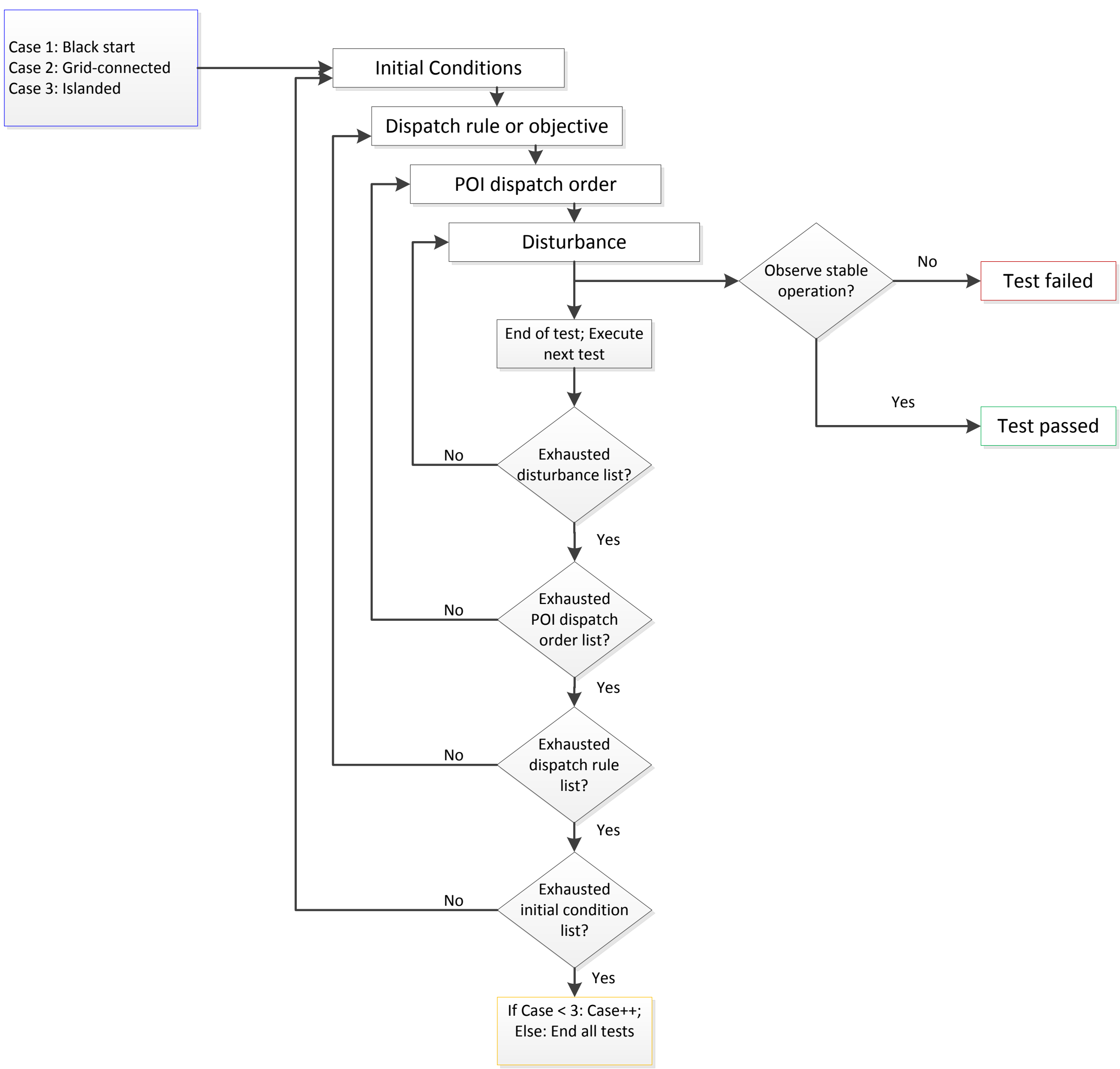

Figure 5. Test plan framework flow diagram

(1) Initial Conditions

At the beginning of each test scenario, a new set of initial conditions shall be loaded. Initial conditions are with respect to the test inputs. The test inputs do not refer to commands or orders issued to the microgrid by another entity. Rather, the test inputs correspond to the current operating status of microgrid assets and the environment (e.g., weather patterns) that the microgrid is operating in. Examples of initial conditions for testing the dispatch function include:

- Renewable energy output (due to solar irradiance) (off, low, medium, high)
- Load demand (low, medium, high)
- Energy storage state-of-charge (min SoC, mid SoC, max SoC)
- POI circuit breaker status (all open, all closed, combination)
- Synchronous generator availability (yes, no)

(2) Dispatch Objectives

The second layer of the testing framework is the dispatch rules and objectives. These are defined by the microgrid owner in accordance with desires of the microgrid owner, microgrid operato, microgrid customer, and DER owner. Additionally, the testing can include co-optimization of these objectives. Examples of dispatch rules and objectives include:

- Minimize real power losses (true, false)
- Minimize emissions (true, false)
- Minimize fuel consumption (true, false)
- Minimize cost of electricity to end user (not included in test plan)
- Minimize critical load-not-served (always true)
- Maximize renewable energy output (always true)

(3) POI Dispatch Orders

The third layer of the testing framework is the point of interconnection (POI) dispatch order from either the distribution system operator (DSO) or the independent system operator (ISO). The POI dispatch orders will need to follow the interconnection agreement between the microgrid and the DSO. This will help dictate which dispatch orders are mandatory and which dispatch orders are optional, but provide some sort of benefit, financial or otherwise. The POI dispatch test for the microgrid controller should follow the specific interconnection requirements for the microgrid to be installed. Examples of POI dispatch orders include:

- Import real power requirement (value)
- Export real power requirement (value)
- Unity power factor at POI (true, false)
- Volt/VAR support
- Frequency regulation
- Spinning reserve provision
- Disconnect request
- Reconnect authorization

(4) Disturbances

The fourth layer of the testing framework details the different types of disturbance the microgrid and power system can experience while performing dispatch functions. The list is not meant to be exhaustive, but it highlights some key disturbances to be investigated. In particular, the fault scenarios will try to generalize what types of faults to inject and where to locate them. Examples of disturbances include:

- Motor start up/large load step up
- Motor trip off/large load drop
- Loss of a single synchronous generator
- Loss of PV
- Significant increase/decrease in PV
- Energy storage loss
- Faults (see below)

(a) Fault Scenarios

There are many fault scenarios that could be encountered, but we will focus on those that may cause: the highest short-circuit fault current contribution, force a swing bus or generator capable of being a swing bus offline, the most reconfigurations, and those that cause conflicting objectives of the microgrid controller. Below is a figure from an unclassified presentation given by Scott Backhaus from Los Alamos National Lab on “Microgrid Protection and Survivability.” We will use this as a base for identifying potential fault types and locations.

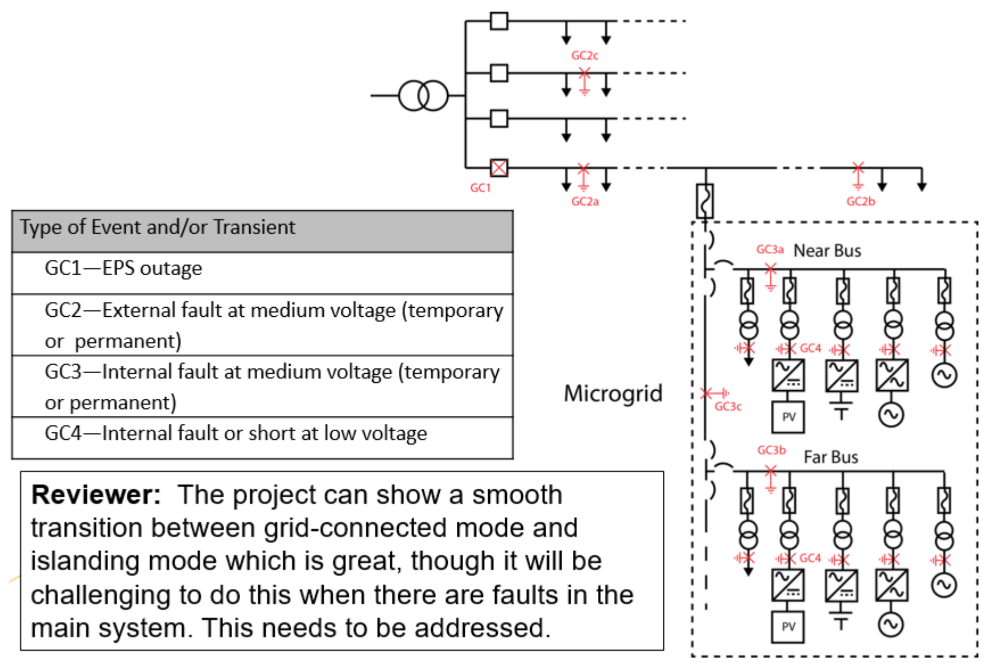

Figure 6. Suggested fault locations. Source: “Microgrid Protection and Survivability,” Los Alamos National Lab.

3.4.4 Test Metrics – Key Performance Parameters (KPP)

3.4.4.1 Tests on Behalf of the Microgrid Customer

KPP #1: Load outage duration
Metric 1: kWh or minutes of service during the outage, averaged for each load category
Option 1a: sum(CLOAD_minutes_served) / (outageTime * # of critical loads) – this treats all loads equally
Option 1b: sum(CLOAD_kWh_served) / (CLOAD_kWh_demand during outage period) – this favors serving the larger loads

KPP #2: Energy cost
Since we will not be using real-time electricity or fuel costs, we will instead have two stand-in metrics for energy cost.
Metric 1: kWh cost; since the simulation does not incorporate electricity costs, use instead:
Stand-in metric 1: Emissions (utility ISO emissions + DER emissions + boiler emissions); this is a stand-in for the energy component of the utility bill
Metric 2: BTU cost; also use stand-in metric 1
Metric 3: kW demand charge; since the simulation does not incorporate electricity costs, use instead:
Stand-in metric 2: Peak 5-minute kW demand

KPP #3: Microgrid survivability / islanded operating duration
Metric 1: Average fuel consumed per minute of outage
Note that KPP #3 and KPP #1 are in conflict with one another. The microgrid controller can burn more fuel to serve more of the loads, or it can shed loads to increase its islanding duration.
This metric will incentivize the microgrid controller to get the PV up and running during islanded mode, maximize the thermal efficiency of the CHP system while islanded, and maintain some reserve energy in the battery during grid-tied operation. As a result of this last item, KPP #3 and KPP #2 metric 3 are potentially in conflict.

3.4.4.2 Test on Behalf of the Microgrid Owner/Operator

The Microgrid Owner / Operator cares about the same KPPs as the DSO and Microgrid Customer.

3.4.4.3 Test on Behalf of the DSO

The DSO cares about KPP #1.
The DSO cares about voltage support, as measured in KPP #6.
The DSO cares about peak demand, as measured in KPP #2 stand-in metric 2, and demand response, as tested with KPP #5.

KPP #4: Compliance with interconnection requirement
Metric 1: PF at POI: 1.0 +/- 0.x
Metric 2: % of time where power at POI export exceeded XYZ kW export

3.4.4.4 Test on Behalf of the ISO and TSO

The TSO cares about regional system-wide frequency regulation. We are not implementing a frequency regulation signal in this testbed.
The TSO cares about peak system-wide demand, as measured in KPP #2 metric 2 and KPP #5.

KPP #5: Ability to meet dispatch order / demand response request
Metric 1: % of sum(time(CMD – TOL < POI Power < CMD + TOL))
(CMD = commanded value from DSO; TOL = tolerance)
Note that KPP #5 and KPP #1 could be in conflict with KPP #1. To meet a large demand response request, the microgrid may need to shed load once generation plus storage are maxed out.

3.4.4.5 Test on Behalf of the DER Owner / Independent Power Producer

DER Owners / Independent Power Producers care about revenue, as measured in KPP #2, stand-in metric 1. Though, they view this metric from the opposite perspective of the end users; they want to maximize energy sales while customers want to minimize energy costs.

KPP #6: Amount of PV production
Metric 1: (Actual kWh produced) / (un-curtailed maximum kWh)
This metric will incentivize the microgrid controller to get the PV up and running during islanded mode.

KPP #7: Operations & Maintenance Costs
Metric 1: fuel costs; instead of fuel costs we'll use KPP #2, stand-in metric 1: DER emissions (but not utility ISO emissions or boiler emissions), since emissions correlate to fuel consumption
Metric 2: count(generator starts)
Metric 3: battery cycles = (kWh charged + kWh discharged) / (battery nameplate capacity) / 2

3.4.4.6 Test on Behalf of Policy Makers / Society / Regulators

KPP #8: Maximum level of PV penetration
Metric 1: worst case(% of test period where the voltage at the load is outside the ANSI limits)

KPP #9: Emissions
Metric 1: same as KPP #2, stand-in metric 1: Emissions (utility ISO emissions + DER emissions + boiler emissions).

3.4.5 Cybersecurity Test Plan

The cybersecurity test plan will focus on testing the microgrid controller's cyber resilience through the following two types of stress tests:

1) Fuzz testing of Modbus TCP parsing; and
2) Stress testing of microgrid controller state-machine logic.

Fuzz testing will explore the robustness of microgrid controller command parsing to determine whether it gracefully rejects traffic, requires a reboot, or bricks. Random data will be sent in the traffic, as well as fuzzing with syntactically correct but unexpected and/or reserved Modbus function codes.

Stress testing of state-machine logic will explore boundary conditions implemented by the microgrid controller. Inappropriate ramp rate requests, conflicting status and metering signals, and setpoint manipulation are examples of stresses that will be implemented.

Key to implementing these tests is the Command and Control Proxy (C2P) being developed by MITLL. The purpose of the C2P is to log all traffic and activities, proxy legitimate control traffic (viewing and modifying as necessary), and capture statistics. Additionally, the C2P will have a module that can send configuration commands and inject them into the packets being sent through the C2P, meaning the traffic between the microgrid controller and microgrid system and components can be altered.

3.5 Interactive Demonstration Prep (Jan / MIT-LL only)

The next Symposium will provide an interactive demo to allow utility engineers to explore the positive impact of microgrid and DER equipment on distribution system operations.

To maximize the likelihood of a successful demonstration, vendors will be down-selected from those who successfully complete the System Integration Test and wish to proceed to the live, interactive Symposium demonstration.

MIT-LL will test out the interactive features before the Symposium and will ask vendors for debugging support only if issues are encountered.

4 Microgrid Controller Interfaces

The microgrid controller under test will need to talk to various interfaces of the device controller and the HIL unit.

4.1 Firewall Description

MITLL utilizes a Firewall (Section 2. Figure 1) to manage network connections between the Vendor Supplied Equipment and the HIL Platform. The Firewall is a SG-4860 pfSense Security Gateway Appliance (website link is below). This firewall is configured to block all connections on the WAN (outside) interface and the LAN (inside) interface. The only allowed connections will be Modbus TCP over Port 502 (Section 4. Figure 1) from the Vendor Supplied Equipment to the HIL Platform. Other ports for Network Address Translation (NAT), Logging capability, Cybersecurity, and other network services (NTP, DNS, etc.) is configured and not covered in the scope of this document. These are MITLL proprietary and will require further vendors integration should the technical need arise. For more information, https://store.pfsense.org/SG-4860/.

4.2 Modbus Device Address Map

All devices on the system communicate via Modbus TCP over ethernet. Figure 2 shows the layout of the controllers and relays referenced in Table 2. Register lists for each device are provided in the device's respective section, below.

Device	IP Address	TCP Port	Feeder Location ID	Notes
Natural Gas Engine Controller	192.168.10.tbd	502	F3	-
Diesel Genset Controller	192.168.10.tbd	502	F1	-
Storage Controller	192.168.10.tbd	502	F2	-
PV Controller	192.168.10.tbd	502	F2	-
SEL-751 Relay 1	192.168.10.tbd	502	F1	F1 POI interconnection relay
SEL-751 Relay 2	192.168.10.tbd	502	F2	F2 POI interconnection relay
SEL-751 Relay 3	192.168.10.tbd	502	F3	F3 POI interconnection relay
CHP Thermal Controller	10.10.45.tbd	502	F3	-
Generic Relay CB101	192.168.10.101	502	F1	-
Generic Relay CB102	192.168.10.102	502	F1	-
Generic Relay CB103	192.168.10.103	502	F1	MCB for Diesel Genset
Generic Relay CB104	192.168.10.104	502	F1	Controls CB for Interruptible Load I1
Generic Relay CB105	192.168.10.105	502	F1	-
Generic Relay CB106	192.168.10.106	502	F1	-
Generic Relay CB107	192.168.10.107	502	F1	Controls CB for Interruptible Load I2
Generic Relay CB108	192.168.10.108	502	F1	Controls tie: F1 and F2 at 13.8 kV
Generic Relay CB109	192.168.10.109	502	F1	Controls tie: F1 and F2 at 480 V

Generic Relay CB110	192.168.10.110	502	F1	-
Generic Relay CB111	192.168.10.111	502	F1	Controls tie: F1 and F2 at 4.16 kV
Generic Relay CB112	192.168.10.112	502	F1	-
Generic Relay CB113	192.168.10.113	502	F1	Controls tie: F1 and F3 at 480 V
Generic Relay CB114	192.168.10.114	502	F1	CB for Priority Load P1, same bus as motor load
Generic Relay CB201	192.168.10.115	502	F2	-
Generic Relay CB202	192.168.10.116	502	F2	-
Generic Relay CB203	192.168.10.117	502	F2	-
Generic Relay CB204	192.168.10.118	502	F2	Controls CB for Priority Load P3
Generic Relay CB205	192.168.10.119	502	F2	Controls CB at BESS (EPC)
Generic Relay CB206	192.168.10.120	502	F2	Controls CB for Interruptible Load I3
Generic Relay CB207	192.168.10.121	502	F2	-
Generic Relay CB208	192.168.10.122	502	F2	Controls CB for Interruptible Load I4
Generic Relay CB209	192.168.10.123	502	F2	-
Generic Relay CB210	192.168.10.124	502	F2	-
Generic Relay CB211	192.168.10.125	502	F2	Controls CB at PV (EPC)
Generic Relay CB212	192.168.10.126	502	F2	Controls CB for Interruptible Load I5
Generic Relay CB213	192.168.10.127	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB214	192.168.10.128	502	F2	-
Generic Relay CB215	192.168.10.129	502	F2	-
Generic Relay CB216	192.168.10.130	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB217	192.168.10.130	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB218	192.168.10.131	502	F2	Controls CB for Priority Load P5
Generic Relay CB219	192.168.10.132	502	F2	Controls CB for Priority Load P2
Generic Relay CB301	192.168.10.133	502	F3	-
Generic Relay CB302	192.168.10.134	502	F3	-
Generic Relay CB303	192.168.10.135	502	F3	MCB for Natural Gas/CHP
Generic Relay CB304	192.168.10.136	502	F3	-
Generic Relay CB305	192.168.10.137	502	F3	-
Generic Relay CB306	192.168.10.138	502	F3	-
Generic Relay CB307	192.168.10.139	502	F3	Controls CB for Priority Load P4
Generic Relay CB308	192.168.10.140	502	F3	Controls CB for Interruptible Load I6
Generic Relay CB309	192.168.10.141	502	F3	Controls CB for Priority Load P6

Table 2: Modbus Device List

5 Control Capabilities

MIT-LL is integrating Woodward EasyGen controllers for the fossil-fueled distributed energy resources (DERs) as well as power electronics controllers from EPC Power for the battery energy storage power converter and solar PV inverter. These various controllers support different control modes, as shown in Table 3. Since the gensets are not co-located, the gensets do not perform automatic load sharing.

	V/f (Isochronous)	P/Q (Real / reactive power command)	Droop (Frequency and voltage based)	Current Source / MPPT
Natural Gas Engine	✓	✓	✓	
Diesel Genset	✓	✓	✓	
Storage	✓	✓		
PV	✓	✓		✓

Table 3: Supported control modes for each distributed energy resource

6 Natural Gas Engine and Diesel Genset

The test feeder microgrid has a 3.5 MVA natural gas-fired combined heat-and-power (CHP) system and a 4 MVA diesel genset. Both have Woodward EasyGen controllers. These controllers support the parameter list shown in Table 5, using identical register numbers. Each generator will have a breaker at the its terminals. The microgrid controller does not need to communicate or control these breakers, which are controlled by the EasyGen controllers.

6.1 Ratings and Characteristics

	4 MVA Diesel Genset	3.5 MVA Natural Gas Engine / CHP
Manufacturer / Model	CAT C175-20	GE/Jenbacher J620
Rating (kVA)	4,000	3,500
Voltage (V)	13,800	13,800
Frequency (Hz)	60	60
Speed (RPM)	1800	1500 (geared to 1800)
Minimum Output Power	100kW	Not specified
Startup Time	<15 sec	5 minutes (to full load)

Table 4: Diesel Genset and Natural Gas Engine ratings and characteristics

6.2 Woodward EasyGen 3500 Controller Interface

Documentation on the Woodward EasyGen 3500 controllers can be located at http://www.woodward.com/easygen3000series.aspx. The EasyGen 3500 has a Modbus RTU over RS485; MIT-LL will provide a protocol converter to make the interface Modbus TCP. This interface is the Lantronix Intellibox 2100 I/O. A subset of the controller's register list is provided below as a basic reference; the EasyGen documentation should be consulted for the complete register list. The Modbus addresses are split between visualization (450001 to 465536) and control/configuration (40001 to 450000) registers. The registers 450001 to 465536 are larger than a 16 bit number, therefore the 4 is removed to be a 16 bit number. Woodward uses the additional number (in this case the "4") to signify the type of Modbus register (in this case "holding register").

The CHP natural gas engine is controlled by a second Woodward EasyGen 3500 controller which uses the same set of Modbus interface registers as the diesel for measurement and control. The most significant difference between the two is the contents of register 3321 at the bottom of Table 6, which needs to be set to "Gas" for the CHP unit to enable the proper startup and shutdown sequences for a natural gas generator as described in the EasyGen 3500 manual. In addition, the load ramp rate of the NG engine is slower than the diesel (~2.5 minutes no load to full load after stable operation at rated speed and voltage is achieved) and the NG engine dynamic response is slower than the diesel.

	Parameter ID < 10000	Parameter ID >= 10000
Modbus Address	40000 + (Par. ID + 1)	400000 + (Par. ID + 1) The 4 is dropped (signifies Modbus register type (4 = holding register))

Parameter	R/W	Reg Number	Unit	Scale	Notes
Protocol ID (5010 Protocol)	R	4 50001	-	-	Value of 5010
Control Mode	R	4 50100	-	-	Auto, Stop, Manual
Gen. Frequency	R	4 50010	Hz	0.01	
Gen. Total Power	R	4 50011	W	-	Scale in 4 50002
Gen. Total Reactive Power	R	4 50012	Var	-	Scale in 4 50002
Gen. Power Factor	R	4 50013	-	0.001	
Gen. Voltage L1-L2	R	4 50014	V	-	Scale in 4 50003
Gen. Voltage L2-L3	R	4 50015	V	-	Scale in 4 50003
Gen. Voltage L3-L1	R	4 50016	V	-	Scale in 4 50003
Gen. Voltage L1-N	R	4 50017	V	-	Scale in 4 50003
Gen. Current L1	R	4 50020	A	-	Scale in 4 50004
Gen. Current L2	R	4 50021	A	-	Scale in 4 50004
Gen. Current L2	R	4 50021	A	-	Scale in 4 50004
Gen. Current L3	R	4 50022	A	-	Scale in 4 50004
Busbar 1: Frequency	R	4 50023	Hz	0.01	
Busbar 1: Voltage L1-L2	R	4 50024	V	-	Scale in 4 50003
Setpoint Frequency	R	4 50029	Hz	-	Multiplier of 1
Setpoint Power Factor	R	4 50030	-	-	Multiplier of 1
Mains Frequency	R	4 50031	Hz	0.01	
Mains Total Power	R	4 50032	W	-	Scale in 4 50002
Mains Total Reactive Power	R	4 50033	Var	-	Scale in 4 50002
Mains Power Factor	R	4 50034	-	0.001	
Mains Voltage L1-L2	R	4 50035	V	-	Scale in 4 50003
Mains Voltage L2-L3	R	4 50036	V	-	Scale in 4 50003
Mains Voltage L3-L1	R	4 50037	V	-	Scale in 4 50003
Mains Voltage L1-N	R	4 50038	V	-	Scale in 4 50003
Mains Current L1	R	4 50041	A	-	Scale in 4 50004

Table 5: This is a subset of visualization registers (protocol 5010 in Woodward manual pages 697-739) for the EasyGen 3500.

Remote control of the Woodward device controller can occur by several methods. Two are highlighted in this document. The first is reading and/or writing to the parameter id's corresponding to the Modbus register. Table 6 is an excerpt of registers from the manual as a helpful reference. The Modbus register for the parameter id is calaculated via the formulas above depending on the value of the parameter id. The parameter id is listed instead of the register to make it easier to search the Woodward manual.

Parameter	Parameter ID	Notes
Password for Serial Interface 2	10430	(0000-9999) password for level 2
Password for Commissioning	10413	Password for commissioning code level
Device Number	1702	(1-32) generator number
Clear Eventlog	1706	Clear event history
f/P Control	12940	Frequency (f) => F, Active Power (P) => T
V/Q Control	12941	Voltage (V) => F, Reactive Power (Q) => T
Control Mode	1735	Mask 000Fh (1 => Auto, 2 => Stop, 4 => Manual)
Start Request in Auto	12120	LM 09.02
Stop Request in Auto	12190	pg 763
Startup in Mode	1795	Mode initiated when powered up
Operation Mode (Auto)	12510	Activated operation mode Automatic
Int. Load Control Setpoint 1	5520	0 to the rated power range (in grid ‖ operation)
Int. Load Control Setpoint 2	5521	0 to the rated power range (in grid ‖ operation)
Frequency Control Droop	5504	(0 to 20%) generator in parallel with other generators. Droop has to be set to the same in all generators (page 339)
Frequency Droop Active	12904	Frequency Droop enabled when T (Logic pg. 808)
Voltage Control Droop	5604	(0 to 20%) generator in parallel with other generators. Droop has to be set to the same in all generators (page 354)
Voltage Droop Active	12905	Voltage Droop enabled when T. (Logic pg. 808)
Gen. Rated Active Power	1752	Rated real power output
Gen. Rated Reactive Power	1758	Rated reactive power output
Droop Tracking	5747	The frequency and voltage setpoint offset is pre-calculated to hold the frequency and voltage, when control is switched into droop.
Load sharing in droop mode	5748	As long the load sharing function is enabled, it is done in droop mode too.
Start/Stop Mode Logic	3321	Set to “Diesel” (default) or “Gas”
Start/Stop	503	Bit 0 to start, Bit 1 to reset, Bit 2 to stop

Table 6: Subset of the Woodward Easygen parameter IDs as a helpful reference. The formula for the Modbus register number depending on the value of the parameter id is in the table above.

The other method for remote control of the generator is controlled using five (5) remote control bits. Voltage and frequency can be changed via the system rated frequency parameter (4762) and the generator rated voltage parameter (4763). More information is provided in the section below.

6.2.1 Remote Control Word 3 (Parameter 505)

The remote control bits are a subset of remote control word 3 (Parameter 505). Remote control of the generator is achieved through Remote Control bits 1 – 4 and 16. The bits and functions are summarized below. See page 673 of user's manual for more information.

1. Remote Control Bit 1 (Bit 0 ID 556) - Start and stop generator.
2. Remote Control Bit 2 (Bit 1 ID 555) - Close and Open generator AC contactor.
3. Remote Control Bit 3 (Bit 2 ID 554) - Frequency droop on and off.
4. Remote Control Bit 4 (Bit 3 ID 553) - Auxiliary fuel enable.
5. Remote Control Bit 16 (Bit 15 ID 541) – Voltage Droop on and off.
6. System Rated Frequency (Parameter 4762) – Generator frequency set point
7. Generator Rated Voltage (Parameter 4763) – Generator voltage set point.

The operation of the generator can be controlled via the front panel command switches or the remote control bits. The remote control bits take precedent over the front panel switches. All remote control bit functionality is active high. When the generator powers up all bits are low, so the generator is off, AC contactor is off, Frequency droop is of or machine is in ISO mode, and the Auxiliary fuel function is disabled. If any of the remote control bits are active high or '1' then the front panel switches which control those functions is ignored.

REMOTE CONTROL BIT 1 (ID 556)

This bit is used to start and stop the generator. When set to '1' this will cause the generator to start without load (output AC contactor is open). When set back to '0' the generator will shut down. If generator is started and running via the front panel start switch then it can be shut down remotely by toggling this bit high '1' and then back low '0'. This state can be detected by looking at the state of the bit ('0') and if the generator is running.

REMOTE CONTROL BIT 2 (ID 555)

This bit is used to close and open the generator output AC contactor. When set to '1' the AC contactor is closed immediately on a dead bus condition, or the synchronizer is enabled and contactor is closed when the generator is synchronized to the bus. When set back to '0' the AC contactor is opened. If the AC contactor was closed via the front panel AC Contactor Closed switch then it can be turned off remotely by toggling the bit high '1' and then low '0'. This state can be detected by looking at the state of the bit ('0') and if the contactor is on.

REMOTE CONTROL BIT 3 (ID 554)

This bit is used to place the generator into frequency droop mode. When set to '1' the frequency droop mode is enabled. When set to '0' the frequency droop mode is disabled and the generator is running in isochronous mode.

REMOTE CONTROL BIT 4 (ID 553)

This bit is used to enable the Auxiliary fuel pump function. The generator is set up to automatically turn on the auxiliary fuel pump when the fuel level dips below 20% and to turn off when fuel level reaches 80%. Setting the bit to '1' will enable this function. Setting the bit to '0' will disable the auxiliary fuel pump function.

REMOTE CONTROL BIT 16 (ID 541)
This bit is used to disable the voltage droop mode. The generator always powers up into voltage droop mode. This bit allows the droop mode to be turned off for test or standalone operation. When set to ‘1’ the voltage droop mode will be disabled – turned off. When set to ‘0’ the voltage droop mode is enabled – default state and normal run condition.

6.2.2 System Rated Frequency (Parameter 4762)
This parameter is set to grid frequency of 60 Hz when run in isochronous mode, and is the power output set point for the generator when run in frequency droop mode.

6.2.3 Generator Rated Voltage (Parameter 4763)
This parameter sets the generator output voltage which is normally set for 208 Volts.

7 CHP Thermal Controller
The CHP thermal controller uses an aggregate thermal load that is derived from actual site measurements of steam in lb/hr. (see Figure 3.). In addition, an aggregate thermal inertia is assumed (related to rate of change of temperature as a function of net heat flow into or out of the site space).

7.1 Thermal Loop Description
The control is done internally and automatically with a single, aggregate measurement of temperature by a PID loop that controls steam supplied by a notional boiler to maintain temperature constant. The CHP heat, taken from an engine exhaust heat exchanger, is used to augment heat provided by the boiler. The microgrid controller is responsible for enabling and disabling CHP heat augmentation based on measured boiler load as well as aggregate temperature. For example, if the heat load is low and CHP heat is enabled, the aggregate temperature will rise above the set point and the microgrid controller will be responsible for “disabling” CHP heat (shunting CHP heat to a radiator). The I/O available to the microgrid controller and the related functions to be performed are:

1. Setting temperature set point in deg F
2. Enabling or disabling CHP heat augmentation (1=on, 0=off)
3. Reading site temperature in deg F
4. Reading boiler load in MBtu/hr

The microgrid controller is responsible for optimizing the timing and duration of CHP heat utilization, as quantified by a CHP figure of merit (see next section.) Factors to consider are the heat demand and the relative cost of electricity produced by the CHP genset vs. the grid. Generally it would be expected that CHP operation will be economical whenever there is a need for heat or when islanded. During periods of grid tied operation when there is no need for the heat recovered from the CHP, operation depends on relative cost of electricity and emissions considerations.

7.2 Controller Interface

Parameter	R/W	Reg Number	Unit	Scale	Notes
TempSetPoint	R/W	2000	degF	1:1	Temp set point value
CHPMode	R/W	2001	-	-	0=disabled 1=enabled
ActualTemp	R	0000	degF	1:1	Actual temp
CHPHeatSupplied	R	0001	MBtu/hr	1:1	CHP heat supplied
BoilerHeatSupplied	R	0002	MBtu/hr	1:1	Boiler heat supplied
NGUsage	R	0003	Nm^3/hr	1:1	NG usage rate
CO2Emission	R	0004	lbm/hr	1:1	CO_2 emissions rate

Table 7: Thermal Controller Modbus register list

7.3 CHP Figure of Merit (FOM)

A simple CHP FOM in dollars per hour that includes the cost of boiler fuel is under consideration. It could be calculated as shown below, based on current pricing for fuel and electricity:

$$FOM = \left(\frac{MBtu}{hr}\right)_{CHP} \times \left(\frac{\$}{MBtu_{Boiler}}\right) - (kW)_{NG} \times \left(\frac{\$}{(kWh)_{NG}} - \frac{\$}{(kWh)_{GRID}}\right) \quad (1)$$

The first term expresses the savings in heat cost that accrue from utilizing CHP heat to offload a boiler (the replacement cost of boiler fuel) and the second term expresses the extra cost incurred from supplying electrical load with more expensive energy represented by the natural gas that fuels the CHP engine. More terms could be added to the expression to capture the emissions benefit of replacing grid power with the natural gas CHP. (Vendor feedback/recommendations are sought.)

8 Solar PV and Energy Storage

EPC's microgrid LC modules accept a wide range DC input from a battery or other DC source, and produce clean AC power to nearly any load, building, or remote facility. The LC module is designed to enable deployment of microgrids, distributed generation, and UPS-style parallel backup. It can preform automatic grid synchronization with commands from the microgrid controller. The modular units allow for larger power ratings to be achieved. The EPC Power website has information about the control commands.

8.1 Ratings

	PV Rating	Energy Storage Rating
AC Power Rating (kW)	5,000	3,000
Storage (kWh)	n/a	1000
Voltage (V)	480	480
Frequency (Hz)	60	60
Maximum Ramp Rate	2.5 MW/min	8 MW/s

Table 8: PV and Energy Storage system ratings

A single, large PV system will be modeled for this symposium. The location of the PV system can be seen on the oneline diagram.

8.2 Power Converter Controller Register List

Both the solar inverter and the battery energy storage power converter are controlled by a MG-LC 12/6 power module controller supplied by EPC Power. EPC's CAN communications specification will be updated with a Modbus register list that has the same capabilities. The CAN manual is available online: http://www.epcpower.com/s/MG_LC12-CAN-Manual-LCCANJD185.pdf

The Modbus specification can be referenced back to the SunSpec Alliance Modus Implementation. This can be found at www.sunspec.org. the goal of the proposed standard is to define a set of common registers values for devices such as but not limited to three-phase and single phase inverters.

Table 9 provides an excerpt of the most relevant registers.

Parameter	R/W	Reg Number	Units	Scale	Notes
Real Power Command	R/W	1	kW	1	(-) discharge; (+) charge
Reactive Power Command	R/W	2	kVAR	1	(+) capacitive; (-) inductive
Modbus Enable	R/W	3	0/1		1 to indicate active Modbus connection.
Fault Status	R/W	4	Bit Field		Starting with LSB Phase A Over Current Phase B Over Current Phase C Over Current DC Link Overvoltage PLL Loss of Sync Vrms out of spec Battery Empty Battery Full
Battery SoC	R/W	5	%	0.01	Battery will start at defined state of charge.
Enable	R/W	6	0/1		Cycle to clear any faults is another button.
MX1	R/W	7	0/1		
MX2	R/W	8	0/1		
Voltage Command	R/W	9	V	0.1	
Frequency Command	R/W	10	Hz	0.01	

Table 9: Relevant registers for EPC power converter controllers

9 SEL-751 Hardware Relays

The HIL system incorporates three SEL-751 relays as hardware-in-the-loop. More information about this relay can be obtained from Schweitzer at https://www.selinc.com/SEL-751/. Table 10 shows an excerpt of the most relevant registers.

9.1 Enabled Relay Settings

The relays are capable of the following protection functions. All settings are based on a moderate inverse time curve (curve B).

- Synchronizing and Synchronism-Check (25)
- Phase instantaneous overcurrent (50P)
- Phase time overcurrent (51P)
- Under voltage (27)
- Overvoltage (59)

9.2 SEL-751 Hardware Relay Register List Excerpt

Parameter	Register Type	Reg Number	Units	Scale	Notes
[registers]		tbd	tbd	tbd	

Table 10: Excerpt of relevant registers for the SEL-751 hardware-in-the-loop relays

10 Simulated Generic Relays

Relays perform the control logic required by the circuit breakers to open or close its contacts. Relays are also used to gather system measurements and status. Each relay in the distribution system has its own tripping current and delay settings. These units can be remotely actuated by the microgrid controller, and provide sensor telemetry values.

10.1 Enabled Generic Relay Settings

The base model was developed to approximate the basic and most executed functions of a commercial relays. The simulated relay functions are the following:

- Synchronizing and Synchronism-Check (ANSI Std. Dev. No. 25)
- Phase instantaneous overcurrent (ANSI Std. Dev. No. 50P)
- Phase time overcurrent (ANSI Std. Dev. No. 51P)
- Under voltage (ANSI Std. Dev. No. 27)
- Overvoltage (ANSI Std. Dev. No. 59)

The relay features four time current characteristics; moderately inverse, inverse, very inverse, and extremely inverse. The degree of inverseness of each TCC is mapped to SEL751 manual, page 4.23 - table 4.17.

Futhermore, the relay includes multiple relay setting groups for protection during different configurations. Currently, only two predefined parameters groups are enabled to establish its active protection settings. Access to change/select the protection group is given through Modbus, see register list in Table 11.

10.2 Simulated Generic Relay

All the simulated generic relays use the same register list. The relays interface via Modbus TCP as slave devices, with the register list shown in Table 11.

Note that addresses 0-24 are input registers, and 2001-2003 are output holding registers.

Parameter	R/W	Reg Number	Units	Scale	Notes
IA PEAK CURRENT	R	0	A	1	
IA ANGLE	R	1	deg	0.1	
IB PEAK CURRENT	R	2	A	1	
IB ANGLE	R	3	deg	0.1	
IC PEAK CURRENT	R	4	A	1	
IC ANGLE	R	5	deg	0.1	
IA RMS CURRENT	R	6	A	1	
IB RMS CURRENT	R	7	A	1	
IC RMS CURRENT	R	8	A	1	
VA RMS VOLTAGE	R	9	V	1	
VB RMS VOLTAGE	R	10	V	1	
VC RMS VOLTAGE	R	11	V	1	
VA PEAK VOLTAGE	R	12	V_{LN}	1	
VA ANGLE	R	13	deg	0.1	
VB PEAK VOLTAGE	R	14	V_{LN}	1	
VB ANGLE	R	15	deg	0.1	
VC PEAK VOLTAGE	R	16	V_{LN}	1	
VC ANGLE	R	17	deg	0.1	
P	R	18	kW	1	
Q	R	19	kVAR	1	
S	R	20	kVA	1	
PF	R	21	-	0.01	
FREQ	R	22	Hz	0.1	
TRIP STATUS LO	R	23	-	-	
TRIP STATUS HI	R	24	-	-	
LOGIC COMMAND	R/W	2001	-	-	Register Raw Value = 0; Close CB and activate relay protection functions Register Raw Value = 1; Close CB and do not activate relay protection functions Register Raw Value = 2; Open CB
RESET DATA	R/W	2002	-	-	Register Value = 1; TRIP RESET
GROUP SETTING SELECTION	R/W	2003	-	-	Register Value = 0; group setting #1 (*default*, and will be used for gridtied settings) Register Value = 1; group setting #2 (will be used for islanded settings) Transition delay = 0 seconds

Table 11: Register list for simulated generic relays

11 Cables

Cables between electrical components on the distribution network are modeld as PI section impedances with length and number of parallel sets of conductors. IEEE Red Book Table 4A-7 gives values for 60 Hz impedance for three-phase copper cable circuits, in approximate ohms per 1000ft. Parallel sets and actual length are used to scale the value. Note that some lines are as long as ½ to 1 mile, meaning that voltage control and power flow optimization may be prudent functions to implement.

12 Loads

12.1 Load Priorities

Load are assigned a priority, as described in Table 12, and is indicated with an abbreviation on the one-line diagram.

Priority	Abbreviation	Objective
Interruptible	**I**	Loads which can be disconnected without penalties during outages.
Priority	**P**	Loads which should be served during outage periods, provided there is sufficient generation or storage.
Critical	**C**	Loads which should always be served. There will be no maximum interruption time criterion; however, we will likely calculate SAIDI as a metric.

Table 12: Load priorities

Label	Feeder	VRMSLL	kVA Demand	Description
C1	F1	480	1200	--
C2	F1	480	1500	--
C3	F2	480	1000	--
C4	F2	480	1000	--
C5	F3	480	1000	--
C6	F3	480	800	--
P1	F1	480	1200	Includes a 200 hp motor with full voltage start
P2	F2	480	1000	--
P3	F2	480	1000	--
P4	F3	480	600	--
P5	F2	480	700	--
P6	F3	480	1000	Includes a 200 hp motor with full voltage start
I1	F1	480	300	--
I2	F1	208	250	--

I3	F2	208	300	--
I4	F2	480	600	--
I5	F2	480	400	--
I6	F3	480	600	--

Table 13: Load demand size

12.2 Major Loads

The largest loads are 200 hp induction line-started motors, with 6x nominal startup current. The location of these loads is shown on the one-line diagram in Figure 2.

The microgrid will be fully off-line at the beginning of the test. The microgrid controller should blackstart and and configure the microgrid to meet the demonstration objectives.

13 Points of Contact

Technical lead; diesel, and CHP: Ed Corbett, 781-981-7762, ecorbett@ll.mit.edu

Logistics, NDAs, equipment loans, Symposium planning:
Liz Dalli, 781-981-5442, dalli@ll.mit.edu

Relays, test feeder, and test sequences: Reynaldo Salcedo, 781-981-0610, rsalcedo@ll.mit.edu

Storage and PV: Kendall Nowocin, 781-981-2704, kendall.nowocin@ll.mit.edu

Remote Communication and IT: Raajiv Rekha, 781-981-1378, raajiv.rekha@ll.mit.edu

Cyber: Joe Cooley, 781-981-2588, cooley@mit.edu

Program management: Erik Limpaecher, 781-981-4006, elimpaecher@ll.mit.edu