2017 Microgrid Controller Procurement Information Packet Volume 1.6

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Revision History

Rev	Date	Description	Editor
1.0	6/19/2017	Initial revision based on 2016 MIT informational packet 2.0	PKoralewicz
1.1	7/7/2017	3.3 - clarified IT infrastructure description Fixed CB numbering in Table 22 Added Appendix C with short description of repository contents Modified scalings in generator, pv, ess inverters modbus maps. Added synchrocheck measurements to generator, pv, ess, cb inverters	PKoralewicz
1.2	8/13/2017	Defined ESS battery capacities in Table 20 Added internal fault status bits to inverter/generator simulated modbus signal map Example test sequence chapter added - 5.3.3 Added remaining KPP prices to Table 6 Added HMI access details Removed substation feeder modbus interfaces Added example power references calculation for POI according to DMS commands - 10.1 Added generators fule consumption curves - Figure 9 and Figure 10 Added power quality analysers chapter 18	PKoralewicz
1.3	8/29/2017	Added information about DNS and NTP servers Changed initial SoC of ESS batteries to 80% Increased tolerance for KPP4 Relay modbus map – added 81U and 81O fault status bits	PKoralewicz

1.4	9/4/2017	KPP2 – changed to fuel usage only KPP2 – reduced costs of generators operation by 50% to allow their economincal usage KPP7 – removed solar measure and replaced with all maintenance and operation factors KPP1 prices reduced proportionally by factor of 3 – most prices that follow KPP1max followed proportionally – just a cosmetical change Increased grid interconnection contract limits by 20% Decreased P31 and P32 by factor of 4 Fixed modbus map addresses in DMS interface Removed CHP startup time limitation	PKoralewicz
1.5	10/23/2017	Updated PHIL IP address lists in chapter 8.1 Updated energy price scaling in DMS interface - Table 12 Added BDP250 operating instruction notes Updated GOOSE load shed map in Table 25	PKoralewicz
1.6	10/28/2017	Updated woodward modbus map - Table 16 & 11.3.2 Added BDP250 notes - 14.3 Added AE100TX settings for restart and ride-through - 13.3 Added description of fault locations - 5.3.2.7	

List of Acronyms

CHIL	Controller hardware-in-the-loop
CHP	Combined heat and power
DER	Distributed energy resources
DMS	Distribution management system
ESIF	Energy Systems Integration Facility
HIL	Hardware in the Loop
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
KPP	Key performance parameter
MGC	Microgird Controller
MGCP	Microgird Controller Procurement
NREL	National Renewable Energy Laboratory
NWTC	National Wind Technology Center
PHIL	Power hardware-in-the-loop
PQVF	Power, voltage and frequency values
PV	Photovoltaic
RTAC	Real-time Automation Controller
RTS	Real-time simulator
SLG	Single Line to Ground
SOC	Stat of Charge
TCP	Transmission Control Protocol

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1 Introduction

Microgrids can be used to decrease customer energy costs while increasing resiliency to electric power outages on the main grid, but often the design and construction of these systems are too expensive to implement. A microgrid controller stands out as an example of a component that has widely varying capabilities, levels of maturity, and project-specific integration costs among different vendors. Incompatibility among components and vendors is another concern. The National Renewable Energy Laboratory (NREL) supports the research and development of various microgrids throughout the United States. Energy systems integration research is a main focus of NREL's Energy Systems Integration Facility (ESIF) (see Appendix A). Thus, the idea was born for a fair evaluation and comparison of performance among commercially available microgird controllers.

1.1 Microgrid Controller Procurement Overview

NREL is conducting a dual-stage (letter of interest and request for proposals) competitive procurement for microgrid control technology wherein up to five respondents will compete on state-of-the-art test beds at the ESIF between June and December 2017. The top performer will have the opportunity for its microgrid controller to be purchased and made part of a permanent microgrid research test bed available to NREL researchers and other users of the ESIF. NREL intends to purchase the winning microgrid controller from the top performer, subject to successful negotiations on a fair and reasonable purchase price. Also, NREL will provide at its own expense the necessary engineering and communications expertise required to successfully procure and install the winning microgrid controller at the ESIF.

1.2 Document Scope

This document serves as a manual for competitors who are going to be evaluated during the procurement process. It outlines the microgrid hardware-in-the-loop test bed implemented in the ESIF as well as its interfaces, the test procedures, and the procurement evaluation criteria. It focuses only on the technical aspects of the test bed and planned evaluation testing. This information packet will be updated as the design is refined, and it must not be distributed.

2 Microgrid System Description

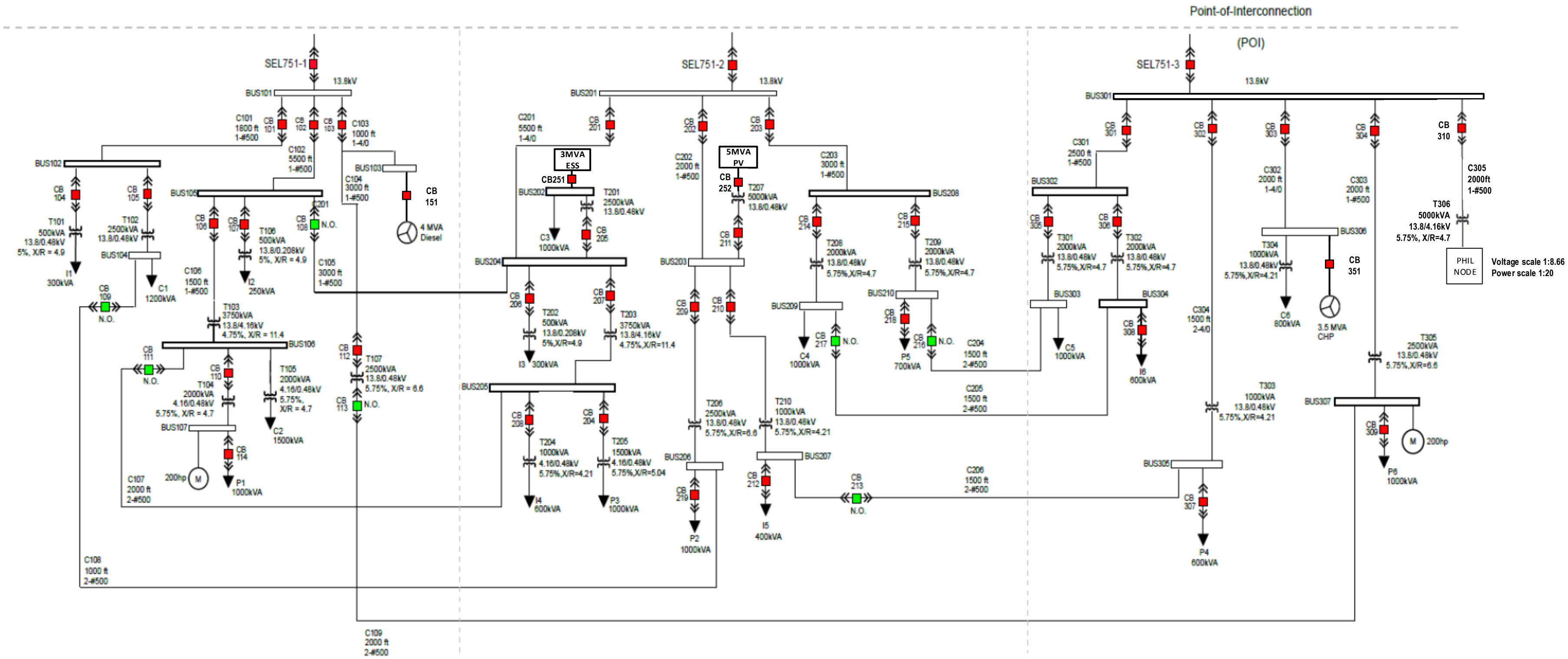

Figure 1. Modified one-line diagram of the Banshee test feeder

NREL will leverage the Massachusetts Institute of Technology Lincoln Laboratory power system model, Banshee, which was developed and verified during the Microgrid & DER Controller Symposium held in February, 2017. NREL will adapt this power system model to the existing power test bed and expend resources to further improve it. Upon completion of the procurement process, improvements to Banshee will be posted to the open-source repository [1] and sent to the Massachusetts Institute of Technology Lincoln Laboratory.

Table 1. Feeder Parameters

Utility Contribution	3PH [A]	X/R	SLG [A]	X/R
Feeder 1	**14,580**	**4.6**	**10,570**	**0.9**
Feeder 2	**15,730**	**7.9**	**10,240**	**2.6**
Feeder 3	**14,580**	**4.6**	**10,570**	**0.9**

2.1 Banshee System

The system modeled for this evaluation consists of three substations supplying an electric power network based on a real-world location and presents challenges that will be found in a community microgrid. The overall electrical demand of the feeders ranges from 5 MW–14 MW for the minimum and maximum loads, 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. Eighteen loads are 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 (sensitive equipment labs, etc.). Priority loads are buildings that, ideally, are always served but might be disconnected during contingencies or islanding because of a lack of generation. Interruptible loads are buildings that are not necessarily required to be served during contingencies or islanded conditions. Further, there are two large induction motors of 200 hp, which is one of the largest sizes recommended by the 2011 National Electrical Code for full voltage start-up. Each of the system loads is modeled as a time-varying dynamic load based on electrical demand profiles extracted from smart metering equipment. The generation assets consist of a 4,000-kVA diesel generator and a 3,500-kVA natural gas-fired combined-heat-and-power (CHP) system. Both units operate at a 13.8-kV nominal voltage and are simulated in a real-time simulator. During the simulations, both generators will be entirely controlled by the microgrid controllers without operator intervention unless the alarms deem necessary. The system also includes a 5,000-kW photovoltaic (PV) system and a 2,000-kVA battery energy storage system. The PV system will be supplied with a varying irradiance profile matching a defined test sequence. The battery energy storage system will be fully controlled by the microgrid controller, enabling the evaluation of power factor correction, peak shaving/smoothing, and possibly power export. The total system demand, available generation, and storage will be sized to evaluate the ability of the microgrid's controller to perform smart load shedding prior to and during islanded conditions. Internal system fault protection will be provided by multiple relays that can be remotely monitored and actuated by the microgrid controller. The relay protection functions are as follows: synchronizing or synchronism check (ANSI Standard Device Number 25), phase instantaneous overcurrent (ANSI 50P), AC inverse time overcurrent (ANSI 51P), undervoltage relay (ANSI 27), and overvoltage relay (ANSI 59). Some relays will be able to transmit their status using International Electrotechnical Commission (IEC) 61850 GOOSE messages, and some will be capable of fast load shedding, also using IEC 61850 GOOSE; these will allow for an operation cycle that has a delay of less than 10 ms, which is required during unplanned islanding.

The only modification to the original Banshee model is an extension of the third feeder with the PHIL node. This means that, to achieve the best performance score, a microgrid controller will always have control of not only the Banshee assets but also the PHIL node's assets.

2.2 Power-Hardware-in-the-Loop Node

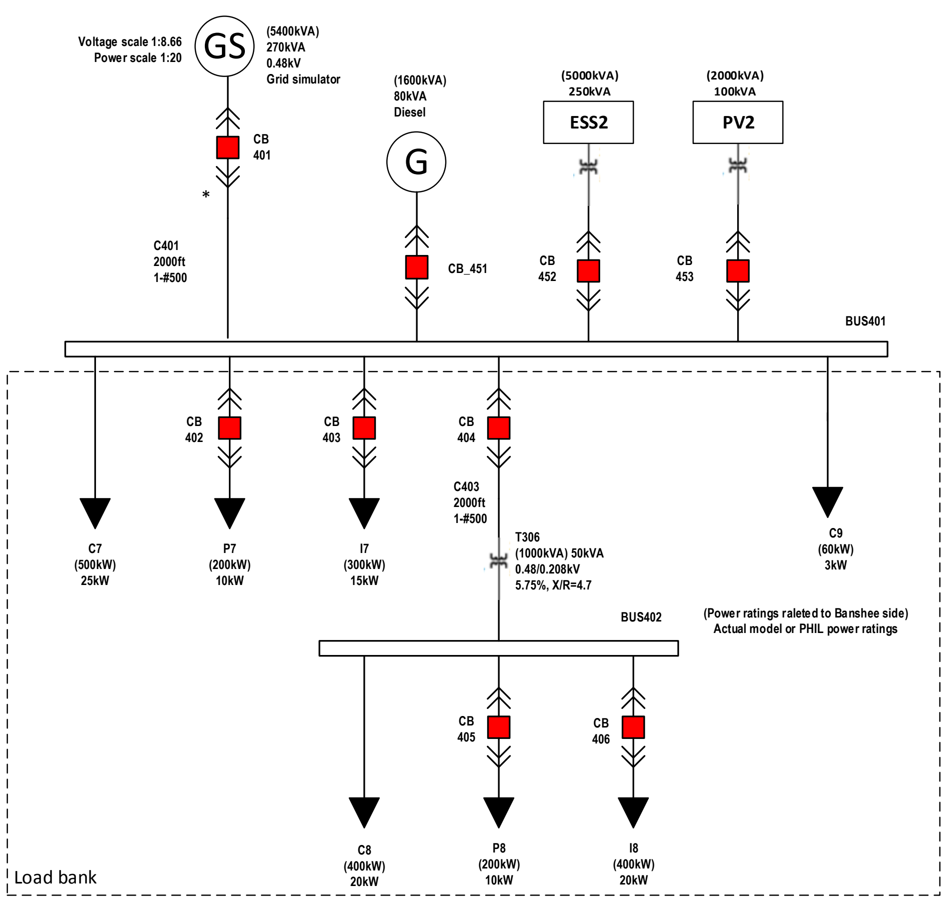

Figure 2. Single-line diagram of the PHIL node

The PHIL experiment will demonstrate the microgrid controller's operation and its ability to integrate with real power devices. The PHIL node will extend the Banshee model at the third feeder by adding additional assets that can be controlled by the microgrid controller with minor modification of Banshee architecture. The circuit shown on Figure 2 corresponds to the actual implementation in the ESIF laboratory. It will consist of two busses, a circuit breaker relay, and various controllable smart distributed energy resource assets. The PV inverter (100 kW) is coupled with a programmable DC source, allowing for various irradiance profiles. The grid-forming battery energy storage system inverter (250 kW) and generator (80-kW Onan) form the grid during islanded operation, but they follow the grid during grid-connected operation; thus, it is important to test real asset integration with the microgrid controller in both states as well as during transition periods. Multiple categorized loads will also be available. Some can be controlled using the same type of generic circuit breakers as in the Banchee model. These will be implemented in the laboratory using a single load bank controlled by generic relays modeled in a real-time simulator.

To enable the PHIL experiment, an Ametek 270-kW, bidirectional, programmable AC grid simulator is used. The grid simulator will follow the voltage calculated within the real-time simulator model, which enables real-time interaction with the entire Banshee power system. All PHIL devices will have additional limits on current and voltage to allow for safe testing in the ESIF laboartory environment.

A real-time simulator model of the PHIL node has also been developed to allow for the execution of the first stage of testing, wherein the microgird controller interfaces only with the real-time simulated model of the microgirid—the controller-hardware-in-the-loop (CHIL) stage.

3 Test Bed Overview

3.1 Controller-Hardware-in-the-Loop

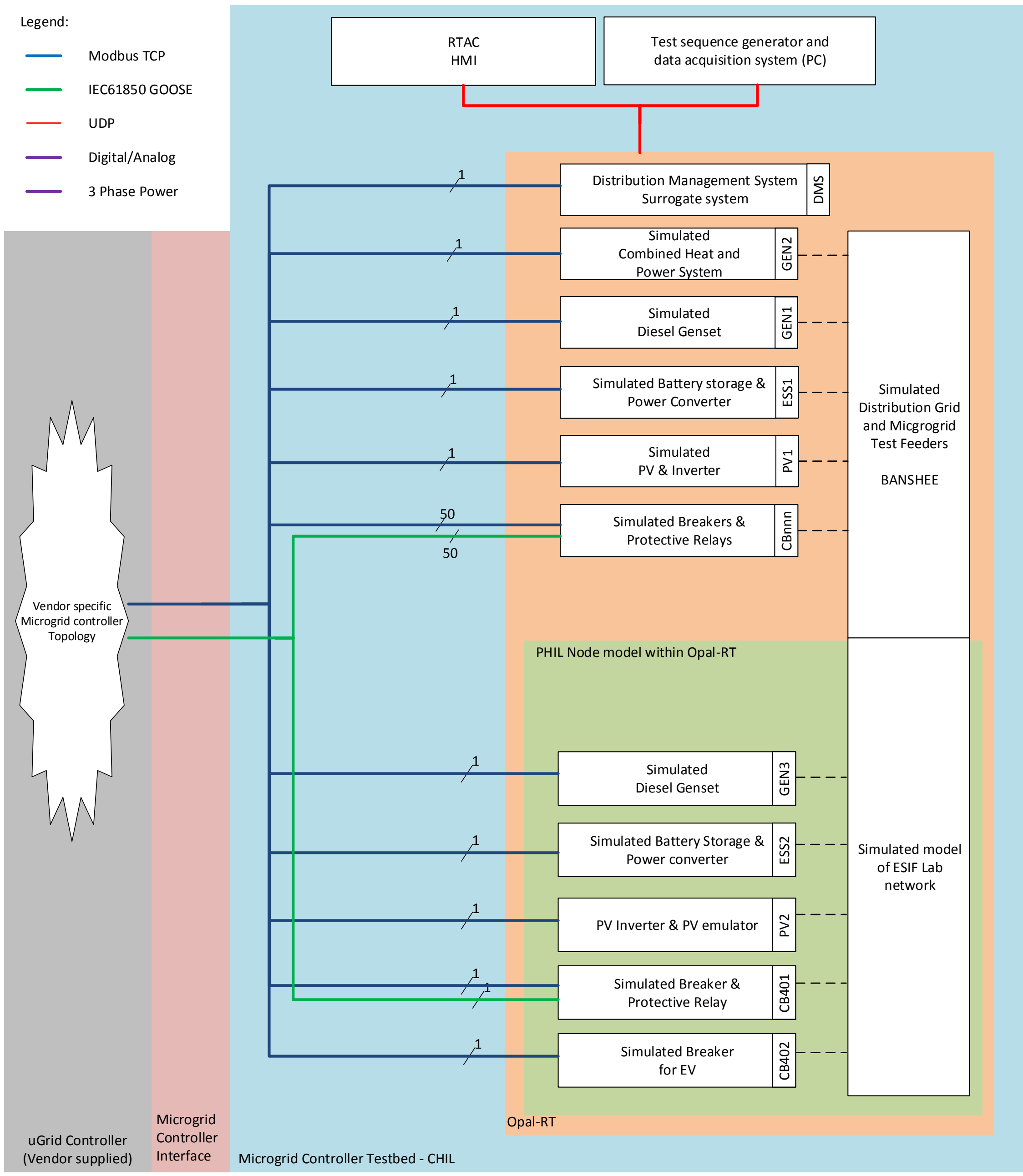

Figure 3. Diagram of the microgrid controller test bed for the CHIL phase

The first stage of the evaluation will be performed in a strictly CHIL manner, wherein the microgrid controller will interface only with the Opal-RT real-time simulation of the microgrid. Using this approach, controllers can be evaluated without needing to set up the ESIF laboratory for each test. This allows for a more flexible working environment and also avoids risks to safety associated with real power testing.

Figure 3 shows a block diagram of the CHIL test bed. The Microgird controller interface consists of multiple Modbus TCP and IEC 61850 GOOSE connections to all simulated devices as shown in the diagram and described in details further in this document.

3.2 Power-Hardware-in-the-Loop

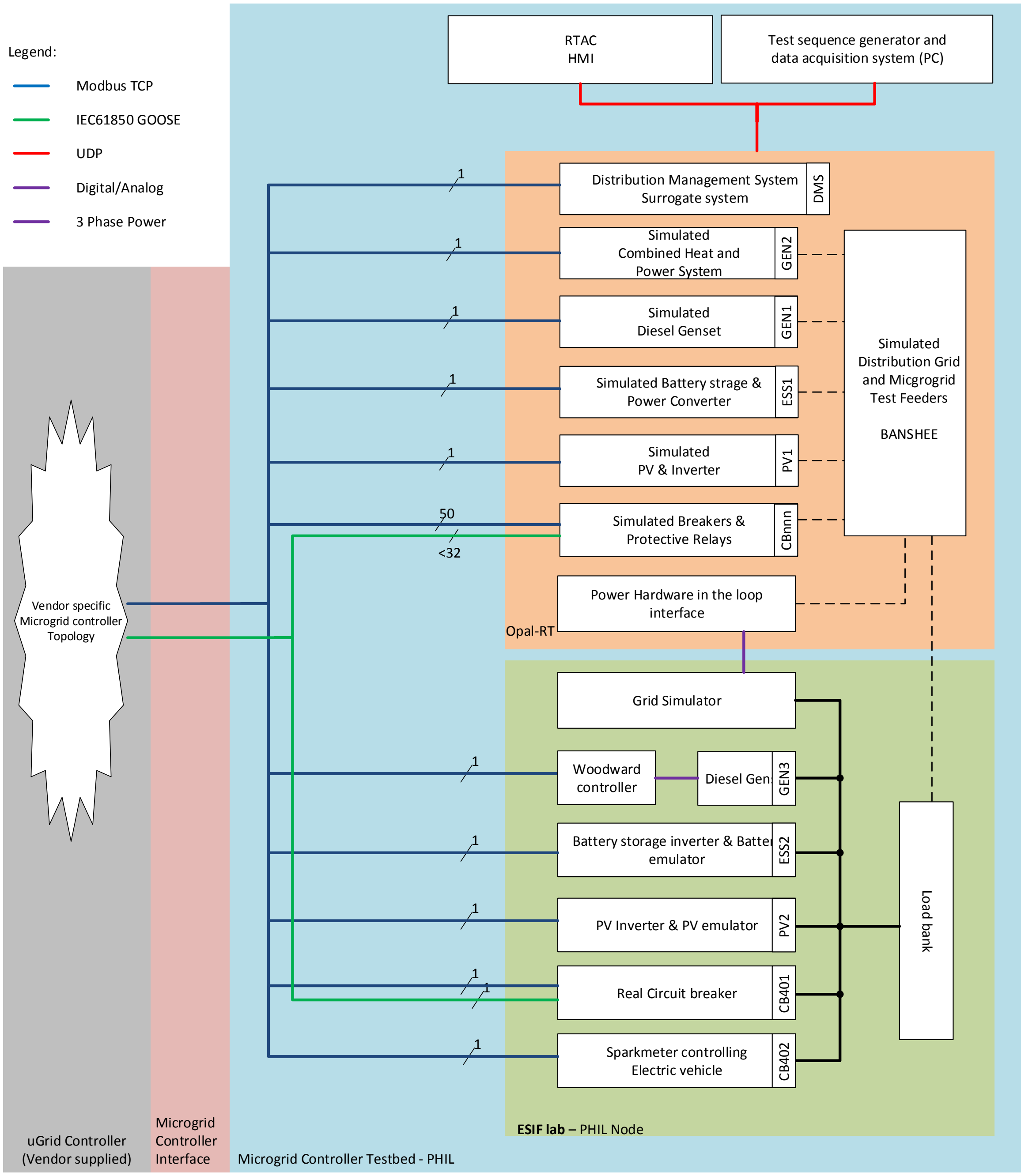

Figure 4. Diagram of the microgrid controller test bed for the PHIL phase

The power-hardware-in-the-loop test bed is designed for the second stage of the evaluation and will be accessible for teams that show the best results in operation against the CHIL test bed. Figure 4 shows a block diagram of the PHIL test bed.

In this phase, a fraction of a microgrid system, called the PHIL node, will be extracted from the simulation and replaced with the real hardware setup in the ESIF's Power Systems Integration Laboratory. The hardware test bed equipment includes:

- Microgrid controller—provided by participant
- Real-time power simulation (real-time simulator)—Opal-RT and Mathworks (MATLAB and Simulink)
- Test management interface and display—SEL RTAC
- Ametek 270-kW, bidirectional, programmable AC source/sink
- AE 100-kW solar inverter with Magna-Power programmable DC source (solar array emulator)
- Loadtec 250-kW resistor-inductor-capacitor load bank
- Caterpillar 250-kW battery inverter with a an AeroVironment AV-900, bidirectional, programmable DC source/sink (battery emulator)
- Cummins Onan 80-kW diesel generator set (genset) with a Woodward paralleling controller
- ABB SACE Emax 2 protective relay with circuit breaker.

3.3 Information Technology Infrastructure

All devices in the experiment will be connected to the NREL-managed switch, including all test bed equipment and contestant devices. To decouple these systems, multiple subnets are configured, as shown in Table 2.

Table 2. Test Bed Subnets

Subnet description	Subnet address range	Number of ports	Remote access
Test bed subnet	10.79.112.nnn	>30 8 – for active vendor	No
Vendor #1 subnet	10.79.181.nnn	8	Yes – vendor #1
Vendor #2 subnet	10.79.182.nnn	8	Yes – vendor #2
Vendor #3 subnet	10.79.183.nnn	8	Yes – vendor #3

Vendor #4 subnet	10.79.184.nnn	8	Yes – vendor #4
Vendor #5 subnet	10.79.185.nnn	8	Yes – vendor #5

Vendor's devices can be connected to ther subnets (10.79.18x.nnn – where "x" equals to vendor number) during entire procurement execution period (active periods and breaks). They will be assigned remote VPN access using RSA tokens only to their assigned subnet. Each vendor can connect up to eight devices to this subnet. IP addresses allocations are up to vendors since their subnets will not be used by other parties. Configuration of devices connected to this subnet should be as following:

- IP address: 10.79.18x.nnn
- Mask: 255.255.255.0
- Gateway: 10.79.18x.1

The test bed subnet (10.79.112.nnn) connects all of the testbed devices (Opal-RT, Inverters, Generator, CB, HMI, NREL researchers laptops). Vendors will be allowed to connect physically to the tesbed subnet (10.79.112.nnn) *only during their active test period at NREL* – see schedules in chapter 4.1. They will be allowed up to 8 ports in switch and IP's of vendor devices should be configured with following parameters:

- IP address: 10.79.112.200 – 10.79.112.255
- Mask: 255.255.255.0
- Gateway: 10.79.112.1

After the active execution window by given vendor the Ethernet cables connected to tesbed subnet will be physically disconnected, marked and reconnected the next time the team comes back to NREL. At the same time connections to vendor's subnet will remain connected thus allowing teams to remotely connect to their equipment while the equipment will be physically disconnected from tesbed subnet. This will allow vendors remote configuration, firmware updates, etc during the periods when they are not at NREL.

It is also foreseen that active team connected to testbed at NREL can be supported by remote conneceted team members. For that purpose it will be useful to provide dual Ethernet port devices (PC, Laptops, Controllers). One Ethernet port can be permanently connected to vendor's subnet (10.79.18x.nnn) while the other will be connected to testbed sybnet (10.79.112.nnn) during active period only.

Each port should be connected by device with single NIC card. Up to 5 MAC addresses are allowed at every port. Exceeding this number will block switch port until NREL IT department clears the issue thus it is highly advisable so that vendors don't bring their own Ethernet switches.

Following DNS (Domain Name System) servers are available:

10.20.6.10
10.20.7.10

3.3.1 Time server – NTP

Following NTP (Network Time Protocol) servers are available for teams for time synchronization purpose:

time.nrel.gov (10.20.5.102)

time2.nrel.gov (10.20.5.101)

3.4 Cyber-Physical Test Bed

In the cyber-physical test bed, NREL will implement a bump-in-the-wire security approach to test the cybersecurity posture of the microgrid controller technologies. The bump-in-the-wire approach protects the mixture of legacy and modern technologies, diminishes reliance on vendors to implement proprietary security controls, and places greater emphasis on securing the entire network against threats. NREL will use a secure distribution grid management test bed with Supervisory Control and Data Acquisition systems, grid simulation, and distributed energy resources on a routed and firewalled network with five purpose-built cybersecurity technologies (three intrusion-detection tools and two in-line blocking tools). Two sets of cyber penetration tests during a 12-month period demonstrated that the cybersecurity architecture employed in this approach can protect critical infrastructure from insider and external cyber threats. For more information on the test bed, see [2].

4 Microgrid Controller Integration and Testing

4.1 Schedules

Table 3. Microgrid Controller Procurement Schedule for the First Stage of Evaluation: CHIL

	Selected Respondent 1 Controller Hardware in the Loop (CHIL) + Cybersecurity									
June 19 Receive Instructional Packet	8 Weeks		1 Week @ NREL		4 weeks		1 Week @ NREL		NREL Evaluation	
	Prep Period		CHIL Integration		CHIL Break		CHIL Evaluation			70% CHIL
	19-Jun	11-Aug	15-Aug	18-Aug	21-Aug	15-Sep	18-Sep	21-Sep	22-Sep	30% CYBER
	Cybersecurity Review and Evaluation = 30% Score									

	Selected Respondent 2 Controller Hardware in the Loop (CHIL) + Cybersecurity									
June 26 Receive Instructional Packet	8 Weeks		1 Week @ NREL		4 weeks		1 Week @ NREL		NREL Evaluation	
	Prep Period		CHIL Integration		CHIL Break		CHIL Evaluation			70% CHIL
	26-Jun	18-Aug	22-Aug	25-Aug	28-Aug	22-Sep	25-Sep	28-Sep	29-Sep	30% CYBER
	Cybersecurity Review and Evaluation = 30% Score									

	Selected Respondent 3 Controller Hardware in the Loop (CHIL) + Cybersecurity									
July 3 Receive Instructional Packet	8 Weeks		1 Week @ NREL		4 weeks		1 Week @ NREL		NREL Evaluation	
	Prep Period		CHIL Integration		CHIL Break		CHIL Evaluation			70% CHIL
	3-Jul	25-Aug	29-Aug	1-Sep	4-Sep	29-Sep	2-Oct	5-Oct	6-Oct	30% CYBER
	Cybersecurity Review and Evaluation = 30% Score									

Selected Respondent 4 Controller Hardware in the Loop (CHIL) + Cybersecurity						
July 10 Receive Compeititon Packet	8 Weeks	1 Week @ NREL	4 weeks	1 Week @ NREL	NREL Evaluation	
	Prep Period 10-Jul 1-Sep	CHIL Integration 5-Sep 8-Sep	CHIL Break 11-Sep 6-Oct	CHIL Evaluation 9-Oct 12-Oct	13-Oct	70% CHIL 30% CYBER
	Cybersecurity Review and Evaluation = 30% Score					

Selected Respondent 5 Controller Hardware in the Loop (CHIL) + Cybersecurity						
July 17 Receive Instructional Packet	8 Weeks	1 Week @ NREL	4 weeks	1 Week @ NREL	NREL Evaluation	
	Prep Period 17-Jul 8-Sep	CHIL Integration 12-Sep 15-Sep	CHIL Break 18-Sep 13-Oct	CHIL Evaluation 16-Oct 19-Oct	20-Oct	70% CHIL 30% CYBER
	Cybersecurity Review and Evaluation = 30% Score					

Table 4. Microgrid Controller Procurement Schedule for the Second Stage of Evaluation: PHIL

Offeror 1 Power Hardware in the Loop (PHIL) + Cyber-Physical Test beds				
23-Oct	1 Week @ NREL	4 weeks	1 Week @ NREL	Cost Proposals Due
Offeror 1 Receives RFP	PHIL Integration 23-Oct 27-Oct	PHIL Break 30-Oct 27-Nov	PHIL Evaluation 27-Nov 1-Dec	8-Dec
Cyber-Physical test bed evaluation takes place during the 4-week Offeror Programming/ break period.				

Offeror 2 Power Hardware in the Loop (PHIL) + Cyber-Physical Test beds				
23-Oct	1 Week @ NREL	4 weeks	1 Week @ NREL	Cost Proposals Due
Offeror 2 Receives RFP	PHIL Integration 30-Oct 3-Nov	PHIL Break 6-Nov 1-Dec	PHIL Evaluation 4-Dec 8-Dec	15-Dec
Cyber-Physical test bed evaluation takes place during the 4-week Offeror Programming/ break period.				

4.1.1 Preparation Period (8 Weeks)

All contestants will have the same amount of time to prepare for the first integration tests at NREL. Contestants will have 8 weeks between receiving this instructional packet and beginning to conduct the first integration tests. During this time frame, the instruction packet should be studied carefully to minimize troubleshooting on-site. Teams should also begin preparing their strategy for optimizing their microgird controller. Finally, the microgrid controller should be shipped to NREL's main campus. Allow 1–2 weeks to ship your controller because of necessary NREL procedures.

4.1.2 Controller-Hardware-in-the-Loop Integration Period (1 Week/4 Days at NREL)

Teams will arrive at NREL on Tuesday morning. During the first integration period, the microgrid controller will be interfaced to the CHIL test bed (see Section 3.1). During the first week, communication protocols will be integrated and the first set of unit tests will be executed to ensure that microgrid controller is able to communicate and control all assets.

4.1.3 Controller-Hardware-in-the-Loop Break (4 Weeks)

The CHIL break allows contestants to summarize their experiences during the first week of on-site testing and implement necessary changes, if required. During this time, contestants will be able to remotely connect to their controllers; however, their controllers will be disconnected from the test bed.

4.1.4 Controller-Hardware-in-the-Loop Evaluation (1 Week/4 Days)

Teams will return to NREL for the final week of testing on Tuesday. During the first 4 days, the teams are allowed to fine-tune their controllers.

4.1.5 Controller-Hardware-in-the-Loop Evaluation (1 Day at NREL)

The last day of the CHIL evaluation week is reserved for NREL researchers to evaluate the model. At this point, contestants are not allowed to modify any settings or operate their controller. Contestants are welcome to stay and witness the evaluation process of the test sequence.

4.1.6 Break Between Controller Hardware-in-the-Loop and Power-Hardware-in-the-Loop (1–5 Weeks)

Contestants will have a break after their evaluation; this will allow NREL to process the results and allow other teams to complete their evaluations. The break will take from 1–5 weeks. If contestants qualify for the second stage of testing, they will be notified at least 1 week prior to their intended start of the PHIL integration period.

4.1.7 Power-Hardware-in-the-Loop Integration (1 Week at NREL)

Teams will arrive at NREL on Tuesday morning. During this period, the microgrid test bed will be converted to the PHIL test bed (see Section 3.2). The PHIL node will no longer exist in the Opal-RT model; the microgrid controller will be reconfigured to communicate with real devices instead. During this period, contestants will be able to use all the devices available, including the possibility of testing with power.

4.1.8 Power-Hardware-in-the-Loop Break (4 Weeks)

The PHIL break allows contestants to summarize their experiences during the first week of on-site testing and implement necessary changes, if required. During this time, contestants will be able to remotely connect to their controllers; however, their controllers will be disconnected from the test bed.

4.1.9 Power-Hardware-in-the-Loop Evaluation (1 Week/4 Days at NREL)

Teams will return to NREL for the final week of testing on Tuesday. During the first 4 days, the teams are allowed to fine-tune their controllers before the final evaluation by NREL on Friday.

4.1.10 Power-Hardware-in-the-Loop Evaluation (1 Day at NREL)

The last day of the PHIL evaluation week is reserved for NREL researchers to evaluate the performance of the microgrid controller. At this point, contestants are not allowed to modify any settings or operate their controller. Contestants are welcome to stay and witness the evaluation process of the test sequence.

4.2 Support from NREL Researchers

During some periods, NREL vendors will be supported by ESIF operations personnel. Additionally, researchers can support integration with basic assistance (not extensive troubleshooting), which is limited to no more than 8 h/week that the team is on-site.

5 Performance Evaluation Test Plan

The goal of the performance evaluation is to equally measure the results so that they can be compared among vendors. This section describes the test procedures and fair evaluation strategy.

5.1 Microgrid Controller Functions Under Test

The microgrid controller needs to be able to complete multiple functions to perform well. Being able to perform as many functions as possible as shown in the list below should translate to a better overall score. Some functions are more critical because these will contribute to a bigger fraction of overall score, whereas others will contribute to a minor fraction of the score. Vendor teams, based on knowledge of key performance parameters (KPP) (see Section 5.4), need to judge which functions to implement and how to optimize their algorithms.

Functions under test:

- Ability to prioritize loads based on their categories and serve loads according to available resources
- Ability to limit power transmitted internally on transformers and cables
- Circuit breakers:
    - Control of 52x circuit breakers
    - Control of Modbus or IEC 61850.
- Energy storage system:
    - Control of two times the energy storage systems
    - Control in isochronous/droop mode to form the grid
    - Control in grid-following mode
    - Optimize and forecast state of charge
    - Use reactive power injection to control the voltage.
- Gensets:
    - Control of three times the generator systems
    - Control in isochronous/droop mode to form the grid
    - Control in grid-following mode
    - Use reactive power injection to control the voltage
    - Control the CHP
    - Ability to limit power within specified range
- PV systems:
    - Control of two times the PV systems

    - Control in grid-following mode
    - Curtail PV production when needed
    - Control reactive power injection to control the voltage.
- Following limitations in interconnection agreement:
    - Limit the point of common coupling active and reactive power limits
    - Limit the point of common coupling power factor
    - Control the frequency and voltage in islanded mode
    - Plan economic operation assuming actual energy and fuel prices
    - Follow active and reactive power dispatch/demand commands from the distribution management system (DMS)
    - Disconnect from the bulk grid when planned
    - Reconnect to the bulk grid seamlessly
    - Disconnect from the grid seamlessly when a fault occurs in the bulk grid
    - Perform fast load shedding during seamless transitions
    - Provide volt/kVAr support from the microgrid to support the bulk grid following a droop
    - Provide Hz/kW support from the microgrid to support the bulk grid following a droop.
    -

5.2 Microgird Controller Evaluation Procedure

When using the test bed, the following steps must be taken. (Some steps are required only for the PHIL experiments, so they can be avoided during the CHIL stage.)

5.2.1 Integration Tests by Vendor

During the integration testing of the microgrid challenge, most of the following steps can be executed by vendors themselves:

1. Vendor configures CB files and initial states.
2. Vendor teams can temporarily modify the model.
3. The system model compilation is loaded onto Opal-RT for the target and run.
4. (PHIL only.) The vendor teams configure the parameters of the following devices: BDP-250, AE-100, Woodward controller.
5. (PHIL only.) ESIF operations personnel evaluate all equipment prior to energization and allows the test execution.

6. (PHIL only.) Initialize all devices needed in the test case, and switch to remote control if necessary.
7. The microgrid controller can be connected to all controllable assets at any time.
8. The teams can use the unit test sequence generator to run example test cases with their controller and store the results for further analysis (see Section 7). Multiple tests can be executed during this period.
9. (PHIL only.) Shut down all devices before stopping the simulation.
10. Stop the simulation model.

5.2.2 Final Evaluation Procedure

The following procedure will be used during the final evaluation of the CHIL and PHIL stages:

1. Vendor configures CB files and initial states and delivers them to NREL staff.
2. Vendor teams are not allowed to modify the Opal-RT model, which is exactly the same for all teams.
3. (PHIL only.) Prior to the test, vendor teams configure the parameters of the following devices: BDP 250, AE-100, Woodward controller.
4. The microgrid controller needs to be started, but it can no longer be controlled by the vendor team.
5. NREL staff loads the model onto the Opal-RT target and runs it.
6. "DMS:Microgrid controller start" = FALSE. After running the model, the distribution management system (DMS) commands the microgrid controller to disable. In this state, the microgrid controller is allowed to initiate connections to controllable assets, but it is prohibited from running any of these devices.
7. (PHIL only.) An NREL ESIF operation electrician needs to evaluate all power equipment prior to energization and allow the test execution.
8. (PHIL only.) Configure all devices to their initial state.
9. The official evaluation test sequence will be loaded by NREL staff; this will not be published to the teams prior to test execution.
10. After starting the test sequence, "DMS:Microgrid controller start" changes to TRUE, and the data acquisition begins to record data for further evaluation.
11. The test sequence takes from 40–100 minutes. Various test cases will be executed as described in Section 5.3.
12. After the sequence has ended, data acquisition stops, and "DMS:Microgrid controller start" changes to FALSE
13. (PHIL only.) All devices need to be shut down before stopping the Opal-RT.
14. Stop the simulation.

15. Results are stored by the NREL team for further processing. These will be published to vendors after all of the teams are evaluated.

5.3 Test Sequence

The test sequence will last 100 minutes, and it will consist of various disturbances that will occur for instances of times unknown to the contestants. A rough scenario is known so that vendors can forecast approximate pricing and solar insulation; see example in Figure 5. The case can be compared to, e.g., a winter morning in a location with a high solar penetration. Before sunrise, loads are increasing while PV does not produce any power yet, causing a short spike in energy price (P31). After sunrise, for which the time can be estimated with good precision, PV production ramps up quickly, causing the price to drop. The energy price varies during the test sequence between the limits of P31 and P32 as defined in this document (see Section 5.4).

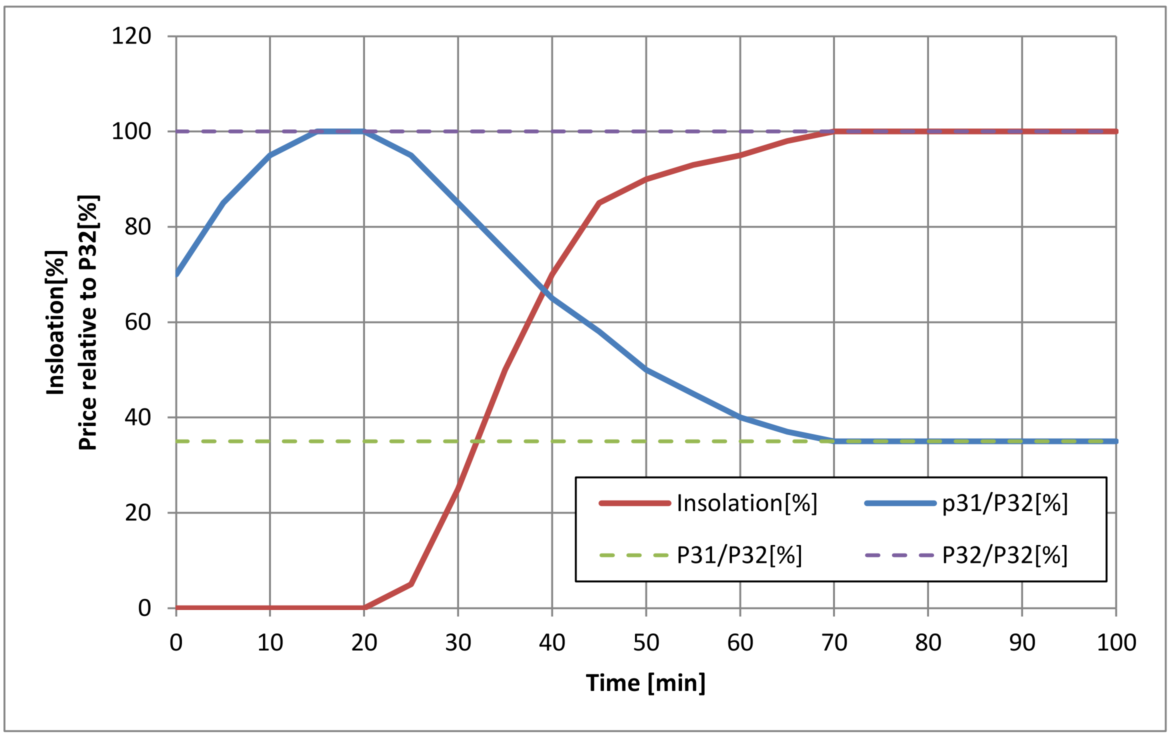

Figure 5. Pricing and insolation variation during test sequence

The test starts in grid-connected mode, but during the test the microgrid will need to disconnect and reconnect at least twice.

5.3.1 Initial Conditions

Before starting the test sequence, the model will be in the following condition:

1. The bulk grid is up and available at the point of common coupling.

2. “DMS:Microgrid controller start” = FALSE will transition to TRUE, indicating the start of test sequence.
3. All distributed energy resources are disabled: GEN1-3, ESS1-2, PV1-2.
4. The state of charge of both ESS1 and ESS2 is 80%
5. PV irradiation is 0% before sunrise.
6. The energy price is set to 70% of maximum ($p_{31} = 0.7 * P_{32}$)
7. Loads are at their nominal values.
8. When starting the model, circuit breakers will be initialized to the condition defined in the XLS configuration files (see. 15.5). The microgrid controller is allowed to operate them before starting the test sequence, if needed.
9. (PHIL only.) CB401 (ABB) is closed.
10. (PHIL only.) The grid simulator is enabled, and all connected devices are able to sense the grid.

5.3.2 Disturbances

The microgrid and power system might experience multiple types of disturbances while performing dispatch functions. Below are some key disturbances to be investigated. The fault scenarios will try to generalize which types of faults to inject and where to locate them.

5.3.2.1 Solar Generation Variation

A rough insulation pattern is known because the sunrise time can be determined based on the test sequence start signal. Additionally, the forecast for the test sequence period of time is sunshine with few clouds, causing a short-term generation drop that will need to be handled by microgrid controller.

5.3.2.2 Motor Start-Up

A large load step can be expected during grid-connected and islanded mode.

5.3.2.3 Motor Trip-Off

A large step-down can be expected during grid-connected and islanded mode.

5.3.2.4 Loss of a Singe Synchronous Generator

An unexpended single generator trip event caused by an internal fault will be tested during grid-connected and islanded operation. The microgrid controller will need to reset and restart the generator.

5.3.2.5 Loss of Energy Storage

A loss of energy storage caused by an internal fault will be tested during grid-connected and islanded operation. The microgrid controller will need to reset and restart the generator.

5.3.2.6 Loss of a Single PV Generator

A loss of single PV generator will be tested during grid-connected and islanded operation.

5.3.2.7 Line Faults

Many fault scenarios could be encountered, but we will focus on those that might, for example, cause the highest short-circuit fault current contribution; force a swing bus or generator capable of being a swing bus offline; cause the most reconfigurations; and cause conflicting objectives of the microgrid controller. Figure 6 shows fault locations implemented in the model.

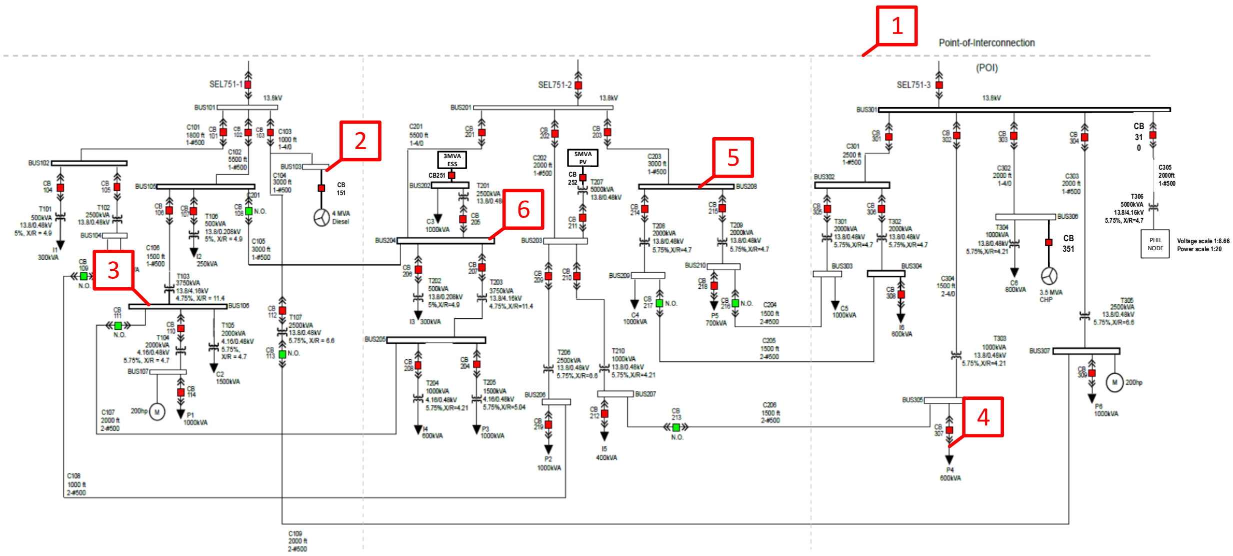

Figure 6. Fault locations.

5.3.3 Example test sequence

Example test sequence is available for training of microgrid controllers, it is shown on Figure 7.

Top plot shows irradiance and price profiles during test sequence.

Second plot shows grid frequency in PU system (60Hz, 115kVrms). Few frequency and voltage events are modeled during test sequence to allow evaluation of controllers ability to support the grid in these cases,

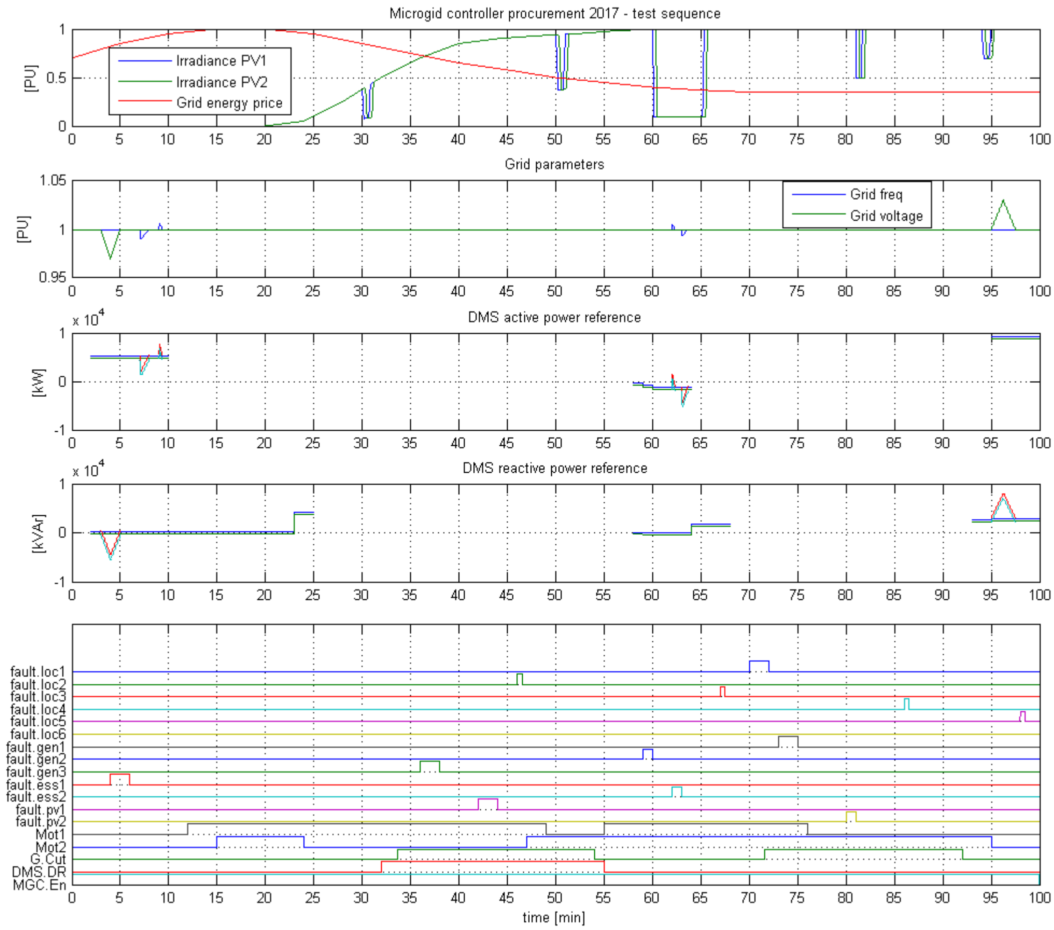

Figure 7 Example test sequence available for integration testing

Third plot shows active power outlines for DMS commands – these are better visible on Figure 8. Green and blue plots correspond to dispatch command from DMS with 5% tolerance. Red and cyan plots are limits for kW/Hz demand response action during frequency excursion with 10% tolerance. Active power will be evaluated only in the period of time when limits are visible on plot:

For DMS dispatch/demand commands – only wjen DMS kW ena bit is on

For DMS kW/Hz droop only when grid frequency is different than nominal

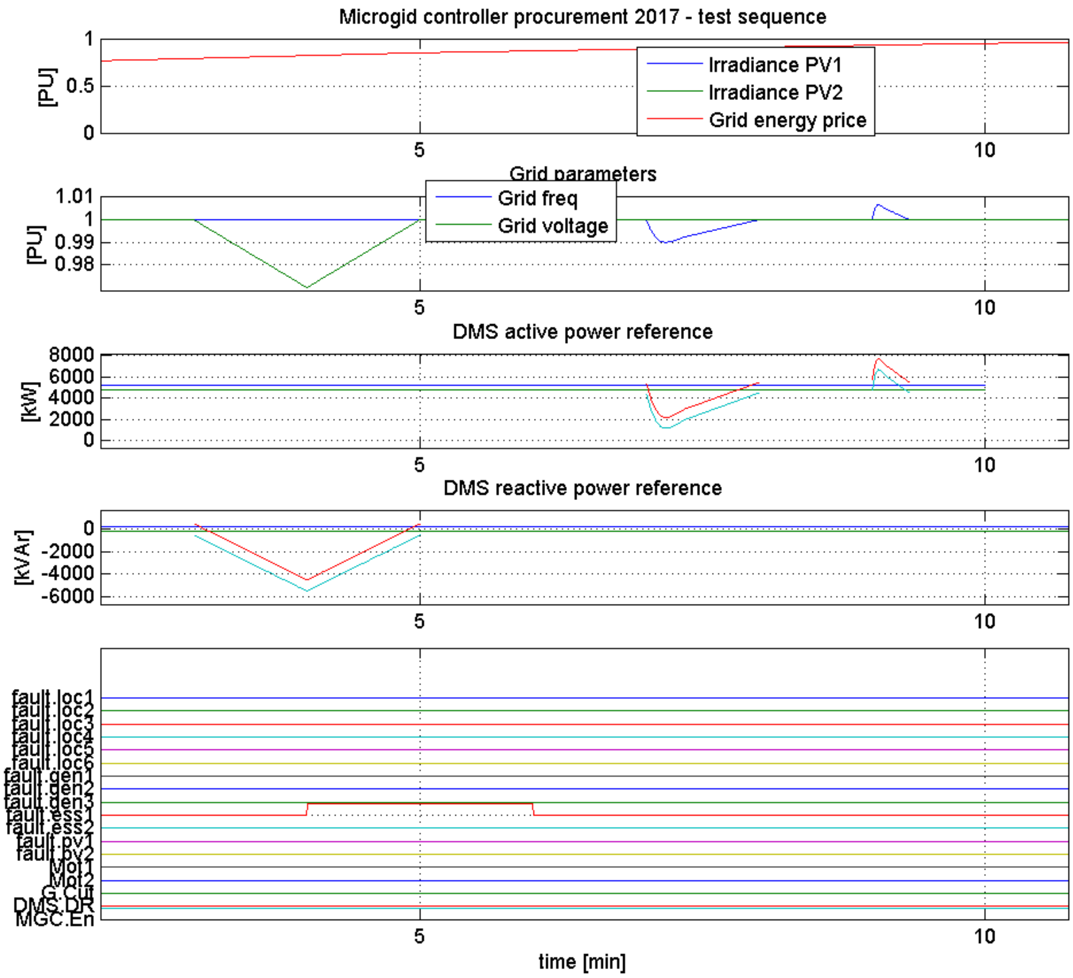

Figure 8 Example test sequence available for integration testing – zoom to DMS active / reactive power request

Fourth plot shows reactive power outlines for DMS commands – these are better visible on Figure 8. Green and blue plots correspond to PF command from DMS with 5% tolerance. For PF request different than 1.0 it is assumed on above plot that measured active power at POI equals 8MW. Red and cyan plots are limits for kVAR/Volt demand response action during frequency excursion with 10% accuracy. Reactive power will be evaluated only in the period of time when limits are visible on plot:

For PF commands – only wjen DMS PF Enable bit is on

For DMS kVAR/Volt droop only when grid voltage is different than nominal

Last plot shows remaining digital stimuli in the system:

fault.locN {N=1..5} – high signal indicates 3-phase to ground fault fault at one of 5 locations:

N=1 – Fault at grid side of Feeder breakers – it should trip feeder breakres and cause unintended islanding. It is succeded by period of grid outage.

N=2...5 – Locations not defined yet

fault.genN {N=1..3} – generator outage – during his period given generator will be disconnected

fault.essN {N=1..2} – ESS outage – during this period given ESS will be disconnected and internal fault will be issued on the inverter which needs to be reset prior to reconnection

fault.pvN {N=1..2} – PV outage – during this period given PV will be disconnected and internal fault will be issued on the inverter which needs to be reset prior to reconnection

motN {N=1..2} – high level indicates motor running

G.cut – indicates that grid is not available at POI – substation feeders are open

DMS.DR – indicates a request from DMS to island the microgird

MGC.En – indicates that sequence is active – refer to 5.2 for sequence of operation

Final evaluation test sequence will be similar in many aspects to given test sequence. Various changes to order of execution and events execution periods will be done and not released before final evaluation.

5.4 Test Metrics: Key Performance Parameters

Each controller will be tested using the same test setup and the same test sequence to challenge its algorithms. Data collected during tests will be postprocessed, and KPPs will be evaluated. Using KPPs, each aspect of the microgrid controller's operation can be compared individually; however, to achieve an overall comparison of controller performance, each KPP is converted into a single unit: U.S. dollars. The conversions used to obtain dollar values are hypothetical and are in place to incorporate the relevant weighting of various KPPs. The weighting of each KPP is based on the publicly available results from two focus groups held in November 2016. To define the impact of each KPP on overall score, the prices will be based on guidelines outlined in

Table 5. KPP1max is the maximum hypothetical income that can be generated during the test sequence assuming all loads will be served 100% of the time.

Table 5. Guidelines for Price Design

KPP	Guidelines
KPP1 Resiliency and reliability	Critical load share in KPP1max – 48% Priority load share in KPP1max – 35% Interruptible loads share in KPP1max – 17% All critical loads outage for 15% of time will cause 40% * KPP1max loss All priority loads outage for 15% of time will cause 10% * KPP1max loss All interruptible loads outage for 25% of time will cause 5% * KPP1max loss
KPP2 Onsite fuel usage	Gen1 – diesel running full power during entire sequence – 20% of KPP1max cost Gen2 – natural gas running full power during entire sequence – 17.5% KPP1max cost Gen2 – heat contribution from Gen 2 at full power – 3.5% KPP1max income Gen3 – diesel running full power during entire sequence – 8% KPP1max cost PV – free
KPP3 Interconnect contract	If no on-site generation was active cost of energy bought from grid would estimate to 49% of KPP1 max (excluding penalties for power above limit)
KPP4 DSO commands	- meeting DMS dispatch&demand command adds 2%*KPP1max premium - following kW/Hz during frequency events adds 3%*KPP1 max premium - meeting DMS power factor command adds 2%*KPP1max premium - following kVAr/Volt during voltage events adds 3%*KPP1 max premium - failure to disconnect from grid during planned disconnect 2%KPP1_max penalty - failure to disconnect from grid after unplanned islanding (fault) – 2% KPP1_max penalty
KPP5 Power quality	- 10x voltage events as shown on Figure 12 at all 23x voltage busses will cause a penalty of 3%*KPP1max - 10x frequency events as shown on Figure 13 at all 23x voltage busses will cause a penalty of 3%*KPP1max

	Maximum penalty from KPP5 is limited to 5%*KPP1max in final score.
KPP6 Survivability	1%*KPP1 max loss when both ESS is kept below 40% SoC in grid connected mode for 20 minutes.
KPP7 Operation and maintenance	Various aspects causing aging of microgrid are monitored. Maximum penalty equals 15%*KPP1max

The final result will be a sum of all revenues and expenditures that the hypothetical microgrid operator operator would encounter. These include only operational costs and revenue and do not include capital capital investment costs that would have been incurred to install the microgrid. Price parameters are are shown in Table 6. (These are subject of change, but they will be communicated immediately with the with the teams and will follow the guidelines in

Table 5 as closely as possible.)

Table 6. Scoring Rubric: Summary of Key Performance Parameters (as a Bill for the Microgrid Operator)

KPP description	Measured units	Unit price	KPP8 sum
KPP1 – Resiliency and reliability The ability to supply power to customers will be measured by calculating the energy delivered to each category of load. The prices of energy will differ considerably. Additionally, a penalty will be added for any outage on critical loads.			KPP1 $
Energy delivered to Critical loads (E_C)	E_C [kWh]	$P_{11} = 0.33[\$/\text{kWh}]$	$E_C{*}P_{11}$ [$]
Energy delivered to Priority loads (E_P)	E_P [kWh]	$P_{12} = 0.30[\$/\text{kWh}]]$	$E_P{*}P_{12}$ [$]
Energy delivered to Interruptible loads (E_I)	E_I [kWh]	$P_{13} = 0.267[\$/\text{kWh}]$	$E_I{*}P_{13}$ [$]
Energy Critical loads Outage (ECO)	E_{CO} [kWh]	$P_{15} = 1.50\ [\$/\text{kWh}]$	$-E_{CO}{*}P_{15}$ [$]
Energy Priority loads Outage (ECO)	E_{PO} [kWh]	$P_{16} = 0.67\ [\$/\text{kWh}]$	$-E_{CO}{*}P_{16}$ [$]
Energy left in ESS at the end of the sequence compared to initial state of charge	E_{ESS} [kWh]	$P_{17} = 0.33\ [\$/\text{kWh}]$	$E_{ESS}{*}P_{17}$[$]
KPP2 – Onsite Fuel Usage This KPP measures the use of fuels by generators within microgrid. See fuel usage curves in 11.1. .			KPP2 $
Used Fuel - Diesel (F_D)	F_D [gal]	$P_{21} = 3.10\ [\$/\text{gal}]$	$-F_D{*}P_{21}$ [$]
Used Fuel- Natural Gas (F_{NG})	F_{NG} [m^3]	$P_{22} = 0.87\ [\$/m^3]$	$-F_{NG}{*}P_{22}$[$]
Energy delivered as Heat (E_H)	E_H [MBtu]	$P_{23} = 24.50[\$/\text{MBtu}]$	$E_H{*}P_{23}$ [$]
KPP3 - Interconnection contract The microgrid is connected to bulk grid based on a contract defining limits of power that can be imported or exported. The instantaneous price of energy p_{31} during the test sequence will vary between $(P_{31}\ P_{32})$ to allow controller to benefit from its variability (e.g. dispatching energy from battery). The price of sold energy and energy over limit will be always proportional to variable p_{31}. Coefficients will penalize use of energy over limit, (e.g. k_{BO} =3, k_{EO} =0.5). Unit prices shown in table below (P_E, P_{EO}, P_B, P_{BO}) reflects average $/kWh price of energy during test execution.			KPP3 $

Limits: $P_{ImportLim}$ = 12000kW $P_{ExportLim}$ = 6000kW P_{VArLim} = 5000kVAr P_{31} = 0.087[$/kWh] and P_{32} = 0.250[$/kWh]			
Exported Energy (E_E)	E_E [kWh]	P_E [$/kWh] ($p_{31}$)	E_E*P_E [$]
Exported Energy Over limit (E_{E0})	E_{E0} [kWh]	P_{EO} [$/kWh] ($p_{32}$=$p_{31}$*$k_{EO}$)	E_{EO}*P_{EO} [$]
Energy imported (bought from grid. E_B)	E_B [kWh]	P_B [$/kWh] ($p_{31}$)	-E_B*P_B[$]
Energy imported over limit (bought from grid, E_{BO})	E_{BO} [kWh]	P_{BO} [$/kWh] ($p_{33}$=$p_{31}$*$k_{BO}$)	-E_{BO}*P_{BO} [$]
Reactive power over limit penalty	E_{RP} [kVArh]	P_{33} = 0.125 [$/kVArh]	-E_{RP} *P_{33}[$]
KPP4 – Distribution Service Operator (DMS) commands The microgrid controller can allow additional revenue by providing services to DMS on request. Some request are necessary, thus violating them causes a penalty. The envelope for all DMS power control commands evaluation is following: - Tolerance = 5% of $P_{ImportLim}$ (DP, DM, PF) - Tolerance = 10% of $P_{ImportLim}$ (VV, HkW) - Settling time = 0.5s Microgrid controller does have 30 second after "DMS Disconnect Request" signal becomes active to initiate islanding action and disconnect from grid. Grid will collapse after 60 seconds from the same signal. Violation of disconnection command will be measured during period when microgrid shall be disconnected and either of mains feeders (CB100, CB200, CB300) is not opened. Microgrid controller does have 60 second to reconnect after before mentioned signal becomes inactive.			KPP4 $
Meeting dispatch command premium (DP). Power from Grid->MG	T_{DP} min	P_{41} = 7.87 [$/min]	T_{DP} * P_{41} [$]

Meeting demand command premium (DM). Power from MG->Grid	T_{DM} min	P_{41} = 7.87 [$/min]	T_{DM} * P_{41} [$]
Following Volt/Var support premium (VV)	T_{VV} min	P_{43} = 49.85 [$/min]	T_{VV} * P_{43} [$]
Following Demand response curve (Freq/kW, FkW)	T_{FkW} min	P_{44} = 96.69 [$/min]	T_{FKW} * P_{44} [$]
Violating planned disconnect request (DR)	T_{DR} min	P_{45} = 6.50 [$/min]	-T_{DR} * P_{45}[$]
Meeting power factor request (PF)	T_{PF} min	P_{46} = 3.73 [$/min]	-T_{PF} * P_{46} [$]
Unplanned disconnect – failure to disconnect (UD)	T_{UD} min	P_{47} = 8.80 [$/min]	-T_{UD}*P_{47} [$]
KPP5 - Power quality Voltage on each bus will be monitored for violation of IEEE 1547a-2014 – every violation exceeding clearing time defined in Table 1 of the standard will be counted. Frequency on grid forming device will be monitored for violation of IEEE 1547a-2014. Every violation exceeding clearing time defined in Table 2 of the standard will be counted. See chapter 18 for details.			KPP5 $
Power quality voltage violations (PQV)	N_{PQV} [PU*sek]	P_{51} =4.88 [$/(sek*PU)]	-N_{PQV}*P_{51} [$]
Power quality frequency violations (PQF)	N_{PQF} [Hz*sek]	P_{52}=*0.49* [$/(sek*Hz)]	-N_{PQF}*P_{52} [$]
KPP6 - Microgrid survivability To assure a certain level of microgrid survivability it is important to keep the level of battery charge at least at certain level (40%) during grid connected operation. Keeping battery state of charge below this level during grid connected conditions will cause penalty.			KPP6 $
Time below requested state of charge (T_{BRS})	T_{BRS} min	P_{61} = *1.87* [$/min]	-T_{BRS}* P_{61}[$/min]
KPP7 - Operation and maintenance Costs of operating and maintaining the microgrid's distributed energy resources and devices will depend on how these assets are managed. The cost places a value on degradation from use of devices (causing them to fail quicker, e.g. circuit			KPP7 $

breakers use, running over current (thermal) limits).			
Number of Diesel starts (N_D)	N_D	P_{71} = 10 00[$]	-N_D*P_{71} [$]
Number Combined Heat & Power re-starts (N_{CHP})	N_{CHP}	P_{72} = 10.00 [$]	-N_{CHP}*P_{72} [$]
Number of Battery cycles (N_B)	N_B	P_{73} = 10.00 [$]	-N_B*P_{73} [$]
Number of Circuit Breaker cycles (N_{CB})	N_{CB}	P_{74} = 0.40 [$]	-N_{CB}*P_{74} [$]
Generators over nominal current (O_G)	O_G[A^2s]	P_{75}=*tbd*[$]	-O_G*P_{75}[$]
Trafos over nominal current (O_T)	O_T[A^2s]	P_{76}=*tbd*[$]	-O_T*P_{76}[$]
Cables over nominal current (O_C)	O_C[A^2s]	P_{77}=*tbd*[$]	-O_C*P_{77}[$]
KPP8 - Economical operation Sum of all KPP's above will show the monetary result of all above performance metrics. A high result means that the microgrid operator achieves higher benefits of having the microgrid controller in comparison to not having it. Selection of prices parameters (Pxx) will define the aspects of microgrid control that impacts the result the most. By analyzing these prices participants should prepare their strategies to achieve highest value of KPP8.			**SUM(KPPn, n=(1..7)) $**

5.5 Baseline Test Plan

A few baseline tests will be developed to establish proper pricing according to the guidelines shown in

Table 5 and to verify the operation of the model and entire test bed. The results of these tests will be published as a reference for vendors to compare performance results.

5.5.1 Baseline 1: No Microgrid Controller

This test will run the microgrid as if it were controlled manually by the operator, whose goal is to maintain as many active critical loads as possible. The operation will include delays for human decisions that might need to be made.

5.5.2 Baseline 2: Optimized Microgird Controller

The optimized microgird controller baseline test sequence will be developed to evaluate a possible optimal result. It will be developed based on the knowledge of the test sequence; thus it will represent a hypothetical ideal controller.

5.6 Cybersecurity Evaluation Process

Stage 1 will include a cybersecurity review in the form of a written questionnaire issued to each of the five selected respondents and corresponding interviewee. Stage 2 will include comprehensive testing in NREL's cyber-physical test bed for the final evaluation.

5.6.1 Stage 1: Cybersecurity Control Review

Selected respondents will provide answers to a series of questions that will reveal detailed information about the cybersecurity posture of their controller. NREL staff will create a custom plan to test the cybersecurity posture of each controller based on the answers to these questions. Specifically, selected respondents will be evaluated on the following functionalities:

1. Capable of supporting a strong username and password (12 ore more characters, including numerals, letters, and symbols)
2. Ability to integrate with a single sign-on methodology, such as LDAP, Kerberos, NIS, etc.
3. Ability to receive and transmit encrypted traffic
4. AES 128 or better encryption
5. Ability to implement Public Key Infrastructure (PKI)
6. Ability to use digital certificates for authentication
7. Ability to use two-factor authentication (using out of band means for secondary authentication)
8. Level of authorization for access to data and controls by user profile
9. Syslog alarming and integration capability
10. Tamper resistance (e.g., last gasp alarm, self-ejection from system if compromised, immunity from registries to be overwritten)
11. Secure firmware upgrade methodology
12. Remote access for security management using secure shell (SSH).

Each of the five selected respondents will review the custom cybersecurity posture report from NREL staff and respond in writing about how they plan to implement improvements. NREL staff will evaluate the strength of the current posture and depth and feasibility of an implementation plan to make enhancements during the course of this opportunity to arrive at the Stage 1 cybersecurity score. Cybersecurity will account for 30% of the final Stage 1 score.

5.6.2 Stage 2: Cyber-Physical Test Bed Evaluation

The microgrid controller of the final two offerors will be evaluated in NREL's cyber-physical test bed. (Offerors do not need to be at NREL during this 2-week period.) NREL staff will develop a custom written report for each offeror that includes a detailed account of test results of the binary scans as well as data fuzz testing and pen testing conducted on each controller. NREL will evaluate the final cybersecurity posture and provide each offeror a mitigation strategies based on this evaluation. The cybersecurity portion of Stage 2 accounts for 20% of the overall Stage 2 score.

5.6.3 Cybersecurity Scoring Rubric

All selected responders will complete a clarifying call in which the following aspects of the technology and respondent's team have been evaluated. The score from the clarifying call (based on the criteria in Table 2) will be added to the evaluation criteria in Table 3 to arrive at the total cybersecurity score for Stage 1 (which comprises 30% of the overall Stage 1 score). The scores from Table 2 and Table 3 have equal weighting in the Stage 1 cybersecurity score.

Table 7. Cybersecurity Evaluation Criteria

Criteria	Weighting
Domain expertise in microgrid technologies	25%
Fluency with cybersecurity controls for microgrids	30%
Level of professionalism	15%
Customer support protocols	15%
Existing partnerships	15%
Total	**100%**

Table 8. Cybersecurity Posture Evaluation Criteria

Criteria	Weighting
Strength of the controller's cybersecurity posture when entering Stage 1	40%

Strength of the implementation plan to improve controllers posture (based on Stage 1 evaluation)	30%
Confidence in the respondent’s team to make the proposed improvements in the timeframe of this opportunity (until Stage 2 cybersecurity testing begins)	30%
Total	**100%**

In Stage 2, offerors will undergo a 2-week cybersecurity evaluation in the NREL’s cyber-physical test bed at NREL. This evaluation will constitute the entirety of the final cybersecurity score. The cybersecurity score will account for 20% of the overall Stage 2 score.

6 Human Machine Interface

The human machine interface will be available for contestants to visualize the state of the microgrid. It offers a simplified single-line diagram with a real-time view of the microgrid by displaying power flows and the status of the circuit breakers in the system. The human machine interface can be accessed by logging through the web browser to the address of the Real Time Automation Controller (RTAC):

10.79.112.33 – from subnet 10.79.112.33

10.79.111.32 – from Opal-RT Host

Dedicated PC with large display will be available for teams use. It is connected to 10.79.112.xxx subnet. User can use following credentials:

User: NREL

Password: Power2grid

To access HMI it is required to login to RTAC. After typing RTAC's IPD address into web browser (Internet Explorer recommended) user will be requested to provide login credentials. Teams can use following:

User: team

Password: teAM8

7 Unit Test Sequence Generator

A MATLAB script will be available for vendor teams to prepare unit tests to verify the functions of their controller before the final NREL evaluation. A test vector of any length can be prepared consisting of fields as described in Table 9. When a script is running, measurement data from Opal-RT are stored and available for vendors for further processing and analysis. Data acquisition is realized with 200-ms resolution based on PQFV data for most nodes and internal data on distributed energy resources as well.

Test scripts will be provided to teams during the first integration periods at NREL.

Table 9. Test Vector for Unit Sequence Generator

Field	Value
Solar radiation	0-100% solar radiation
Fault injection node	0 – no fault 1 – activate fault in location 1 2 – activate fault in location 2 3 – activate fault in location 3 4 – activate fault in location 4 5 – activate fault in location 5 6 – activate fault in location 6
Gen fault	0 – no fault 1 – trip generator 1 with internal fault 2 – trip generator 2 with internal fault 3 – trip generator 3 with internal fault
ESS fault	0 – no fault 1 – trip ESS1 with internal fault 2 – trip ESS2 with internal fault
PV fault	0 – no fault 1 – trip PV1 with internal fault

	2 – trip PV2 with internal fault
Motor	
DMS Disconnect Request	0 – Transition from 1->0 means connect to grid unless other disconnect conditions are met. Microgrid shall reconnect to grid within 60 s from transition 1 - Initiate disconnect request action. Microgrid controller shall island the microgrid within 30 s from this signal
DMS Export/Import – Enable	0 – kW request disabled 1 – Microgrid shall follow active power request as close to DMS Export/Import Value
DMS Export/Import Value	0 – 10MW for import -5MW – 0 for export
DMS PF Correction – Enable	0 – disable PF correction 1 – enable PF correction. PF at the point of common coupling shall follow DMS PF Correction Value set point
DMS PF Correction Value	-1.00 … -0.75– Leading +0.75 … +1.0 – Lagging
DMS Hz/W droop	-50% - +50% @10MWAr base
DMS Volt/VAr droop	-50% - +50% @10MW base
Microgrid controller start - Enable	0 – Microgrid controller disabled – not allowed to enable any distributed energy resource 1 – Microgrid controller enabled - test sequence started
Cut-off grid	0 – Grid is running normally
Grid frequency	Used for frequency events emulation. Scale x100. Default: 6000

Grid voltage	Used for voltage events emulation for droop testing Scale: x0.1 Default: 11500 (115kV ph-ph)
Actual energy price	Actual price of energy from grid – p_{31} [$/kWh]

8 Microgrid Controller Interface

The microgrid controller under test will need to talk to various interfaces of the device controller and the hardware-in-the-loop unit.

8.1 Modbus Device Address Map

All devices on the system communicate via Modbus TCP over the Ethernet. Register lists for each device are provided in the devices' respective sections belowTable 10. Modbus Device List

Device	IP Address	TCP Port	Feeder Location ID	Notes
GEN3 – Real Diesel Genset Controller	10.79.110.50	502	F4	PHIL only - Woodward easYgen 3500 controlling the 80 kVA diesel genset in ESIF
ESS2 Inverter – BDP250	10.79.112.38	502	F4	PHIL only (use ESS2 Simulated Controller ip for SoC information)
PV2 Inverter – AE 100	10.79.112.39	502	F4	PHIL only
CB401- ABB SACE Emax2	10.79.112.36	502	F4	PHIL only
"DMS" Dispatch Interface	10.79.112.80	502	n/a	Dispatch instructions for the microgrid controller
GEN1 – Simulated Diesel Genset Controller	10.79.112.81	502	F1	Woodward easYgen 3500 controlling the 4 MVA diesel genset
GEN2 – Simulated Natural Gas Engine Controller	10.79.112.82	502	F3	Woodward easYgen 3500 controlling the 3.5-MVA natural gas-fired CHP system
GEN2 – Simulated CHP Thermal Controller	10.79.112.83	502	F3	-
GEN3 – Simulated Diesel Genset Controller	10.79.112.84	502	F1	CHIL only
ESS1 Simulated	10.79.112.85	502	F2	-

Controller				
ESS2 Simulated Controller	10.79.112.86	502	F2	CHIL only
PV1 Simulated Controller	10.79.112.87	502	F2	-
PV2 Simulated Controller	10.79.112.88	502	F2	CHIL only
Generic Relay CB101	10.79.112.101	502	F1	-
Generic Relay CB102	10.79.112.102	502	F1	-
Generic Relay CB103	10.79.112.103	502	F1	MCB for Diesel Genset
Generic Relay CB104	10.79.112.104	502	F1	Controls CB for Interruptible Load I1
Generic Relay CB105	10.79.112.105	502	F1	-
Generic Relay CB106	10.79.112.106	502	F1	-
Generic Relay CB107	10.79.112.107	502	F1	Controls CB for Interruptible Load I2
Generic Relay CB108	10.79.112.108	502	F1	Controls tie: F1 and F2 at 13.8 kV
Generic Relay CB109	10.79.112.109	502	F1	Controls tie: F1 and F2 at 480 V
Generic Relay CB110	10.79.112.110	502	F1	-
Generic Relay CB111	10.79.112.111	502	F1	Controls tie: F1 and F2 at 4.16 kV
Generic Relay CB112	10.79.112.112	502	F1	-
Generic Relay CB113	10.79.112.113	502	F1	Controls tie: F1 and F3 at 480 V
Generic Relay CB114	10.79.112.114	502	F1	CB for Priority Load P1, same bus as motor load
Generic Relay CB201	10.79.112.115	502	F2	-

Generic Relay CB202	10.79.112.116	502	F2	-
Generic Relay CB203	10.79.112.117	502	F2	-
Generic Relay CB204	10.79.112.118	502	F2	Controls CB for Priority Load P3
Generic Relay CB205	10.79.112.119	502	F2	Controls CB at battery energy storage system (EPC)
Generic Relay CB206	10.79.112.120	502	F2	Controls CB for Interruptible Load I3
Generic Relay CB207	10.79.112.121	502	F2	-
Generic Relay CB208	10.79.112.122	502	F2	Controls CB for Interruptible Load I4
Generic Relay CB209	10.79.112.123	502	F2	-
Generic Relay CB210	10.79.112.124	502	F2	-
Generic Relay CB211	10.79.112.125	502	F2	Controls CB at PV (EPC)
Generic Relay CB212	10.79.112.126	502	F2	Controls CB for Interruptible Load I5
Generic Relay CB213	10.79.112.127	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB214	10.79.112.128	502	F2	-
Generic Relay CB215	10.79.112.129	502	F2	-
Generic Relay CB216	10.79.112.130	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB217	10.79.112.131	502	F2	Controls tie: F2 and F3 at 480 V
Generic Relay CB218	10.79.112.132	502	F2	Controls CB for Priority Load P5
Generic Relay CB219	10.79.112.133	502	F2	Controls CB for Priority Load P2
Generic Relay CB301	10.79.112.134	502	F3	-
Generic Relay CB302	10.79.112.135	502	F3	-
Generic Relay CB303	10.79.112.136	502	F3	MCB for Natural Gas/CHP
Generic Relay CB304	10.79.112.137	502	F3	-
Generic Relay CB305	10.79.112.138	502	F3	-

Generic Relay CB306	10.79.112.139	502	F3	-
Generic Relay CB307	10.79.112.140	502	F3	Controls CB for Priority Load P4
Generic Relay CB308	10.79.112.141	502	F3	Controls CB for Interruptible Load I6
Generic Relay CB309	10.79.112.142	502	F3	Controls CB for Priority Load P6
Generic Relay CB310	10.79.112.143	502	F3	Controls of PHIL node
Generic Relay CB401	10.79.112.144	502	F4	Controls of PHIL node
Generic Relay CB402	10.79.112.145	502	F4	
Generic Relay CB403	10.79.112.146	502	F4	
Generic Relay CB404	10.79.112.147	502	F4	
Generic Relay CB405	10.79.112.148	502	F4	
Generic Relay CB406	10.79.112.149	502	F4	
Generic Relay CB100	10.79.112.91	502	F1	F1 POI interconnection relay
Generic Relay CB200	10.79.112.92	502	F2	F2 POI interconnection relay
Generic Relay CB300	10.79.112.93	502	F3	F3 POI interconnection relay

8.2 IEC 61850 Interface

Circuit breakers can be interfaced using only IEC 61850 GOOSE. See Section 15.4 for a description of the IEC 61850 interface for circuit breakers.

9 Control Capabilities

The test bed consists of multiple controllable resources. These controllers support different control modes, as shown in Table 11. In the CHIL phase, all controllers are simulated; in the PHIL phase, some devices are replaced with real devices and their interfaces. Because the gensets are not colocated, they do not perform automatic load sharing.

Table 11. Supported Control Modes for Each Distributed Energy Resource

	V/f (Isochronous)	P/Q (Real / reactive power command)	Droop (Frequency and voltage based)
Simulated devices			
Natural Gas Engine	✓	✓	✓
Diesel Genset	✓	✓	✓
Storage	✓	✓	✓
PV		✓	✓
Real devices			
Onan Diesel Genset	✓	✓	✓
BDP250 ESS Inverter	✓	✓	✓
AE 100 PV Inverter		✓	Volt/VAR only

10 Distribution Management System Dispatch Interface

The test script will instruct the microgrid controller to change its optimization objective using this interface. The surrogate DMS is implemented as a Modbus slave device that is located at the Internet Protocol address specified in Section 8.1. Its registers are loaded by the test script engine. The microgrid controller must periodically poll the following registers in the surrogate DMS to determine the current optimization objective and the present DMS supervisory commands and conditions.

Table 12. Distribution Management System Dispatch Interface Registers

Parameter	R/W	Reg Number	Unit	Scale
Epoch Time	R	0	-	-
DMS Disconnect Request	R	1	-	-
DMS Export/Import – Enable	R	2	-	-
DMS Export/Import Value Negative – Demand – Export - MG=>Grid Positive – Dispatch – Import - Grid=>MG	R	3	KW	1x
DMS PF Correction – Enable	R	4	-	-
DMS PF Correction – Value	R	5	-	1000x
DMS Hz/W droop	R	6	%	100x
DMS Volt/VAr droop	R	7	%	100x
Microgrid controller start - Enable	R	8	-	-
Actual energy price in per unit – p_{31}/P_{32}	R	9	%	10x

Table 13. Distribution Management System Dispatch Commands and Corresponding Values

Command	Range of Values	Units	Scale
DMS Export/Import	+10 MW (import Grid -> MG) to –5 MW (export MG->grid);	MW	1:1

DMS PF	(-1.0 … -0.75) /(+0.75 +1.0)	Leading/Lagging	1:1
Volt/VAR support	-50% - +50% @10MWAr	%	1:1
Hz/W droop	-50% - +50% @10WM	%	1:1

10.1 Example power calculation for active power

When DMS Eport/Import = 1 the cumulative power on feeder shall equal:

$$P_{Cmd} = P_{Ref} \mp \frac{(f_g - f_N)}{f_N D_P} P_N$$

Assuming:

P_{Ref} = DMS Export/Import Value

D_P = DMS Hz/W droop

f_g = Grid frequency

f_N = nominal grid frequency (60Hz)

P_N = nominal grid power = Pimportlim

Reactive power setpoint for the grid shall be used only when DMS PF Correction – Enable = 1. Reactive power setpoint shall include terms from power factor correction and Volt/Var as following:

$$Q_{cmd} = \frac{\sqrt{1-PF^2}}{PF} P_{meas} + \frac{(V_g - V_N)}{V_N D_Q} P_N,$$

Q_{cmd} – cumulative reactive power command that will be used to compare with actual measured reactive power

P_{meas}- actual measured active power at PCC

PF – power factor command from DMS

V_g- measured grid voltage – average RMS of all 3 feeders

V_N-nominal grid voltage

D_Q- Volt/Var droop

11 Natural Gas Engine and Diesel Genset

The test feeder microgrid has a 3.5-MVA natural gas-fired CHP system and two diesel gensets: 4 MVA and 1.6 MVA . During the CHIL stage of procurement, all of these generators will be simulated. These will be equipped with simulated secondary controllers described in Section 11.2. During the PHIL stage, a 1.6-MVA diesel genset will be replaced with a real generator in the ESIF: the Cummins Onna 80-kW diesel genset with a Woodward easYgen paralleling controller. All controllers can be controlled using the Modbus TCP interface. Each generator will have a breaker at its terminals. The microgrid controller does not need to communicate or control these breakers; they are controlled by the easYgen controllers.

11.1 Ratings and Characteristics

Table 14. Diesel Genset and Natural Gas Engine Ratings and Characteristics

	4 MVA Diesel Genset	3.5 MVA Natural Gas Engine / CHP	1.6 MVA (80kVA) Diesel Genset
Generator ID	GEN1	GEN2	GEN3
Manufacturer / Model	CAT C175-20	GE/Jenbacher J620	ONAN Cummins
Rating (kVA)	4,000	3,500	1,600 (80 PHIL)
Voltage (V)	13,800	13,800	4,160 (480 PHIL)
Frequency (Hz)	60	60	60
Inertia H(s)*	0.3468	0.3468	0.1268
Speed (RPM)	1800	1500 (geared to 1800)	1800
Minimum Output Power	Not specified	Not specified	Not specified
Startup Time	<15 sec	<15 sec	<15 sec

* - as defined in Simulink – Synchronous Machine PU fundamental model

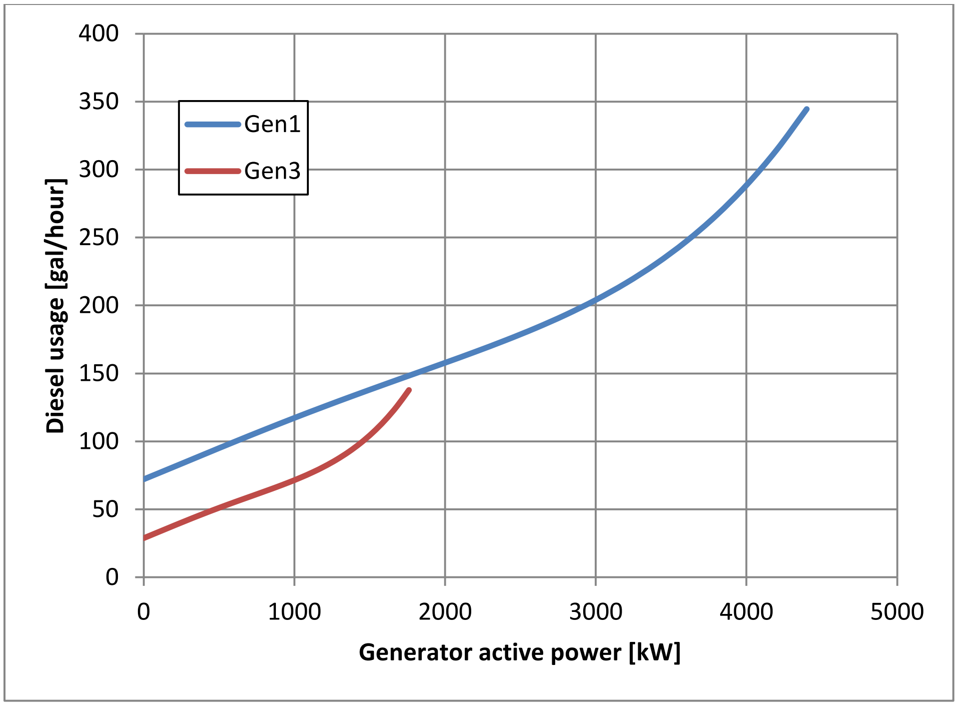

Figure 9 Diesel genrators fuel consumption (see diesel fuel prices in 5.4)

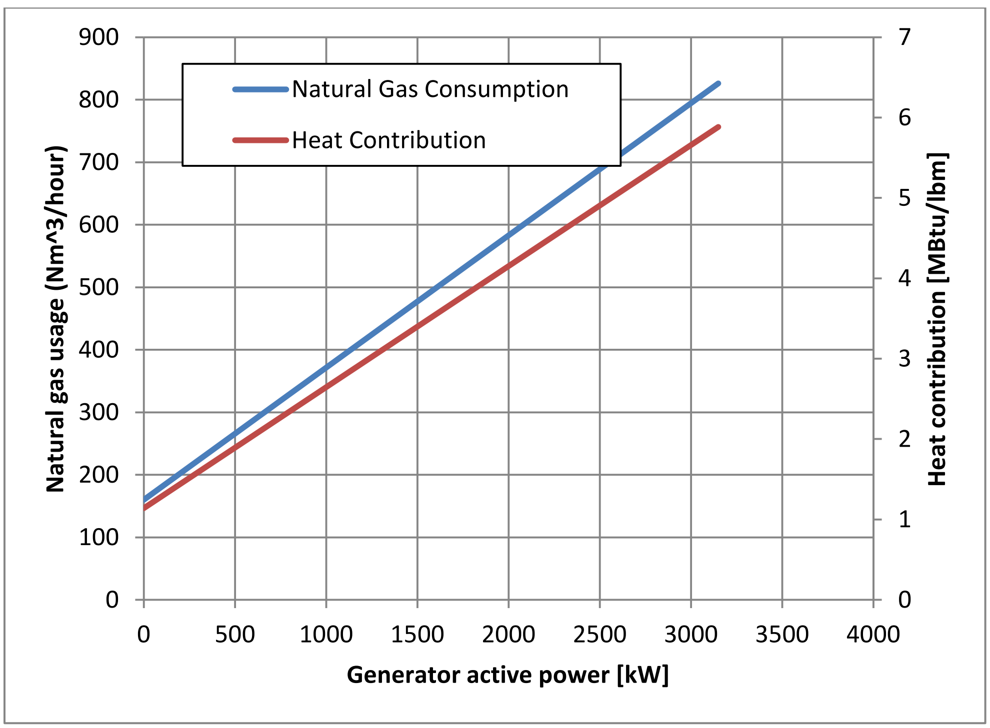

Figure 10 CHP natural gas consumption and heat contribution curves (see natural gas prices in 5.4)

11.2 Simulated Controller Description

The following registers can be used to control the simulated gensets.

Table 15. Simulated Generator Controller Modbus Registers

Parameter	R/W	Reg Number	Units	Scale*	Notes
IA PEAK CURRENT	R	0000	A	1	
IA ANGLE	R	0001	deg	0.1	
IB PEAK CURRENT	R	0002	A	1	
IB ANGLE	R	0003	deg	0.1	
IC PEAK CURRENT	R	0004	A	1	
IC ANGLE	R	0005	deg	0.1	
IA RMS CURRENT	R	0006	A	1	
IB RMS CURRENT	R	0007	A	1	
IC RMS CURRENT	R	0008	A	1	
VA RMS VOLTAGE	R	0009	V	1 (0.1)	
VB RMS VOLTAGE	R	0010	V	1 (0.1)	
VC RMS VOLTAGE	R	0011	V	1 (0.1)	
VA PEAK VOLTAGE	R	0012	V_{LN}	1 (0.1)	
VA ANGLE	R	0013	deg	0.1	
VB PEAK VOLTAGE	R	0014	V_{LN}	1 (0.1)	
VB ANGLE	R	0015	deg	0.1	
VC PEAK VOLTAGE	R	0016	V_{LN}	1 (0.1)	
VC ANGLE	R	0017	deg	0.1	
P	R	0018	kW	1 (0.1)	
Q	R	0019	kVAR		

S	R	0020	kVA		
PF	R	0021	-	0.001	
FREQ	R	0022	Hz	0.01	
SYNCHK FREQ SLIP	R	0023	Hz	0.01	
SYNCHK VOLT DIFF	R	0024	V_{LN}	1	
SYNCHK ANG DIFF	R	0025	deg	0.1	
Status	R	0026	Bit Field		
Enabled	R	Bit 0(LSB)	0/1		
Tripped	R	Bit 1	0/1		
Connected to grid	R	Bit 2	0/1		
Not used	R	Bit 3-15	0/1		
Fault Status	R	0027	Bit Field		
50P (1: trip, 0: not trip)	R	Bit 0(LSB)	0/1		
51P (1: trip, 0: not trip)	R	Bit 1	0/1		
27P (1: trip, 0: not trip)	R	Bit 2	0/1		
59P (1: trip, 0: not trip)	R	Bit 3	0/1		
Internal fault	R	Bit 4	0/1		
Not used		Bit 5-15	0/1		
Control word	R/W	2000	Bit Field		Starting with LSB: -Enable

Enable	R/W	Bit 0 (LSB)	0/1		Enable=1: In PQ mode generator will connect GCB after PLL got locked In VF mode – will issue connect command to syncheck of protective relay Enable=0 – GCB opened
VF / PQ control	R/W	Bit 1	0/1		1 – V&F referneces are used 0 – P&Q references are used
Reset faults	R/W	Bit 2	0/1		Faults are reset at positive edge of this signal
Generator run	R/W	Bit 3	0/1		0 – stop generator 1 – start generator
Not used	R/W	Bit 4-15	0/1		
Real Power Command	R/W	2001	kW	1	(-) discharge; (+) charge
Reactive Power Command	R/W	2002	kVAR	(0.1)	(+) capacitive; (-) inductive
Voltage Command	R/W	2003	V	1 (0.1)	
Frequency Command	R/W	2004	Hz	0.01	
Volt/VAR droop ($\boldsymbol{VQdroop}$)	R/W	2005	%	0.01	Default – 3%
Freq/kW droop ($\boldsymbol{FPdroop}$)	R/W	2006	%	0.01	Default – 3%
Faults auto reset time	R/W	2007	s	1	Automatically resets faults after Set 0 to remove auto reset

					Default – 20s

* scale of Gen3 in brackets, Gen1&Gen2 no brackets

11.3 Woodward easYgen 3500 Controller Interface

The Cummins Onan diesel generator is controlled by a Woodward easYgen 3500 controller as described in this section. Documentation on the Woodward easYgen 3500 controllers can be found in [3]. The easYgen 3500 natively speaks Modbus RTU and CANbus; NREL has installed proconX ESENET [4] protocol converter in order to provide a Modbus TCP/IP interface. The easYgen documentation should be consulted for the complete Modbus register list and for the translation formulas required to access the registers if needed. Modbus TCP/IP registers map directly to the Modbus RTU registers provided in the EasyGen documentation. The register list below is all that is required to control the easYgen devices for the purpose of this procurement.

Table 16. Extract from EasyGen Modbus register list

Parameter/Data Type	R/W	Reg Number	Unit	Scale	Notes
Remote Control Word 1	R/W	503	-	-	See Next Section
Remote Control Word 3	R/W	505	-	-	See Next Section
Active Pwr Set point (sint32)	R/W	507	kW	10x	1.5 MW=”15000”
PF Set point (uint16)	R/W	508	-	1000x	.95=”950”
Frequency Set point (uint16)	R/W	509	Hz	100x	60 Hz=”6000”
Voltage Set point (uint32)	R/W	510	V	1x	13.8kV=”13800”
Frequency Droop (uint16)	R/W	5504	%	1x	0% - 20%
Voltage Droop (uint16)	R/W	5604	%	1x	0% - 20%
Control Mode (sint16)	R	50002	-	-	1=Auto, 2=Stop, 4=Manual; Mask: 000F (hex)
Gen. Frequency (sint16)	R	50006	Hz	0.01	
Gen. Total Power (sint32)	R	50052	W	1x	
Gen. Total Reactive Power (sint32)	R	50058	Var	1x	
Gen. Power Factor (sint16)	R	50003	-	0.001	

Gen. Voltage L1-L2 (sint32)	R	50073	V	0.1	
Gen. Voltage L2-L3 (sint32)	R	50079	V	0.1	
Gen. Voltage L3-L1 (sint32)	R	50085	V	0.1	
Gen. Voltage L1-N (sint32)	R	50076	V	0.1	
Gen. Voltage L2-N (sint32)	R	50082	V	0.1	
Gen. Voltage L3-N (sint32)	R	50088	V	0.1	
Gen. Current L1 (sint32)	R	50034	A	0.001	
Gen. Current L2 (sint32)	R	50037	A	0.001	
Gen. Current L3 (sint32)	R	50040	A	0.001	
Busbar 1: Frequency (sint16)	R	50015	Hz	0.01	
Busbar 1: Voltage L1-L2 (sint32)	R	50064	V	0.1	
Setpoint Frequency (sint16)	R	50129	Hz	0.01	
Setpoint Active Power (sint32)	R	50130	kW	0.1	
Setpoint Voltage (sint32)	R	50132	V	1x	
Setpoint Power Factor (sint16)	R	50134	-	0.001	
Mains Frequency (sint16)	R	50009	Hz	0.01	
Mains Total Power (sint32)	R	50055	W	1x	
Mains Total Reactive Power (sint32)	R	50061	Var	1x	
Mains Power Factor (sint16)	R	50012	-	0.001	
Mains Voltage L1-L2 (sint32)	R	50091	V	0.1	
Mains Voltage L2-L3 (sint32)	R	50097	V	0.1	
Mains Voltage L3-L1 (sint32)	R	50103	V	0.1	
Mains Voltage L1-N (sint32)	R	50094	V	0.1	

Mains Voltage L2-N (sint32)	R	50100	V	0.1	
Mains Voltage L3-N (sint32)	R	50106	V	0.1	
Ave. Mains Current (sint32)	R	50022	A	0.001	
GCB Status Open (sint16)	R	50084	-	-	1=open, 0=closed; Mask: 0100 (hex)

The section below elaborates the use of the R/W registers (holding registers) used to control the easYgens.

11.3.1 Remote Control Word 1 (Parameter 503)

1. Remote Control Bit 0—start bit—rising edge
2. Remote Control Bit 1—stop bit—rising edge
3. Remote Control Bit 4—external acknowledge—rising edge—must be set twice to acknowledge
4. Remote Control Bit 9—shutdown command—rising edge.

11.3.2 Remote Control Word 3 (Parameter 505)

Remote Control Word 3 is a generic 16 bit control word with specific NREL defined functionality. Mode control of the generator is achieved through remote control bits 0–2. The bits and functions are summarized below.

1. Remote Control Bit 0—kW/Hz—Frequency droop on (1) and off (0)
2. Remote Control Bit 1—kVAr/volt droop on (1) and off(0)
3. Remote Control Bit 2—MCB open (1) or closed (0).
4. Remote Control Bit 3—Active power control enabled (1) / disabled(0).
5. Remote Control Bit 4—Reactive power control enabled (1) / disabled (0).

11.3.2.1 REMOTE CONTROLBIT 0

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.

11.3.2.2 REMOTE CONTROL BIT 1

This bit is used to enable the voltage droop mode. The generator always powers up into voltage droop mode. This bit allows the droop mode to be turned on when set to 1. When set to 0, the voltage droop mode will be disabled (i.e., turned off).

11.3.2.3 REMOTE CONTROL BIT 2

This bit informs the woodward controller about the status of MCB controller. If MCB closed status is sent generator will not allow GCB to be closed on deadbus.

11.3.2.4 REMOTE CONTROL BIT 3

When enabled ese active power control instead of frequency controller. When enabled generator will follow active power setpoint (Parameter 507). This mode should only be enabled when generator is connected to at least one grid forming source. When disabled generator will follow frequency setpoint (Parameter 509). This mode should not be used when connected to other grid forming source if P/Hz droop is not enabled (Remote Control Bit 0)

11.3.2.5 REMOTE CONTROL BIT 4

When enabled ese power factor control instead of voltage controller. Generator will follow power factor set point (Parameter 508). This mode should only be enabled when generator is connected to at least one grid forming source. When disabled generator will follow voltage setpoint (Parameter 510). This mode should not be used when connected to other grid forming source if Q/Volt droop is not enabled (Remote Control Bit 1)

11.3.3 Active Power Set Point (Parameter 507)

This specifies the active power set point when in grid-tied mode (when both the GCB and MCB are closed). The range is from 0–999,999.

11.3.4 Power Factor Set Point (Parameter 508)

This specifies the PF set point when in grid-tied mode (when both the GCB and MCB are closed). The range is from -710–-1,000 and from 1,000–710.

11.3.5 Frequency Set Point (Parameter 509)

This specifies the frequency set point when in islanded mode (MCB open). The range is from 0–7,000.

11.3.6 Voltage Set Point (Parameter 510)

This parameter sets the generator output voltage, which is normally 480 V.

When in droop mode, active and reactive power is set by changing the voltage and frequency set points. NOTE: Registers 507–510 must be loaded before the generator is placed in start by writing a 1 to Bit 0 of Parameter (Register) 503.

12 Combined Heat and Power Thermal Controller

NOTE: Heat controller doesn't affect KPP results. It is assumed that all heat enearted by Generator 2 is being paid for with price as specified in Table 6.

The CHP thermal controller uses an aggregate thermal load that is derived from actual site measurements of steam in l b/h (see Figure 11.). In addition, an aggregate thermal inertia is assumed (related to the rate of change of temperature as a function of net heat flow into or out of the site space).

12.1 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 constant temperature. 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 the CHP heat is enabled, the aggregate temperature will rise above the set point, and the microgrid controller will be responsible for disabling the 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 the temperature set point in °F
2. Enabling or disabling the CHP heat augmentation (1 = on, 0 = off)
3. Reading the site temperature in °F
4. Reading the boiler load in MBtu/h.

The microgrid controller is responsible for optimizing the timing and duration of the 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 compared to 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 the relative cost of electricity and emissions considerations.

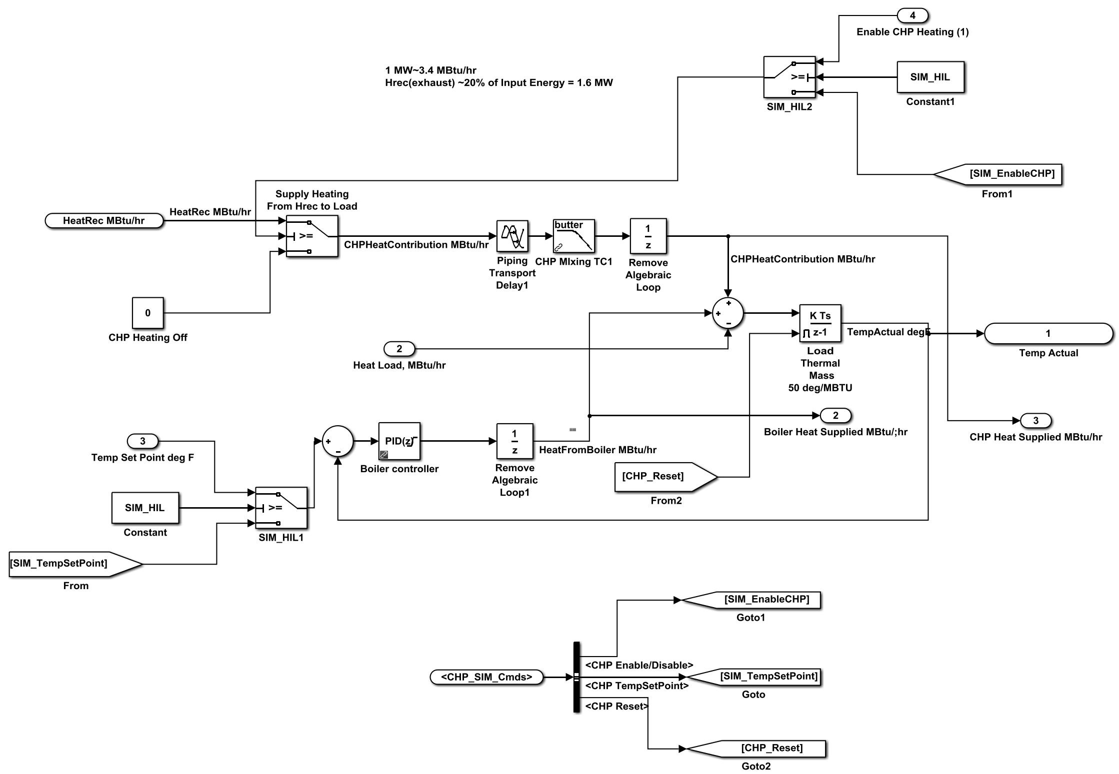

Figure 11. System thermal control diagram

12.2 Controller Interface

Table 17. Thermal Controller Modbus Registers

Parameter	R/W	Reg Number	Unit	Scale	Notes
Temp Set point	R/W	2000	°F	1:1	Temp set point value
CHPMode	R/W	2001	-	-	0=disabled 1=enabled
ActualTemp	R	0000	degF	1:1	Actual temp
HeatFromBoiler	R	0001	MBtu/h	1:1	Boiler heat supplied
HeatFromCHP	R	0002	MBtu/h	1:1	CHP heat supplied
HeatRecovered	R	0003	MBtu/h	1:1	Usable heat from CHP
CHPCO2Emissions	R	0004	lbm/h	1:1	CHP CO_2 emissions

BoilerFuelUsage	R	0005	Nm^3/h	1:1	Boiler NG usage rate
BoilerCO2Emissions	R	0006	lbm/h	1:1	Boiler CO_2 emissions

12.3 Combined Heat and Power Figure of Merit

A simple CHP figure of merit 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:

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

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 the 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.)

13 Solar Photovoltaic

Two solar power plants are available in the test bed: PV1 and PV2. The microgrid controller can communicate to both of them to monitor and control their intelligent functions. During the CHIL stage, both inverters together with PV will be modeled in a real-time simulator. During the PHIL phase, PV2 will be replaced with a real hardware unit, AE 100. The real-time simulated PV interface and references to AE 100 documents are described below.

13.1 Ratings

Table 18. PV and Energy Storage System Ratings

	PV1	PV2	
	CHIL&PHIL	PHIL	CHIL
AC Power Rating (kVA)	5,000	100	2,000
Voltage (V)	480	480	480
Frequency (Hz)	60	60	60
Maximum Ramp Rate (kVA/s)	5,000	100	2,000

13.2 Simulated Power Converter Register List

Table 19. Simulated PV Power Converter Modbus Registers

Parameter	R/W	Reg Number	Units	Scale*	Notes
IA PEAK CURRENT	R	0000	A	1	
IA ANGLE	R	0001	deg	0.1	
IB PEAK CURRENT	R	0002	A	1	
IB ANGLE	R	0003	deg	0.1	
IC PEAK CURRENT	R	0004	A	1	
IC ANGLE	R	0005	deg	0.1	
IA RMS CURRENT	R	0006	A	1	
IB RMS CURRENT	R	0007	A	1	

IC RMS CURRENT	R	0008	A	1	
VA RMS VOLTAGE	R	0009	V	0.1	
VB RMS VOLTAGE	R	0010	V	0.1	
VC RMS VOLTAGE	R	0011	V	0.1	
VA PEAK VOLTAGE	R	0012	V_{LN}	0.1	
VA ANGLE	R	0013	deg	0.1	
VB PEAK VOLTAGE	R	0014	V_{LN}	0.1	
VB ANGLE	R	0015	deg	0.1	
VC PEAK VOLTAGE	R	0016	V_{LN}	0.1	
VC ANGLE	R	0017	deg	0.1	
P	R	0018	kW	1 (0.1)	
Q	R	0019	kVAR	1 (0.1)	
S	R	0020	kVA	1 (0.1)	
PF	R	0021	-	0.001	
FREQ	R	0022	Hz	0.01	
SYNCHK FREQ SLIP	R	0023	Hz	0.01	
SYNCHK VOLT DIFF	R	0024	V_{LN}	1	
SYNCHK ANG DIFF	R	0025	deg	0.1	
DC Current	R	0026	A	0.1	
DC Voltage	R	0027	V	1	
Status	R	0028	Bit Field		
Enabled	R	Bit 0(LSB)	0/1		
Tripped	R	Bit 1	0/1		

Connected to grid	R	Bit 2	0/1		
Not used	R	Bit 3-15	0/1		
Fault Status	R	0029	Bit Field		
50P (1: trip, 0: not trip)	R	Bit 0(LSB)	0/1		
51P (1: trip, 0: not trip)	R	Bit 1	0/1		
27P (1: trip, 0: not trip)	R	Bit 2	0/1		
59P (1: trip, 0: not trip)	R	Bit 3	0/1		
PLL Loss of Sync	R	Bit 4	0/1		
Not used	R	Bit 5-6	0/1		
Internal fault	R	Bit 7	0/1		
Not used	R	Bit 8-15	0/1		
Control word	R/W	2000	Bit Field		Starting with LSB: -Enable
Enable	R/W	Bit 0 (LSB)	0/1		When Enable=1: In PQ mode inverter will connect MCB after PLL got locked In VF mode – will issue connect command to syncheck of protective relay Enable=0 – inverter's MCB opened
VF / PQ control	R/W	Bit 1	0/1		Not relevant for PV – only PQ

					mode
Reset faults	R/W	Bit 2	0/1		Faults are reset at positive edge of this signal
Not used	R/W	Bit 3-15	0/1		
Real Power Curtail Command	R/W	2001	kW	1 (0.1)	(-) discharge; (+) charge
Reactive Power Command	R/W	2002	kVAR	1 (0.1)	(+) capacitive; (-) inductive
Voltage Command	R/W	2003	V	0.1	
Frequency Command	R/W	2004	Hz	0.01	
Volt/VAR droop ($\boldsymbol{VQdroop}$)	R/W	2005	%	0.01	Default – 3%
Freq/kW droop ($\boldsymbol{FPdroop}$)	R/W	2006	%	0.01	Default – 3%
Faults auto reset time	R/W	2007	s	1	Automatically resets faults after Set 0 to remove auto reset Default – 20s

* power scale of PV2 in brackets, PV1 no brackets

The FPdroop is defined as following:

$$FPdroop = \frac{\Delta F}{F_{Cmd}} \frac{P_{Nom}}{\Delta P}$$

The VQdroop is defined as following:

$$VQdroop = \frac{\Delta V}{V_{Cmd}} \frac{Q_{Nom}}{\Delta Q}$$

13.3 AE 100 Specifications

The AE 100TX inverter is a commercially available solar inverter that will be used during the PHIL experiment. The data sheet [5] shows features of the inverter. The inverter can be controlled using the Modbus TCP, and a register map is available [6].

By using the AE serial programming software tool (available on the NREL laptop) the following settings can be programmed to decrease the restart time and increase the ride through capabilities:

On memory tab, change startup_timeout to 6 seconds. Default is 300 seconds.

On the trip setting tab, change the setpoints as follows then click “set”:

trip_limits	voltage%	time(*8ms)	frequency	time(*10ms)
	140	250	62.5	500
	125	370	60.5	5000
	80	370	59.3	5000
	50	250	57	500

These trip settings will make the AE100TX less sensitive to voltage and frequency transients, but may exceed a local utility’s required disconnection times (per interconnection agreement) when the inverter is grid-connected (not applicable for lab testing).

14 Energy Storage

Two energy storage systems are available in the test bed: ESS1 and ESS2. The microgrid controller can communicate to both of them to monitor and control their intelligent functions. During the CHIL stage, both inverters together with the battery will be modeled in a real-time simulator. During the PHIL phase, ESS2 will be replaced with a real hardware unit, BDP250. The real-time simulated ESS interface and references to the BDP250 documents are described below.

14.1 Ratings

Table 20. Energy Storage Ratings

	ESS1	ESS2	
	CHIL&PHIL	PHIL	CHIL
AC Power Rating (kVA)	3,000	250	5,000
Storage (kWh)	600	12000	1200
Voltage (V)	480	480	480
Frequency (Hz)	60	60	60
Maximum Ramp Rate (kVA/s) in PQ mode	3,000	250	5,000

14.2 Simulated Power Converter Registers

Table 21. Simulated PV Power Converter Modbus Registers

Parameter	R/W	Reg Number	Units	Scale*	Notes
IA PEAK CURRENT	R	0000	A	1	
IA ANGLE	R	0001	deg	0.1	
IB PEAK CURRENT	R	0002	A	1	
IB ANGLE	R	0003	deg	0.1	
IC PEAK CURRENT	R	0004	A	1	
IC ANGLE	R	0005	deg	0.1	

IA RMS CURRENT	R	0006	A	1	
IB RMS CURRENT	R	0007	A	1	
IC RMS CURRENT	R	0008	A	1	
VA RMS VOLTAGE	R	0009	V	0.1	
VB RMS VOLTAGE	R	0010	V	0.1	
VC RMS VOLTAGE	R	0011	V	0.1	
VA PEAK VOLTAGE	R	0012	V_{LN}	0.1	
VA ANGLE	R	0013	deg	0.1	
VB PEAK VOLTAGE	R	0014	V_{LN}	0.1	
VB ANGLE	R	0015	deg	0.1	
VC PEAK VOLTAGE	R	0016	V_{LN}	0.1	
VC ANGLE	R	0017	deg	0.1	
P	R	0018	kW	1 (0.1)	
Q	R	0019	kVAR	1 (0.1)	
S	R	0020	kVA	1 (0.1)	
PF	R	0021	-	0.001	
FREQ	R	0022	Hz	0.01	
SYNCHK FREQ SLIP	R	0023	Hz	0.01	
SYNCHK VOLT DIFF	R	0024	V_{LN}	1	
SYNCHK ANG DIFF	R	0025	deg	0.1	
DC Current	R	0026	A	0.1	
DC Voltage	R	0027	V	1	
Status	R	0028	Bit Field		
Enabled	R	Bit 0(LSB)	0/1		

Tripped	R	Bit 1	0/1		
Connected to grid	R	Bit 2	0/1		
Battery Full	R	Bit 3	0/1		
Battery Empty	R	Bit 4	0/1		
Not used	R	Bit 5-15	0/1		
Fault Status	R	0029	Bit Field		
50P (1: trip, 0: not trip)	R	Bit 0(LSB)	0/1		
51P (1: trip, 0: not trip)	R	Bit 1	0/1		
27P (1: trip, 0: not trip)	R	Bit 2	0/1		
59P (1: trip, 0: not trip)	R	Bit 3	0/1		
PLL Loss of Sync	R	Bit 4	0/1		
Battery Full while in VF mode	R	Bit 5	0/1		Since there is no control over power flow direction in VF mode inverter will trip in case of full or empty battery in this mode.
Battery full while in VF mode	R	Bit 6	0/1		
Internal fault	R	Bit 7	0/1		
Not used	R	Bit 8-15	0/1		
Battery State of Charge	R	0030	%	0.01	Battery will start at defined state of charge.
Control word	R/W	2000	Bit Field		Starting with LSB: -Enable

Enable	R/W	Bit 0 (LSB)	0/1		Enable=1: In PQ mode inverter will connect MCB after PLL got locked In VF mode – will issue connect command to syncheck of protective relay Enable=0 – inverter's MCB opened
VF / PQ control	R/W	Bit 1	0/1		1 – V&F referneces are used 0 – P&Q references are used
Reset faults	R/W	Bit 2	0/1		Faults are reset at positive edge of this signal
Not used	R/W	Bit 3-15	0/1		
Real Power Command	R/W	2001	kW	1 (0.1)	(-) discharge; (+) charge
Reactive Power Command	R/W	2002	kVAR	1 (0.1)	(+) capacitive; (-) inductive
Voltage Command	R/W	2003	V	0.1	
Frequency Command	R/W	2004	Hz	0.01	
Volt/VAR droop	R/W	2005	%	0.01	Default – 3%
Freq/kW droop	R/W	2006	%	0.01	Default – 3%
Faults auto reset time	R/W	2007	s	1	Automatically resets faults after Set 0 to remove auto reset Default – 20s

* power scale of ESS2 in brackets, ESS1 no brackets

14.3 BDP250 Specifications

14.3.1 Introduction

BDP250 is Caterpillar's commercially available storage inverter, which allows for multiple features outlined in the data sheet [7]. It will be used during the PHIL experiment together with AeroVironment's AV-900, controllable, bidirectional DC source, which will emulate the battery state of charge. The microgrid controller can communicate directly to the BDP250 using the Modbus TCP protocol. The Modbus signal map is available [8].

The Caterpillar BDP-250 is a bidirectional power converter (inverter) which interacts with either an ultra-capacitor or a battery to store direct current (DC) energy. It connects to the alternating current (AC) grid via a delta-wye transformer. The BDP-250 has "grid tie" (GT) mode as well as "grid forming" (GF) mode which means it can provide power even when no grid exists. When the grid exists, the BDP-250 automatically imports/exports real power (kW) depending on grid frequency. Simultaneously, it automatically imports/exports reactive power (kVAR) depending on grid voltage. The BDP-250 is controlled with a proprietary non-linear droop scheme and will temporarily overload itself for up to five seconds in order to stabilize the grid during any frequency or voltage excursions.

Note: For PHIL stage use simulated power converter modbus interface

14.3.2 Data Sheet Information

Power: 312kVA (250kW at 0.8 power factor); firmware temporarily limited to -100kW to +250kW

Surge power: 600kVA for 13 seconds, then slowly curtails power; 500kVA for 31-44 seconds

DC: 300-625vDC

AC: 380vAC delta converted to 480vAC wye via included transformer (with 400A AC breaker)

14.3.3 Quick Start Guide

Connect energy storage (bidirectional DC) to the DC connectors on left side of cabinet.
Connect to 480vAC system via connectors on bottom of AC breaker enclosure (on transformer).
Connect 120vAC house power to outlet on top of cabinet. Or, press the "black start" button.
While EMCP control panel is in "Stop" mode, view and reset any errors/alarms.
Connect via Modbus TCP if needed. Else, the inverter will run is autonomous mode.
Press the "Run" button.

Shutdown: Press "Stop" button. Disconnect power sources.

14.3.4 Modbus Quick Reference

For full Modbus map, see Caterpillar documentation. Note: Modbus_address = register_number - 1.

Register (Write)	Description	Notes
100	AC volts	Volts line-to-line, no scaling
102	Frequency	*2^-7
106-107	P actual	-2,000,000,000 in watts
141-142	Q actual	-2,000,000,000 in VAR
176-177 W	P command	Requires MMC mode; -2,000,000,000 in watts
179-180	P setpoint	-2,000,000,000 in watts
202	DC voltage	For 24VDC UPS battery. Use register 9307 for high voltage DC.
302 W	Run / stop	0=stop, 1=auto, 2=run
1057	V setpoint	Volts line-to-line, no scaling
1058	V bias %	(*0.0078125) -251 [in percent]
1059 W	Voltage bias	(*0.0078125) -251 [in percent]
1061	Speed bias %	(*0.0078125) -251 [in percent]
1062 W	Speed bias	(*0.0078125) -251 [in percent]
1136	V droop %	Read only
2186-2187	Q setpoint	-2,000,000,000 in VAR
2230-2231 W	Q command	Requires MMC mode; -2,000,000,000 in VAR
2269 W	MMC mode	Write "1" repeatedly to enter MMC mode (PQ mode)
9020	SOC	Seems to be % used (%_available = 100 - %_used)
9307	DC voltage	(*2^-3) -4000
9333	V at grid	(*2^-3) -4000 [scaled to 380 nominal]
9338	F at grid	*2^-7

14.3.5 Performance Observations

BDP in auto mode (not controlled by MMC) will push/pull real power to achieve 85% battery SOC (625v DC) and simultaneously push real power if grid frequency falls below 60Hz. Even in PQ mode (MMC enabled), BDP seems to push power (which can exceed P_setpoint) if grid frequency falls below 60Hz. Further investigation is needed to determine if this grid voltage also overrides the Q_setpoint.

In auto mode at 625v DC, 482v AC, and 60.0 Hz, there is no P or Q flowing… this is the equilibrium point.

In auto mode at 585v DC, the SOC will be 75% and the inverter will be charging at max (-100kW).

Voltage droop:

181kVAR at 477v

136 at 478v

89 at 479v

52 at 480v

0kVAR at 482-492v [dead band]

-63kVAR at 502v

-89 at 511v

-110 at 517v

Frequency droop (observed while in PQ mode with P_command at zero):

100-200+kW (slowly increases) at 59.7hz

35kW at 59.8hz

17kW at 59.9hz

0kW at 60.0hz

-19kW at 60.1hz (negative = BDP is charging battery)

-37kW at 60.2hz

X (unstable) at 60.25hz

State of charge (SOC):

VDC	SOC %	P_limit (kW) [assuming 250vDC 500Adc limit of AV900]
670.0	98	250+
625.0	84	250+
550.0	66	250+
400.0	36	200
250.0	12	125

15 Protective 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 they provide sensor telemetry values. Two versions of generic relays are used to allow for the full or a limited set of protective functions.

15.1 Generic Relay Features

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

- Synchronizing and synchronism-check (ANSI Standard Device Number 25)
- Phase instantaneous overcurrent (ANSI 50P)
- Phase time overcurrent (ANSI 51P)
- Undervoltage (ANSI 27)
- Overvoltage (ANSI 59)
- Overfrequency (ANSI 81O)
- Underfrequency (ANSI 81U)
- Fast rate of change of frequency (ANSI 81R).

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 the SEL751 manual (pp. 4.23, Table 4.17).

Futher, the relay includes multiple relay setting groups for protection during different configurations. Currently, only two predefined parameter 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 23.

15.2 Generic Relays in the Model

Table 22. Generic Relays in the Microgrid Controller System

Generic Relay ID	25	50P	51P	27	59	81U	81O	81R	Fast Shed	MGC Ctrl	Note
CB100	X	X	X	X	X	X	X	X	X	X	
CB200	X	X	X	X	X	X	X	X	X	X	
CB300	X	X	X	X	X	X	X	X	X	X	
CB101	X	X	X	X	X	X	X	X		X	-
CB102	X	X	X	X	X	X	X	X		X	-
CB103	X	X	X	X	X	X	X	X		X	MCB for Diesel Genset
CB104	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I1
CB105	X	X	X	X	X	X	X	X		X	-
CB106	X	X	X	X	X	X	X	X		X	-
CB107	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I2
CB108	X	X	X	X	X	X	X	X	X	X	Controls tie: F1 and F2 at 13.8 kV
CB109	X	X	X	X	X	X	X	X	X	X	Controls tie: F1 and F2 at 480 V
CB110	X	X	X	X	X	X	X	X	X	X	-
CB111	X	X	X	X	X	X	X	X	X	X	Controls tie: F1 and F2 at 4.16 kV

CB112	X	X	X	X	X	X	X	X		X	-
CB113	X	X	X	X	X	X	X	X	X	X	Controls tie: F1 and F3 at 480 V
CB114	X	X	X	X	X	X	X	X	X	X	CB for Priority Load P1, same bus as motor load
CB201	X	X	X	X	X	X	X	X		X	-
CB202	X	X	X	X	X	X	X	X		X	-
CB203	X	X	X	X	X	X	X	X		X	-
CB204	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P3
CB205	X	X	X	X	X	X	X	X		X	Controls CB at battery energy storage system (EPC)
CB206	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I3
CB207	X	X	X	X	X	X	X	X		X	-
CB208	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I4
CB209	X	X	X	X	X	X	X	X		X	-
CB210	X	X	X	X	X	X	X	X		X	-
CB211	X	X	X	X	X	X	X	X		X	Controls CB at PV (EPC)
CB212	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I5
CB213	X	X	X	X	X	X	X	X	X	X	Controls tie: F2 and F3 at 480 V
CB214	X	X	X	X	X	X	X	X		X	-
CB215	X	X	X	X	X	X	X	X		X	-
CB216	X	X	X	X	X	X	X	X	X	X	Controls tie: F2 and F3 at 480 V
CB217	X	X	X	X	X	X	X	X	X	X	Controls tie: F2 and F3 at 480 V
CB218	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P5

CB219	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P2
CB301	X	X	X	X	X	X	X	X		X	-
CB302	X	X	X	X	X	X	X	X		X	-
CB303	X	X	X	X	X	X	X	X		X	MCB for Natural Gas/CHP
CB304	X	X	X	X	X	X	X	X		X	-
CB305	X	X	X	X	X	X	X	X		X	-
CB306	X	X	X	X	X	X	X	X		X	-
CB307	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P4
CB308	X	X	X	X	X	X	X	X	X	X	Controls CB for Interruptible Load I6
CB309	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P6
CB310	X	X	X	X	X	X	X	X	X	X	Controls CB for Priority Load P6
CB401	X	X	X	X	X	X	X	X	X	X	
CB403	X	X	X	X	X	X	X	X	X	X	
CB404	X	X	X	X	X	X	X	X	X	X	
CB405	X	X	X	X	X	X	X	X		X	
CB406	X	X	X	X	X	X	X	X	X	X	
CB151	X	X	X	X	X	X	X	X			
CB251	X	X	X	X	X	X	X	X			
CB252	X	X	X	X	X	X	X	X			
CB351	X	X	X	X	X	X	X	X			
CB451	X	X	X	X	X	X	X	X			
CB452	X	X	X	X	X	X	X	X			
CB453	X	X	X	X	X	X	X	X			

15.3 Simulated Generic Relay Modbus Interface

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 23.

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

Table 23. Simulated Generic Relays Registers

Parameter	R/W	Reg Number	Units	Scale	Notes
IA PEAK CURRENT	R	0000	A	1	
IA ANGLE	R	0001	deg	0.1	
IB PEAK CURRENT	R	0002	A	1	
IB ANGLE	R	0003	deg	0.1	
IC PEAK CURRENT	R	0004	A	1	
IC ANGLE	R	0005	deg	0.1	
IA RMS CURRENT	R	0006	A	1	
IB RMS CURRENT	R	0007	A	1	
IC RMS CURRENT	R	0008	A	1	
VA RMS VOLTAGE	R	0009	V	1	
VB RMS VOLTAGE	R	0010	V	1	
VC RMS VOLTAGE	R	0011	V	1	
VA PEAK VOLTAGE	R	0012	V_{LN}	1	
VA ANGLE	R	0013	deg	0.1	
VB PEAK VOLTAGE	R	0014	V_{LN}	1	
VB ANGLE	R	0015	deg	0.1	
VC PEAK VOLTAGE	R	0016	V_{LN}	1	
VC ANGLE	R	0017	Deg	0.1	

P	R	0018	kW	1	
Q	R	0019	kVAR	1	
S	R	0020	kVA	1	
PF	R	0021	-	0.001	
FREQ	R	0022	Hz	0.01	
SYNCHK FREQ SLIP	R	0023	Hz	0.01	
SYNCHK VOLT DIFF	R	0024	V_{LN}	1	
SYNCHK ANG DIFF	R	0025	deg	0.1	
TRIP STATUS LO	R	0026	-	-	Bit 0 = 25 (1: synch, 0: not synch) Bit 1 = 50P (1: trip, 0: not trip) Bit 2 = 51P (1: trip, 0: not trip) Bit 3 = 27P (1: trip, 0: not trip) Bit 4 = 59P (1: trip, 0: not trip) Bit 5 = 81U (1: trip, 0 not trip) Bit 6 = 81O (1: trip, 0 not trip) Bit 7 = 81RF (1 trip, 0 not trip)
TRIP STATUS HI	R	0027	-	-	Bit 0 = trip_cmd (1: close, 0: open) Bit 1 = 52A (1: closed, 0: opened) Bit 2 = 52B (1: opened, 0: closed)
TRIP RESET	R/W	2000	-	-	This is used to reset a “lockout” and allow a close command to be accepted. TRIP RESET will be commanded on positive edge

LOGIC COMMAND	R/W	2001	-	-	Register Raw Value = 0 or 1; Close CB and activate relay protection functions Register Raw Value = 2; Open CB Changing value of this register also causes TRIP RESET
GROUP SETTING SELECTION	R/W	2002	-	-	Register Value = 0; group setting #1 (*default*, and will be used for grid-tied settings) Register Value = 1; group setting #2 (will be used for islanded settings) Transition delay = 0 s

15.4 Simulated Generic Relay IEC 61850 GOOSE Interface

Each generic circuit breaker will have the IEC 61 850 GOOSE interface, allowing the microgird controller to receive very low latency event-based messages after each breaker state transition. Relays that are equipped with load-shedding feature (see Table 22) will also listen to a combined message from the microgrid controller that allows for fast tripping of this circuit breaker.

Each circuit breaker will come with its IED Capability Description (ICD) file describing the message being transmitted by each relay. The ICD file name will follow the pattern: <CB_ID>.icd, e.g.: CB100, CB209, CB451

The microgrid controller should transmit messages according to the MGC.icd specification file. It consists of multiple binary inputs mapped within a model to fast-tripping signals of circuit breakers with the load-shedding feature enabled in the order specified in Table 25. Bit value 1 corresponds to the trip request; 0 takes no action.

Note: Load sheding is implemented at the breaker close command input to relay. Request to close command follows the truth function from below table.

Table 24Load shed truth function

Modbus:2001	Load shed	Request close

0/1	0	1
2	0	0
0/1	1	0
2	1	0

Table 25. Map of Microgrid Controller GOOSE Message to Circuit Breaker's Fast-Shedding Trip Inputs

Bit ID	MGC Message to CB_ID
0	**CB100**
1	**CB200**
2	**CB300**
3	**CB104**
4	**CB107**
5	**CB108**
6	**CB109**
7	**CB110**
8	**CB111**
9	**CB113**
10	**CB114**
11	**CB204**
12	**CB206**
13	**CB208**
14	**CB212**
15	**CB213**
16	**CB216**

17	**CB217**
18	**CB218**
19	**CB219**
20	**CB307**
21	**CB308**
22	**CB309**
23	**CB310**
24	**CB401**
25	**CB402**
26	**CB403**
27	**CB405**
28	**CB406**

15.5 Parameters

Contestants can modify selected protective parameters of the generic relay by adjusting the following spreadsheets prior to model compilation.

Table 26. Generic Relay Configuration Files

File name	Contents	Notes
F0_relay_banshee.xlsx	CB100, CB200, CB300	Grid tie feeders parameters
F1_relay_banshee.xlsx	CB101 – CB114	Feeder 1 relay parameters
F2_relay_banshee.xlsx	CB201 – CB219	Feeder 2 relay parameters
F3_relay_banshee.xlsx	CB301 – CB309	Feeder 3 relay parameters
F4_relay_nrel.xlsx	CB401 – CB407	Feeder 4 (PHIL node) relay parameters
DER_relay.xlsx	CBx5x	All DER controlled breakers

Each protection function can be configured by adjusting, for example, pickup or delays. Two sets of parameters are available to allow for a dynamic parameter change using the Modbus interface selector.

During integration testing, contestants are encouraged to modify these files to achieve their performance goals. Prior to the final evaluation, test contestants need to provide the configuration files to the NREL team.

15.6 ABB SACE Emax CB

During the PHIL experiment, CB401 will be replaced with the ABB SACE Emax 2 circuit breaker [9] [10]. It can be controlled and monitored using the Modbus TCP interface [11]. A Modbus TCP register map can be found in [12]. Additionally, the IEC 61850 interface is available; see [11].

16 Cables

Cables between electrical components on the distribution network are modeled as PI section impedances with length and number of parallel sets of conductors. The Institute of Electrical and Electronics Engineers (IEEE) Red Book Table 4A-7 gives values for a 60-Hz impedance for three-phase copper cable circuits in approximate ohms per 1,000 ft. 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 it might be prudent to implement voltage control and power flow optimization.

17 Loads

17.1 Load Priorities

Load are assigned a priority, as described in Table 27 and as indicated with abbreviations in the one-line diagrams in section 2.

Table 27. Load Priorities

Priority	Abbreviation	Objective
Interruptible	**I**	Loads which can be disconnected without penalties during outages.
Priority	**P**	Loads that 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 28. Load Demand Size

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	--
C7	F4	480	500	--
C8	F4	208	400	--
C9	F4	480	60	-
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
P7	F4	480	200	--
P8	F4	208	200	--
I1	F1	480	300	--
I2	F1	208	250	--
I3	F2	208	300	--
I4	F2	480	600	--
I5	F2	480	400	--
I6	F3	480	600	--
I7	F4	480	300	--

I8	F4	208	400	--

17.2 Motor Loads

The largest loads are 200-hp induction line-started motors, with six times the nominal startup current. The locations of these loads are shown in Figure 1.

18 Power quality analyzers

To evaluate power quality of voltage in busses of the system power quality analyzers has beein embedded into real time model. Two type of power quality analyzers are implemented to be able to evaluate KKP5: frequency and voltage quality analyzers. This kind of analyzers are implemented on every bus within the microgrid. Total of 23 analyzers are implemented: six in feeder 1, nine in feeder 2, five in feeder 3 and three in feeder 4.

18.1 Voltage quality analyzer

Frequency is analyzed according to IEEE1547a-2014 standard. Thresholds defined as defaults in Table 29 are used by power quality analyzer to quantify the size of voltage violation. Example voltage event is shown on Figure 12. As long as voltage fits within outlines no error is indicated. When voltage exceeds outline error appears wchich is further integrated. The integrated value is used for KPP5 penalty calculation.

Table 29 IEEE1547a-2014 Table1 describing abnormal voltage response

Default settings[a]		
Voltage range (% of base voltage[b])	Clearing time (s)	Clearing time: adjustable up to and including (s)
V < 45	0.16	0.16
45 ≤ V < 60	1	11
60 ≤ V < 88	2	21
110 < V < 120	1	13
V ≥ 120	0.16	0.16

[a] Under mutual agreement between the EPS and DR operators, other static or dynamic voltage and clearing time trip settings shall be permitted
[b] Base voltages are the nominal system voltages stated in ANSI C84.1-2011, Table 1.

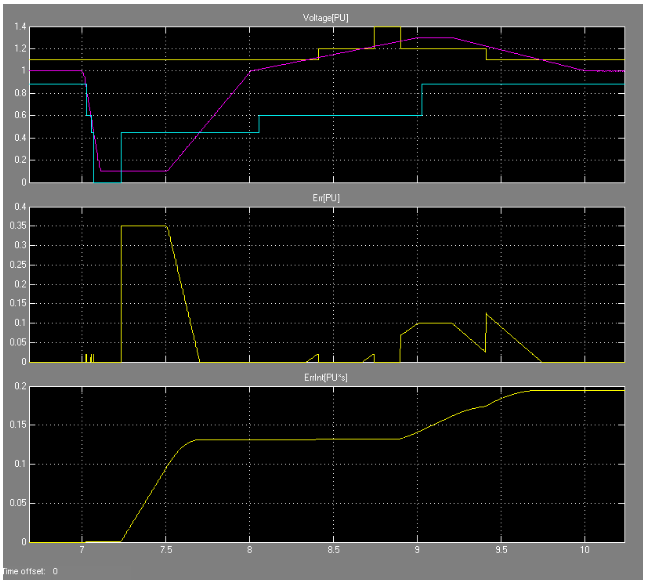

Figure 12 Voltage quality analyzer operating principle (top plot colors: magenta – actual measured rms PU voltage, yellow – top voltage limit, cyan – bottom voltage limit)

18.2 Frequency quality analyzer

Frequency is analyzed according to IEEE1547a-2014 standard. Thresholds defined as defaults in Table 30 are used by power quality analyzer to quantify the size of frequency violation. Example frequency event is shown on Figure 13. As long as frequency fits within outlines no error is indicated. When frequency exceeds outline error appears wchich is further integrated. The integrated value is used for KPP5 penalty calculation.

Table 30 IEEE1547a-2014 Table2 describing abnormal frequencies response

	Default settings		Ranges of adjustability	
Function	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s) adjustable up to and including
UF1	< 57	0.16	56 – 60	10
UF2	< 59.5	2	56 – 60	300
OF1	> 60.5	2	60 – 64	300
OF2	> 62	0.16	60 – 64	10

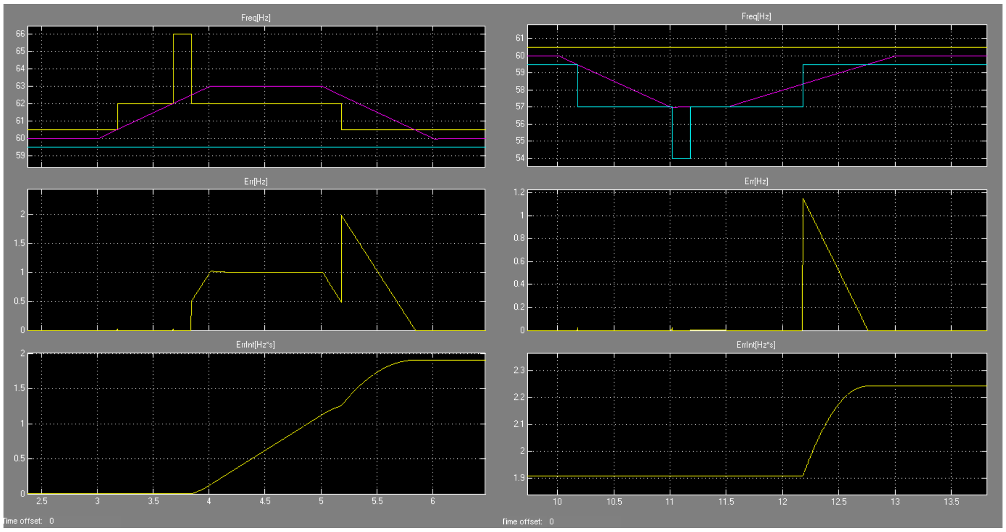

Figure 13Frequency quality analyzer operating principle (top plot colors: magenta – actual measured frequency, yellow – top frequency limit, cyan – bottom frequency limit)

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Appendix A. NREL ESIF Microgrid Research Focus and Capabilities

National Renewable Energy Laboratory (NREL) researchers have extensive modeling and simulation expertise in microgrid control algorithm development, stability analysis, and microgrid operations. In addition, the Energy Systems Integration Facility (ESIF) and Controllable Grid Interface (CGI) at NREL offer world-class testing capabilities for demonstrating microgrid controls and testing at rated power with a connection to a utility grid. Researchers at NREL are available to support the modeling, simulation, and testing of microgrid systems.

20.1 Energy Systems Integration Facility

NREL's ESIF, shown in Figure A-1. , contains a unique collection of laboratories specifically focused on overcoming challenges related to the interconnection of distributed energy systems and the integration of renewable energy technologies into the electric grid. More than a dozen laboratories are divided into four research areas—electricity, thermal, fuel, and data analysis and visualization—and they are connected through multiple electrical, thermal, and fuel busses that enable easy interconnection for testing systems spanning multiple laboratories. The research electrical distribution bus is monitored and controlled with a Supervisory Control and Data Acquisition System that gathers real-time, high-resolution data for monitoring, control, and visualization. A suite of AC grid simulators, load banks, connections to the local electric utility, DC power supplies, photovoltaic (PV) simulators, diesel generators, fixed energy storage devices, mobile electric vehicles, and PV inverters are available for interfacing with microgrid systems. These capabilities make the ESIF a unique environment to test microgrid controller technology, including system functionality and operability testing as well as system compliance with current standards, such as the Institute of Electrical and Electronics Engineers (IEEE) 1547 series of interconnection standards.

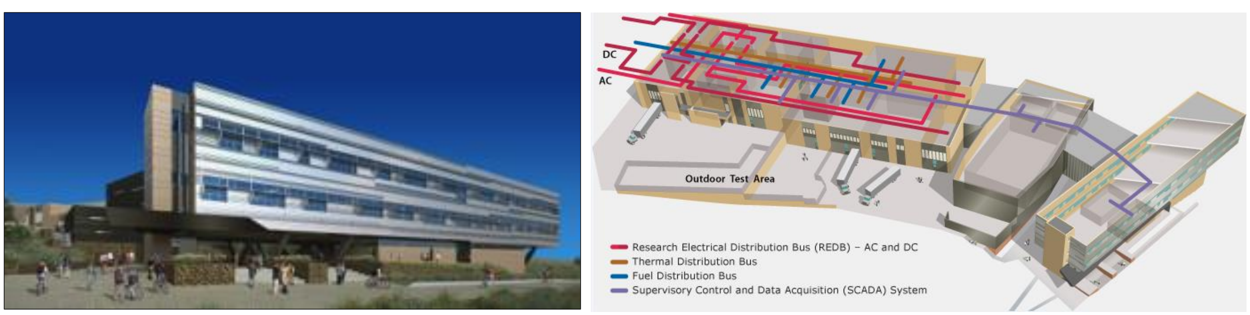

Figure A-1. ESIF facility and multi-energy busses connecting various laboratories

The ESIF's megawatt-scale, power-hardware-in-the-loop (PHIL) capability allows researchers and manufacturers to conduct integration tests of hardware devices in the context of real-time, dynamic grid models. The ESIF's 1-MW, bidirectional, three-phase AC grid simulator has independent phase control that enables simulation of a wide variety of grid scenarios. A 1-MW resistor-inductor-capacitor load bank with 50-VA resolution allows for the development of control and optimal dispatch algorithms for distributed energy resources and loads. The ESIF's overall system level, local control development, and real-time simulation capabilities are shown in Figure 2. The real-time simulation platforms used are Opal-RT/RT-Lab, which is fully integrated with MATLAB/Simulink; and RTDS/RSCAD. Additionally, cosimulation of the real-time simulator with a large number of commercially available power system analysis software tools is possible.

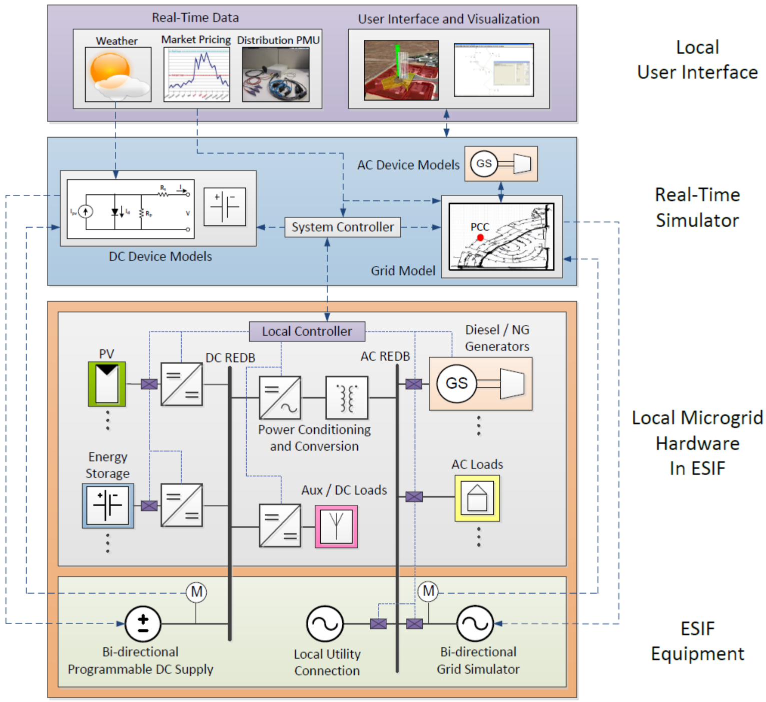

Figure A-2. ESIF facility and multi-energy busses connecting various laboratories

The expansive infrastructure and distinctive connection capabilities at the ESIF allow researchers to test advanced microgrid technologies under many operating scenarios. Potential microgrid tests at the ESIF that can support procurement plan include:

- Performance testing, verification, and validation:
    - Operational functions (e.g., energizing, synchronization)
    - Operating modes (e.g., current control, droop) and states (e.g., on grid, off grid).
- Systems integration and transition testing:
    - Testing key state transitions and sequencing
    - Load-shedding schemes
    - Seamless transitions to microgrid mode.
- Fault and protection testing:
    - Fault contribution of distributed energy resources to varying impedance faults
    - Interaction with typical distribution lateral protection devices.

20.2 Electricity Laboratories at the ESIF

Among some of the unique electricity laboratories at the ESIF that enable microgrid controller technology testing are the Power Systems Integration Laboratory, the Smart Power Laboratory (SPL), and the Energy Storage Laboratory (ESL) described below. These laboratories can be connected via the research electrical distribution bus and the shared Supervisory Control and Data Acquisition system, and have 1-MW scale power testing capability as well as advanced hardware-in-the-loop simulation capabilities.

Power Systems Integration Laboratory

The Power Systems Integration Laboratory enables the development and testing of large-scale distributed energy systems for grid-connected, stand-alone, and microgrid applications. The laboratory can accommodate large power system components, such as inverters for PV and wind systems, diesel and natural gas generators, storage batteries, microgrid interconnection switchgear, and vehicles. Thermal heating and cooling loops and fuel also allow testing of combined heating/cooling and power systems.

Example testing scenarios include:

- Hardware-in-the-loop experiments
- Development of control algorithms for distributed energy resources
- Development and evaluation of optimal dispatch algorithms and communication interfaces
- Simulation of grid conditions for the development and evaluation of power system components and systems
- Islanding and synchronization testing
- Prototype development and testing
- Electrical interconnection testing (i.e., IEEE 1547, UL 1741 types of tests) and advanced functionality testing (i.e., IEEE 1547.4, IEEE 1547.8, IEEE 2030 capability tests) including interoperability and conformance testing
- Model validation testing, performance testing, safety testing, and long-duration reliability testing.

Smart Power Laboratory

The Smart Power Laboratory focuses on the development and integration of smart technologies, including the integration of distributed and renewable energy resources through power electronics and smart energy management for building applications. This laboratory is designed to be highly flexible and configurable, and it is essential for a large variety of smart power applications that range from developing advanced inverters and power converters to testing residential and commercial-scale meters and control technologies.

Some of the application scenarios include:

- Development of power converters for the integration of distributed and renewable energy resources
- Development of advanced controls for smart power electronics and microgrid controller functionality
- Testing prototype and commercially available power converters and microgrid controllers for electrical interconnection and performance, advanced functionality, long-duration reliability, and safety
- Hardware-in-the-loop development and testing for microgrid controller functionality
- Testing advanced microgrid load control (appliances; home automation; heating, ventilating, and air conditioning; and energy management systems)
- Residential-scale generation and storage integrated with home energy managements systems
- Electric vehicle integration
- Advanced metering technology, including utility-grade smart meters and energy metering.

Energy Storage Laboratory

The Energy Storage Laboratory focuses on the integration of energy storage systems (both stationary and vehicle-mounted). The laboratory is focused on battery technologies, but it can host ultra-capacitors and other electrical energy storage technologies. The laboratory provides all resources necessary to develop, test, and prove energy storage system performance and compatibility with distributed energy systems. The laboratory also provides robust vehicle testing capability, including a drive-in environmental chamber, which can accommodate commercial-sized hybrid, electric, biodiesel, ethanol, compressed natural gas, and hydrogen fueled vehicles.

20.3 Controllable Grid Interface at the National Wind Technology Center

In addition to microgrid testing capabilities at the ESIF, the CGI allows microgrid testing at power levels up to 7 MVA (30 MVA instantaneous) and includes the ability to perform hybrid microgrid experiments that include wind turbines, PV, energy storage, and dynamometers. The CGI also provides the ability to perform fault testing.

The CGI is located at NREL’s National Wind Technology Center (NWTC) at the base of the foothills south of Boulder, Colorado. Approximately 11 MW of total variable generation (wind and PV) are currently installed at the NWTC (Fig. 3). This generation mix, in combination with the existing 7-MVA CGI and two multi-megawatt-scale dynamometers that can be used to simulate variable or synchronous generation, creates a unique environment for the testing and demonstration of many grid integration aspects of renewable generation, energy storage, protection equipment, advanced controls, and energy management systems. In addition, a multi-megawatt energy storage testing facility will be available in late 2014 for testing various energy storage technologies.

The CGI also contains PHIL capability, which is used to emulate grid disturbances and estimate grid impacts of renewable energy systems, emerging technologies, and microgrids. In addition, the power electronic interface to the local utility allows providing the ability to absorb a 30-MVA fault (instantaneous). Through a virtual link with the ESIF's supercomputing capabilities, researchers and industry partners can enhance visualizations of complex systems in a virtual environment and realize advanced real-time testing schemes by combining the CGI's extreme flexibility with the ESIF's grid simulator and smart grid capabilities.

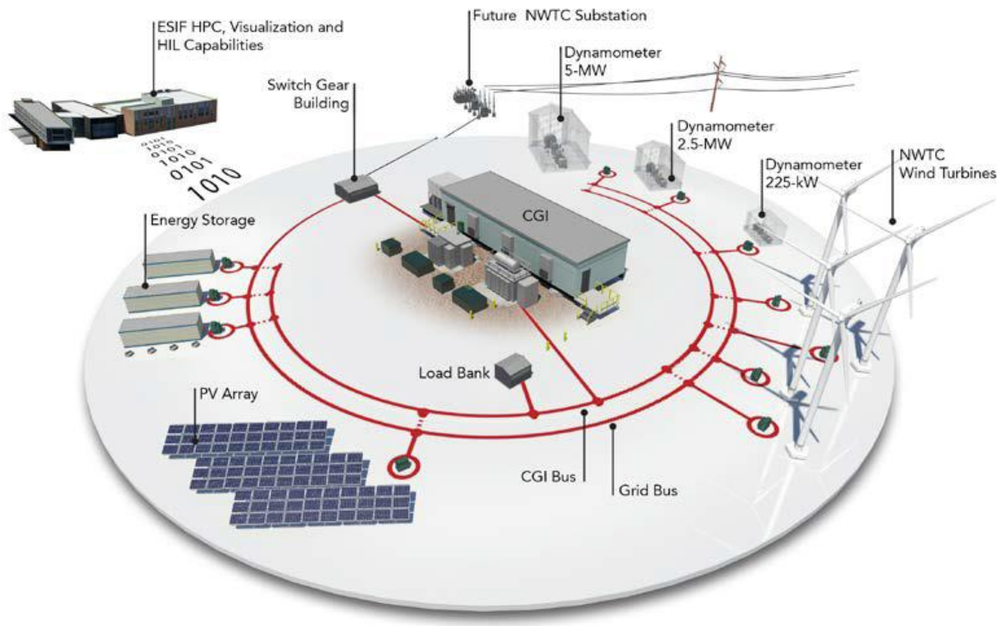

Figure A-3. Controllable grid interface at the National Wind Technology Center

The CGI in combination with the NWTC's variable renewable generation creates a unique platform for microgrid testing at the megawatt scale and provides world-class testing capabilities for Phase 2 testing for the U.S. Department of Energy Microgrid Controller Procurement funding opportunity. Prototype and advanced microgrid controllers can be tested, verified, and optimized in the controlled grid environment coupled with the real variability of multi-megawatt renewable generation. For example, the reliability and effectiveness of advanced microgrid control to achieve voltage and frequency stability in the most economic manner can be tested and demonstrated using the CGI in both a stand-alone microgrid as well as connected to the Xcel operating grid in the Public Service Company of Colorado balancing authority area. Other unique features include testing methods for seamless transition between islanded and grid-connected modes, electrical protection and fault-ride through under real voltage disturbances, and the integration of energy storage and electric vehicle technologies.

Appendix B. Questions and Answers

Vendors can ask questions for clarification of this manual. Relevant questions and answers will be posted in the appendix of this manual.

What will be the metering accuracy and measurement interval that is going to be used?
There are multiple measurement layers. Instantaneous voltages and currents will be sampled 100us within model and converted into PQVF data. This data will be available to vendors over Modbus interface with polling rate configured in vendor's controller. For purpose of KPP evaluation ca. 100ms sampled PQVF data will be used. Additionally for power quality analysis more sophisticated algorithms are going to be implemented in Opal with 100us making sure that voltage disturbances shorter than 100ms are also captured for KPP evaluation.
What are the dollar values for penalties and violations?
Some $ values are already included in instructional packet. All of them will be published to vendors prior to their integration periods. These are actually being refined with base scenarios. See chapter 5.4. Rough guidelines for price evaluations are also given.
Is there a typical load profile for critical and other loads?
For simplicity loads are going to be constant during test execution. Their values can be found in chapter 16. Only generation is going to be variable.
Is there a outages event schedule?
Both planned and unplanned islanding will be performed. Exact timing of this event's will not be published. For planned islanding controllers will get the request and will have 30 seconds to disconnect.
Is there a typical thermal profile for CHP for heat energy calculations?
TBD – as in 2016 symposium
Do we have the inertia values for the generators used?
We can share generator models if needed.
Why are fixed costs accounted for under operation and maintenance?
These are just to offset baseline scenario result. These are exactly the same for all vendors thus doesn't matter for performance comparison.
What is a typical battery cycle assumed for calculating KPP2?
This parameter will have negligible $ value. It is only captured for statistics to be able to compare how much is the ESS used by all vendors.
For DSO commands, what is the typical response time allocated for the controller? What would be the settling time for the controller response and is there a dead band (around $\pm$2%) for the settling value?
Settling time for dispatch / VoltVAR / HzW droops – 1 second. Tolerance around 5%. For planned disconnect request: 30 second and 60 second for reconnect.
For calculating the voltage violations, what is the level of voltage ranges used? Which type of ANSI standard C84.1 standard will be used for evaluation?
IEEE 1547a-2014 – Table 1 - will be used to detect voltage violations on each voltage bus

What are the upper and lower frequency limits and accuracy of measurement for calculating frequency violations?
IEEE 1547a-2014 - Table 2 - will be used to detect frequency violation on each voltage bus

Appendix C. NREL team repository description

This is the repository for models source code and documentation for team participating in 2017 Microgrid Controller Procurement. Access to this repository is only granted to particular team members and NREL staff responsible for competition preparation. Files stored by teams will not be distributed.

20.4 Content of repository

$\0_Instruction

Instruction packet directory stores all released versions of Instruction Packet. Always use the most recent document.

$\1_References

Stores electronic copies of most references mentioned in instruction packet. It includes mostly description of hardware and their interface signals lists used during PHIL stage.

$\5_Source\Components\SimulinkOpal

It consists of libraries used by distribution model. Libraries are generic and can by used in maby possible distribution systems. Some of this libraries consist of unit test models which can be used to quickly characterise some of these devices.

\Genset\NREL_Diesel_Genset_Test_System.mdl is an example of useful unit test model. It allows testing of all 3 generator's steady state and dynamic behaviour. Test sequence implemented includes islanded and grid connected operation together with all the transitions which are implemented using sync check capabilities of relays.

$\5_Source\DistributionSystems\SimulinkOpal\Banshee

It consists of test model which is going to be used during competition and settings specific to this distribution system. Below most relevant files and directories are desribed

UrbanCHIL.mdl - is a real-time model which is going to be used during test execution process. It can be used by teams for intergation tests.

RemoteCHIL.mdl - is a real time model of PHIL node based on Feeder_4.mdl library - the same as used in UrbanCHIL.mdl. It is a smaller and easier to modify model which still utilises most devices which microgrid controller needs to interface to thus may be a good starting point for interation efforts.

relay_settings - NREL repository comes with default relays configuration. Teams may modify this settings. If team wishes to run using modified relay protection settings they should push proposed settings prior to evaluation and inform NREL staff about it.

iec61850_settings - the directory consists of IEC61850 IED files describing one message each. See Instruction Packet 15.4 for more details.

20.5 Use of repository

This repository shall be used as an interface for files exchange between NREL development team and participating vendor teams. NREL will push documentation and source code at given release dates to **master** branch.

Teams should use other branch than **master** to store their code changes. The repository must be used by teams e.g. to store circuit breakers settings excel files which will be used by NREL team in final evaluation - see 15.5 of Instruction packet.

20.6 Opening model in Simulink

To open or edit the model following matlab toolboxes are required (all are 32bit):

MATLAB	Version 8.1	(R2013a)
Simulink	Version 8.1	(R2013a)
SimPowerSystems	Version 5.8	(R2013a)
Simscape	Version 3.9	(R2013a)

Before opening the model (RemoteCHIL or UrbanCHIL) it is required to run *$\5_Source\Components\SimulinkOpal\components_path_init.m* to add components paths to Matlab.