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CERTS MICROGRID LABORATORY TEST BED

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

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Commission Work Authorization No: MR-041

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Acknowledgments

The authors are grateful for the technical direction provided by the Public Interest Energy Research (PIER), Energy Commission staff Bernard Treanton, and former staff Jose Palomo and Mark Rawson.

The authors also acknowledge the technical contributions of the members of the technical advisory committee:

Merrill Smith and, formerly, Poonum Agrawal, U.S. Department of Energy

Richard DeBlasio and Benjamin Kroposki, National Renewable Energy Laboratory

Mohammed Vaziri, Pacific Gas and Electric Company

Scott Lacy, Southern California Edison Company

Mark McGranaghan, EPRI Solutions

Narain Hingorani, independent consultant

This work was supported by the Office of Electricity Delivery and Energy Reliability, Office of Electric Transmission and Distribution, U. S. Department of Energy under contract No. DE-AC02-05CH11231.

Citation

Please cite this report as follows:

Eto, Joseph, Robert Lasseter, Ben Schenkman, John Stevens, Harry Volkommer, Dave Klapp, Ed Linton, Hector Hurtado, Jean Roy, Nancy Jo Lewis. Consortium for Electric Reliability Technology Solutions (CERTS). 2008. *CERTS Microgrid Laboratory Test Bed*. California Energy Commission, Public Interest Energy Research Program. CEC-500-2008-XXX.

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by part nering with RD&D entities, including individuals, businesses, utilities, and public or private res earch institutions.

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CERTS Microgrid Laboratory Test Bed is the final report for the CERTS Microgrid Laboratory Test Bed project (contract number 500-03-024) conducted by CERTS. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

The objective of the CERTS Microgrid Laboratory Test Bed project was to enhance the ease of integrating small energy sources into a microgrid. The project accomplished this objective by developing and demonstrating three advanced techniques, collectively referred to as the CERTS Microgrid concept, that significantly reduce the level of custom field engineering needed to operate microgrids consisting of small generating sources. The techniques comprising the CERTS Microgrid concept are: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications.

The techniques were demonstrated at a full-scale test bed built near Columbus, Ohio and operated by American Electric Power. The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all Institute of Electrical and Electronics Engineers 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

The results from these tests are expected to lead to additional testing of enhancements to the basic techniques at the test bed to improve the business case for microgrid technologies, as well to field demonstrations involving microgrids that involve one or more of the CERTS Microgrid concepts.

Keywords: CERTS, microgrid, control protection, electrical protection, voltage and frequency stability control, inverter, distributed energy resources, distributed generation, distributed resource, islanding.

Executive Summary

Evolutionary changes in the regulatory and operational climate of traditional electric utilities and the emergence of smaller generating systems, including internal combustion engines, microturbines, photovoltaics, and fuel cells, have opened new opportunities for electricity users to generate power on site. In this context, distributed energy resources – small power generators typically located at sites where the energy (both electric and thermal) they generate is used – are a promising option to meet growing customer needs for economic and reliable electric power. In addition to generators, the distributed energy resources portfolio also includes energy storage, and load control. Organizing all of these resources into microgrids is a promising way to capture smaller distributed energy resources' significant potential to meet customers' and utilities' needs.

A key feature of a microgrid, is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid (e.g., in the CERTS Microgrid concept, no impacts on power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid, in an equally seamless fashion.

The CERTS Microgrid concept seeks to provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

The peer-to-peer concept insures that no single component, such as a master controller or a central storage unit, is required for operation of the microgrid. Therefore, by its very design, the CERTS Microgrid can continue operating with loss of an individual component or generator. (With one additional source, (N+1) it can insure even higher levels of reliability.)

The plug-and-play concept means that a distributed energy resources unit can be placed at any point within the microgrid without re-engineering its controls. The plug-and-play functionality is similar to the flexibility one has with home appliances. That is, just as an appliance can be plugged in wherever there is an outlet, one can similarly locate distributed energy resources units at any location within a facility or building where they might be most needed. This is in sharp contrast to the traditional model, which clusters distributed generation at a single point in order to make the electrical integration tasks simpler. In combined heat and power applications, the plug-and-play model facilitates placing distributed energy resources immediately adjacent to heat loads, thereby allowing more effective use of waste heat without a complex heat distribution system, such as steam and chilled water pipes, and the energy losses associated with them.

A critical feature of the CERTS Microgrid is its presentation to the surrounding distribution grid as a single self-controlled entity. A CERTS Microgrid appears to the grid as indistinguishable from other customer sites that do not include DER. This presentation means that the microgrid

avoids many of the current concerns associated with integrating DER, such as how many DER the system can tolerate before their collective electrical impact begins to create problems like excessive current flows into faults and voltage fluctuations.

These functionalities are provided through three advanced techniques comprising the CERTS Microgrid concept, including: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications.

The techniques were demonstrated at a full-scale test bed built near Columbus, Ohio and operated by American Electric Power. See Figure 1. Tecogen and its inverter manufacturer, Youtility, modified and factory tested three combined heat and power units to incorporate the CERTS Microgrid control algorithms. Northern Power Systems designed, fabricated, and factory tested a static switch that implemented CERTS Microgrid islanding and resychronization procedures and also fabricated the other major hardware elements required, including load banks, power and control circuitry, protective relaying, and data-acquisition equipment, installed in metal-clad switchgear cabinets for protection in an outdoor location.

Five sets of tests were conducted by American Electric Power (AEP);

The first set of tests examined the operation of the static switch to determine that it and its digital signal processing control operated as designed. This included five tests of dead-bus and synchronized closing, reverse power and Institute of Electrical and Electronics Engineers (IEEE) 1547 protective relay functions. The goal was to confirm the correct operation (and thus the protection) of the static switch, which is located at the interface between the protected and unprotected portions of the microgrid.

The second set of tests examined a preliminary set of faults (i.e., overload simulating a high impedance fault) within the microgrid to ensure protection and safety of the test bed, prior to performing other planned tests. The fault condition tests were intended to cover the basic concepts of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2T) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to open first, followed by the opening of the zone breaker of the faulted zone. The goal was to test and adjust protection settings to achieve the most ideal conditions and protection design within a limited fault current system. Sixteen separate tests were conducted.

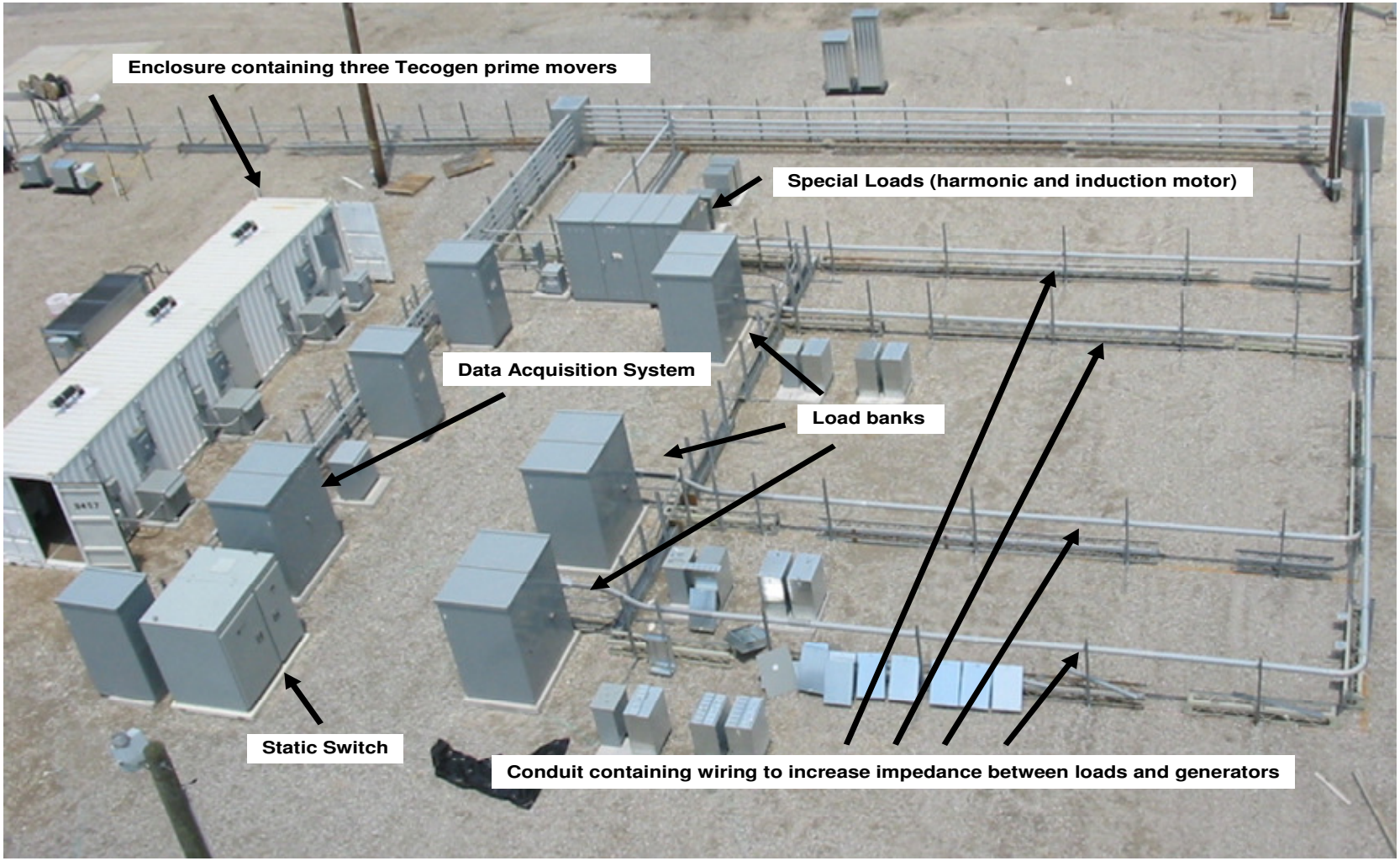

Figure 1. CERTS Microgrid Test Bed at American Electric Power

Photo Credit: American Electric Power

The third set of tests was designed to ensure that the Gen-set inverter controls were working as designed during grid-connected and islanded modes of operation. This includes unit control, zone control, and mixed power controls, in conjunction with limiting controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine-coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions. Thirteen separate tests were conducted.

The fourth set of tests demonstrated the flexibility of the microgrid while both grid connected and islanded, for different loads, power flows, and utility impact. These tests employed "weak grid" inductors in the circuit simulating the microgrid connection at the end of a lengthy feeder. Three sets of tests were conducted.

The fifth and final set of testing began to explore the operational limits of the microgrid with difficult induction motor starting loads. Two primary sets of tests were conducted under "weak grid" conditions.

Detailed, standalone reports (referenced as appendices to this report) were prepared containing narrative descriptions of the purpose and performance goal for each test, along with extensive graphical and tabular summaries of the results for each test.

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

The results from these tests are expected to lead to additional testing of enhancements to the basic techniques at the test bed, to improve the business case for microgrid technologies, as well to field demonstrations involving microgrids that involve one or more of the CERTS Microgrid concepts.

1.0 Introduction

This report describes the Consortium for Electric Reliability Solutions (CERTS) Microgrid Laboratory Test Bed project, which developed and tested innovative strategies for islanding and resychronizing microgrids with the grid, providing electrical protection within the microgrid, and controlling energy sources within the microgrid autonomously during islanded operation. Under earlier research contracts, the CERTS Microgrid team first developed these strategies using computer simulations, and then further refined them with laboratory-scale emulations. In this research contract, the team implemented them in commercial-grade hardware, with thorough testing at several stages of development, including at a full-scale test bed.

1.1. Background and Overview

Evolutionary changes in the regulatory and operational climate of traditional electric utilities and the emergence of smaller generating systems, including internal combustion engines, microturbines, photovoltaics, and fuel cells, have opened new opportunities for electricity users to generate power on site. In this context, distributed energy resources (DER) – small power resources typically located at sites where the energy (both electric and thermal) they provide is used locally – are a promising option to meet growing customer needs for economic and reliable electric power. In addition to generators, the DER portfolio also includes energy storage, and load control. Organizing all of these resources into microgrids is a promising way to capture smaller DER's significant potential to meet customers' and utilities' needs.

The CERTS Microgrid is an entirely new approach to integrating DER. Traditional approaches for integrating DER focus on the impacts on grid performance of a single or relatively small number of microsources. An example of the traditional approach to DER is the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 for Distributed Resources Interconnected with Electric Power Systems. This standard focuses on ensuring that interconnected systems will not affect the operation of the grid should problems arise on the grid. In compliance with this standard, the CERTS Microgrid is designed to seamlessly disconnect and operate as an island, separate from the grid, in case of problems and to reconnect to the grid once the problems are resolved. (Lasseter, et al. 2002. Lasseter, Piagi. 2005. Lasseter, Piagi. 2006.)

A critical feature of the CERTS Microgrid is its presentation to the surrounding distribution grid as a single, self-controlled entity. A CERTS Microgrid appears to the grid as indistinguishable from other customer sites that do not include DER. This presentation means that the microgrid avoids many of the current concerns associated with integrating DER, such as how many DER the system can tolerate before their collective electrical impact begins to create problems like excessive current flows into faults and voltage fluctuations. The CERTS Microgrid architecture insures that the microgrid will be a good citizen within the bulk power provider network, complying with grid rules and doing no harm beyond what would be acceptable from any existing customer. In return for appropriate compensation, the microgrid could provide interruptible load. Although technical barriers currently discourage it, the microgrid could also be a small source of power or ancillary services. The benefits it could offer to the distribution

system include; congestion relief, postponement of new generation or delivery capacity, rapid response to load changes, and local voltage support.

A key feature of a microgrid is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid (e.g., in the CERTS Microgrid concept, with no impact on power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself in an equally seamless fashion.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

The peer-to-peer concept insures that no single component, such as a master controller or a central storage unit, is required for operation of the microgrid. Therefore, by its very design, the CERTS Microgrid can continue operating with loss of an individual component or generator. (With one additional source, (N+1) it can insure even higher levels of reliability.)

The plug-and-play concept means that a DER unit can be placed at any point within the microgrid without re-engineering its controls. The plug-and-play functionality is similar to the flexibility one has with home appliances. That is, just as an appliance can be plugged in wherever there is an outlet, one can similarly locate DER units at any location within a facility or building where they might be most needed. This is in sharp contrast to the traditional model, which clusters DG at a single point in order to make the electrical integration tasks simpler. In combined heat and power (CHP) applications, the plug-and-play model facilitates placing DER immediately adjacent to heat loads, thereby allowing more effective use of waste heat without a complex heat distribution system, such as steam and chilled water pipes, and the energy losses associated with them.

These functionalities are enabled by three innovations: First, the CERTS Microgrid concept relies on embedding intelligence in the interface between the microsources and the surrounding microgrid.[1] This innovation enables autonomous operation of each microsource without high-speed communication or hierarchical control among microsources. This innovation is the key toward enabling a plug-and-play environment in which many microsources can operate harmoniously with one another with a minimum of expensive, custom site engineering.

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[1] For pragmatic reasons of availability and controllability, this CERTS effort initially focused on small internal combustion (IC) engines. All DER technologies, especially those that rely on power electronic interfaces, including microturbines, fuel cells, photovoltaics, and energy storage, are candidates for inclusion in microgrids based on CERTS Microgrid concepts.

Second, as a result of enabling an environment in which, in principle, any number of microsources might operate within a single microgrid, the CERTS Microgrid concept also incorporates an intelligent static switch for rapid disconnect and resynchronization of the entire microgrid to the larger, utility grid at the point of common coupling (PCC). A single, intelligent switch is innovative because it is a much more economic alternative to providing this functionality at each individual microsource.

Third, the CERTS Microgrid includes an innovative, additional level of protective relaying within the microgrid that complements traditional protection. The approach addresses that fact that power electronic interfaces can, by design, limit the fault current available to detect system faults, which is the traditional means used for detecting faults within an electrical network. Thus, while a microgrid can use bi-directional over-current protection devices when connected to the utility, it cannot rely on these approaches when the microgrid is islanded. The CERTS Microgrid protection scheme uses sequence components to detect low-fault currents in utility-connected and islanded operation. This protection scheme allows for plug-and-play without changing the existing over-current devices on the electrical system.

The development and testing of the CERTS Microgrid concept is the culmination of over 7 years of research efforts supported by both the U.S. Department of Energy and (DOE) the California Energy Commission (Energy Commission). In 2001, the DOE provided research support to develop the initial CERTS Microgrid concept. In 2002, the Energy Commission began providing research support to demonstrate the CERTS Microgrid concept. Under prior Energy Commission Contract # 150−99−003, Tasks 2.4 and 2.7, in the area of Distributed Energy Resources Integration, the CERTS team: 1) conducted analytical simulations of aspects of the concept (Lasseter, et. al. 2002); 2) prepared the design for test bed where a full-scale demonstration of the concepts could be tested (Appendix A. Test Bed Design Schematics); and 3) completed a review of potential sites and research partners where the test bed could be built (Akhil, et. al. 2002).

This document is the final report for the testing that has been conducted at the test bed.

The CERTS Microgrid Laboratory Test Bed project team initially included Lawrence Berkeley National Laboratory (LBNL); Sandia National Laboratory (SNL); the University of Wisconsin (UW); and Northern Power Systems (NPS), which designs, builds and installs electric power systems. Through this project, the CERTS team was expanded to include Tecogen, Inc., a manufacturer of engine-driven cooling and combined heat and power (CHP) systems, and Youtility, a supplier of power electronic systems for distributed power. In addition, American Electric Power (AEP), one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states, was selected by the team to host the test bed and conduct the tests.

The CERTS team was aided throughout the research process by a Technical Advisory Committee (TAC) consisting of representatives from 1) the DOE's Office of Electricity Delivery and Energy Reliability; 2) two major California electric utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) with expertise in interconnection of distributed

generation; 3) the National Renewable Energy Laboratory (NREL) who manage aspects of the IEEE 1547 standards development process; 4) the Electric Power Research Institute (EPRI) with expertise in power quality; and 5) an independent consultant with expertise in power electronics.

1.2. Project Objectives

The objectives of this project were to:

- Demonstrate stable operation of the CERTS control algorithms during a variety of conditions including:
- Transitions between utility-interconnected and islanded operation
- Islanded operation that involved such traditionally difficult loads as motor starting
- Demonstrate the ability to detect faults within the microgrid under a variety of conditions when either interconnected to the utility or islanded

The CERTS Microgrid Laboratory Test Bed project meets the PIER Goal of Improving the Reliability/Quality of California's Electricity by creating technologies and control strategies needed to capture the full potential of DER to improve the reliability and quality of the California interconnected power system. This project also meets the secondary goal of Improving the Energy Cost/Value of California's Electricity by lowering the cost of power delivery.

1.3. Report Organization

The CERTS Microgrid Laboratory Test Bed project consists of one technical task, CERTS Microgrid Laboratory Test Bed, with four Subtasks and five Sub-subtasks, as follows:

Subtask 2.1: Select a laboratory test bed

Subtask 2.2: Prepare equipment for the test bed

Sub-subtask 2.2.1: Prepare three prime movers and inverters for the test bed, including factory acceptance testing

Sub-subtask 2.2.2: Design, fabricate and factory test other test bed equipment, including the static switch

Subtask 2.3: Conduct tests of the CERTS Microgrid concept at the test bed

Sub-subtask 2.3.1 Prepare the test bed for testing

Sub-subtask 2.3.2 Conduct tests of the CERTS Microgrid concepts

Sub-subtask 2.3.3 Prepare a microgrid protective relaying report

Subtask 2.4 Plan a field demonstration of the CERTS Microgrid concept

The next two major sections of this report, 2.0 Project Approach and 3.0 Project Outcomes, follow this Subtask and Sub-subtask structure.

The report is supplemented by a number of stand-alone technical appendices that provide additional information and details on the results from all subtasks and sub-subtasks of this project. Several, separate appendices were required to organize voluminous tabular and graphical summaries of the data collected from each of the many tests conducted at the test bed.

2.0 Project Approach

The CERTS Microgrid Laboratory Test Bed project implemented the CERTS Microgrid concept and test bed design initiated under Energy Commission Contact #150-99-003, tasks 2.4 and 2.7, to develop tools and techniques for significant integration of distributed technologies in support of electricity reliability.

The subsections below describe the approach taken under each Subtask and Sub-subtask and in the project.

2.1. Test Bed Selection (Subtask 2.1)

The goal of this task was to select and execute a contract with a facility to conduct a full-scale test-bed demonstration of CERTS Microgrid concepts. The task included developing criteria for selecting a testing facility and, using information from past reviews conducted by the team to identify candidate sites, working with the Technical Advisory Committee (TAC) and Energy Commission Contract Manager to select the most appropriate site. Finally, following the Commission Contract Manager's approval, LBNL was to execute a subcontract with the Energy Commission-approved facility.

2.2. Equipment Preparation (Subtask 2.2)

The goal of this subtask was to enter into contracts with a microsource manufacturer, Tecogen/Youtility, to prepare three microsource prime movers with modified inverters and with a DER engineering firm, Northern Power Systems (NPS), to fabricate test bed hardware including a static switch, for use in the laboratory test bed demonstration (Subtask 2.3).

The first phase of work required Tecogen/Youtility to upgrade the current design of its inverter to incorporate CERTS Microgrid control algorithms and to conduct extensive factory tests of the modified microsource prime movers and inverters (Sub-subtask 2.2.1). The machines had to be as identical to one other as possible so that impacts from machines with differing characteristics did not mask important observations about performance, especially during transients, within the test bed. Because of the technical requirements for the test bed prime movers, the supplier had to be able to dedicate a small, technically skilled team to this project. The supplier also had to have the flexibility to revisit and rebuild aspects of the units because the team expected that initial testing would reveal the need for modifications.

In the original Energy Commission contract, Capstone Microturbines was expected to supply the modified microsource prime movers. However, Capstone Microturbines declined to execute a contract with LBNL due to a change in business priorities and withdrew from the project. Following an introduction provided by the Energy Commission contract manager, the team partnered with Tecogen/Youtility to supply the modified prime mover microsources and inverters. Aspects of the laboratory test bed design were modified by NPS to accommodate this change in prime movers.

The second phase of work required NPS to develop and conduct factory tests of a static switch that implements the CERTS Microgrid islanding and resynchronization procedures (Sub-

subtask 2.2.2). As an additional element of the second phase of work, NPS also fabricated the major electrical components required by the test bed, such as load banks and emulators, switchgear, and the data acquisition system (DAS). NPS was well-qualified to conduct this work because they had, under a previous Energy Commission contract with CERTS, prepared the complete design of the laboratory test bed.

2.3. Laboratory Tests (Subtask 2.3)

The goal of this subtask was to conduct tests of the CERTS Microgrid concept. That is, the laboratory test facility selected in Subtask 2.1 was to build the test bed and conduct tests of the test bed equipment, prime movers, and static switch prepared under Subtask 2.2. This subtask was conducted through three sub-subtasks.

The goal of sub-subtask 2.3.1 was to prepare the test bed for conducting the tests. This involved preparation of the physical test bed site following the design of the test bed, which was prepared under an earlier contract. (See Figures 2, 3, and 4, which are based on Appendix A, Test Bed Design Schematics). The tasks included erection of enclosures to house the microsources and associated facilities to cool the engines in operation and the laying out of conduits and associated wiring to interconnect the microgrid elements. Finally, the task involved installing the cabinets assembled by NPS as well as the microsources prepared by Tecogen/Youtility. See Figure 1.

The goal of sub-subtask 2.3.2 was to conduct a large number of tests exercising all functions of the CERTS Microgrid concept. This goal was accomplished in three phases. First, a detailed test plan was developed. Second, the tests were executed following the test plan. Third, the test results were analyzed and assessed with respect to the test plan and overall project objectives.

The CERTS team, led by NPS, developed a comprehensive list of tests that would exercise every aspect of the CERTS Microgrid concept. The tests were presented to and refined through discussions with the TAC. After the list of tests was deemed complete, AEP developed "registered" test procedure, following AEP corporate rules that would meet all testing needs safely. This registered test procedure is presented in Appendix B. CERTS Microgrid Testbed – Test Plan.

The registered test procedure contains ten sections. The first five are procedural. Sections six through ten refer to actual tests in which measurements are recorded. The tests were conducted by AEP in accordance with the registered test procedure. Testing was conducted sequentially, one section at a time.

Prior to each test day, the person in charge performed a job safety briefing including an inspection of the barricades and test setup for safety and compliance. A minimum of two people were on-site during each planned test

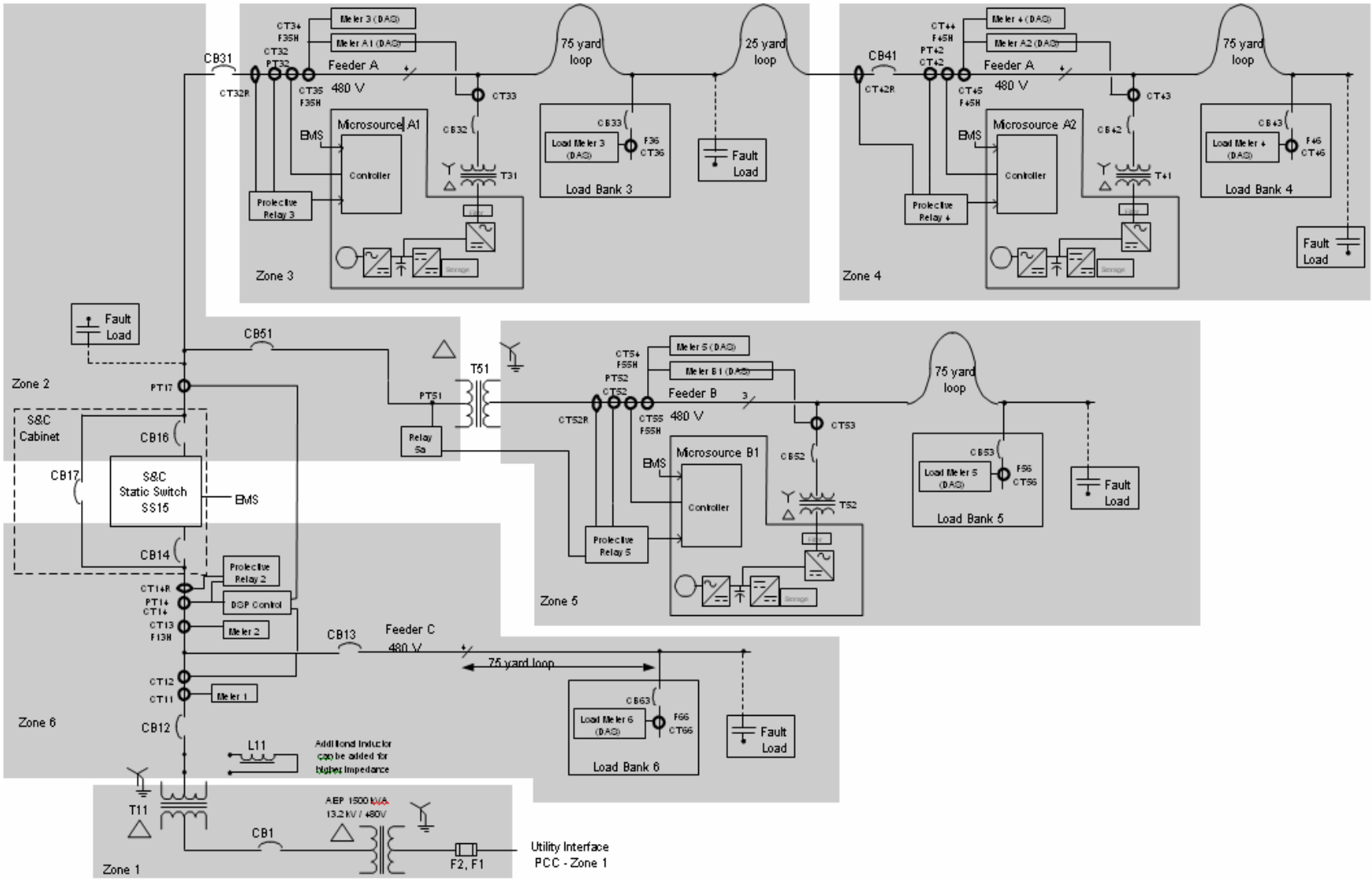

Figure 2. One-Line Diagram of CERTS Microgrid Test Bed

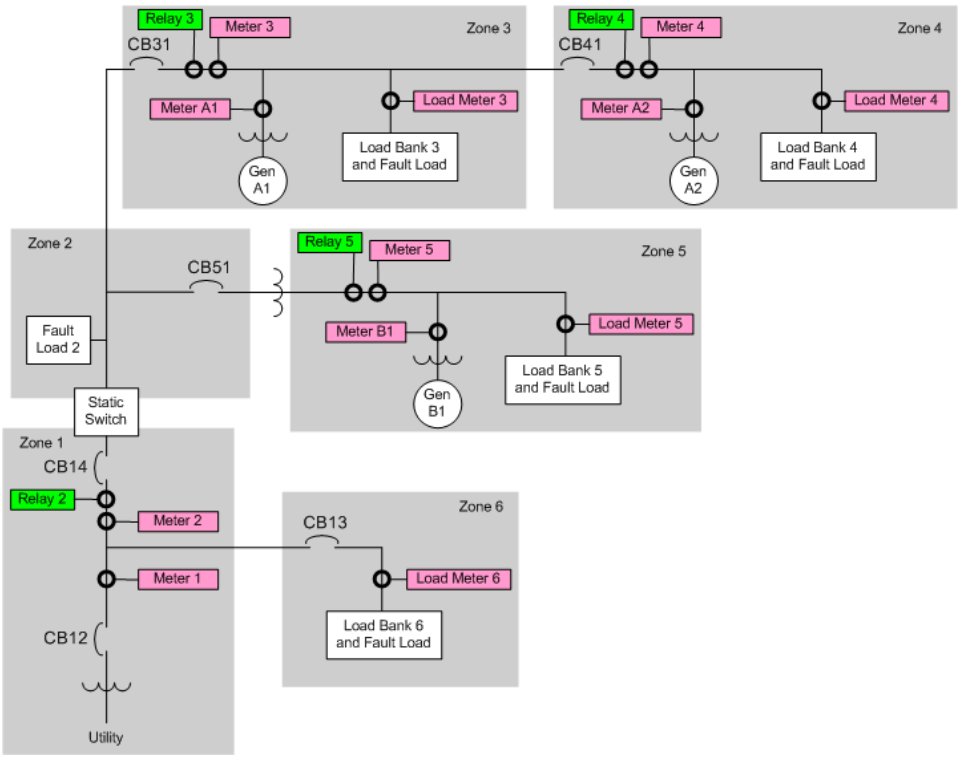

Figure 3. One-Line Diagram with Meter and Relay Locations CERTS Microgrid Test Bed

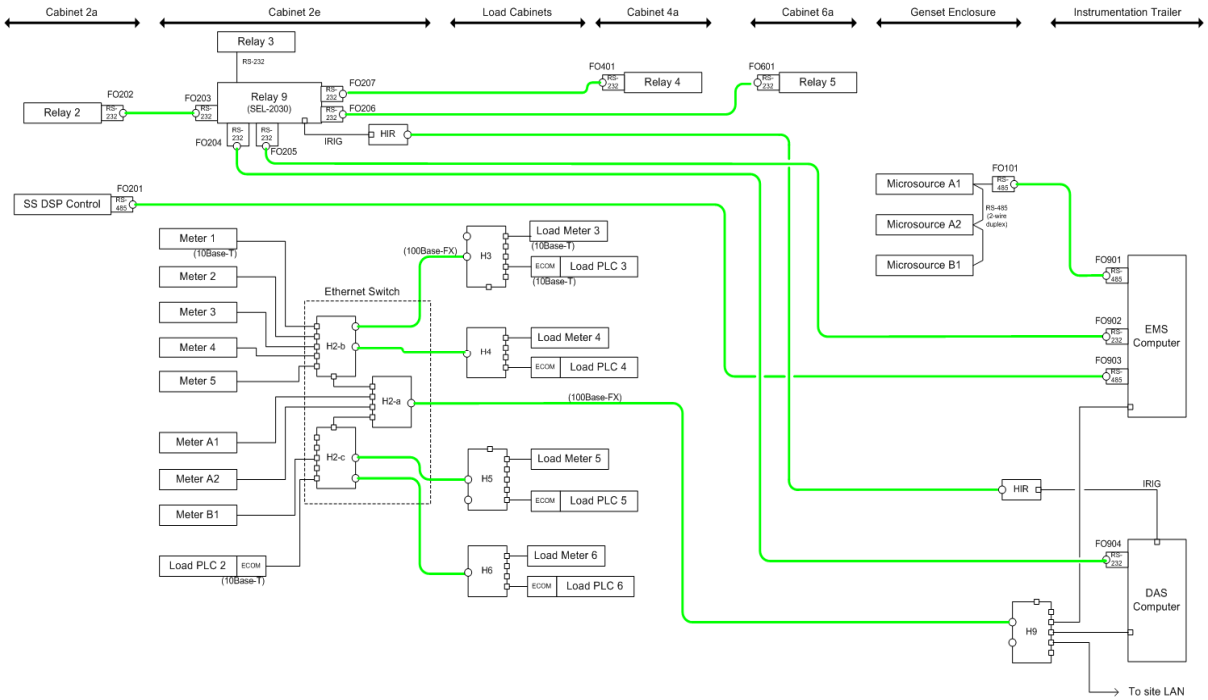

Figure 4. Diagram of DAS & EMS Data networks

Visual and audible alarms warned persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed," not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Microgrid Test Bed area (i.e., saw-horse style barricades with a red plastic chain surrounded the test area containing the Gen-set Enclosure, Microgrid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

The first set of tests (Section 6 of the test plan) examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. The goal was to confirm the correct operation (and thus the protection) of the static switch, which is located at the interface between the protected and unprotected portions of the microgrid. Successful completion of these tests was a prerequisite to performing subsequent tests in the test plan.

The tests were designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. They included five tests of dead-bus and synchronized closing, reverse power and IEEE 1547 protective relay functions. The switch functions were tested with a single Gen-set A1 online. The measurements taken were unique to each test. Waveform and RMS data from Meter 2 were of prime interest.

The second set of tests (Section 7 of the test plan) examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The goal was to confirm the new protection design developed in Task 2.3.3. This goal was to be accomplished by testing and adjusting protection settings to achieve the most ideal conditions and protection design. The tests included inductor L11 in the circuit, reflecting "weak grid" conditions. Sixteen separate tests were conducted.

The fault (i.e., overload simulating a fault) condition tests were intended to cover the basic concept of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2t) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to "OPEN" first, followed by the zone breaker of the faulted zone.

During each fault event waveforms of phase currents and line-to-neutral voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded. The relay element that caused the "TRIP" with trip times for each relay relative to when the fault condition was applied was also recorded.

Two power control modes were defined for the third and fourth sets of tests:

Unit Power Control Mode controls the amount of power (i.e., kW) being injected into the Zone from the Gen-set being controlled.

Zone Power Control Mode controls the amount of power (i.e., kW) entering/exiting the Zone using the Gen-set to offset the difference in that Zone.

The third set of tests (Section 8 of the test plan) was designed to ensure that the Gen-set inverter controls were working as designed. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions (i.e., static switch "OPEN"/ "CLOSE" and load steps). Thirteen separate tests were conducted.

Several measurements were made for each test:

- Sources –Injected power (kW), reactive load (kVAr), frequency (freq), and voltage (V) for each Gen-set (i.e., A1p, A2p and B1p).
- Zone input power flow into Zones 3 (A1z), 4 (A2z), 5 (B1z) and 6.
- Loads - Voltage at Load Bank 3 (L3), 4 (L4), 5 (L5), and 6 (L6).
- Static Switch - Power (kW) and current (I) through the static switch.
- Static Switch Control Signal: Forced "OPEN" and release to allow self synchronization.
- Voltage (V) and frequency (Freq) difference across the static switch.

The fourth set of tests (Section 9 of the test plan) demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The tests included the "weak grid" inductors (i.e., L11) in the circuit. Three sets of tests were conducted.

The measurements taken for these tests involved collecting RMS data for V, I, kW, kVAr, and Freq for each flow change at the following points:

- Meter 1 –V, I, kW, kVAr for the utility connection
- Meter 2 - V, I, kW, kVAr and utility-side V and Freq
- Meter 3 - V, I, kW, and kVAr for Feeder A and Microgrid side V and Freq
- Meter A1p – V, I, kW, kVAr for Gen-set A1
- Load Meter 3 – V, I, Zone 3 load kW and kVAr
- Meter 4 – V, I, kW, kVAr for Zone 4
- Meter A2p – V, I, kW, kVAr for Gen-set A2
- Load Meter 4 – V, I, Zone 4 load kW and kVAr
- Meter 5 – V, I, kW, kVAr for Feeder B

- Meter B1p – V, I, kW, kVAr for Gen-set B1
- Load Meter 5 – V, I, Zone 5, Feeder B load kW and kVAr
- Load Meter 6 – V, I, Zone 6, Feeder C load kW and kVAr

In addition V and I waveform data for unexpected events and for static switch transitions.

The fifth and final set of testing (Section 10 of the test plan) began to explore the operational limits of the microgrid (i.e., power quality, protection and inverter limits). Two primary sets of tests were conducted under "weak grid" conditions; the first involved induction motor starting loads under balanced and unbalanced load conditions; the second involved only unbalanced loads.

The measurements collected included the following:

- RMS data for kW, kVAr V, and I injected by each Gen-set
- Freq at each connection point
- V and I from Meters 1 - 5, and Load Meters 3 - 6

The analysis of the test results consisted of comparing test results to findings from earlier analyses of CERTS Microgrid concepts. As noted, successive analysis and testing of the CERTS Microgrid concepts have include analytical simulation, laboratory-scale emulations, and factory testing of the commercial-grade hardware installed at the test bed.

A number of software tools were used to process raw test data into a format suitable for review and presentation. These included: PQView, AcSELerator QuickSet Designer, Excel, and Word. Test results were posted by AEP onto a secure website where they could be reviewed and discussed by the entire CERTS team.

Test bed results were then presented and discussed with the TAC. TAC members were also invited to review and provide comments each of the extensive reports that have been prepared detailing the results of the testing.

The goal of sub-subtask 2.3.3 was to develop an innovative approach to provide protective relaying within the microgrid. The approach addresses that fact that power electronic interfaces, by design, limit the fault current available to detect system faults, which is the traditional means for detecting faults within an electrical network. Hence, in addition to traditional protection schemes that were already in place, the CERTS team, led by University of Wisconsin, needed to design an additional level of protection for faults that occur within the microgrid. These designs were then implemented and tested as part of the tests conducted in sub-subtask 2.3.2.

2.4. Field Demonstration Planning (Subtask 2.4)

The goal of subtask 2.4 was to identify and engage one or more partners for a field demonstration of the CERTS Microgrid concept. While a field demonstration was not to be conducted in this project, it was important to engage potential partners prior to and during the

laboratory test-bed phase so that partner-specific technical or operational issues could be addressed in the test bed prior to conducting the field demonstration.

This task was a continuation of work initiated under a previous Energy Commission agreement (amendment #150-99-003, task 2.7). That contract led to preparation of a field demonstration planning and partner recruitment strategy. The current task continued the implementation of that strategy.

The approach primarily involved conducting meetings with potential field demonstration partners to brief them on the CERTS Microgrid concept and test bed prior to and during the testing. Other activities that contributed to field demonstration planning by increasing the visibility of the CERTS Microgrid concept to a wide audience included presentations and publications of the CERTS Microgrid concept in a variety of fora, including professional meetings, domestic and international conferences, and academic and trade publications. These activities directly contributed to and supported follow-up discussions with potential field demonstration partners.

3.0 Project Results

This section presents projects results from Subtasks 2.1-2.4 of the Microgrid Laboratory Test Bed project. As discussed earlier, the project produced a number of deliverables. Several of these are quite voluminous, as they contain extensive tabular and graphical summaries from each of the tests conducted at the test bed. For brevity, this report only summarizes and highlights selected findings from these deliverables. This report is supplemented by numerous, separately bound appendices, which contain these detail project findings; these appendices are referenced throughout the following discussions.

3.1. Test Bed Selection (Subtask 2.1)

The goal of Subtask 2.1 was accomplished through the selection of and execution of a contract with the American Electric Power Company to join the CERTS team to build the test bed and conduct the testing program. The steps including developing selection criteria, applying them to candidate facilities, and determining the most qualified facility.

The final test site selection criteria included the following:

1. Physical requirements
    a) Adequate space for the test bed and generators (including safe working space around equipment)
    b) Availability of a "stiff" distribution voltage (preferably 15kV class)
    c) Availability of natural gas
    d) Availability of "standard" test equipment
2. Personnel –Test engineers and technicians with appropriate experience
3. Project leader with appropriate experience
4. Corporate interest and involvement
5. Timing and availability to meet CERTS requirements
6. Utility-owned and operated site – Important for utility community acceptance of the credibility of test results
7. Accessibility of test site to interested researchers

Under an earlier Energy Commission contract 150-99-003, the CERTS team conducted a preliminary assessment of possible sites for the test bed.[2] Based on this preliminary assessment, the team applied the above criteria and identified three candidate test sites:

1. Pacific Gas and Electric (PG&E) Technology and Ecological Services, San Ramon, California;
2. Southern California Edison (SCE) Electric Vehicle Technology Center, Pomona, California
3. American Electric Power (AEP) Dolan Technology Center, Groveport, Ohio

[2] "Review of Test Facilities for Distributed Energy Resources" by A. Akhil, C. Marnay, and T. Lipman, SAND2003-1602, May, 2003.

Input from the TAC and discussions with the Energy Commission contract manager on the list of final candidate test sites and the test site selection criteria led the team to modify the scope of sub-subtask 2.2.2 to have NPS also fabricate the majority of the test bed hardware, rather than have it fabricated by the test facility. There were two reasons: First, the team determined that the test facility should be selected primarily based on its ability to conduct the tests, not based on its ability to fabricate test bed hardware. Second, NPS was uniquely qualified to fabricate the equipment because it had designed the equipment, as part of its preparation of the overall test bed design (conducted as part of an earlier Energy Commission contract 150-99-003.

With this revised scope for the test facility, the team then sent a questionnaire to each of the three final candidate sites requesting detailed written information on four topics:

1. Required steps to prepare the physical site;
2. Equipment availability, data acquisition hardware and approach, and energy management system (EMS);
3. Personnel; and
4. Project scheduling and coordination.

At this point, PG&E indicated that would not able to respond because it would not be able to conduct the tests within the available time, largely due to prior commitments to other Energy Commission PIER DER Integration projects. This potential conflict was acknowledged by the Energy Commission contract manager and it was agreed that PG&E should not be considered to host the tests.

The CERTS team and the Energy Commission contract manager then scheduled oral presentations from representatives from both SCE and AEP. On the basis of these presentations, the CERTS team and the Energy Commission contract manager further followed up with on-site visits to the proposed test sites at both SCE and AEP.

Following the site visits, the team recommended the selection of AEP, as the host for the test bed. The SCE site did not have a natural gas supply line and would have required extensive modifications to the electric service interconnection. The AEP site was well-suited physically, had natural gas service, and had an appropriate electric service interconnection.

In conjunction with the contract award, AEP and CERTS entered into a Memorandum of Understanding to work cooperatively in areas of mutual interest for research, development, and demonstration of distributed energy resource (DER) technology microgrids. Subsequent to the initiation of work on this Energy Commission project, CERTS and AEP have won a competitive solicitation from the U.S. Department of Energy to conduct additional tests using the microgrid equipment developed in this project.

3.2. Equipment Preparation (Subtask 2.2)

The goal of subtask 2.2 was accomplished by work led by Tecogen and their subcontractor, Youtility, to modify three Tecogen prime movers to incorporate CERTS Microgrid control algorithms (Sub-subtask 2.2.1) and by work led by NPS to fabricate a static switch that implemented CERTS islanding and resychronization procedures and fabricate the other major hardware elements required by the CERTS laboratory test bed design. A critical element of these sub-subtasks involved detailed factory acceptance testing to confirm the performance of the equipment prior to shipment to AEP.

3.2.1. The Prime Movers and Inverters (Sub-subtask 2.2.1)

CERTS contracted with Tecogen to obtain three 100kW prime movers, each of which was modified to incorporate the CERTS Microgrid control algorithms. The complete systems, which were delivered and installed in the CERTS Microgrid test bed site at AEP, each included an engine/generator, a "surge module" and an inverter. See Figure 5.



Figure 5. Tecogen Prime Mover with Inverter

A critical aspect of this project was the incorporation of the CERTS Microgrid control algorithms into the inverters provided by Youtility. This required not only providing the algorithms to Youtility, but also providing Youtility with an in-depth understanding of the function of these algorithms so that they could understand the expected response, and the significance of deviations from that response, when the completed inverters were subjected to test scenarios. Providing this understanding required considerable interaction between the Youtility designer and the project's technical director from the University of Wisconsin, Professor Robert Lasseter.

Professor Lasseter also provided Youtility with a set of test scenarios that were used to confirm correct operation of the completed inverters. These test scenarios then comprised a Youtility factory acceptance test that was performed prior to sending the inverters to Tecogen. The test report for the Youtility factory acceptance tests is included as Appendix C. Youtility Factory Test Plan Final Test Results.

The prime mover for the engine/generator is a 454 cubic inch displacement natural gas-fired V8 reciprocating engine. This engine was designed to be operated at an engine speed selected to give the best combination of fuel efficiency and response to load changes. Thus, the engine speed will not necessarily be synchronous with a 60Hz system. The electrical generator a variable AC output which is rectified to a direct current (DC) output. The inverter converts the DC to utility-synchronous AC. For this project, the inverter was modified to incorporate the CERTS Microgrid control algorithms. The surge module is an energy storage device, consisting of batteries, power electronics, and controls, which is tied to the DC bus in parallel with the electrical generator and the inverter. The purpose of the surge module is to provide instantaneous power when there is a load increase, while waiting for the engine/generator to adjust its speed to the new loading conditions. The inverters and surge modules were both supplied to Tecogen by Youtility, Inc. Tecogen integrated the entire prime mover system and performed a set of factory acceptance tests, as specified by the CERTS team, before Tecogen shipped the units to the test bed site. (See Appendix D. Tecogen 60kW Inverter–Based CHP Modules Factory Testing.)

Once at AEP's facilities, the Tecogen units were retested to ensure there had been no shipping damage. The tests confirmed that the performance of the units once installed at AEP was consistent with the factory tests. (Appendix E. Tecogen CHP Modules Commissioning Report.)

3.2.2. The Static Switch and Other Test Bed Equipment

CERTS contracted with NPS to design, fabricate, and test a static switch that implemented CERTS Microgrid islanding and resychronization procedures and to fabricate the other major hardware elements required by the CERTS laboratory test bed design, including load banks, power and control circuitry, protective relaying, and data-acquisition equipment, installed in metal-clad switchgear cabinets for protection in an outdoor location.

NPS designed and built the controls that would allow the static switch to implement the CERTS Microgrid islanding and resychronization procedures. The controls were implemented onto the static switch hardware associated with the Purewave uninterruptible power supply system manufactured by S&C Electric. See Figure 6. The islanding procedures consisted of trip sensing (i.e., detect and trip on IEEE 1547-specified criteria such as voltage or frequency deviations and reverse power flow) followed by disconnection (islanding) of the microgrid from the utility. The voltage-trip function included trip-characteristics required by IEEE 1547 for distributed resource interconnection, those specified by the Information Technology Industry Council for power quality, as well as a custom-voltage-versus-time-trip characteristic that could be specified by the user.

The resynchronizing function had to meet a more stringent requirement than the commonly accepted criteria of IEEE 1547. The reason for the more stringent requirement was to insure transient free transitions for power flow either into or out of the microgrid at the instant of switch closing. IEEE 1547 requires the phase difference across the switch is less than 20° before the switch can close. This phase difference is too large for for our needs. We require closing at a zero phase difference. The high-speed static switch and digital signal processing (DSP), insures that the voltage phase difference a closing is zero.



Figure 6. The Static Switch

NPS tested the static switch with low-level power (i.e., signal injection) to confirm proper operation before shipping the switch to AEP. TAC members from the National Renewable Energy Laboratory shipped additional testing equipment and lent expertise to NPS in support of this testing. (Appendix F. CERTS Test Bed CERTEQUIP-V06-002, CERTS Switch, Low Power Factory Acceptance Test Report.)

Once at AEP's facilities, the switch was retested with low power to ensure there had been no shipping damage. After confirming that the static switch was in good condition, AEP performed further testing at the Dolan Test Facility to examine selected power quality issues prior to installing equipment at the test bed. (Appendix G. Summary of CERTS Microgrid Static Switch Power Quality Tests at AEP Dolan, CERTS Microgrid Static Switch Testing.)

NPS also fabricated cabinets containing all the sensing hardware for the protection and data-acquisition equipment; the circuit breakers, switches and fuses; and all the loads. The loads include a variety of resistive, inductive, capacitive and motor loads as well a six-pulse power rectifier to provide a non-linear load.

3.3. CERTS Microgrid Laboratory Tests

This section describes the preparation of the laboratory test bed for testing (Sub-subtask 2.3.1), the results of the CERTS microgrid laboratory tests (Sub-subtask 2.3.2), and the development of an approach for internal protection within the microgrid (Sub-subtask 2.3.3).

3.3.1. Prepare Laboratory Test Bed for Testing

After preparing the site, erecting supporting structures, cooling equipment, and wiring, and installing the equipment prepared by NPS and Tecogen/Youtility, AEP and Northern Power performed a field acceptance test. See Figure 1. The field acceptance testing also included exercising the complete data acquisition and control systems. After completing this testing and rectifying the minor issues that it uncovered, the team declared the test bed ready to conduct the full set of CERTS Microgrid tests, as outlined in the test plan. (Appendix H. CERTS Test Bed Design and Commissioning Lessons Learned Summary.)

3.3.2. Test of CERTS Microgrid Concepts

As described in section 2.3.2, five sets of tests were conducted. The results of these five sets of tests are contained in separate, stand-alone appendices to this report, as follows:

1. Static Switch (Section 6 of the test plan – 6 tests – Appendix I)
2. Protection (Section 7 of the test plan – 16 tests – Appendix J)
3. Reduced System (Section 8 of the test plan – 13 tests – Appendix K)
4. Power Flow Control (Section 9 of the test plan – 3 banks of tests – Appendix L)
5. Difficult Loads (Section 10 of the test plan – 1 set of motor starting tests – Appendix M)

Each appendix contains a narrative description of the purpose and performance goal for each test, along with graphical and tabular summaries of the results for each test. In addition, a sixth appendix (Appendix N) contains the test log developed by AEP during the conduct of the tests.

For brevity, this report will summarize and highlight selected findings for each of the five sets of tests. This includes listing each test conducted and its performance objective. The interested reader is referred to the individual appendices to see detailed results from each test performed.

The first set of tests (Section 6 of the test plan) examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. This included six tests of dead-bus and synchronized closing, reverse power and IEEE 1547 protective relay functions. These tests were designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal was to ensure that, by confirming the correct operation of the static switch, which is located at the interface (and thus serves as the protection) between the unprotected and protected portions of the microgrid, was ready to perform the remaining tests.

A synchronized closing test of the static switch was required to verify that when conditions were within synchronization limits set in the EMS, the static switch performed a synchronized close and thus provided a smooth connection transition. The dead-bus bus (de-energized bus) reclose test's goal was to verify that the static switch can close when de-energized bus conditions exist on the Gen-set side of the static switch; and that the dead-bus reclose algorithm requires user interaction (i.e., Operator needs to "Enable" the dead-bus reclose using pushbutton in the EMS).

The reverse power tests consisted of three tests: three-phase reverse power condition test, single-phase reverse power condition test, and anti-islanding Micro-grid settings reset test. Both three-phase and single-phase reverse power condition tests were required to verify the reverse power functionality of the static switch and confirm that the static switch islands the microgrid for a three-phase or single-phase reverse power conditions. The anti-islanding Micro-grid settings reset test was needed to verify that if a reverse power event occurred, due to a mismatch of Gen-set settings (i.e., total Gen-set power is greater than Microgrid load), the static switch will lockout and go to the "Fault" state, where user interaction is required.

The next goal was to verify the reconnection timers of the static switch (i.e., set by default at 300 seconds based on IEEE Standard 1547-2003). The length of time is programmed into the control system and designed to prevent reconnection until after the utility source voltage returns to nominal steady state conditions.

Table 1 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
6.1. Start-up system, synchronized closing	Verification that when conditions are appropriate (within synchronization limits set in the EMS), the switch can perform a synchronized closing and thus give smooth closing transitions.	When electrical system conditions met established criteria, the static switch performed a synchronized “Close”. A smooth voltage transition occurred from island to utility-connected mode.
6.2. Reverse power, grid islanding (IEEE 1547, loss of utility service)	Verify the reverse power functionality of the static switch and confirm that the static switch islands the Microgrid for a reverse power condition due to an upstream utility operation at the PCC. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standard).	The static switch islanded the microgrid from the utility grid due to an undervoltage condition. This occurred after the utility feeder opened separating the microgrid with 500kW of feeder load which was supplied by Gen-set A1 until the static switch opened. Once the static switch opened Gen-set A1 continued serving the protected load within the microgrid. After 300 seconds, the static switch synchronized and closed back into the utility grid with a smooth transition.
6.3. Reverse power, single-phase (IEEE 1547 voltage events)	Verification that the static switch islands the Microgrid when a reverse power condition, due an open-phase occurs. Note there are no single-phase breakers to disconnect the utility; reducing the load on one phase of the Microgrid will simulate the “open phase” condition. This condition does not properly test the reconnection logic, after an open phase, since the utility voltage will still be present on all three phases (i.e., test didn’t really disconnected a phase).	When A-phase of Load Bank 6 was reduced near 0kW a single-phase reverse power condition was created and the static switch opened. The microgrid remained electrically stable, matching generation with load demand. Once the A-phase of Load Bank 6 was increased above the reverse power threshold and the static switch was reset a synchronized closed occured.
6.4. Reverse power, anti-islanding microgrid settings reset	Verify that if a reverse power event occurs, due to a mismatch of Gen-set settings (Total Gen-set power > Microgrid load), the static switch will lockout and go to the “Fault” state, where user interaction is required.	Load was reduced within the microgrid which caused the static switch to open on a reverse power condition. The Gen-sets picked up the load within the microgrid. All loads were reset and the static switch synchronized and closed back into the utility.

6.5. De-energized bus (dead bus) reclose	Verify that the static switch can close when de-energized bus conditions (< 15V) on the DG side are measured and that the Dead Bus Reclose algorithm requires user interaction (i.e., Operator needs to “Enable” the Dead Bus Reclose using pushbutton in the EMS).	The static switch synchronized and closed into the utility grid with less than 15V on the DG side.

Table 1. Static Switch Testing Summary

The second set of tests (Section 7 of the test plan) examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The goal was to test and adjust protection settings to achieve the most ideal conditions and protection design. The tests included inductor L11 in the circuit, reflecting "weak grid" conditions. Sixteen separate tests were conducted. The fault (i.e., overload simulating a fault) condition tests were intended to cover the basic concept of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2t) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to "OPEN" first, followed by the zone breaker of the affected zone. The objective was to confirm the protective action detailed in the Protection document developed in Task 2.3.3.

Test 7.1 induced a three-phase-to-ground balanced overload fault condition in Zone 4 to verify the I^2t protection and a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection. Zone 3 and Zone 5 were tested similar to Zone 4 by introducing a three-phase-to-ground balanced overload fault and a single line-to-ground fault conditions in the zones, verifying the protection scheme in Test 7.2 (Zone 3) and Test 7.3 (Zone 5). During the 7.1, 7.2 and 7.3 tests, all three Gen-sets were off-line and the CERTS Microgrid was connected to the utility. Test 7.4 tested a three-phase-to-ground balanced overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus to confirm a reverse power event after the zone breaker "opens".

Test 7.5 through Test 7.10 involved applying a single line-to-ground overload fault condition in each Zone, located beyond the static switch, while connected to the utility grid. Each one of the six tests differs from one another by which Gen-sets are on-line during the fault, which phase is faulted, and in which zone the fault is applied. These tests were designed to verify zero-sequence, negative-sequence or residual over-current protection settings. Test 7.5 verified the protection in Zone 3 by applying a single line-to-ground overload fault condition with Gen-sets A1 operating in parallel with the utility grid. Test 7.6 tested a single line-to-ground overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.7 tested a single line-to-ground overload fault condition in Zone 5 with Gen-set B1 operating in parallel with the utility grid. Test 7.8 tested a single line-to-ground overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid. Test 7.9 tested a single line-to-ground overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.10 tested a single line-to-ground overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in parallel with the utility grid.

Tests 7.11 and 7.12 both applied a single line-to-ground overload fault condition in Zone 6 while connected to the utility. Test 7.11 involved only Gen-set A1 operating in parallel with the grid; and Test 7.12 involved Gen-sets A1 and B1 operating in-parallel with the grid. Both tests were designed to verify the I^2t protection of the breaker in Zone 6.

The four tests, 7.13 – 7.16, applied a line-to-line overload fault condition in one of the five zones beyond the static switch with a combination of two Gen-sets, operating in parallel with the

utility grid. These tests were designed to test negative-sequence, I^2t protection or residual over-current protection settings. Test 7.13 tested a phase-to-phase overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.14 tested a phase-to-phase overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.15 tested a phase-to-phase overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid. Test 7.16 tested a phase-to-phase overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid.

Table 2 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
7.1. Validate zone 4 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 4 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 4 detected an I^2t protection event and opened circuit breaker CB41 during the three-phase balanced fault. All other breakers remained closed. Relay 2 detected a ground over-current during the single line-to-ground fault and opened the static switch. All other breakers remained closed.
7.2. Validate zone 3 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 3 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 3 to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 3 detected an I^2t protection event and opened circuit breaker CB31 during the three-phase balanced fault. All other breakers remained closed. Relay 2 detected a ground over-current during the single line-to-ground fault and opened the static switch. All other breakers remained closed.
7.3. Validate zone 5 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 5 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 5 to verify zero-sequence, negative-sequence or residual over-current protection	Relay 5 detected an I^2t protection event and opened circuit breaker 5 during the three-phase balanced fault. All other breakers remained closed. Relay 5 detected a negative-sequence over-current during the single line-to-ground fault and opened circuit breaker CB51. All other breakers remained closed.
7.4. Zone 4 three-phase un-grounded fault, gen-sets (A1+A2), utility connected	Test a three-phase balanced fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus confirm a reverse power event after the Zone breaker “opens”.	Relay 4 detected an I^2t protection and opened circuit breaker CB41. The static switch opened 30 seconds later due to a reverse power event.
7.5. Zone 3 A-phase line-to-ground fault, gen-set A1, utility connected	Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 3 opened circuit breaker CB31 0.15 seconds after the static switch when it detected a ground over-current
7.6. Zone 3 A-phase line-to-ground fault,	Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 and A2 operating in-	Relay 2 detected a ground over-current and opened the static switch in 0.02 seconds. Relay 4 opened circuit breaker CB41 0.07 seconds

gen-sets (A1+A2), utility connected	parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection	after the static switch when it detected a neutral over-current. Relay 3 opened circuit breaker CB31 0.04 seconds after circuit breaker CB41 when it detected a ground over-current.
7.7. Zone 5 B-phase line-to-ground fault, gen-set B1, utility connected	Test a single line-to-ground fault condition in Zone 5 with Gen-sets B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection	Relay 5 opened circuit breaker CB51 in 0.07 seconds when it detected a ground over-current. The static switch opened 0.03 seconds after circuit breaker CB51 when it detected a negative sequence over-current.
7.8. Zone 5 B-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition	Relay 5 opened circuit breaker CB51 in 0.06 seconds when it detected a ground over-current. All other breakers remained closed.
7.9. Zone 4 B-phase line-to-ground fault, gen-sets (A1+A2), utility connected	Test a single line-to-ground fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 4 opened circuit breaker 4 0.058 seconds after the static switch when it detected a ground over-current.
7.10. Zone 2 C-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 3 opened circuit breaker CB31 0.17 seconds after the static switch when it detected a ground over-current. Relay 5 opened circuit breaker CB51 due to an under-voltage condition.
7.11. Zone 6 C-phase line-to-ground fault, gen-set A1, utility connected	Test a single line-to-ground fault condition in Zone 6 with Gen-set A1 operating in-parallel with the utility grid to verify I^2t protection.	Relay 2 detected a neutral over-current and opened the static switch in 0.07 seconds. Circuit breaker CB13 tripped on an I^2t protection event.

7.12. Zone 6 C-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 6 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify I^2t protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition.	Relay 2 detected a neutral over-current and opened the static switch in 0.07 seconds. Circuit breaker CB13 tripped on an I^2t protection event.
7.13. Zone 3 A-to-B phase fault, gen-sets (A1+A2), utility connected	Test a phase-to-phase fault condition in Zone 3 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 2 detected a negative sequence over-current and opened the static switch in 0.028 seconds. All other breakers remained online.
7.14. Zone 4 A-to-B phase fault, gen-sets (A1+A2), utility	Test a phase-to-phase fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 2 detected a negative sequence over-current and opened the static switch in 0.078 seconds. Relay 4 opened circuit breaker CB41 after the static switch when it detected a negative sequence over-current.
7.15. Zone 2 A-to-B phase fault, gen-sets (A1+B1), utility connected	Test a phase-to-phase fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	There was not enough current produced by the fault, therefore, all breakers remained closed during the test.
7.16. Zone 5 A-to-B phase fault, gen-sets (A1+B1), utility connected	Test a phase-to-phase fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 5 detected a negative sequence over-current and opened circuit breaker in 0.075 seconds. Relay 2 opened the static switch 0.016 seconds after circuit breaker CB51 when it detected a negative sequence over-current.

Table 2. Internal Protection Testing Summary

The third set of tests (Section 8 of the test plan) was designed to ensure that the Gen-set inverter controls were working as designed. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions (i.e., static switch "OPEN"/ "CLOSE" and load steps). Thirteen separate tests were conducted.

Test 8.1 verified smooth transitions in Gen-set A1 when different step conditions of load are applied in Load Bank 3 with voltage set points ranging from +5% to -5%. The same test was repeated for Gen-set A2 and Load Bank 4 and Gen-set B1 and Load Bank 5.

Test 8.2 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A1 to a lower limit of zero kW.

Test 8.3 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A2 to an upper limit of 60kW.

Test 8.4 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions with an un-balanced load in Zone 3.

Test 8.5 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode. During a load step change in Load Bank 3, Gen-set A1 was driven to an upper limit of 60kW.

Test 8.6 verified smooth transitions of Gen-sets, A1 in zone operation mode and Gen-set A2 in Unit operation mode. During a load step change in Load Bank 4, Gen-set A1 is driven to its maximum which causes an automatic reset of the zone set points.

Test 8.7 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A.

Test 8.8 verified smooth transition of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded.

Test 8.9 verified smooth transition of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded. Gen-set A1 was driven to its maximum which caused an automatic reset of both Gen-sets set-points.

Test 8.10 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded.

Test 8.11 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded. When

islanded, Gen-set A1 and B1 set-points were reset based on the remaining load in the islanded system.

Test 8.12 tested the manual procedure used to black-start the CERTS Micro-grid Test Bed in the event of a lengthy utility outage occurs with the Gen-sets off-line.

Test 8.13 was designed to determine the black-start capacity by increasing the amount of load on the CERTS Microgrid Test Bed from a black-out condition without generation or protection trips.

Table 3 summarizes the test performance goals and results from each of these tests

Test Description	Performance Goal	Results
8.1. Initial voltage regulation test – single zone, islanded with gen-set A1	Verify smooth transitions of Gen-set A1 response to different step conditions of load in Load Bank 3 with voltage set point changes ranging from +5% to -5%. Repeat tests with Gen-set A2 in Load Bank 4, and then Gen-set B1 in Load Bank 5	All Gen-sets had smooth transitions through each load step and voltage change.
8.2. Open static switch test, check P = 0 limit, gen-set A1	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with the unit power limit of Gen-set A1 equal to zero	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.3. Open static switch test, check P = 60kW limit, gen-set A2	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with the unit power limit of Gen-set A2 equal to 60kW	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.4. Test island operation, unbalanced load	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with an un-balanced load condition in Zone 3	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.5. Mixed mode operation test – Zone 3 and 4, gen-set A1 to 60kW maximum	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with a 60kW limit and A2 in Unit operation mode, during a load step change in Load Bank 3	Gen-set had smooth transition from grid connected to island mode and vice versa. Gen-sets responded as predicted.
8.6. Mixed mode operation test – Zones 3 and 4, automatic reset of zone level set-point	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with an automatic reset of the set point and A2 in Unit operation mode, during a load step change in Load Bank 4	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.7. Mixed mode operation test –	Verify smooth transitions of Gen-sets, A1 in Zone	Gen-sets had smooth transition from

Zones 3 and 4, zone power change	operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A	grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.8. Mixed mode operation test – Zones 3 and 4 , zone power change when islanded	Verify smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.9. Mixed mode operation test – Zones 3 and 4, when islanded, automatic reset of zone level set-point, both gen-sets P = 60kW Maximum	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with automatic reset of set point and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.10. Two sources in zone control - separate zones, when islanded, automatic reset of zone level set-point, new zones sum equal zero	Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.11. Two sources in zone control - separate zones, when islanded, automatic reset of zone level set-points	Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode and both having automatic reset of set points, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.12. Test generator black-start	Bring up the Microgrid Test Bed from a black-out condition without generation or protection trips. Measurement – Record the transition of the Gen-set meters as they are started and brought on-line and as load banks are switched on-line. Note, the transition time between all events outage occurs with the Gen-sets off-line This test checks the manual procedure used to black-start the Microgrid Test Bed in the event of a lengthy utility	Gen-sets had smooth transitions and met the load demand.

8.13. Test/establish generator black-start capacity	Determine the Black-start capacity of the microgrid by increasing the amount of load on the Microgrid Test Bed from a black-out condition without generation or protection trips	Total capacity was not determined because the Gen-set stayed online during each test supplying the load demand even for the 70kW + j30kVAr load. This test proved that the Gen-sets are more robust for blackstart then previously predicted.

Table 3. Reduced System Testing Summary

The fourth set of tests (Section 9 of the test plan) demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The tests included the "weak grid" inductors (i.e., L11) in the circuit. Three sets of tests were conducted.

Tests 9.1 – 9.3 verified and documented power flow and microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. In each test, 9.1 – 9.3, a series of tests were performed that vary in the amount of load that is applied to the microgrid in a weak grid scenario along with the power settings of each Gen-set. The difference between each test is the type of control mode that the Gen-sets are in. In Test 9.1, all the Gen-sets were set for unit control mode and then the next test, 9.2, all the Gen-sets were set for zone control mode. Test 9.3 mixed the unit and zone control modes of the Gen-sets during each test.

Table 4 summarizes the test performance goals and results from each of these tests

Test Description	Performance Goal	Results
9.1. Unit control mode, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. During each sequence of tests , maintain a weak grid connection with L11 in the circuit and the static switch “Closed”; all zone and load bank circuit breakers “Closed”; Gen-sets A1, A2 and B1 set for Unit (injection power) control mode; and all load banks initially set at zero	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.
9.2. Zone control mode, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation.	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.
9.3. Mixed zone and unit control modes, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation.	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.

Table 4. Power Flow Control Testing Summary

The fifth and final set of testing (Section 10 of the test plan) began to explore the operation limits of the microgrid (i.e., power quality, protection and inverter limits). Two primary sets of tests were conducted under weak grid conditions; the first involved induction motor starting loads under balanced and unbalanced load conditions; the second involved only unbalanced loads.

Motor start tests conducted in Test 10.2 had balanced loads at a 0.9 power factor under weak grid conditions. These tests verified and documented power flow, microgrid frequency changes, and protection design with different Gen-set settings during motor starts when utility connected and then again during islanded mode of operation. Test 10.3 was similar to Test 10.2, except that the loads were unbalanced with a 0.9 power factor.

In Test 10.4 verified and documented power flow, microgrid frequency changes, and protection design with different Gen-set settings during changes of unbalanced load in load banks.

Table 5 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
10.2. Motor Start Tests, Weak Grid, Balanced Load	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and island mode of operation.	CERTS Microgrid remained electrically stable during the 10 Hp induction motor start in Zone 3 while utility connected and islanded mode for all six test.
10.3. Motor Start Tests, Weak Grid, Unbalanced Load	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and island mode of operation.	CERTS Microgrid remained electrically stable during the 10 Hp induction motor start in Zone 3 while utility connected and islanded mode for all six test.
10.4. Unbalanced Load Tests, Weak Grid	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during changes of unbalanced load in Load Banks while utility connected and in islanded mode of operation.	Static switch opened on a reverse power trip while utility connected in Tests 10.4.12 and 10.4.14 when Load Banks 3 and 6 A-phase was reduced by 50%. CERTS Microgrid remained electrically stable when the A-phase in the load demands equaled 0kW and in island mode of operation. The static switched opened on a reverse power trip for all three tests when the microgrid was reconnected to the utility grid. Once the static switch opened, the CERTS microgrid remained electrically stable. All test results performed as predicted.

Table 5. Difficult Load Testing Summary

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

Test bed results were then presented and discussed jointly with and then reviewed individually by members of the TAC. The reviews were uniformly positive:

"Concepts are elegant, yet simple. Simple translates to more affordable."

"Demonstration that static switch can comply with 1547, with non-compliant generation behind it, is a major accomplishment. The team has confirmed that a static switch is very fast. It is recognized that ground fault testing on the utility side of the static switch is still missing from this aspect of 1547 compliance."

"Inverter controls are impressive."

"Test plan was well laid-out. A wide range of concerns that were identified have now been successfully addressed. In particular, motor starting was a challenging test and the results are very encouraging. Should be a major contribution to the literature."

"The test bed platform should be used for future research."

A summary of the TAC meeting at which test bed results were reviewed as well as the additional written comments received from the TAC are contained in Appendix O. Technical Advisory Committee Meeting Summary and Review Comments.

In addition, AEP has prepared a standalone technical assessment and recommendations:

> "The major objective of plug and play gen-sets has been proven to work very well and is seen as a major stepping stone toward increasing the commercial adoption of microgrids. The keystone of this plug and play approach is the CERTS frequency versus power and voltage versus VAR algorithms which have proven to be robust in the control of multiple voltage source inverters on a common bus. The specific advantages offered by this approach are expected to include: improved operation, more manageable equipment requirements, all at lower total system costs compared to a traditional custom-designed distributed generation power system involving multiple prime movers.
>
> In addition, the concept of placing generation, which is non-compliant with IEEE Standard 1547, beyond a static switch, which is compliant, was tested and proven to be successful. This is expected to be another effective tool in reducing the cost of a

traditional custom-designed, distributed generation power system involving multiple prime movers, while still maintaining safe interconnection with a utility system.

It is recognized that the tests conducted by AEP represent the first full-scale tests of the CERTS Microgrid Concept. AEP looks forward to participation in future research and testing to advance this Concept. Toward this end, we recommend focus on the following areas:

1. Demonstrate the ability of power electronic inverters to adjust fault contribution from the gen-sets.
2. Re-examine and potentially re-tune the anti-islanding philosophy governing operation of the static switch, in light of expected unbalanced voltages presented by utility distribution systems to the microgrid.
3. Develop and test means for minimizing VAR flows by using the Energy Manager to direct voltage set-point changes to the gen-sets based on actual voltages on the utility distribution system.
4. Continue testing to explore performance of the CERTS Microgrid in supporting difficult loads.
5. Confirm the adequacy or revise the management of the static switch when the utility closes into a dead bus.
6. Examine enhanced functionalities for the Energy Manager to address customer and utility needs, such as power factor correction, fault and error handling, energy efficiency, and price- or reliability-driven demand management.
7. Examine system impacts for scenarios involving significant deployment of microgrids."

3.3.3. Microgrid Protective Relaying Design

Traditionally, power flow in the existing electrical infrastructure flows from the power plant through transmission and possibly distribution lines to the load that is demanding power. Protection schemes were based on this concept, which allowed for uni-directional over-current protection devices to be installed. Uni-directional over-current protection devices sense when there is a fault on the electrical system by opening up when the current exceeds a certain value in a certain direction.

Uni-directional over-current protection schemes are not feasible within microgrids, because of microgrids' reverse power-flow capability; if current is flowing in the opposite direction (i.e., from the microsources toward the point of common coupling (PCC)), it will not trip the over-current device when a fault occurs. A microgrid can use bi-directional over-current protection devices when the microgrid is connected to the utility but not while the microgrid is islanded. During islanded operation, the microgrid fault current magnitudes are less significant than

when the microgrid is connected to the utility, so uni-directional and bi-directional detection may not detect the fault current preventing the protection device from operating.

The team developed a protection scheme that uses sequence components to detect low-fault currents in utility-connected and islanded operation. Sequence components take a balanced or unbalanced voltage or current and break it up into three separate components: positive, negative, and zero sequence. Adding these three components together gives the magnitude and phase angle of balanced and unbalanced currents and voltages. A single line-to-ground fault produces a zero sequence current, providing a trip signal for the zone with the fault that does not depend on the direction of the current and magnitude as is the case with traditional over-current protection devices. A line-to-line fault produces a negative sequence current that signals the zone with the fault to trip. This protection scheme allows for plug-and-play without changing the existing over-current devices on the electrical system.

The technical report on the microgrid protective relaying design is contained in Appendix O. Microgrid Fault Protection Based on Symmetrical and Differential Current Components.

3.4. Field Demonstration Planning (Task 2.4)

The goal of task 2.4 was to identify and engage one or more partners for a field demonstration of the CERTS Microgrid concept. While a field demonstration was not included in the project plan for this project, it was important to engage potential partners prior to and during the laboratory test bed phase so that partner-specific technical or operational issues could be addressed in the laboratory test bed prior to conducting a field demonstration.

The identification of potential field demonstration partners took place through a variety of means. Central to most of them was outreach conducted through a variety of presentations and publications.

Presentations

R.H. Lasseter, "Advanced Distribution using DER," Rethinking T&D Architecture for DER, 24 April 2008, T&D Panel, Chicago

R.H. Lasseter, "DER and Microgrids," IEEE Distinguish Lecturer, IEEE PES St. Louis chapter, 6 November 2007

R.H. Lasseter, "Microgrids and Distributed Generation," ASCE Journal Energy Engineering, Volume 133, Number 3, September 2007.

H. Nikkhajoei and R.H. Lasseter, "Microgrid Protection," IEEE Panel: Microgrid Research and Field Testing, IEEE PES General Meeting, 24-28 June 2007, Tampa, FL

R.H. Lasseter, "Extended Microgrid Using (DER) Distributed Energy Resources," IEEE Panel: Sustainable Energy, IEEE PES General Meeting, 24-28 June 2007, Tampa, FL

R.H. Lasseter, "CERTS Microgrid," Panel on Microgrids Systems, International Conference on System of Systems Engineering, April 16-18, 2007 San Antonio

R.H. Lasseter, "CERTS Microgrid," ERDC/CERL_RDCOM, Army Engineers, 18 January 2007, Champaign, Ill.

R.H. Lasseter, "Microgrids on Distribution Scale," Panel, Army Installation Energy Security & Independence Conference, Greensboro, N.C., 12-13 December 2006

R.H. Lasseter. "Methods for Controlling Multiple Independent Generators in an Intentional Island (Microgrids)," Minnesota Power 11/8/06

R.H. Lasseter. "Distributed Energy Resources and Microgrids," IEEE Distinguish Lecturer, IEEE Cuernavaca, Mexico, 2 July 2006.

R.H. Lasseter. "Directions In Microgrid research", PSerc Lecture, 6 June 2006, Madison, Wi

R.H. Lasseter." Autonomous Control", 2006 PES General Meeting, 22 June 2006, Montréal, Québec Canada

R.H. Lasseter. "Microgrids and Protection", CERTS IAB Meeting, 27 June 2006, Cleveland, Ohio

R.H. Lasseter. "Enhanced Microgrid", Microgrid Road Map. 18 May 2006, Office of Electric Energy, Washington, DC

R.H. Lasseter. "Dynamics Distribution", IEEE T&D Meeting, Panel on Future of Distribution, Dallas, 20 May 2006 "Enhanced Business Case for CERTS Microgrid", Peer Review Meeting for the Department of Energy's , Electric Distribution R&D Program, 26 May 2006, San Ramon Ca

R.H. Lasseter. "The Role of Distributed Energy Resources in Future Electric Power Systems", Energy System Seminar, 27 March 2006, Madison, Wi

R.H. Lasseter. "DER based Distribution", DOE Energy Workshop, Panel, January 31 to February 1 2006, Tallahassee, Fl

R.H. Lasseter. "Microgrid Test Plan", CERTS IAB Meeting, 6 October 2005, Cleveland, Ohio

R.H. Lasseter. "CERTS Microgrid", International Microgrid Workshop, Panel Speaker, 17 June 2005, University of California-Berkeley, Berkeley, California

R.H. Lasseter. "CERTS Microgrid", California Energy Commission R&D Forum, 4 May 2005, Sacramento, Ca

R.H. Lasseter. *"Microgrid: A Conceptual Solution,"* Wisconsin Distributed Resources Collaborative, September 16, 2004

R.H. Lasseter. "CERTS Microgrid," CEC Technical Advisory Committee Meeting, July 19, 2004

R.H. Lasseter. *"Where are Microgrids Going?,"* Distributed Resources Workshop, CEA, May 9-11, 2004 Calgrary

R.H. Lasseter. *"Microgrids: What's Next,"* PSerc Industrial Advisory Board, May 20-21, 2004

Publications

Klapp, D., H.T. Vollkommer. *Application of an Intelligent Static Switch to the Point of Common Coupling to Satisfy IEEE 1547 Compliance*. Panel: Microgrid Research and Field Testing IEEE PES General Meeting, 24-28 June 2007, Tampa, FL. 4 pages.

Lasseter, R.H., P. Piagi. 2006. *Control and Design of Microgrid Components.* January. 257 pages. http://www.pserc.org/ecow/getpublicatio/reports/2006report

Lasseter, R. *Dynamic Distribution using (DER) Distributed Energy Resources*. 2006. IEEE PES T & D Meeting, Dallas, May. 3 pages.

Lasseter, R.H. 2007. "Microgrids and Distributed Generation." *Journal of Energy Engineering*, Volume 133, Issue3, ASCE, Sept. 7 pages.

Lasseter, R.H. 2007. "CERTS Microgrid." International Conference on System of Systems Engineering , April 16-18. 6 pages.

Nichols, D.K., J. Stevens, R.H. Lasseter, J.H. Eto, H.T. Vollkommer. 2006 *Validation of the CERTS Microgrid Concept: The CEC/CERTS Microgrid Testbed*. Power Engineering Society General Meeting, IEEE. 3 pages.

Nikkhajoei, H., R. H. Lasseter. 2007. *Microgrid Protection*. IEEE PES General Meeting, 24-28, Tampa, FL. June. 6 pages.

Nikkhajoei, H., R. H. Lasseter. 2006. *Microgrid Fault Protection Based on Symmetrical and Differential Current Components*. December. 72 pages. (Power Systems Engineering Research Center (PSERC) website)

Panora, R.A., J.B. Gehret Jr., P. Piagi. 2007. *Design and Testing of an Inverter-Based Combined Heat and Power Module for Special Application in a Microgrid*. Panel: Microgrid Research and Field Testing IEEE PES General Meeting, June 24-28, Tampa FL. 7 pages.

Stevens, J., H. Vollkommer, D.Klapp. CERTS Microgrid System Tests. Power Engineering Society General Meeting, June 24-28. 4 pages.

In addition, the CERTS Microgrid concepts have appeared in Distributed Energy Journal, May/June 2008, which can be found at http://www.distributedenergy.com/de_0805_micro.html.

Through this outreach, members of the CERTS team met with a wide variety of potential field demonstrations partners during the course of the project. A separate Energy Commission contract to Navigant Consulting further augmented efforts to develop field demonstrations involving the CERTS Microgrid concept.

At the time of the preparation of this report, the status of discussions with potential partners for field demonstrations involving the CERTS Microgrid Concept is as follows:

Tecogen, a partner in the CERTS Microgrid Test Bed project, is currently conducting a research project for the New York State Energy Research and Development Authority to demonstrate aspects of the CERTS Microgrid Concept at a school in upstate New York.

The Energy Commission PIER program is considering funding for two demonstrations involving aspects of the CERTS Microgrid Concept. Chevron Energy Solutions is proposed to lead a demonstration, which would involve battery storage, renewable energy, and engine generators at a correctional facility in Northern California. Sacramento Municipal Utilities District (SMUD) is proposed to lead a demonstration that would involve engine generators at SMUD corporate headquarters.

Two additional demonstrations involving aspects of the CERTS Microgrid Concept have been submitted in response to a competitive solicitation from the U.S. Department of Energy (DOE). The identities of the firms leading these proposals are being withheld pending the announcement of solicitation awardees by DOE.

In addition, active discussions are also under way for additional field demonstrations, involving the U.S. Army Corp of Engineers/Construction Research Laboratory and with Cummins Engines.

4.0 Conclusions and Recommendations

This section describes the conclusions drawn from the successful demonstration of the CERTS Microgrid concept at a full-scale test bed operated by AEP and lists recommendations for future work.

4.1. Conclusions

The objective of the CERTS Microgrid Laboratory Test Bed Demonstration project was to demonstrate three advanced techniques comprising the CERTS Microgrid concept at a full-scale test bed operated by AEP.

The advance techniques, which included: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a new method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications, were demonstrated through a carefully orchestrated sequence of five sets of tests by AEP.

The first set of tests examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. The second set of tests examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The third set of tests was designed to ensure that the Gen-set inverter controls were working as designed. The fourth set of tests demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The fifth and final set of testing began to explore the operation limits of the microgrid (i.e., power quality, protection and inverter limits) with motor starting loads.

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions.

4.2. Recommendations

The next logical phase for RD&D on the CERTS Microgrid Concept is to build from the base established by the currently operational CERTS Microgrid to prioritize, develop, and then demonstrate needed additional technology enhancements required to optimize the microgrid from the explicit perspective of enhancing the business case for microgrids. That is, having demonstrated the technical feasibility of microgrid functions, RD&D optimization efforts are now needed to accelerate commercial deployment. The should pay special attention to the economic drivers, such as economic dispatch responsive to pricing signals and demand management programs, customer willingness to pay premiums for increased power reliability and quality, etc.

In order to enhance the business case for microgrids, the cost and functionalities of the CERTS Microgrid need to be compared directly against traditional solutions for a) CHP including the heat distribution systems and system reliability, and b) power quality, including multiple feeders and/or UPS systems. That is, enhancing the business case for microgrids involves, first, identifying the cost and performance targets of the traditional approaches for providing the values offered by a microgrid and then, second, prioritizing development and testing of CERTS Microgrid technology enhancements to beat these targets. Some promising areas to consider include: 1) lowering the costs of providing protection among microsources and loads; 2) determining the optimal amount of storage required on the DC bus; 3) the best size, technology, and control strategy (or strategies) for integration of AC storage; and 4) inclusion of non-inverter-based prime-movers along side of inverter-based prime-movers within a microgrid.

4.3. Benefits to California

DER – small power generators typically located at sites where the energy (both electric and thermal) they generate is used – are a promising option to meet growing customer needs for economic and reliable electric power (the DER portfolio also includes energy storage, and load control). Organizing all of these resources into microgrids is a promising way to capture smaller DER's significant potential to meet customers' and utilities' needs.

A key feature of a microgrid is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with no disruption to the loads within the microgrid (including no reduction in power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid, in an equally seamless fashion.

The CERTS Microgrid concept seeks to provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

In so doing, the CERTS Microgrid concept will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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6.0 Glossary

Acronym	Definition
AC	alternating current
AEP	American Electric Power
CERTS	Consortium for Electric Reliability Technology Solutions
CHP	combined heat and power
DC	direct current
DER	distributed energy resources
DOE	Department of Energy
EMS	energy management system (a control system that optimizes operation of the Microgrid to economically meet electricity and heat loads)
EPRI	Electric Power Research Institute
Energy Commission	California Energy Commission
IEEE	Institute of Electrical and Electronics Engineers
LBNL	Lawrence Berkeley National Laboratory
NPS	Northern Power Systems
NREL	National Renewable Energy Laboratory
PCC	point of common coupling
PIER	Public Interest Energy Research
PSERC	Power Systems Engineering Research Center
RD&D	research, development, and demonstration
SCE	Southern California Edison
SMUD	Sacramento Municipal Utilities District
SNL	Sandia National Laboratories
Static Switch	Separation device used to interconnect microgrid with distribution system
TAC	Technical Advisory Committee
UW	University of Wisconsin

Appendices

Appendices are available as separate documents

Appendix A. Test Bed Design Schematics

Appendix B. CERTS Microgrid Test Plan

Appendix C. Youtility Factory Test Plan Final Test Results

Appendix D. Tecogen 60kW Inverter-Based CHP Modules: Factory Testing

Appendix E. Tecogen CHP Modules Commissioning Report

Appendix F. CERTS Test Bed CERTEQUIP-V06-002, CERTS Switch, Low Power Factory Acceptance Test Report

Appendix G. Summary of CERTS Microgrid Static Switch Power Quality Tests at AEP Dolan, CERTS Microgrid Static Switch Testing

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Appendix O. Technical Advisory Committee Meeting Summary and Review Comments

Appendix P. Microgrid Fault Protection Based on Symmetrical and Differential Current Components

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by part nering with RD&D entities, including individuals, businesses, utilities, and public or private res earch institutions.

PIER funding efforts are focused on the following RD&D program areas:

Buildings End-Use Energy Efficiency

Energy Innovations Small Grants

Energy-Related Environmental Research

Energy Systems Integration

Environmentally Preferred Advanced Generation

Industrial/Agricultural/Water End-Use Energy Efficiency

Renewable Energy Technologies

Transportation

CERTS Microgrid Laboratory Test Bed is the final report for the CERTS Microgrid Laboratory Test Bed project (contract number 500-03-024) conducted by CERTS. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

The objective of the CERTS Microgrid Laboratory Test Bed project was to enhance the ease of integrating small energy sources into a microgrid. The project accomplished this objective by developing and demonstrating three advanced techniques, collectively referred to as the CERTS Microgrid concept, that significantly reduce the level of custom field engineering needed to operate microgrids consisting of small generating sources. The techniques comprising the CERTS Microgrid concept are: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications.

The techniques were demonstrated at a full-scale test bed built near Columbus, Ohio and operated by American Electric Power. The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all Institute of Electrical and Electronics Engineers 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

The results from these tests are expected to lead to additional testing of enhancements to the basic techniques at the test bed to improve the business case for microgrid technologies, as well to field demonstrations involving microgrids that involve one or more of the CERTS Microgrid concepts.

Keywords: CERTS, microgrid, control protection, electrical protection, voltage and frequency stability control, inverter, distributed energy resources, distributed generation, distributed resource, islanding.

Executive Summary

Evolutionary changes in the regulatory and operational climate of traditional electric utilities and the emergence of smaller generating systems, including internal combustion engines, microturbines, photovoltaics, and fuel cells, have opened new opportunities for electricity users to generate power on site. In this context, distributed energy resources – small power generators typically located at sites where the energy (both electric and thermal) they generate is used – are a promising option to meet growing customer needs for economic and reliable electric power. In addition to generators, the distributed energy resources portfolio also includes energy storage, and load control. Organizing all of these resources into microgrids is a promising way to capture smaller distributed energy resources' significant potential to meet customers' and utilities' needs.

A key feature of a microgrid, is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid (e.g., in the CERTS Microgrid concept, no impacts on power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid, in an equally seamless fashion.

The CERTS Microgrid concept seeks to provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

The peer-to-peer concept insures that no single component, such as a master controller or a central storage unit, is required for operation of the microgrid. Therefore, by its very design, the CERTS Microgrid can continue operating with loss of an individual component or generator. (With one additional source, (N+1) it can insure even higher levels of reliability.)

The plug-and-play concept means that a distributed energy resources unit can be placed at any point within the microgrid without re-engineering its controls. The plug-and-play functionality is similar to the flexibility one has with home appliances. That is, just as an appliance can be plugged in wherever there is an outlet, one can similarly locate distributed energy resources units at any location within a facility or building where they might be most needed. This is in sharp contrast to the traditional model, which clusters distributed generation at a single point in order to make the electrical integration tasks simpler. In combined heat and power applications, the plug-and-play model facilitates placing distributed energy resources immediately adjacent to heat loads, thereby allowing more effective use of waste heat without a complex heat distribution system, such as steam and chilled water pipes, and the energy losses associated with them.

A critical feature of the CERTS Microgrid is its presentation to the surrounding distribution grid as a single self-controlled entity. A CERTS Microgrid appears to the grid as indistinguishable from other customer sites that do not include DER. This presentation means that the microgrid

avoids many of the current concerns associated with integrating DER, such as how many DER the system can tolerate before their collective electrical impact begins to create problems like excessive current flows into faults and voltage fluctuations.

These functionalities are provided through three advanced techniques comprising the CERTS Microgrid concept, including: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications.

The techniques were demonstrated at a full-scale test bed built near Columbus, Ohio and operated by American Electric Power. See Figure 1. Tecogen and its inverter manufacturer, Youtility, modified and factory tested three combined heat and power units to incorporate the CERTS Microgrid control algorithms. Northern Power Systems designed, fabricated, and factory tested a static switch that implemented CERTS Microgrid islanding and resychronization procedures and also fabricated the other major hardware elements required, including load banks, power and control circuitry, protective relaying, and data-acquisition equipment, installed in metal-clad switchgear cabinets for protection in an outdoor location.

Five sets of tests were conducted by American Electric Power (AEP);

The first set of tests examined the operation of the static switch to determine that it and its digital signal processing control operated as designed. This included five tests of dead-bus and synchronized closing, reverse power and Institute of Electrical and Electronics Engineers (IEEE) 1547 protective relay functions. The goal was to confirm the correct operation (and thus the protection) of the static switch, which is located at the interface between the protected and unprotected portions of the microgrid.

The second set of tests examined a preliminary set of faults (i.e., overload simulating a high impedance fault) within the microgrid to ensure protection and safety of the test bed, prior to performing other planned tests. The fault condition tests were intended to cover the basic concepts of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2T) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to open first, followed by the opening of the zone breaker of the faulted zone. The goal was to test and adjust protection settings to achieve the most ideal conditions and protection design within a limited fault current system. Sixteen separate tests were conducted.

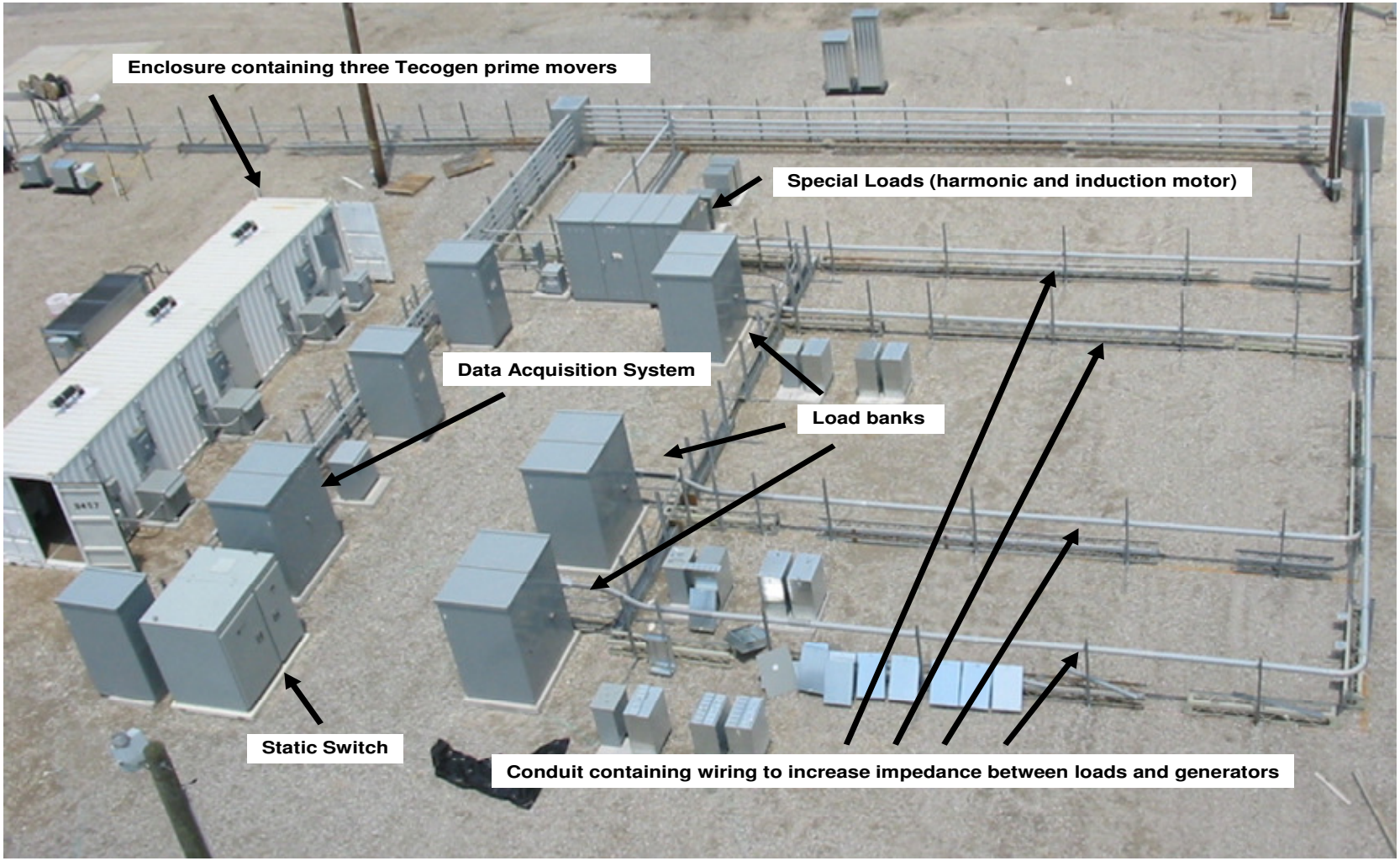

Figure 1. CERTS Microgrid Test Bed at American Electric Power

Photo Credit: American Electric Power

The third set of tests was designed to ensure that the Gen-set inverter controls were working as designed during grid-connected and islanded modes of operation. This includes unit control, zone control, and mixed power controls, in conjunction with limiting controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine-coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions. Thirteen separate tests were conducted.

The fourth set of tests demonstrated the flexibility of the microgrid while both grid connected and islanded, for different loads, power flows, and utility impact. These tests employed "weak grid" inductors in the circuit simulating the microgrid connection at the end of a lengthy feeder. Three sets of tests were conducted.

The fifth and final set of testing began to explore the operational limits of the microgrid with difficult induction motor starting loads. Two primary sets of tests were conducted under "weak grid" conditions.

Detailed, standalone reports (referenced as appendices to this report) were prepared containing narrative descriptions of the purpose and performance goal for each test, along with extensive graphical and tabular summaries of the results for each test.

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

The results from these tests are expected to lead to additional testing of enhancements to the basic techniques at the test bed, to improve the business case for microgrid technologies, as well to field demonstrations involving microgrids that involve one or more of the CERTS Microgrid concepts.

1.0 Introduction

This report describes the Consortium for Electric Reliability Solutions (CERTS) Microgrid Laboratory Test Bed project, which developed and tested innovative strategies for islanding and resychronizing microgrids with the grid, providing electrical protection within the microgrid, and controlling energy sources within the microgrid autonomously during islanded operation. Under earlier research contracts, the CERTS Microgrid team first developed these strategies using computer simulations, and then further refined them with laboratory-scale emulations. In this research contract, the team implemented them in commercial-grade hardware, with thorough testing at several stages of development, including at a full-scale test bed.

1.1. Background and Overview

Evolutionary changes in the regulatory and operational climate of traditional electric utilities and the emergence of smaller generating systems, including internal combustion engines, microturbines, photovoltaics, and fuel cells, have opened new opportunities for electricity users to generate power on site. In this context, distributed energy resources (DER) – small power resources typically located at sites where the energy (both electric and thermal) they provide is used locally – are a promising option to meet growing customer needs for economic and reliable electric power. In addition to generators, the DER portfolio also includes energy storage, and load control. Organizing all of these resources into microgrids is a promising way to capture smaller DER's significant potential to meet customers' and utilities' needs.

The CERTS Microgrid is an entirely new approach to integrating DER. Traditional approaches for integrating DER focus on the impacts on grid performance of a single or relatively small number of microsources. An example of the traditional approach to DER is the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 for Distributed Resources Interconnected with Electric Power Systems. This standard focuses on ensuring that interconnected systems will not affect the operation of the grid should problems arise on the grid. In compliance with this standard, the CERTS Microgrid is designed to seamlessly disconnect and operate as an island, separate from the grid, in case of problems and to reconnect to the grid once the problems are resolved. (Lasseter, et al. 2002. Lasseter, Piagi. 2005. Lasseter, Piagi. 2006.)

A critical feature of the CERTS Microgrid is its presentation to the surrounding distribution grid as a single, self-controlled entity. A CERTS Microgrid appears to the grid as indistinguishable from other customer sites that do not include DER. This presentation means that the microgrid avoids many of the current concerns associated with integrating DER, such as how many DER the system can tolerate before their collective electrical impact begins to create problems like excessive current flows into faults and voltage fluctuations. The CERTS Microgrid architecture insures that the microgrid will be a good citizen within the bulk power provider network, complying with grid rules and doing no harm beyond what would be acceptable from any existing customer. In return for appropriate compensation, the microgrid could provide interruptible load. Although technical barriers currently discourage it, the microgrid could also be a small source of power or ancillary services. The benefits it could offer to the distribution

system include; congestion relief, postponement of new generation or delivery capacity, rapid response to load changes, and local voltage support.

A key feature of a microgrid is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid (e.g., in the CERTS Microgrid concept, with no impact on power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself in an equally seamless fashion.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

The peer-to-peer concept insures that no single component, such as a master controller or a central storage unit, is required for operation of the microgrid. Therefore, by its very design, the CERTS Microgrid can continue operating with loss of an individual component or generator. (With one additional source, (N+1) it can insure even higher levels of reliability.)

The plug-and-play concept means that a DER unit can be placed at any point within the microgrid without re-engineering its controls. The plug-and-play functionality is similar to the flexibility one has with home appliances. That is, just as an appliance can be plugged in wherever there is an outlet, one can similarly locate DER units at any location within a facility or building where they might be most needed. This is in sharp contrast to the traditional model, which clusters DG at a single point in order to make the electrical integration tasks simpler. In combined heat and power (CHP) applications, the plug-and-play model facilitates placing DER immediately adjacent to heat loads, thereby allowing more effective use of waste heat without a complex heat distribution system, such as steam and chilled water pipes, and the energy losses associated with them.

These functionalities are enabled by three innovations: First, the CERTS Microgrid concept relies on embedding intelligence in the interface between the microsources and the surrounding microgrid.[1] This innovation enables autonomous operation of each microsource without high-speed communication or hierarchical control among microsources. This innovation is the key toward enabling a plug-and-play environment in which many microsources can operate harmoniously with one another with a minimum of expensive, custom site engineering.

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[1] For pragmatic reasons of availability and controllability, this CERTS effort initially focused on small internal combustion (IC) engines. All DER technologies, especially those that rely on power electronic interfaces, including microturbines, fuel cells, photovoltaics, and energy storage, are candidates for inclusion in microgrids based on CERTS Microgrid concepts.

Second, as a result of enabling an environment in which, in principle, any number of microsources might operate within a single microgrid, the CERTS Microgrid concept also incorporates an intelligent static switch for rapid disconnect and resynchronization of the entire microgrid to the larger, utility grid at the point of common coupling (PCC). A single, intelligent switch is innovative because it is a much more economic alternative to providing this functionality at each individual microsource.

Third, the CERTS Microgrid includes an innovative, additional level of protective relaying within the microgrid that complements traditional protection. The approach addresses that fact that power electronic interfaces can, by design, limit the fault current available to detect system faults, which is the traditional means used for detecting faults within an electrical network. Thus, while a microgrid can use bi-directional over-current protection devices when connected to the utility, it cannot rely on these approaches when the microgrid is islanded. The CERTS Microgrid protection scheme uses sequence components to detect low-fault currents in utility-connected and islanded operation. This protection scheme allows for plug-and-play without changing the existing over-current devices on the electrical system.

The development and testing of the CERTS Microgrid concept is the culmination of over 7 years of research efforts supported by both the U.S. Department of Energy and (DOE) the California Energy Commission (Energy Commission). In 2001, the DOE provided research support to develop the initial CERTS Microgrid concept. In 2002, the Energy Commission began providing research support to demonstrate the CERTS Microgrid concept. Under prior Energy Commission Contract # 150−99−003, Tasks 2.4 and 2.7, in the area of Distributed Energy Resources Integration, the CERTS team: 1) conducted analytical simulations of aspects of the concept (Lasseter, et. al. 2002); 2) prepared the design for test bed where a full-scale demonstration of the concepts could be tested (Appendix A. Test Bed Design Schematics); and 3) completed a review of potential sites and research partners where the test bed could be built (Akhil, et. al. 2002).

This document is the final report for the testing that has been conducted at the test bed.

The CERTS Microgrid Laboratory Test Bed project team initially included Lawrence Berkeley National Laboratory (LBNL); Sandia National Laboratory (SNL); the University of Wisconsin (UW); and Northern Power Systems (NPS), which designs, builds and installs electric power systems. Through this project, the CERTS team was expanded to include Tecogen, Inc., a manufacturer of engine-driven cooling and combined heat and power (CHP) systems, and Youtility, a supplier of power electronic systems for distributed power. In addition, American Electric Power (AEP), one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states, was selected by the team to host the test bed and conduct the tests.

The CERTS team was aided throughout the research process by a Technical Advisory Committee (TAC) consisting of representatives from 1) the DOE's Office of Electricity Delivery and Energy Reliability; 2) two major California electric utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) with expertise in interconnection of distributed

generation; 3) the National Renewable Energy Laboratory (NREL) who manage aspects of the IEEE 1547 standards development process; 4) the Electric Power Research Institute (EPRI) with expertise in power quality; and 5) an independent consultant with expertise in power electronics.

1.2. Project Objectives

The objectives of this project were to:

- Demonstrate stable operation of the CERTS control algorithms during a variety of conditions including:
- Transitions between utility-interconnected and islanded operation
- Islanded operation that involved such traditionally difficult loads as motor starting
- Demonstrate the ability to detect faults within the microgrid under a variety of conditions when either interconnected to the utility or islanded

The CERTS Microgrid Laboratory Test Bed project meets the PIER Goal of Improving the Reliability/Quality of California's Electricity by creating technologies and control strategies needed to capture the full potential of DER to improve the reliability and quality of the California interconnected power system. This project also meets the secondary goal of Improving the Energy Cost/Value of California's Electricity by lowering the cost of power delivery.

1.3. Report Organization

The CERTS Microgrid Laboratory Test Bed project consists of one technical task, CERTS Microgrid Laboratory Test Bed, with four Subtasks and five Sub-subtasks, as follows:

Subtask 2.1: Select a laboratory test bed

Subtask 2.2: Prepare equipment for the test bed

Sub-subtask 2.2.1: Prepare three prime movers and inverters for the test bed, including factory acceptance testing

Sub-subtask 2.2.2: Design, fabricate and factory test other test bed equipment, including the static switch

Subtask 2.3: Conduct tests of the CERTS Microgrid concept at the test bed

Sub-subtask 2.3.1 Prepare the test bed for testing

Sub-subtask 2.3.2 Conduct tests of the CERTS Microgrid concepts

Sub-subtask 2.3.3 Prepare a microgrid protective relaying report

Subtask 2.4 Plan a field demonstration of the CERTS Microgrid concept

The next two major sections of this report, 2.0 Project Approach and 3.0 Project Outcomes, follow this Subtask and Sub-subtask structure.

The report is supplemented by a number of stand-alone technical appendices that provide additional information and details on the results from all subtasks and sub-subtasks of this project. Several, separate appendices were required to organize voluminous tabular and graphical summaries of the data collected from each of the many tests conducted at the test bed.

2.0 Project Approach

The CERTS Microgrid Laboratory Test Bed project implemented the CERTS Microgrid concept and test bed design initiated under Energy Commission Contact #150-99-003, tasks 2.4 and 2.7, to develop tools and techniques for significant integration of distributed technologies in support of electricity reliability.

The subsections below describe the approach taken under each Subtask and Sub-subtask and in the project.

2.1. Test Bed Selection (Subtask 2.1)

The goal of this task was to select and execute a contract with a facility to conduct a full-scale test-bed demonstration of CERTS Microgrid concepts. The task included developing criteria for selecting a testing facility and, using information from past reviews conducted by the team to identify candidate sites, working with the Technical Advisory Committee (TAC) and Energy Commission Contract Manager to select the most appropriate site. Finally, following the Commission Contract Manager's approval, LBNL was to execute a subcontract with the Energy Commission-approved facility.

2.2. Equipment Preparation (Subtask 2.2)

The goal of this subtask was to enter into contracts with a microsource manufacturer, Tecogen/Youtility, to prepare three microsource prime movers with modified inverters and with a DER engineering firm, Northern Power Systems (NPS), to fabricate test bed hardware including a static switch, for use in the laboratory test bed demonstration (Subtask 2.3).

The first phase of work required Tecogen/Youtility to upgrade the current design of its inverter to incorporate CERTS Microgrid control algorithms and to conduct extensive factory tests of the modified microsource prime movers and inverters (Sub-subtask 2.2.1). The machines had to be as identical to one other as possible so that impacts from machines with differing characteristics did not mask important observations about performance, especially during transients, within the test bed. Because of the technical requirements for the test bed prime movers, the supplier had to be able to dedicate a small, technically skilled team to this project. The supplier also had to have the flexibility to revisit and rebuild aspects of the units because the team expected that initial testing would reveal the need for modifications.

In the original Energy Commission contract, Capstone Microturbines was expected to supply the modified microsource prime movers. However, Capstone Microturbines declined to execute a contract with LBNL due to a change in business priorities and withdrew from the project. Following an introduction provided by the Energy Commission contract manager, the team partnered with Tecogen/Youtility to supply the modified prime mover microsources and inverters. Aspects of the laboratory test bed design were modified by NPS to accommodate this change in prime movers.

The second phase of work required NPS to develop and conduct factory tests of a static switch that implements the CERTS Microgrid islanding and resynchronization procedures (Sub-

subtask 2.2.2). As an additional element of the second phase of work, NPS also fabricated the major electrical components required by the test bed, such as load banks and emulators, switchgear, and the data acquisition system (DAS). NPS was well-qualified to conduct this work because they had, under a previous Energy Commission contract with CERTS, prepared the complete design of the laboratory test bed.

2.3. Laboratory Tests (Subtask 2.3)

The goal of this subtask was to conduct tests of the CERTS Microgrid concept. That is, the laboratory test facility selected in Subtask 2.1 was to build the test bed and conduct tests of the test bed equipment, prime movers, and static switch prepared under Subtask 2.2. This subtask was conducted through three sub-subtasks.

The goal of sub-subtask 2.3.1 was to prepare the test bed for conducting the tests. This involved preparation of the physical test bed site following the design of the test bed, which was prepared under an earlier contract. (See Figures 2, 3, and 4, which are based on Appendix A, Test Bed Design Schematics). The tasks included erection of enclosures to house the microsources and associated facilities to cool the engines in operation and the laying out of conduits and associated wiring to interconnect the microgrid elements. Finally, the task involved installing the cabinets assembled by NPS as well as the microsources prepared by Tecogen/Youtility. See Figure 1.

The goal of sub-subtask 2.3.2 was to conduct a large number of tests exercising all functions of the CERTS Microgrid concept. This goal was accomplished in three phases. First, a detailed test plan was developed. Second, the tests were executed following the test plan. Third, the test results were analyzed and assessed with respect to the test plan and overall project objectives.

The CERTS team, led by NPS, developed a comprehensive list of tests that would exercise every aspect of the CERTS Microgrid concept. The tests were presented to and refined through discussions with the TAC. After the list of tests was deemed complete, AEP developed "registered" test procedure, following AEP corporate rules that would meet all testing needs safely. This registered test procedure is presented in Appendix B. CERTS Microgrid Testbed – Test Plan.

The registered test procedure contains ten sections. The first five are procedural. Sections six through ten refer to actual tests in which measurements are recorded. The tests were conducted by AEP in accordance with the registered test procedure. Testing was conducted sequentially, one section at a time.

Prior to each test day, the person in charge performed a job safety briefing including an inspection of the barricades and test setup for safety and compliance. A minimum of two people were on-site during each planned test

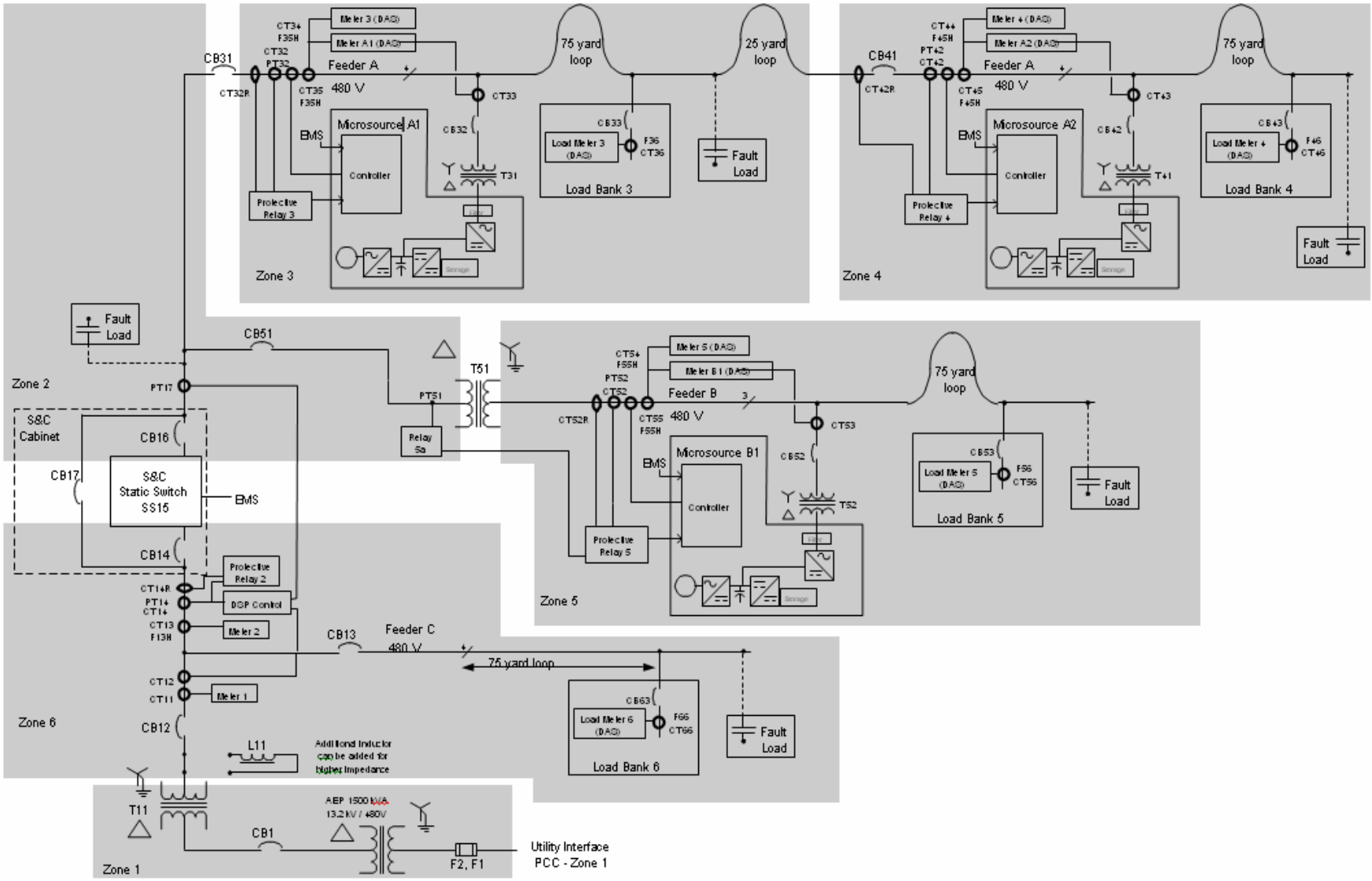

Figure 2. One-Line Diagram of CERTS Microgrid Test Bed

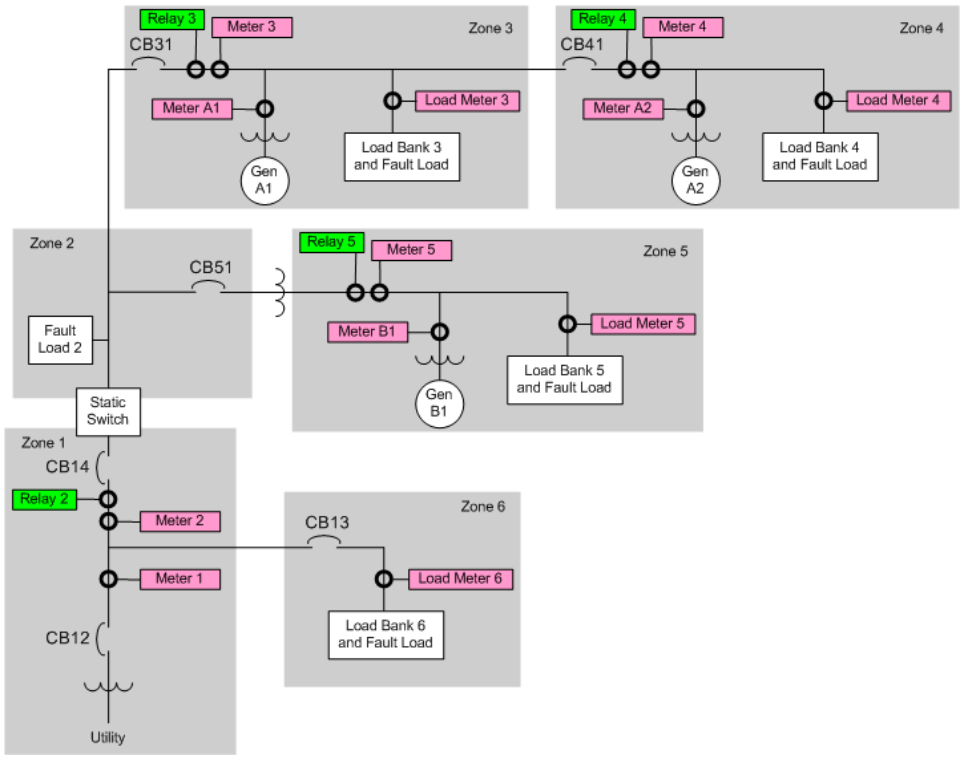

Figure 3. One-Line Diagram with Meter and Relay Locations CERTS Microgrid Test Bed

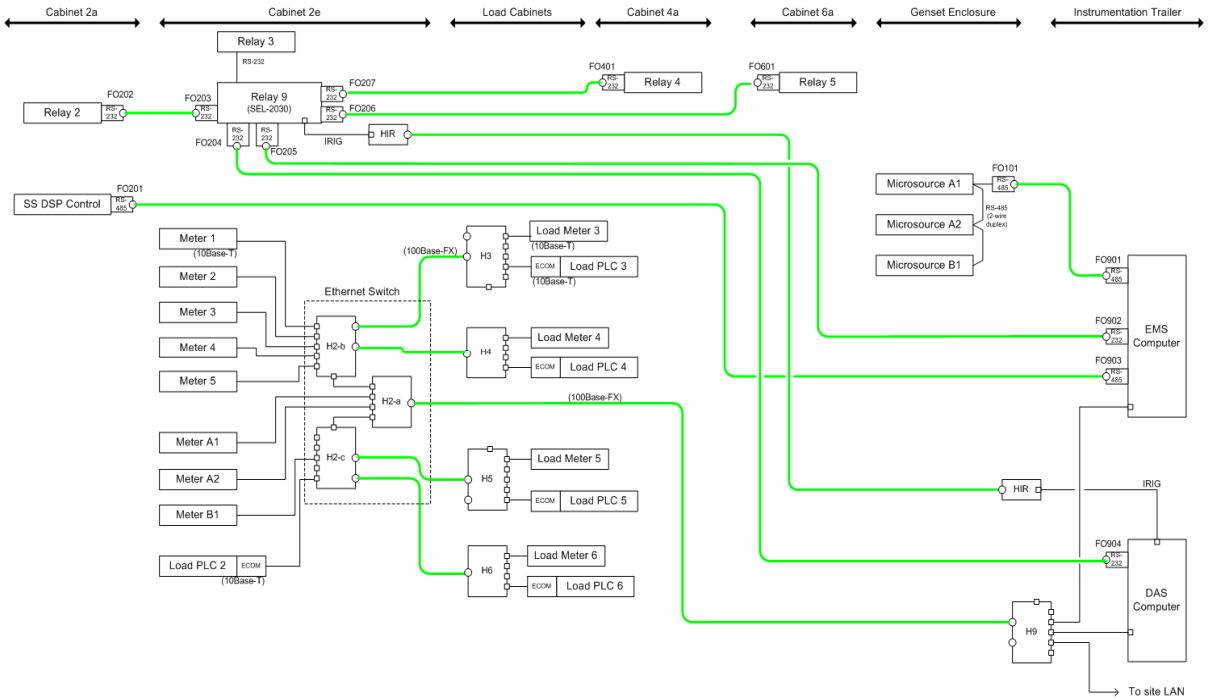

Figure 4. Diagram of DAS & EMS Data networks

Visual and audible alarms warned persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed," not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Microgrid Test Bed area (i.e., saw-horse style barricades with a red plastic chain surrounded the test area containing the Gen-set Enclosure, Microgrid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

The first set of tests (Section 6 of the test plan) examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. The goal was to confirm the correct operation (and thus the protection) of the static switch, which is located at the interface between the protected and unprotected portions of the microgrid. Successful completion of these tests was a prerequisite to performing subsequent tests in the test plan.

The tests were designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. They included five tests of dead-bus and synchronized closing, reverse power and IEEE 1547 protective relay functions. The switch functions were tested with a single Gen-set A1 online. The measurements taken were unique to each test. Waveform and RMS data from Meter 2 were of prime interest.

The second set of tests (Section 7 of the test plan) examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The goal was to confirm the new protection design developed in Task 2.3.3. This goal was to be accomplished by testing and adjusting protection settings to achieve the most ideal conditions and protection design. The tests included inductor L11 in the circuit, reflecting "weak grid" conditions. Sixteen separate tests were conducted.

The fault (i.e., overload simulating a fault) condition tests were intended to cover the basic concept of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2t) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to "OPEN" first, followed by the zone breaker of the faulted zone.

During each fault event waveforms of phase currents and line-to-neutral voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded. The relay element that caused the "TRIP" with trip times for each relay relative to when the fault condition was applied was also recorded.

Two power control modes were defined for the third and fourth sets of tests:

Unit Power Control Mode controls the amount of power (i.e., kW) being injected into the Zone from the Gen-set being controlled.

Zone Power Control Mode controls the amount of power (i.e., kW) entering/exiting the Zone using the Gen-set to offset the difference in that Zone.

The third set of tests (Section 8 of the test plan) was designed to ensure that the Gen-set inverter controls were working as designed. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions (i.e., static switch "OPEN"/ "CLOSE" and load steps). Thirteen separate tests were conducted.

Several measurements were made for each test:

- Sources –Injected power (kW), reactive load (kVAr), frequency (freq), and voltage (V) for each Gen-set (i.e., A1p, A2p and B1p).
- Zone input power flow into Zones 3 (A1z), 4 (A2z), 5 (B1z) and 6.
- Loads - Voltage at Load Bank 3 (L3), 4 (L4), 5 (L5), and 6 (L6).
- Static Switch - Power (kW) and current (I) through the static switch.
- Static Switch Control Signal: Forced "OPEN" and release to allow self synchronization.
- Voltage (V) and frequency (Freq) difference across the static switch.

The fourth set of tests (Section 9 of the test plan) demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The tests included the "weak grid" inductors (i.e., L11) in the circuit. Three sets of tests were conducted.

The measurements taken for these tests involved collecting RMS data for V, I, kW, kVAr, and Freq for each flow change at the following points:

- Meter 1 –V, I, kW, kVAr for the utility connection
- Meter 2 - V, I, kW, kVAr and utility-side V and Freq
- Meter 3 - V, I, kW, and kVAr for Feeder A and Microgrid side V and Freq
- Meter A1p – V, I, kW, kVAr for Gen-set A1
- Load Meter 3 – V, I, Zone 3 load kW and kVAr
- Meter 4 – V, I, kW, kVAr for Zone 4
- Meter A2p – V, I, kW, kVAr for Gen-set A2
- Load Meter 4 – V, I, Zone 4 load kW and kVAr
- Meter 5 – V, I, kW, kVAr for Feeder B

- Meter B1p – V, I, kW, kVAr for Gen-set B1
- Load Meter 5 – V, I, Zone 5, Feeder B load kW and kVAr
- Load Meter 6 – V, I, Zone 6, Feeder C load kW and kVAr

In addition V and I waveform data for unexpected events and for static switch transitions.

The fifth and final set of testing (Section 10 of the test plan) began to explore the operational limits of the microgrid (i.e., power quality, protection and inverter limits). Two primary sets of tests were conducted under "weak grid" conditions; the first involved induction motor starting loads under balanced and unbalanced load conditions; the second involved only unbalanced loads.

The measurements collected included the following:

- RMS data for kW, kVAr V, and I injected by each Gen-set
- Freq at each connection point
- V and I from Meters 1 - 5, and Load Meters 3 - 6

The analysis of the test results consisted of comparing test results to findings from earlier analyses of CERTS Microgrid concepts. As noted, successive analysis and testing of the CERTS Microgrid concepts have include analytical simulation, laboratory-scale emulations, and factory testing of the commercial-grade hardware installed at the test bed.

A number of software tools were used to process raw test data into a format suitable for review and presentation. These included: PQView, AcSELerator QuickSet Designer, Excel, and Word. Test results were posted by AEP onto a secure website where they could be reviewed and discussed by the entire CERTS team.

Test bed results were then presented and discussed with the TAC. TAC members were also invited to review and provide comments each of the extensive reports that have been prepared detailing the results of the testing.

The goal of sub-subtask 2.3.3 was to develop an innovative approach to provide protective relaying within the microgrid. The approach addresses that fact that power electronic interfaces, by design, limit the fault current available to detect system faults, which is the traditional means for detecting faults within an electrical network. Hence, in addition to traditional protection schemes that were already in place, the CERTS team, led by University of Wisconsin, needed to design an additional level of protection for faults that occur within the microgrid. These designs were then implemented and tested as part of the tests conducted in sub-subtask 2.3.2.

2.4. Field Demonstration Planning (Subtask 2.4)

The goal of subtask 2.4 was to identify and engage one or more partners for a field demonstration of the CERTS Microgrid concept. While a field demonstration was not to be conducted in this project, it was important to engage potential partners prior to and during the

laboratory test-bed phase so that partner-specific technical or operational issues could be addressed in the test bed prior to conducting the field demonstration.

This task was a continuation of work initiated under a previous Energy Commission agreement (amendment #150-99-003, task 2.7). That contract led to preparation of a field demonstration planning and partner recruitment strategy. The current task continued the implementation of that strategy.

The approach primarily involved conducting meetings with potential field demonstration partners to brief them on the CERTS Microgrid concept and test bed prior to and during the testing. Other activities that contributed to field demonstration planning by increasing the visibility of the CERTS Microgrid concept to a wide audience included presentations and publications of the CERTS Microgrid concept in a variety of fora, including professional meetings, domestic and international conferences, and academic and trade publications. These activities directly contributed to and supported follow-up discussions with potential field demonstration partners.

3.0 Project Results

This section presents projects results from Subtasks 2.1-2.4 of the Microgrid Laboratory Test Bed project. As discussed earlier, the project produced a number of deliverables. Several of these are quite voluminous, as they contain extensive tabular and graphical summaries from each of the tests conducted at the test bed. For brevity, this report only summarizes and highlights selected findings from these deliverables. This report is supplemented by numerous, separately bound appendices, which contain these detail project findings; these appendices are referenced throughout the following discussions.

3.1. Test Bed Selection (Subtask 2.1)

The goal of Subtask 2.1 was accomplished through the selection of and execution of a contract with the American Electric Power Company to join the CERTS team to build the test bed and conduct the testing program. The steps including developing selection criteria, applying them to candidate facilities, and determining the most qualified facility.

The final test site selection criteria included the following:

1. Physical requirements
    a) Adequate space for the test bed and generators (including safe working space around equipment)
    b) Availability of a "stiff" distribution voltage (preferably 15kV class)
    c) Availability of natural gas
    d) Availability of "standard" test equipment
2. Personnel –Test engineers and technicians with appropriate experience
3. Project leader with appropriate experience
4. Corporate interest and involvement
5. Timing and availability to meet CERTS requirements
6. Utility-owned and operated site – Important for utility community acceptance of the credibility of test results
7. Accessibility of test site to interested researchers

Under an earlier Energy Commission contract 150-99-003, the CERTS team conducted a preliminary assessment of possible sites for the test bed.[2] Based on this preliminary assessment, the team applied the above criteria and identified three candidate test sites:

1. Pacific Gas and Electric (PG&E) Technology and Ecological Services, San Ramon, California;
2. Southern California Edison (SCE) Electric Vehicle Technology Center, Pomona, California
3. American Electric Power (AEP) Dolan Technology Center, Groveport, Ohio

[2] "Review of Test Facilities for Distributed Energy Resources" by A. Akhil, C. Marnay, and T. Lipman, SAND2003-1602, May, 2003.

Input from the TAC and discussions with the Energy Commission contract manager on the list of final candidate test sites and the test site selection criteria led the team to modify the scope of sub-subtask 2.2.2 to have NPS also fabricate the majority of the test bed hardware, rather than have it fabricated by the test facility. There were two reasons: First, the team determined that the test facility should be selected primarily based on its ability to conduct the tests, not based on its ability to fabricate test bed hardware. Second, NPS was uniquely qualified to fabricate the equipment because it had designed the equipment, as part of its preparation of the overall test bed design (conducted as part of an earlier Energy Commission contract 150-99-003.

With this revised scope for the test facility, the team then sent a questionnaire to each of the three final candidate sites requesting detailed written information on four topics:

1. Required steps to prepare the physical site;
2. Equipment availability, data acquisition hardware and approach, and energy management system (EMS);
3. Personnel; and
4. Project scheduling and coordination.

At this point, PG&E indicated that would not able to respond because it would not be able to conduct the tests within the available time, largely due to prior commitments to other Energy Commission PIER DER Integration projects. This potential conflict was acknowledged by the Energy Commission contract manager and it was agreed that PG&E should not be considered to host the tests.

The CERTS team and the Energy Commission contract manager then scheduled oral presentations from representatives from both SCE and AEP. On the basis of these presentations, the CERTS team and the Energy Commission contract manager further followed up with on-site visits to the proposed test sites at both SCE and AEP.

Following the site visits, the team recommended the selection of AEP, as the host for the test bed. The SCE site did not have a natural gas supply line and would have required extensive modifications to the electric service interconnection. The AEP site was well-suited physically, had natural gas service, and had an appropriate electric service interconnection.

In conjunction with the contract award, AEP and CERTS entered into a Memorandum of Understanding to work cooperatively in areas of mutual interest for research, development, and demonstration of distributed energy resource (DER) technology microgrids. Subsequent to the initiation of work on this Energy Commission project, CERTS and AEP have won a competitive solicitation from the U.S. Department of Energy to conduct additional tests using the microgrid equipment developed in this project.

3.2. Equipment Preparation (Subtask 2.2)

The goal of subtask 2.2 was accomplished by work led by Tecogen and their subcontractor, Youtility, to modify three Tecogen prime movers to incorporate CERTS Microgrid control algorithms (Sub-subtask 2.2.1) and by work led by NPS to fabricate a static switch that implemented CERTS islanding and resychronization procedures and fabricate the other major hardware elements required by the CERTS laboratory test bed design. A critical element of these sub-subtasks involved detailed factory acceptance testing to confirm the performance of the equipment prior to shipment to AEP.

3.2.1. The Prime Movers and Inverters (Sub-subtask 2.2.1)

CERTS contracted with Tecogen to obtain three 100kW prime movers, each of which was modified to incorporate the CERTS Microgrid control algorithms. The complete systems, which were delivered and installed in the CERTS Microgrid test bed site at AEP, each included an engine/generator, a "surge module" and an inverter. See Figure 5.



Figure 5. Tecogen Prime Mover with Inverter

A critical aspect of this project was the incorporation of the CERTS Microgrid control algorithms into the inverters provided by Youtility. This required not only providing the algorithms to Youtility, but also providing Youtility with an in-depth understanding of the function of these algorithms so that they could understand the expected response, and the significance of deviations from that response, when the completed inverters were subjected to test scenarios. Providing this understanding required considerable interaction between the Youtility designer and the project's technical director from the University of Wisconsin, Professor Robert Lasseter.

Professor Lasseter also provided Youtility with a set of test scenarios that were used to confirm correct operation of the completed inverters. These test scenarios then comprised a Youtility factory acceptance test that was performed prior to sending the inverters to Tecogen. The test report for the Youtility factory acceptance tests is included as Appendix C. Youtility Factory Test Plan Final Test Results.

The prime mover for the engine/generator is a 454 cubic inch displacement natural gas-fired V8 reciprocating engine. This engine was designed to be operated at an engine speed selected to give the best combination of fuel efficiency and response to load changes. Thus, the engine speed will not necessarily be synchronous with a 60Hz system. The electrical generator a variable AC output which is rectified to a direct current (DC) output. The inverter converts the DC to utility-synchronous AC. For this project, the inverter was modified to incorporate the CERTS Microgrid control algorithms. The surge module is an energy storage device, consisting of batteries, power electronics, and controls, which is tied to the DC bus in parallel with the electrical generator and the inverter. The purpose of the surge module is to provide instantaneous power when there is a load increase, while waiting for the engine/generator to adjust its speed to the new loading conditions. The inverters and surge modules were both supplied to Tecogen by Youtility, Inc. Tecogen integrated the entire prime mover system and performed a set of factory acceptance tests, as specified by the CERTS team, before Tecogen shipped the units to the test bed site. (See Appendix D. Tecogen 60kW Inverter–Based CHP Modules Factory Testing.)

Once at AEP's facilities, the Tecogen units were retested to ensure there had been no shipping damage. The tests confirmed that the performance of the units once installed at AEP was consistent with the factory tests. (Appendix E. Tecogen CHP Modules Commissioning Report.)

3.2.2. The Static Switch and Other Test Bed Equipment

CERTS contracted with NPS to design, fabricate, and test a static switch that implemented CERTS Microgrid islanding and resychronization procedures and to fabricate the other major hardware elements required by the CERTS laboratory test bed design, including load banks, power and control circuitry, protective relaying, and data-acquisition equipment, installed in metal-clad switchgear cabinets for protection in an outdoor location.

NPS designed and built the controls that would allow the static switch to implement the CERTS Microgrid islanding and resychronization procedures. The controls were implemented onto the static switch hardware associated with the Purewave uninterruptible power supply system manufactured by S&C Electric. See Figure 6. The islanding procedures consisted of trip sensing (i.e., detect and trip on IEEE 1547-specified criteria such as voltage or frequency deviations and reverse power flow) followed by disconnection (islanding) of the microgrid from the utility. The voltage-trip function included trip-characteristics required by IEEE 1547 for distributed resource interconnection, those specified by the Information Technology Industry Council for power quality, as well as a custom-voltage-versus-time-trip characteristic that could be specified by the user.

The resynchronizing function had to meet a more stringent requirement than the commonly accepted criteria of IEEE 1547. The reason for the more stringent requirement was to insure transient free transitions for power flow either into or out of the microgrid at the instant of switch closing. IEEE 1547 requires the phase difference across the switch is less than 20° before the switch can close. This phase difference is too large for for our needs. We require closing at a zero phase difference. The high-speed static switch and digital signal processing (DSP), insures that the voltage phase difference a closing is zero.



Figure 6. The Static Switch

NPS tested the static switch with low-level power (i.e., signal injection) to confirm proper operation before shipping the switch to AEP. TAC members from the National Renewable Energy Laboratory shipped additional testing equipment and lent expertise to NPS in support of this testing. (Appendix F. CERTS Test Bed CERTEQUIP-V06-002, CERTS Switch, Low Power Factory Acceptance Test Report.)

Once at AEP's facilities, the switch was retested with low power to ensure there had been no shipping damage. After confirming that the static switch was in good condition, AEP performed further testing at the Dolan Test Facility to examine selected power quality issues prior to installing equipment at the test bed. (Appendix G. Summary of CERTS Microgrid Static Switch Power Quality Tests at AEP Dolan, CERTS Microgrid Static Switch Testing.)

NPS also fabricated cabinets containing all the sensing hardware for the protection and data-acquisition equipment; the circuit breakers, switches and fuses; and all the loads. The loads include a variety of resistive, inductive, capacitive and motor loads as well a six-pulse power rectifier to provide a non-linear load.

3.3. CERTS Microgrid Laboratory Tests

This section describes the preparation of the laboratory test bed for testing (Sub-subtask 2.3.1), the results of the CERTS microgrid laboratory tests (Sub-subtask 2.3.2), and the development of an approach for internal protection within the microgrid (Sub-subtask 2.3.3).

3.3.1. Prepare Laboratory Test Bed for Testing

After preparing the site, erecting supporting structures, cooling equipment, and wiring, and installing the equipment prepared by NPS and Tecogen/Youtility, AEP and Northern Power performed a field acceptance test. See Figure 1. The field acceptance testing also included exercising the complete data acquisition and control systems. After completing this testing and rectifying the minor issues that it uncovered, the team declared the test bed ready to conduct the full set of CERTS Microgrid tests, as outlined in the test plan. (Appendix H. CERTS Test Bed Design and Commissioning Lessons Learned Summary.)

3.3.2. Test of CERTS Microgrid Concepts

As described in section 2.3.2, five sets of tests were conducted. The results of these five sets of tests are contained in separate, stand-alone appendices to this report, as follows:

1. Static Switch (Section 6 of the test plan – 6 tests – Appendix I)
2. Protection (Section 7 of the test plan – 16 tests – Appendix J)
3. Reduced System (Section 8 of the test plan – 13 tests – Appendix K)
4. Power Flow Control (Section 9 of the test plan – 3 banks of tests – Appendix L)
5. Difficult Loads (Section 10 of the test plan – 1 set of motor starting tests – Appendix M)

Each appendix contains a narrative description of the purpose and performance goal for each test, along with graphical and tabular summaries of the results for each test. In addition, a sixth appendix (Appendix N) contains the test log developed by AEP during the conduct of the tests.

For brevity, this report will summarize and highlight selected findings for each of the five sets of tests. This includes listing each test conducted and its performance objective. The interested reader is referred to the individual appendices to see detailed results from each test performed.

The first set of tests (Section 6 of the test plan) examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. This included six tests of dead-bus and synchronized closing, reverse power and IEEE 1547 protective relay functions. These tests were designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal was to ensure that, by confirming the correct operation of the static switch, which is located at the interface (and thus serves as the protection) between the unprotected and protected portions of the microgrid, was ready to perform the remaining tests.

A synchronized closing test of the static switch was required to verify that when conditions were within synchronization limits set in the EMS, the static switch performed a synchronized close and thus provided a smooth connection transition. The dead-bus bus (de-energized bus) reclose test's goal was to verify that the static switch can close when de-energized bus conditions exist on the Gen-set side of the static switch; and that the dead-bus reclose algorithm requires user interaction (i.e., Operator needs to "Enable" the dead-bus reclose using pushbutton in the EMS).

The reverse power tests consisted of three tests: three-phase reverse power condition test, single-phase reverse power condition test, and anti-islanding Micro-grid settings reset test. Both three-phase and single-phase reverse power condition tests were required to verify the reverse power functionality of the static switch and confirm that the static switch islands the microgrid for a three-phase or single-phase reverse power conditions. The anti-islanding Micro-grid settings reset test was needed to verify that if a reverse power event occurred, due to a mismatch of Gen-set settings (i.e., total Gen-set power is greater than Microgrid load), the static switch will lockout and go to the "Fault" state, where user interaction is required.

The next goal was to verify the reconnection timers of the static switch (i.e., set by default at 300 seconds based on IEEE Standard 1547-2003). The length of time is programmed into the control system and designed to prevent reconnection until after the utility source voltage returns to nominal steady state conditions.

Table 1 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
6.1. Start-up system, synchronized closing	Verification that when conditions are appropriate (within synchronization limits set in the EMS), the switch can perform a synchronized closing and thus give smooth closing transitions.	When electrical system conditions met established criteria, the static switch performed a synchronized “Close”. A smooth voltage transition occurred from island to utility-connected mode.
6.2. Reverse power, grid islanding (IEEE 1547, loss of utility service)	Verify the reverse power functionality of the static switch and confirm that the static switch islands the Microgrid for a reverse power condition due to an upstream utility operation at the PCC. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standard).	The static switch islanded the microgrid from the utility grid due to an undervoltage condition. This occurred after the utility feeder opened separating the microgrid with 500kW of feeder load which was supplied by Gen-set A1 until the static switch opened. Once the static switch opened Gen-set A1 continued serving the protected load within the microgrid. After 300 seconds, the static switch synchronized and closed back into the utility grid with a smooth transition.
6.3. Reverse power, single-phase (IEEE 1547 voltage events)	Verification that the static switch islands the Microgrid when a reverse power condition, due an open-phase occurs. Note there are no single-phase breakers to disconnect the utility; reducing the load on one phase of the Microgrid will simulate the “open phase” condition. This condition does not properly test the reconnection logic, after an open phase, since the utility voltage will still be present on all three phases (i.e., test didn’t really disconnected a phase).	When A-phase of Load Bank 6 was reduced near 0kW a single-phase reverse power condition was created and the static switch opened. The microgrid remained electrically stable, matching generation with load demand. Once the A-phase of Load Bank 6 was increased above the reverse power threshold and the static switch was reset a synchronized closed occured.
6.4. Reverse power, anti-islanding microgrid settings reset	Verify that if a reverse power event occurs, due to a mismatch of Gen-set settings (Total Gen-set power > Microgrid load), the static switch will lockout and go to the “Fault” state, where user interaction is required.	Load was reduced within the microgrid which caused the static switch to open on a reverse power condition. The Gen-sets picked up the load within the microgrid. All loads were reset and the static switch synchronized and closed back into the utility.

6.5. De-energized bus (dead bus) reclose	Verify that the static switch can close when de-energized bus conditions (< 15V) on the DG side are measured and that the Dead Bus Reclose algorithm requires user interaction (i.e., Operator needs to “Enable” the Dead Bus Reclose using pushbutton in the EMS).	The static switch synchronized and closed into the utility grid with less than 15V on the DG side.

Table 1. Static Switch Testing Summary

The second set of tests (Section 7 of the test plan) examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The goal was to test and adjust protection settings to achieve the most ideal conditions and protection design. The tests included inductor L11 in the circuit, reflecting "weak grid" conditions. Sixteen separate tests were conducted. The fault (i.e., overload simulating a fault) condition tests were intended to cover the basic concept of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2t) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch was expected to "OPEN" first, followed by the zone breaker of the affected zone. The objective was to confirm the protective action detailed in the Protection document developed in Task 2.3.3.

Test 7.1 induced a three-phase-to-ground balanced overload fault condition in Zone 4 to verify the I^2t protection and a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection. Zone 3 and Zone 5 were tested similar to Zone 4 by introducing a three-phase-to-ground balanced overload fault and a single line-to-ground fault conditions in the zones, verifying the protection scheme in Test 7.2 (Zone 3) and Test 7.3 (Zone 5). During the 7.1, 7.2 and 7.3 tests, all three Gen-sets were off-line and the CERTS Microgrid was connected to the utility. Test 7.4 tested a three-phase-to-ground balanced overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus to confirm a reverse power event after the zone breaker "opens".

Test 7.5 through Test 7.10 involved applying a single line-to-ground overload fault condition in each Zone, located beyond the static switch, while connected to the utility grid. Each one of the six tests differs from one another by which Gen-sets are on-line during the fault, which phase is faulted, and in which zone the fault is applied. These tests were designed to verify zero-sequence, negative-sequence or residual over-current protection settings. Test 7.5 verified the protection in Zone 3 by applying a single line-to-ground overload fault condition with Gen-sets A1 operating in parallel with the utility grid. Test 7.6 tested a single line-to-ground overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.7 tested a single line-to-ground overload fault condition in Zone 5 with Gen-set B1 operating in parallel with the utility grid. Test 7.8 tested a single line-to-ground overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid. Test 7.9 tested a single line-to-ground overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.10 tested a single line-to-ground overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in parallel with the utility grid.

Tests 7.11 and 7.12 both applied a single line-to-ground overload fault condition in Zone 6 while connected to the utility. Test 7.11 involved only Gen-set A1 operating in parallel with the grid; and Test 7.12 involved Gen-sets A1 and B1 operating in-parallel with the grid. Both tests were designed to verify the I^2t protection of the breaker in Zone 6.

The four tests, 7.13 – 7.16, applied a line-to-line overload fault condition in one of the five zones beyond the static switch with a combination of two Gen-sets, operating in parallel with the

utility grid. These tests were designed to test negative-sequence, I^2t protection or residual over-current protection settings. Test 7.13 tested a phase-to-phase overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.14 tested a phase-to-phase overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.15 tested a phase-to-phase overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid. Test 7.16 tested a phase-to-phase overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid.

Table 2 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
7.1. Validate zone 4 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 4 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 4 detected an I^2t protection event and opened circuit breaker CB41 during the three-phase balanced fault. All other breakers remained closed. Relay 2 detected a ground over-current during the single line-to-ground fault and opened the static switch. All other breakers remained closed.
7.2. Validate zone 3 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 3 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 3 to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 3 detected an I^2t protection event and opened circuit breaker CB31 during the three-phase balanced fault. All other breakers remained closed. Relay 2 detected a ground over-current during the single line-to-ground fault and opened the static switch. All other breakers remained closed.
7.3. Validate zone 5 circuit breaker settings, utility connected	Initially test a three-phase balanced fault condition in Zone 5 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 5 to verify zero-sequence, negative-sequence or residual over-current protection	Relay 5 detected an I^2t protection event and opened circuit breaker 5 during the three-phase balanced fault. All other breakers remained closed. Relay 5 detected a negative-sequence over-current during the single line-to-ground fault and opened circuit breaker CB51. All other breakers remained closed.
7.4. Zone 4 three-phase un-grounded fault, gen-sets (A1+A2), utility connected	Test a three-phase balanced fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus confirm a reverse power event after the Zone breaker “opens”.	Relay 4 detected an I^2t protection and opened circuit breaker CB41. The static switch opened 30 seconds later due to a reverse power event.
7.5. Zone 3 A-phase line-to-ground fault, gen-set A1, utility connected	Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 3 opened circuit breaker CB31 0.15 seconds after the static switch when it detected a ground over-current
7.6. Zone 3 A-phase line-to-ground fault,	Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 and A2 operating in-	Relay 2 detected a ground over-current and opened the static switch in 0.02 seconds. Relay 4 opened circuit breaker CB41 0.07 seconds

gen-sets (A1+A2), utility connected	parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection	after the static switch when it detected a neutral over-current. Relay 3 opened circuit breaker CB31 0.04 seconds after circuit breaker CB41 when it detected a ground over-current.
7.7. Zone 5 B-phase line-to-ground fault, gen-set B1, utility connected	Test a single line-to-ground fault condition in Zone 5 with Gen-sets B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection	Relay 5 opened circuit breaker CB51 in 0.07 seconds when it detected a ground over-current. The static switch opened 0.03 seconds after circuit breaker CB51 when it detected a negative sequence over-current.
7.8. Zone 5 B-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition	Relay 5 opened circuit breaker CB51 in 0.06 seconds when it detected a ground over-current. All other breakers remained closed.
7.9. Zone 4 B-phase line-to-ground fault, gen-sets (A1+A2), utility connected	Test a single line-to-ground fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 4 opened circuit breaker 4 0.058 seconds after the static switch when it detected a ground over-current.
7.10. Zone 2 C-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.	Relay 2 detected a ground over-current and opened the static switch within a cycle. Relay 3 opened circuit breaker CB31 0.17 seconds after the static switch when it detected a ground over-current. Relay 5 opened circuit breaker CB51 due to an under-voltage condition.
7.11. Zone 6 C-phase line-to-ground fault, gen-set A1, utility connected	Test a single line-to-ground fault condition in Zone 6 with Gen-set A1 operating in-parallel with the utility grid to verify I^2t protection.	Relay 2 detected a neutral over-current and opened the static switch in 0.07 seconds. Circuit breaker CB13 tripped on an I^2t protection event.

7.12. Zone 6 C-phase line-to-ground fault, gen-sets (A1+B1), utility connected	Test a single line-to-ground fault condition in Zone 6 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify I^2t protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition.	Relay 2 detected a neutral over-current and opened the static switch in 0.07 seconds. Circuit breaker CB13 tripped on an I^2t protection event.
7.13. Zone 3 A-to-B phase fault, gen-sets (A1+A2), utility connected	Test a phase-to-phase fault condition in Zone 3 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 2 detected a negative sequence over-current and opened the static switch in 0.028 seconds. All other breakers remained online.
7.14. Zone 4 A-to-B phase fault, gen-sets (A1+A2), utility	Test a phase-to-phase fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 2 detected a negative sequence over-current and opened the static switch in 0.078 seconds. Relay 4 opened circuit breaker CB41 after the static switch when it detected a negative sequence over-current.
7.15. Zone 2 A-to-B phase fault, gen-sets (A1+B1), utility connected	Test a phase-to-phase fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	There was not enough current produced by the fault, therefore, all breakers remained closed during the test.
7.16. Zone 5 A-to-B phase fault, gen-sets (A1+B1), utility connected	Test a phase-to-phase fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.	Relay 5 detected a negative sequence over-current and opened circuit breaker in 0.075 seconds. Relay 2 opened the static switch 0.016 seconds after circuit breaker CB51 when it detected a negative sequence over-current.

Table 2. Internal Protection Testing Summary

The third set of tests (Section 8 of the test plan) was designed to ensure that the Gen-set inverter controls were working as designed. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests were based on replicating tests that had previously been conducted by Tecogen and Youtility during the factory acceptance testing of the standalone inverters, and the engine coupled inverters. The performance goal was to observe smooth transitions of the Gen-sets response to different step conditions (i.e., static switch "OPEN"/ "CLOSE" and load steps). Thirteen separate tests were conducted.

Test 8.1 verified smooth transitions in Gen-set A1 when different step conditions of load are applied in Load Bank 3 with voltage set points ranging from +5% to -5%. The same test was repeated for Gen-set A2 and Load Bank 4 and Gen-set B1 and Load Bank 5.

Test 8.2 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A1 to a lower limit of zero kW.

Test 8.3 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A2 to an upper limit of 60kW.

Test 8.4 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions with an un-balanced load in Zone 3.

Test 8.5 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode. During a load step change in Load Bank 3, Gen-set A1 was driven to an upper limit of 60kW.

Test 8.6 verified smooth transitions of Gen-sets, A1 in zone operation mode and Gen-set A2 in Unit operation mode. During a load step change in Load Bank 4, Gen-set A1 is driven to its maximum which causes an automatic reset of the zone set points.

Test 8.7 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A.

Test 8.8 verified smooth transition of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded.

Test 8.9 verified smooth transition of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded. Gen-set A1 was driven to its maximum which caused an automatic reset of both Gen-sets set-points.

Test 8.10 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded.

Test 8.11 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded. When

islanded, Gen-set A1 and B1 set-points were reset based on the remaining load in the islanded system.

Test 8.12 tested the manual procedure used to black-start the CERTS Micro-grid Test Bed in the event of a lengthy utility outage occurs with the Gen-sets off-line.

Test 8.13 was designed to determine the black-start capacity by increasing the amount of load on the CERTS Microgrid Test Bed from a black-out condition without generation or protection trips.

Table 3 summarizes the test performance goals and results from each of these tests

Test Description	Performance Goal	Results
8.1. Initial voltage regulation test – single zone, islanded with gen-set A1	Verify smooth transitions of Gen-set A1 response to different step conditions of load in Load Bank 3 with voltage set point changes ranging from +5% to -5%. Repeat tests with Gen-set A2 in Load Bank 4, and then Gen-set B1 in Load Bank 5	All Gen-sets had smooth transitions through each load step and voltage change.
8.2. Open static switch test, check P = 0 limit, gen-set A1	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with the unit power limit of Gen-set A1 equal to zero	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.3. Open static switch test, check P = 60kW limit, gen-set A2	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with the unit power limit of Gen-set A2 equal to 60kW	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.4. Test island operation, unbalanced load	Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch “OPEN”/ “CLOSE”) with an un-balanced load condition in Zone 3	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.5. Mixed mode operation test – Zone 3 and 4, gen-set A1 to 60kW maximum	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with a 60kW limit and A2 in Unit operation mode, during a load step change in Load Bank 3	Gen-set had smooth transition from grid connected to island mode and vice versa. Gen-sets responded as predicted.
8.6. Mixed mode operation test – Zones 3 and 4, automatic reset of zone level set-point	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with an automatic reset of the set point and A2 in Unit operation mode, during a load step change in Load Bank 4	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.7. Mixed mode operation test –	Verify smooth transitions of Gen-sets, A1 in Zone	Gen-sets had smooth transition from

Zones 3 and 4, zone power change	operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A	grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.8. Mixed mode operation test – Zones 3 and 4 , zone power change when islanded	Verify smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.9. Mixed mode operation test – Zones 3 and 4, when islanded, automatic reset of zone level set-point, both gen-sets P = 60kW Maximum	Verify smooth transitions of Gen-sets, A1 in Zone operation mode with automatic reset of set point and A2 in Unit operation mode, with a static switch operation and a change of zone power in Zone 3 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.10. Two sources in zone control - separate zones, when islanded, automatic reset of zone level set-point, new zones sum equal zero	Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.11. Two sources in zone control - separate zones, when islanded, automatic reset of zone level set-points	Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode and both having automatic reset of set points, with a static switch operation and a change of zone power in Zones 3 and 5 when islanded	Gen-sets had smooth transition from grid connected to island mode and vice versa. All Gen-sets responded as predicted.
8.12. Test generator black-start	Bring up the Microgrid Test Bed from a black-out condition without generation or protection trips. Measurement – Record the transition of the Gen-set meters as they are started and brought on-line and as load banks are switched on-line. Note, the transition time between all events outage occurs with the Gen-sets off-line This test checks the manual procedure used to black-start the Microgrid Test Bed in the event of a lengthy utility	Gen-sets had smooth transitions and met the load demand.

8.13. Test/establish generator black-start capacity	Determine the Black-start capacity of the microgrid by increasing the amount of load on the Microgrid Test Bed from a black-out condition without generation or protection trips	Total capacity was not determined because the Gen-set stayed online during each test supplying the load demand even for the 70kW + j30kVAr load. This test proved that the Gen-sets are more robust for blackstart then previously predicted.

Table 3. Reduced System Testing Summary

The fourth set of tests (Section 9 of the test plan) demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The tests included the "weak grid" inductors (i.e., L11) in the circuit. Three sets of tests were conducted.

Tests 9.1 – 9.3 verified and documented power flow and microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. In each test, 9.1 – 9.3, a series of tests were performed that vary in the amount of load that is applied to the microgrid in a weak grid scenario along with the power settings of each Gen-set. The difference between each test is the type of control mode that the Gen-sets are in. In Test 9.1, all the Gen-sets were set for unit control mode and then the next test, 9.2, all the Gen-sets were set for zone control mode. Test 9.3 mixed the unit and zone control modes of the Gen-sets during each test.

Table 4 summarizes the test performance goals and results from each of these tests

Test Description	Performance Goal	Results
9.1. Unit control mode, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. During each sequence of tests , maintain a weak grid connection with L11 in the circuit and the static switch “Closed”; all zone and load bank circuit breakers “Closed”; Gen-sets A1, A2 and B1 set for Unit (injection power) control mode; and all load banks initially set at zero	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.
9.2. Zone control mode, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation.	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.
9.3. Mixed zone and unit control modes, weak grid	Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation.	Voltage and frequency remained stable during grid connected to island mode and vice versa for all four tests. Control of Power was as expected from Gen-sets to load demand.

Table 4. Power Flow Control Testing Summary

The fifth and final set of testing (Section 10 of the test plan) began to explore the operation limits of the microgrid (i.e., power quality, protection and inverter limits). Two primary sets of tests were conducted under weak grid conditions; the first involved induction motor starting loads under balanced and unbalanced load conditions; the second involved only unbalanced loads.

Motor start tests conducted in Test 10.2 had balanced loads at a 0.9 power factor under weak grid conditions. These tests verified and documented power flow, microgrid frequency changes, and protection design with different Gen-set settings during motor starts when utility connected and then again during islanded mode of operation. Test 10.3 was similar to Test 10.2, except that the loads were unbalanced with a 0.9 power factor.

In Test 10.4 verified and documented power flow, microgrid frequency changes, and protection design with different Gen-set settings during changes of unbalanced load in load banks.

Table 5 summarizes the test performance goals and results from each of these tests.

Test Description	Performance Goal	Results
10.2. Motor Start Tests, Weak Grid, Balanced Load	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and island mode of operation.	CERTS Microgrid remained electrically stable during the 10 Hp induction motor start in Zone 3 while utility connected and islanded mode for all six test.
10.3. Motor Start Tests, Weak Grid, Unbalanced Load	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and island mode of operation.	CERTS Microgrid remained electrically stable during the 10 Hp induction motor start in Zone 3 while utility connected and islanded mode for all six test.
10.4. Unbalanced Load Tests, Weak Grid	Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during changes of unbalanced load in Load Banks while utility connected and in islanded mode of operation.	Static switch opened on a reverse power trip while utility connected in Tests 10.4.12 and 10.4.14 when Load Banks 3 and 6 A-phase was reduced by 50%. CERTS Microgrid remained electrically stable when the A-phase in the load demands equaled 0kW and in island mode of operation. The static switched opened on a reverse power trip for all three tests when the microgrid was reconnected to the utility grid. Once the static switch opened, the CERTS microgrid remained electrically stable. All test results performed as predicted.

Table 5. Difficult Load Testing Summary

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions, including difficult motor starts.

Test bed results were then presented and discussed jointly with and then reviewed individually by members of the TAC. The reviews were uniformly positive:

"Concepts are elegant, yet simple. Simple translates to more affordable."

"Demonstration that static switch can comply with 1547, with non-compliant generation behind it, is a major accomplishment. The team has confirmed that a static switch is very fast. It is recognized that ground fault testing on the utility side of the static switch is still missing from this aspect of 1547 compliance."

"Inverter controls are impressive."

"Test plan was well laid-out. A wide range of concerns that were identified have now been successfully addressed. In particular, motor starting was a challenging test and the results are very encouraging. Should be a major contribution to the literature."

"The test bed platform should be used for future research."

A summary of the TAC meeting at which test bed results were reviewed as well as the additional written comments received from the TAC are contained in Appendix O. Technical Advisory Committee Meeting Summary and Review Comments.

In addition, AEP has prepared a standalone technical assessment and recommendations:

> "The major objective of plug and play gen-sets has been proven to work very well and is seen as a major stepping stone toward increasing the commercial adoption of microgrids. The keystone of this plug and play approach is the CERTS frequency versus power and voltage versus VAR algorithms which have proven to be robust in the control of multiple voltage source inverters on a common bus. The specific advantages offered by this approach are expected to include: improved operation, more manageable equipment requirements, all at lower total system costs compared to a traditional custom-designed distributed generation power system involving multiple prime movers.
>
> In addition, the concept of placing generation, which is non-compliant with IEEE Standard 1547, beyond a static switch, which is compliant, was tested and proven to be successful. This is expected to be another effective tool in reducing the cost of a

traditional custom-designed, distributed generation power system involving multiple prime movers, while still maintaining safe interconnection with a utility system.

It is recognized that the tests conducted by AEP represent the first full-scale tests of the CERTS Microgrid Concept. AEP looks forward to participation in future research and testing to advance this Concept. Toward this end, we recommend focus on the following areas:

1. Demonstrate the ability of power electronic inverters to adjust fault contribution from the gen-sets.
2. Re-examine and potentially re-tune the anti-islanding philosophy governing operation of the static switch, in light of expected unbalanced voltages presented by utility distribution systems to the microgrid.
3. Develop and test means for minimizing VAR flows by using the Energy Manager to direct voltage set-point changes to the gen-sets based on actual voltages on the utility distribution system.
4. Continue testing to explore performance of the CERTS Microgrid in supporting difficult loads.
5. Confirm the adequacy or revise the management of the static switch when the utility closes into a dead bus.
6. Examine enhanced functionalities for the Energy Manager to address customer and utility needs, such as power factor correction, fault and error handling, energy efficiency, and price- or reliability-driven demand management.
7. Examine system impacts for scenarios involving significant deployment of microgrids."

3.3.3. Microgrid Protective Relaying Design

Traditionally, power flow in the existing electrical infrastructure flows from the power plant through transmission and possibly distribution lines to the load that is demanding power. Protection schemes were based on this concept, which allowed for uni-directional over-current protection devices to be installed. Uni-directional over-current protection devices sense when there is a fault on the electrical system by opening up when the current exceeds a certain value in a certain direction.

Uni-directional over-current protection schemes are not feasible within microgrids, because of microgrids' reverse power-flow capability; if current is flowing in the opposite direction (i.e., from the microsources toward the point of common coupling (PCC)), it will not trip the over-current device when a fault occurs. A microgrid can use bi-directional over-current protection devices when the microgrid is connected to the utility but not while the microgrid is islanded. During islanded operation, the microgrid fault current magnitudes are less significant than

when the microgrid is connected to the utility, so uni-directional and bi-directional detection may not detect the fault current preventing the protection device from operating.

The team developed a protection scheme that uses sequence components to detect low-fault currents in utility-connected and islanded operation. Sequence components take a balanced or unbalanced voltage or current and break it up into three separate components: positive, negative, and zero sequence. Adding these three components together gives the magnitude and phase angle of balanced and unbalanced currents and voltages. A single line-to-ground fault produces a zero sequence current, providing a trip signal for the zone with the fault that does not depend on the direction of the current and magnitude as is the case with traditional over-current protection devices. A line-to-line fault produces a negative sequence current that signals the zone with the fault to trip. This protection scheme allows for plug-and-play without changing the existing over-current devices on the electrical system.

The technical report on the microgrid protective relaying design is contained in Appendix O. Microgrid Fault Protection Based on Symmetrical and Differential Current Components.

3.4. Field Demonstration Planning (Task 2.4)

The goal of task 2.4 was to identify and engage one or more partners for a field demonstration of the CERTS Microgrid concept. While a field demonstration was not included in the project plan for this project, it was important to engage potential partners prior to and during the laboratory test bed phase so that partner-specific technical or operational issues could be addressed in the laboratory test bed prior to conducting a field demonstration.

The identification of potential field demonstration partners took place through a variety of means. Central to most of them was outreach conducted through a variety of presentations and publications.

Presentations

R.H. Lasseter, "Advanced Distribution using DER," Rethinking T&D Architecture for DER, 24 April 2008, T&D Panel, Chicago

R.H. Lasseter, "DER and Microgrids," IEEE Distinguish Lecturer, IEEE PES St. Louis chapter, 6 November 2007

R.H. Lasseter, "Microgrids and Distributed Generation," ASCE Journal Energy Engineering, Volume 133, Number 3, September 2007.

H. Nikkhajoei and R.H. Lasseter, "Microgrid Protection," IEEE Panel: Microgrid Research and Field Testing, IEEE PES General Meeting, 24-28 June 2007, Tampa, FL

R.H. Lasseter, "Extended Microgrid Using (DER) Distributed Energy Resources," IEEE Panel: Sustainable Energy, IEEE PES General Meeting, 24-28 June 2007, Tampa, FL

R.H. Lasseter, "CERTS Microgrid," Panel on Microgrids Systems, International Conference on System of Systems Engineering, April 16-18, 2007 San Antonio

R.H. Lasseter, "CERTS Microgrid," ERDC/CERL_RDCOM, Army Engineers, 18 January 2007, Champaign, Ill.

R.H. Lasseter, "Microgrids on Distribution Scale," Panel, Army Installation Energy Security & Independence Conference, Greensboro, N.C., 12-13 December 2006

R.H. Lasseter. "Methods for Controlling Multiple Independent Generators in an Intentional Island (Microgrids)," Minnesota Power 11/8/06

R.H. Lasseter. "Distributed Energy Resources and Microgrids," IEEE Distinguish Lecturer, IEEE Cuernavaca, Mexico, 2 July 2006.

R.H. Lasseter. "Directions In Microgrid research", PSerc Lecture, 6 June 2006, Madison, Wi

R.H. Lasseter." Autonomous Control", 2006 PES General Meeting, 22 June 2006, Montréal, Québec Canada

R.H. Lasseter. "Microgrids and Protection", CERTS IAB Meeting, 27 June 2006, Cleveland, Ohio

R.H. Lasseter. "Enhanced Microgrid", Microgrid Road Map. 18 May 2006, Office of Electric Energy, Washington, DC

R.H. Lasseter. "Dynamics Distribution", IEEE T&D Meeting, Panel on Future of Distribution, Dallas, 20 May 2006 "Enhanced Business Case for CERTS Microgrid", Peer Review Meeting for the Department of Energy's , Electric Distribution R&D Program, 26 May 2006, San Ramon Ca

R.H. Lasseter. "The Role of Distributed Energy Resources in Future Electric Power Systems", Energy System Seminar, 27 March 2006, Madison, Wi

R.H. Lasseter. "DER based Distribution", DOE Energy Workshop, Panel, January 31 to February 1 2006, Tallahassee, Fl

R.H. Lasseter. "Microgrid Test Plan", CERTS IAB Meeting, 6 October 2005, Cleveland, Ohio

R.H. Lasseter. "CERTS Microgrid", International Microgrid Workshop, Panel Speaker, 17 June 2005, University of California-Berkeley, Berkeley, California

R.H. Lasseter. "CERTS Microgrid", California Energy Commission R&D Forum, 4 May 2005, Sacramento, Ca

R.H. Lasseter. *"Microgrid: A Conceptual Solution,"* Wisconsin Distributed Resources Collaborative, September 16, 2004

R.H. Lasseter. "CERTS Microgrid," CEC Technical Advisory Committee Meeting, July 19, 2004

R.H. Lasseter. *"Where are Microgrids Going?,"* Distributed Resources Workshop, CEA, May 9-11, 2004 Calgrary

R.H. Lasseter. *"Microgrids: What's Next,"* PSerc Industrial Advisory Board, May 20-21, 2004

Publications

Klapp, D., H.T. Vollkommer. *Application of an Intelligent Static Switch to the Point of Common Coupling to Satisfy IEEE 1547 Compliance*. Panel: Microgrid Research and Field Testing IEEE PES General Meeting, 24-28 June 2007, Tampa, FL. 4 pages.

Lasseter, R.H., P. Piagi. 2006. *Control and Design of Microgrid Components.* January. 257 pages. http://www.pserc.org/ecow/getpublicatio/reports/2006report

Lasseter, R. *Dynamic Distribution using (DER) Distributed Energy Resources*. 2006. IEEE PES T & D Meeting, Dallas, May. 3 pages.

Lasseter, R.H. 2007. "Microgrids and Distributed Generation." *Journal of Energy Engineering*, Volume 133, Issue3, ASCE, Sept. 7 pages.

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Nichols, D.K., J. Stevens, R.H. Lasseter, J.H. Eto, H.T. Vollkommer. 2006 *Validation of the CERTS Microgrid Concept: The CEC/CERTS Microgrid Testbed*. Power Engineering Society General Meeting, IEEE. 3 pages.

Nikkhajoei, H., R. H. Lasseter. 2007. *Microgrid Protection*. IEEE PES General Meeting, 24-28, Tampa, FL. June. 6 pages.

Nikkhajoei, H., R. H. Lasseter. 2006. *Microgrid Fault Protection Based on Symmetrical and Differential Current Components*. December. 72 pages. (Power Systems Engineering Research Center (PSERC) website)

Panora, R.A., J.B. Gehret Jr., P. Piagi. 2007. *Design and Testing of an Inverter-Based Combined Heat and Power Module for Special Application in a Microgrid*. Panel: Microgrid Research and Field Testing IEEE PES General Meeting, June 24-28, Tampa FL. 7 pages.

Stevens, J., H. Vollkommer, D.Klapp. CERTS Microgrid System Tests. Power Engineering Society General Meeting, June 24-28. 4 pages.

In addition, the CERTS Microgrid concepts have appeared in Distributed Energy Journal, May/June 2008, which can be found at http://www.distributedenergy.com/de_0805_micro.html.

Through this outreach, members of the CERTS team met with a wide variety of potential field demonstrations partners during the course of the project. A separate Energy Commission contract to Navigant Consulting further augmented efforts to develop field demonstrations involving the CERTS Microgrid concept.

At the time of the preparation of this report, the status of discussions with potential partners for field demonstrations involving the CERTS Microgrid Concept is as follows:

Tecogen, a partner in the CERTS Microgrid Test Bed project, is currently conducting a research project for the New York State Energy Research and Development Authority to demonstrate aspects of the CERTS Microgrid Concept at a school in upstate New York.

The Energy Commission PIER program is considering funding for two demonstrations involving aspects of the CERTS Microgrid Concept. Chevron Energy Solutions is proposed to lead a demonstration, which would involve battery storage, renewable energy, and engine generators at a correctional facility in Northern California. Sacramento Municipal Utilities District (SMUD) is proposed to lead a demonstration that would involve engine generators at SMUD corporate headquarters.

Two additional demonstrations involving aspects of the CERTS Microgrid Concept have been submitted in response to a competitive solicitation from the U.S. Department of Energy (DOE). The identities of the firms leading these proposals are being withheld pending the announcement of solicitation awardees by DOE.

In addition, active discussions are also under way for additional field demonstrations, involving the U.S. Army Corp of Engineers/Construction Research Laboratory and with Cummins Engines.

4.0 Conclusions and Recommendations

This section describes the conclusions drawn from the successful demonstration of the CERTS Microgrid concept at a full-scale test bed operated by AEP and lists recommendations for future work.

4.1. Conclusions

The objective of the CERTS Microgrid Laboratory Test Bed Demonstration project was to demonstrate three advanced techniques comprising the CERTS Microgrid concept at a full-scale test bed operated by AEP.

The advance techniques, which included: 1) a method for effecting automatic and seamless transitions between grid-connected and islanded modes of operation; 2) an approach to electrical protection within the microgrid that does not depend on high fault currents; and 3) a new method for microgrid control that achieves voltage and frequency stability under islanded conditions without requiring high-speed communications, were demonstrated through a carefully orchestrated sequence of five sets of tests by AEP.

The first set of tests examined the operation of the static switch to determine that it and its digital signal processing (DSP) control operated as designed. The second set of tests examined a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the test bed, prior to performing other planned tests. The third set of tests was designed to ensure that the Gen-set inverter controls were working as designed. The fourth set of tests demonstrated the flexibility of the microgrid both grid connected and islanded for different loads, power flows and impact on the utility. The fifth and final set of testing began to explore the operation limits of the microgrid (i.e., power quality, protection and inverter limits) with motor starting loads.

The testing fully confirmed earlier research that had been conducted initially through analytical simulations, then through laboratory emulations, and finally through factory acceptance testing of individual microgrid components. The islanding and resychronization method met all IEEE 1547 and power quality requirements. The electrical protection system was able to distinguish between normal and faulted operation. The controls were found to be robust under all conditions.

4.2. Recommendations

The next logical phase for RD&D on the CERTS Microgrid Concept is to build from the base established by the currently operational CERTS Microgrid to prioritize, develop, and then demonstrate needed additional technology enhancements required to optimize the microgrid from the explicit perspective of enhancing the business case for microgrids. That is, having demonstrated the technical feasibility of microgrid functions, RD&D optimization efforts are now needed to accelerate commercial deployment. The should pay special attention to the economic drivers, such as economic dispatch responsive to pricing signals and demand management programs, customer willingness to pay premiums for increased power reliability and quality, etc.

In order to enhance the business case for microgrids, the cost and functionalities of the CERTS Microgrid need to be compared directly against traditional solutions for a) CHP including the heat distribution systems and system reliability, and b) power quality, including multiple feeders and/or UPS systems. That is, enhancing the business case for microgrids involves, first, identifying the cost and performance targets of the traditional approaches for providing the values offered by a microgrid and then, second, prioritizing development and testing of CERTS Microgrid technology enhancements to beat these targets. Some promising areas to consider include: 1) lowering the costs of providing protection among microsources and loads; 2) determining the optimal amount of storage required on the DC bus; 3) the best size, technology, and control strategy (or strategies) for integration of AC storage; and 4) inclusion of non-inverter-based prime-movers along side of inverter-based prime-movers within a microgrid.

4.3. Benefits to California

DER – small power generators typically located at sites where the energy (both electric and thermal) they generate is used – are a promising option to meet growing customer needs for economic and reliable electric power (the DER portfolio also includes energy storage, and load control). Organizing all of these resources into microgrids is a promising way to capture smaller DER's significant potential to meet customers' and utilities' needs.

A key feature of a microgrid is its ability, during a utility grid disturbance, to separate and isolate itself from the utility seamlessly with no disruption to the loads within the microgrid (including no reduction in power quality). Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid, in an equally seamless fashion.

The CERTS Microgrid concept seeks to provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid also provides high system reliability and great flexibility in the placement of distributed generation within the microgrid. The CERTS Microgrid is intended to offer these functionalities at much lower costs than traditional approaches by incorporating *peer-to-peer* and *plug-and-play* concepts for each component within the microgrid.

In so doing, the CERTS Microgrid concept will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

5.0 References

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Panora, R.A., J.B. Gehret Jr., P. Piagi. 2007. *Design and Testing of an Inverter-Based Combined Heat and Power Module for Special Application in a Microgrid*. Panel: Microgrid Research and Field Testing IEEE PES General Meeting, June 24-28, Tampa FL. 7 pages.

Piagi, P., H.R. Lasseter. 2006. *Autonomous Control of Microgrids*. IEEE PES Meeting, Montreal, June. 8 pages.

Stevens, J., H. Vollkommer, D.Klapp. CERTS Microgrid System Tests. Power Engineering Society General Meeting, June 24-28. 4 pages.

6.0 Glossary

Acronym	Definition
AC	alternating current
AEP	American Electric Power
CERTS	Consortium for Electric Reliability Technology Solutions
CHP	combined heat and power
DC	direct current
DER	distributed energy resources
DOE	Department of Energy
EMS	energy management system (a control system that optimizes operation of the Microgrid to economically meet electricity and heat loads)
EPRI	Electric Power Research Institute
Energy Commission	California Energy Commission
IEEE	Institute of Electrical and Electronics Engineers
LBNL	Lawrence Berkeley National Laboratory
NPS	Northern Power Systems
NREL	National Renewable Energy Laboratory
PCC	point of common coupling
PIER	Public Interest Energy Research
PSERC	Power Systems Engineering Research Center
RD&D	research, development, and demonstration
SCE	Southern California Edison
SMUD	Sacramento Municipal Utilities District
SNL	Sandia National Laboratories
Static Switch	Separation device used to interconnect microgrid with distribution system
TAC	Technical Advisory Committee
UW	University of Wisconsin

Appendices

Appendices are available as separate documents

Appendix A. Test Bed Design Schematics

Appendix B. CERTS Microgrid Test Plan

Appendix C. Youtility Factory Test Plan Final Test Results

Appendix D. Tecogen 60kW Inverter-Based CHP Modules: Factory Testing

Appendix E. Tecogen CHP Modules Commissioning Report

Appendix F. CERTS Test Bed CERTEQUIP-V06-002, CERTS Switch, Low Power Factory Acceptance Test Report

Appendix G. Summary of CERTS Microgrid Static Switch Power Quality Tests at AEP Dolan, CERTS Microgrid Static Switch Testing

Appendix H. CERTS Test Bed Design and Commissioning: Lessons Learned Summary

Appendix I. Test Plan Section 6.0 Microgrid Test Bed System Checkout (Static Switch)

Appendix J. Test Plan Section 7.0 Validate Protection Settings and Initial Fault Testing

Appendix K. Test Plan Section 8.0 Reduced System Tests

Appendix L. Test Plan Section 9.0 Power Flow Control Tests

Appendix M. Test Plan Section 10.0 Difficult Loads

Appendix N. Test Log

Appendix O. Technical Advisory Committee Meeting Summary and Review Comments

Appendix P. Microgrid Fault Protection Based on Symmetrical and Differential Current Components

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Bed Design Schematics

APPENDIX A

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
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CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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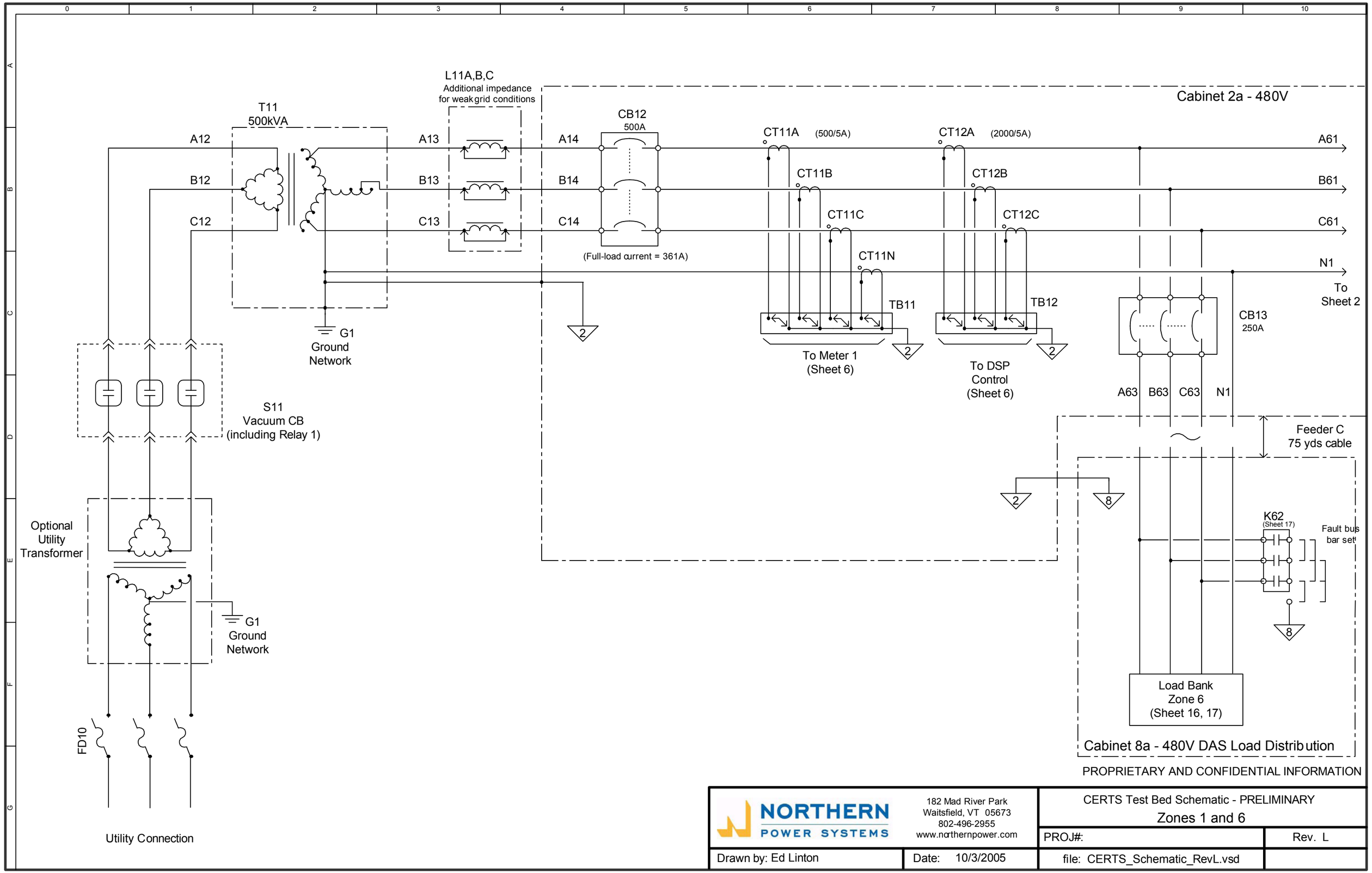

PROPRIETARY AND CONFIDENTIAL INFORMATION

NORTHERN POWER SYSTEMS
182 Mad River Park
Waitsfield, VT 05673
802-496-2955
www.northernpower.com

CERTS Test Bed Schematic - PRELIMINARY
Zones 1 and 6

PROJ#:

Rev. L

Drawn by: Ed Linton

Date: 10/3/2005

file: CERTS_Schematic_RevL.vsd

Figure 1: CERTS Test Bed Schematic - Preliminary - Zones 1 and 6

Cabinet 2b & 2c - Static Switch - 480V

Cabinet 2a - 480V

Cabinet 2d - 480V

From Sheet 1

A61 CT13A (400/5A)

B61 CT13B

C61 CT13C

N1 CT13N

CT14A (1500/5A) CT14R

CT14B

CT14C

TB13

TB14

To Meter 2 (Sheet 6)

To Relay 2 and DSP Control (Sheet 6)

F13H-A,B,C (2A)

To Meter 1 and Meter 2 (Sheet 6)

F14H-A,B,C (2A)

PT14A, B, C 277/120V

F14X-A,B,C (1.6A)

To Relay 2 and DSP Control (Sheet 6)

CB17

CB14

CB16

Static Switch SS15 Thyristor Assembly

(Full-load current = 271A)

A62

B62

C62

N1

A22

B22

C22

N1

Fault bus bar set

K22 (Sheet 18)

To Sheet 3

F17H-A,B,C (2A)

PT17A, B, C 277/120V

F17X-A,B,C (1.6A)

To DSP Control (Sheet 6)

Cabinet 2e

Voltage Relay 5a

Va

Vb

Vc

com

F51H-A,B,C (2A)

CB51 250A

A51 B51 C51

To Sheet 5

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CERTS Test Bed Schematic - PRELIMINARY

Zone 6 and 2

PROJ#:

Rev. L

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Date: 10/3/2005

file: CERTS_Schematic_RevL.vsd

Figure 2: CERTS Test Bed Schematic - Preliminary - Zones 6 and 2

Cabinet 2d - 480V

From Sheet 2

CB31
250A

A22 A31
B22 B31
C22 C31
N1

CT32A (250/5A) CT32R
CT32B
CT32C

CT34A (300A)
CT34B
CT34C

CT35A (250/5A)
CT35B
CT35C
CT35N

F35H-A,B,C
(2A)

To Meter 3 and Meter A1 (Sheet 8) and Microsource A1 Controller

TB32

To Microsource A1 Controller

TB35

To Meter 3 (Sheet 8)

F32H-A,B,C
(2A)

PT32A, B, C
277/120V

F32X-A,B,C
(1.6A)

Va
Vb
Vc
com
Vs
Vsn

DAS_24dcCOM
DAS_24dcPOS

Relay 3
(also Sheet 10)

+
PWR
-
G

Ia (5A)
Ib
Ic
In

Cabinet 2e

75 yds cable

Cabinet 3a - 480V DAS Load Distribution

25 yds cable

A31
B31
To Sheet 4
C31
N1

Load Bank Zone 3 (Sheet 7, 8)

K32
(Sheet 8)

Fault bus bar set

G1

TB33

CT33N
(150/5A)
CT33C
CT33B
CT33A

To Meter A1 (Sheet 8)

A31 B31 C31 N1

to CB32, and Microsource A1

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CERTS Test Bed Schematic - PRELIMINARY
Zone 3

PROJ#:

Rev. L

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Date: 10/3/2005

file: CERTS_Schematic_RevL.vsd

Figure 3: CERTS Test Bed Schematic - Preliminary - Zone 3

Cabinet 4a - 480V

From Zone 3 Sheet 3

CB41 250A

A31 A41

B31 B41

C31 C41

N1

(Full-load current = 90A)

CT42A (150/5A) CT42R

CT42B

CT42C

CT44A (200A)

CT44B

CT44C

CT45A (150/5A)

CT45B

CT45C

CT45N

TB42

TB45

To Microsource A2 Controller

To Meter 4 (Sheet 13)

To Meter 4 and Meter A2 (Sheet 13) and Microsource A2 Controller

F45H-A,B,C (2A)

F42H-A,B,C (2A)

PT42A, B, C 277/120V

F42X-A,B,C (1.6A)

Va Vb Vc com Vs Vsn Ia (5A) Ib Ic In

DAS_24dcCOM

DAS_24dcPOS

Relay 4 (also Sheet 10)

+ PWR -

G

75 yard cable

Cabinet 5a - 480V DAS Load Distribution

G1

Load Bank Zone 4 (Sheet 12, 13)

K42 (Sheet 13)

Fault bus bar set

TB43

CT43N (150/5A)

CT43C

CT43B

CT43A

To Meter A2 (Sheet 13)

A41 B41 C41 N1

to CB42 and Microsource A2

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CERTS Test Bed Schematic - PRELIMINARY
Zone 4

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Rev. L

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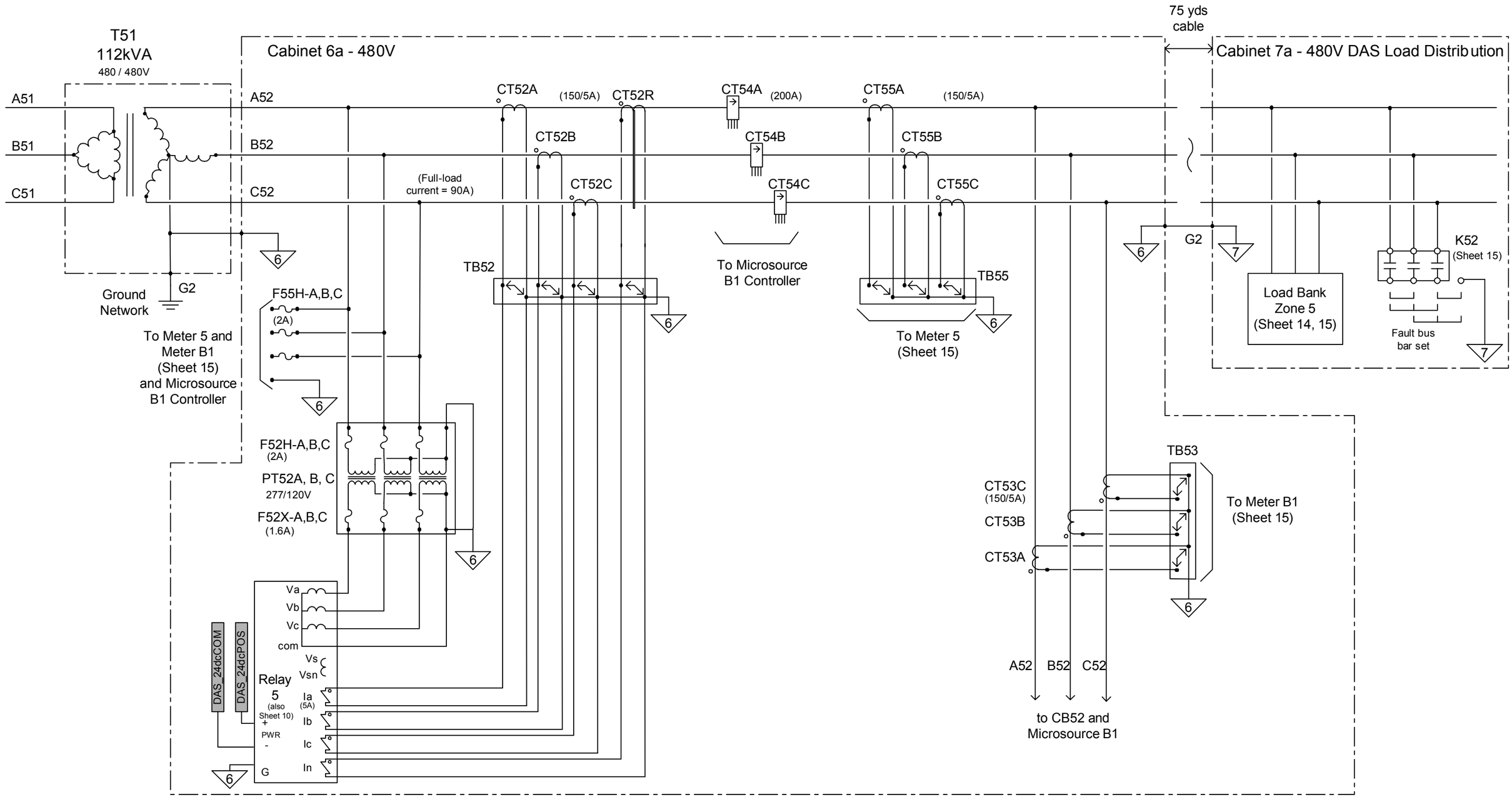
file: CERTS_Schematic_RevL.vsd

Figure 4: CERTS Test Bed Schematic - Preliminary - Zone 4



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NORTHERN POWER SYSTEMS	182 Mad River Park Waitsfield, VT 05673 802-496-2955 www.northernpower.com	CERTS Test Bed Schematic - PRELIMINARY Zone 5
		PROJ#: — Rev. L
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Schematic_RevL.vsd

Figure 5: CERTS Test Bed Schematic - Preliminary - Zone 5

Cabinet 2a -
480V

Va
Vb
Vc
com
To
PT17

DSP
Control
Ia
(1A)
Ib
Ic
To CT12

Ia
(1A)
Ib
Ic
To CT14

To CT14R

DAS_24dcCOM
DAS_24dcPOS
+
PWR
-
G
2

Va
Vb
Vc
com
To
PT14

Relay 2
(also Sheet 10)
Va
Vb
Vc
com
Vs
Vsn
Ia
(1A)
Ib
Ic
In
DAS_24dcCOM
DAS_24dcPOS
+
PWR
-
G
2

Cabinet 2e -
LV SS Control

DAS_120acBLK
DAS_120acWHT
L/+
N/-
G
2
Meter 1
(See also
Sheet 19)
V1
V2
V3
Vref
V4
I1
(5A)
I2
I3
I4
To CT11

(Va)
(Vb)
(Vc)
(Vn)
(Vg)
To
F13H

V1
V2
V3
Vref
V4
L/+
N/-
G
2
Meter 2
(See also
Sheet 19)
I1
(5A)
I2
I3
I4
To CT13

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CERTS Test Bed Schematic - PRELIMINARY
Zone 2 Controls

PROJ#:
Rev. L

Drawn by: Ed Linton
Date: 10/3/2005
file: CERTS_Schematic_RevL.vsd

Figure 6: CERTS Test Bed Schematic - Preliminary - Zone 2 Controls

Cabinet 3a - 480V DAS Load Distribution

From Sheet 3

CB33 250A

A31 A32 B31 B32 C31 C32 N1

CT36A (200/5A) CT36B CT36C CT36N

J31 1 2 3 4

To Sheet 8

A32 B32 C32 N1

F36H-A,B,C (2A)

TB36

CB38 15A

CB34 30A

CB35 150A

MS34

Load3_120acBLK

K38 (Cabinet 3c)

MS 34

Load3_120acWHT

Cabinet 3b - LV DAS Load Control

Load3_120acWHT Load3_120acBLK

Load Meter 3 (See also Sheet 20)

V1 V2 V3 Vref V4

I1 (5A) I2 I3 I4

L/+ N/- G

T38 480 / 120V

F38X

DC Power Supply PS38

R38

M34

SR31

Motor Load 10 to 20 HP see specification

Torque sensor

Cabinet 3b

load bit 1 (lsb)

load bit 6 (msb)

DO-1 DO-2 DO-3 DO-16 DO-17 DO-18 DO-19 DO-20 DO-24 DO-25

TB37 TB37

K36-1a K36-1b K36-1c K36-6a K36-6b K36-6c

Load control SSR's K36-1a through K36-6c

K38 K37-1 K37-3

(Sheet 8)

Zone 3 Load Control PLC

Load3_24dcPOS Load3_24dcCOM

to DAS Trigger Circuit (Sheet 19)

(See also sheet 8)

AI-1 DC power supply monitor

AI-2 Motor torque sensor

Cabinet 3b - 480V DAS Load Control

CB36-1 CB36-1 through CB36-6 CB36-6

K36-1a,b,c K36-1a,b,c through K36-6a,b,c K36-6a,b,c

R36-1 5kW

Load resistor array R36-1 through R36-6

R36-6 20kW

5kW, 10kW, 4 x 20kW 3-phase resistors

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CERTS Test Bed Schematic - PRELIMINARY
Load Bank 3

PROJ#: Rev. L

Drawn by: Ed Linton Date: 10/3/2005 file: CERTS_Schematic_RevL.vsd

Figure 7: CERTS Test Bed Schematic - Preliminary - Load Bank 3

Cabinet 3a - 480V DAS Load Distribution

From Sheet 7

A32
B32
C32
N1

CB39
100A

K39-1
L39-1A,B,C
10 kVAR
61.1 mH, 24A

K39-3
L39-3A,B,C
30 kVAR
20.4 mH, 72A

K39-2a,b,c
L39-2A,B,C
20 kVAR
30.5 mH, 48A

Cabinet 2e - LV

Meter 3
(See also Sheet 19)
V1, V2, V3, Vref, V4
(Va), (Vb), (Vc), (Vn), (Vg)
To F35H (Sheet 3)
I1 (5A), I2, I3, I4
To TB35 (Sheet 3)
L/+, N/-, G
2

Meter A1
(See also Sheet 19)
V1, V2, V3, Vref, V4
I1 (5A), I2, I3, I4
To TB33 (Sheet 3)
L/+, N/-, G
2

Load3_120acBLK
Load3_120acWHT

Load3_120acBLK
K37-1, K37-2a, K37-2b, K37-2c, K37-3
K39-1, K39-2a, K39-2b, K39-2c, K39-3
Load3_120acWHT
(K37-x in Cabinet 3c)

Cabinet 3b - LV DAS Load Control

Load3_24dcPOS
Fault 3 Local Arming Key Switch
S31
DAQ Fault 3 Arm
K33-1
K33-2
DAQ Fault 3 Apply
K33-3
Fault Switch (Cabinet 3a, Sheet 3)
c11, c12, c1, c2
K32 YO (open)
K34
K32 YC (close)
LT31 "Fault 3 Locally Armed"
LT32 "Fault 3 Remotely Armed"
LT33 Fault 3 Warning Strobe Light
Load3_24dcCOM
Trigger circuit (Sheet 19)

Zone 3 Load Control PLC
(See also sheet 7)
Load3_24dcPOS
Load3_24dcCOM
DO-26, DO-27, DO-28, DO-29, DO-30
K33-1, K33-2, K33-3
J32
1, 2, 3, 4, 5, 6
- Pwr +
G
3

Load3_120acBLK
u1
Fault Switch Spring Motor
K32 M
u2
Load3_120acWHT

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CERTS Test Bed Schematic - PRELIMINARY
Load Bank 3 continued

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Figure 8: CERTS Test Bed Schematic - Preliminary - Load Bank 3 Continued

Isolated, secure 20 kVA, source that will not be effected by testing, use UPS if necessary, voltage TBD.

120V

T91
15kVA

G3

CB1
15A

CB10
100A

CB2
15A

CB3
15A

CB4
15A

CB5
15A

CB6
15A

CB9
15A

DAS Power Supply
Cabinet 2e

DAS_120acBLK
DAS_120acWHT
Duplex Outlet U2a
PS1
FD1
DAS_24dcPOS
DAS_24dcCOM
2
Distributed to Cabinets 2a, 2e, 4a & 6a

CB Power Supply
Cabinet 2a

CB_120acBLK
CB_120acWHT
Duplex Outlet U2e
PS2
FD2
CB_24dcPOS
CB_24dcCOM
2
Distributed to Cabinets 2a, 2d, 4a & 6a

Load 3 Control Power
Cabinet 3b

Load3_120acBLK
Load3_120acWHT
Duplex Outlet U3b
PS3
FD3
Load3_24dcPOS
Load3_24dcCOM
3
Distributed to Cabinets 3a, 3b

Load 4 Control Power
Cabinet 5b

Load4_120acBLK
Load4_120acWHT
Duplex Outlet U5b
PS4
FD4
Load4_24dcPOS
Load4_24dcCOM
5
Distributed to Cabinets 5a, 5b

Load 5 Control Power
Cabinet 7b

Load5_120acBLK
Load5_120acWHT
Duplex Outlet U7b
PS5
FD5
Load5_24dcPOS
Load5_24dcCOM
7
Distributed to Cabinets 7a, 7b

Load 6 Control Power
Cabinet 8b

Load6_120acBLK
Load6_120acWHT
Duplex Outlet U8b
PS6
FD6
Load6_24dcPOS
Load6_24dcCOM
8
Distributed to Cabinets 8a, 8b

EMS & DAS
Workstation 9b

PC_120acBLK
PC_120acWHT
Duplex Outlet U9b

Cabinet 9a -
120V DAS Power
Distribution

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CERTS Test Bed Schematic - PRELIMINARY
Control Power

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Figure 9: CERTS Test Bed Schematic - Preliminary - Control Power

Cabinet 2a | Cabinet 2e | Load Cabinets | Cabinet 4a | Cabinet 6a | Microsources | DAS & EMS Computers

Relay 3
RS-232
FO202
Relay 2
RS-232
FO203
RS-232
SEL-2030
FO207
RS-232
FO401
RS-232
Relay 4
FO601
RS-232
Relay 5
RS-232
RS-232
FO206
RS-232
RS-232
FO204
FO205

FO201
SS DSP Control
RS-485

Meter 1
Ethernet
Meter 2
Meter 3
Meter 4
Meter 5
Meter A1
Meter A2
Meter B1

Ethernet Hub
EIR 308 -2ST
EIR 305 -1ST
EIR 308 -2ST
EIR 308 -2ST
Load Meter 3
Load Meter 4
Load Meter 5
Load Meter 6

Ethernet Hub
Load PLC 2
ECOM
EIR 308 -2ST
EIR 305 -1ST
EIR 308 -2ST
ECOM -F
Load PLC 3
ECOM -F
Load PLC 4
ECOM -F
Load PLC 5
ECOM -F
Load PLC 6

FO101
Microsource A1
RS-485
RS-485
Microsource A2
Microsource B1

FO901
RS-485
FO902
RS-232
FO903
RS-485
EMS Computer

FO904
RS-232
DAS Computer
EIR 308 -2ST

Ledgend:
- RS-232 — SEL-2812 fiber optic converter
- RS-485 — B&B FOSTCDR fiber optic converter
- Fiber Optic Cable Pairs, multimode with ST connectors

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CERTS Test Bed Schematic - PRELIMINARY
DAS & EMS Communications

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Figure 10: CERTS Test Bed Schematic - Preliminary - DAS & EMS Communications

Feeder A

Cabinet 2

2d

2e Low Voltage

CB31

CT32R

3

N

G1

75 yards

Cabinet 3

3a

25 yards

Cabinet 4a

CB41

CT42R

3

N

G1

75 yards

Cabinet 5

5a

CB33

Fault Load

CB43

Fault Load

CB32

CB34, CB35, CB39

3b

CB42

CB45, CB48, CB49

5b

3

N

G1

CB51

Load Elements Zone 3

Load Elements Zone 4

Battery

Microsource A1

Battery

Microsource A2

Fault Load

Feeder B

T51

Cabinet 6a

75 yards

Cabinet 7

7a

3

CT52R

3

G2

G2

CB53

Fault Load

CB52

CB55, CB57, CB59

7b

Load Elements Zone 5

Battery

Microsource B1

DAS and EMS Control Power

Cabinet 9a

120V

Reliable control power source

Zone power supplies

G3

S&C

CB16

CB17

Static Switch SS15

CB14

CT14R

CB13

Feeder C (75 yards)

Cabinet 8

8a

3

N

G1

2a

CB12

CB63

Fault Load

CB65, CB69

8b

T11

G1

Load Elements Zone 6

Optional Transformer

S11

FD10

Utility

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CERTS Test Bed Schematic - PRELIMINARY

Ground & Neutral Treatment

PROJ#:

Rev. L

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Date: 10/3/2005

file: CERTS_Schematic_RevL.vsd

Figure 11: CERTS Test Bed Schematic - Preliminary - Ground & Neutral Treatment

Cabinet 5a - 480V DAS Load Distribution

CB43
250A

A41 A42
B41 B42
C41 C42
N1

From
Sheet 4

CT46A (200/5A)
CT46B
CT46C
CT46N

J41
1
2
3
4
5

To
Sheet 13

A42
B42
C42
N1

F46H-A,B,C
(2A)

TB46

CB48
15A

CB45
150A

Load
Meter 4
(See also
Sheet 20)

V1
V2
V3
Vref
V4
I1
(5A)
I2
I3
I4
L/+
N/-
G

Load4_120acWHT
Load4_120acWHT

T48
480 / 120V

F48X

DC Power
Supply
PS48

R48

Cabinet 5b

load bit 1
(lsb)

load bit 6
(msb)

DO-1
DO-2
DO-3
DO-16
DO-17
DO-18
DO-19
DO-23
DO-24

TB47
TB47

K46-1a
K46-1b
K46-1c
K46-6a
K46-6b
K46-6c
K47-1
K47-3

Load control
SSR's K46-1a
through K46-6c

Zone 4
Load
Control
PLC

(Sheet 13)

Load4_24dcPOS
Load4_24dcCOM

to DAS Trigger Circuit (Sheet 19)

AI-1 DC power supply monitor

(See also sheet 13)

Cabinet 5b - LV DAS Load Control

Cabinet 5b -
480V DAS
Load Control

CB46-1
CB46-1 through
CB46-6
CB46-6

K46-1a,b,c through
K46-6a,b,c

K46-1a,b,c
K46-6a,b,c

R46-1
5kW

Load resistor array
R46-1 through
R46-6

R46-6
20kW

5kW, 10kW, 4 x 20kW
3-phase resistors

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CERTS Test Bed Schematic - PRELIMINARY
Load Bank 4

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Figure 12: CERTS Test Bed Schematic - Preliminary - Load Bank 4

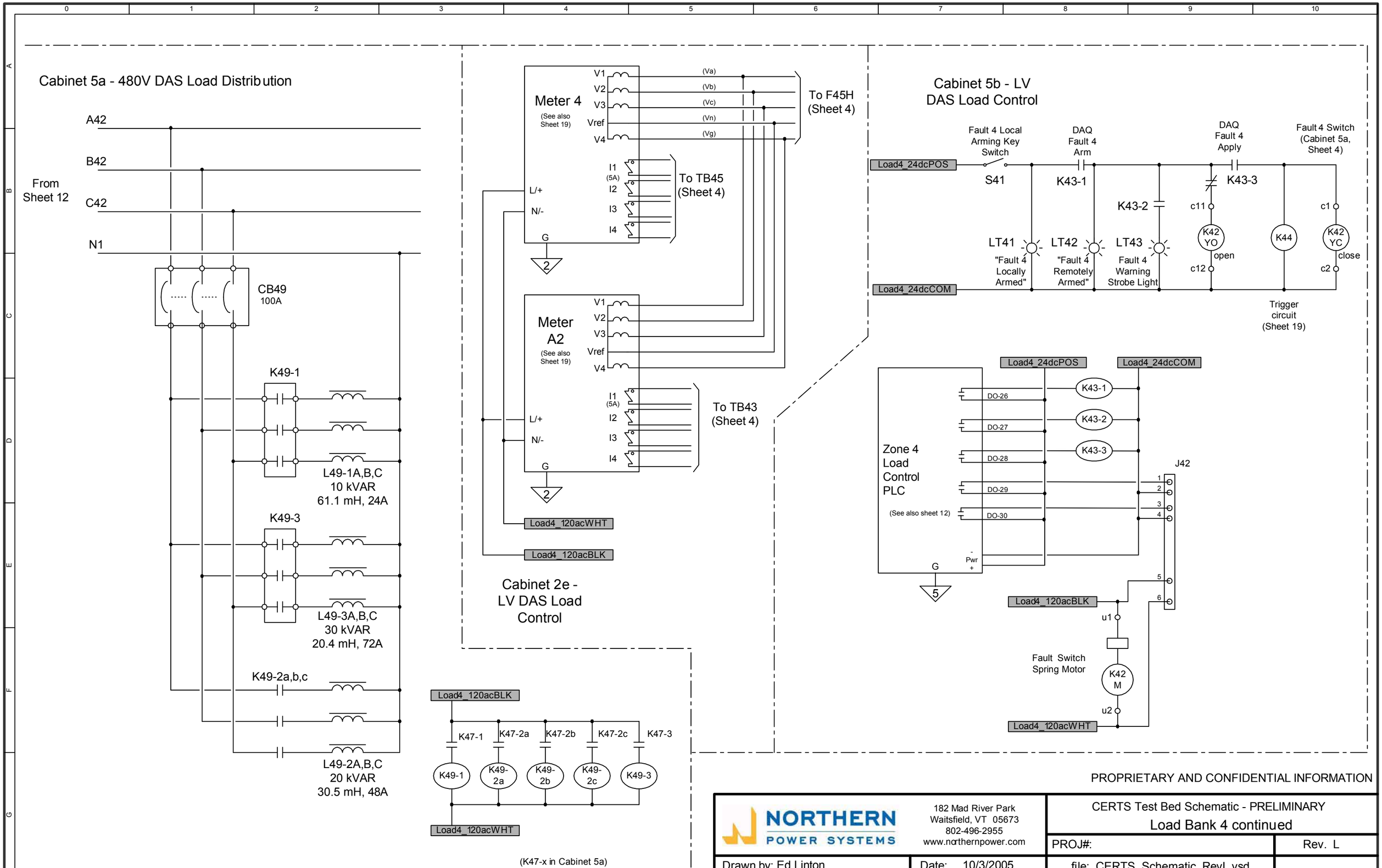

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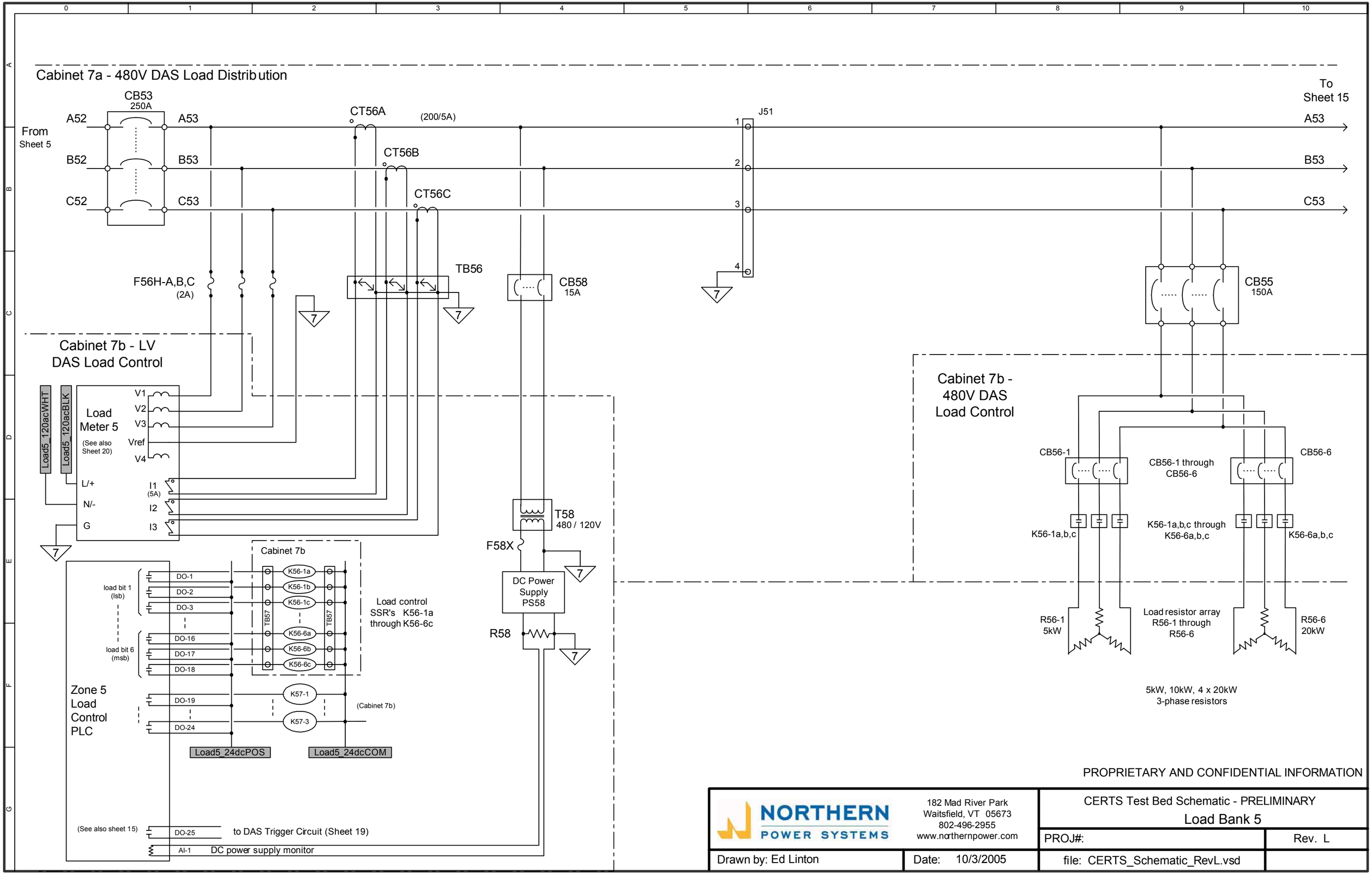
Figure 13: CERTS Test Bed Schematic - Preliminary - Load Bank 4 Continued



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CERTS Test Bed Schematic - PRELIMINARY
Load Bank 5

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file: CERTS_Schematic_RevL.vsd

Figure 14: CERTS Test Bed Schematic - Preliminary - Load Bank 5

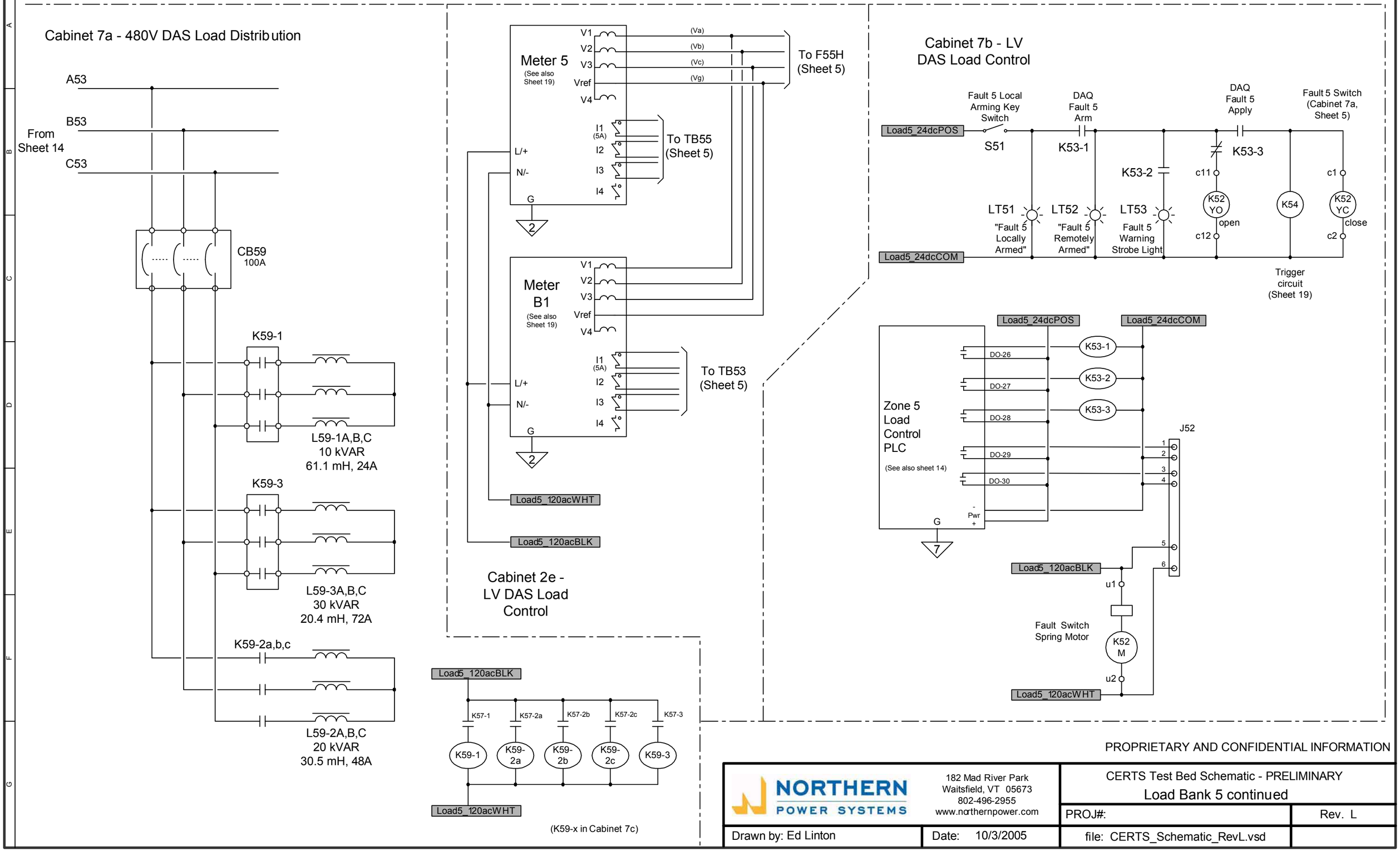

Figure 15: CERTS Test Bed Schematic - Preliminary - Load Bank 5 Continued

Cabinet 8a - 480V DAS Load Distribution

From Sheet 1

A63 A64 B63 B64 C63 C64 N1

CB63 250A

CT66A (200/5A)

CT66B

CT66C

CT66N

F66H-A,B,C (2A)

TB66

CB68 15A

J61 1 2 3 4

8

To Sheet 17

A63 B63 C63 N1

CB65 150A

Cabinet 8b - LV DAS Load Control

Load Meter 6 (See also Sheet 20)

V1 V2 V3 Vref V4

I1 (5A) I2 I3 I4

L/+ N/-

G

Load6_120acWHT

Load6_120acBLK

T68 480 / 120V

F68X

DC Power Supply PS68

R68

Cabinet 8b

load bit 1 (lsb)

load bit 6 (msb)

DO-1 DO-2 DO-3 DO-16 DO-17 DO-18 DO-19 DO-24

TB67 TB67

K66-1a K66-1b K66-1c K66-6a K66-6b K66-6c

K67-1 K67-3

Load control SSR's K66-1a through K66-6c

(Cabinet 8b)

Zone 6 Load Control PLC

Load6_24dcPOS Load6_24dcCOM

DO-24 to DAS Trigger Circuit (Sheet 19)

AI-1 DC power supply monitor

(See also sheet 17)

Cabinet 8b - 480V DAS Load Control

CB66-1 CB66-1 through CB66-6 CB66-6

K66-1a,b,c K66-1a,b,c through K66-6a,b,c K66-6a,b,c

R66-1 5kW Load resistor array R66-1 through R66-6 R66-6 20kW

5kW, 10kW, 4 x 20kW 3-phase resistors

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CERTS Test Bed Schematic - PRELIMINARY

Load Bank 6

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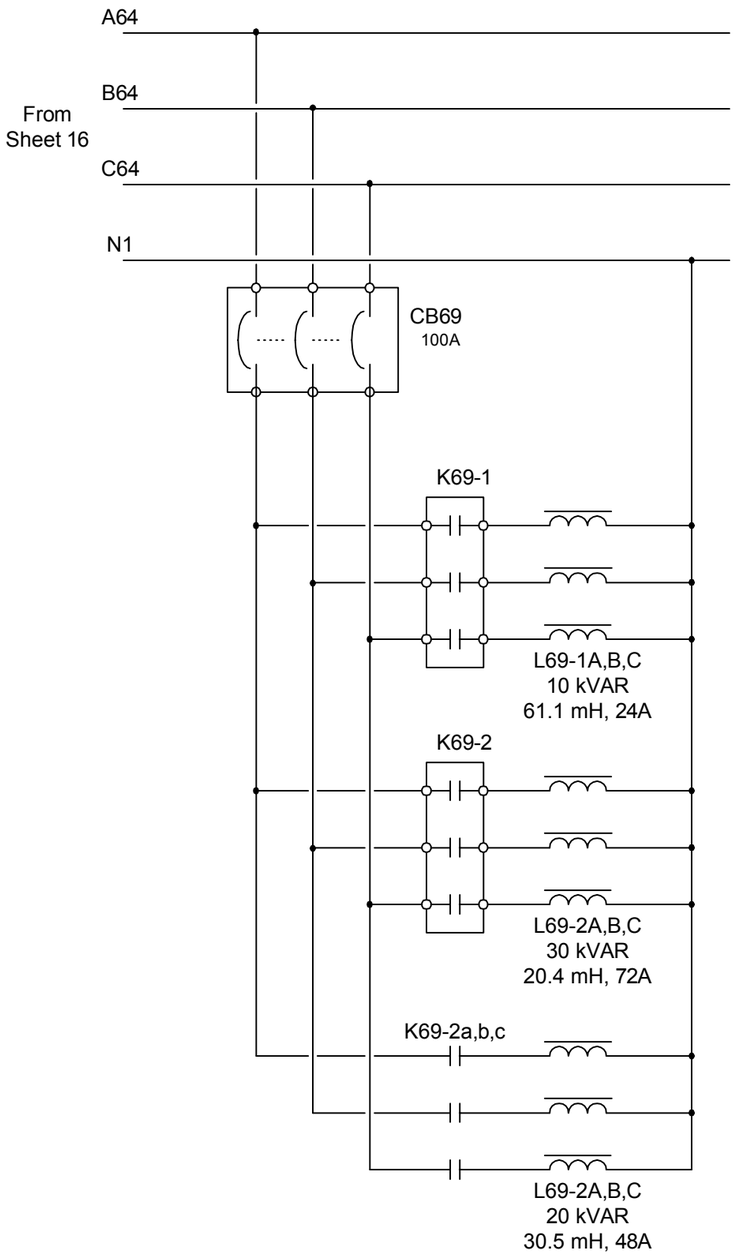
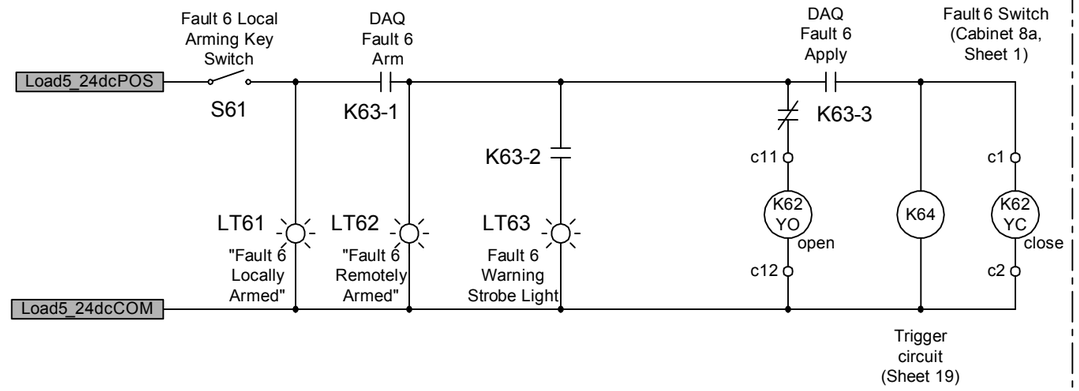
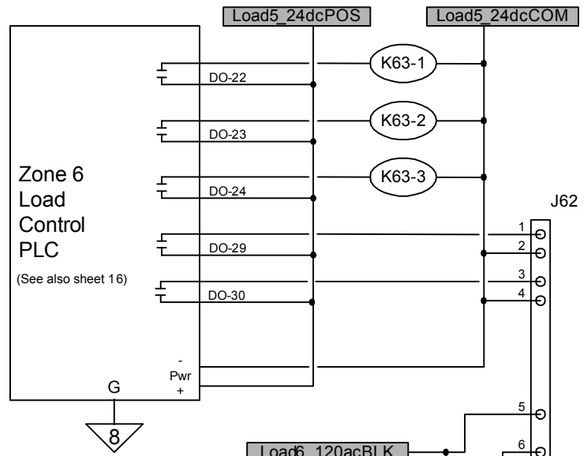
Figure 16: CERTS Test Bed Schematic - Preliminary - Load Bank 6

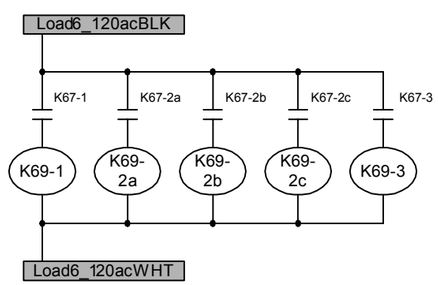
Cabinet 8a - 480V DAS Load Distribution



Cabinet 8b - LV DAS Load Control







(K69-x in Cabinet 8c)

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CERTS Test Bed Schematic - PRELIMINARY
Load Bank 6 continued

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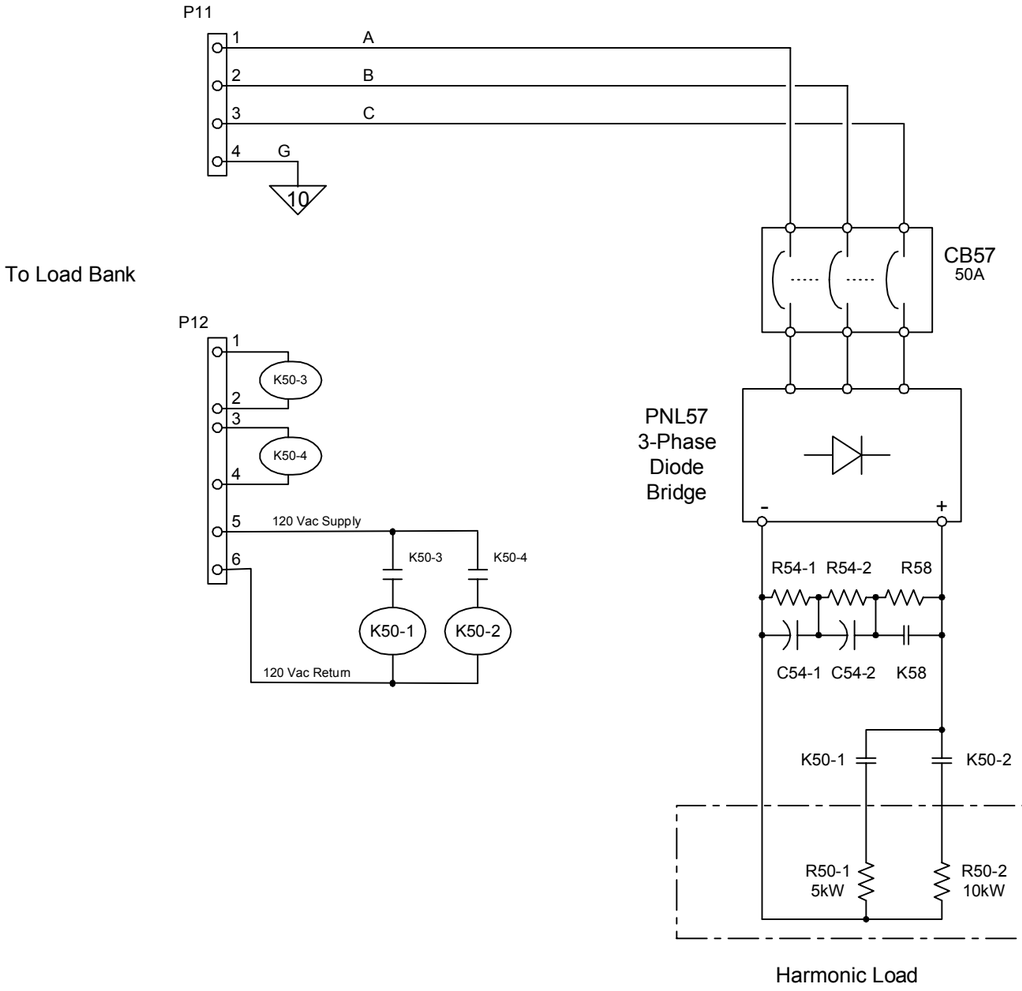
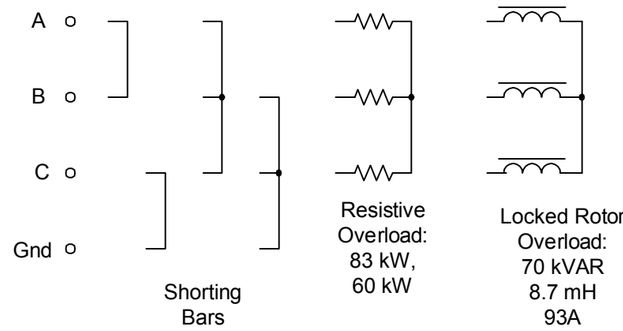
Figure 17: CERTS Test Bed Schematic - Preliminary - Load Bank 6 Continued

Cabinet 10 - 480V



Typical Fault Bus Bar & Load Set



Cabinet 2e - LV DAS

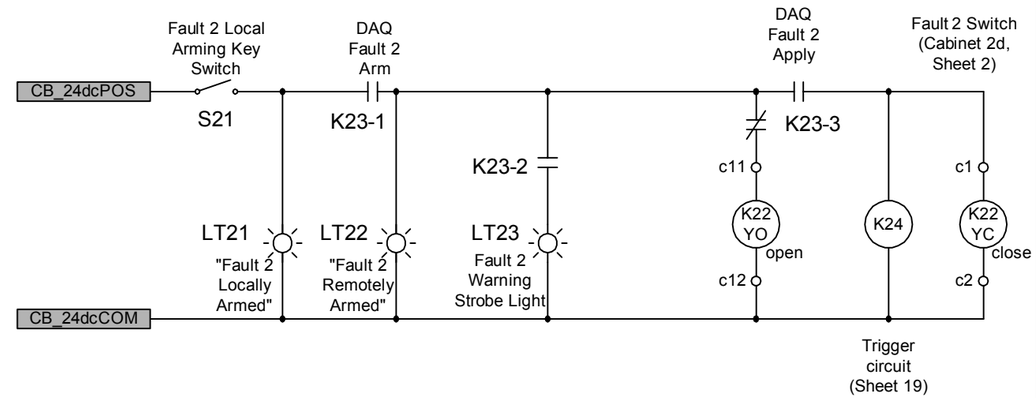


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Figure 18: CERTS Test Bed Schematic - Preliminary - Harmonic Load and Zone 2 Fault Control

DAS Trigger Pos

DAS Trigger Neg

SS15 Status b

CB31 Aux b

CB41 Aux b

CB51 Aux b

SCOM

Meter 1 Digital Input

Meter 2 Digital Input

Meter 3 Digital Input

Meter 4 Digital Input

Meter 5 Digital Input

S1

S8

Cabinet 2e

Meter A1 Digital Input

Meter B1 Digital Input

Meter A2 Digital Input

Relay 2 OUT102 (sheet 10)

K24

Load Cabinets

Load Meter 3 Digital Input

Load PLC 3 DO-24

K34

(Cabinet 3b, sheet 7, 8)

Load Meter 4 Digital Input

Load PLC 4 DO-24

K44

(Cabinet 5b, sheet 12, 13)

Load Meter 5 Digital Input

Load PLC 5 DO-24

K54

(Cabinet 7b, sheet 14, 15)

Load Meter 6 Digital Input

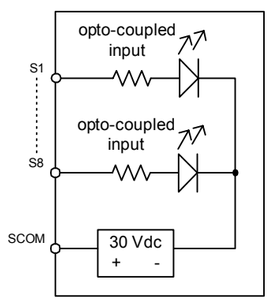
Load PLC 6 DO-24

K64

(Cabinet 8c, sheet 16, 17)

DAS PC

DAS digital output



Typical meter digital input

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CERTS Test Bed Schematic - PRELIMINARY
DAS Trigger Circuit

PROJ#:

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Date: 10/3/2005

file: CERTS_Schematic_RevL.vsd

Figure 19: CERTS Test Bed Schematic - Preliminary - DAS Trigger Circuit

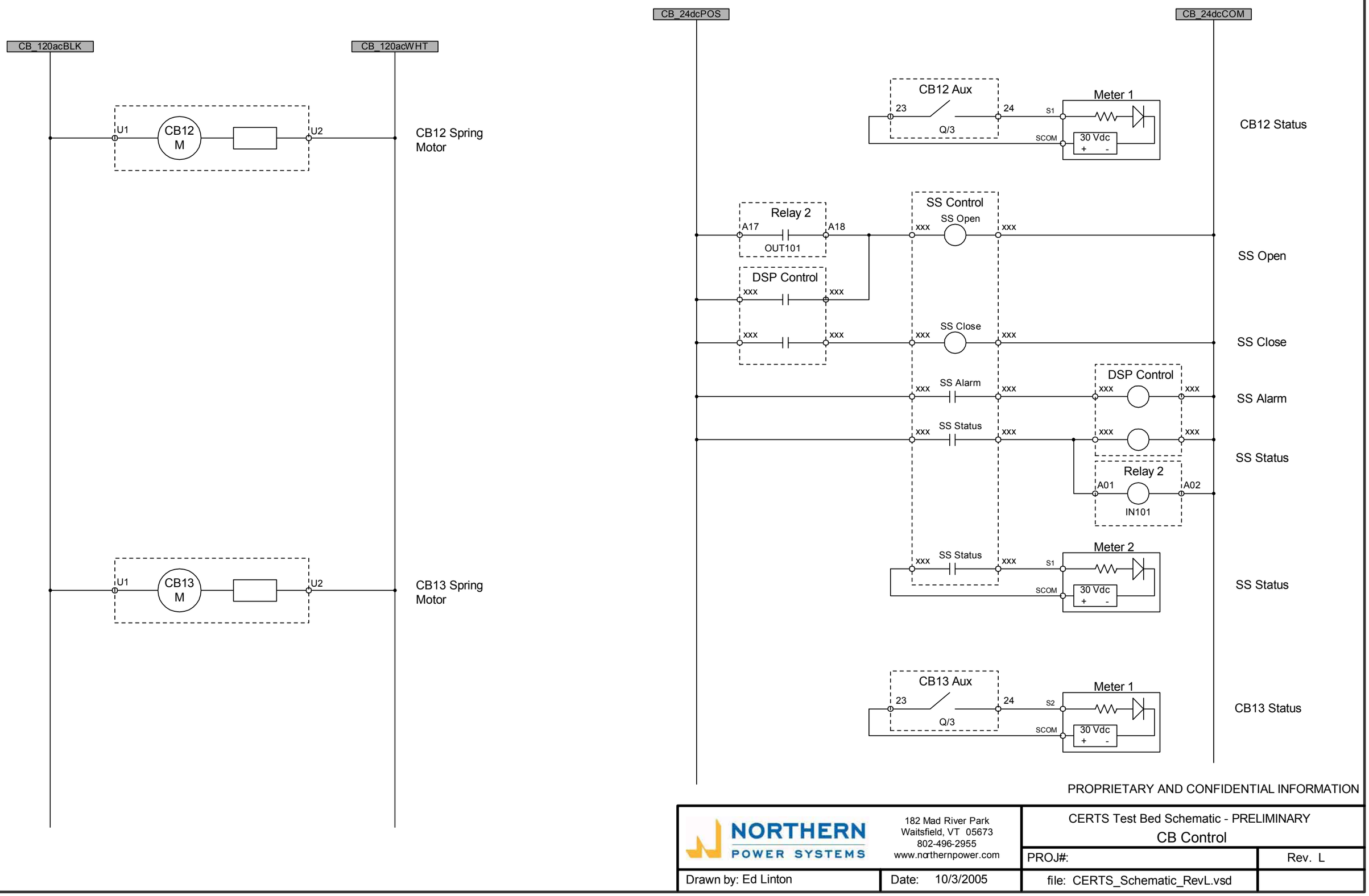
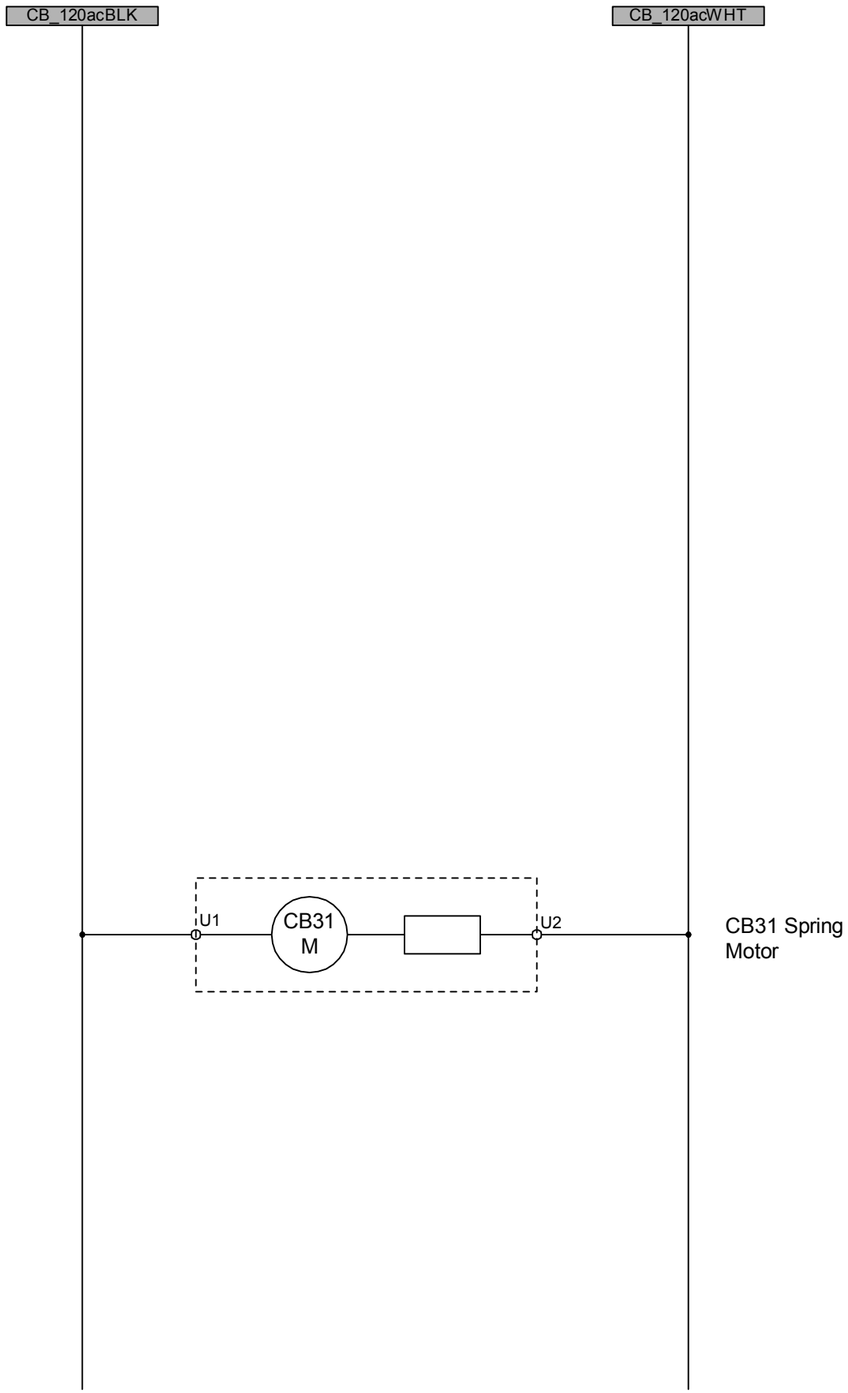
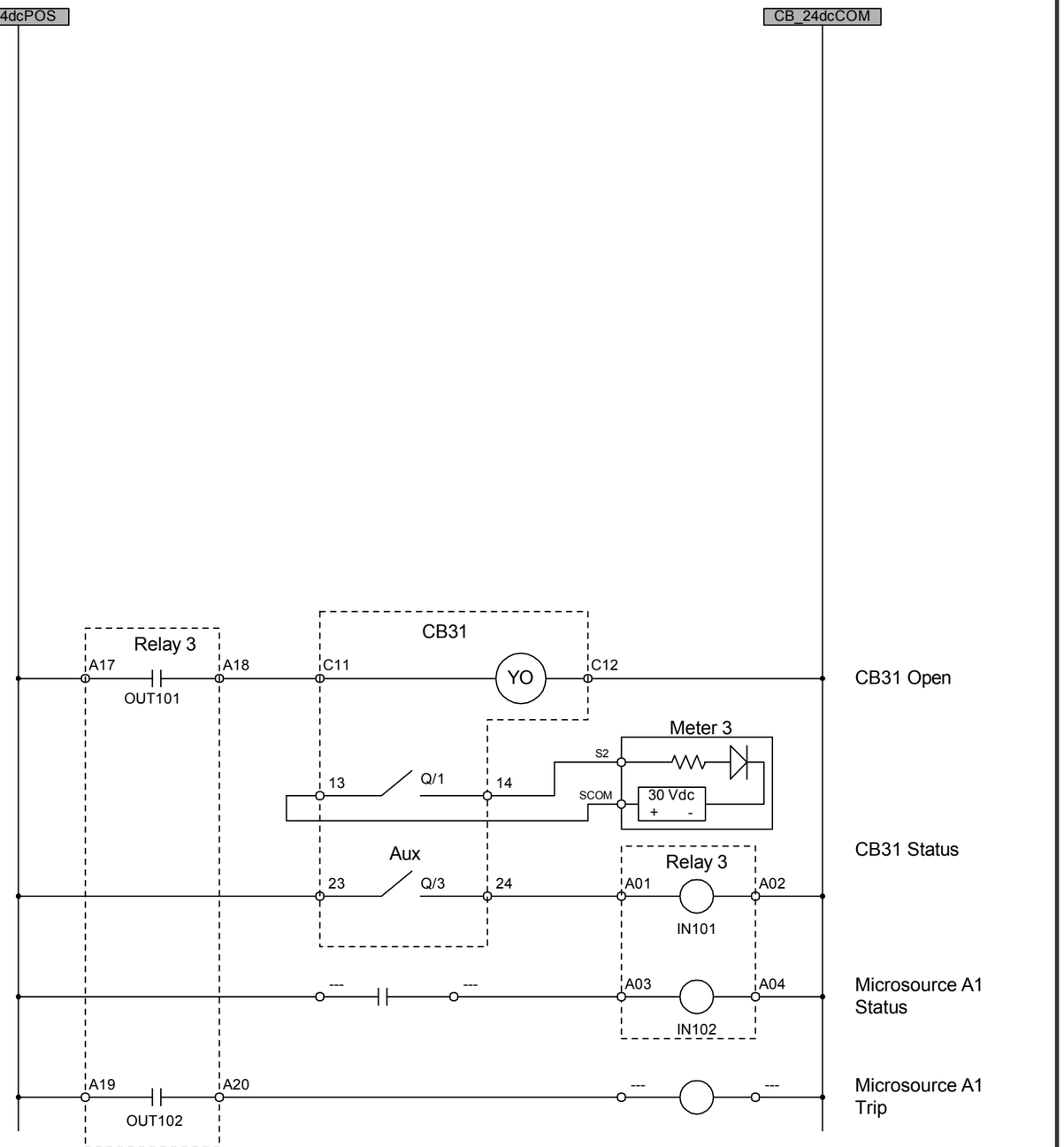


Figure 20: CERTS Test Bed Schematic - Preliminary - CB Control





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CERTS Test Bed Schematic - PRELIMINARY
CB Control

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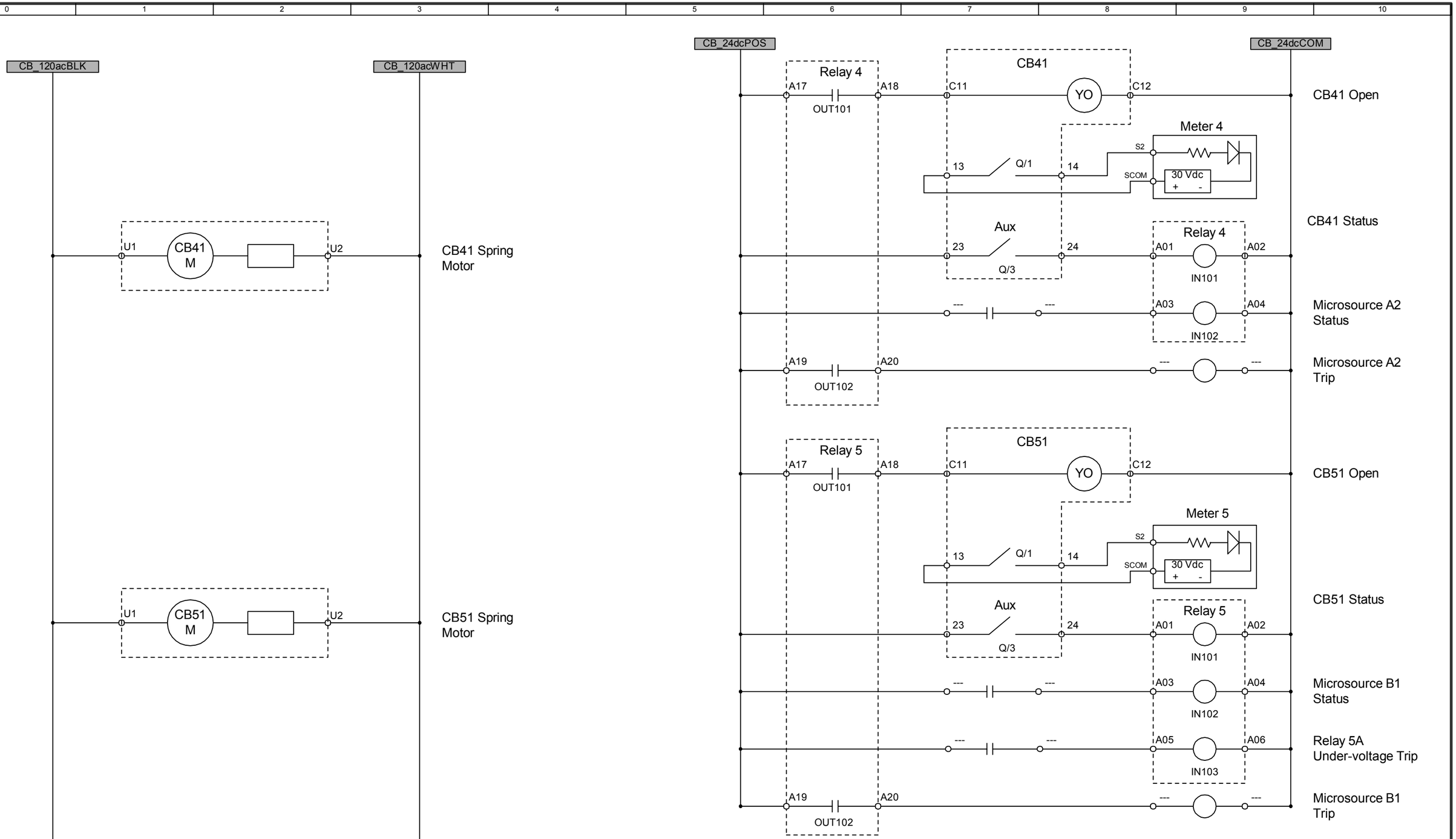
		file: CERTS_Schematic_RevL.vsd	

Figure 21: CERTS Test Bed Schematic - Preliminary - CB Control



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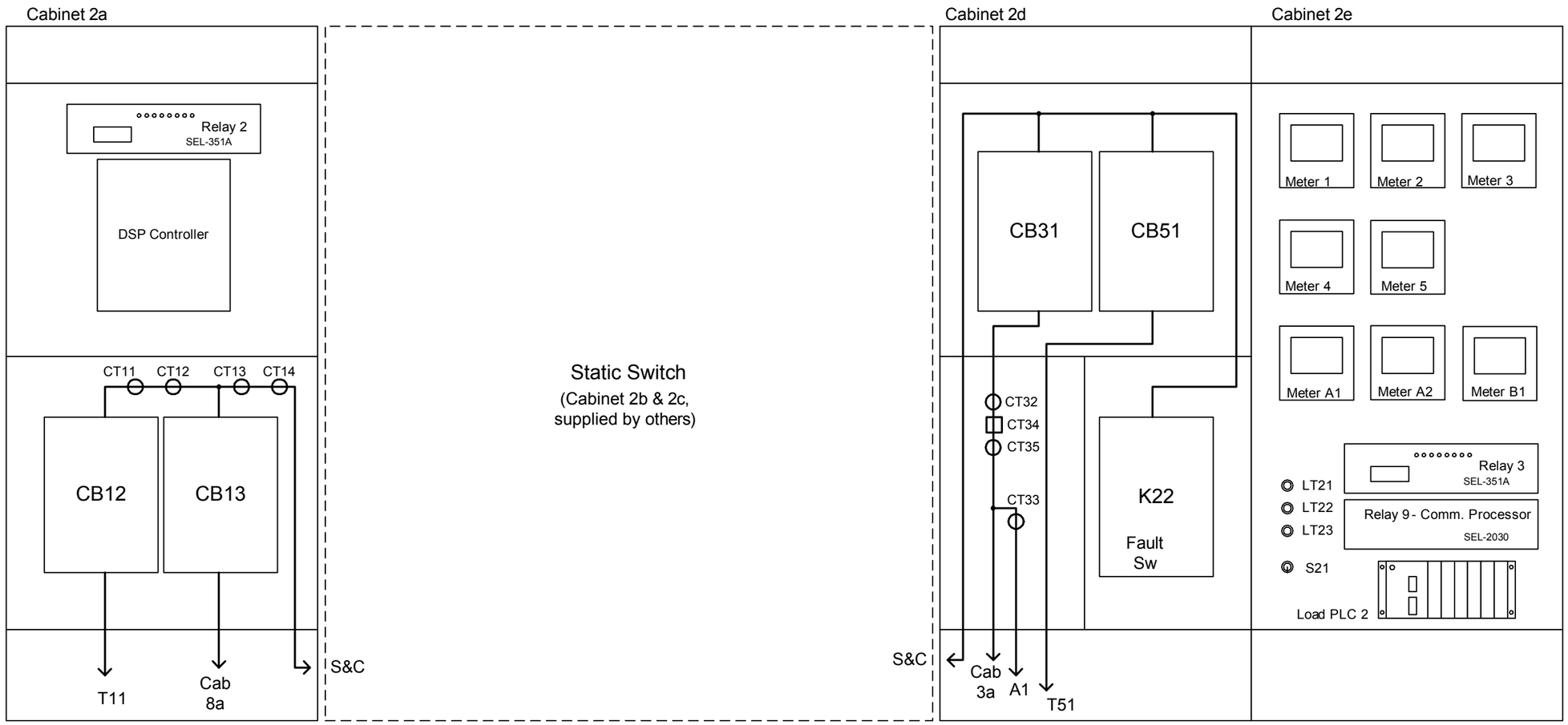
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Schematic_RevL.vsd

Figure 22: CERTS Test Bed Schematic - Preliminary - CB Control



Cabinets also include:

600A bus
- TB11
- TB12
- TB13
- TB14
- PT14
- F14H
- F14X
- F13H
- U2a outlet
- PS2
- FD2

Static switch:
- CB14
- CB16
- CB17

400A bus
- TB32
- TB35
- F35H
- TB33
- F51H
- PT32
- F32H
- F32X
- PT17
- F17H
- F17X

- K23-1,2,3
- K24
- K25
- PS1
- FD1
- Relay 5a
- U2e outlet

10 cm

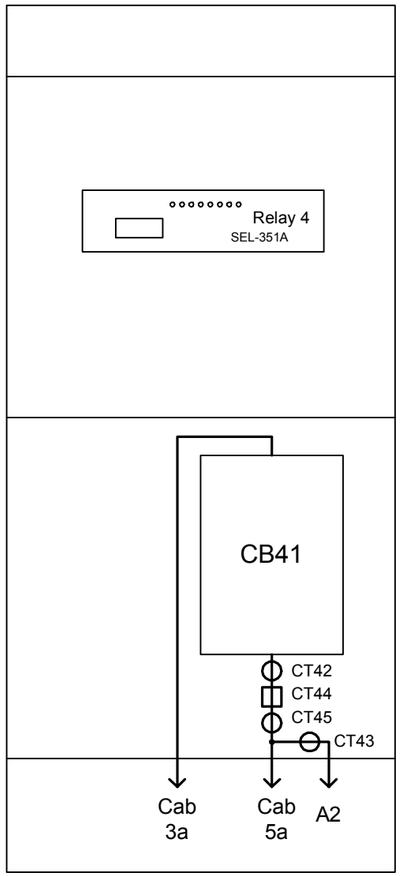
NORTHERN POWER SYSTEMS 182 Mad River Park Waitsfield, VT 05673 802-496-2955 www.northernpower.com		CERTS Test Bed - Suggested Cabinet Layout
		PROJ#: Rev. E
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Cabinet_Layout_RevE.vsd

Figure 23: CERTS Test Bed - Suggested Cabinet Layout

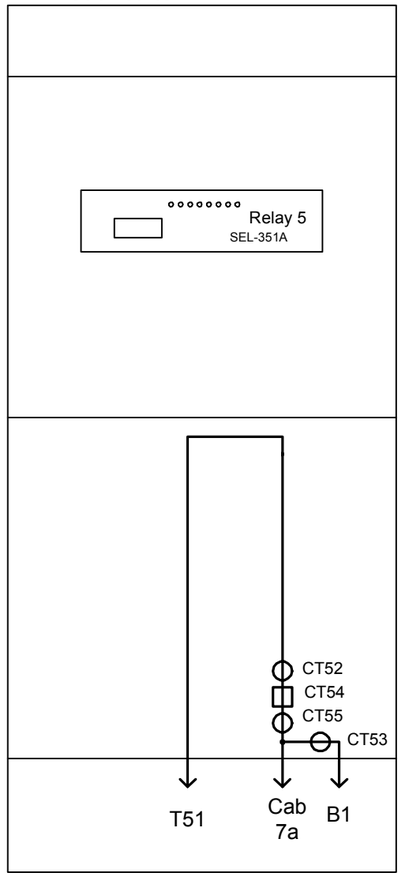
Similar Cabinets:

5a	5b
7a	7b
8a	8b

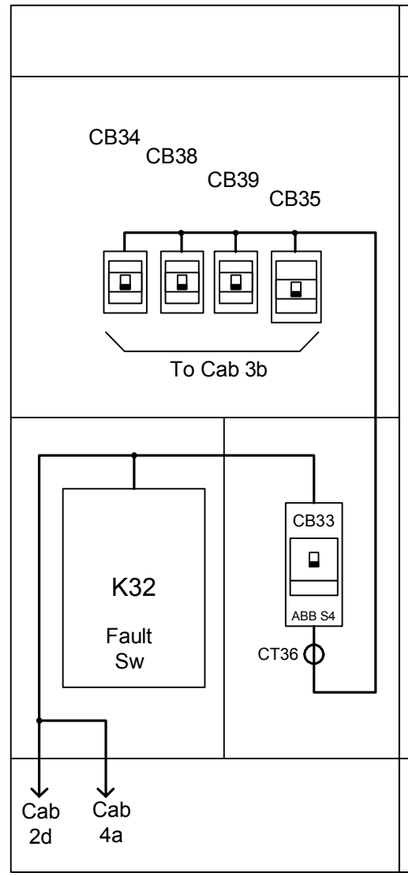
Cabinet 4a



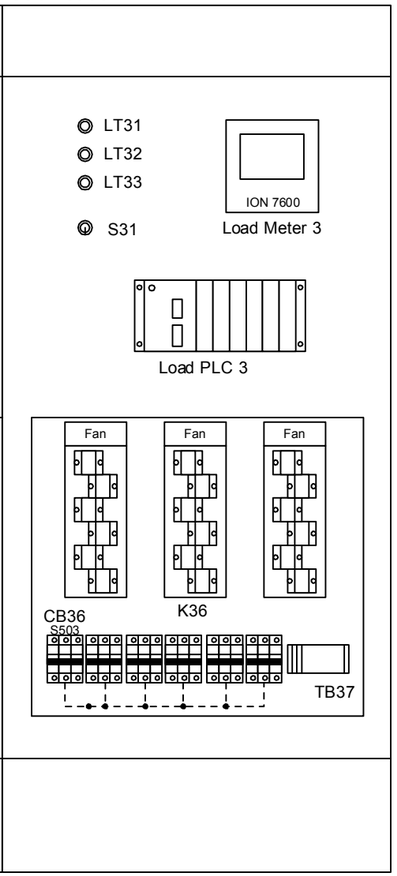
Cabinet 6a



Cabinet 3a



Cabinet 3b



Cabinets also include:

TB42 TB45 F45H TB43 PT42 F42H F42X	225A bus	
TB52 TB55 F55H TB53 PT52 F52H F52X	225A bus	
TB36 F36H J31 K39-2a,b,c	225A bus	FD3 PS3 K38 K37 K33 K34 K39 MS34 J32

10 cm

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CERTS Test Bed - Suggested Cabinet Layout

PROJ#:		Rev. E
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Cabinet_Layout_RevE.vsd

Figure 24: CERTS Test Bed - Suggested Cabinet Layout

Zone 3
Meter 3 (DAS)
Meter A1 (DAS)
CT34
F35H
CT32
PT32
CB31
CT32R
CT35
F35
Feeder A
480 V
4
CT33
75 yard loop
25 yard loop
EMS
Microsource A1
Controller
CB32
T31
Filter
Storage
Protective Relay 3
CB33
Load Meter 3 (DAS)
F36
CT36
Load Bank 3
Fault Load

Zone 4
Meter 4 (DAS)
Meter A2 (DAS)
CT44
F45H
PT24
CT42
CB41
CT42R
CT45
F45
Feeder A
480 V
4
CT43
75 yard loop
EMS
Microsource A2
Controller
CB42
T41
Filter
Storage
Protective Relay 4
CB43
Load Meter 4 (DAS)
F46
CT46
Load Bank 4
Fault Load

Zone 2
Fault Load
PT17
CB51
T51
PT51
Relay 5a
S&C
CB16
CB17
Static Switch
SS15
EMS
CB14
Protective Relay 2
CT14R
PT14
CT14
CT13
F13
DSP Control
Meter 2
CT12
CT11
Meter 1
CB12
L11
Additional inductor can be added for higher impedance
Zone 6
CB13
Feeder C
480 V
4
75 yard loop
CB63
Load Meter 6 (DAS)
F66
CT66
Load Bank 6
Fault Load
T11
S11
FD10
Utility Interface
PCC - Zone 1
Zone 1
Optional Transformer for Wye Interface

Zone 5
Meter 5 (DAS)
Meter B1 (DAS)
CT54
F55H
PT52
CT52
CT52R
CT55
F55
Feeder B
480 V
3
CT53
75 yard loop
EMS
Microsource B1
Controller
CB52
T52
Filter
Storage
Protective Relay 5
CB53
Load Meter 5 (DAS)
F56
CT56
Load Bank 5
Fault Load

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CERTS Test Bed - One-Line Diagram
Power Schematic

PROJ#:
Rev. P

Drawn by: Ed Linton
Date: 10/3/2005
file: CERTS_Test_Bed_RevP.vsd

Figure 25: CERTS Test Bed - One-line Diagram - Power Schematic

Feeder A
480 V

CB31 CT32 CT32R PT32 4 CB32 T32 CB33 Fault Current Zone 3

CB41 CT42 CT42R PT42 CB42 T42 CB43 Fault Current Zone 4

trip 51 50 G 27 p-p trip

Relay 3 Microsource A1 Load Bank Zone 3

Relay 4 Microsource A2 Load Bank Zone 4

Zone 2

Fault Current Zone 2

Relay 2, DSP, and Static Switch Control

PT17 CB16 CB17 CB14 PT14 CT14 CT14R CB12

25 close EMS trip Static Switch SS15

59 27 p-p 81 O/U 50 51 50 G 32

CB51 T51 trip 27 Relay 5A

Feeder B
480 V

CT52R CT52 PT52 3 CB52 T52 CB53 Fault Current Zone 5

51 50 G 27 p-p trip

Relay 5 Microsource B1 Load Bank Zone 5

Feeder C 4
480 V

CB13 CB63 Fault Current Zone 6 Load Bank Zone 6

T11 (ground fault detection on delta system) 51 27 S11 FD10 Utility Interface PCC - Zone 1

Optional Transformer for Wye Interface

Devices:

52	Vacuum interrupter and manual load-break switch
Static Switch	Back-to back SCR switch

Relay Functions:

25	Synchronization
27 p-p	Undervoltage phase-to-phase
27	Undervoltage
32	Directional power
46	Negative sequence current
47	Negative sequence voltage
50	Instantaneous overcurrent
50 G	Residual current (A+B+C+N) (zero-sequence residual current)
51	Time overcurrent
59	Overvoltage
81 O/U	Over / under frequency

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CERTS Test Bed - One-Line Diagram
Protection Schematic

PROJ#: Rev. P

Drawn by: Ed Linton Date: 10/3/2005 file: CERTS_Test_Bed_RevP.vsd

Figure 26: CERTS Test Bed - One-line Diagram - Protection Schematic

CB

CT

Load
Meter
(DAS)
Ser

DAS Trigger

DAS Ethernet

DC Power
Supply

Electronic Load
with DC voltage
monitor

Motor Starter
/ Protector

Torque sensor

Mechanical
Load

Asynchronous Motor
Load 15 HP
(Load Bank 3 only)

Diode Bridge

Harmonic load
0 - 15 kW
(moveable to any load bank)

Zero-crossing
SSR array

Main Load Array
0 - 95 kW, 0-60 kVAR
(all load banks)

Load
Control
PLC

DAS RS-485

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CERTS Test Bed - One-Line Diagram
Load Bank Schematic

PROJ#:

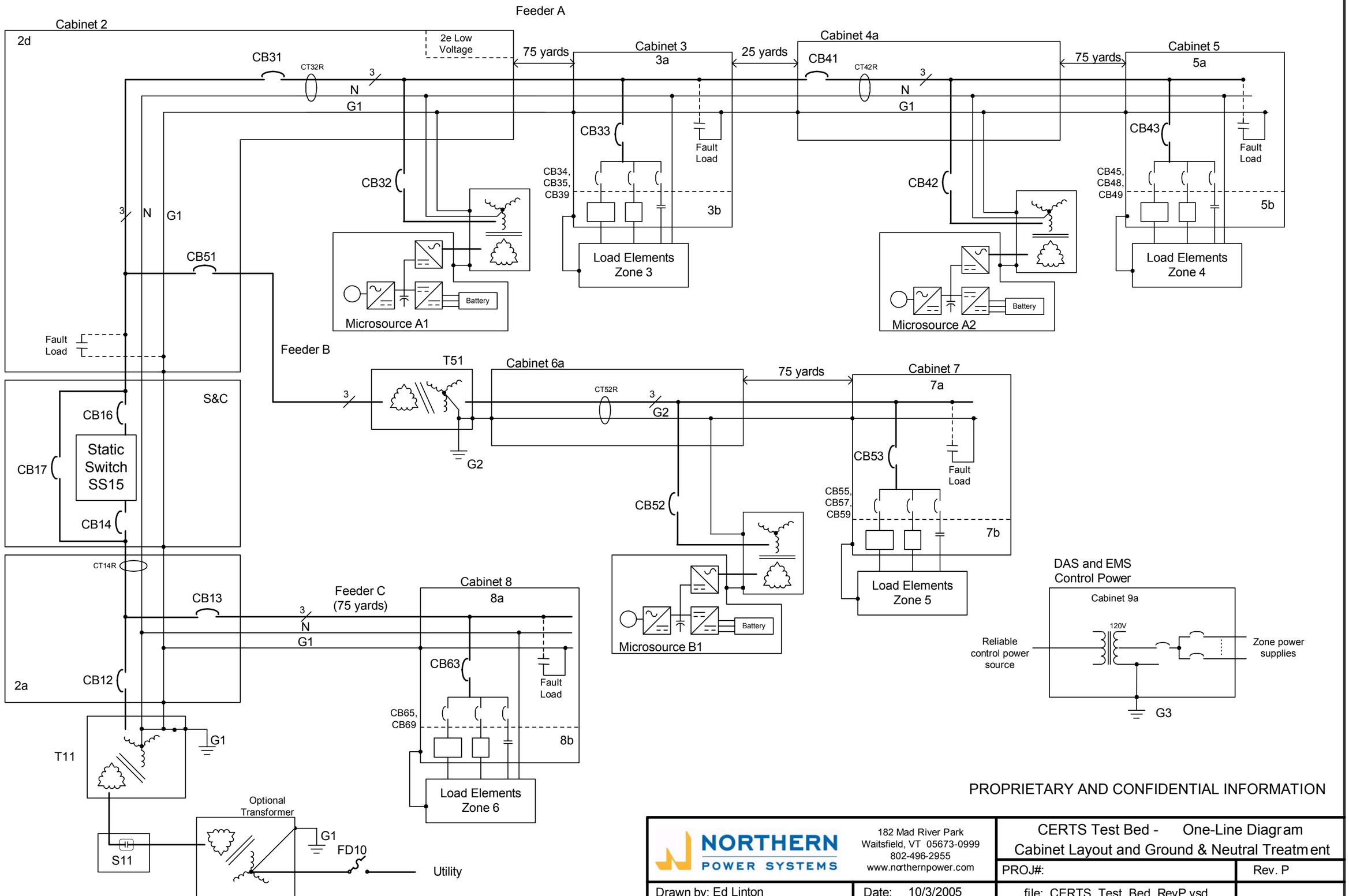
Rev. P

Drawn by: Ed Linton

Date: 10/3/2005

file: CERTS_Test_Bed_RevP.vsd

Figure 27: CERTS Test Bed - One-line Diagram - Load Bank Schematic



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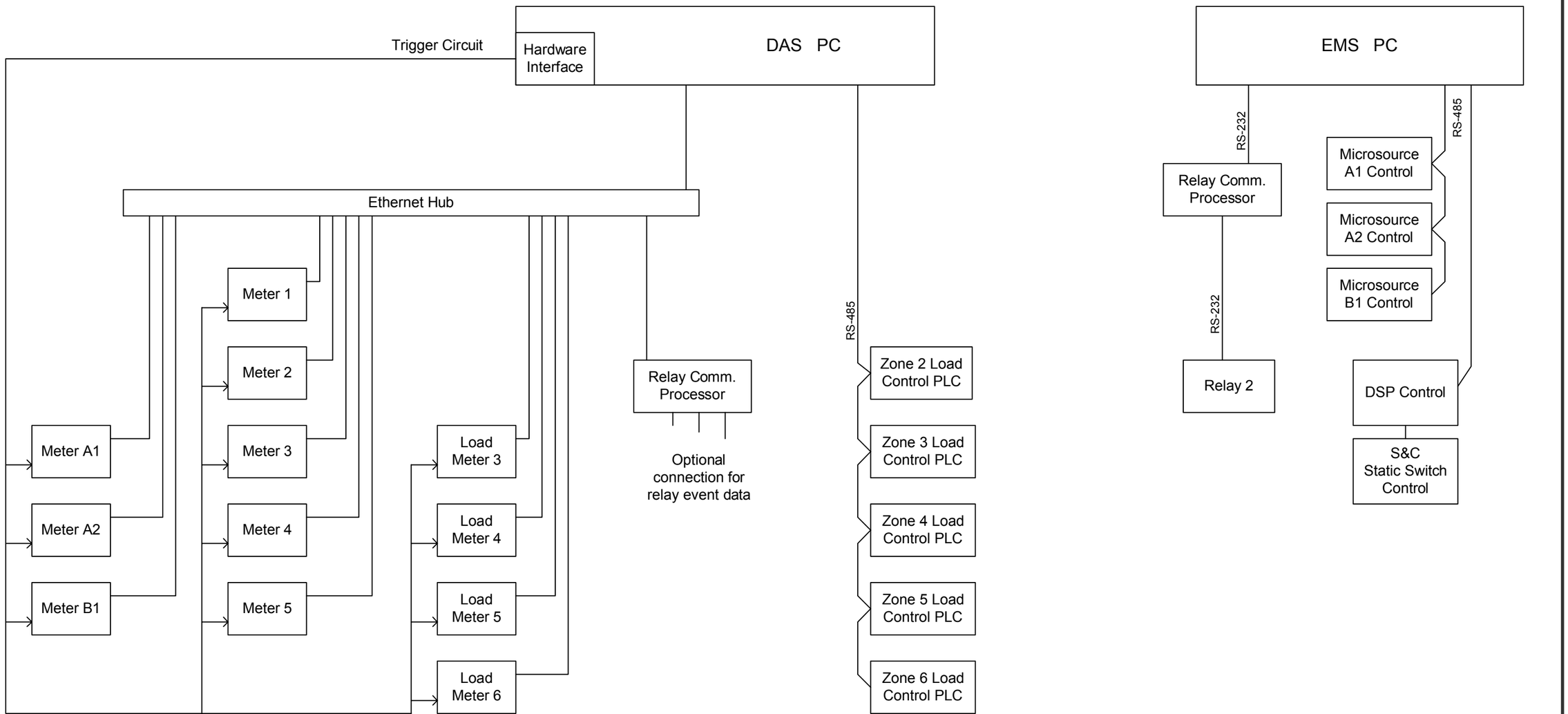
NORTHERN POWER SYSTEMS 182 Mad River Park Waitsfield, VT 05673-0999 802-496-2955 www.northernpower.com	CERTS Test Bed - One-Line Diagram Cabinet Layout and Ground & Neutral Treatment	
	PROJ#:	Rev. P
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Test_Bed_RevP.vsd

Figure 28: CERTS Test Bed - One-line Diagram - Cabinet Layout and Ground & Neutral Treatment



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CERTS Test Bed - One-Line Diagram
DAS and EMS Communications Architecture

PROJ#:		Rev. P
Drawn by: Ed Linton	Date: 10/3/2005	file: CERTS_Test_Bed_RevP.vsd

Figure 29: CERTS Test Bed - One-line Diagram - DAS and EMS Communications Architecture

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

CERTS Microgrid Test Plan

APPENDIX B

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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CERTS Microgrid Test Plan
Date: January 24, 2007

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Appendix A "CERTS Microgrid Test Bed Single Line Diagram"
Appendix B "CERTS Microgrid Test Bed – Lockout/Tagout Log"
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Revision #	Date	Revision Description
0	01/24/07	Original

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Revision #	Date	Revision Description
0	02/23/07	Original

Team Members and Roles

Name	Group	Primary Roles
Kevin P. Loving	DTC Operations	Test Site Coordinator
Dave A. Klapp	DTC Operations	Project & Test Engineer #1
Galen W. Perry	DTC Operations-Contractor	Test Operator/Technician #1
H. T. Vollkommer	Consultant-Contractor	Technical Support Consultant
John Stevens	Sandia National Lab.	CERTS Microgrid Test Team
Robert Lasseter	University of Wisconsin	CERTS Microgrid Test Team
Ed Linton	Northern Power Systems	CERTS Microgrid Test Team
Jean Roy	TECOGEN, Inc.	CERTS Microgrid Test Team

1.0 Purpose, References, Definitions

1.1 The purpose of this document is to establish procedures for testing of the CERTS Microgrid Test Bed, located at the Walnut Test Site near Columbus, Ohio. This Test Site is part of AEP's Dolan Technology Center (DTC) campus. The CERTS Microgrid Test Bed (referred to as "Microgrid") is connected on the load side of the 2000 ampere safety breaker of Test Cell #1, identified as CB1 in the single line diagram, CERTEQUIP-J01-001, dated March 24, 2006, and located in Appendix A.

1.2 Procedures necessary to perform tests on the Microgrid require:

1.2.1 Walnut Test Site specifically adapted "DTC Clearance Permit System" procedures to facilitate on site testing of CERTS Microgrid Test Bed.

1.2.2 Verification that the equipment is properly installed and wired in accordance with Northern Power System (NPS) and TECOGEN wiring prints, the controls operate as designed, protective equipment is installed and each piece of equipment is ready to be placed in service.

1.2.3 On-line verification of voltages, phase rotations, control operations, and communications.

1.3 Pre-energizing tests of electrical components shall be performed to verify that no short-circuits exist or possible faulty equipment will be energized.

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1.4 The Microgrid shall be considered commissioned and available for use only after all the requirements identified in the NPS document, titled CERTS Test Bed, CERTEQUIP-T06-001-X9, Site Commissioning Plan, have been met.

1.5 References documents:

1.5.1 DTC Standard Operating Procedures

1.5.1.1 SOP – DTC Clearance Permit System, 204-DTC-05
1.5.1.2 SOP – Barricades, Barriers and Guards, 204-DTC-11
1.5.1.3 SOP – Personal Protective Equipment, 204-DTC-32
1.5.1.4 SOP – DTC Parent SOP for Primary Distribution Switching, 204-DTC-50.0
1.5.1.5 SOP – Sub-Procedure Primary Distribution Switching – Walnut Test Site, 204-DTC-50.08
1.5.1.6 SOP – Job Safety Briefing, 204-DTC-70

1.5.2 AEP Safety Manual

1.5.2.1 Section 1.00 "General Safety"
1.5.2.2 Section 6.00 "Basic Electrical Safety, clauses 6.01, 6.02, 6.04, 6.05, and 6.16.

1.5.3 NFPA 70: "National Electric Code 2005"

1.5.4 OSHA 1910.269 Electric Power Generation, Transmission and Distribution: Electrical Protective Equipment

1.5.4.1 Subpart o – Testing and Test Facilities
1.5.4.2 Subpart v – Power Generation

1.5.5 Northern Power Systems (NPS) Documents – CERTS Test Bed

1.5.5.1 CERTEQUIP-J01-001, Single Line Diagram
1.5.5.2 CERTEQUIP-J06-001, Top Level Schematic
1.5.5.3 CERTEQUIP-B02-001, General Arrangement
1.5.5.4 CERTEQUIP-J06-003, Load Bank Schematic
1.5.5.5 CERTEQUIP-J14-001, Grounding and Neutral Schematic
1.5.5.6 CERTEQUIP-T06-001, Site Commissioning Plan
1.5.5.7 CERTEQUIP-Y01-001, DAS Manual – LabView
1.5.5.8 CERTEQUIP-Y01-002, EMS Manual
1.5.5.9 CERTEQUIP-Y01-003, DAS Manual – Ion Meter
1.5.5.10 CERTEQUIP-Y01-004, DAS & EMS System Overview

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1.5.5.11 CERTEQUIP-C16-001, Protection Document

1.6 Definitions

1.6.1 Walnut Test Site Issuing Authority Designee

1.6.1.1 A Designee assigned by the "DTC Issuing Authority" who will temporarily serve as the Walnut Test Site Issuing Authority Designee for this registered procedure.

1.6.1.2 Shall not be the Permit Holder for the CERTS Microgrid Test Bed or any part of this procedure or related equipment.

1.6.1.3 Is restricted to the CERTS Microgrid Test Bed and the switching of the Walnut Test Site 2000 ampere Station Safety Breaker, CB1.

1.6.2 CERTS Microgrid Test Bed – Test bed consisting of the Northern Power System (NPS) and TECOGEN equipment located at the Walnut Test Site. The boundary between the CERTS Microgrid Test Bed and AEP Grid is at the delta-wye transformer (T11) connected to the terminal box of the Walnut Test Site Station Safety Breaker CB1. Note, between T11 transformer and the CERTS Test Bed Safety Breaker (CB12) is a selectable High/Low in-series inductive impedance cabinet (L11).

1.6.3 Lockout/Tagout Log – A log listing the date and time of the Lock / Tag "in" and "out" operation of a designated disconnect device or circuit breaker that shall be tagged and locked out for a particular test sequence and test change.

1.6.4 Electrical One-Line Status Board – A cork bulletin board with the CERTS Microgrid Test Bed electrical one-line overlaid on the corkboard.

1.6.5 Red Pin – A red bulletin board pushpin, which designates location and a visual Red Clearance Permit Tag presence.

1.6.6 Lockout Lock Board – A board with five (5) green locks to be used for each lockout/tagout procedure. Each lock shall have a designated breaker or disconnect device and the board shall reflect labeling to this effect.

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1.6.7 Walnut Circuit Breaker Program – AEP created software to control the Walnut Test Site Recloser and Station Safety Breakers. This software is found on the Walnut Test Site Computer in the test trailer.

2.0 Responsibilities

Scheduling:	Test Site Coordinator
Parameter Specifications:	Project Engineer, Technical Support Consultant, CERTS Microgrid Test Team
Setup:	Test Engineer #1 & Test Operator/Technician #1 (Alternate: Technical Support Consultant)
Execution:	Test Engineer #1 & Test Operator/Technician #1 (Alternate: Technical Support Consultant)
Report:	Project Engineer, Technical Support Consultant, and CERTS Microgrid Test Team
Analysis:	Project Engineer, Technical Support Consultant, CERTS Microgrid Test Team
Approval:	Sponsor, CERTS Microgrid Test Team

2.1 Team Members

2.1.1 Team members shall comply with DTC operating procedures, as required by this registered procedure.

2.1.2 At least two people shall be on-site during test(s) and either Test Engineer #1 or Technical Support Consultant shall be on-site and in charge during the test(s). Test Engineer #1, Test Operator/Technician #1 and Technical Support Consultant, must be trained and qualified in the operation of both the DAS (Data Acquisition System) and EMS (Energy Management System) equipment, familiar with the test plan and emergency shutdown procedures, and has the most immediate control of the hazard-producing devices that is practical.

2.1.3 During a test event, the test shall be initiated and performed from the Control Trailer with “NO” humans physically located in the Microgrid Test Bed area or on the East, South or West sides of the Gen-set Enclosure during the test.

2.1.4 In preparation of and/or prior to performing a test event, one person may enter the Microgrid Test Bed with power enclosure doors in the Test Bed “latched” with no energized equipment

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terminals exposed or in contact with people. The second person on-site will be in the Control Trailer and situated such that he/she can view the test area and available to perform an immediate Emergency Shutdown Procedure.

2.1.5 The Test Engineer #1 or Technical Support Consultant shall be in the Control Trailer and situated such that he/she can view the test area, while the Test Operator/Technician #1 is performing the test(s). If an unsafe condition arises while the test area is energized, the Test Operator/Technician #1 shall be directed to perform an immediate Emergency Shutdown Procedure.

2.1.6 The Test Site Coordinator shall ensure that the required qualifications of all participants are met, including training cited in Section 3.0 of this Procedure.

2.1.7 The Test Site Coordinator shall be responsible for approving this procedure and any revisions.

2.2 Walnut Test Site Issuing Authority Designee

2.2.1 Shall comply with the DTC Clearance Permit System or the "CERTS Microgrid Test Bed Lockout/Tagout" procedure, cited in Section 4.0.

2.2.2 Shall place all tags, lockout devices and/or grounds associated with the CERTS Microgrid Test Bed.

2.2.3 Shall use AEP System safety procedures, PPE, and approved tools when isolating equipment and/or placing grounds for the CERTS Microgrid Test Bed.

2.2.4 Shall be knowledgeable about the CERTS Microgrid Test Bed and other systems distributing hazardous energy.

2.2.5 Shall not be a Clearance Permit holder for the CERTS Microgrid Test Bed. This ensures that at least two independent judgments are involved in deciding that the Clearance Permit provides a safe arrangement of devices and that the tags are properly placed.

2.2.6 Is responsible for addressing any observed non-compliance issues.

3.0 Training – Team Members

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3.1 The skills necessary to distinguish exposed high voltage/energy parts of the test equipment.

3.2 Basic Electrical Safety practices of the AEP Safety Manual shall be a followed with Section 6.02 being the guiding principle and minimum approach distances specified in Section 6.03.

3.3 The proper use of personal protective equipment and insulated tools when working on or near exposed energized equipment.

3.4 The proper use of barricades, barriers or guards.

3.5 The proper operation of associated test equipment, based on the manufacturer's operator's manual, and of the DAS and EMS computer-based operating systems.

4.0 Procedure – CERTS Microgrid Test Bed Lockout/Tagout

4.1 The CERTS Microgrid Test Bed Lockout/Tagout procedure is designed to provide the same level of safety afforded by the DTC Clearance Permit system with less implementation overhead. Because of this, it can ONLY be applied under a limited set of applications, described as follows:

4.1.1 To make adjustments of Fault/Overload breaker connections; or

4.1.2 To make adjustments to the weakening grid inductor in Cabinet L11.

4.2 These are the ONLY two reasons that the CERTS Microgrid Test Bed Lockout/Tagout procedure may be used. Any other application requiring the lockout/tagout of hazardous energy equipment will default back to the DTC Clearance Permit Procedure.

4.3 The Walnut Test Site Issuing Authority Designee shall:

4.3.1 Issue a "Microgrid Clearance Permit" for the CERTS Microgrid Test Bed prior to testing and advance the permit to a "Permission to Test Operate" status.

4.3.2 Assign this Clearance Permit to the Walnut Test Site Station Safety Breaker CB1, the Microgrid Main Breaker (CB12), the three Fused Disconnects on Gen-sets A1, B1 and A2.

4.3.3 Be responsible for Lockout/Tagout of Walnut Test Site Station Safety Breaker (CB1), the Microgrid Main Breaker (CB12), the three Fused Disconnects on Gen-sets A1, B1 and A2, as required in these procedures.

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4.3.4 Verify that all tags and lockout devices are properly installed at the designated locations prior to a test.

4.3.5 Assure a "Job Safety Briefing" (JSB) has taken place prior to each test.

4.4 Walnut Test Site Issuing Authority Designee and Team Members shall independently confirm that the test configuration provides the protection required for the procedures to be undertaken.

4.5 A re-useable Microgrid Clearance Permit Tag shall be assigned to each circuit breaker and disconnect device that requires lockout/tagout for a particular test sequence.

4.6 Lockout Devices

4.6.1 In addition to the tag types allowed by "AEP Fossil and Hydro Generation Clearance Permit System", keyed padlocks will be placed in combination with each red tag placed on a device that is capable of being locked out, in accordance with the AEP Control of Hazardous Energy Policy.

4.6.2 A green keyed-alike padlock shall be used as the default lockout device for the CERTS Microgrid Test Bed.

4.6.3 Keys for the green keyed-alike padlocks shall be located:

4.6.3.1 One key provided to the Issuing Authority.
4.6.3.2 One key provided to the Walnut Test Site Issuing Authority Designee.
4.6.3.3 Spare keys will be secured in the DTC key safe

4.7 Each time a CERTS Microgrid Test Bed Lockout/Tagout is required, the Walnut Test Site Issuing Authority Designee shall isolate the CERTS Microgrid Test Bed from the utility as follows:

4.7.1 Remotely "Shutdown" all Gen-sets (i.e., A1, B1 & A2).

4.7.2 Remotely "Trip" the Station Safety Breaker CB1, using the Walnut Circuit Breaker Program found on the Walnut Test Site Computer in the Control Trailer.

4.7.3 Verify that no voltage exists on the Microgrid Test Bed, using the DAS meter readouts.

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4.7.4 Lockout/Tagout the Station Safety Breaker CB1, using the designated green lock.

4.7.5 Manually "Trip" circuit breaker CB12 to the CERTS Microgrid Test Bed.

4.7.6 Lockout/Tagout the CERTS Microgrid Test Bed circuit breaker CB12, using the designated green lock.

4.7.7 Open the Fused Disconnects on Gen-sets A1, B1 and A2.

4.7.8 Lockout/Tagout the Fused Disconnects to Gen-sets A1, B1 and A2, using the designated green locks.

4.7.9 The area (i.e., within/near cabinets) where work is to be performed shall then be checked with a voltage detector to confirm that hazardous potential has been removed.

4.7.10 Using the proper PPE, an approximately sized grounding conductor shall be connected between the electrical bus and ground, as close to the work area as reasonably feasible.

4.7.11 The Lockout/Tagout Log is in Appendix B and shall be completed, reflecting completion of the Lockout/Tagout procedure. The horizontal axis includes the breakers and disconnects, while the vertical axis includes the date, time and specific test described in this procedure document.

4.7.12 The work requiring this Logout/Tagout procedure may now be completed with the Red Clearance Permit Tag pins positioned on the Electrical One-Line Status Board to inform others of site status.

4.7.13 Perform these steps in reverse order. Then:

4.7.13.1 Check to verify all grounds have been removed before energizing;

4.7.13.2 Re-energize the CERTS Microgrid Test Bed; and

4.7.13.3 Verify the proper nominal voltages in Meter 1.

4.8 CERTS Microgrid Test Bed-Test Log

4.8.1 A list of test events shall be organized in a logical sequence to complete all tests involving energizing work progressing from the utility source and Gen-sets to the last piece of equipment.

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4.8.2 Appendix C lists the "CERTS Microgrid Test Bed-Test Log" to be completed.

4.8.3 A single copy of Appendix C shall be printed out, initialed by the Test Engineer #1 performing the test or Technical Support Consultant, and dated.

4.8.4 Once Appendix C is completed, the appendix shall be attached to this document and stored in an electronic file.

4.8.5 All Team Members involved with the actual test shall acknowledge to the Test Engineer #1 or designated person that they are "Ready to go".

4.8.6 Test Engineer #1 or designated person shall verify that the front gate to the Walnut Test Site is "Closed", not locked, with an audible alarm in operation.

4.8.7 Test Engineer #1 or designated person shall then start the visual alarms.

4.8.8 Test Engineer #1 or designated person shall notify the Team Members "The test is about to begin".

5.0 Procedure - General

5.1 Prior to testing each day, the person in charge during the planned test(s) or his designee shall perform a JSB, and the barricades and test setup shall be inspected for safety and compliance.

5.2 Alarms – Visual & Audible

5.2.1 These alarms shall warn persons that energized testing is being performed in the Microgrid Test Bed area.

5.2.2 Visual alarm, consisting of a portable red flashing light, shall be located between the Control Trailer and Gen-set Enclosure (i.e., North side of Enclosure between the coolant system structure and natural gas lines into the Enclosure).

5.2.3 Audible alarm, consisting of a portable buzzer, shall be located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and an audible alarm in operation during test(s).

5.3 Barricades, Barriers, or Guarding of Test Area

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5.3.1 Barricades shall be set up around major equipment of the Microgrid Test Bed (i.e., saw-horse style barricades with plastic chain shall surround the test area containing the Gen-set Enclosure, Microgrid switching cabinets, plus load and fault bank cabinets).

5.3.2 Barricades set up at the entrance area to the Gen-set Enclosure and Microgrid Test Bed switching cabinets shall include "Danger – Test In Progress" signs.

5.4 Other Precautions

5.4.1 During initial energizing tests all personnel shall remain within or adjacent to the Control Trailer while tests are being performed.

5.4.2 All nonessential personnel shall either leave the main site or shall shelter in the Control Trailer.

5.5 Items to Verify Prior to Energizing Microgrid Test Bed Equipment.

5.5.1 Test Engineer #1 or Technical Support Consultant shall verify that all personnel and visitors are properly protected and in assigned locations prior to performing each test.

5.5.2 The test area is properly reviewed and secured.

5.5.3 Auxiliary power sources fed from circuit breakers in electrical cabinets 9a and 9b are switched "On", energizing down-line equipment, located in the Test Bed and Gen-set Enclosure.

5.5.4 Gen-set Enclosure doors (i.e., located on East, South and West sides) must remain "Open" for proper airflow during Gen-set operation.

5.5.5 Gen-set Enclosure exhaust fans and the coolant system/pump shall be "On" whenever one or more Gen-sets are operating.

5.6 Verify Operation of DAS and EMS, Prior to Performing Test Plan.

5.6.1 All recording instrumentation shall be checked and readied for operation.

5.6.2 Twelve PML Ion 7650 meters are distributed within the Microgrid Test Bed with locations shown in Figure 1. These meters are prime data collection elements in the system for DAS and EMS. They monitor electrical system conditions, plus acquire phase current and voltage waveforms; and

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calculate RMS values of voltage, current, active power, reactive power, and frequency.

5.6.3 An Ethernet network is provided, as shown in Figure 2, for communications between all meters, load control PLCs, and the DAS computer, using fiber-optic links and switches. The DAS and EMS computers are also networked into the local Dolan LAN. Additional serial links connect all SEL-351 relays, the static switch DSP control, and the Tecogen Gen-set controls to the EMS computer, using fiber optic converters.

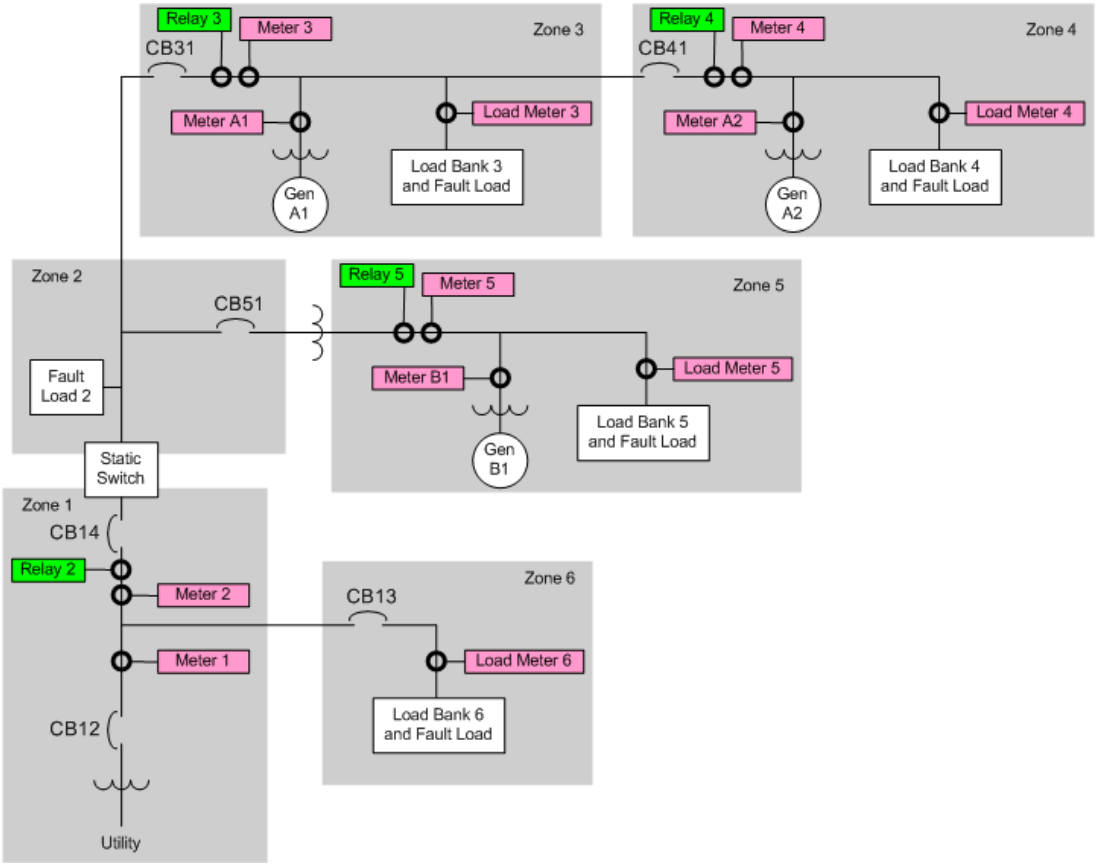

Figure 1 - Test Bed 1-Line with Meter and Relay Locations

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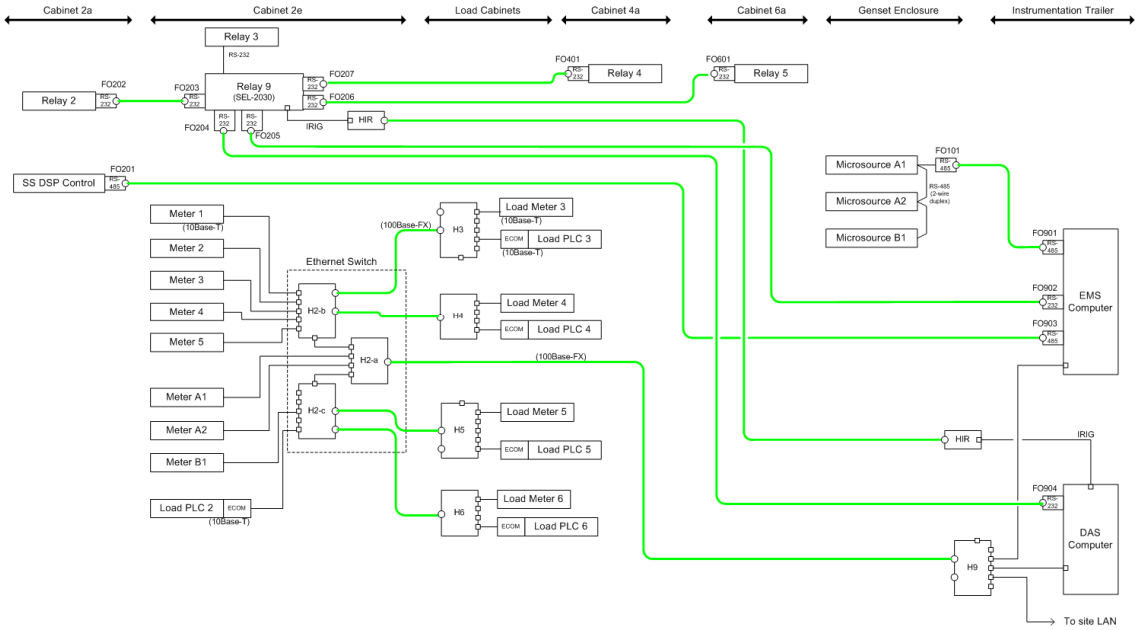

Figure 2 - DAS & EMS Data Network

6.0 Procedure – Microgrid Test Bed System Checkout

Objective: The tests described in Section 6 are designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of this test document. During these system checkout tests, the series inductor L11 shall be connected in the circuit to minimize any impact to the Test Bed.

6.1 Function of Static Switch

Objective: Check operation of the static switch, to assure it and its DSP control is operating as designed. This will include tests of dead-bus and synchronized closing, reverse power and IEEE 1547 protective relay functions. Waveform and RMS data from Meter 2 will be of prime interest. At this stage, the switch functions will be tested with a single Gen-set A1 online.

6.1.1 Start-up System, Synchronized Closing

Measure – Voltage waveforms for phases A, B & C on both sides of the static switch, current waveforms for phase A at the switch. To obtain the voltage across each phase of the switch, using Meter 2 and Meter A1 to measure the voltage on both sides of the switch.

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Performance Goal – Verification that when conditions are appropriate (within synchronization limits set in the EMS), the switch can perform a synchronized closing and thus give smooth closing transitions.

6.1.1.1 Verify the following items:

6.1.1.1.1 All alarms are reset on both the S&C PES and DSP, and that system is ready to start.

6.1.1.1.2 Circuit breakers in Cabinet 3 and Cabinet 8 to Load Banks are "Closed".

6.1.1.1.3 CB 32 is "Closed".

6.1.1.1.4 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.1.1.5 Set loads on Load Bank 3 and Load Bank 6 to 40kW.

6.1.1.2 Start the system with the "Start" command from the EMS. The system should enter the "Disconnect" State on the DSP, and the Gen-set side voltage at Meter A1 should indicate a frequency of approximately 59.65 Hz.

6.1.1.3 When conditions are appropriate, the static switch should do a synchronized "Close". A smooth transition should occur from island to utility-connected mode in Gen-set A1. This will happen relatively quickly, after the "Start" command is issued.

6.1.1.4 When the static switch closes, "CONNECT" is displayed in the Control State block of the EMS, and "PES OK" is displayed in the PES Status block. Verify that the readings of power flow measurements are accurate.

6.1.1.5 Once steady state is reached, power flow should be ~ 60 kW at the remote location (Meter 1) and 20kW at the static switch (Meter 2); the frequency should stabilize to the grid frequency (~60Hz).

6.1.2 Reverse Power, Grid Islanding (IEEE 1547, Loss of Utility Source).

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Measure – RMS voltage and active power at static switch, current waveforms at the static switch and timing of event sequence.

Performance Goal – Verify the reverse power functionality of the static switch and confirm that the static switch islands the Microgrid for a reverse power condition due to an upstream utility operation at the PCC. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standard).

6.1.2.1 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.2.2 Set load on Load Bank 3 to 40kW and on Load Bank 6 to 20kW. Also, set load on the AEP Load Bank to 500kW.

6.1.2.3 Perform a synchronized "Close" of the static switch and verify closing after one minute.

6.1.2.4 Next disconnect the utility grid from the Microgrid via "Opening" CB1 (three-pole breaker). Note, the static switch should "Open" within 2 seconds of opening CB1. Once the static switch opens, no voltage is present on the grid side of the switch, which creates an "IEEE 1547 voltage test" event. Verify in the EMS screen that the indicator of this event is turned "ON".

6.1.2.5 Verify in the "Event" Logger file that the above "Reverse Power" event was recorded, that the data acquisition was triggered and data was recorded, via a review of the DAS database.

6.1.2.6 Wait for approximately 20 seconds, and verify that the "IEEE 1547 voltage test" event remains high.

6.1.2.7 Reduce load on the AEP Load Bank to zero, than reconnect the grid by remote manual "Close" of CB1. The "IEEE 1547 voltage test" indicator should turn "Off".

6.1.2.8 The static switch should not attempt to reconnect immediately, since IEEE 1547 reconnection timer is set to 300 seconds. When synchronization conditions are

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appropriate, the switch should attempt to do a synchronized "Close".

6.1.2.9 Verify a synchronized "Close" of the static switch, after the IEEE 1547 reconnection timer has elapsed.

6.1.2.10 Verify in the DAS database that the synchronized "Close" of the static switch was triggered and data was recorded.

6.1.3 **Reverse Power, Single -Phase (IEEE 1547 Voltage Event).**
Measure – RMS voltage and active power at static switch, current waveforms for phase A at static switch, and timing of event sequence.

Performance Goal – Verification that the static switch islands the Microgrid when a reverse power condition, due an open-phase occurs. Note there are no single-phase breakers to disconnect the utility; reducing the load on one phase of the Microgrid will simulate the "open phase" condition. This condition does not properly test the reconnection logic, after an open phase, since the utility voltage will still be present on all three phases (i.e., test didn't really disconnected a phase).

6.1.3.1 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.3.2 Select load on Load Bank 3 and Load Bank 6 to 40kW.

6.1.3.3 Start by removing the entire load on phase A of Load Bank 6. After this load change, the power measurement at the remote location (Meter 1) in phase A should be approximately 6.6 kW, and in phases B and C should each be approximately 20 kW.

6.1.3.4 Maintain zero load on phase A of Load Bank 6 and repeat the above load step change for Load Bank 3. Note, since the power measurement at remote location (Meter 1) in phase A is below the set threshold of 3.3kW, this should create a reverse power condition on phase A and open the

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static switch within 2 seconds. Once the switch opens, voltage should still be present on all phases of the utility grid side of the switch, the static switch will go to lockout by the DSP stopping the S&C PES switch (i.e., opening CB14 and going to the "Fault" state in the EMS).

6.1.3.5 Verify in the EMS that the system entered the "Fault" state, and check that the "Reverse power Anti-islanding, Microgrid Settings Reset" Alarm indicator has turned "On".

6.1.3.6 Verify in "Event" Logger file that at the time when this test was performed, a "Reverse Power" event was recorded, DAS was triggered and data was recorded.

6.1.3.7 Remove the reverse power single phase condition by bringing all phase A loads at Zone 6 and at Zone 3 back to default conditions (i.e., 40kW each). The "Reverse power Anti-islanding, Microgrid Settings Reset Alarm" indicator should turn "Off". Note, the static switch will need to be "Reset" to return it to service, as it will think this is a mis-dispatch of the generation within the Microgrid. Also, the static switch will not wait for the 300 seconds to reconnect to the utility grid.

6.1.3.8 Use the EMS to give a "Reset" command to clear all faults and events.

6.1.3.9 Once all events and alarms are cleared, "Start" the system and observe a synchronized closing of the static switch.

6.1.4 **Reverse Power, Anti-islanding Microgrid Settings Reset**
Measure - RMS voltage and active power at static switch, current waveforms for phase A at switch and timing of event sequence.

Performance Goal - Verify that if a reverse power event occurs, due to a mismatch of Gen-set settings (Total Gen-set power > Microgrid load), the static switch will lockout and go to the "Fault" state, where user intervention is required.

6.1.4.1 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW

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MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.4.2 Select load on Load Bank 3 and Load Bank 6 to 40kW.

6.1.4.3 Once the static switch "Closes", the power flow at Meter 1 is approximately 60kW.

6.1.4.4 Reduce the load to 0kW at Load Bank 6 and verify the power measurement at Meter 1 drops to roughly 20 kW. Wait 5 seconds and note that no reverse power trip should occur (i.e., above minimum 10 kW threshold value).

6.1.4.5 Reduce the load at Load Bank 3 by 5 kW, wait about 5 seconds and verify a reverse power trip occurs. If not, repeat the step 6.1.4.4, reducing load at Load Bank 3 by an additional 5kW. Continue until the reverse power condition occurs and the static switch "Opens".

6.1.4.6 Once the static switch opens, since there is still voltage present in all phases of the grid side of the switch, the system will lockout by the DSP stopping the S&C PES switch (i.e., opening CB14 and going to the "Fault" state in the EMS).

6.1.4.7 Verify in the EMS that the system entered the "Fault" state, and check that the "Reverse Power Anti-islanding, Microgrid Settings Reset" alarm indicator has turned "On".

6.1.4.8 Verify in the "Event" Logger file that at the time when this test was performed, a "Reverse Power" event was recorded, DAS was triggered and data was recorded.

6.1.4.9 Return load in Load Banks 3 and 6 back to 40kW.

6.1.4.10 Using the EMS, give a "Reset" command to clear all faults and events.

6.1.4.11 Once all events and alarms are cleared, "Start" the system and verify a synchronized closing of the static switch.

6.1.5 De-energized Bus (Dead Bus) Reclose

Measure – RMS voltage and active power at static switch, voltage on both sides of the switch, and timing of event sequence.

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Performance Goal - Verify that the static switch can close when de-energized bus conditions (< 15V) on the DG side are measured and that the Dead Bus Reclose algorithm requires user intervention (i.e., Operator needs to "Enable" the Dead Bus Reclose using pushbutton in the EMS).

6.1.5.1 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.5.2 Select load on Load Bank 3, and Load Bank 6 to 40kW.

6.1.5.3 Open the static switch using "Manual Open" command in the EMS.

6.1.5.4 Perform a controlled "Shutdown" of Gen-set A1.

6.1.5.5 Verify in the EMS display that "DG side Dead Bus" event indicator turns "On". This confirms that the DSP detects a de-energized bus; the static switch doesn't "CLOSE" because "Manual Open" is enabled and "Dead Bus Reclose" is disabled.

6.1.5.6 Remove "Manual Open" and verify that the switch still remains "Open".

6.1.5.7 Enable "Dead Bus Reclose" by pressing the pushbutton in the EMS and verify the static switch "Close" event.

6.1.6 Power Quality Trip, Grid Islanding (IEEE 1547, Loss of Utility Source).

Measure – RMS voltage and active power at static switch, current waveforms at the static switch and timing of event sequence.

Performance Goal – Verify the reverse power functionality of the static switch and confirm that the static switch islands the Microgrid for a reverse power condition due to an upstream utility operation at the PCC. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standard).

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6.1.6.1 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V

6.1.6.2 Set load on Load Bank 3 to 40kW and on Load Bank 6 to 20kW. Also, set load on the AEP Load Bank to 500kW.

6.1.6.3 Perform a synchronized "Close" of the static switch and verify closing after one minute.

6.1.6.4 Next disconnect the utility grid from the Microgrid via "Opening" CB1 (three-pole breaker). Note, the static switch should "Open" within the CBEMA requirement after the opening of CB1. Once the static switch opens, no voltage is present on the grid side of the switch, which creates an "IEEE 1547 voltage test" event. Verify in the EMS screen that the indicator of this event is turned "ON".

6.1.6.5 Verify in the "Event" Logger file that the above "Reverse Power" event was recorded, that the data acquisition was triggered and data was recorded, via a review of the DAS database.

6.1.6.6 Wait for approximately 20 seconds, and verify that the "IEEE 1547 voltage test" event remains high.

6.1.6.7 Reduce load on the AEP Load Bank to zero, than reconnect the grid by remote manual "Close" of CB1. The "IEEE 1547 voltage test" indicator should turn "Off".

6.1.6.8 The static switch should not attempt to reconnect immediately, since IEEE 1547 reconnection timer is set to 300 seconds. When synchronization conditions are appropriate, the switch should attempt to do a synchronized "Close".

6.1.6.9 Verify a synchronized "Close" of the static switch, after the IEEE 1547 reconnection timer has elapsed.

6.1.6.10 Verify in the DAS database that the synchronized "Close" of the static switch was triggered and data was recorded.

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7.0 Procedure – Validate Protection Settings & Initial Fault Testing

Objective: The tests described in Section 7 are designed to examine a preliminary set of fault (i.e., overload simulating a fault) condition tests to ensure protection and safety of the Microgrid Test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design. Tests performed in this section will include inductor L11 in the circuit, reflecting weak grid conditions.

Definitions – To maintain a common understanding of Gen-set control modes during tests proposed in the following paragraphs:

- Unit Power Control Mode involves the amount of power (i.e., kW) being injected into the Zone from the Gen-set being controlled.
- Zone Power Control Mode involves the amount of power (i.e., kW) entering/exiting the Zone which controls the output of the Gen-set in that Zone.

Measure – During each fault event record waveforms of phase currents and line-to-neutral voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5). Record the relay element that caused the "TRIP" with trip times for each relay relative to when the fault condition was applied.

Performance Goal - The fault (i.e., overload simulating a fault) condition tests are intended to cover the basic concept of the protection design and to study its effectiveness (e.g., zero-sequence, negative-sequence and residual currents for line-to-ground faults; negative-sequence or (I^2t) protection for phase-to-phase faults). For the majority of these test scenarios, the static switch should "OPEN" first, followed by a "TRIP" at the specified relay. Confirm the protective action detailed in the Protection document.

7.1 Validate Zone 4 Circuit Breaker Settings, Utility Connected

Performance Goal - Initially test a three-phase balanced fault condition in Zone 4 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection.

7.1.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.1.2 To simulate a high impedance three-phase ungrounded fault, setup the Overload Load Bank for 85kW and connect portable cable/plug into the exterior receptacle of Cabinet 5a.

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7.1.3 Install/physically connect portable overload cabling inside the cabinet at the outlet receptacle to phases A, B, and C (i.e., connecting and tightening the bolted connection).

7.1.4 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.1.5 Verify CB43 is Closed along with the circuit breakers to the Overload and Load Banks, manually "ARM" the key switch in the cabinet and close/lock the entry doors to Cabinet 5.

7.1.6 Verify that the Microgrid Test Bed is energized with nominal voltages indicated on all three phases at Meter 1.

7.1.7 Using the Load Control program, set the load in Load Bank 4 to 60kW.

7.1.8 Using the EMS, give a "Reset" command to clear all faults and events in the system.

7.1.9 After the dead-bus closing of the static switch from the EMS, the Microgrid Test Bed is connected to the utility grid with 60kW at Meter 2 and Meter 1.

7.1.10 Using the DAS Load Control program set the duration of the simulated fault to 100 seconds, set the software to "ARM" and initiate a three-phase, ungrounded fault (overload) in Zone 4, which adds 85kW to the 60kW load.

7.1.11 Verify that CB41 "TRIPS" first on over-current clearing the fault. Breaker K42 should Open under PLC control, removing the fault of the Overload Load Bank.

7.1.12 Verify in the DAS Database that:

7.1.12.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "Trip" with trip times for each relay relative to when the fault was applied.

7.1.12.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.1.13 Remove load from Load Bank 4 to complete this simulated fault test event. Turn the key switch in Cabinet 5 to the "Off" position.

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7.1.14 Perform the Microgrid Test Bed lockout/Tagout Procedure in Section 4.7 to prepare for a single-phase-to-ground fault (i.e., overload) test in Zone 4.

7.1.15 Within Cabinet 5a, physically remove the overload cabling inside the cabinet from phases B and C.

7.1.16 Change the wiring in Cabinet 5 between the external connector and the fault contactor K42 for a single phase fault of 28kW between Phase A and ground (i.e., connecting and tightening the bolted connections).

7.1.17 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.1.18 Verify CB43 is "Closed" along with the circuit breakers to the Load Bank, manually "ARM" the key switch in the cabinet and close entry doors to Cabinet 5.

7.1.19 Using the Load Control program, set the load in Load Bank 4 to 60 kW.

7.1.20 Using the EMS, give a "Reset" command to clear all faults and events in the system.

7.1.21 After performing a dead-bus closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 60kW at Meter 2 and Meter 1.

7.1.22 Using the DAS Load Control program, set the duration of the simulated fault to 10 seconds, set the software to "ARM" and initiate a single-phase to ground fault (overload) in Zone 4, which adds 28kW to the 20kW load on A-phase.

7.1.23 Verify that the static switch "TRIPS" first on Ground over-current, which clears the fault (overload), followed by breaker CB41. Breaker K42 should Open under PLC control, removing the fault of the Overload Load Bank.

7.1.24 Verify in the DAS Database that:

7.1.24.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

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7.1.24.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.1.25 Remove load from Load Bank 4 and "STOP" the static switch.

7.1.26 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.1.27 Remove the Overload Load Bank portable cable/plug from the exterior receptacle of Cabinet 5a.

7.1.28 Physically remove the portable overload cabling inside Cabinet 5 between A-phase to ground.

7.1.29 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.1.30 Verify CB41 and the breaker to the Load Bank is closed. Close the entry doors to Cabinet 5 to complete this fault test event.

7.2 **Validate Zone 3 Circuit Breaker Settings, Utility Connected**
Performance Goal - Initially test a three-phase balanced fault condition in Zone 3 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 3 to verify zero-sequence, negative-sequence or residual over-current protection.

7.2.1 Repeat steps 7.1.1 through 7.1.30 to simulate a three-phase ungrounded fault (i.e., overload), and then a single-phase to ground fault (i.e., overload) on B-phase in Zone 3, Cabinet 3 and circuit breaker CB31. Note, for this test 60kW of additional load is required in Zone 4 on Load Bank 4.

7.3 **Validate Zone 5 Circuit Breaker Settings, Utility Connected**
Performance Goal - Initially test a three-phase balanced fault condition in Zone 5 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 5 to verify zero-sequence, negative-sequence or residual over-current protection.

7.3.1 Repeat steps 7.1.1 through 7.1.30 to simulate a three-phase ungrounded fault (i.e., overload), and then a single-phase to ground fault (i.e., overload) on C-phase in Zone 5, Cabinet 7b and circuit breaker CB51.

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7.4 **Zone 4 Three-Phase Un-grounded Fault, Gen-sets (A1+A2) & Utility Connected**

Performance Goal - Test a three-phase balanced fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus confirm a reverse power event after the Zone breaker "opens".

7.4.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.4.2 Setup the Overload Load Bank for a three-phase un-grounded fault of 85kW and connect portable cable/plug into the exterior receptacle of Cabinet 5a.

7.4.3 Install/physically connect portable overload cabling inside the cabinet from the outlet receptacle to phases A, B, and C (i.e., connecting and tightening the bolted connections).

7.4.4 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.4.5 Verify CB43 is "Closed" along with the circuit breakers to the Load Banks, and manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 5.

7.4.6 Verify that the static switch is "Open".

7.4.7 Set Gen-sets A1 and A2 to the following set-points:
Gen-set A1 and A2 = Unit Power Control Mode
Output Power Command of A1 = 50kW
Output Power Command of A2 = 20kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.4.8 Select load on Load Bank 3 to 10kW and Load Bank 6 to 40kW, and load on Load Bank 4 to 50kW.

7.4.9 Using EMS, give a "Reset" command to clear all faults and events.

7.4.10 Once all events and alarms are cleared, "Start" the Gen-sets. Note, there is 60kW of load in the microgrid when the first Gen-set starts, causing it to go to full (i.e., 60kW) power as soon as it connects and simulating a Black Start into 60kW.

7.4.11 Once the Gen-sets are running and on-line, which will take a few minutes to occur, use the EMS to put the static switch in "Start" mode and verify a synchronized closing of the static switch. Note, if the static switch does not "Close", reduce output of Gen-set A1

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to 30kW (this will reduce frequency as A1 and A2 change their frequency to balance generation loss of 10kW).

7.4.12 After synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with -10kW at Meter 2 and 30kW at Meter 1.

7.4.13 Using the DAS Load Control program, set the duration of the fault (overload) to 100 seconds, set the software to "ARM" and initiate a three-phase, ungrounded fault (overload) in Zone 4, which adds 85kW to the 50kW load.

7.4.14 Verify that CB41 "TRIPS" first on over-current, which clears the fault and shuts down Gen-set A2. Breaker K42 should Open under PLC control, removing the fault of the Overload Load Bank.

7.4.15 Verify that the static switch "Opens", due to reverse power and Gen-set A1 continues to operate, but reduces its output power to 10kW.

7.4.16 Verify in the DAS Database that:

7.4.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.4.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.4.17 Shutdown Gen-set A1, remove remaining load, "STOP" the static switch, and re-close CB41 to complete this fault (overload) test event.

7.5 Zone 3 A-Phase Line-to-Ground Fault, Gen-set A1 & Utility Connected

Performance Goal - Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

7.5.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

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7.5.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 5a.

7.5.3 Setup the Overload Load Bank for a single-phase fault (overload) on A-phase of 28kW and connect the portable cable/plug into the exterior receptacle of Cabinet 3a

7.5.4 Install/physically connect the portable overload cabling inside Cabinet 3 from the outlet receptacle to A-phase and Ground (i.e., connecting and tightening the bolted connections).

7.5.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.5.6 Verify CB33 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" key switch in the cabinet and close the entry door to Cabinet 3.

7.5.7 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control Mode
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.5.8 Select loads on Load Bank 3 and Load Bank 6 to 40kW.

7.5.9 Using EMS, give a "Reset" command to clear all faults and events

7.5.10 Once all events and alarms are cleared, "Start" Gen-set A1.

7.5.11 Once the Gen-set is running and on-line, use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.5.12 After synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 20kW at Meter 2 and 60kW at Meter 1.

7.5.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a Phase A-to ground fault in Zone 3.

7.5.14 Verify that the static switch "TRIPS" first followed by breaker CB31, which clears the fault and shuts down Gen-set A1. Breaker K32 should then Open under PLC control, removing the fault of the Overload Load Bank.

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7.5.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1, serving the 40kW in Load Bank 6.

7.5.16 Verify in the DAS Database that:

7.5.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.5.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.5.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breaker CB31 to complete this fault test event.

7.6 Zone 3 A-Phase Line-to-Ground Fault, Gen-sets (A1+A2) & Utility Connected

Performance Goal - Test a single line-to-ground fault condition in Zone 3 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

7.6.1 Verify CB33 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" key switch in the cabinet and close the entry doors to Cabinet 3.

7.6.2 Set Gen-sets A1 & A2 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.6.3 Using EMS, give a "Reset" command to clear all faults and events.

7.6.4 Once all events and alarms are cleared, "Start" the Gen-sets.

7.6.5 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW.

7.6.6 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

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7.6.7 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.6.8 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a A-phase to ground fault in Zone 3.

7.6.9 Verify that the static switch "Trips/Opens" first followed by breaker CB41 opening on zero-sequence current and Gen-set A2 will shut down. About 7 cycles after this protection sequence, CB31 will Trip/Open and Gen-set A1 will shut down. Breaker K32 should "Open" under PLC control, removing the fault on the Overload Load Bank.

7.6.10 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1, serving the 40kW in Load Bank 6.

7.6.11 Verify in the DAS Database that:

7.6.11.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.6.11.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.6.12 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB41 and CB31 to complete this fault test.

7.7 Zone 5 B-Phase Line-to-Ground Fault, Gen-set B1 & Utility Connected

Performance Goal - Test a single line-to-ground fault condition in Zone 5 with Gen-sets B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

7.7.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.7.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 3a.

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7.7.3 Setup the Overload Load Bank for a single-phase fault (overload) on B-phase of 28kW and connect the portable cable/plug into the exterior receptacle of Cabinet 7a.

7.7.4 Install/physically connect the portable overload cabling inside Cabinet 7 from the outlet receptacle to B-phase and Ground (i.e., connecting and tightening the bolted connections).

7.7.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.7.6 Verify breaker CB53 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet, and close the entry doors to Cabinet 7.

7.7.7 Set Gen-sets B1 to the following set-points:
Gen-set B1 = Unit Power Control Mode
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.7.8 Select loads on Load Bank 3 and Load Bank 6 to 40kW.

7.7.9 Using EMS, give a "Reset" command to clear all faults and events

7.7.10 Once all events and alarms are cleared, "Start" Gen-set B1.

7.7.11 Once the Gen-set is running and on-line, use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.7.12 After synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 20kW at Meter 2 and 60kW at Meter 1.

7.7.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a B-phase to ground fault in Zone 5.

7.7.14 Verify that CB51 "Opens" first on differential or zero-sequence current which clears the fault and shuts down Gen-set B1. Breaker K52 should then Open under PLC control, removing the fault on the Overload Load Bank. Note, the static switch is not expected to "Trip" during this test event.

7.7.15 Verify power flow change of 40kW at Meter 2 and 80kW at Meter 1, serving the 40kW in Load Bank 3 and Load Bank 6.

7.7.16 Verify in the DAS Database that:

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7.7.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.7.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.7.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breaker CB51 to complete this fault test event.

7.8 **Zone 5 B-Phase Line-to-Ground Fault, Gen-sets (A1+B1) & Utility Connected**

Performance Goal - Test a single line-to-ground fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition.

7.8.1 Verify CB31 and CB51 are "Closed" along with the circuit breakers to the Load Banks, manually "ARM" key switch in the cabinet and close the entry doors to Cabinet 7.

7.8.2 Set Gen-sets A1 & B1 to the following set-points:
Gen-set A1 & B1 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.8.3 Using EMS, give a "Reset" command to clear all faults and events.

7.8.4 Once all events and alarms are cleared, "Start" the Gen-sets.

7.8.5 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW.

7.8.6 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.8.7 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

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7.8.8 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a B-phase to ground fault in Zone 3.

7.8.9 Verify that CB51 "Opens" first on zero-sequence current which clears the fault and shuts down Gen-set B1. Breaker K52 should then Open under PLC control, removing the fault of the Overload Load Bank. Note, the static switch is not expected to "Trip" during this test event.

7.8.10 Verify the static switch remains "Closed", Gen-set A1 continues to operate, and the power flow change of 60kW at Meter 2 and 100kW at Meter 1.

7.8.11 Verify in the DAS Database that:

7.8.11.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.8.11.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.8.12 Remove remaining load from the Microgrid Test Bed, shut down Gen-set A1, "STOP" the static switch, and re-close breaker CB51 to complete this fault test.

7.9 Zone 4 B-Phase Line-to-Ground Fault, Gen-sets (A1+A2) & Utility Connected

Performance Goal - Test a single line-to-ground fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

7.9.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.9.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 7a.

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7.9.3 Setup the Overload Load Bank for a single-phase fault (overload) on B-phase of 28kW and connect the portable cable/plug into the exterior receptacle of Cabinet 5a

7.9.4 Install/physically connect the portable overload cabling inside Cabinet 5 from the outlet receptacle to B-phase and Ground (i.e., connecting and tightening the bolted connections).

7.9.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.9.6 Verify CB43 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" key switch in the cabinet and close the entry doors to Cabinet 5.

7.9.7 Set Gen-sets A1 & A2 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.9.8 Using EMS, give a "Reset" command to clear all faults and events

7.9.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.9.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW.

7.9.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.9.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.9.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a B-phase to ground fault in Zone 4.

7.9.14 Verify that the static switch "Trips/Opens" first followed by breaker CB41 opening zero-sequence current, which clears the fault and shuts down Gen-set A2. Breaker K42 should "Open" under PLC control, removing the fault of the Overload Load Bank. Gen-set A1 should increase to 40kW to serve the load in Zone 3.

7.9.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1, serving the 40kW in Load Bank 6.

7.9.16 Verify in the DAS Database that:

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7.9.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.9.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.9.17 Remove remaining load from the Microgrid Test Bed, shut down Gen-set A1, "STOP" the static switch, and re-close breaker CB41 to complete this fault test.

7.10 **Zone 2 C-Phase Line-to-Ground Fault, Gen-sets (A1+B1) & Utility Connected**

Performance Goal - Test a single line-to-ground fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

7.10.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.10.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 5a.

7.10.3 Setup the Overload Load Bank for a single-phase fault (overload) on C-phase of 28kW and connect the portable cable/plug into the exterior receptacle of Cabinet 2d

7.10.4 Install/physically connect the portable overload cabling inside Cabinet 2 from the outlet receptacle to C-phase and Ground (i.e., connecting and tightening the bolted connections).

7.10.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.10.6 Verify CB31 and CB51 are "Closed" along with the circuit breakers to the Load Banks, manually "ARM" key switch in the cabinet and close the entry doors to Cabinet 2d.

7.10.7 Set Gen-sets A1 & B1 to the following set-points:
Gen-set A1 & B1 = Unit Power Control Mode
Output Power Command = 20 kW each

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MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.10.8 Using EMS, give a "Reset" command to clear all faults and events

7.10.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.10.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW

7.10.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.10.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.10.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a C-phase to ground fault in Zone 2.

7.10.14 Verify that the static switch "Trips/Opens" first followed by breaker CB51 opening on line-to-neutral under-voltage and shuts down Gen-set B1. About 7 cycles after this protection sequence, CB31 will Trip/Open on differential current and Gen-set A1 will shut down. Breaker K22 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.10.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1, serving the 40kW in Load Bank 6.

7.10.16 Verify in the DAS Database that:

7.10.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.10.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.10.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB51 and CB31 to complete this fault test.

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7.11 **Zone 6 C-Phase Line-to-Ground Fault, Gen-set A1 & Utility Connected**

Performance Goal - Test a single line-to-ground fault condition in Zone 6 with Gen-set A1 operating in-parallel with the utility grid to verify I^2t protection.

7.11.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.11.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 2d.

7.11.3 Setup the Overload Load Bank for a single-phase fault (overload) on C-phase of 28kW and connect the portable cable/plug into the exterior receptacle of Cabinet 8a

7.11.4 Install/physically connect the portable overload cabling inside Cabinet 8 from the outlet receptacle to C-phase and Ground (i.e., connecting and tightening the bolted connections).

7.11.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.11.6 Verify CB63 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 8.

7.11.7 Set Gen-set A1 to the following set-points:
Gen-set A1 = Unit Power Control Mode
Output Power Command = 20 kW
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.11.8 Select loads on Load Bank 3 and Load Bank 6 to 40kW.

7.11.9 Using EMS, give a "Reset" command to clear all faults and events.

7.11.10 Once all events and alarms are cleared, "Start" the Gen-sets.

7.11.11 Once the Gen-sets are running and on-line, use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.11.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 20kW at Meter 2 and 60kW at Meter 1.

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7.11.13 Using the DAS Load Control program, set the duration of the fault (overload) to 100 seconds, set the software to "ARM" and initiate a Phase C-to-ground fault in Zone 6.

7.11.14 Verify that the static switch "TRIPS" first, followed by breaker CB13 opening, which clears the fault. Breaker K62 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.11.15 Verify that Gen-set A1 power output increases from 20kW to 40kW to serve the 40kW load in Load Bank 3.

7.11.16 Verify in the DAS Database that:

7.11.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.11.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.11.17 Shutdown Gen-set A1, "STOP" the static switch, and remove load from the Microgrid Test Bed to complete this fault test event.

7.12 **Zone 6 C-Phase Line-to-Ground Fault, Gen-set (A1+B1) & Utility Connected**

Performance Goal - Test a single line-to-ground fault condition in Zone 6 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify I^2t protection. This test is similar to the prior test, but evaluates the resultant impact of two Gen-sets operating during a fault condition.

7.12.1 Verify CB63 is "Closed" along with the circuit breakers to the Load Banks. Manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 8.

7.12.2 Set Gen-set A1 & B1 to the following set-points:
Gen-set A1 & B1 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

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7.12.3 Select loads on Load Bank 3, Load Bank 5 and Load Bank 6 to 40kW.

7.12.4 Using EMS, give a "Reset" command to clear all faults and events.

7.12.5 Once all events and alarms are cleared, "Start" the Gen-sets.

7.12.6 Once the Gen-sets are running and on-line, use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.12.7 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.12.8 Using the DAS Load Control program, set the duration of the fault (overload) to 100 seconds, set the software to "ARM" and initiate a Phase C-to-ground fault in Zone 6.

7.12.9 Verify that the static switch "TRIPS" first, followed by breaker CB13 opening, which clears the fault. Breaker K62 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.12.10 Verify that Gen-set A1 and B1 power output increases from 20kW to 40kW to serve the 40kW load in Load Bank 3 and Load Bank 5.

7.12.11 Verify in the DAS Database that:

7.12.11.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.12.11.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.12.12 Shutdown Gen-set A1 & A2, "STOP" the static switch, and remove load from the Microgrid Test Bed to complete this fault test event.

7.12.13 Verify CB63 is "Closed" along with the circuit breakers to the Load Bank; and close the entry doors to Cabinet 8.

7.13 **Zone 3 A-to-B Phase Fault, Gen-set (A1+A2) & Utility Connected**
Performance Goal - Test a phase-to-phase fault condition in Zone 3 with

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Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

7.13.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.13.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 8a.

7.13.3 Setup the Overload Load Bank for a phase-to-phase fault (overload) between A and B phases of 84kW and connect the portable cable/plug into the exterior receptacle of Cabinet 3a

7.13.4 Install/physically connect the portable overload cabling inside Cabinet 3 from the outlet receptacle to A and B phases (i.e., connecting and tightening the bolted connections).

7.13.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.13.6 Verify CB33 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 3.

7.13.7 Set Gen-set A1 & A2 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.13.8 Using EMS, give a "Reset" command to clear all faults and events.

7.13.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.13.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW.

7.13.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.13.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.13.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a Phase A-to-Phase B fault in Zone 3.

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7.13.14 Verify that the static switch "Trips/Opens" first, followed by breakers CB31, CB41 and CB51 clearing the fault. Gen-set A1 & A2 will shut down and breaker K32 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.13.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1 to Load Bank 6.

7.13.16 Verify in the DAS Database that:

7.13.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.13.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.13.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB31, CB41 and CB51 to complete this fault test event.

7.14 **Zone 4 A-to-B Phase Fault, Gen-set (A1+A2) & Utility Connected**
Performance Goal - Test a phase-to-phase fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

7.14.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.14.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 3a.

7.14.3 Setup the Overload Load Bank for a phase-to-phase fault (overload) between A and B phases of 84kW and connect the portable cable/plug into the exterior receptacle of Cabinet 5a

7.14.4 Install/physically connect the portable overload cabling inside Cabinet 5 from the outlet receptacle to A and B phases (i.e., connecting and tightening the bolted connections).

7.14.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

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7.14.6 Verify CB43 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 5.

7.14.7 Set Gen-set A1 & A2 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.14.8 Using EMS, give a "Reset" command to clear all faults and events.

7.14.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.14.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 4 and Load Bank 6 to 40kW.

7.14.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.14.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.14.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a Phase A-to-Phase B fault in Zone 4.

7.14.14 Verify that the static switch "Trips/Opens" first, followed by breakers CB31, CB41 and CB51 clearing the fault. Gen-set A1 & A2 will shut down and breaker K42 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.14.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1 to Load Bank 6.

7.14.16 Verify in the DAS Database that:

7.14.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.14.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

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7.14.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB31, CB41 and CB51 to complete this fault test event.

7.15 **Zone 2 A-to-B Phase Fault, Gen-set (A1+B1) & Utility Connected**
Performance Goal - Test a phase-to-phase fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection

7.15.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.15.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 5a.

7.15.3 Setup the Overload Load Bank for a phase-to-phase fault (overload) between A and B phases of 84kW and connect the portable cable/plug into the exterior receptacle of Cabinet 2d.

7.15.4 Install/physically connect the portable overload cabling inside Cabinet 2d from the outlet receptacle to A and B phases (i.e., connecting and tightening the bolted connections).

7.15.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.15.6 Verify CB31, CB41, CB51, and K22 are "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 2d.

7.15.7 Set Gen-set A1 & B1 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.15.8 Using EMS, give a "Reset" command to clear all faults and events.

7.15.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.15.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 5 and Load Bank 6 to 40kW.

7.15.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

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7.15.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.15.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a Phase A-to-Phase B fault in Zone 2.

7.15.14 Verify that the static switch "Trips/Opens" first, followed by breakers CB31, CB41 and CB51 clearing the fault. Gen-set A1 & B1 will shut down and breaker K22 should "Open" under PLC control, removing the fault of the Overload Load Bank.

7.15.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1 to Load Bank 6.

7.15.16 Verify in the DAS Database that:

7.15.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.15.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.15.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB31, CB41 and CB51 to complete this fault test event.

7.16 **Zone 5 A-to-B Phase Fault, Gen-set (A1+B1) & Utility Connected**
Performance Goal - Test a phase-to-phase fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

7.16.1 Perform the Microgrid Test Bed Lockout/Tagout Procedure, described in Section 4.7.

7.16.2 Remove the Overload Load Bank portable cable/plug from the exterior receptacle and physically remove the portable overload cabling inside Cabinet 2d.

7.16.3 Setup the Overload Load Bank for a phase-to-phase fault (overload) between A and B phases of 84kW and connect the portable cable/plug into the exterior receptacle of Cabinet 7a.

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7.16.4 Install/physically connect the portable overload cabling inside Cabinet 7 from the outlet receptacle to A and B phases (i.e., connecting and tightening the bolted connections).

7.16.5 Reverse the Microgrid Test Bed Lockout/Tagout Procedure.

7.16.6 Verify CB53 is "Closed" along with the circuit breakers to the Load Banks, manually "ARM" the key switch in the cabinet and close the entry doors to Cabinet 7.

7.16.7 Set Gen-set A1 & B1 to the following set-points:
Gen-set A1 & A2 = Unit Power Control Mode
Output Power Command = 20 kW each
MG Power/Frequency Droop= -0.0833 Hz/kW
MG Voltage Command= 277 V.

7.16.8 Using EMS, give a "Reset" command to clear all faults and events.

7.16.9 Once all events and alarms are cleared, "Start" the Gen-sets.

7.16.10 Once the Gen-sets are running and on-line, select loads on Load Bank 3, Load Bank 5 and Load Bank 6 to 40kW.

7.16.11 Use EMS to put the static switch in "Start" mode. Verify synchronized closing of the static switch.

7.16.12 After the synchronized closing of the static switch, the Microgrid Test Bed is connected to the utility grid with 40kW at Meter 2 and 80kW at Meter 1.

7.16.13 Using the DAS Load Control program, set the duration of the fault (overload) to 10 seconds, set the software to "ARM" and initiate a Phase A-to-Phase B fault in Zone 5.

7.16.14 Verify that the static switch "Trips/Opens" first, followed by breakers CB31, CB41 and CB51 clearing the fault. Gen-set A1 & B1 will shut down and breaker K52 should "Open" under PLC control, removing the fault of the Overload Load Bank. (Note, due to the delta-wye transformer (T51) the zero-sequence and negative-sequence detection is less sensitive to faults in Zone 5.)

7.16.15 Verify power flow change of 0kW at Meter 2 and 40kW at Meter 1 to Load Bank 6.

7.16.16 Verify in the DAS Database that:

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7.16.16.1 The fault event waveforms of phase currents and voltages at all Relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, as well as the relay element that caused the "TRIP" with trip times for each relay relative to when the fault was applied.

7.16.16.2 The waveform and RMS Meter data were recorded. Note the above collection of all data and waveforms will take approximately 30 minutes to arrive.

7.16.17 Remove remaining load from the Microgrid Test Bed, "STOP" the static switch, and re-close breakers CB31, CB41 and CB51 to complete this fault test event.

8.0 Procedure – Reduced System Tests

Objective: The tests described in Section 8 are designed to ensure that the Gen-set inverter controls are working correctly. This includes unit control, feeder control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the Tecogen / Youtility factory acceptance testing.

Measurement

- Sources – Injected power (kW), reactive load (kVAr), frequency (freq), and voltage (V) for each Gen-set (i.e., $A1_P$, $A2_P$ and $B1_P$).
- Zone input power flow into Zones 3 ($A1_Z$), 4 ($A2_Z$), 5 ($B1_Z$) and 6.
- Loads - Voltage at Load Bank 3 (L3), 4 (L4), 5 (L5), and 6 (L6).
- Static Switch (SS) - Power (kW) and current (I) through the static switch.
- Static Switch Control Signal: Forced "OPEN" and release to allow self synchronization.
- Voltage (V) and frequency (Freq) difference across the static switch.

Performance Goal – Expect to observe smooth transitions of the Gen-sets response to different step conditions (i.e., static switch "OPEN"/ "CLOSE" and load steps).

8.1 Initial Voltage Regulation Test – Single Zone, Islanded With Gen-set A1

Performance Goal – Verify smooth transitions of Gen-set A1 response to different step conditions of load in Load Bank 3 with voltage set point

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changes ranging from +5% to -5%. Repeat tests with Gen-set A2 in Load Bank 4, and then Gen-set B1 in Load Bank 5.

8.1.1 Verify the utility's CB1 breaker is "Closed" and the Microgrid Test Bed is energized with nominal voltages indicated on all three phases at Meter 1.

8.1.2 During the next sequence of tests, verify in the "DAS Database" file that when the test was performed, the event waveforms at all relay locations (i.e., Relays 2, 3, 4 & 5) were recorded, along with the test event times when the event was initiated.

8.1.3 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Open", all zone and load bank circuit breakers are "Closed", Gen-sets A1, A2 and B1 set for injection power control, and all load banks initially set at zero load.

8.1.4 Start Gen-set A1 in Zone 3 and then bring Load Bank 3 up to 20kW, balanced load, verify during this event that the voltage magnitude remains unchanged with minimum transients.

8.1.5 Verify in the DAS Database that the event waveforms of phase currents and voltages, plus RMS Meter data were recorded at all locations when the event was applied.

8.1.6 Apply step change of load event in Load Bank 3 from 20kW to 40kW, balanced load and observe the voltage magnitude remains unchanged with minimum transients.

8.1.7 Verify in the DAS Database that the event waveforms of phase currents and voltages, plus RMS Meter data were recorded at all locations when the event was applied.

8.1.8 Apply another step change of load event in Load Bank 3 from 40kW to 60kW, balanced load, and observe the voltage magnitude remains unchanged with minimum transients.

8.1.9 Verify in the DAS Database that the event waveforms of phase currents and voltages, plus RMS Meter data were recorded at all locations when the event was applied.

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8.1.10 Change the voltage set point from nominal to +5%. Then, repeat steps 8.1.4 through 8.1.9, and observe stable voltage control. Verify that the event waveforms of phase currents and voltages, plus RMS Meter data were recorded.

8.1.11 Change the voltage set point from +5% to -5%. Then, repeat steps 8.1.4 through 8.1.9, and observe stable voltage control. Verify that the event waveforms of phase currents and voltages, plus RMS Meter data were recorded

8.1.12 Reduce Load Bank 3 to zero and shutdown Gen-set A1.

8.1.13 Repeat steps 8.1.4, through 8.1.11 for Zone 4, using Load Bank 4 and Gen-set A2.

8.1.14 Reduce Load Bank 4 to zero and shutdown Gen-set A2.

8.1.15 Repeat steps 8.1.4, through 8.1.11 for Zone 5, using Load Bank 5 and Gen-set B1.

8.1.16 Reduce Load Bank 5 to zero and shutdown Gen-set B1.

8.2 **Open Static Switch Test, Check P = 0 Limit, Gen-set A1**
Performance Goal – Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN"/ "CLOSE") with the unit power limit of Gen-set A1 equal to zero.

8.2.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.2.2 Set balanced load in Load Banks 3, 4 & 6 to the kW values in the **Start** column. Then, start Gen-sets A1 and A2 in unit control mode with the settings indicated in **Start** column.

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Test Event - Open Static Switch				
	Mode	**Start**	**Event**	**End**
$A1_P$	Unit	5kW		0.0kW
$A2_P$	Unit	55kW		40kW
$B1_P$		Off		Off
Freq.		~60Hz		~60.12
L3		20kW		20kW
L4		20kW		20kW
L5		0		
L6		20kW		20kW
SS	CLOSED	-20kW	OPEN	0.0kW
Grid		0		20kW
Let SS to Re-close				

8.2.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.2.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column.

8.2.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.2.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.2.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.2.8 Verify that system conditions returned to the values listed in the **Start** column.

8.2.9 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3, 4, & 6 to zero.

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8.3 **Open Static Switch Test, Check P = 60kW Limit, Gen-set A2**
Performance Goal – Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN"/ "CLOSE") with the unit power limit of Gen-set A2 equal to 60kW.

8.3.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed" and Gen-sets A1, A2 and B1 set for injection power control.

8.3.2 Set balanced load in Load Banks 3 & 4 to the kW values in the **Start** column. Then, start Gen-sets A1 and A2 in unit control mode with the settings indicated in **Start** column.

Event Open SS				
	Mode	**Start**	**Event**	**End**
$A1_P$	Unit	5kW		40kW
$A2_P$	Unit	55kW		60kW
$B1_P$		Off		Off
Freq		~60Hz		~59.72
L3		60kW		60kW
L4		40kW		40kW
L5		0		0
L6		0		0
SS	CLOSED	40kW	OPEN	0kW
Grid		40kW		0kW
Let SS re-close				

8.3.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.3.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column (i.e., Gen-set A1 power increases from 5kW to 40kW and Gen-set A2 power increases from 55kW to 60kW).

8.3.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was

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initiated.

8.3.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.3.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.3.8 Verify that system conditions return to the values listed in the **Start** column.

8.3.9 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.4 **Test Island Operation, Unbalanced Load**

Performance Goal –Verify smooth transitions of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN"/ "CLOSE") with an un-balanced load condition in Zone 3.

8.4.1 During this sequence of tests, maintain the static switch "Open", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.4.2 Start Gen-sets A1 and A2 in unit control mode with the settings indicated in **Start** column. Then, set balanced load in Load Bank 3 to the kW value in the **Start** column.

Reduce A-Phase Load in Load Bank 3				
	Mode	Start	Event	End
$A1_P$	Unit	15kW		~2.5kW
$A2_P$	Unit	45kW		~37.5kW
$B1_P$		Off		Off
Freq		~60Hz		~60.09
L3		60kW	A-phase = 0kW	40kW
L4		0kW		0kW
L5		0kW		0kW
L6		0kW		0kW
SS	OPEN	0kW		0kW
Grid		0kW		0kW
Should be no current in phase a				

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8.4.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, reduce A-phase load in Load Bank 3 from 20kW to 0kW.

8.4.4 Verify that there is zero kW (approximate) in Phase A, and that Gen-set and load conditions are similar to the values in the **End** column.

8.4.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.4.6 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 to zero.

8.5 **Mixed Mode Operation Test – Feeder A, Gen-set A1 to 60kW Maximum**

Performance Goal –Verify smooth transitions of Gen-sets, A1 in Zone operation mode with a 60kW limit and A2 in Unit operation mode, during a load step change in Load Bank 3.

8.5.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.5.2 Start Gen-sets A1 in zone control mode and A2 in unit control mode with the settings indicated in **Start** column. Then, set balanced load in Load Banks 3 & 4 to the kW values in the **Start** column.

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Step load				
	Mode	**Start**	**Event**	**End**
A1z	Zone	54kW		54kW
$A1_P$	Injected Power	10kW		60kW Max
$A2_P$	Unit	6kW		6kW
$B1_P$		Off		Off
Freq		~60Hz		~60Hz
L3		35kW	Add 50kW	85kW
L4		35kW		35kW
L5		0		0
L6		0		0
SS	CLOSED	54kW		54kW
Grid		54kW		54kW
SS stays Closed				

8.5.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, increase balanced three phase load in Load Bank 3 from 35kW to 85kW.

8.5.4 Verify that Gen-set and load conditions are similar to the values in the **End** column (i.e., injected power from Gen-set A1 increases from 10kW to 60kW with the Zone power in Feeder A maintained at 54kW).

8.5.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.5.6 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.6 **Mixed Mode Operation Test – Feeder A, Automatic Reset of Zone Level Set-Point**

Performance Goal –Verify smooth transitions of Gen-sets, A1 in Zone operation mode with an automatic reset of the set point and A2 in Unit operation mode, during a load step change in Load Bank 4.

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8.6.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.6.2 Start Gen-sets A1 in zone control mode and A2 in unit control mode with the settings indicated in **Start** column. Then, set balanced load in Load Banks 3 & 4 to the kW values in the **Start** column.

Step load				
	Mode	**Start**	**Event**	**End**
A1z	Zone	55kW		65kW
A1p	Injected Power	50kW		60kW, A1 at Max
$A2_P$	Unit	5kW		5kW
$B1_P$		Off		Off
Freq		~60Hz		~60Hz
L3		75kW		75kW
L4		35kW	Add 20kW	55kW
L5		0		0
L6		0		0
SS	CLOSED	55kW		65kW
Grid		55kW		65kW
SS stays Closed				

8.6.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, increase balanced three phase load in Load Bank 4 from 35kW to 55kW.

8.6.4 Verify that Gen-set and load conditions are similar to the values in the **End** column (i.e., load change forces the injected power of Gen-set A1 to exceed its maximum and the system should automatically reset its Zone power level set-point from 55kW to 65kW to hold Gen-set A1 to 60kW with power from the grid increased from 55kW to 65kW).

8.6.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the

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DAS, along with the test event date/time when the event was initiated.

8.6.6 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.7 **Mixed Mode Operation Test – Feeder A, Zone Power Change**
Performance Goal –Verify smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A.

8.7.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.7.2 Start Gen-sets A1 in zone control mode and A2 in unit control mode with the settings indicated in **Start** column. Then, set a balanced load in Load Banks 3 & 4 to the kW values in the **Start** column.

Large Zone Set to Pickup System				
	Mode	Start	Event	End
$A1_Z$	Zone	54kW	Add 56kW	110kW
$A1_P$	Injected Power	60kW A1 at max		4kW
$A2_P$	Unit	6kW		6kW
$B1_P$		Off		Off
Freq		~60Hz		~60Hz
L3		85kW		85kW
L4		35kW		35kW
L5		0		0
L6		0		0
SS	CLOSED	54kW		110kW
Grid		54kW		110kW
EMS : Zone A1 from 54kW to 110 kW				

8.7.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, use the EMS to change/increase the Zone power level in Feeder A from 54kW to 110kW.

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8.7.4 Verify that Gen-set and load conditions are similar to the values in the **End** column (i.e., the Zone power change in Feeder A forces Gen-set A1 to reduce its injected power from 60kW to 4kW and power from the grid increased from 54kW to 110kW).

8.7.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.7.6 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.8 **Mixed Mode Operation Test – Feeder A, Zone Power Change When Islanded**

Performance Goal –Verify smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Feeder A when islanded.

8.8.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.8.2 Start Gen-sets A1 in zone control mode and A2 in unit control mode with the settings indicated in **Start** column. Then, set a balanced load in Load Banks 3 & 4 to the kW values in the **Start** column.

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Open SS				
	Mode	**Start**	**Event**	**End**
$A1_Z$	Zone	50kW		0kW
$A1_P$	Injected Power	14kW		~18kW
$A2_P$	Unit	6kW		~52kW
$B1_P$		Off		Off
Freq		~60Hz		~59.6Hz
L3		35kW		35kW
L4		35kW		35kW
L5		0		0
L6		0		0
SS	CLOSED	50kW	OPEN	0kW
Grid		50kW		0kW
Allow SS to Re-close				

8.8.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.8.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column (i.e., Zone power in Feeder A decreases from 50kW to 0kW, Gen-set A1 power increases from 14kW to about 18kW, Gen-set A2 power increases from 6kW to about 52kW, frequency decreases by about 0.4Hz, and power from the grid decreases from 50kW to zero).

8.8.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.8.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.8.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations

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were recorded in the DAS, along with the test event date/time when the event was initiated.

8.8.8 Verify that system conditions returned to the values listed in the **Start** column.

8.8.9 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.9 **Mixed Mode Operation Test - Feeder A, When Islanded Automatic Reset of Zone Level Set-point, Both Gen-sets P = 60kW Maximum Performance Goal** –Verify smooth transitions of Gen-sets, A1 in Zone operation mode with automatic reset of set point and A2 in Unit operation mode, with a static switch operation and a change of zone power in Feeder A when islanded.

8.9.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.9.2 Start Gen-sets A1 in zone control mode and A2 in unit control mode with the settings indicated in **Start** column. Then, set a balanced load in Load Banks 3 & 4 to the kW values in the **Start** column.

Open SS, Test Gen-set $P_{max.}$				
	Mode	Start	Event	End
$A1_Z$	Zone	54kW		0kW
$A1_P$	Injected Power	60kW		60kW A1 at Max.
$A2_P$	Unit	6kW		60kW A2 at Max.
$B1_P$		Off		Off
Freq		~60Hz		~59.5Hz
L3		60kW		60kW
L4		60kW		60kW
L5		0		0
L6		0		0
SS	CLOSED	54kW	OPEN	0kW
Grid		54kW		0kW
Allow SS to Re-close				

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8.9.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.9.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column (i.e., Zone power in Feeder A decreases from 50kW to 0kW, Gen-set A1 power remains at 60kW, Gen-set A2 power increases from 6kW to about 60kW, frequency decreases by about 0.5 Hz, and power from the grid decreases from 50kW to zero).

8.9.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.9.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.9.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.9.8 Verify that system conditions returned to the values listed in the **Start** column.

8.9.9 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero.

8.10 **Two Sources in Zone Control - Separate Feeders, When Islanded Automatic Reset of Zone Level Set-point, New Zones Sum Equal Zero**
Performance Goal –Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Feeder A and Feeder B when islanded.

8.10.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

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8.10.2 Start Gen-sets A1 and B1 in zone control mode with the settings indicated in **Start** column. Then, set a balanced load in Load Banks 3 & 5 to the kW values in the **Start** column.

Two Zone Control Test: Separate Event Open SS				
	Mode	Start	Event	End
$A1_Z$	Zone	40kW		10kW
$A1_P$	Injected Power	0kW		30kW
$A2_P$		Off		Off
$B1_Z$	Zone	10kW		-10Kw
$B1_P$	Injected Power	40kW		60kW B1 at Max.
Freq		~60Hz		~59.76
L3		40kW		40kW
L4		0		0
L5		50kW		50kW
L6		0		0
SS	CLOSED	50kW	OPEN	0.0kW
Grid		50kW		0.0kW
Let SS Re-close				

8.10.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.10.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column (i.e., Zone power in Feeder A decreases from 40kW to 10kW and Gen-set A1 injected power increases from 0kW to 30kW; Zone power in Feeder B decreases from +10kW to -10kW and Gen-set B1 injected power increases from 40W to about 60kW, frequency decreases by about 0.25 Hz, and power from the grid decreases from 50kW to zero). Also, verify when the system islands, the sum of the new zone settings equal zero (i.e., -10kW +10kW).

8.10.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the

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DAS, along with test event date/time when the event was initiated.

8.10.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.10.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.10.8 Verify that system conditions returned to the values listed in the **Start** column.

8.10.9 Shutdown Gen-sets A1 & A2 and reduce load in Load Banks 3 & 4 to zero

8.11 **Two Sources in Zone Control - Separate Feeders, When Islanded Automatic Reset of Zone Level Set-points**
Performance Goal –Verify smooth transitions of Gen-sets, A1 and B1 in Zone operation mode and both having automatic reset of set points, with a static switch operation and a change of zone power in Feeder A and Feeder B when islanded.

8.11.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed", and Gen-sets A1, A2 and B1 set for injection power control.

8.11.2 Start Gen-sets A1 and B1 in zone control mode with the settings indicated in **Start** column. Then, set a balanced load in Load Banks 3, 5, & 6 to the kW values in the **Start** column.

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Two-Zones: Event Open SS				
	Mode	Start	Event	End
$A1_Z$	Zone	-30kW		-25kW
$A1_P$	Injected Power	50kW		45kW
$A2_P$		Off		Off
$B1_Z$	Zone	20kW		25Kw
$B1_P$	Injected Power	20kW		15kW
Freq		~60Hz		~60.04Hz
L3		20kW		20kW
L4		0		0
L5		40kW		40kW
L6		20kW		20kW
SS	CLOSED	-10kW	OPEN	0.0kW
Grid		10kW		20kW
Let SS Re-close				

8.11.3 Allow a few minutes for the Gen-sets to warm up. When the system is in steady state condition, force "Open" static switch control signal.

8.11.4 Verify that the Gen-set and load conditions are similar to the values in the **End** column (i.e., Zone power in Feeder A changes from -30kW to -25kW and Gen-set A1 injected power decreases from 50kW to 45kW; Zone power in Feeder B increases from +20kW to +25kW; and Gen-set B1 injected power decreases from 20W to 15kW, frequency increases by about 0.04 Hz, and power from the grid increases from 10kW to 20kW). Also, verify when the system islands, the automatic reset of the Zones with one Zone exporting power and the other Zone importing power. Note, at the start of this test 10kW of power is being exported through the Static Switch to Feeder C

8.11.5 Verify in the "DAS Database" file that at the time when this test was performed, that the test event data and waveforms of phase currents and voltages at affected locations were recorded in the

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DAS, along with test event date/time when the event was initiated.

8.11.6 Release the static switch "Open" condition and allow self synchronization of the static switch to "Re-close".

8.11.7 Verify in the "DAS Database" file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with the test event date/time when the event was initiated.

8.11.8 Verify that system conditions returned to the values listed in the **Start** column.

8.11.9 Shutdown Gen-sets A1 & B1 and reduce load in Load Banks 3, 5, & 6 to zero.

8.12 **Test Generator Black-Start Procedure**

Objective: This test will check the manual procedure used to black-start the Microgrid Test Bed in the event of a lengthy utility outage occurs with the Gen-sets off-line.

Measurement – Record the transition of the Gen-set meters as they are started and brought on-line and as load banks are switched on-line. Note, the transition time between all events.

Performance Goal - Bring up the Microgrid Test Bed from a black-out condition without generation or protection trips.

8.12.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed" and all load banks initially set at zero load.

8.12.2 Begin with Gen-sets A1, A2 and B1 set for injection power control, off-line and shut down. Using the Walnut Breaker Control Program, "Open" CB1 to simulate a utility outage with the Microgrid de-energized, referred to as a black-out.

8.12.3 Using the EMS and DAS programs:

8.12.3.1 Set a manual "Open" on the static switch.

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8.12.3.2 Using the DAS Load Control program, reduce load on Load Banks 3, 4 and 5 to zero.

8.12.3.3 Individually start Gen-set A1, Gen-set A2 and Gen-set B1; wait a few minutes (e.g., 3-4 minutes) to allow them to warm up and come on-line.

8.12.3.4 Using the DAS Load Control program, select the load in each Load Bank (i.e., 3, 4 & 5) to 27kW +j 13kVAr, and then switch the load on-line. The Microgrid is now manually islanded and supporting 90kVA of loads.

8.12.3.5 Remove the manual "Open" on the static switch.

8.12.4 Using the Walnut Breaker Control Program, "Close" circuit breaker CB1 to restore utility voltage and observe automatic reconnection (i.e., synchronization) after the IEEE 1547 restoration timer elapses, which is 300 seconds (recall utility outage creates an IEEE 1547 voltage event).

8.12.5 Verify in the DAS Database file that at the time when this synchronization event was performed, that the event data and waveforms of phase currents and voltages at affected locations were recorded in the DAS, along with test event date/time when the event was initiated.

8.12.6 Shutdown Gen-sets A1, A2, & B1 and reduce load in Load Banks 3, 4 & 5 to zero.

8.13 **Test/Establish Generator Black-Start Capacity**

Performance Goal – Determine the Black-start capacity of the microgrid by increasing the amount of load on the Microgrid Test Bed from a black-out condition without generation or protection trips.

8.13.1 Maintain the weak grid connection at L11 during this sequence of tests with the static switch "Closed", all zone and load bank circuit breakers are "Closed" and all load banks initially set at zero load.

8.13.2 Begin with Gen-sets A1, A2 and B1 set for injection power control, off-line and shut down. Using the Walnut Breaker Control Program, "Open" CB1 to simulate a utility outage with the Microgrid de-energized, referred to as a black-out.

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8.13.3 Using the EMS and DAS programs:

8.13.3.1 Set a manual "Open" on the static switch.

8.13.3.2 Set the load in Load Bank 3 at 27kW +j 13kVAr, and verify that load bank circuit breaker CB33 is "Closed".

8.13.3.3 Start Gen-set A1 with Load Bank 3 load connected when starting the generator wait a few minutes (e.g., 3-5 minutes) for the engine to warm up, than the inverter contactor will "Close" to serve load on-line.

8.13.3.4 Verify in the DAS Database file that at the time when the inverter contactor Closed, the test event data and waveforms of phase currents and voltages were recorded in the DAS, along with test event date/time when the event was initiated.

8.13.3.5 Shutdown Gen-set A1. Note, Gen-set A1 was manually islanded and supporting 30kVA of load.

8.13.3.6 Increase load in Load Bank 3 to 36kW +j 19.5VAr, and verify that load bank circuit breaker CB33 is "Closed".

8.13.3.7 Start Gen-set A1 with Load Bank 3 load connected when starting the generator wait a few minutes (e.g., 3-5 minutes) for the engine to warm up, than the inverter contactor will "Close" to serve load on-line

8.13.3.8 Verify in the DAS Database file that at the time when the inverter contactor Closed, the test event data and waveforms of phase currents and voltages were recorded in the DAS, along with test event date/time when the event was initiated.

8.13.3.9 Shutdown Gen-set A1. Note, Gen-set A1 was manually islanded and supporting 40kVA of load.

8.13.3.10 Increase load in Load Bank 3 to 54kW +j 26VAr, and verify that load bank circuit breaker CB33 is "Closed".

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8.13.3.11 Start Gen-set A1 with Load Bank 3 load connected when starting the generator wait a few minutes (e.g., 3-4 minutes) for the engine to warm up, than the inverter contactor will "Close" to serve load on-line.

8.13.3.12 Verify in the DAS Database file that at the time when the inverter contactor Closed, the test event data and waveforms of phase currents and voltages were recorded in the DAS, along with test event date/time when the event was initiated.

8.13.3.13 Shutdown Gen-set A1. Note, Gen-set A1 was manually islanded and supporting 60kVA of load.

8.13.3.14 If Gen-set A1 successfully islanded and supported 60kVA of load, increase load in Load Bank 3 to 63kW+j30.5kVAr, and verify that load bank circuit breaker CB33 is "Closed".

8.13.3.15 Start Gen-set A1 with Load Bank 3 load connected when starting the generator wait a few minutes (e.g., 3-4 minutes) for the engine to warm up, than the inverter contactor will "Close" to serve load on-line.

8.13.3.16 Verify in the DAS Database file that at the time when the inverter contactor Closed, the test event data and waveforms of phase currents and voltages were recorded in the DAS, along with test event date/time when the event was initiated.

8.13.3.17 Shutdown Gen-set A1. Note, if successful, then Gen-set A1 manually islanded and supported 70kVA of load.

9.0 Procedure – Demonstration Tests of Control Power Flow

Objective - To demonstrate the flexibility of the Microgrid both grid connected and islanded for different loads, power flows and impact on the utility. First sequence of tests will include the weak grid inductors (i.e., L11) in the circuit.

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Second sequence of tests will repeat a select number of the most interesting results under strong grid conditions.
Measurements: Collect RMS data for V, I, kW, kVAr, and Freq for each flow change at the following points:

- Meter 1 – I, kW, kVAr for the utility connection
- Meter 2 - I, kW, kVAr and utility-side V and Freq
- Meter 3 - I, kW, and kVAr for Feeder A and Microgrid side V and Freq
- Meter A1p – I, kW, kVAr for Gen-set A1
- Load Meter 3 – Zone 3 load kW and kVAr
- Meter 4 – I, kW, kVAr for Zone 4
- Meter A2p – I, kW, kVAr for Gen-set A2
- Load Meter 4 – Zone 4 load kW and kVAr
- Meter 5 – I, kW, kVAr for Feeder B
- Meter B1p – I, kW, kVAr for Gen-set B1
- Load Meter 5 – Zone 5, Feeder B load kW and kVAr
- Load Meter 6 – Zone 6, Feeder C load kW and kVAr

In addition collect:

- V and I waveform data for unexpected events and for static switch transitions.
- Motor torque waveforms for all switch transitions.

Loading: Load on Feeder A & Feeder B must be less than 170 kW and Feeder C should be such that there is no power into the utility grid. All loads should include an approximate 0.9 power factor (pf), if possible. The motor load will be included as part of Zone 3.

9.1 Unit Control Mode, Weak Grid

Performance Goal – Verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. During each sequence of tests in Table 1, maintain a weak grid connection with L11 in the circuit and the static switch "Closed"; all zone and load bank circuit breakers "Closed"; Gen-sets A1, A2 and B1 set for Unit (injection power) control mode; and all load banks initially set at zero.

9.1.1 Each test event procedure begins with setting the load (i.e., balanced load) conditions as indicated in the Table, using the EMS with reactive load set at each Load Bank to achieve an

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Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Youtility Factory Test Plan
Final Test Results

APPENDIX C

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Youtility Factory Test Plan Final Test Results

For Inverter Functions

Test Results:

The data provided in this paper are the final results to demonstrate the capabilities of the microgrid algorithm implemented in the Youtility inverter microgrid system. Also, the data provided in this paper only depicts two-unit series operation. In each plot the data is formatted in the following fashion:

Ch1 = Unit RMS Power Output;
0.0V = -15KW
0.5V = 0KW
1.5V = 30KW
2.5V = 60KW
Ch2 = Unit Operating Frequency;
60Hz --> 2.3V
59.5Hz --> 1.66V
60.5Hz --> 2.94V
Ch 3 = Micro Grid Voltage; 1V = 1V
Ch4 = Unit Output Current; 1V = 100Amps

Also, the result of each test are organized in a table, shown below in Table 1, which define the set points of the load and the individual micro gird inverters (abbreviated S.P) and the actual load of the load bank and the actual power output from the unit. The table also contains the microgrid operating frequency before and after the transient event occurs. Data contained in column A defines the operating condition and the state of the microgrid before the transient condition being tested occurs. Data contained in column B defines the operating condition and the state of the microgrid after the transient condition being tested has occurred.

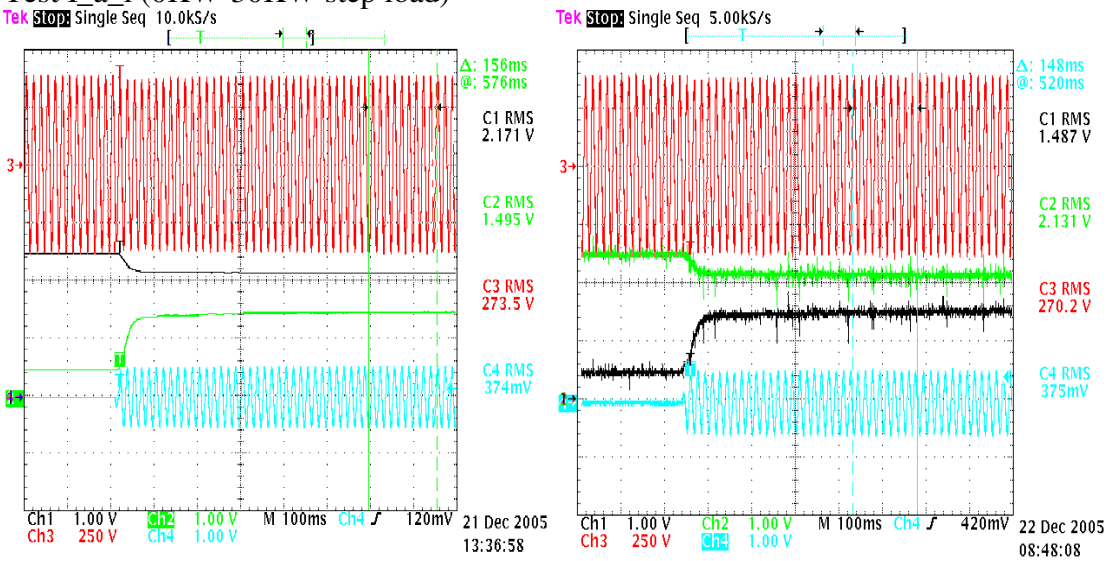
	A (Grid or Island)	B (Grid or Island)
Load Bank #1(S.P/Actual) KW	XX KW	XX KW
Load Bank #2(S.P/Actual) KW	XX KW	XX KW
Unit #1 (S.P/Pout) KW	XX KW Feeder or Unit	XX KW Feeder or Unit
Unit #2 (S.P/Pout) KW	XX KW Feeder or Unit	XX KW Feeder or Unit
Frequency Hz	XX.X Hz	XX.X Hz

Table 1 Sample Test Data Table

Phase One Testing:

Phase one testing consists of data taken while operating individual inverters in an islanded condition. The data provided in this section depicts step loads of various magnitudes applied on the inverter. In each test, the inverter is operated in unit power mode with a command of 20KW. In this section, the plots for the individual units and the information contained in each table are grouped together for ease of comparison. The units ARE NOT operating synchronized together as a microgrid.

Test I_a_i (0KW-30KW step load)



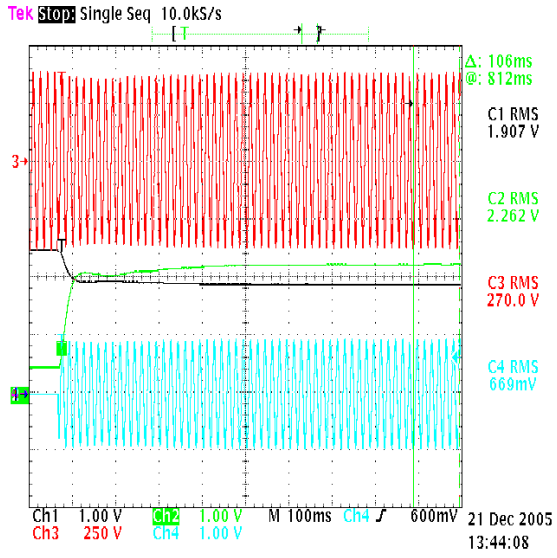
Unit #1 Transient Response Unit #2 Transient Response

Figure 1 Individual Inverter Transient Response 0 – 30 kW

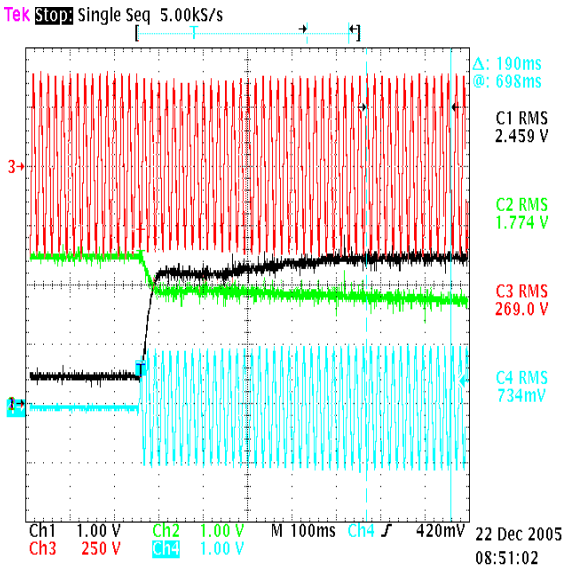
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	30/31.4 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Actual) KW	20.0/0.0 KW Unit	20.0/30.7 KW Unit
Unit #2 (S.P/Actual) KW	20.0/0.0 KW Unit	20.0/30.3 KW Unit
Frequency Hz	60.12 Hz	59.91Hz

Table 2 Individual Inverter Transient Response 0 – 30 kW

Test I_a_ii (0KW-60KW step load)



Unit #1 Transient Response



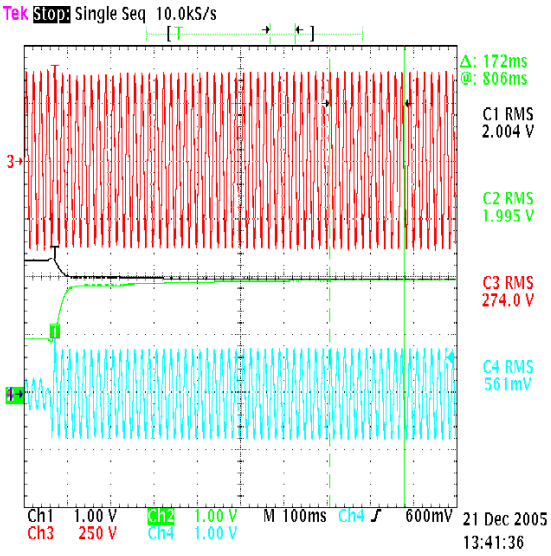
Unit #2 Transient Response

Figure 2 Individual Inverter Transient Response 0 – 60 kW

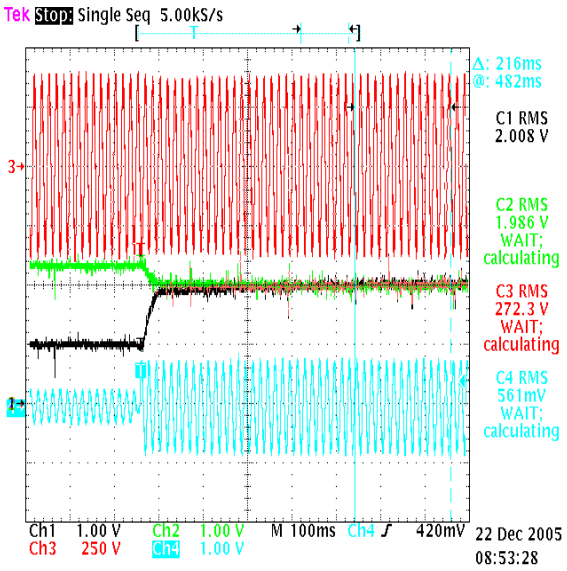
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	60/62.8 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	20.0/0.0 KW Unit	20.0/54.1 KW Unit
Unit #2 (S.P/Pout) KW	20.0/0.0 KW Unit	20.0/59.2 KW Unit
Frequency Hz	60.12 Hz	59.61 Hz

Table 3 Individual Inverter Transient Response 0 – 60 kW

Test I_a_iii (15KW-45KW step load)



Unit #1 Transient Response



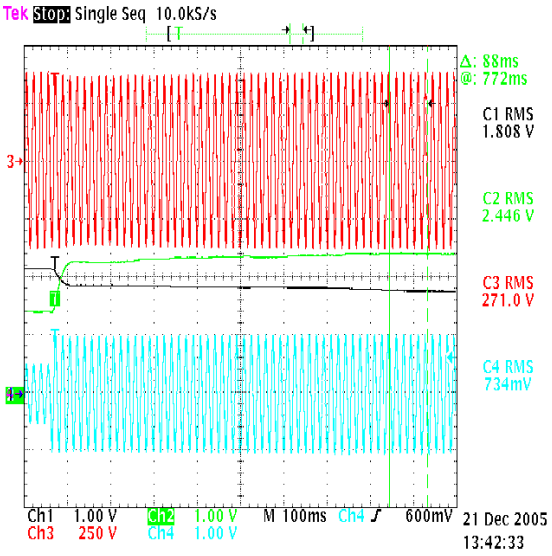
Unit #2 Transient Response

Figure 3 Individual Inverter Transient Response 15 – 45 kW

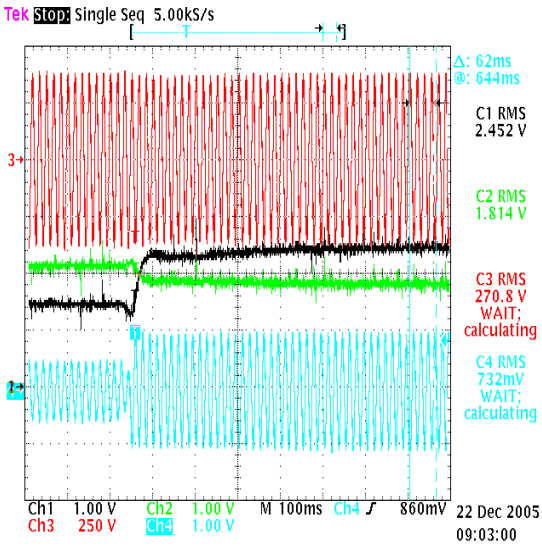
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	15.0/15.5 KW	45.0/47.1 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	20.0/15.5 KW Unit	20.0/46.1 KW Unit
Unit #2 (S.P/Pout) KW	20.0/15.3 KW Unit	20.0/45.8 KW Unit
Frequency Hz	59.99 Hz	59.77Hz

Table 4 Individual Inverter Transient Response 15 – 45 kW

Test I_a_iv (30KW-60KW step load)



Unit #1 Transient Response



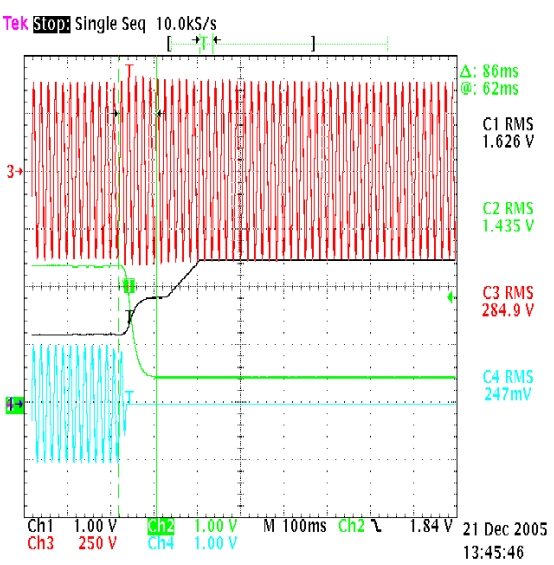
Unit #2 Transient Response

Figure 4 Individual Inverter Transient Response 30 – 60 kW

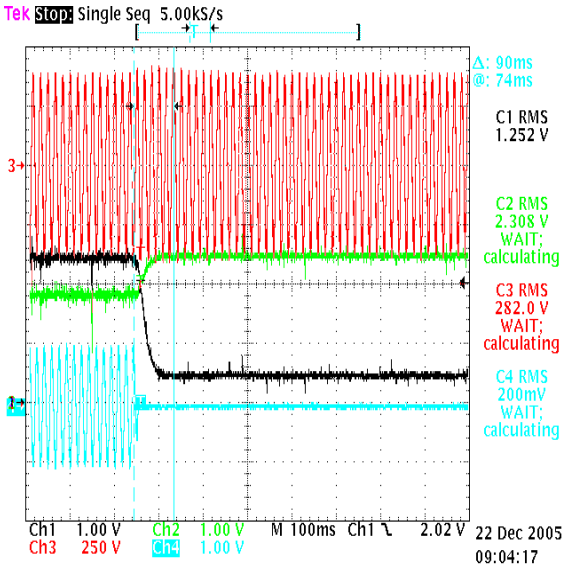
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	30.0/31.4 KW	60.0/62.8 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	20.0/30.7 KW Unit	20.0/59.6 KW Unit
Unit #2 (S.P/Pout) KW	20.0/30.3 KW Unit	20.0/59.4 KW Unit
Frequency Hz	59.92 Hz	59.57 Hz

Table 5 Individual Inverter Transient Response 30 – 60 kW

Test I_a_vi (60KW-0KW step load)



Unit #1 Transient Response



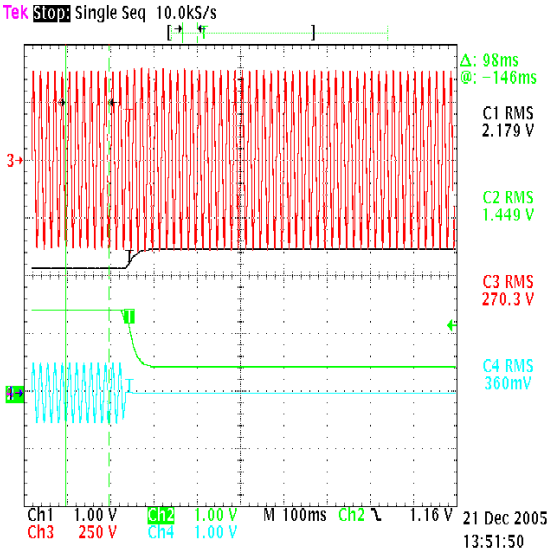
Unit #2 Transient Response

Figure 5 Individual Inverter Transient Response 60 – 0 kW

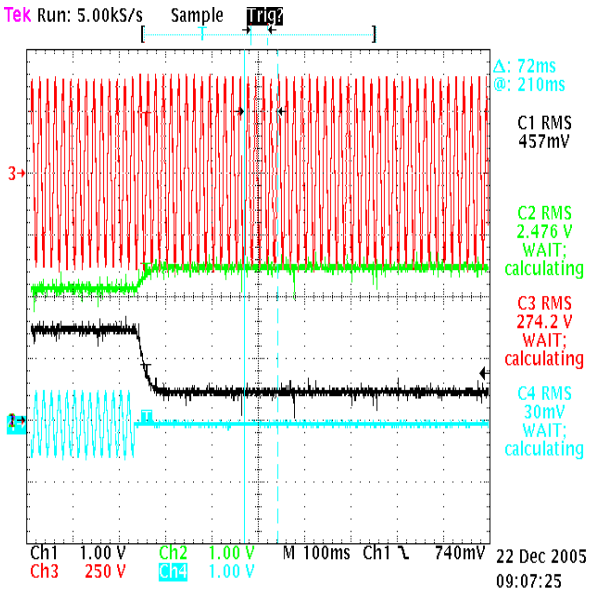
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	60.0/62.8 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	20.0/59.6 KW Unit	20.0/0.0 KW Unit
Unit #2 (S.P/Pout) KW	20.0/59.4 KW Unit	20.0/0.0 KW Unit
Frequency Hz	59.62 Hz	60.12 Hz

Table 6 Individual Inverter Transient Response 60 – 0 kW

Test I_a_vii (30KW-0KW step load)



Unit #1 Transient Response



Unit #2 Transient Response

Figure 6 Individual Inverter Transient Response 30 – 0 kW

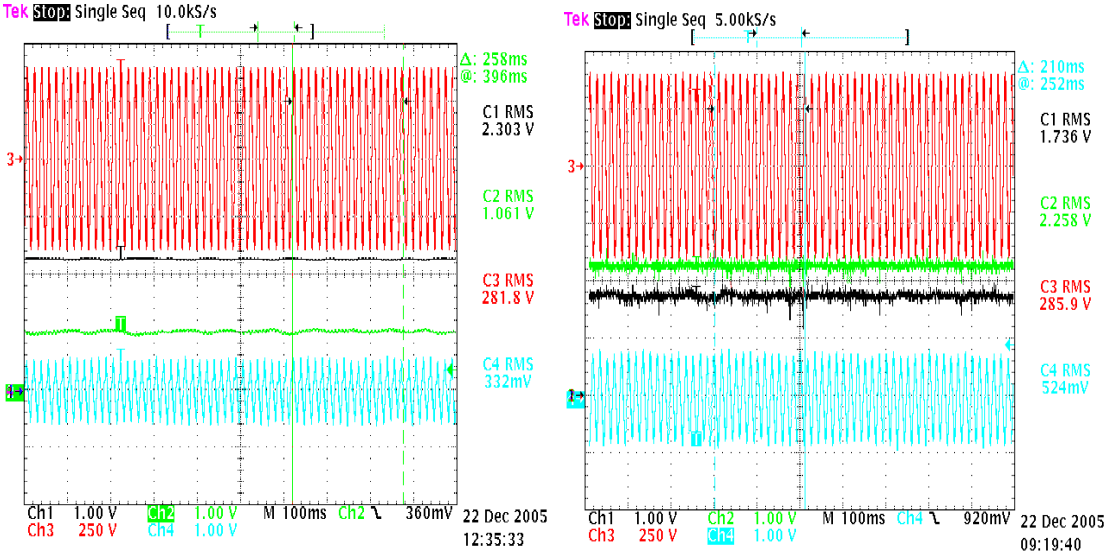
	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	30.0/31.4 KW	30.0/0.0 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	XX KW Feeder or Unit	XX KW Feeder or Unit
Unit #2 (S.P/Pout) KW	XX KW Feeder or Unit	XX KW Feeder or Unit
Frequency Hz	59.91 Hz	60.13 Hz

Table 7 Individual Inverter Transient Response 30 – 0 kW

Phase Two Testing:

Phase two testing consists of two inverters connected in parallel operating in unit power control mode while connected to the grid, transitioning from a grid connection to an island case and while operating in an islanded case. The data provided in this section depicts various changes in the micro grid system including step loads, changes in commanded output power and changes in the state of the gird. For each test case, the initial conditions and the final conditions after the transient event of the micro grid occurred are given.

a. Unit Power Control Mode Grid Connected Evaluation
   i. Step Load Evaluation 1
      1. Load Bank #1 Start Load = 10KW
      2. Load Bank #2 Start Load = 20KW
      3. Unit A CMD = 20KW
      4. Unit B CMD = 40KW
      5. Load Bank #1 End Load = 70KW
      6. Load Bank #2 End Load = 20KW



Unit #1 Transient Response Unit #2 Transient Response

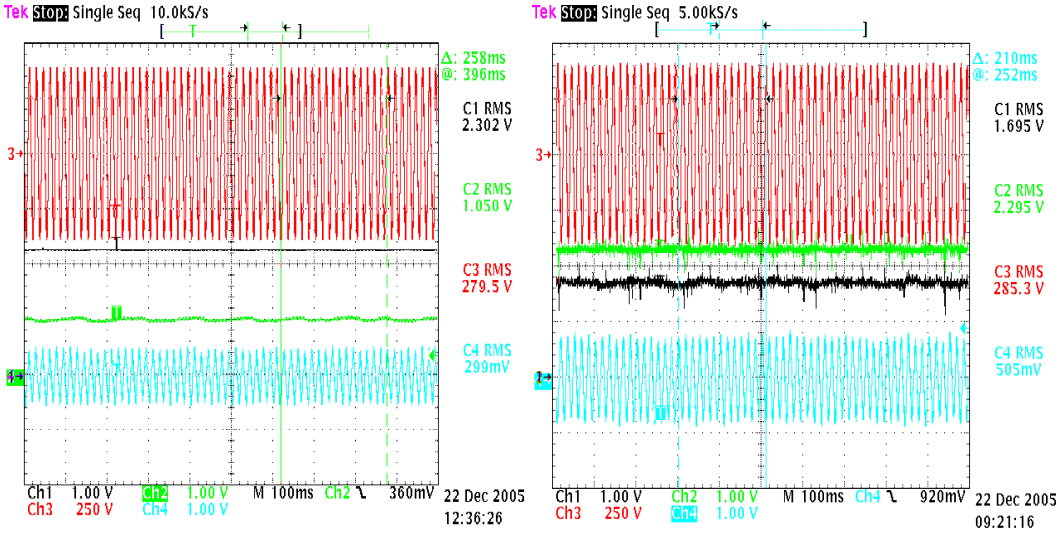
Figure 7 Parallel Inverters –Unit Power Control, Grid Connect–Step Load Evaluation 1

	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	10.0/10.5KW	70.0/73.5 KW
Load Bank #2(S.P/Actual) KW	20.0/21.5 KW	20.0/21.5 KW
Unit #1 (S.P/Pout) KW	20.0/16.8 KW Unit	20.0/16.8 KW Unit
Unit #2 (S.P/Pout) KW	40.0/37.8 KW Unit	40.0/37.8 KW Unit
Frequency Hz	59.97 Hz	59.97 Hz

Table 8 Parallel Inverters –Unit Power Control, Grid Connect–Step Load Evaluation 1

ii. Step Load Evaluation 2

1.Load Bank #1 Start Load = 70KW
2.Load Bank #2 Start Load = 20KW
3.Unit A CMD = 20KW
4.Unit B CMD = 40KW
5.Load Bank #1 End Load = 25KW
6.Load Bank #2 End Load = 20KW



Unit #1 Transient Response Unit #2 Transient Response

Figure 8 Parallel Inverters –Unit Power Control, Grid Connect–Step Load Evaluation 2

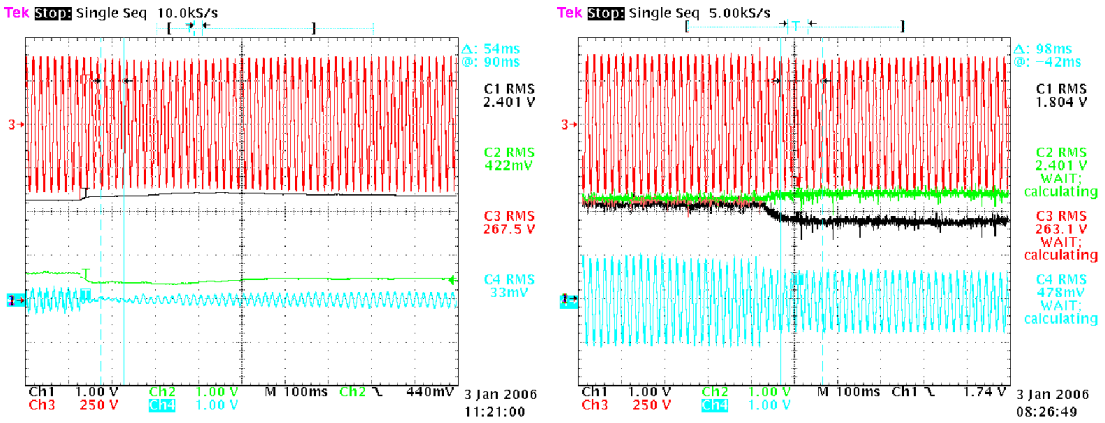
	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	70.0/73.5 KW	25.0/26.1 KW
Load Bank #2(S.P/Actual) KW	20.0/21.5 KW	20.0/21.5 KW
Unit #1 (S.P/Pout) KW	20.0/16.5 KW Unit	20.0/16.5 KW Unit
Unit #2 (S.P/Pout) KW	40.0/36.8 KW Unit	40.0/36.8 KW Unit
Frequency Hz	60.01 Hz	60.01 Hz

Table 9 Parallel Inverters –Unit Power Control, Grid Connect–Step Load Evaluation 2

b.) Unit Power Control Mode Grid Tie to Island Transition Evaluation

i.)Unit Power Limit Evaluation

7. Load Bank #1 Start Load = 20KW
8. Load Bank #2 Start Load = 20KW
9. Unit A Power CMD = 6KW
10. Unit B Power CMD = 54KW
11. Transition to Island
12. Load Bank #1 End Load = 20KW
13. Load Bank #2 End Load = 20KW



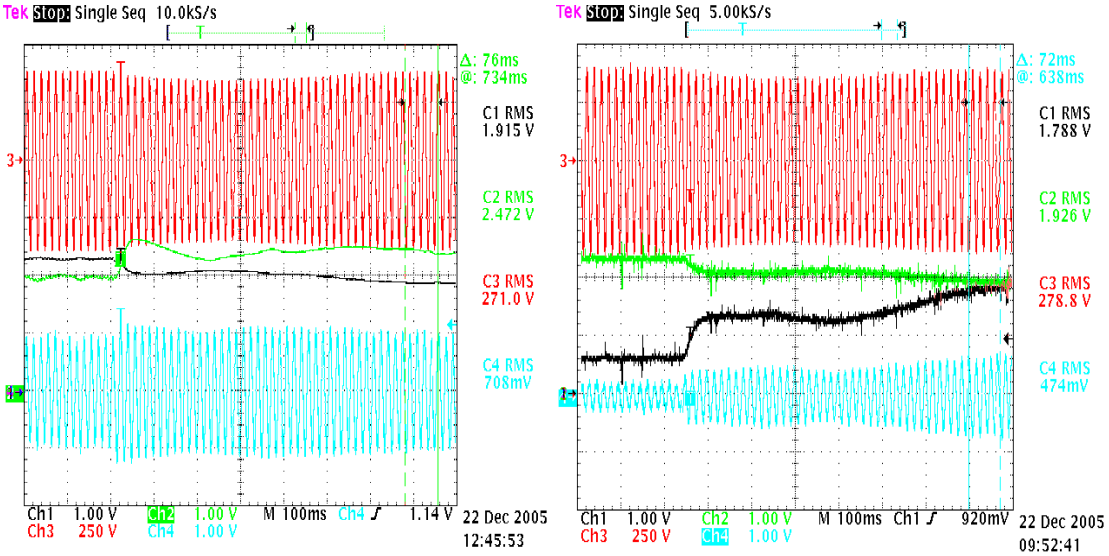
Unit #1 Transient Response Unit #2 Transient Response

Figure 9 Parallel Inverters - Unit Power Control – Grid to Island Transition

	A (Grid)	B (Island)
Load Bank #1(S.P/Actual) KW	20.0/21.5 KW	20.0/21.5 KW
Load Bank #2(S.P/Actual) KW	20.0/21.3 KW	20.0/21.3 KW
Unit #1 (S.P/Pout) KW	6.0/3.0 KW Unit	6.0/~0.0 KW Unit
Unit #2 (S.P/Pout) KW	54.0/51.0 KW Unit	54.0/39.1KW Unit
Frequency Hz	59.92 Hz	60.08 Hz

Table 10 Parallel Inverters - Unit Power Control – Grid to Island Transition

ii. Unit Power Limit Evaluation
14. Load Bank #1 Start Load = 60KW
15. Load Bank #2 Start Load = 40KW
16. Unit A Power CMD = 54KW
17. Unit B Power CMD = 6KW
18. Transition to Island
19. Load Bank #1 End Load = 60KW
20. Load Bank #2 End Load 40KW



Unit #1 Transient Response Unit #2 Transient Response

Figure 10 Parallel Inverters –Unit Power Control – Unit Power Limit Evaluation

	A (Grid)	B (Island)
Load Bank #1(S.P/Actual) KW	60.0/62.8 KW	60.0/62.8 KW
Load Bank #2(S.P/Actual) KW	40.0/42.3 KW	40.0/42.3 KW
Unit #1 (S.P/Pout) KW	54.0/50.0 KW Unit	54.0/60.1 KW Unit
Unit #2 (S.P/Pout) KW	6.0/3.0 KW Unit	6.0/39.0 KW Unit
Frequency Hz	59.99Hz	59.69Hz

Table 11 Parallel Inverters –Unit Power Control – Unit Power Limit Evaluation

c.) Unit Power Control Mode Island Evaluation

i.)Unit Power Limit Evaluation

1.) Load Bank #1 Start Load = 0KW
2.) Load Bank #2 Start Load = 50KW
3.) Unit A Power CMD = 0KW (will reduce frequency)
4.) Unit B Power CMD = 6KW (into energized line)
5.) Load Bank #1 End Load = 0KW
6.) Load Bank #2 End Load = 120KW

Unit 1 closes into an islanded 50KW load, Unit 2 is off

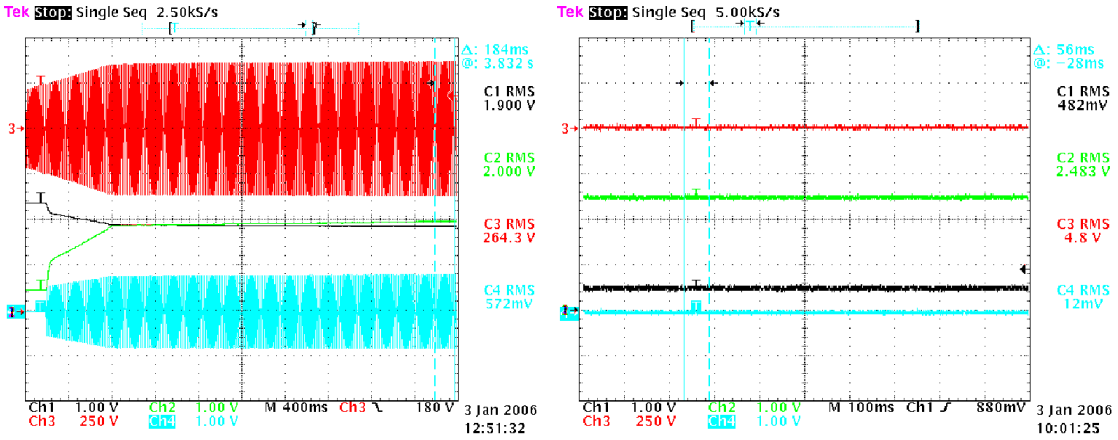
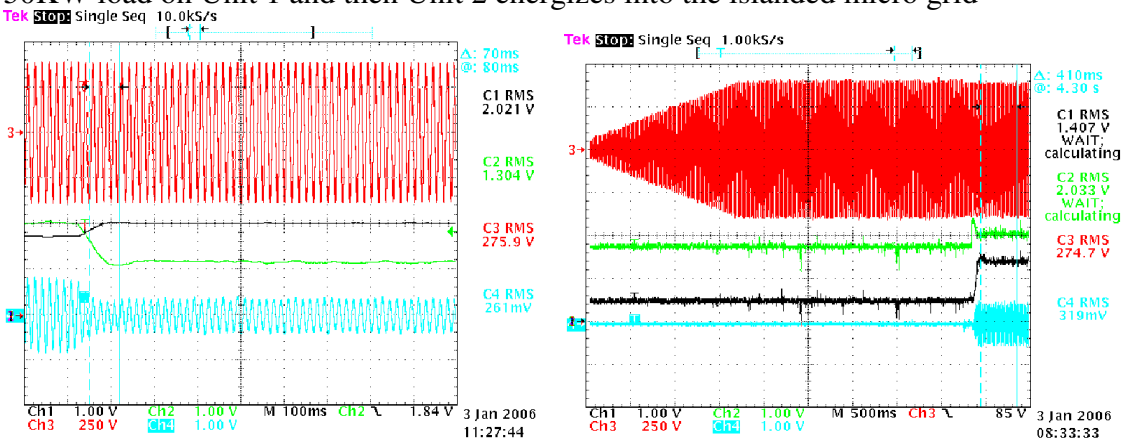


Figure 11 Parallel Inverters –Power Control, Island – Unit Power Limit Evaluation 1 (Step 1)

	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	50.0/51.6 KW	50.0/51.6 KW
Unit #1 (S.P/Pout) KW	6.0/0.0 KW Unit	6.0/49.5 KW Unit
Unit #2 (S.P/Pout) KW	NA	NA
Frequency Hz	60.12Hz	59.68 Hz

Table 12 Parallel Inverters – Power Control, Island – Unit Power Limit Evaluation 1 (Step 1)

50KW load on Unit 1 and then Unit 2 energizes into the islanded micro grid



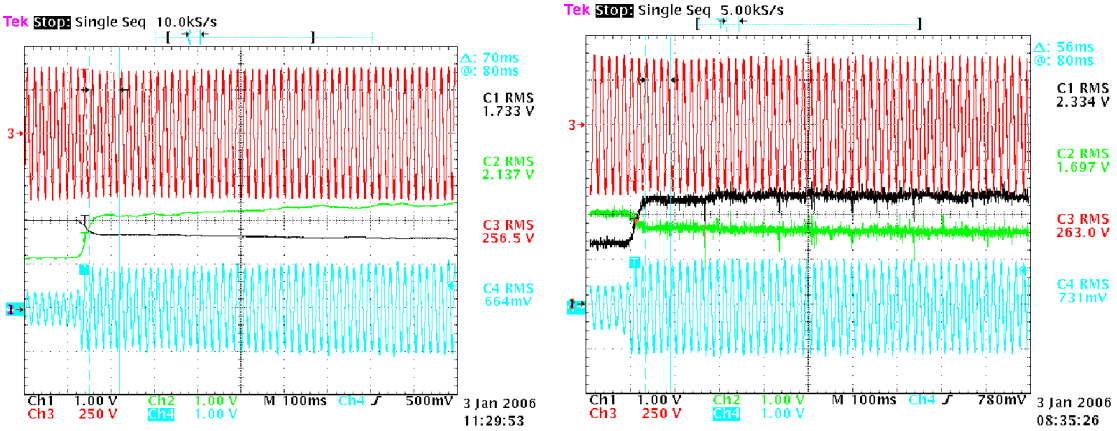
Unit #1 Transient Response Unit #2 Transient Response

Figure 12 Parallel Inverters – Power Control, Island– Unit Power Limit Evaluation 1 (Step 2)

	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	50.0/51.6 KW	50.0/51.6 KW
Unit #1 (S.P/Pout) KW	0.0/49.1 KW Unit	0.0/21.8 KW Unit
Unit #2 (S.P/Pout) KW	6.0/0.0 KW Unit	6.0/26.2KW Unit
Frequency Hz	59.61 Hz	59.79 Hz

Table 13 Parallel Inverters – Power Control, Island – Unit Power Limit Evaluation 1 (Step 2)

Load change from 50Kw to 120KW



Unit #1 Transient Response Unit #2 Transient Response

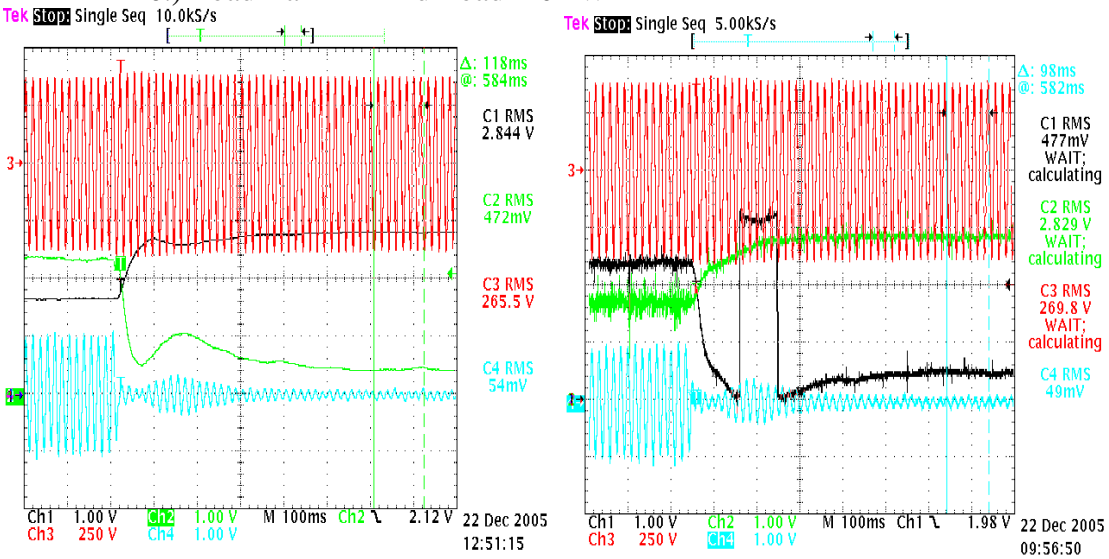
Figure 13 Parallel Inverters –Power Control, Island – Unit Power Limit Evaluation 1 (Step 3)

	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	50.0/51.6 KW	50.0/125.6 KW
Unit #1 (S.P/Pout) KW	0.0/21.8 KW Unit	0.0/58.6 KW Unit
Unit #2 (S.P/Pout) KW	6.0/26.2 KW Unit	6.0/57.9 KW Unit
Frequency Hz	59.79 Hz	59.45Hz

Table 14 Parallel Inverters – Power Control, Island – Unit Power Limit Evaluation 1 (Step 3)

ii.) Unit Power Limit Evaluation

1.) Load Bank #1 Start Load = 120KW
2.) Load Bank #2 Start Load = 0KW
3.) Unit A Power CMD = 54KW
4.) Unit B Power CMD = 6KW
5.) Load Bank #1 End Load = 0KW
6.) Load Bank #2 End Load = 0KW



Unit #1 Transient Response Unit #2 Transient Response

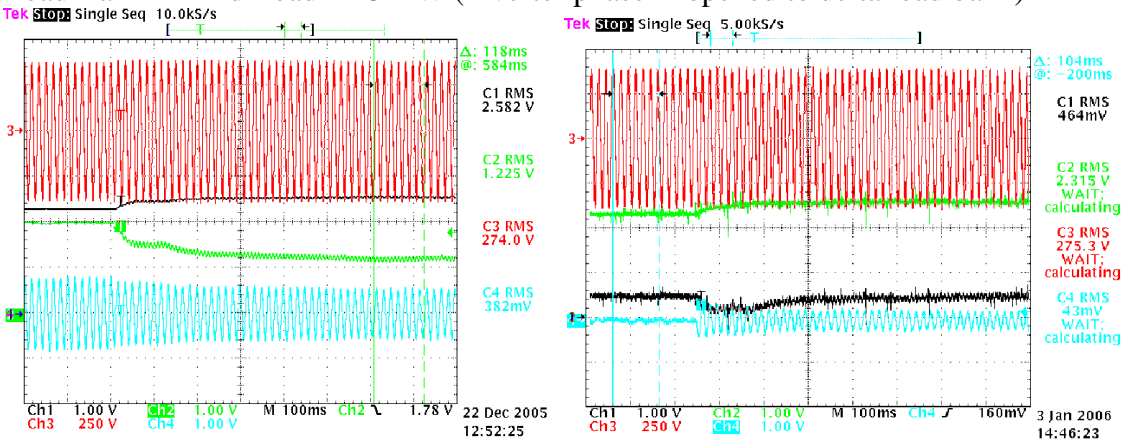
Figure 14 Parallel Inverters – Power Control, Island – Unit Power Limit Evaluation 2

	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	120.0/124.6 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Unit #1 (S.P/Pout) KW	54.0/58.2 KW Unit	54.0/0.0 KW Unit
Unit #2 (S.P/Pout) KW	6.0/57.4 KW Unit	6.0/0.0 KW Unit
Frequency Hz	59.45 Hz	60.42 Hz

Table 15 Parallel Inverters – Power Control, Island – Unit Power Limit Evaluation 2

iii.Unbalanced Load

1.Load Bank #1 Start Load = 0KW
2.Load Bank #2 Start Load = 50KW
3.Unit A Power CMD = 54KW
4.Unit B Power CMD = 6KW
5.Load Bank #1 End Load = 0KW
6.Load Bank #2 End Load = 25 KW (Inverter phase A opened to delta load bank)



Unit #1 Transient Response Unit #2 Transient Response

Figure 15 Parallel Inverters – Power Control, Island – Unbalanced Load

	A (Island)	B (Island)
Load Bank #1(S.P/Actual) KW	0.0/0.0 KW	0.0/0.0 KW
Load Bank #2(S.P/Actual) KW	50.0/51.9 KW	33.3/34.6KW
Unit #1 (S.P/Pout) KW	54.0/45.6 KW Unit	54.0/23.0 KW Unit
Unit #2 (S.P/Pout) KW	6.0/0.0 KW Unit	6.0/3.0 KW Unit
Frequency Hz	60.01 Hz	60.22 Hz

Table 16 Parallel Inverters – Power Control, Island – Unbalanced Load

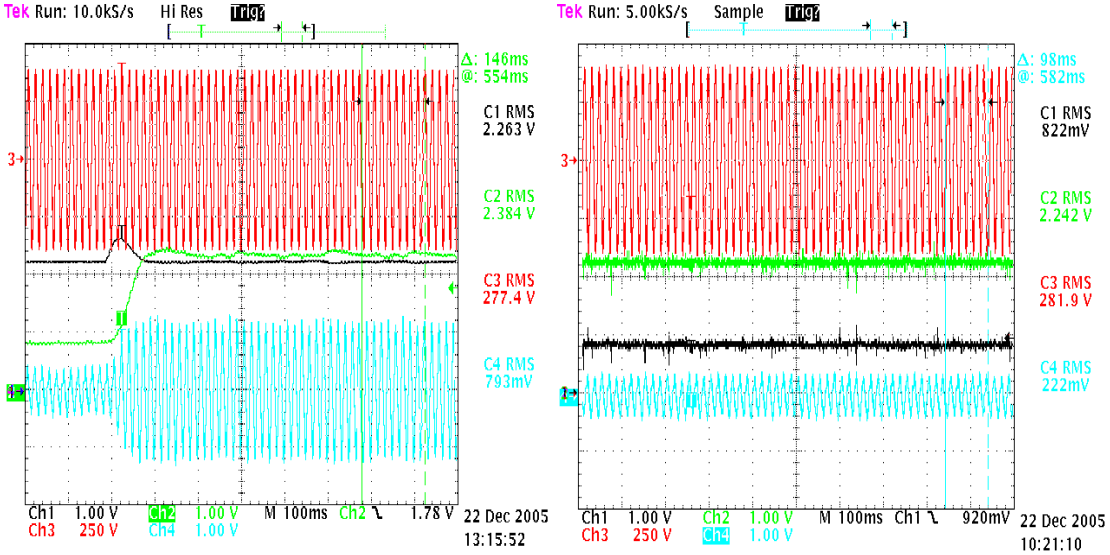
Phase Three Testing:

Phase three testing consists of two inverters connected in parallel operating with unit one operating in power control mode and unit two operating in unit flow control while connected to the grid, transitioning from a grid connection to an island case and while operating in an islanded case. The data provided in this section depicts various changes in the micro grid system including step loads, changes in commanded output power and changes in the state of the gird. For each test case, the initial conditions and the final conditions after the transient event of the micro grid occurred are given.

a. Grid Tie Feeder Control Mode Evaluation

i. Step Load Evaluation 1

1. Load Bank #1 Start Load = 35KW
2. Load Bank #2 Start Load = 35KW
3. Unit A Feeder CMD = 54KW
4. Unit B Power CMD = 6KW
5. Load Bank #1 End Load = 85KW
6. Load Bank #2 End Load = 35KW



Unit #1 Transient Response

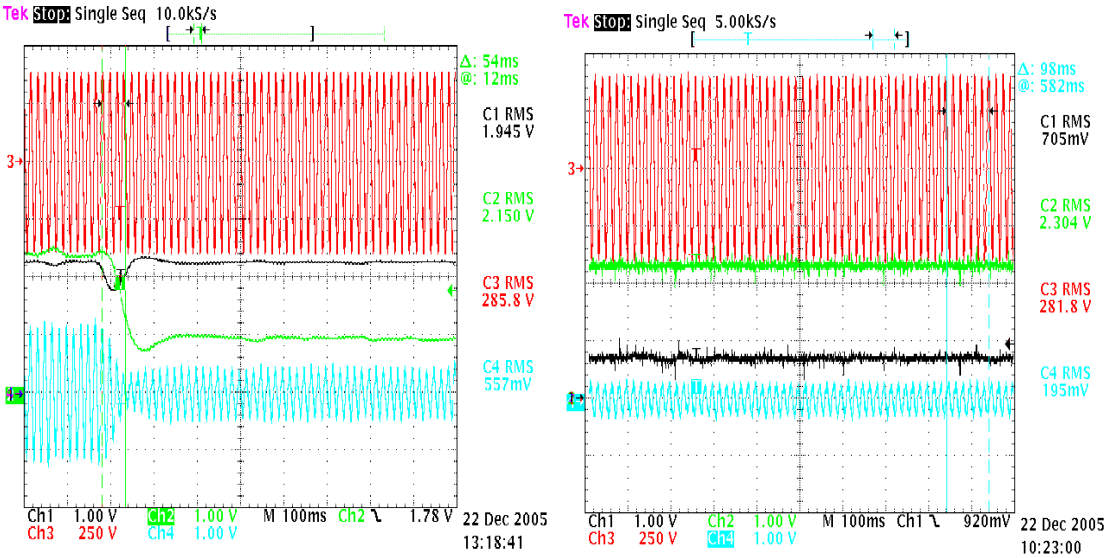
Unit #2 Transient Response

Figure 16 Parallel Inverters – Feeder Control, Grid Tie – Step Load Evaluation 1

	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	35.0/37.2 KW	85.0/88.1 KW
Load Bank #2(S.P/Actual) KW	35.0/36.9 KW	35.0/36.9 KW
Unit #1 (S.P/Pout) KW	54.0/8.2 KW Feeder	54.0/56.8 KW Feeder
Unit #2 (S.P/Pout) KW	6.0/7.2 KW Unit	6.0/7.2 KW Unit
Frequency Hz	59.97 Hz	59.96Hz

Table 17 Parallel Inverters – Feeder Control, Grid Tie – Step Load Evaluation 1

ii.) Step Load Evaluation 2
1.) Load Bank #1 Start Load = 85KW
2.) Load Bank #2 Start Load = 35KW
3.) Unit A Feeder CMD = 40KW
4.) Unit B Power CMD = 6KW
5.) Load Bank #1 End Load = 25KW
6.) Load Bank #2 End Load = 35KW



Unit #1 Transient Response Unit #2 Transient Response

Figure 17 Parallel Inverters – Feeder Control, Grid Tie – Step Load Evaluation 2

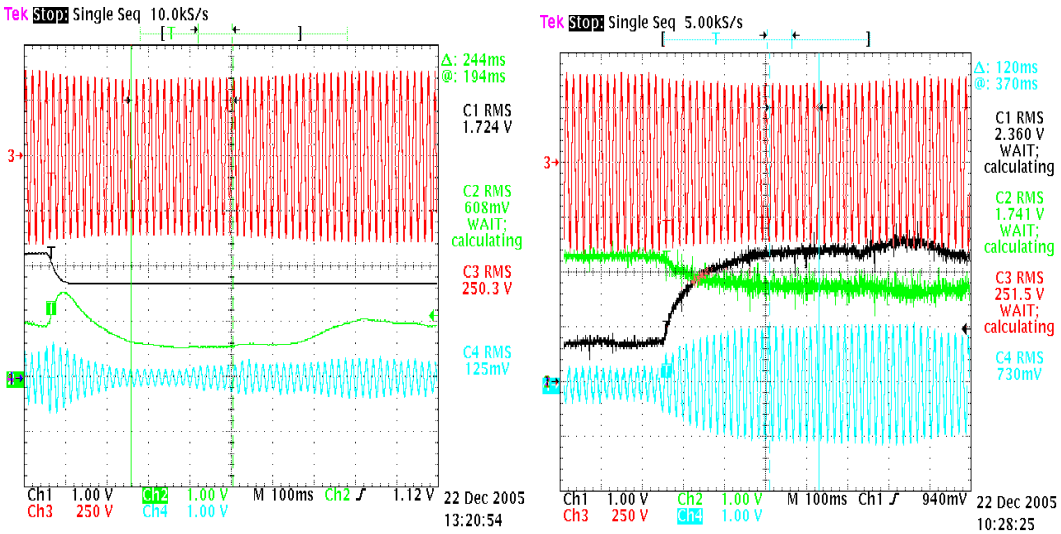
	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	85.0/88.1 KW	35.0/37.2 KW
Load Bank #2(S.P/Actual) KW	35.0/36.9 KW	25.0/38.1 KW
Unit #1 (S.P/Pout) KW	40.0/61.1 KW Feeder	40.0/14.0 KW Feeder
Unit #2 (S.P/Pout) KW	6.0/ KW Unit	6.0/6.5 KW Unit
Frequency Hz	59.7 Hz	59.8 Hz

Table 18 Parallel Inverters – Feeder Control, Grid Tie – Step Load Evaluation 2

b. Feeder Control Mode to Island Transition Evaluation

i. Unit Power Limit Evaluation

1. Load Bank #1 Start Load = 35KW
2. Load Bank #2 Start Load = 35KW
3. Unit A Feeder CMD = 50KW
4. Unit B Power CMD = 6KW
5. Transition to island
6. Load Bank #1 End Load = 35KW
7. Load Bank #2 End Load = 35KW



Unit #1 Transient Response Unit #2 Transient Response

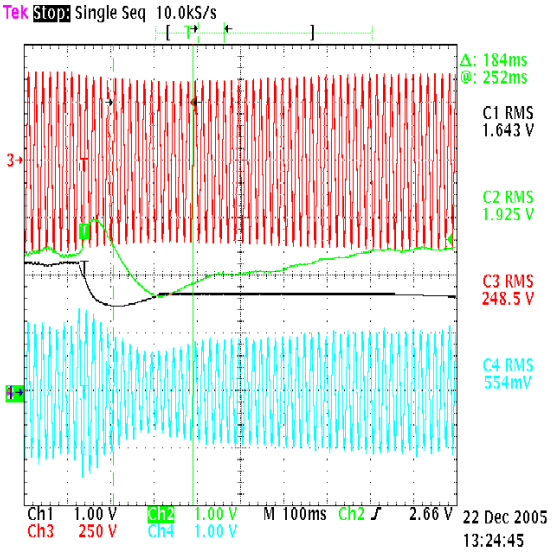
Figure 18 Parallel Inverters – Feeder Control, Island Transition – Unit Power Limit Evaluation 1

	A (Grid)	B (Island)
Load Bank #1(S.P/Actual) KW	35.0/37.2 KW	35.0/37.2KW
Load Bank #2(S.P/Actual) KW	35.0/36.9 KW	35.0/36.9 KW
Unit #1 (S.P/Pout) KW	50.0/9.0 KW Feeder	50.0/10.0 KW Feeder
Unit #2 (S.P/Pout) KW	6.0/ KW Unit	6.0/51.0 KW Unit
Frequency Hz	59.92 Hz	59.54 Hz

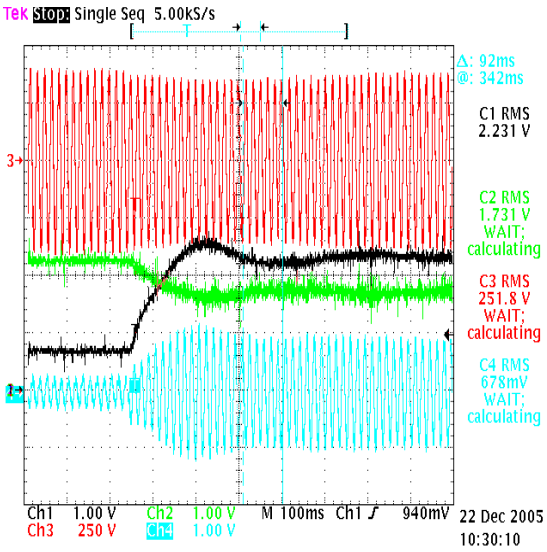
Table 19 Parallel Inverters – Feeder Control, Island Transition – Unit Power Limit Evaluation 1

ii. Unit Power Limit Evaluation

1. Load Bank #1 Start Load = 70KW
2. Load Bank #2 Start Load = 50KW
3. Unit A Feeder CMD = 54KW
4. Unit B Power CMD = 6KW
5. Transition to island
6. Load Bank #1 End Load = 70KW
7. Load Bank #2 End Load = 50KW



Unit #1 Transient Response



Unit #2 Transient Response

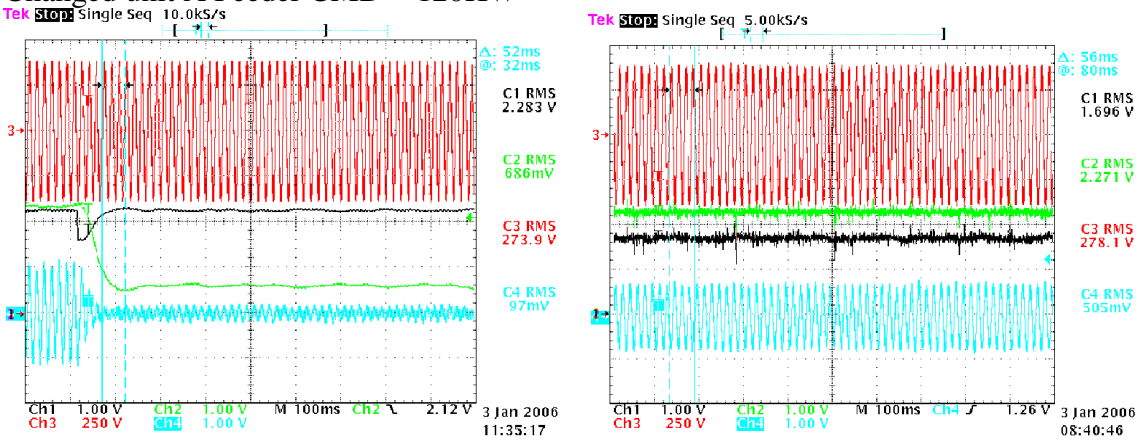
Figure 19 Parallel Inverters – Feeder Control, Island Transition – Unit Power Limit Evaluation 2

	A (Grid)	B (Island)
Load Bank #1(S.P/Actual) KW	70.0/73.5 KW	70.0/73.5 KW
Load Bank #2(S.P/Actual) KW	50.0/51.9KW	50.0/51.9KW
Unit #1 (S.P/Pout) KW	54.0/61.2 KW Feeder	54.0/61.2 KW Feeder
Unit #2 (S.P/Pout) KW	6.0/5.5 KW Unit	6.0/60.9 KW Unit
Frequency Hz	59.92 Hz	59.53 Hz

Table 20 Parallel Inverters – Feeder Control, Island Transition – Unit Power Limit Evaluation 2

c. Feeder Control; grid connected
i. Feeder control to check digital round-off.
1. Load Bank #1 Start Load = 80KW
2. Load Bank #2 Start Load = 80KW
3. Unit A Feeder CMD = 60KW
4. Unit B Power CMD = 40KW
5. Change unit A Feeder CMD = 120KW
6. Change unit B Power CMD = 10KW
7. Change unit A Feeder CMD = 150KW
8. Load Bank #1 End Load = 80KW
9. Load Bank #2 End Load = 80KW

Changed unit A Feeder CMD = 120KW



Unit #1 Transient Response

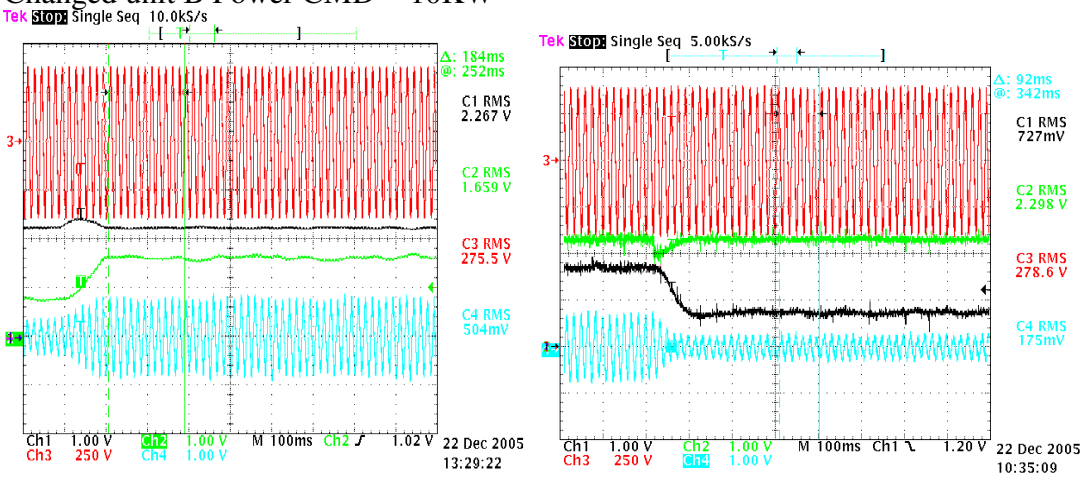
Unit #2 Transient Response

Figure 20 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 1

	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	80.0/83.9 KW	80.0/83.9 KW
Load Bank #2(S.P/Actual) KW	80.0/84.3 KW	80.0/84.3 KW
Unit #1 (S.P/Pout) KW	60/57.5 KW Feeder	120.0/2.2 KW Feeder
Unit #2 (S.P/Pout) KW	40/37.5 KW Unit	40/37.5 KW Unit
Frequency Hz	59.97Hz	59.97 Hz

Table 21 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 1

Changed unit B Power CMD = 10KW



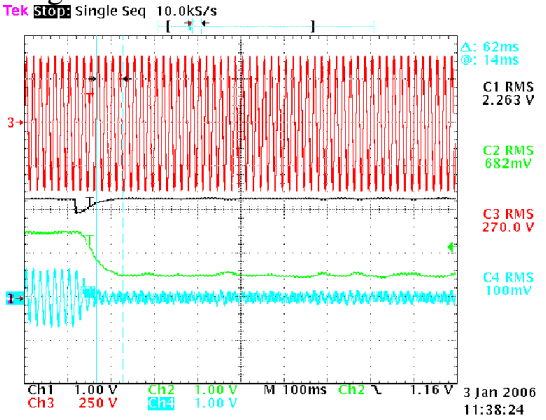
Unit #1 Transient Response Unit #2 Transient Response

Figure 21 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 2

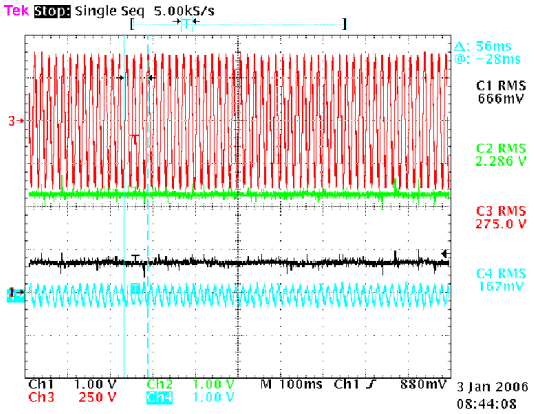
	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	80.0/83.9 KW	80.0/83.9 KW
Load Bank #2(S.P/Actual) KW	80.0/84.3 KW	80.0/84.3 KW
Unit #1 (S.P/Pout) KW	120/2.2 KW Feeder	120.0/34.6 KW Feeder
Unit #2 (S.P/Pout) KW	40/37.5 KW Unit	10/8.3KW Unit
Frequency Hz	59.97Hz	59.99 Hz

Table 22 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 2

Changed unit A Feeder CMD = 150KW



Unit #1.) Transient Response



Unit #2.) Transient Response

Figure 22 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 3

	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	80.0/83.9 KW	80.0/83.9 KW
Load Bank #2(S.P/Actual) KW	80.0/84.3 KW	80.0/84.3 KW
Unit #1 (S.P/Pout) KW	120/34.6 KW Feeder	150.0/0.5 KW Feeder
Unit #2 (S.P/Pout) KW	10.0/5.5 KW Unit	10.0/5.5 KW Unit
Frequency Hz	59.98Hz	59.99 Hz

Table 23 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 3

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Tecogen 60kW Inverter-Based CHP Modules Factory Testing

APPENDIX D

Prepared For:
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Public Interest Energy Research Program

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CERTS
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TECOGEN 60 kW
Inverter-Based CHP Modules

CERTS Microgrid Test Bed Project

Tecogen Factory Testing
Unit Serial #200835

3/15/06

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Introduction

This report presents the factory test data of the first Tecogen CHP unit (Serial # 200835), equipped with a customized inverter (by Youtility) that is configured with the CERTS microgrid control algorithm. Figure 1 presents a one-line diagram of the test set-up. The unit generates power in a stand-alone mode (no grid-tie) and is connected to a load bank. The output of the inverter is connected to the Delta side of a transformer in a 3-wire configuration. The output of the transformer is wired to the load bank in a 4-wire configuration with a 25-yard loop.

The inverter is also equipped with a Surge Module wired directly to the DC Bus. The Surge Module is a battery powered energy storage device with a rating of 20 kW for 3 seconds. Its purpose is to assist the engine/inverter's response to step loads. It is housed separately in an adjacent cabinet (DC power wiring length:12.5 feet).

All testing was done with the inverters set to Power Control Mode.

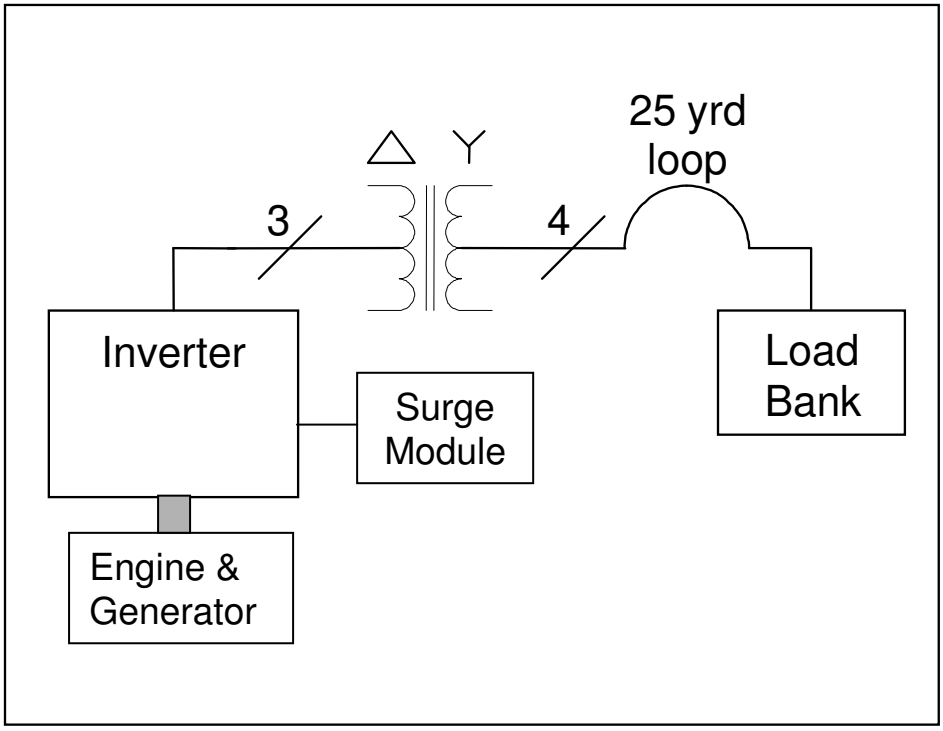


Figure 1 Factory Test One-line Diagram

B.2. Step Load Evaluations with Surge Module – Variable Speed Operation

The following step loads were tested:

	Test Plan	Actual Test Point	Comments
i.	0-30 kW	0 – 30 kW	
ii.	0 – 60 kW	0 – 50 kW	Engine stalls at a step load of 0 – 55 kW in this variable speed mode. A 0 – 60 kW step load can be achieved at fixed speed (see section B.3). Minimum engine speed will be raised in testing of Unit #2 to 1560 rpm (52 Hz) in order to achieve 0 – 60 kW in variable speed mode with the surge module.
iii.	15 – 45 kW	15 – 50 kW	A 15 – 50 increment was easier to implement with the load bank.
iv.	30 – 60 kW	30 – 55 kW	As was done in Phase 1 at Youtility, 55 kW was done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
v.	60 – 0 kW	60 – 0 kW	
vi.	30 – 0 kW	30 – 0 kW	

Table 1: Test Point Summary – Step Loads with Surge Module/Variable Speed

For each step load point, an oscilloscope trace was captured that measured the power output, frequency, voltage, and current. These measurements were taken on the microgrid side (Y side) of the transformer. In each plot the data is formatted in the following way:

Ch1 = Unit RMS Power Output;
0.0V = -15KW
0.5V = 0KW
1.5V = 30KW
2.5V = 60KW

Ch2 = Unit Operating Frequency;
60Hz --> 2.3V
59.5Hz --> 1.66V
60.5Hz --> 2.94V

Ch 3 – The graphical trace is Grid Voltage L-N, nominal 277 Volts. The displayed value on right hand side is the measured frequency after the step load.

Channel 4

Ch4 = Unit Output Current; 1V = 100Amps

Also, the Step "Up" load points (i-iv.) were run two separate times so that additional data on the system dynamics, with the surge module, could be captured. This oscillocope data is formatted as follows:

Channel 1 = Engine RPM;
120 Hz (3600 rpm) per 3.3 volts
1 volt per division
Zero point is at black "1" marker on left-hand side of Figure
Nominal Minimum Speed = 50 Hz (1500 rpm)

Channel 2 = Bus Voltage
Zero point is actually 500 volts and measures from black "l" marker on left-hand side of Figure
100 volts per division
Nominal Voltage; 860 volts

Channel 3 = AC Current ; 1 V = 100 amps

Channel 4 = Surge Module Current
10 mV = 20 amps
10 mV per division
Nominal Current; 26 amps

The results of each test is organized in a table that defines the load setpoint (abbreviated S.P) and the actual power output from the unit. The table also contains the microgrid operating frequency before and after the transient event occurs (These frequency values are obtained from the units software and not the oscilloscope measurement). Data contained in column A defines the operating condition and the state of the microgrid before the transient condition being tested occurs. Data contained in column B defines the operating condition and the state of the microgrid after the transient condition being tested has occurred.

i. Step Load Evaluation 1

1.Load Bank Start Load = 0 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load = 30 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/30.45 kW
Frequency Hz	60.16 Hz	59.91 Hz

Table 2 Step Load Evaluation 1: 0 – 30 kW (w/Surge Module)

0 – 30 KW Step Load –Surge Module- Variable Speed

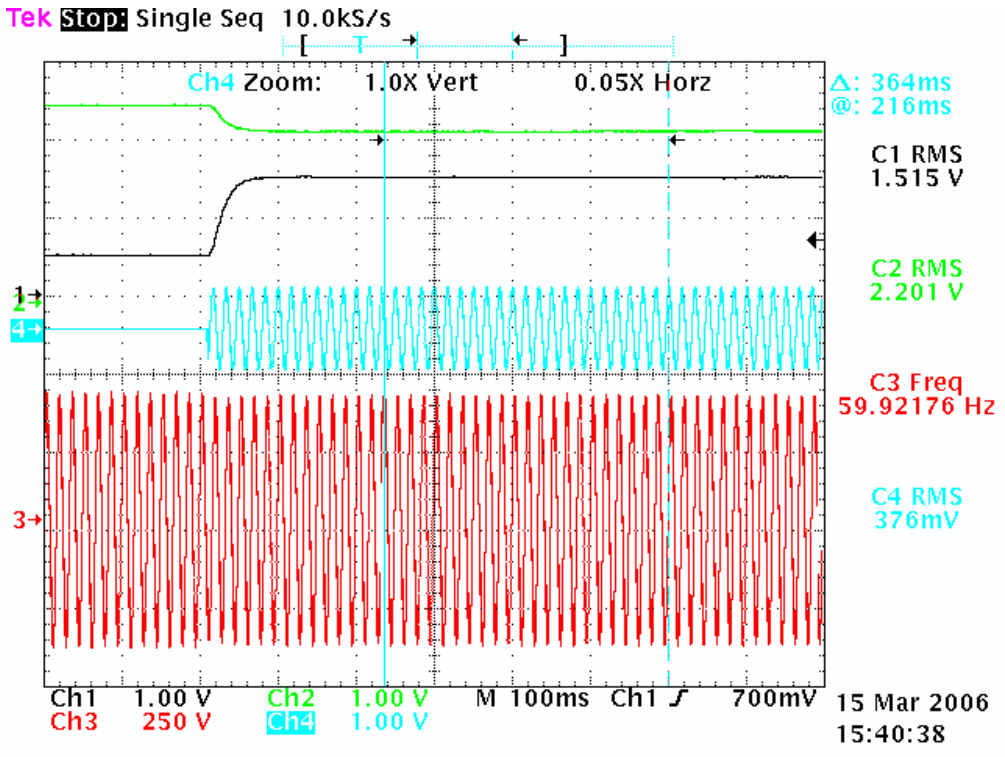


Figure 2 0 –30 kW: Power, Frequency, Voltage, Current

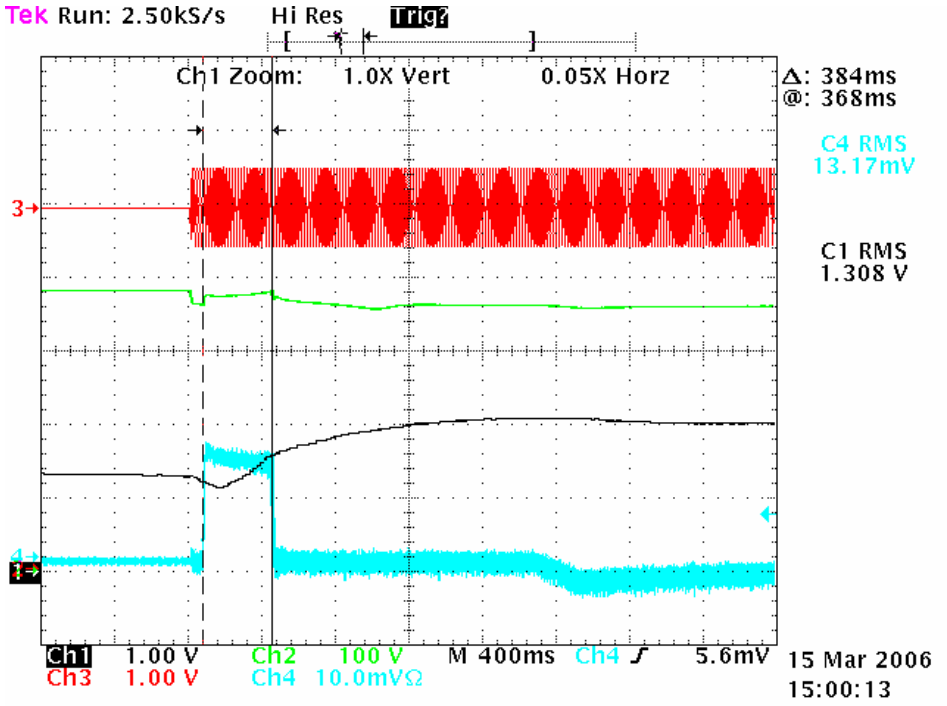


Figure 3 0 – 30 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

ii. Step Load Evaluation 2

1. Load Bank Start Load = 0KW
2. Unit A CMD = 20KW
3. Load Bank End Load =60KW (Engine Stalled)
   Load Bank End Load = 55 kW (Engine Stalled)
   Load Bank End Load = 50 kW (Okay)

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/50.97 kW
Frequency Hz	60.16 Hz	59.75 Hz

Table 3 Step Load Evaluation 2: 0 – 60 kW (w/Surge Module)

O – 50 kW Step Load –Surge Module- Variable Speed

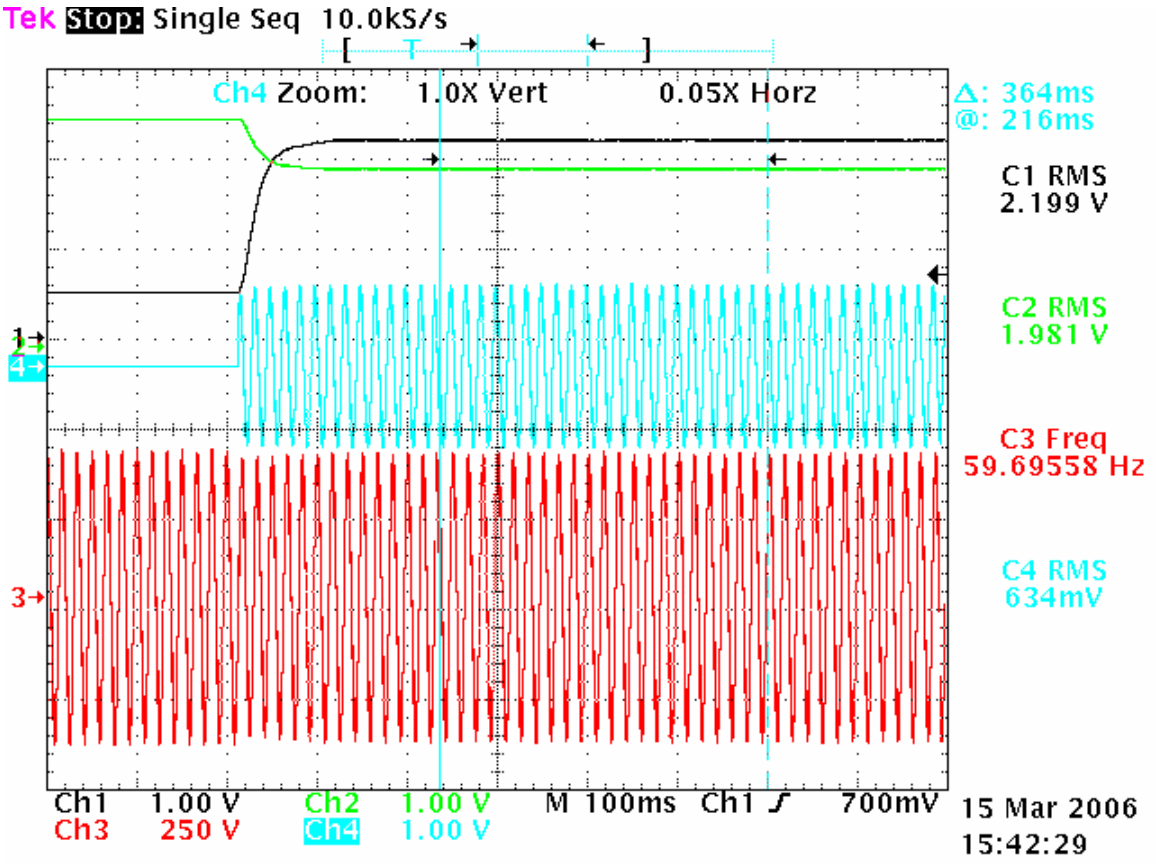


Figure 4 0 –50 kW: Power, Frequency, Voltage, Current

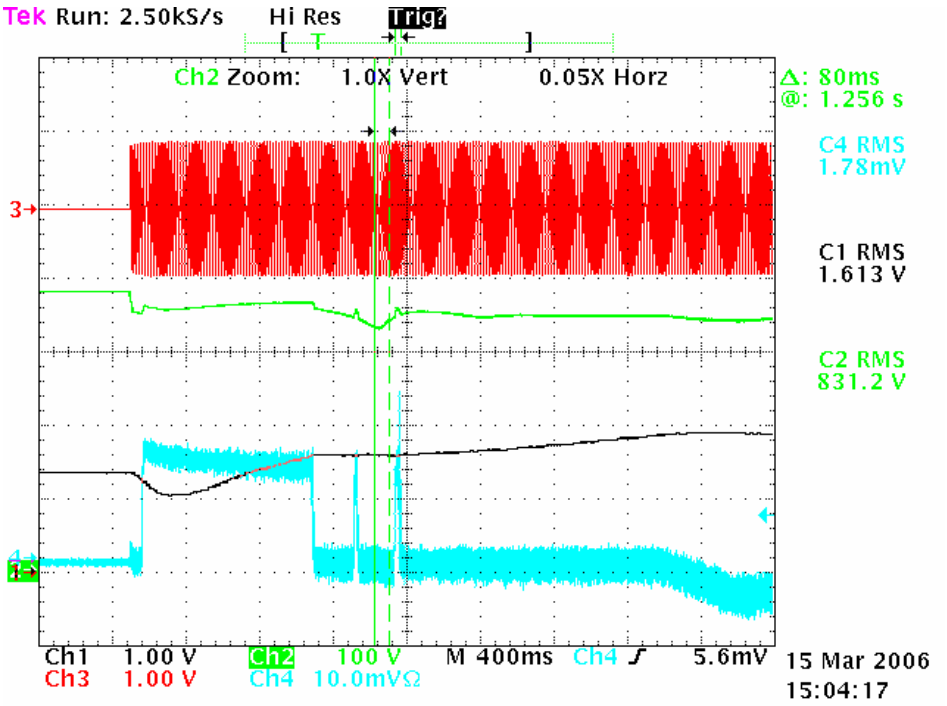
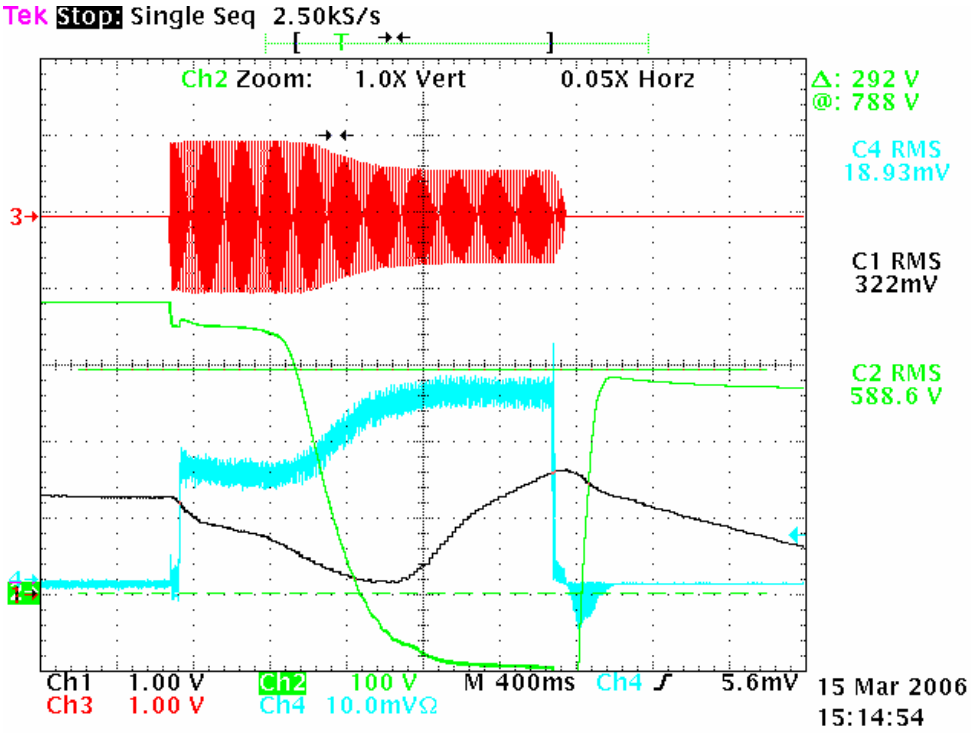


Figure 5 0 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

0 – 55 KW Step Load –Surge Module- Variable Speed



Engine Stalled

Figure 6 0 – 55 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

iii. Step Load Evaluation 3

1.Load Bank Start Load = 15 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =50 kW (Changed from 45 kW because easier to implement on Load Bank)

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/49.86 kW
Frequency Hz	60.16 Hz	59.75 Hz

Table 4 Step Load Evaluation 3: 15 – 50 kW (w/Surge Module)

15 – 50 KW Step Load –Surge Module- Variable Speed

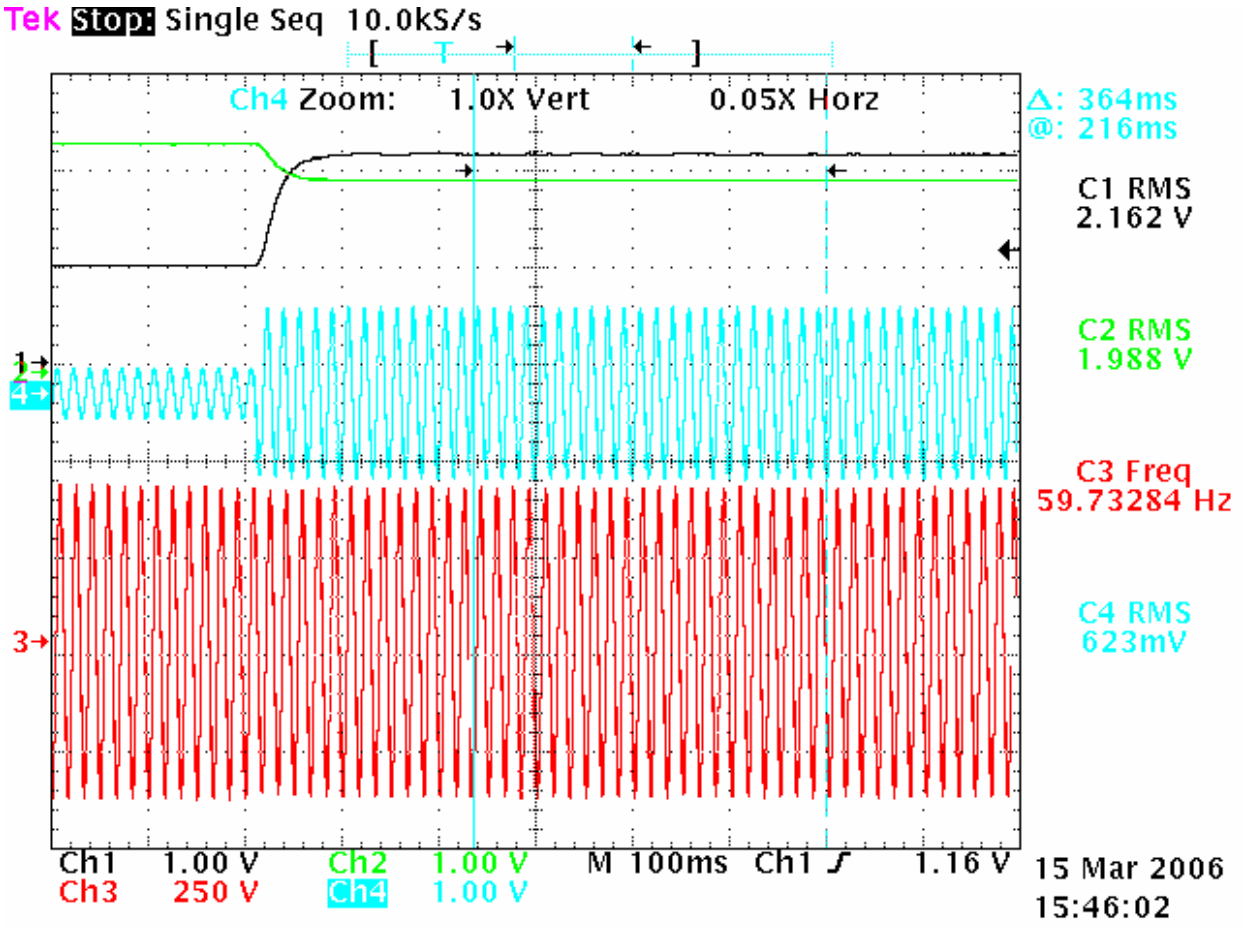


Figure 7 15 – 50 kW: Power, Frequency, Voltage, Current

15 – 50 KW Step Load –Surge Module- Variable Speed

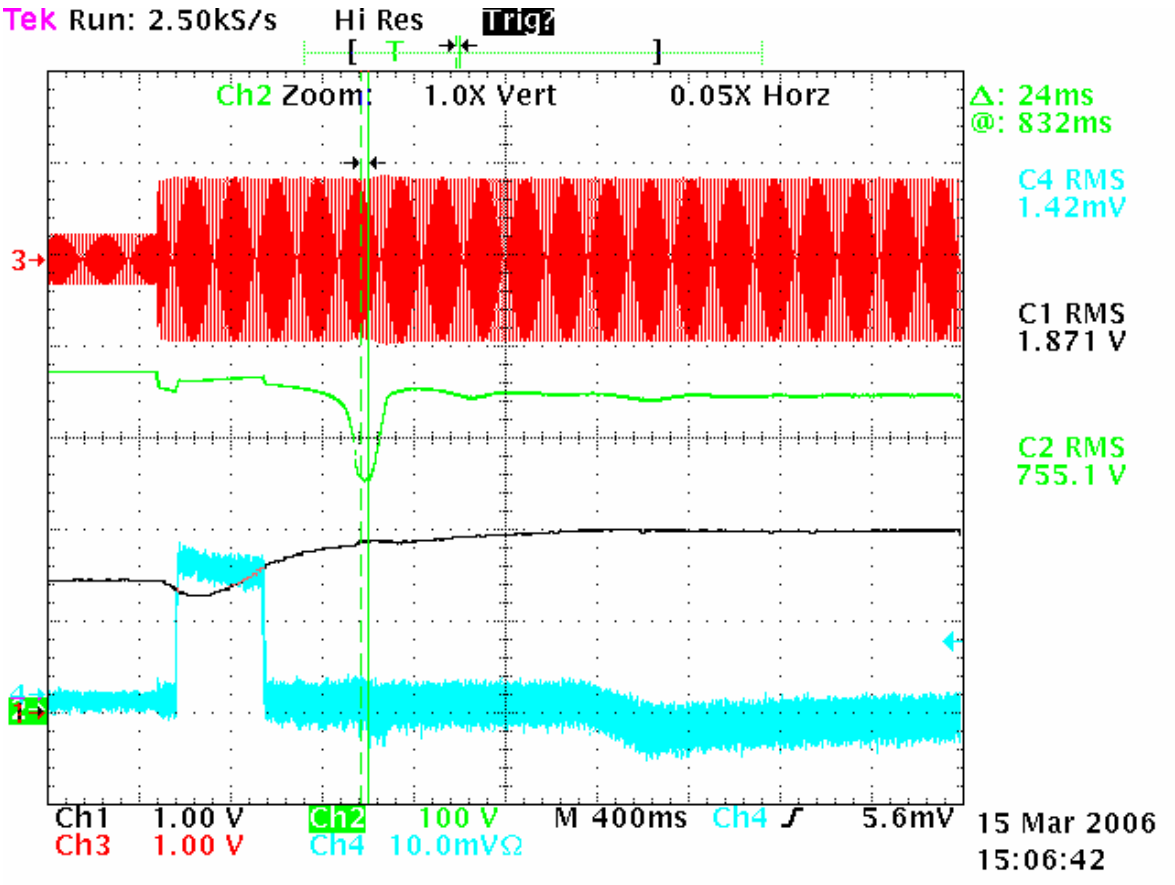


Figure 8 15 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

iv. Step Load Evaluation 4

1.Load Bank Start Load = 30 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load = 55 kW

	A	B
Unit #1 (S.P/Actual) KW	20.0/0.0 kW	20.0/55.5 kW
Frequency Hz	60.16 Hz	59.70 Hz

Table 5 Step Load Evaluation 4: (30 – 55 kW) (w/Surge Module)

30– 55 KW Step Load –Surge Module- Variable Speed

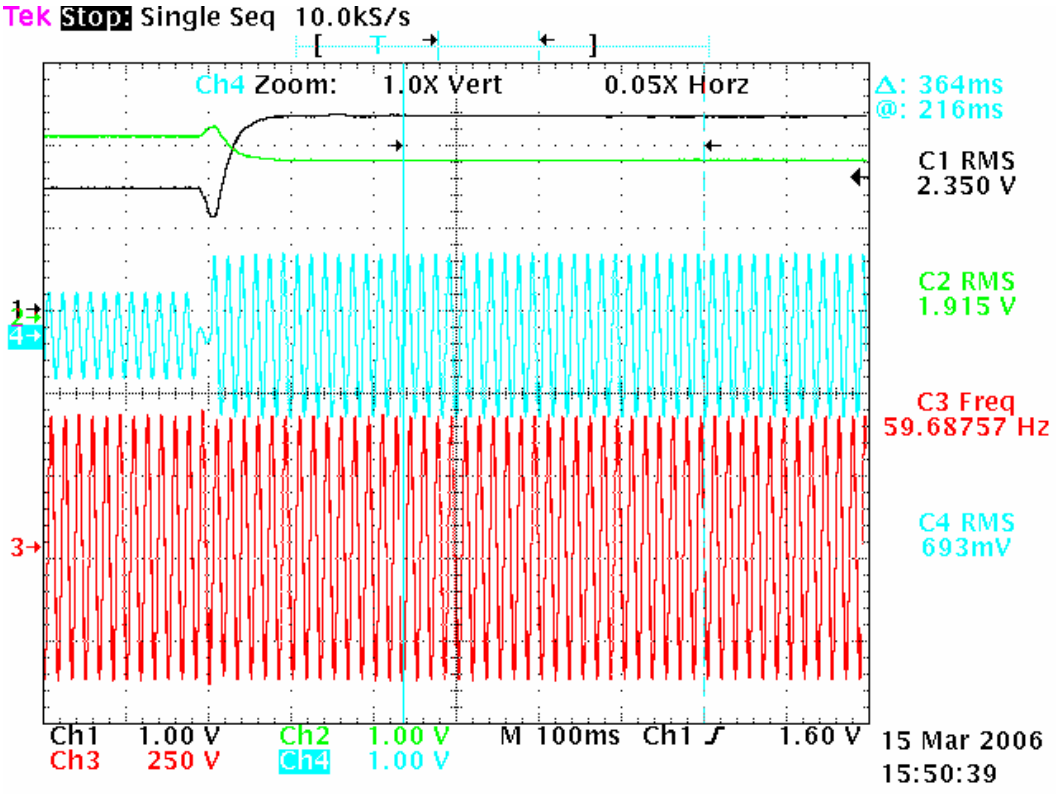


Figure 9 30 – 55 kW Power, Frequency, Voltage, Current

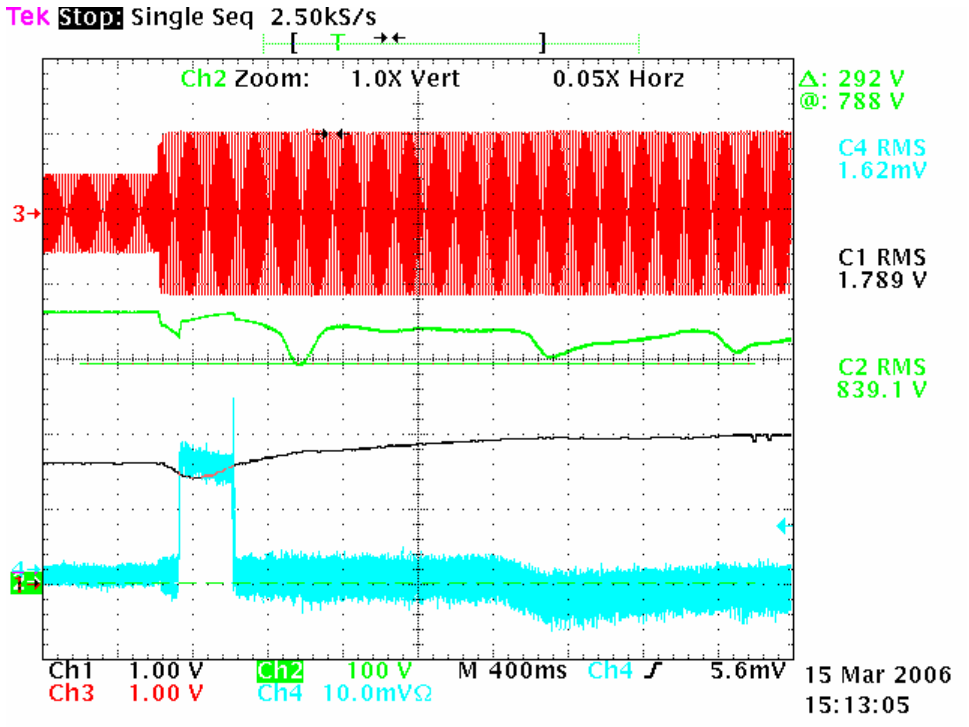


Figure 10 30 – 55 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

v. Step Load Evaluation 5

1.Load Bank Start Load = 60 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/60 kW	20.0/0 kW
Frequency Hz	59.67 Hz	60.6 Hz

Table 6 Step Load Evaluation 5: 60 – 0 kW (w/Surge Module)

60– 0 kW Step Load –Surge Module- Variable Speed

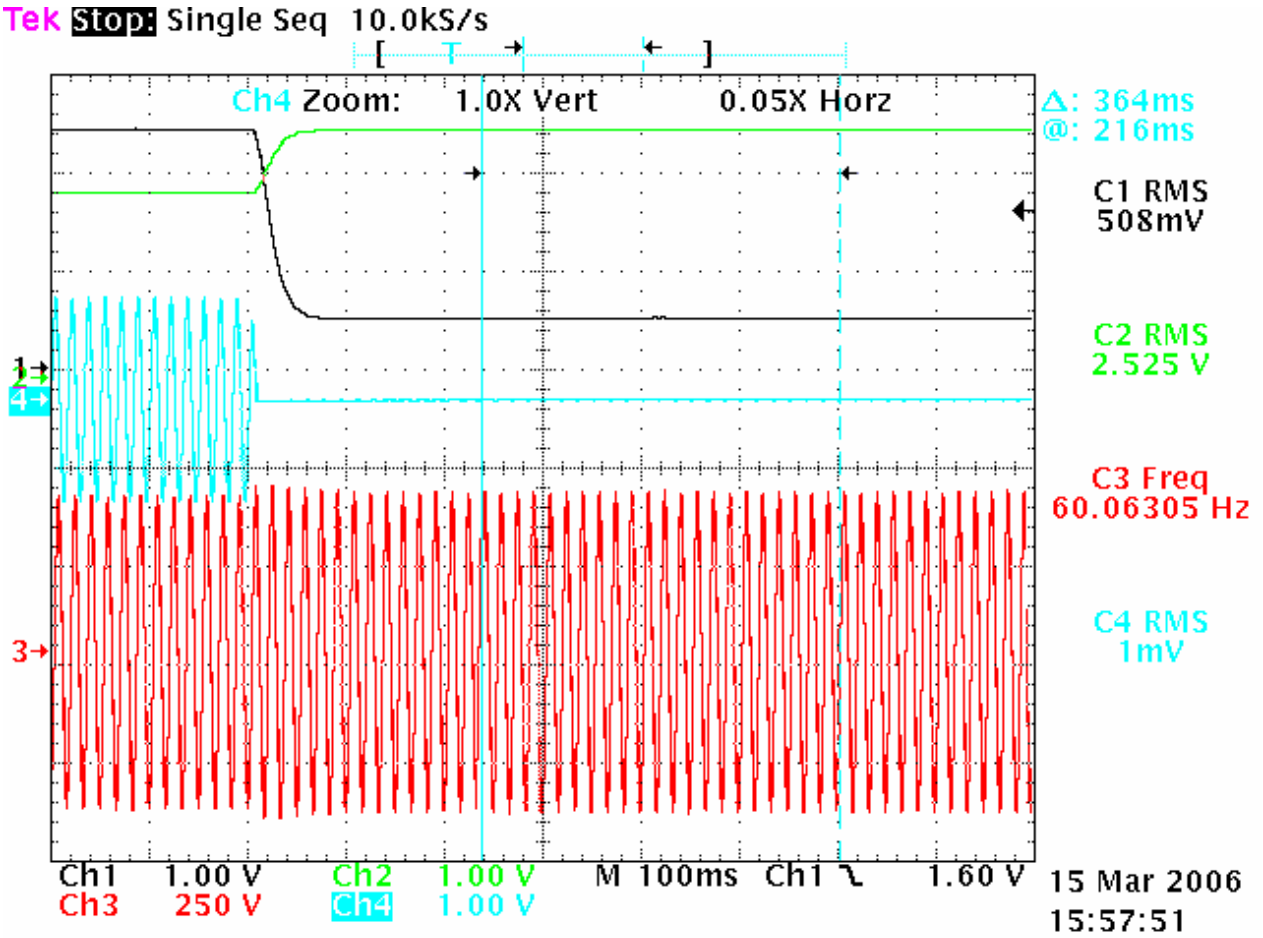


Figure 11 60-0 kW: Power, Frequency, Voltage, Current

vi. Step Load Evaluation 6

1. Load Bank Start Load = 30 kW
2. Unit A CMD = 20 kW
3. Load Bank End Load =0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/30 kW Unit	20.0/0 kW
Frequency Hz	59.91 Hz	60.16 Hz

Table 7 Step Load Evaluation 6: 30 – 0 kW (w/Surge Module)

30– 0 kW Step Load –Surge Module- Variable Speed

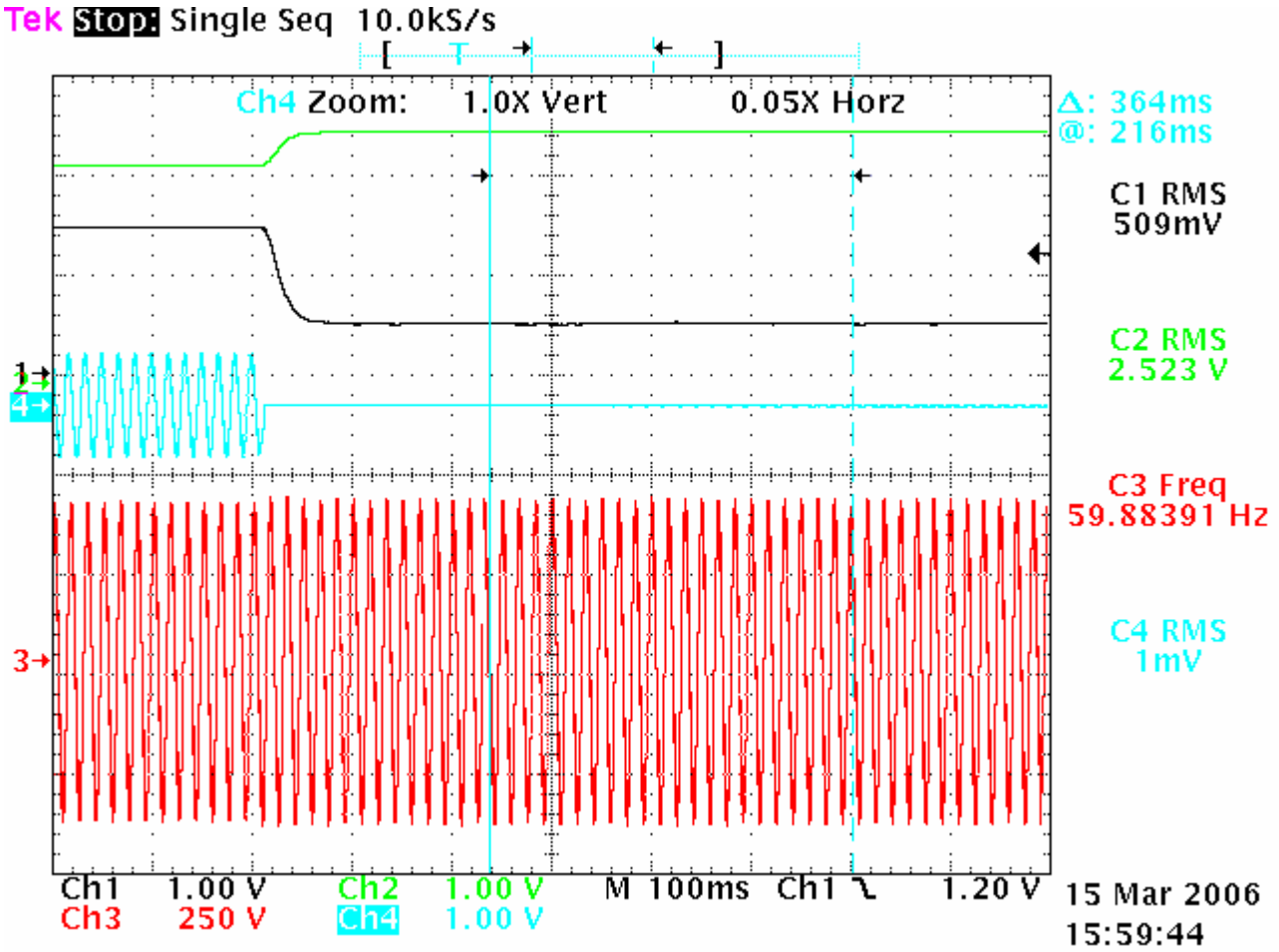


Figure 12 30 – 0 kW Power, Frequency, Voltage, Current

B.3. Step Load Evaluations without Surge Module – Fixed Speed Operation

The CHP unit was tested with the surge module disabled. The results showed that the dynamics of the engine/inverter could successfully handle a step load without the surge module. However, the engine must operate at a fixed speed and there is a minimum engine operating speed for each load step to prevent the engine from stalling. This minimum speed was determined for each "step-up" load.

The following table summarizes the test results. The minimum operational speed required for the given step load is highlighted with a bold box.

Fixed Engine Speed – No Surge Module			
Step Loads	**Engine Speed [Hz]**	**Engine Speed [RPM]**	**Pass/Fail**
0 - 30	65	**1950**	Pass
	60	1800	Fail
0 - 60	72	2160	Pass
	70	**2100**	Pass
	68	2040	Fail
15 - 50	68	2040	Pass
	66	1980	Pass
	65	1950	Pass
	64	1920	Pass
	63	1890	Pass
	62	1860	Pass
	61	**1830**	Pass
	60	1800	Fail
30 - 60	70	2100	Pass
	68	2040	Pass
	67	2010	Pass
	66	1980	Pass
	65	1950	Pass
	64	**1920**	Pass
	63	1890	Fail

Table 8 Test Point Summary – Step Loads without Surge Module/Fixed Speed

i.) Step Load Evaluation 1

1.Load Bank Start Load = 0 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load = 30 kW

Engine Speed: 1950 rpm (65 Hz)

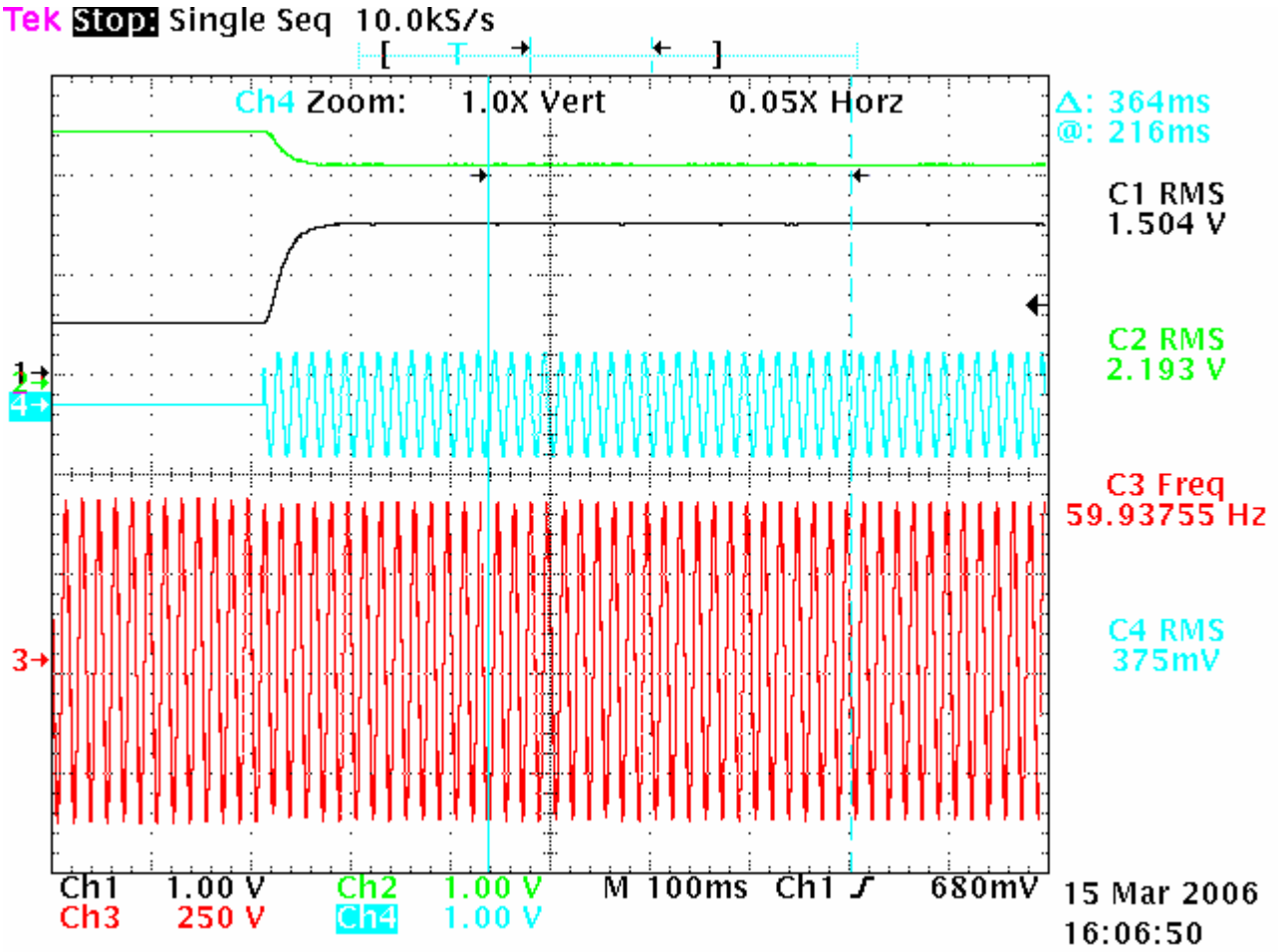


Figure 13 0-30 kW (Fixed Speed): Power, Frequency, Voltage, Current

ii.) Step Load Evaluation 2

4. Load Bank Start Load = 0 kW
5. Unit A CMD = 20 kW
6. Load Bank End Load =60 kW

Engine Speed: 2160 rpm (72 Hz)

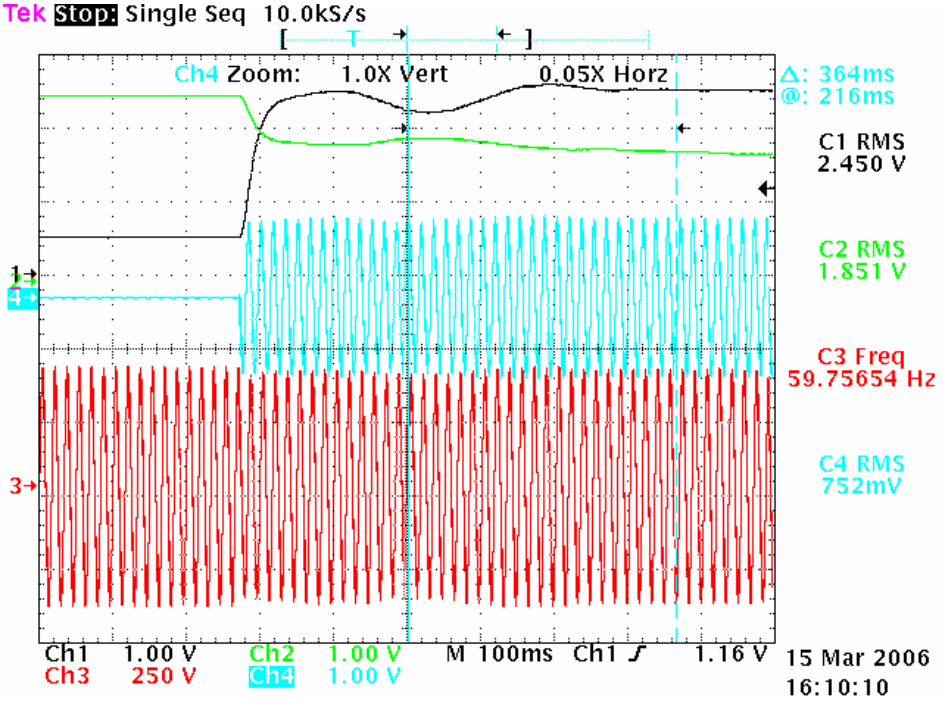


Figure 14 0 – 60 kW (Fixed Speed – 2160 rpm) Power, Frequency, Voltage, Current

Engine Speed: 2100 rpm (70 Hz)

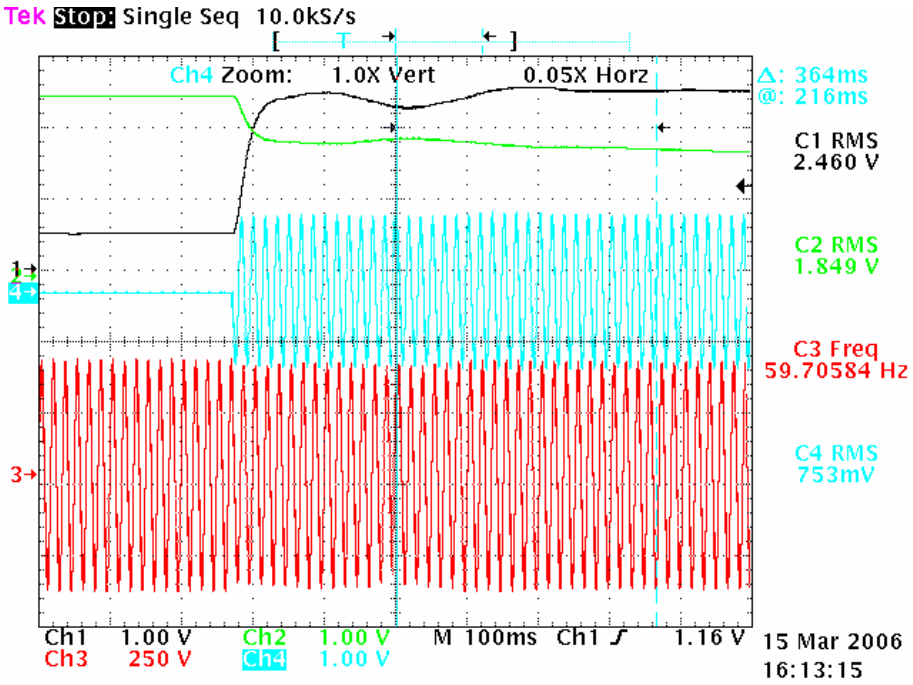


Figure 15 0 – 60 kW (Fixed Speed – 2100 rpm) Power, Frequency, Voltage, Current

iii.) Step Load Evaluation 3

1.Load Bank Start Load = 15 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =50 kW (Changed from 45 kW because easier to implement on Load Bank)

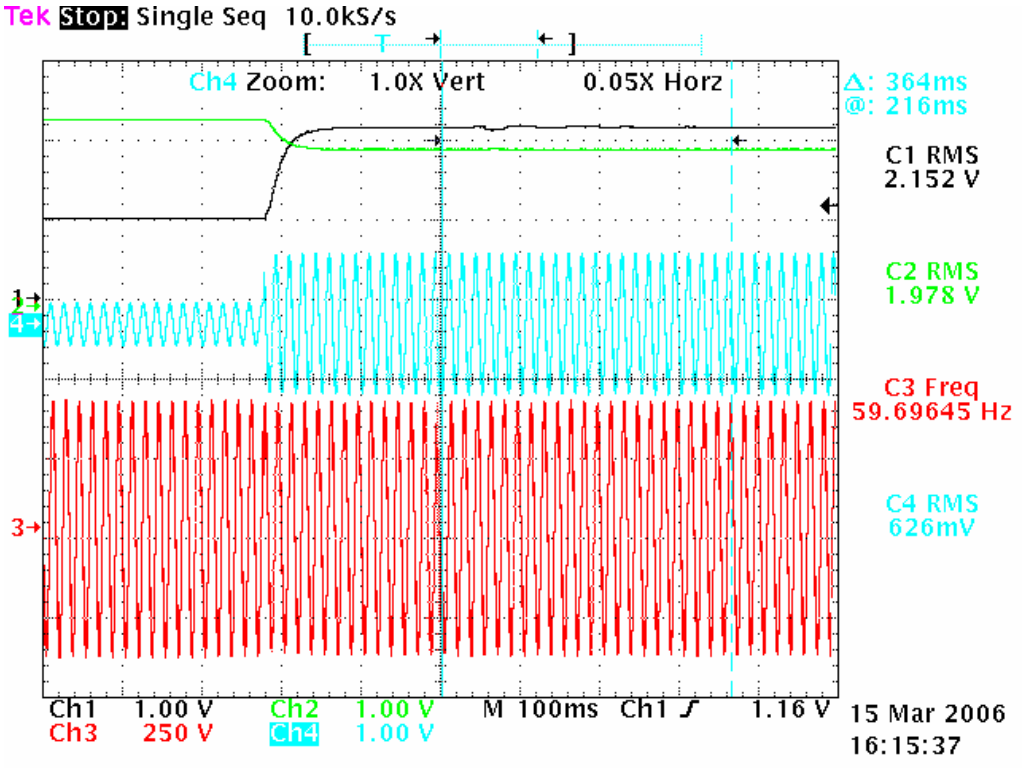


Figure 16 15 – 45 kW (Fixed Speed) Power, Frequency, Voltage, Current

iv.) Step Load Evaluation 4

1.Load Bank Start Load = 30 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =60 kW

Engine Speed: 2100 rpm (70 Hz)

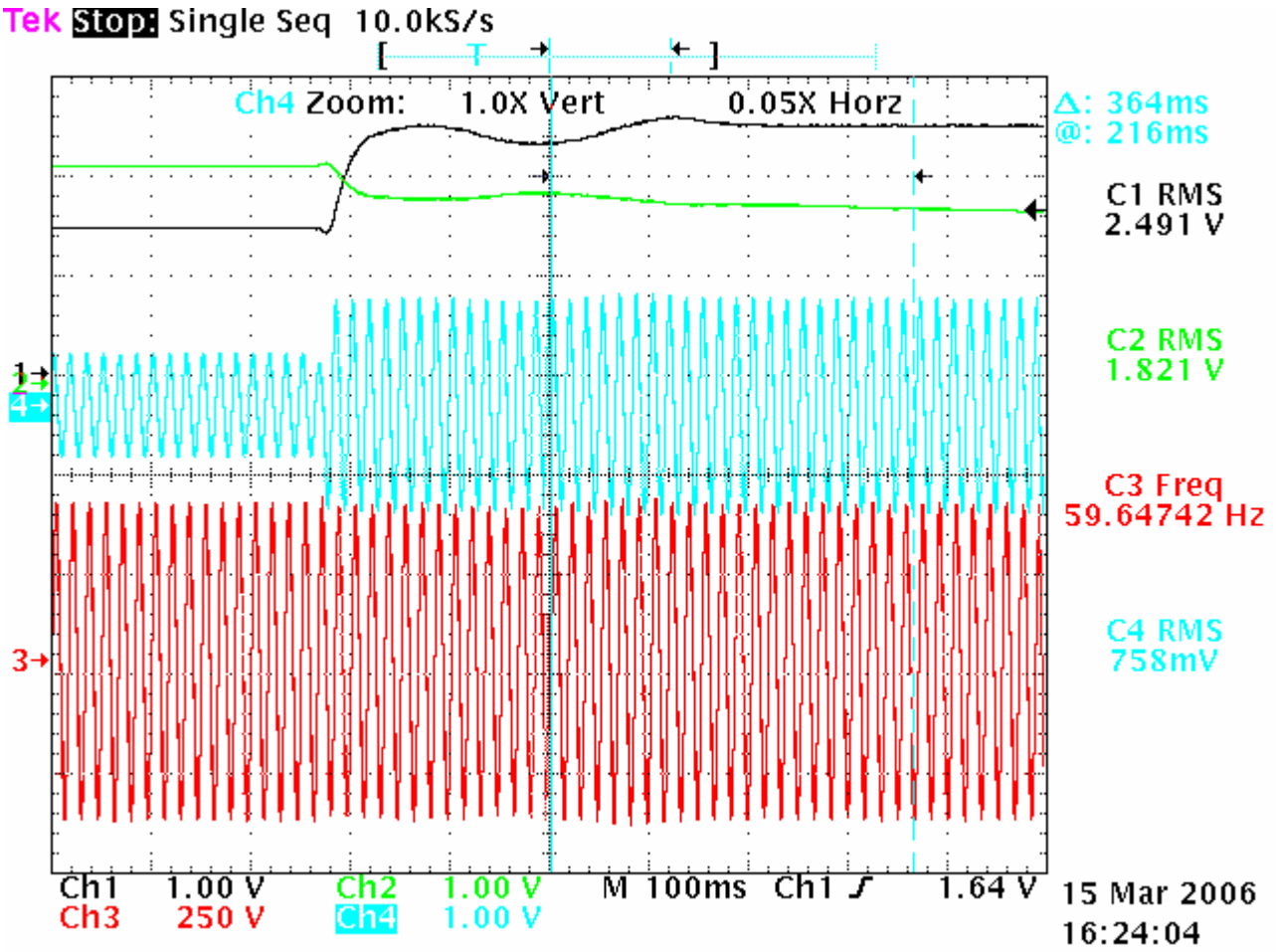


Figure 17 30 – 60 kW (Fixed Speed) Power, Frequency, Voltage, Current

TECOGEN 60 kW
Inverter-Based CHP Modules

CERTS Microgrid Test Bed Project

Tecogen Factory Testing
Unit Serial #200836

4/13/06

Introduction

This report presents the factory test data of the first Tecogen CHP unit (Serial # 200836), equipped with a customized inverter (by Youtility) that is configured with the CERTS microgrid control algorithm. Figure 1 presents a one-line diagram of the test set-up. The unit generates power in a stand-alone mode (no grid-tie) and is connected to a load bank. The output of the inverter is connected to the Delta side of a transformer in a 3-wire configuration. The output of the transformer is wired to the load bank in a 4-wire configuration with a 25-yard loop.

The inverter is also equipped with a Surge Module wired directly to the DC Bus. The Surge Module is a battery powered energy storage device with a rating of 20 kW for 3 seconds. Its purpose is to assist the engine/inverter's response to step loads. It is housed separately in an adjacent cabinet (DC power wiring length:12.5 feet).

All testing was done with the inverters set to Power Control Mode.

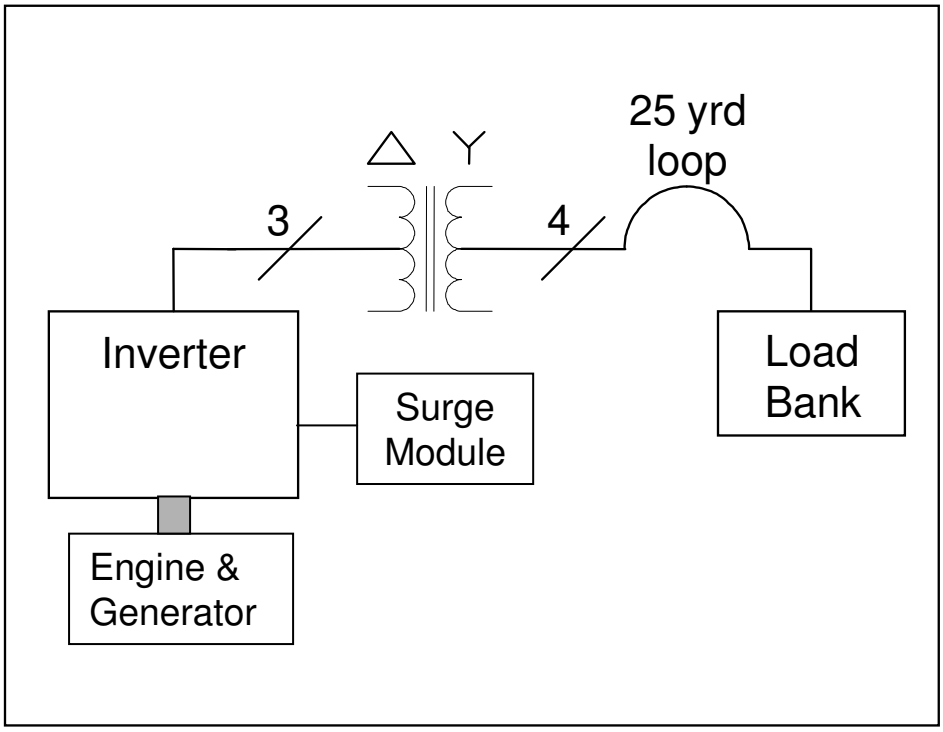


Figure 18 Factory Test One-line Diagram

B.2. Step Load Evaluations with Surge Module – Variable Speed Operation

In prior testing on Unit# 200835, it was determined that with a minimum speed setting of 1500 rpm (50 Hz), the system could not achieve the 0 – 60 kW step load. The objective for testing this second unit was to raise the minimum engine speed in Variable Speed mode to a level that would successfully accomplish the 0 – 60 kW step load. This would then establish the lower speed limit for Variable Speed operation. This speed was determined to be 1800 rpm (60 Hz). Therefore, all data was taken with the following settings in the software:

Minimum Engine Speed: 60 Hz (1800 rpm)
Maximum Engine Speed: 72 Hz (2160 rpm)

The following step loads were tested :

	Test Plan	Actual Test Point	Comments
i.	0-30 kW	0 – 30 kW	
ii. a		0 – 50 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
ii. b	0 – 60 kW	0 – 60 kW	
iii.	15 – 45 kW	15 – 50 kW	Changed to 50 kW because easier to implement on load bank
iv. a		30 – 55 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
iv. b	30 – 60 kW	30 – 60 kW	
v. a	60 – 0 kW	60 – 0 kW	
v. b		55 – 0 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
vi.	30 – 0 kW	30 – 0 kW	

Table 9 Test Point Summary – Step Loads with Surge Module/Variable Speed

For each step load point, an oscilloscope trace was captured that measured the power output, frequency, current, and voltage. These measurements were taken on the microgrid side (Y side) of the transformer. In each plot the data is formatted in the following way:

Ch1 = Unit RMS Power Output;
0.0V = -15KW
0.5V = 0KW
1.5V = 30KW
2.5V = 60KW

Ch2 = Unit Operating Frequency;
60Hz --> 2.3V
59.5Hz --> 1.66V
60.5Hz --> 2.94V

Ch 3 –Grid Voltage L-N

Channel 4

Ch4 = Unit Output Current; 1V = 100Amps

Also, the Step "Up" load points (i-iv.) were run two separate times so that additional data on the system dynamics, with the surge module, could be captured. This oscillocope data is formatted as follows:

Channel 1 = Engine RPM;
Not Recorded

Channel 2 = Bus Voltage
Zero point is actually 500 volts and measures from black "l" marker on left-hand side of Figure
100 volts per division
Nominal Voltage; 860 volts

Channel 3 = AC Current ; 1 V = 100 amps

Channel 4 = Surge Module Current
10 mV = 10 amps *(Need to verify with J. Wen of Youtility)*
10 mV per division
Nominal Current; 26 amps

The results of each test is organized in a table that defines the load setpoint (abbreviated S.P) and the actual power output from the unit. The table also contains the microgrid operating frequency before and after the transient event occurs (These frequency values are obtained from the units software and not the oscilloscope measurement). Also recorded in the table is the engine speed before and after the transient. Data contained in column A defines the operating condition and the state of the microgrid before the transient condition being tested occurs. Data contained in column B defines the operating condition and the state of the microgrid after the transient condition being tested has occurred.

i. Step Load Evaluation 1

4.Load Bank Start Load = 0 kW
5.Unit A CMD = 20 kW
6.Load Bank End Load = 30 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/30.5 kW
Frequency Hz	60.16 Hz	59.91 Hz
Engine Speed (Hz/rpm)	60 / 1800	60 / 1800

Table 10 Step Load Evaluation 1: 0 – 30 kW (w/Surge Module)

i. 0 – 30 KW Step Load –Surge Module- Variable Speed

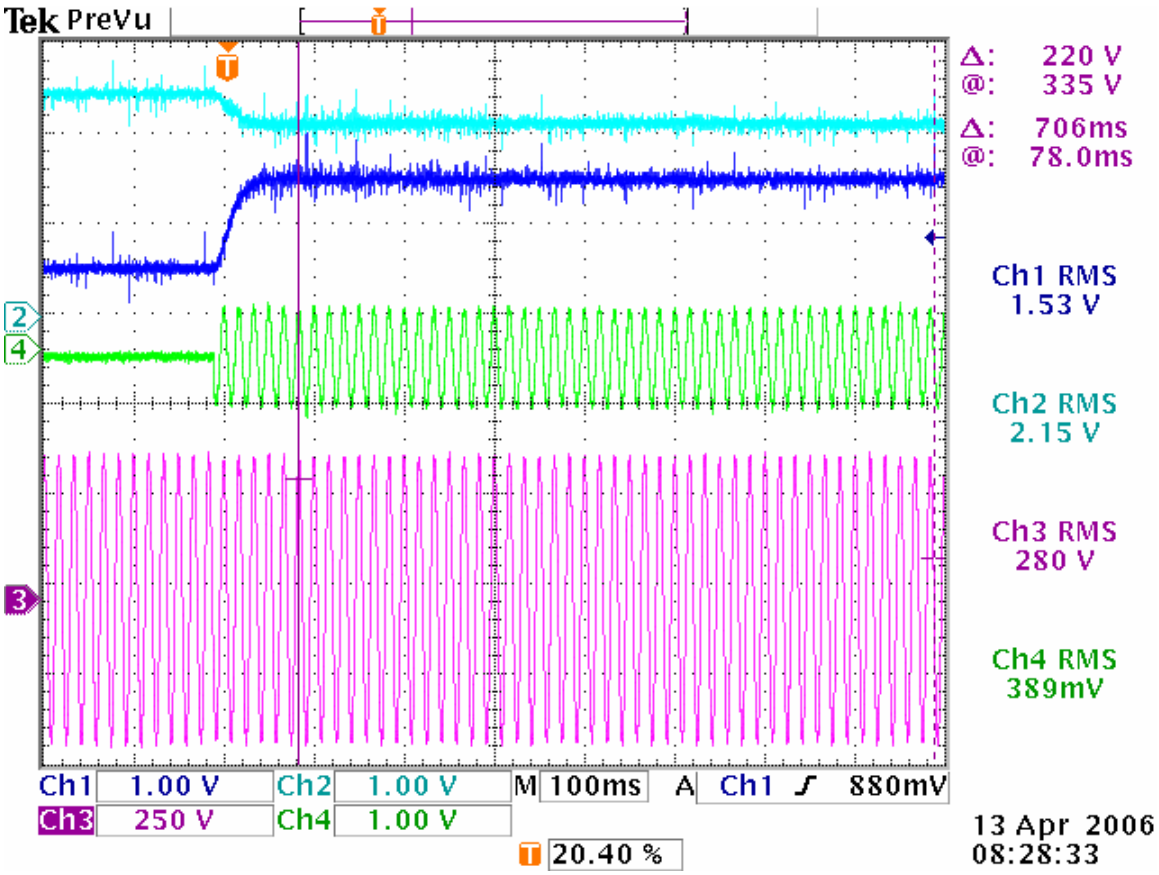


Figure 19 0 –30 kW: Power, Frequency, Voltage, Current

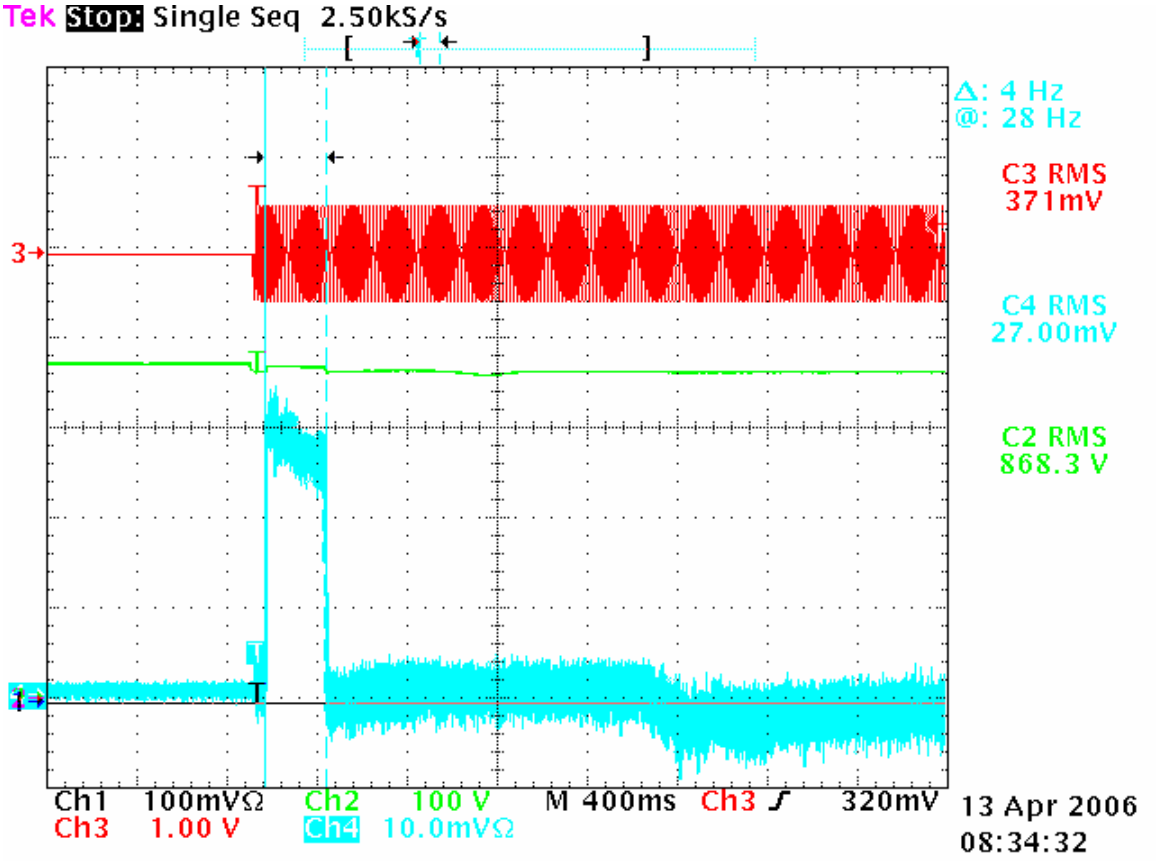


Figure 20 0 – 30 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

vi. Step Load Evaluation 2

7. Load Bank Start Load = 0KW
8. Unit A CMD = 20KW
9. Load Bank End Load =60 kW

ii a. 0 – 50 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/50.9 kW
Frequency Hz	60.16 Hz	59.74 Hz
Engine Speed (Hz/rpm)	60/ 1800	67.7 / 2031

Table 11 Step Load Evaluation 2a: 0 – 50 kW (w/Surge Module)

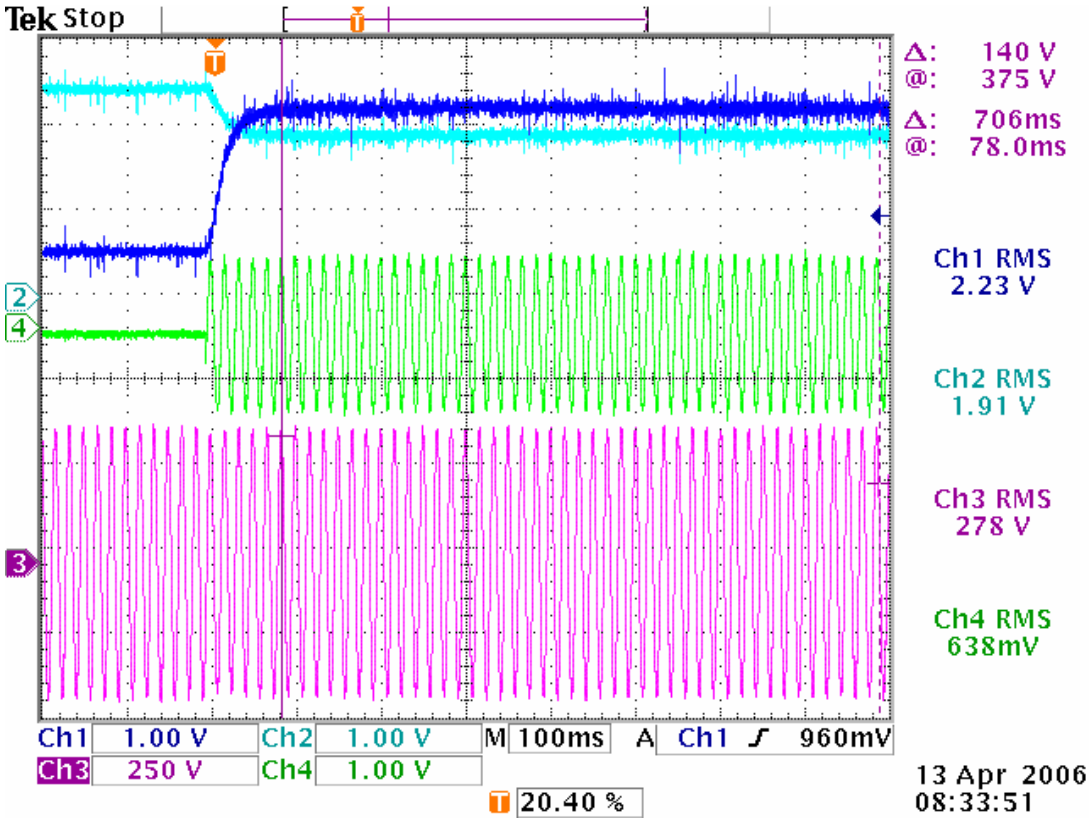


Figure 21 0 –50 kW: Power, Frequency, Voltage, Current

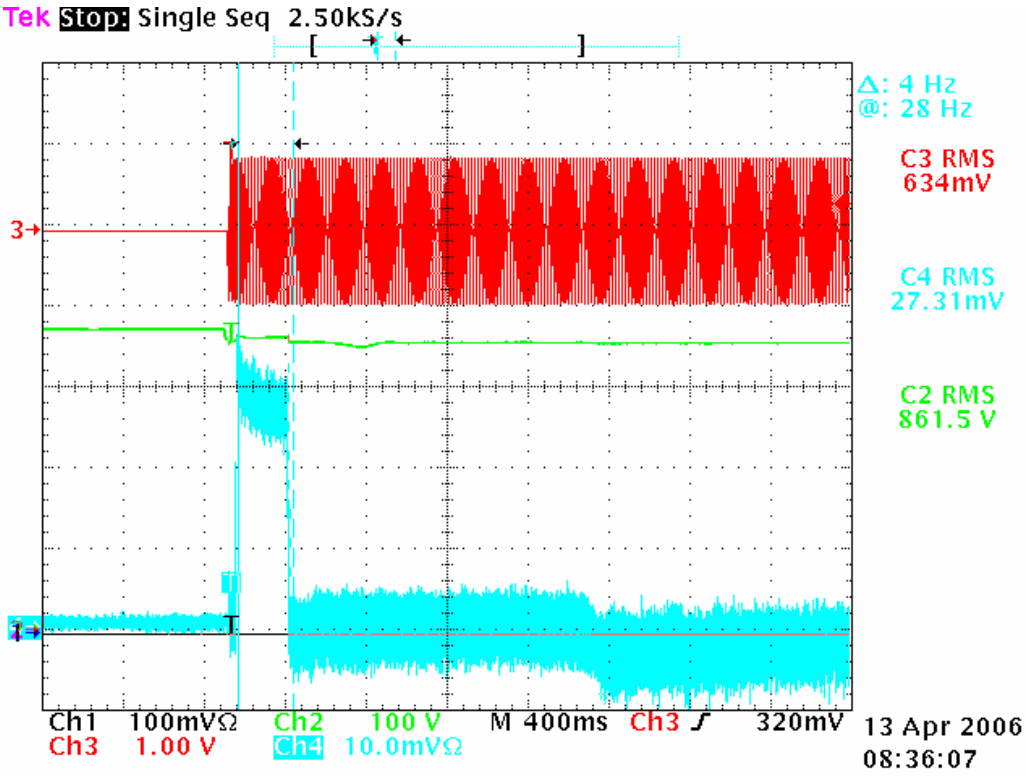


Figure 22 0 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

ii b. 0 – 60 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/60.7 kW
Frequency Hz	60.16 Hz	59.18 Hz
Engine Speed (Hz/rpm)	60 / 1800	72.7 / 2181

Table 12 Step Load Evaluation 2b: 0 – 60 kW (w/Surge Module)

ii b. 0 – 60 KW Step Load –Surge Module- Variable Speed

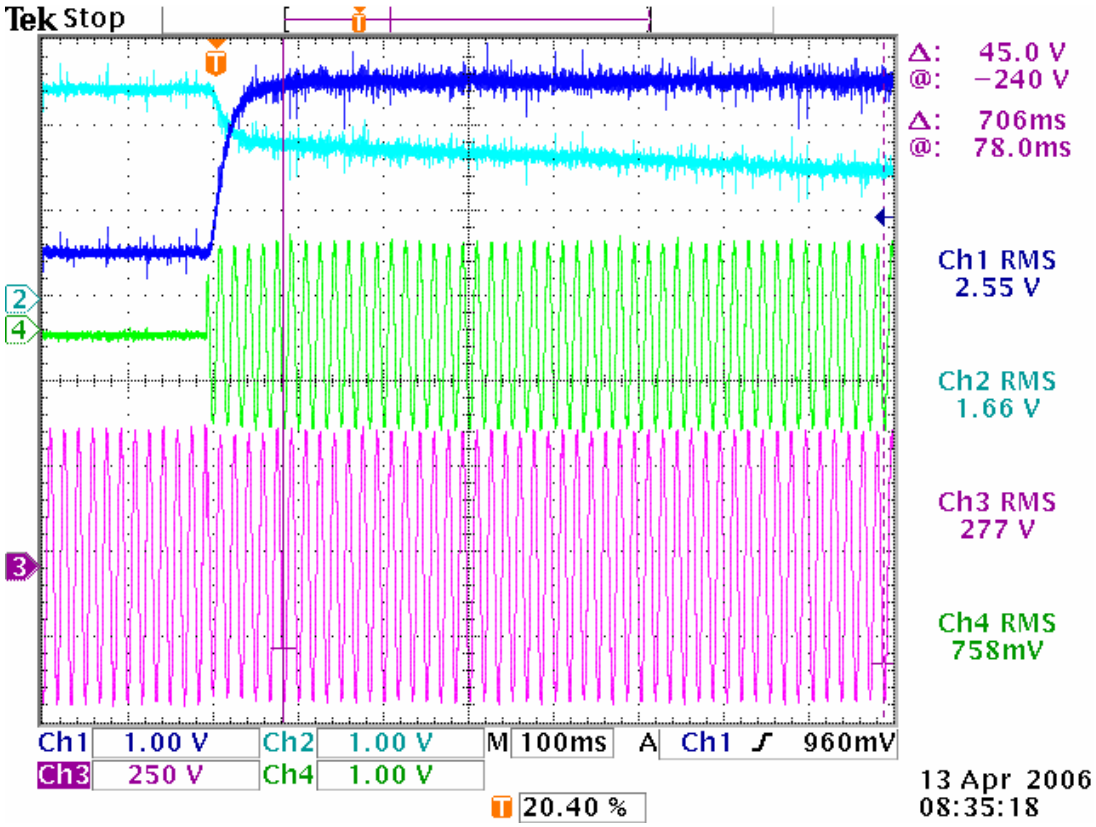


Figure 23 0 –60 kW: Power, Frequency, Voltage, Current

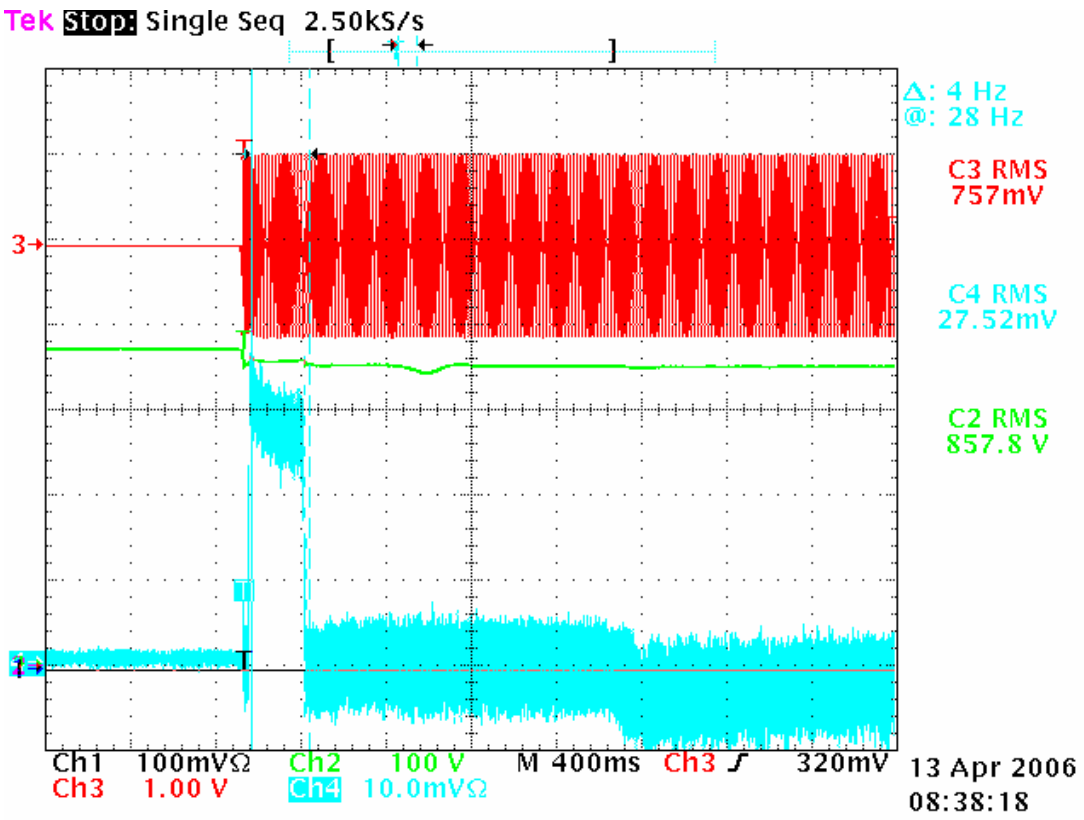


Figure 24 0 – 60 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

vii. Step Load Evaluation 3

1.Load Bank Start Load = 15 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =50 kW (Changed from 45 kW because easier to implement on Load Bank)

	A	B
Unit #1 (S.P/Actual) kW	20.0/15.5 kW	20.0/50.9 kW
Frequency Hz	60.03 Hz	59.74 Hz
Engine Speed (Hz/rpm)	60 / 1800	67.7/ 2031

Table 13 Step Load Evaluation 3: 15 – 50 kW (w/Surge Module)

iii. 15 – 50 KW Step Load –Surge Module- Variable Speed

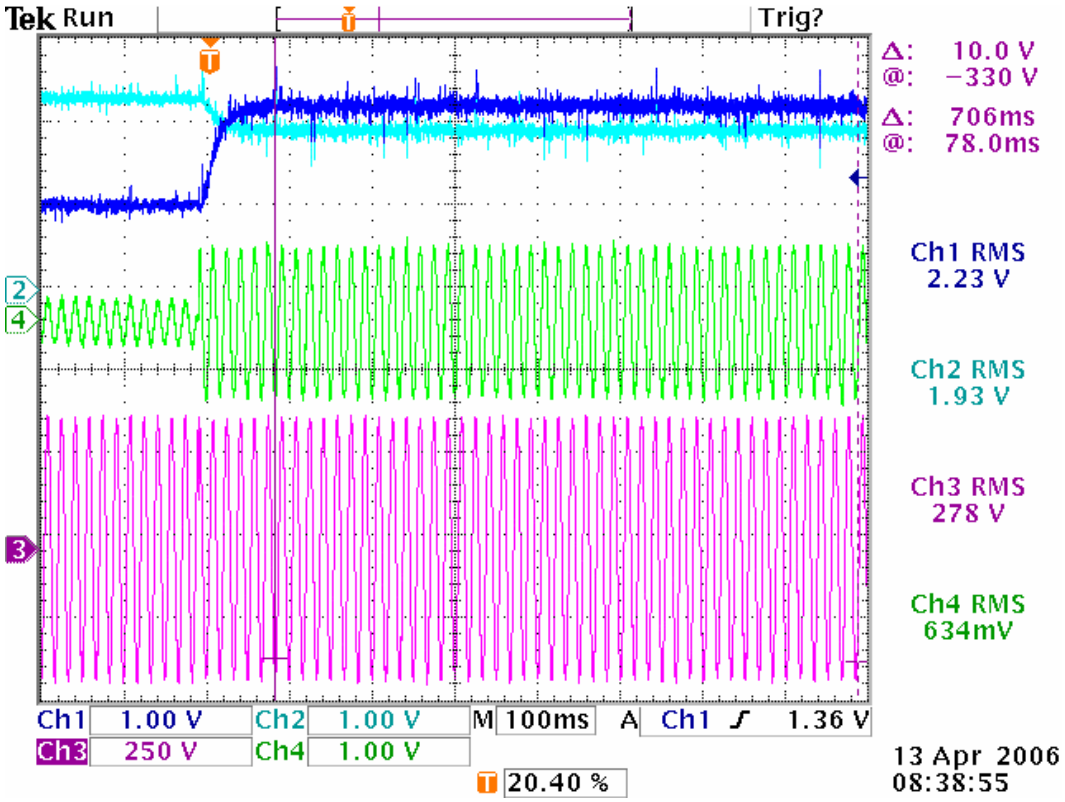


Figure 25 15 – 50 kW: Power, Frequency, Voltage, Current

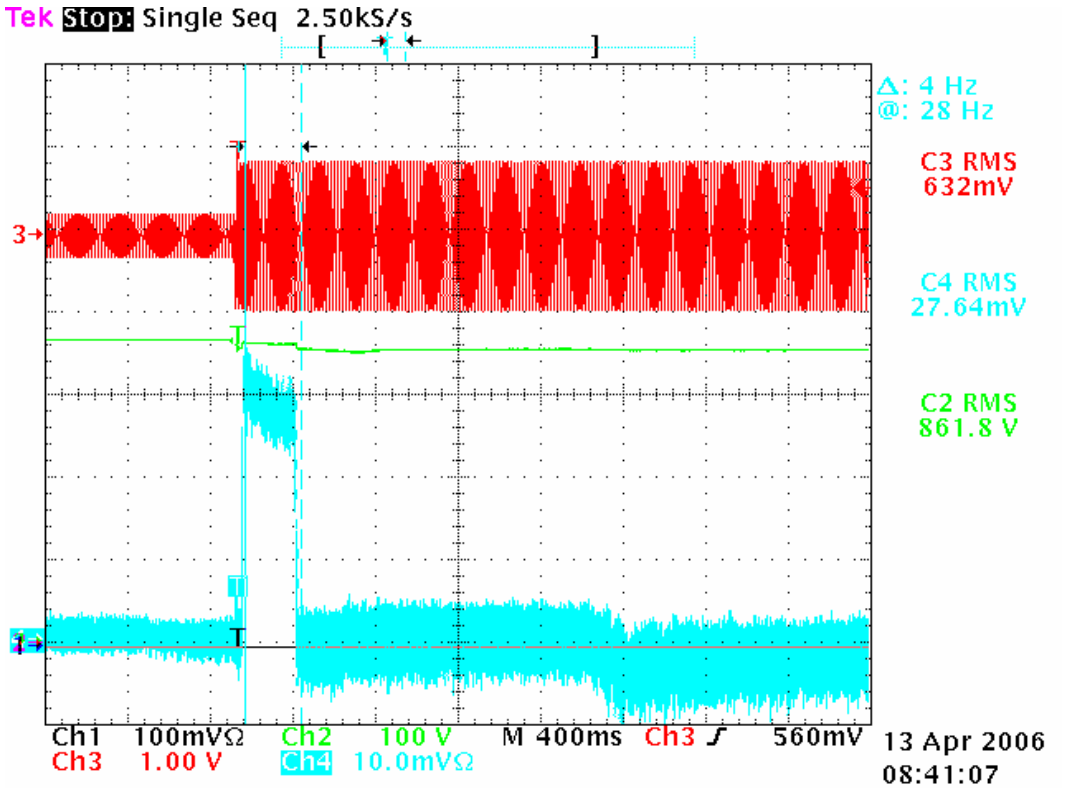


Figure 26 15 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

viii. Step Load Evaluation 4

1.Load Bank Start Load = 30 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load = 60 kW

iv a. 30 – 55 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) KW	20.0/30.4 kW	20.0/55.8 kW
Frequency Hz	59.91 Hz	59.70 Hz
Engine Speed (Hz/rpm)	60 / 1800	70.1/ 2103

Table 14 Step Load Evaluation 4a: 30 - 55 kW (w/Surge Module)

iv.a 30– 55 KW Step Load –Surge Module- Variable Speed

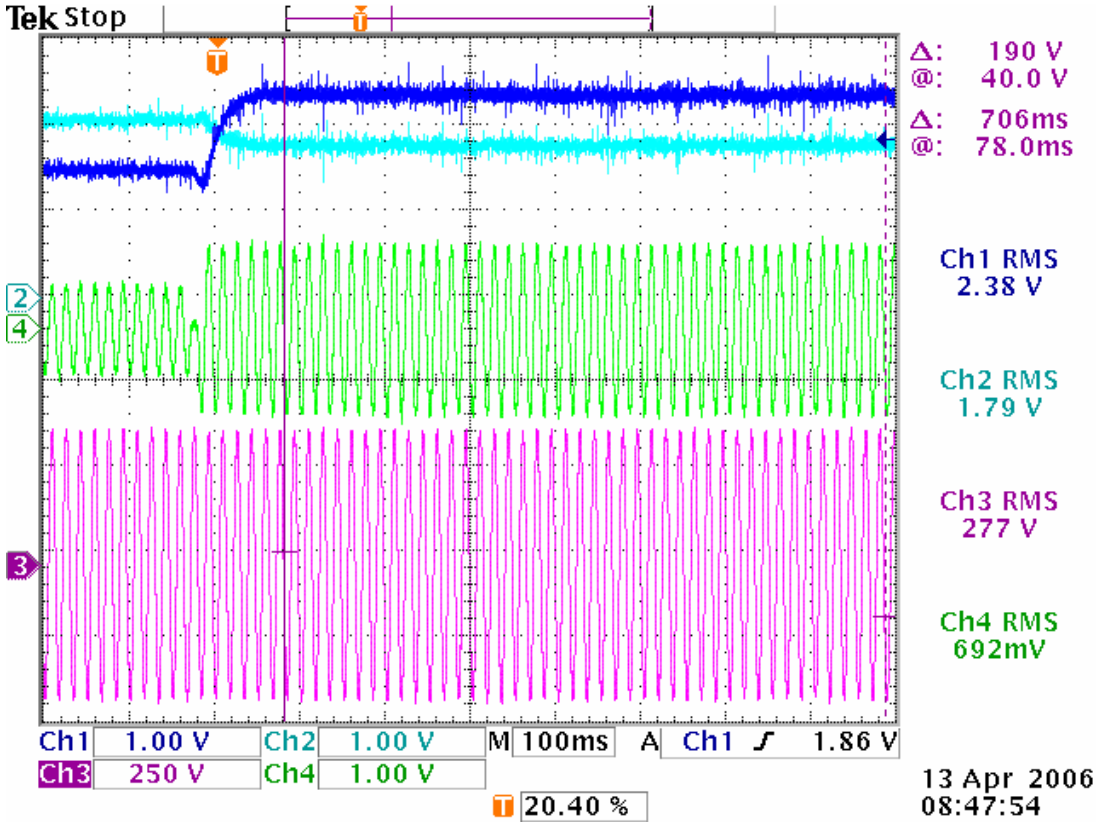


Figure 27 30 –55 kW: Power, Frequency, Voltage, Current

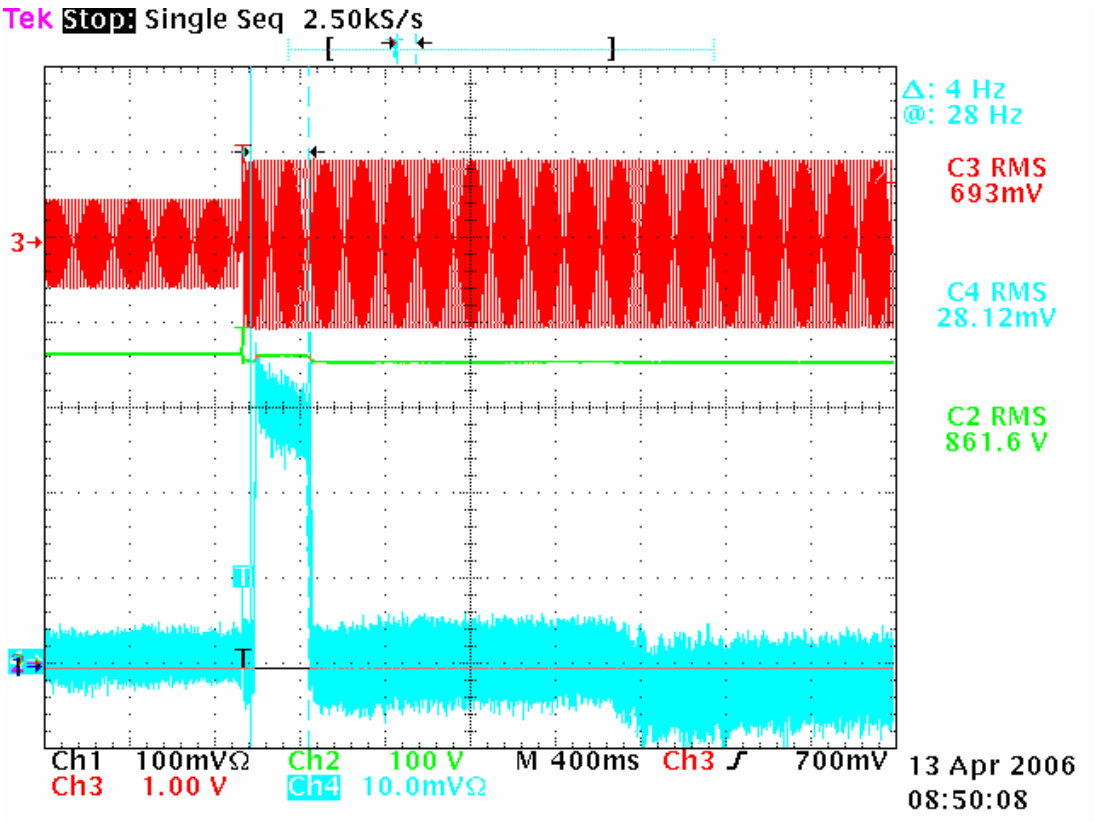


Figure 28 30 – 55 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

iv b. 30 – 60 kW

	A	B
Unit #1 (S.P/Actual) KW	20.0/30.4 kW	20.0/60.7 kW
Frequency Hz	59.91 Hz	59.16 Hz
Engine Speed (Hz/rpm)	60 / 1800	72.5/ 2175

Table 15 Step Load Evaluation 4b: 30 – 60 kW (w/Surge Module)

iv.b 30– 60 KW Step Load –Surge Module- Variable Speed

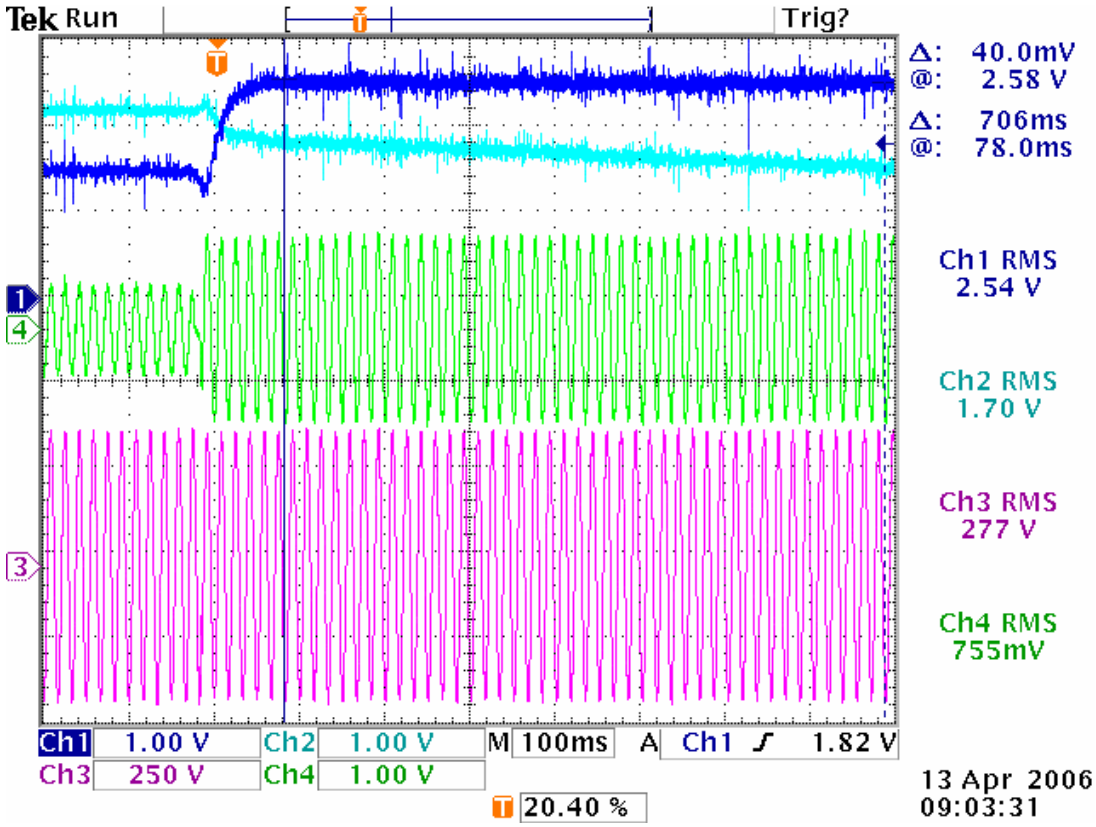


Figure 29 30 –60 kW: Power, Frequency, Voltage, Current

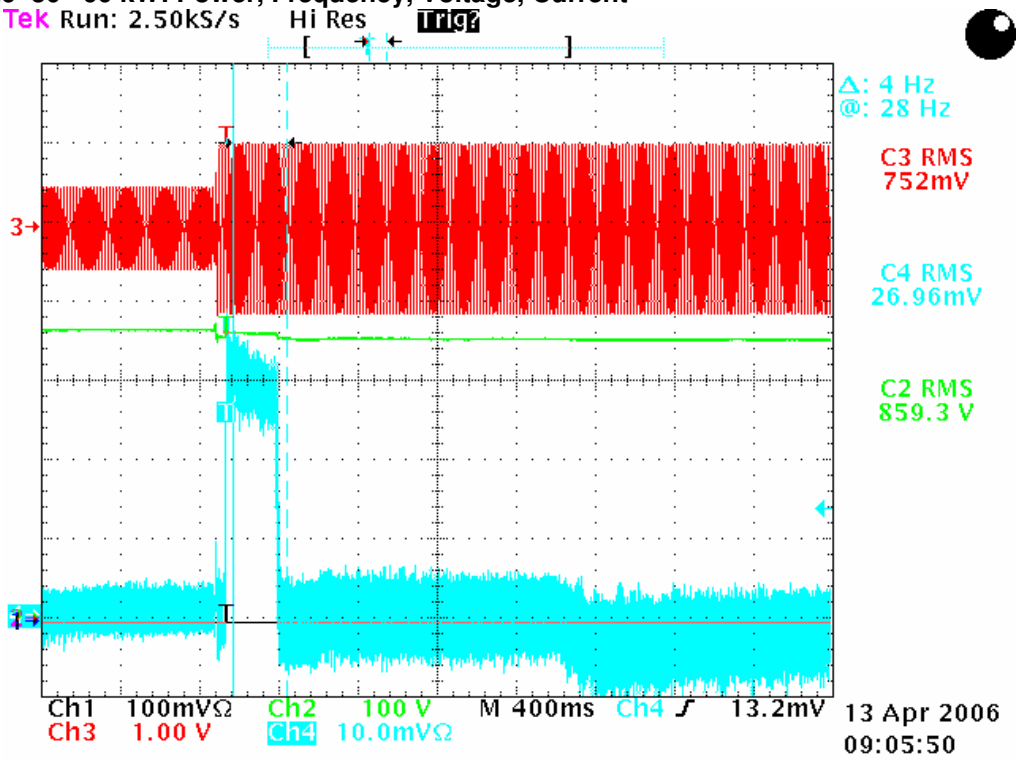


Figure 30 30 – 60 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

ix. Step Load Evaluation 5

1.Load Bank Start Load = 60 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =0 kW

v a. 60 - 0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/60.7 kW	20.0/0 kW
Frequency Hz	59.16 Hz	60.16 Hz
Engine Speed (Hz/rpm)	72.5/ 2175	60/1800

Table 16 Step Load Evaluation 5a: 60 - 0 kW (w/Surge Module)

60– 0 kW Step Load –Surge Module- Variable Speed

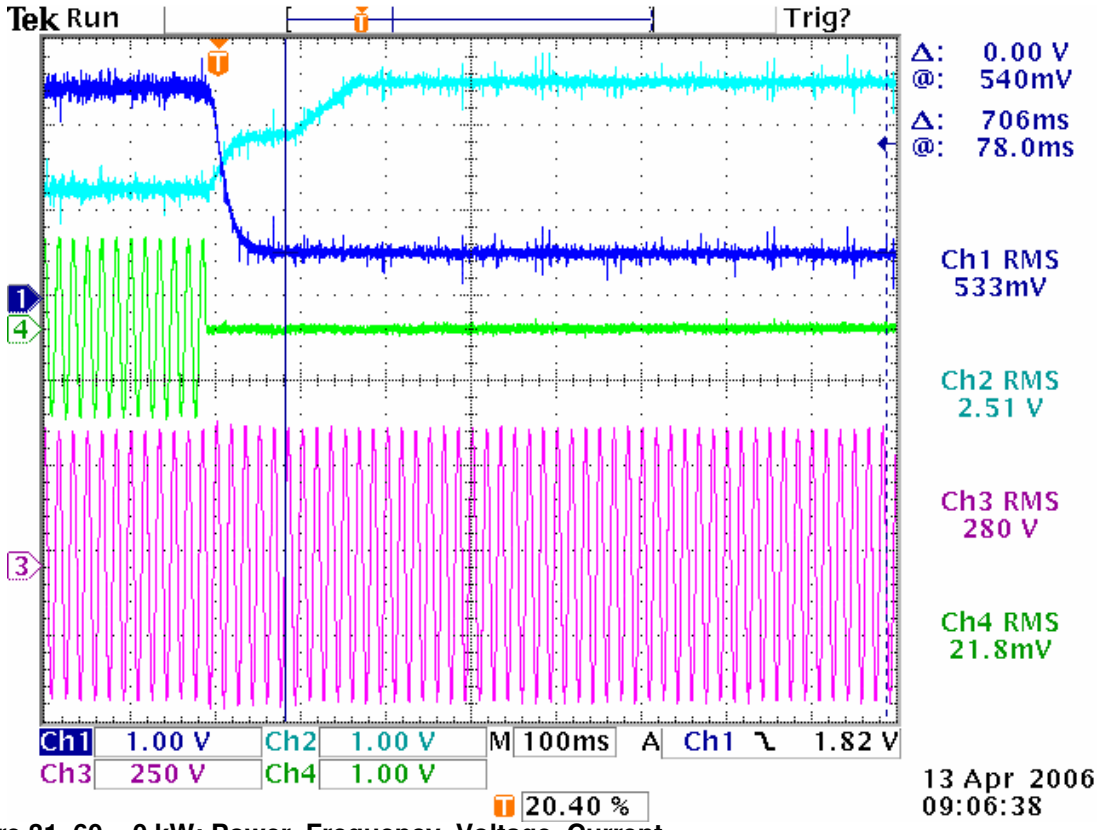


Figure 31 60 – 0 kW: Power, Frequency, Voltage, Current

v b. 55 - 0 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) kW	20.0/55.8 kW	20.0/0 kW
Frequency Hz	59.70 Hz	60.16 Hz
Engine Speed (Hz/rpm)	70.1/ 2103	60/1800

Table 17 Step Load Evaluation 5b: 55 - 0 kW (w/Surge Module)

55– 0 kW Step Load –Surge Module- Variable Speed

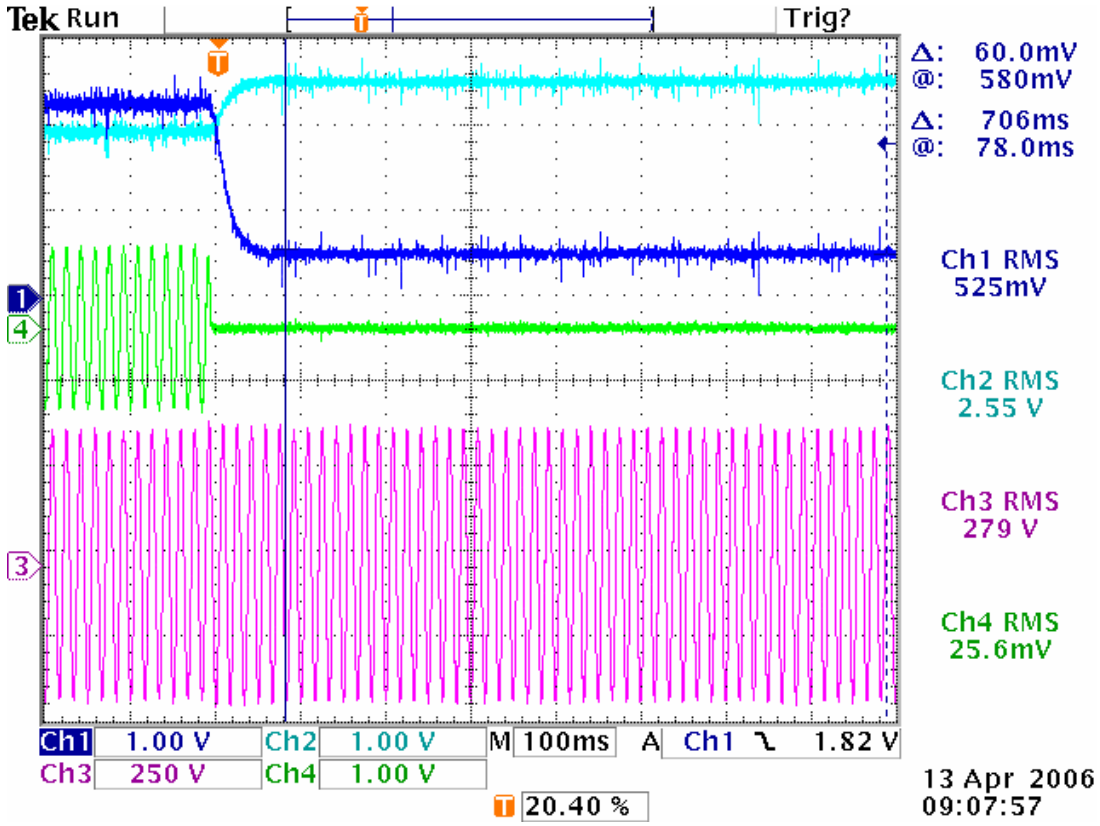


Figure 32 55 – 0 kW: Power, Frequency, Voltage, Current

vi. Step Load Evaluation 6

4. Load Bank Start Load = 30 kW
5. Unit A CMD = 20 kW
6. Load Bank End Load =0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/30.4 kW Unit	20.0/0 kW
Frequency Hz	59.91 Hz	60.16 Hz
Engine Speed (Hz/rpm)	60/ 1800	60/1800

Table 18 Step Load Evaluation 6: 30 – 0 kW (w/Surge Module)

30– 0 kW Step Load –Surge Module- Variable Speed

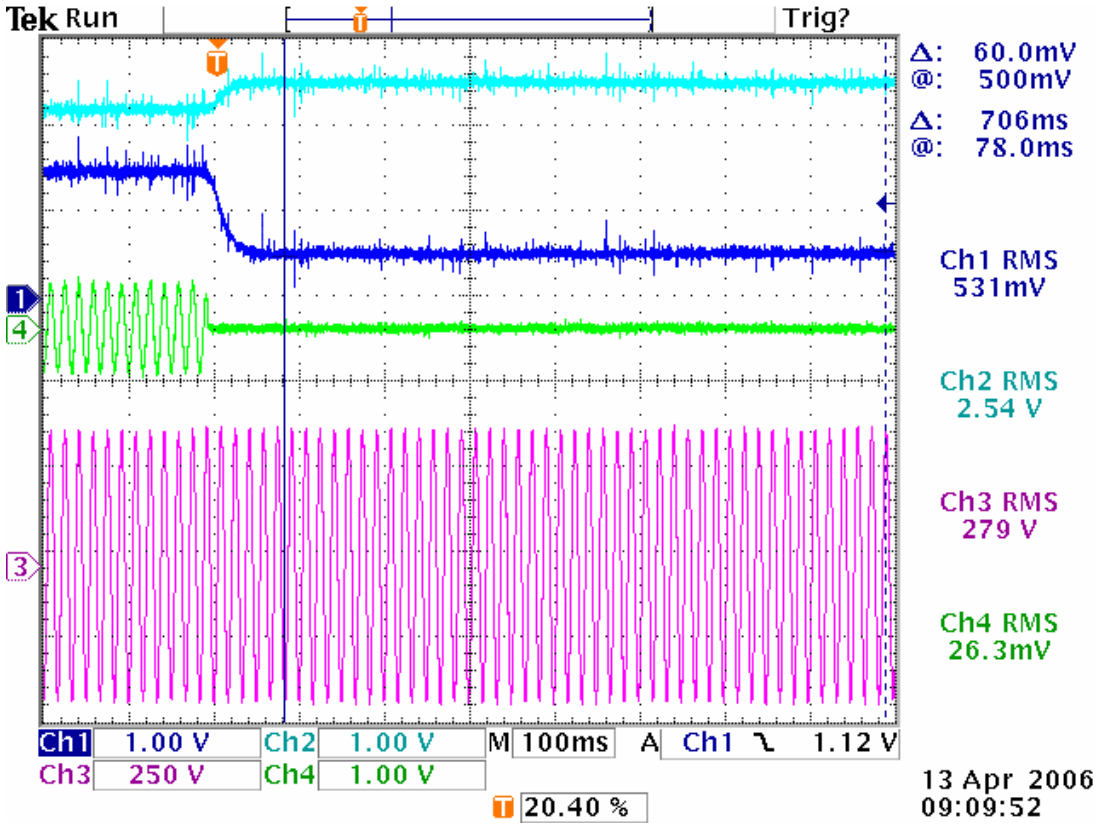


Figure 33 30 – 0 kW: Power, Frequency, Voltage, Current

B.3. Step Load Evaluations without Surge Module – Fixed Speed Operation

The CHP unit was tested with the surge module disabled. As with the first unit (Serial # 200835), the results confirmed that the dynamics of the engine/inverter allows the unit to successfully handle a step load without the surge module. The engine was set at the fixed speed required for the maximum load step of 0 – 60 kW (2160 rpm). Each step load point was run to confirm Pass/Fail. Oscilloscope data was not recorded since, as demonstrated in the testing of Unit #200835, if the unit "Passes", the electrical output signatures (Figure 1) are the same as in Variable Speed operation.

The following table summarizes the test results.

Fixed Engine Speed 2160 rpm (72 Hz) No Surge Module		
	Step Load	**Pass/Fail**
i.	0 – 30 kW	Pass
ii. a	0 – 50 kW	Pass
ii. b	0 – 60 kW	Pass
iii.	15 – 50 kW	Pass
iv. a	30 – 55 kW	Pass
iv. b	30 – 60 kW	Pass
v. a	60 – 0 kW	Pass
v. b	55 – 0 kW	Pass
vi.	30 – 0 kW	Pass

Table 19 Test Point Summary – Step Loads without Surge Module/Fixed Speed

TECOGEN 60 kW
Inverter-Based CHP Modules

CERTS Microgrid Test Bed Project

Tecogen Factory Testing
Unit Serial #200837

5/09/06

Introduction

This report presents the factory test data of the third Tecogen CHP unit (Serial # 200837), equipped with a customized inverter (by Youtility) that is configured with the CERTS microgrid control algorithm. Figure 1 presents a one-line diagram of the test set-up. The unit generates power in a stand-alone mode (no grid-tie) and is connected to a load bank. The output of the inverter is connected to the Delta side of a transformer in a 3-wire configuration. The output of the transformer is wired to the load bank in a 4-wire configuration with a 25-yard loop.

The inverter is also equipped with a Surge Module wired directly to the DC Bus. The Surge Module is a battery powered energy storage device with a rating of 20 kW for 3 seconds. Its purpose is to assist the engine/inverter's response to step loads. It is housed separately in an adjacent cabinet (DC power wiring length:12.5 feet).

All testing was done with the inverters set to Power Control Mode.

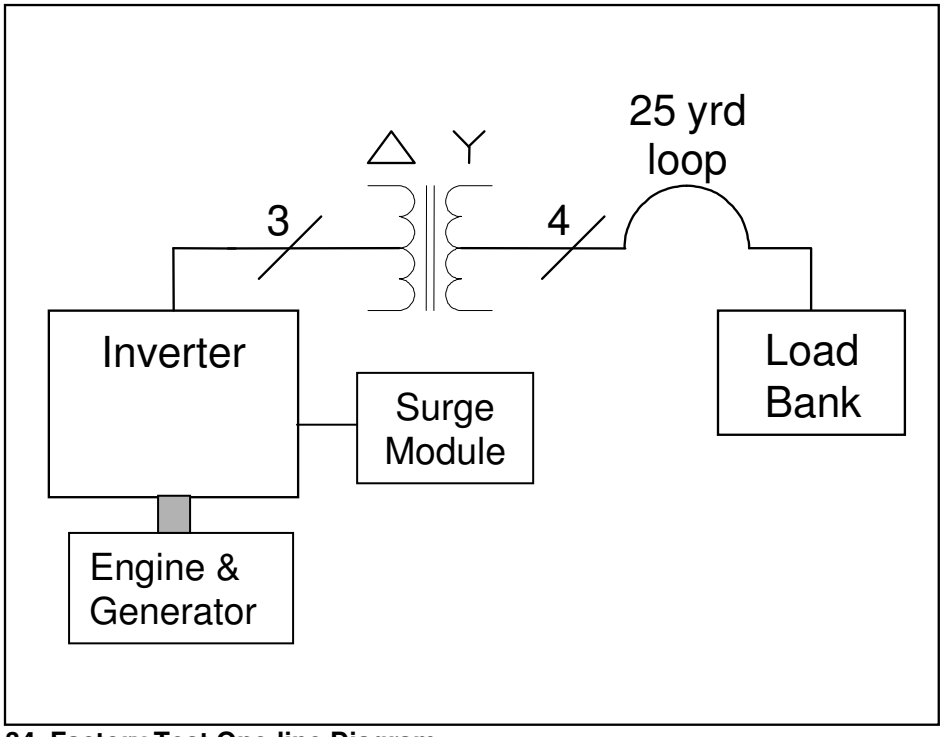


Figure 34 Factory Test One-line Diagram

B.2. Step Load Evaluations with Surge Module – Variable Speed Operation

All data was taken with the following settings in the software:

Minimum Engine Speed: 60 Hz (1800 rpm)
Maximum Engine Speed: 72 Hz (2160 rpm)

The following step loads were tested :

	Test Plan	Actual Test Point	Comments
i.	0-30 kW	0 – 30 kW	
ii. a		0 – 50 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
ii. b	0 – 60 kW	0 – 60 kW	
iii.	15 – 45 kW	15 – 50 kW	Changed to 50 kW because easier to implement on load bank
iv. a		30 – 55 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
iv. b	30 – 60 kW	30 – 60 kW	
v. a	60 – 0 kW	60 – 0 kW	
v. b		55 – 0 kW	Done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank.
vi.	30 – 0 kW	30 – 0 kW	

Table 20 Test Point Summary – Step Loads with Surge Module/Variable Speed

For each step load point, an oscilloscope trace was captured that measured the power output, frequency, current, and voltage. These measurements were taken on the microgrid side (Y side) of the transformer. In each plot the data is formatted in the following way:

Ch1 = Unit RMS Power Output;
0.0V = -15KW
0.5V = 0KW
1.5V = 30KW
2.5V = 60KW

Ch2 = Unit Operating Frequency;
60Hz --> 2.3V
59.5Hz --> 1.66V
60.5Hz --> 2.94V

Ch 3 –Grid Voltage L-N

Channel 4

Ch4 = Unit Output Current; 1V = 100Amps

Also, the Step "Up" load points (i-iv.) were run two separate times so that additional data on the system dynamics, with the surge module, could be captured. This oscillocope data is formatted as follows:

Channel 1 = Engine RPM;
Not Recorded

Channel 2 = Bus Voltage
Zero point is actually 500 volts and measures from black "l" marker on left-hand side of figure
100 volts per division
Nominal Voltage; 860 volts

Channel 3 = AC Current ; 1 V = 100 amps

Channel 4 = Surge Module Current
10 mV = 10 amps
10 mV per division
Nominal Current; 26 amps

The results of each test is organized in a table that defines the load setpoint (abbreviated S.P) and the actual power output from the unit. The table also contains the microgrid operating frequency before and after the transient event occurs (These frequency values are obtained from the units software and not the oscilloscope measurement). Also recorded in the table is the engine speed before and after the transient. Data contained in column A defines the operating condition and the state of the microgrid before the transient condition being tested occurs. Data contained in column B defines the operating condition and the state of the microgrid after the transient condition being tested has occurred.

i. Step Load Evaluation 1

4.Load Bank Start Load = 0 kW
5.Unit A CMD = 20 kW
6.Load Bank End Load = 30 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/30.5 kW
Frequency Hz	60.16 Hz	59.91 Hz
Engine Speed (Hz/rpm)	60 / 1800	60 / 1800

Table 21 Step Load Evaluation 1: 0 – 30 kW (w/Surge Module)

i. 0 – 30 KW Step Load –Surge Module- Variable Speed

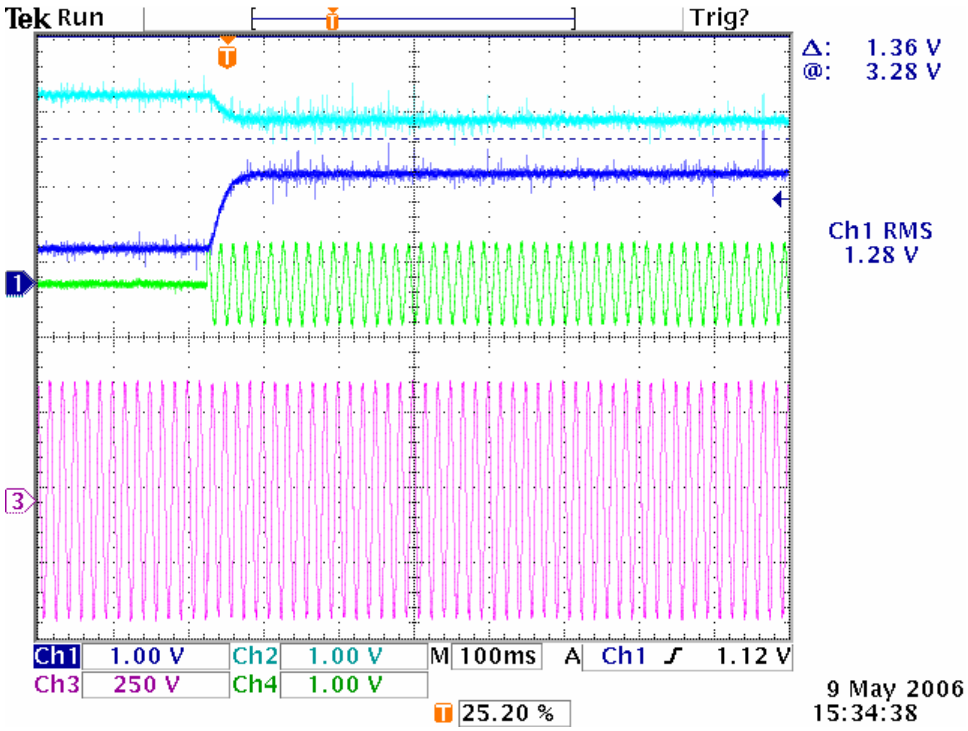


Figure 35 0 –30 kW: Power, Frequency, Voltage, Current

x. Step Load Evaluation 2

10. Load Bank Start Load = 0KW
11. Unit A CMD = 20KW
12. Load Bank End Load =60 kW

ii a. 0 – 50 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/51.3 kW
Frequency Hz	60.16 Hz	59.73 Hz
Engine Speed (Hz/rpm)	60/ 1800	65.9 / 1977

Table 22 Step Load Evaluation 2a: 0 – 50 kW (w/Surge Module)

iia. 0 – 50 kW Step Load –Surge Module- Variable Speed

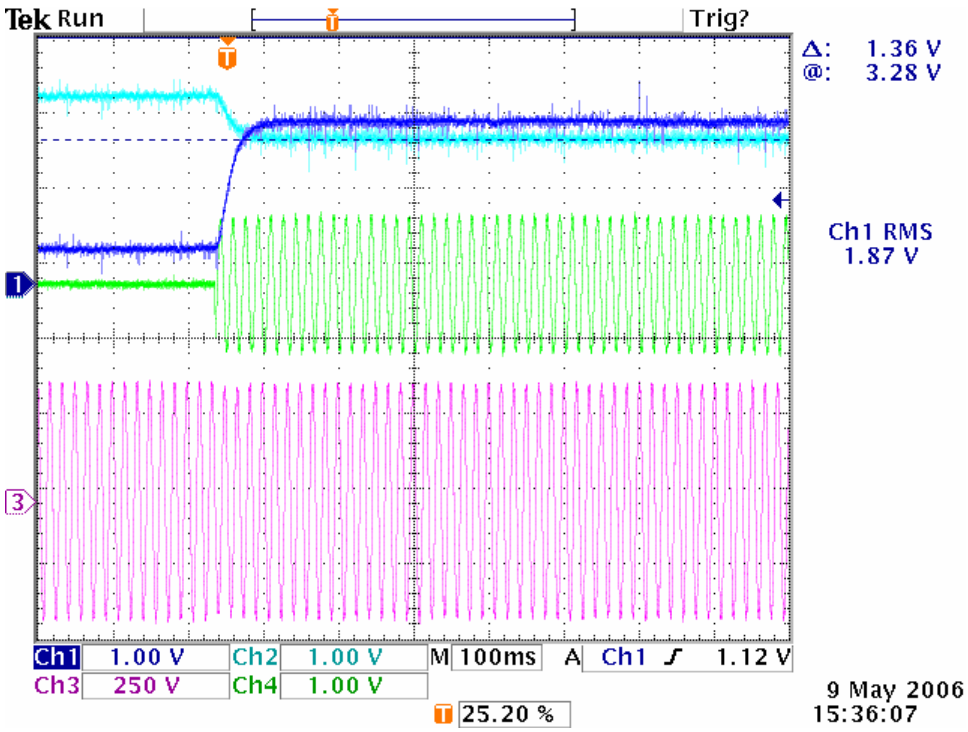


Figure 36 0 –50 kW: Power, Frequency, Voltage, Current

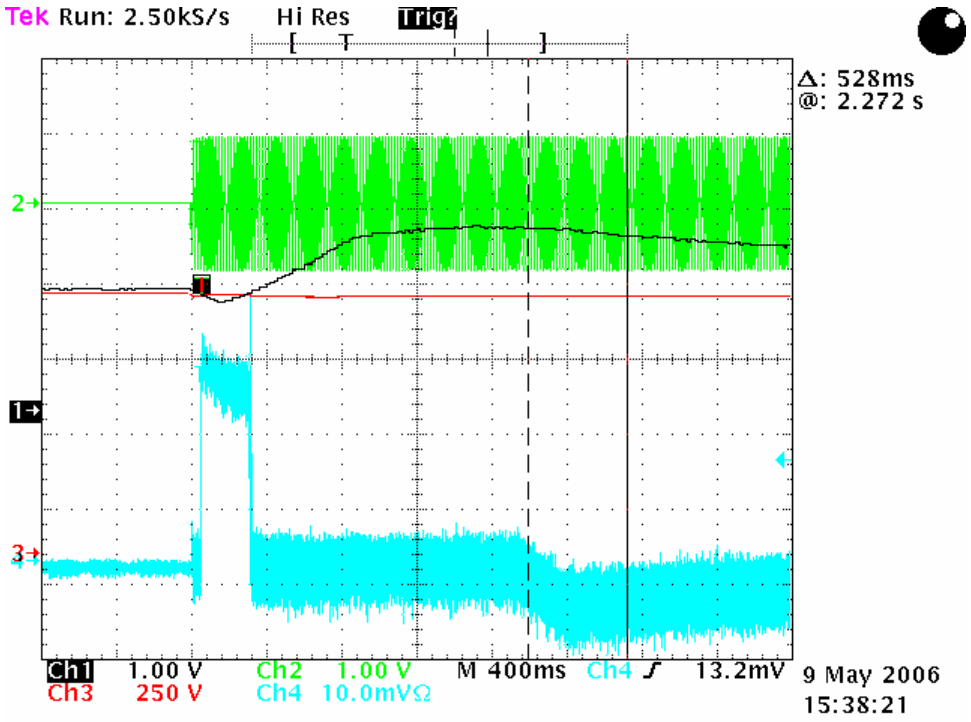


Figure 37 0 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

ii b. 0 – 60 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/0.0 kW	20.0/61.0 kW
Frequency Hz	60.16 Hz	59.16 Hz
Engine Speed (Hz/rpm)	60 / 1800	67.8 / 2034

Table 23 Step Load Evaluation 2b: 0 – 60 kW (w/Surge Module)

ii b. 0 – 60 KW Step Load –Surge Module- Variable Speed

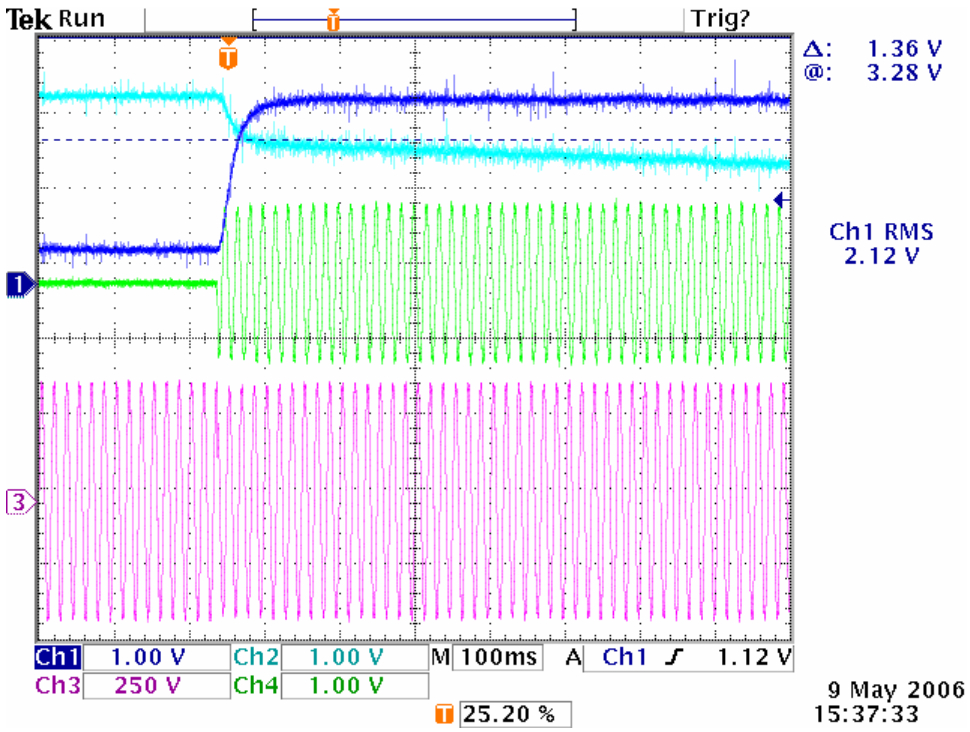


Figure 38 0 –60 kW: Power, Frequency, Voltage, Current

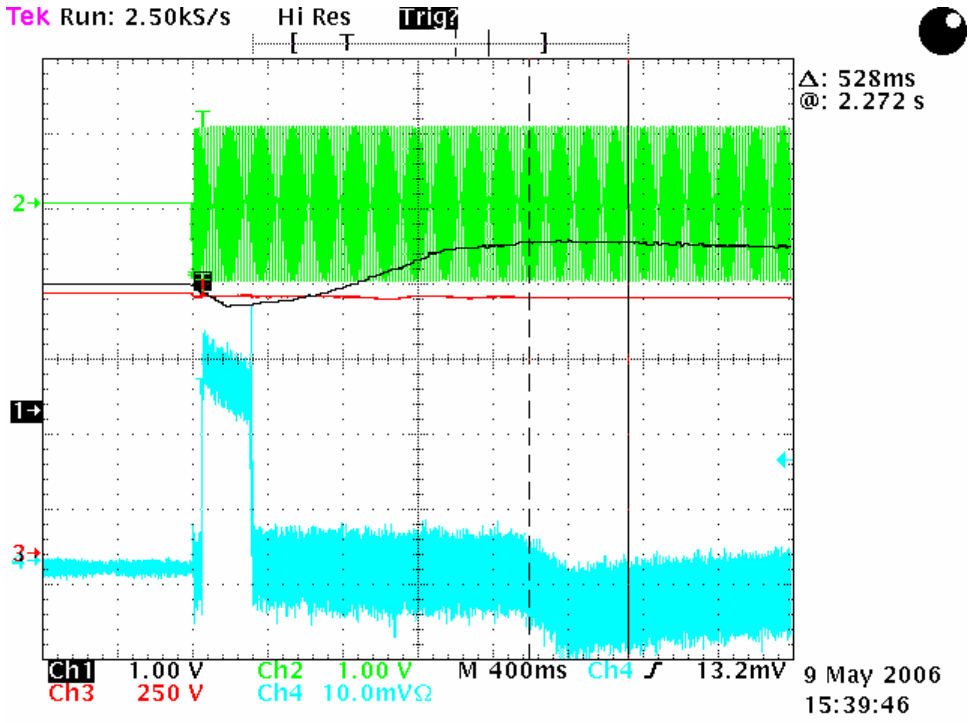


Figure 39 0 – 60 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

xi. Step Load Evaluation 3

1.Load Bank Start Load = 15 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =50 kW (Changed from 45 kW because easier to implement on Load Bank)

	A	B
Unit #1 (S.P/Actual) kW	20.0/15.5 kW	20.0/50.9 kW
Frequency Hz	60.03 Hz	59.74 Hz
Engine Speed (Hz/rpm)	60 / 1800	67.7/ 2031

Table 24 Step Load Evaluation 3: 15 - 50 kW (w/Surge Module)

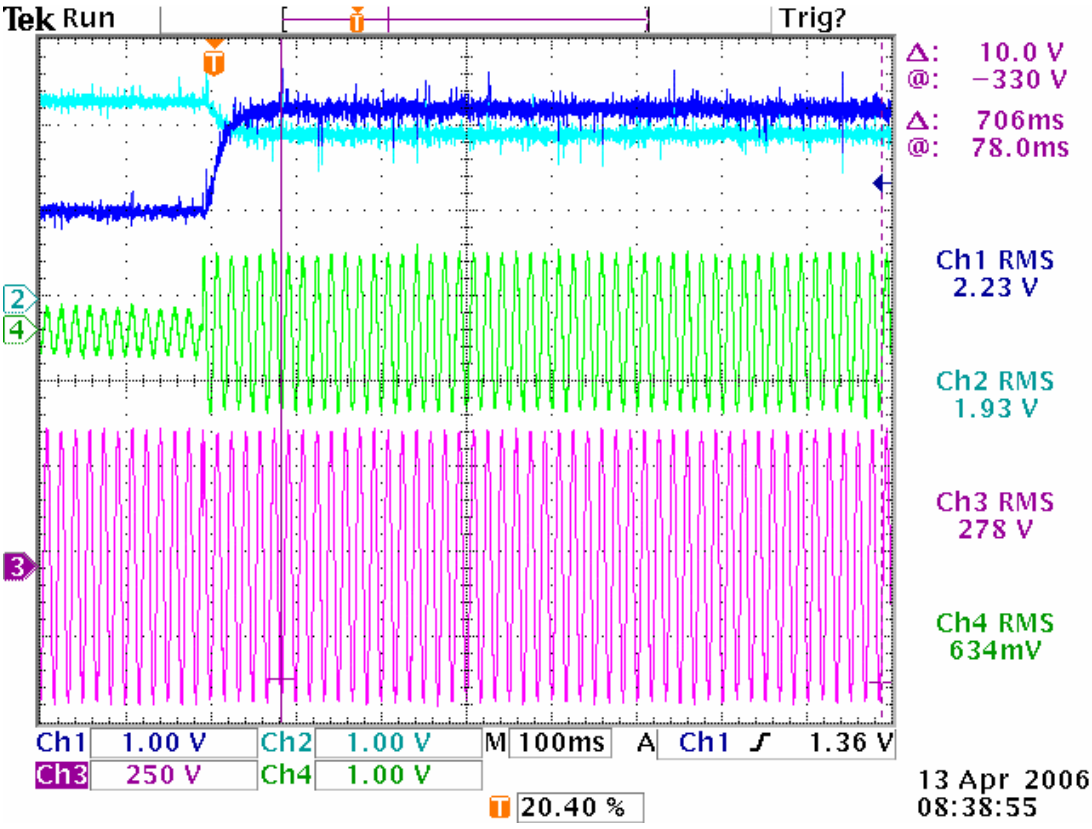


Figure 40 15 – 50 kW: Power, Frequency, Voltage, Current

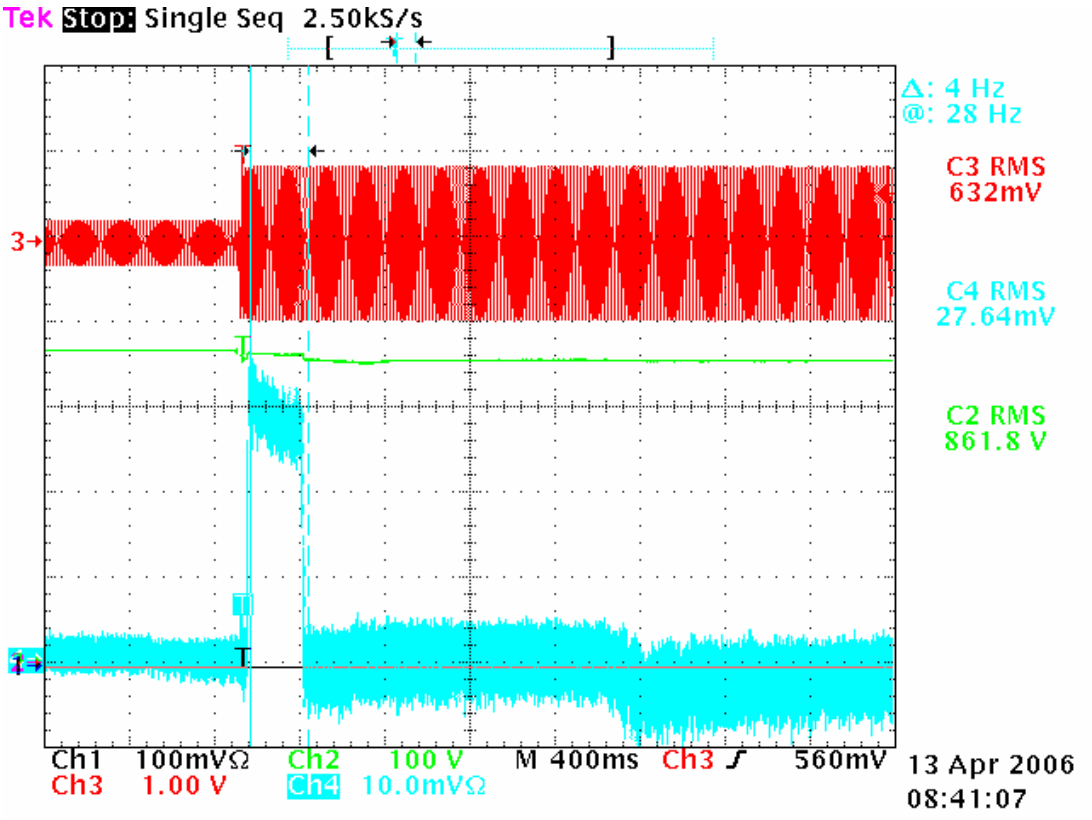


Figure 41 15 – 50 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

xii. Step Load Evaluation 4

1.Load Bank Start Load = 30 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load = 60 kW

iv a. 30 – 55 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) KW	20.0/30.4 kW	20.0/55.8 kW
Frequency Hz	59.91 Hz	59.70 Hz
Engine Speed (Hz/rpm)	60 / 1800	70.1/ 2103

Table 25 Step Load Evaluation 4a: 30 – 55 kW (w/Surge Module)

iv.a 30– 55 KW Step Load –Surge Module- Variable Speed

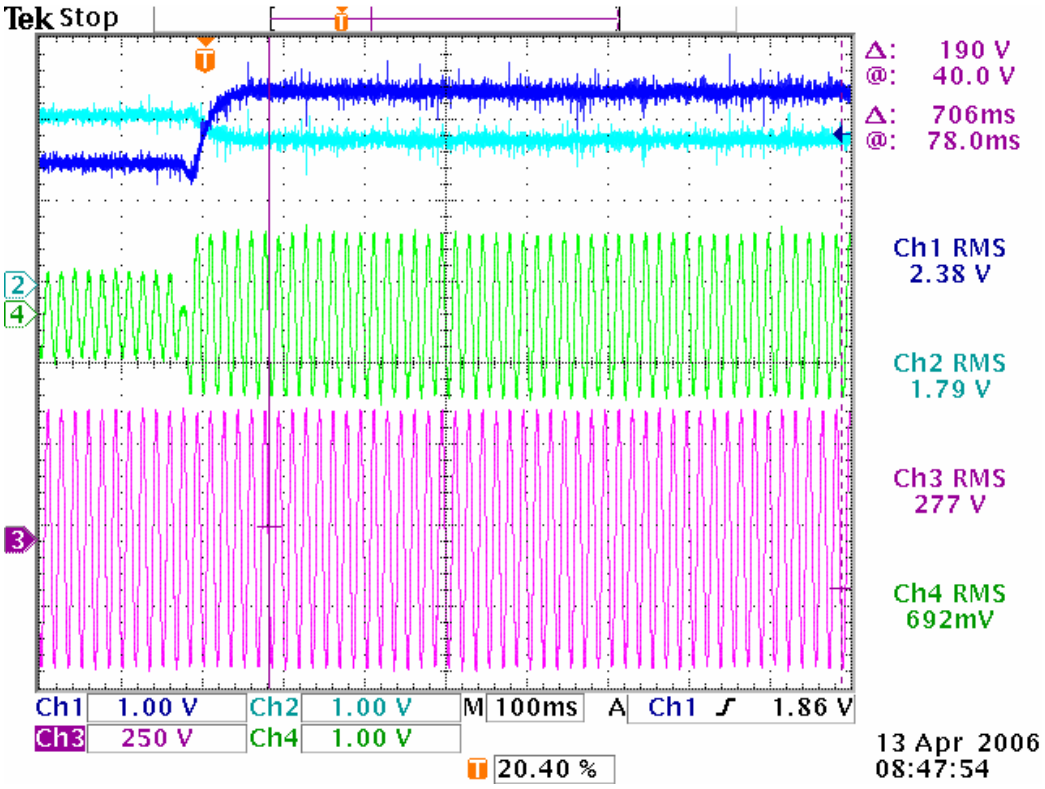


Figure 42 30 –55 kW: Power, Frequency, Voltage, Current

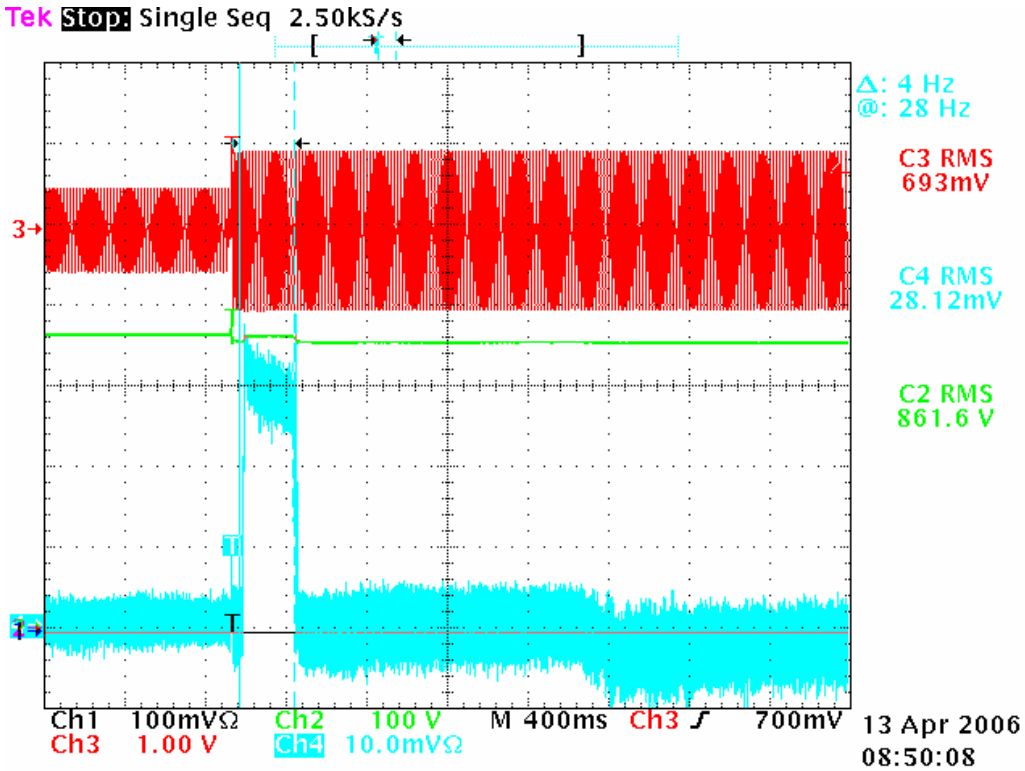


Figure 43 30 – 55 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

iv b. 30 – 60 kW

	A	B
Unit #1 (S.P/Actual) KW	20.0/30.4 kW	20.0/60.7 kW
Frequency Hz	59.91 Hz	59.16 Hz
Engine Speed (Hz/rpm)	60 / 1800	72.5/ 2175

Table 26 Step Load Evaluation 4b: 30 – 60 kW (w/Surge Module)

iv.b 30– 60 KW Step Load –Surge Module- Variable Speed

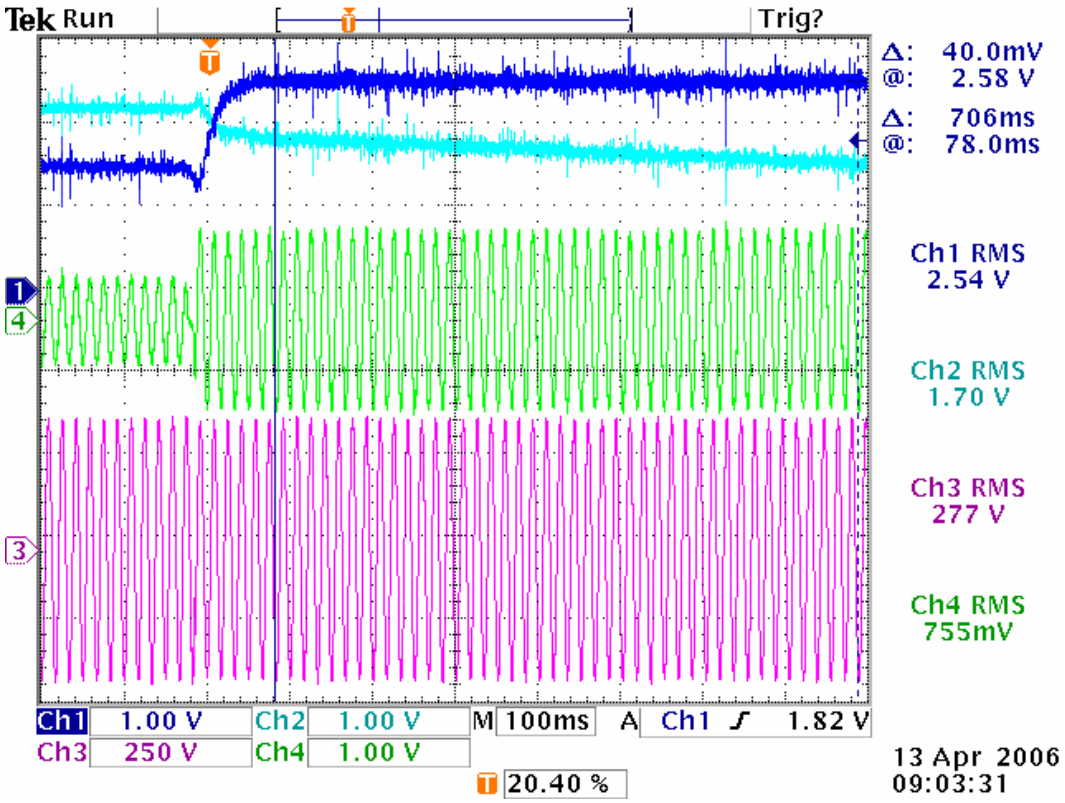


Figure 44 30 – 60 kW: Power, Frequency, Voltage, Current

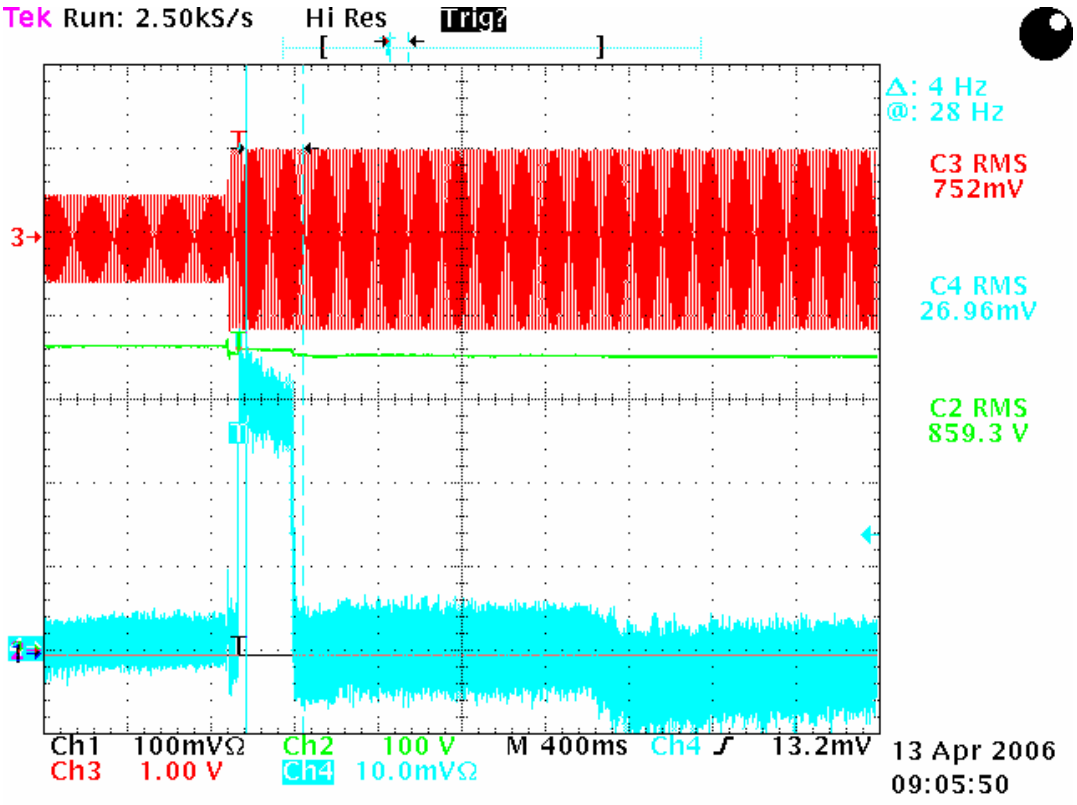


Figure 45 30 – 60 kW: Engine RPM, Bus Voltage, AC Current, Surge Module Current

xiii. Step Load Evaluation 5

1.Load Bank Start Load = 60 kW
2.Unit A CMD = 20 kW
3.Load Bank End Load =0 kW

v a. 60 - 0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/60.7 kW	20.0/0 kW
Frequency Hz	59.16 Hz	60.16 Hz
Engine Speed (Hz/rpm)	72.5/ 2175	60/1800

Table 27 Step Load Evaluation 5a: 60 – 0 kW (w/Surge Module)

60– 0 kW Step Load –Surge Module- Variable Speed

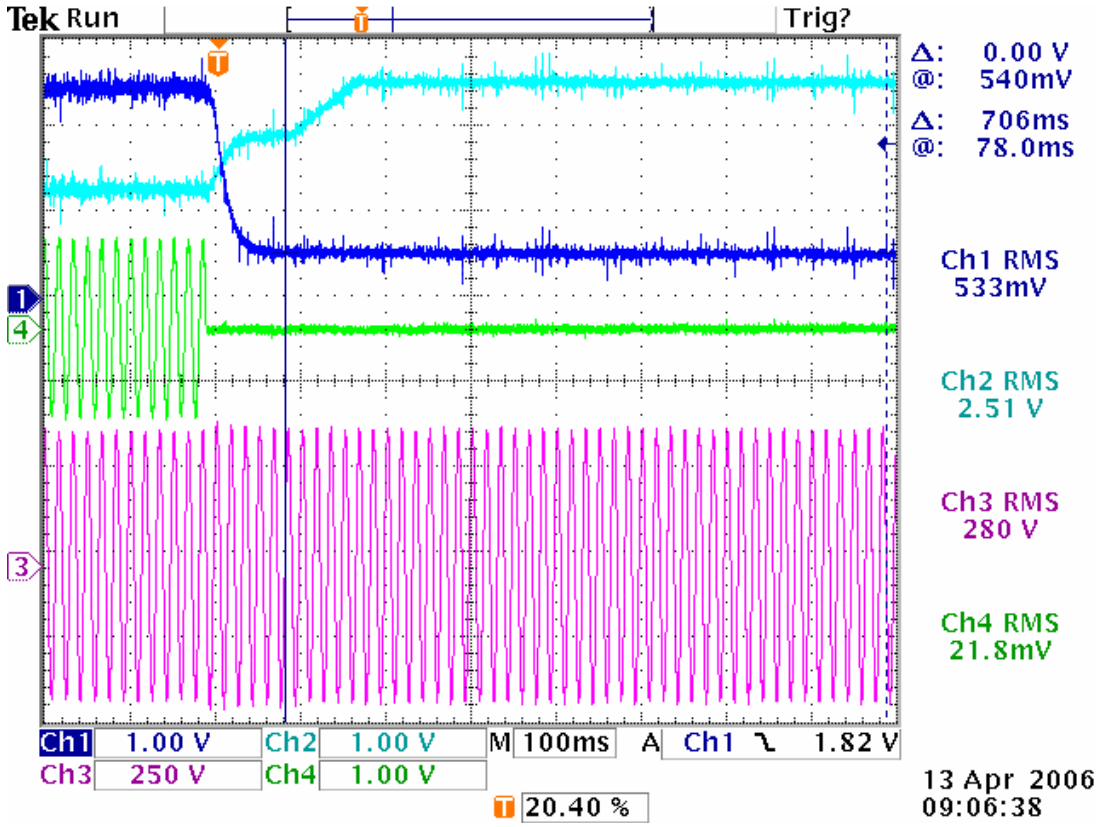


Figure 46 60 – 0 kW: Power, Frequency, Voltage, Current

v b. 55 - 0 kW *(Additional test point done to ensure the frequency did not go out of range if the load slightly exceeded 60 kW from the load bank)*

	A	B
Unit #1 (S.P/Actual) kW	20.0/55.8 kW	20.0/0 kW
Frequency Hz	59.70 Hz	60.16 Hz
Engine Speed (Hz/rpm)	70.1/ 2103	60/1800

Table 28 Step Load Evaluation 5b: 55 – 0 kW (w/Surge Module)

55– 0 kW Step Load –Surge Module- Variable Speed

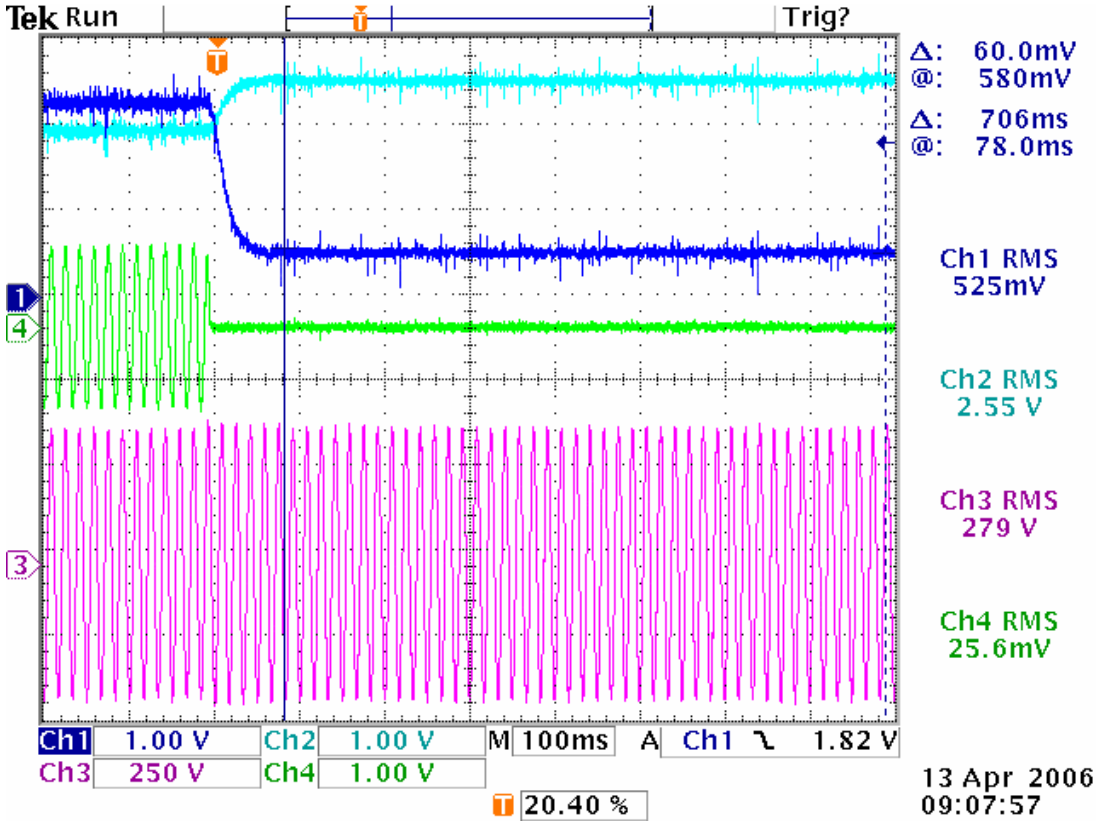


Figure 47 55 – 0 kW: Power, Frequency, Voltage, Current

vi. Step Load Evaluation 6

7. Load Bank Start Load = 30 kW
8. Unit A CMD = 20 kW
9. Load Bank End Load =0 kW

	A	B
Unit #1 (S.P/Actual) kW	20.0/30.4 kW Unit	20.0/0 kW
Frequency Hz	59.91 Hz	60.16 Hz
Engine Speed (Hz/rpm)	60/ 1800	60/1800

Table 29 Step Load Evaluation 6: 30 – 0 kW (w/Surge Module)

30– 0 kW Step Load –Surge Module- Variable Speed

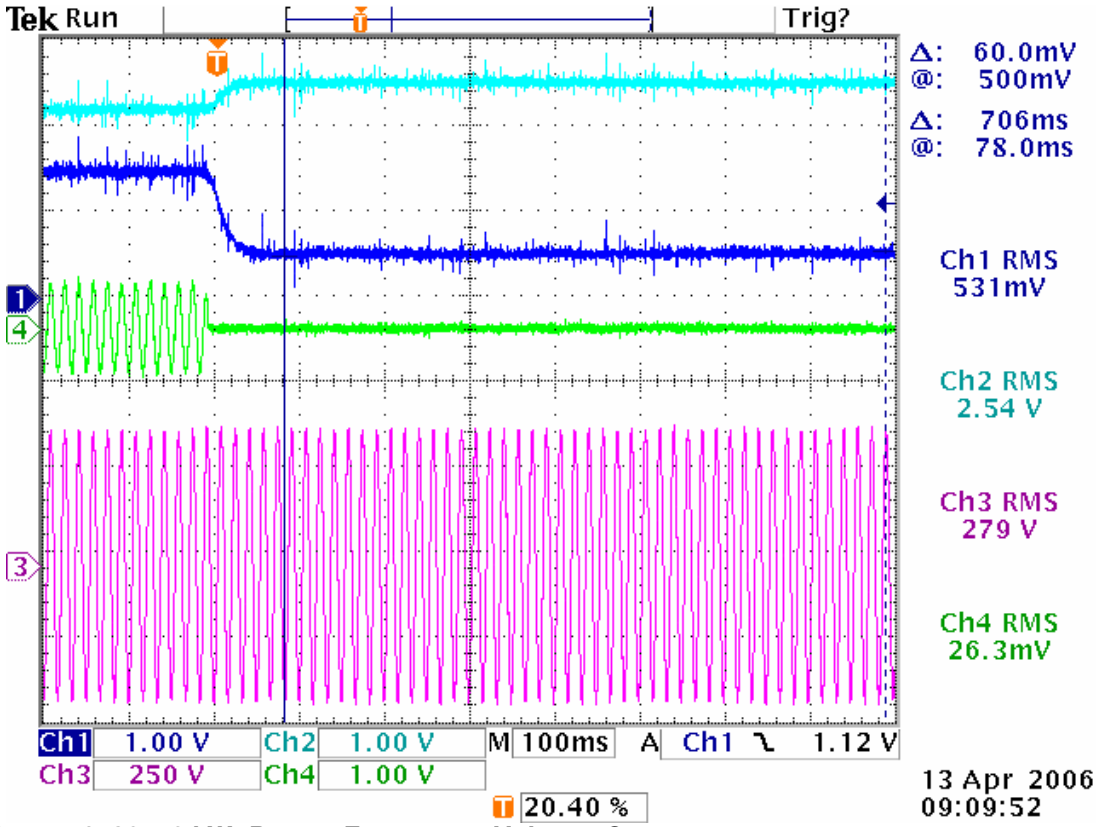


Figure 48 30 – 0 kW: Power, Frequency, Voltage, Current

B.3. Step Load Evaluations without Surge Module – Fixed Speed Operation

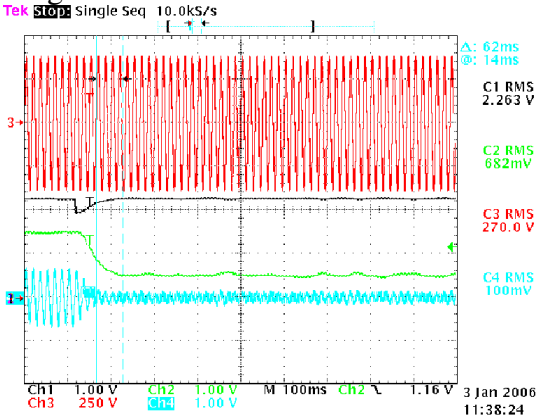
The CHP unit was tested with the surge module disabled. As with the first unit (Serial # 200835), the results confirmed that the dynamics of the engine/inverter allows the unit to successfully handle a step load without the surge module. The engine was set at the fixed speed required for the maximum load step of 0 – 60 kW (2160 rpm). Each step load point was run to confirm Pass/Fail. Oscilloscope data was not recorded since, as demonstrated in the testing of Unit #200835, if the unit "Passes", the electrical output signatures (Figure 1) are the same as in Variable Speed operation.

The following table summarizes the test results.

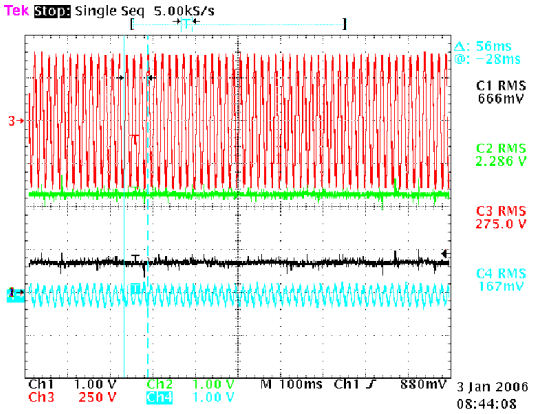
Fixed Engine Speed 2160 rpm (72 Hz) No Surge Module		
	Step Load	**Pass/Fail**
i.	0 – 30 kW	Pass
ii. a	0 – 50 kW	Pass
ii. b	0 – 60 kW	Pass
iii.	15 – 50 kW	Pass
iv. a	30 – 55 kW	Pass
iv. b	30 – 60 kW	Pass
v. a	60 – 0 kW	Pass
v. b	55 – 0 kW	Pass
vi.	30 – 0 kW	Pass

Table 30 Test Point Summary – Step Loads without Surge Module/Fixed Speed

Changed unit A Feeder CMD = 150KW



Unit #1.) Transient Response



Unit #2.) Transient Response

Figure 22 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 3

	A (Grid)	B (Grid)
Load Bank #1(S.P/Actual) KW	80.0/83.9 KW	80.0/83.9 KW
Load Bank #2(S.P/Actual) KW	80.0/84.3 KW	80.0/84.3 KW
Unit #1 (S.P/Pout) KW	120/34.6 KW Feeder	150.0/0.5 KW Feeder
Unit #2 (S.P/Pout) KW	10.0/5.5 KW Unit	10.0/5.5 KW Unit
Frequency Hz	59.98Hz	59.99 Hz

Table 23 Parallel Inverters – Feeder Control, Grid Connected – Digital Round-off Check 3

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Tecogen CHP Modules Commissioning Report

APPENDIX E

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Melissa Jones
Executive Director

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TECOGEN

Natural Gas Engine-Driven Products

TECOCHILL®
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TECOFROST™

Tecogen CHP Modules
Commissioning Report

Introduction

Tecogen, Inc. supplied (3) 60 kW, inverter-based, natural gas engine driven generators to the CERTS research program for the AEP Microgrid Test Bed. Tecogen subcontracted with Youtility Inc. (Hudson, NH) to supply the inverter cabinet. Each unit was packaged on a skid that includes the engine and its subsystems, synchronous generator, Youtility inverter, and the master control system. The master control system was equipped with a communications link to the Northern Power Energy Management System. The master control system also communicates internally with the inverter via a CAN Bus.

Each unit was also equipped with a separate energy storage device, or Surge Module that was also supplied by Youtility. It was packaged in a cabinet for wall mount at the test site. The Surge Module provides 20 kW of battery power for 250 milliseconds to assist the engine/ inverter's response to a step load when the unit is islanded.

All three units were extensively tested prior to shipment to the AEP test site. First, each inverter cabinet was bench-tested at Youtility both individually, and in pairs as a simulated microgrid. Rather than the engine/generator providing the input power, the grid was used as the power source. The purpose of this testing was to verify the implementation of the various microgrid software control algorithms.

Once the Youtility bench testing was complete, the three inverter cabinets were sent to Tecogen for final packaging with the engine/generator. Each module was then tested to verify the integration of the inverter with the engine/generator. The three Surge Modules were also included in the scope of the factory testing at Tecogen to verify their performance. Both phases of the factory testing were successfully completed with each unit meeting the requirements established by the CERTS technical team.

Commissioning of the units commenced in July of 2006. In general, there were some normal shakedown issues encountered in getting the units on line. The most significant problem discovered during the commissioning was the speed control of the engine. The inverter was designed to directly control the engine throttle, via an electronic actuator, to adjust the engine

speed in reaction to the load. It was able to sufficiently accomplish this during normal grid-tie operation where load changes were gradual. However, the units had problems with step loads, even with the assistance of the surge module.

Although this feature was extensively tested at the Tecogen factory, only specific step loads were checked. The control software was tuned to be able to handle these, but it was not possible to check the wide range of possible step-load scenarios at the Tecogen factory. Although additional software tuning by Youtility at the AEP test site may have possibly resolved the problem, Tecogen and Youtility felt a more prudent resolution was to remove the inverter control of the engine speed and use a conventional engine governor. This modification was successfully implemented and the governor was set to control the engine at fixed speed. The engine was then able to reliably handle the various step loads.

However, the change in the method of speed control caused a problem with the surge modules. The inverter software was using the speed signal to trigger the on/off control of the surge modules. When the inverter speed control was disabled, it corrupted the surge module control sequence such that the batteries were allowed to discharge, but not recharge. As a result, all the batteries discharged to such a low level that most of them were permanently damaged. Once this problem was identified, the inverter software was modified and the batteries replaced. The surge modules then successfully operated with the independent governor speed control. Subsequently, the Commissioning Test Matrix was then successfully completed by AEP.

In the following section, the details of the commissioning are summarized in a tabular format. Several documents are referenced in the table and attached to this document, including the test matrix, commissioning checklists, and the test data collected throughout the process.

Tecogen Commissioning Summary

Date	Activity	Attendees	Events	Outstanding Issues
7/10/06-7/12/06	Engine Commissioning	John Freeman (Tecogen)	• Got all three engines operating • See Attachments 2, 3, and 4	
7/26/06 – 7/28/06	Commissioning of inverters and surge modules	John Freeman (Tecogen) Jian Wen (Youtility)	• Corrected Phase Rotation • Ran each unit through individual step loads – islanded. • Paralleled all 3 units together – islanded. • Paralleled all 3 units to the grid and transferred from grid-tie mode to micro-grid mode. • Transferred generator from micro-grid mode to grid-tie mode. • Refer to Attachment 5	• Only could run engines in fixed speed mode – engine would stall with large step loads in variable speed mode • Even in fixed speed mode, engine would stall with 0 – 60 kW • Full Matrix testing not done • Required waveform data not collected • Load banks on generator feeders overheated
8/23/06	Execute Test Matrix in Fixed Speed Mode	John Freeman (Tecogen)	• Ran single unit step load tests on all three units • Frequency droop did not respond properly on all units for the 0 - 60 kW tests. The reason was because the load banks actually produced slightly more the 60 kW putting the software out of its control range. • Unit A2 had a software problem where the frequency droop was not functioning properly at all. It was later determined some of the software constants were inadvertently reset by AEP when testing the EMS system. • Refer to Attachment 6 and 7	• The single unit testing was redone on 8/28/06 by Dave Klapp of AEP. • Repeat testing of Units A1 and B1 at slightly less than 60 kW showed correct frequency droop response. • Refer to Attachments 8, 9, 10
9/19/06 – 9/21/06	Install commercial governor to maintain engine speed at a fixed value independent of Youtility's inverter software.	John Freeman (Tecogen)	• Governor control was successful • Individual unit island tests were completed on units A1, A2 and B1. Surge modules were energized. • Problem arose with units A1 and A2 unable to phase lock. • See Attachments 11 and 12	• The Microgrid interface board was removed from one of the units and brought back to be inspected by Youtility.

Date	Activity	Attendees	Events	Outstanding Issues
10/11/06 – 10/14/06	Correct phase lock problem of A1 and A2 Capture oscilloscope data on surge modules Complete test matrix for multiple units	Jian Wen (Youtility) Paolo Piagi (Youtility) John Freeman (Tecogen)	• Two CT's, installed on the feeders by AEP were found to be reversed causing the phase lock problem. This was corrected. • It was discovered that the testing that occurred after the governors had been installed damaged the surge modules. By disabling the Youtility engine speed control software, the surge module control was adversely affected. The batteries discharged to such a low value that they were permanently damaged. The software was updated on all three units. New batteries were obtained to repair the A2 surge module. The governor speed setting was reduced from 2000 rpm to 1750 rpm on A2 to allow the surge module to trigger. The single unit step-load tests were run on unit A2 and oscilloscope waveforms were obtained. The surge module function on unit A2 was found to be acceptable. • The Commissioning Test Matrix was completed on all three units. Units A1 and B1 had the surge modules off with the engine speed fixed at 2200 rpm. Unit A2 had the surge module functioning. All tests passed. • See Attachments 13 and 14	• New batteries for surge modules A1 and B1 were going to be obtained and installed by AEP. John Stevens was going to evaluate the surge module design to determine if any design changes or additional sensors, for diagnostics or fault detection, would be required before commencing with further testing. • Once the surge modules got back on line, AEP would redo the matrix testing for all three units.
1/ 07	Replace cylinder head on engine A2	Bob Buday (Tecogen)	• The cylinder head had a factory defect causing water to leak into the exhaust.	• None

ATTACHMENTS

1. Commissioning Test Matrix

	Microsource Generators		
Test Point	**A1**	**A2**	**B1**
Island Tests			
Individual Unit – Power Control Mode *Scheduled 7/11 – 7/12 by Tecogen*			
I.a.i	X	X	X
I.a.ii	X	X	X
I.a.iii	X	X	X
I.a.iv	X	X	X
I.a.v	X	X	X
I.a.vi	X	X	X
Two Unit-Power Control Mode *Scheduled 7/26 –7/28 by Tecogen & Youtility*			
II.c.i	X	X	
II.c.ii	X	X	
II.c.i	X		X
II.c.ii	X		X
Grid Tie Tests			
Two Unit –Power Control Mode *Scheduled 7/26 –7/28 by Tecogen & Youtility*			
II.a.i	X	X	
II.a.i		X	X
Two Unit – Mixed Mode *Scheduled 7/26 –7/28 by Tecogen & Youtility*			
III.a.i	X	X	
III.a.i		X	X
Grid Tie to Island Tests			
Two Unit –Power Control Mode *Scheduled 7/26 –7/28 by Tecogen & Youtility*			
II.b.i	X	X	
II.b.i		X	X
Two Unit – Mixed Mode *Scheduled 7/26 –7/28 by Tecogen & Youtility*			
III.b.i	X	X	
III.b.i		X	X

Attachment 2

TECOGEN
Natural Gas Engine-Driven Products

TECOCHILL™
TECOGEN®
TecoFROST™

Tecogen Generator Commissioning Plan

Revision 1, 06/09/06

Unit Serial Number: 200837 unit A 1

Date: 7-11-06

By: John Freeman

Each Tecogen unit will go through the procedure presented in this document.

I. Inspection

1. Inspect Exhaust System
   - ✓a. Self-supporting – no significant force applied to exhaust connection
   - b. Insulated and with fire - resistant roof penetration
   - ✓c. Proper termination that prevents rainwater from entering piping system

2. Inspect Natural Gas System
   - ✓a. Proper pipe size
   - b. Dead-end Lock-up type regulator
   - ✓c. Gas supply pressure: 10 – 28" wc

3. Inspect Engine Coolant and Oil systems for leaks.

II. Energize Control Power

✓1. Ensure breaker on cabinet door is open.

✓2. Reconnect battery negative cable.

✓3. Energize 208 Volt power to coolant pump.

✓4. Close microprocessor switch to boot up control system.

✓5. Check all Input switch positions

Safety Switch	Position	Check
Low Engine Oil Level	On	✓
Low Coolant Pressure	Off	✓
Low Engine Oil Pressure	Off	✓
High Coolant Pressure	On	✓

6. Check all Temperatures

Thermistors	Record
Engine Coolant Temperature	77.6
Engine Oil Temperature	75.3
Ambient Temperature	74.9
~~High Coolant Pressure~~	
Water Temperature In	77.4
Water Temperature Out	77.3

7. Energize Outputs in Calibrate Mode

   a. Coolant System Pump
      i. Open shut-off valves to unit
      ii. Record System Static Pressure: _____
      iii. Energize Main System Circulating Pump
      iv. Record Inlet and Outlet Pressure of Main Pump
      Inlet Pressure: _____
      Outlet Pressure: _____
      v. Check Low Coolant Pressure Switch is "On"

   b. Natural Gas System
      i. Open shut-off valve to unit
      ii. Energize Gas Solenoid
      iii. Bleed Gas Line
      iv. Record Gas Pressure: 14" inlet 4" outlet

   c. Energize Inverter Control Power
      i. Record MAP Pressure: 28.9

   d. Energize Alarm Output

III. Start Engine – No Electric Power Output

✓1. Ensure breaker on cabinet door is still open.
✓2. Ensure system is set to Variable Speed mode.
✓3. Disconnect Field Control (J5).
✓4. Start engine and verify proper speed loop operation. It should shut down after approximately 10 seconds.
✓5. Reconnect Field Control.
✓6. Restart engine.
7. Check and record the following:
   a. Engine Timing: 30°
   b. Engine Oil Pressure: 50
   c. DC Bus Voltage: _____
8. Engine will shut down once PCS is energized.

III. Generate Power using Load Bank (Static Switch Open)

1. Close breaker on cabinet door.
2. Restart Engine
3. Apply 10 kW load. Check the following: 20 KW
   a. Speed Control
   b. Engine Temperatures
   c. Voltage and Current Output
   d. Verify Emergency Stop button
4. Restart and slowly bring load up to 60 kW. Continuously check the following:
   a. Speed Control
   b. Engine Temperatures
   c. Voltage and Current Output
5. Download 60 kW data with RMCS

IV. Perform Step Load Tests – Refer to Northern Power's Commissioning Plan – Section 10

1. 0 – 30 kW
2. 0 - 60 kW
3. 15 - 50 kW
4. 30 – 60 kW
5. 60 – 0 kW
6. 30 – 0 kW

Attachment 3

TECOGEN
Natural Gas Engine-Driven Products

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TECOGEN®
TecoFROST™

Tecogen Generator Commissioning Plan

Revision 1, 06/09/06

Unit Serial Number: 200836 unit 42

Date: 7-11-06

By: John Freeman

Each Tecogen unit will go through the procedure presented in this document.

I. Inspection

1. Inspect Exhaust System
   - ✓ a. Self-supporting – no significant force applied to exhaust connection
   - b. Insulated and with fire - resistant roof penetration Not Yet
   - ✓ c. Proper termination that prevents rainwater from entering piping system

2. Inspect Natural Gas System
   - ✓ a. Proper pipe size
   - ✓ b. Dead-end Lock-up type regulator
   - ✓ c. Gas supply pressure: 10 - 28" wc 14" static

3. Inspect Engine Coolant and Oil systems for leaks.

II. Energize Control Power

✓ 1. Ensure breaker on cabinet door is open.

✓ 2. Reconnect battery negative cable.

✓ 3. Energize 208 Volt power to coolant pump.

✓ 4. Close microprocessor switch to boot up control system.

✓ 5. Check all Input switch positions

Safety Switch	Position	Check
Low Engine Oil Level	On	✓
Low Coolant Pressure	Off	✓
Low Engine Oil Pressure	Off	✓
High Coolant Pressure	On	✓

6. Check all Temperatures

Thermistors	Record
Engine Coolant Temperature	72.2
Engine Oil Temperature	73.5
Ambient Temperature	78.7
~~High Coolant Pressure~~	
Water Temperature In	72.2
Water Temperature Out	74.4

7. Energize Outputs in Calibrate Mode

   a. Coolant System Pump
      i. Open shut-off valves to unit
      ii. Record System Static Pressure: 15 psi
      iii. Energize Main System Circulating Pump
      iv. Record Inlet and Outlet Pressure of Main Pump
      Inlet Pressure: _____
      Outlet Pressure: _____
      v. Check Low Coolant Pressure Switch is "On"

   b. Natural Gas System
      i. Open shut-off valve to unit
      ii. Energize Gas Solenoid
      iii. Bleed Gas Line
      iv. Record Gas Pressure: 16"

   c. Energize Inverter Control Power
      i. Record MAP Pressure: 29.5

   d. Energize Alarm Output

III. Start Engine – No Electric Power Output

✓ 1. Ensure breaker on cabinet door is still open.

✓ 2. Ensure system is set to Variable Speed mode.

✓ 3. Disconnect Field Control (J5).

✓ 4. Start engine and verify proper speed loop operation. It should shut down after approximately 10 seconds.

✓ 5. Reconnect Field Control.

✓ 6. Restart engine.

✓ 7. Check and record the following:

   a. Engine Timing: 30°
   b. Engine Oil Pressure: 78
   c. DC Bus Voltage: 432

✓ 8. Engine will shut down once PCS is energized.

III. Generate Power using Load Bank (Static Switch Open)

1. Close breaker on cabinet door.
2. Restart Engine
3. Apply 10 kW load. Check the following:
    a. Speed Control
    b. Engine Temperatures
    c. Voltage and Current Output
    d. Verify Emergency Stop button
4. Restart and slowly bring load up to 60 kW. Continuously check the following:
    a. Speed Control
    b. Engine Temperatures
    c. Voltage and Current Output
5. Download 60 kW data with RMCS

IV. Perform Step Load Tests – Refer to Northern Power's Commissioning Plan – Section 10

1. 0 – 30 kW
2. 0 - 60 kW
3. 15 - 50 kW
4. 30 60 kW
5. 60 0 kW
6. 30 – 0 kW

Attachment 4

TECOGEN
Natural Gas Engine-Driven Products

TECOCHILL®
TECOGEN ®
TECOFROST™

Tecogen Generator Commissioning Plan

Revision 1, 06/09/06

Unit Serial Number: 200835 unit B1

Date: 7-11-06

By: John Freeman

Each Tecogen unit will go through the procedure presented in this document.

I. Inspection

1. Inspect Exhaust System
   - ✓a. Self-supporting no significant force applied to exhaust connection
   - b. Insulated and with fire - resistant roof penetration stack not yet insulated.
   - ✓c. Proper termination that prevents rainwater from entering piping system

2. Inspect Natural Gas System
   - ✓a. Proper pipe size
   - ✓b. Dead-end Lock-up type regulator
   - ✓c. Gas supply pressure: 10 - 28" wc 14"

3. Inspect Engine Coolant and Oil systems for leaks.

II. Energize Control Power

✓ 1. Ensure breaker on cabinet door is open.

✓ 2. Reconnect battery negative cable.

✓ 3. Energize 208 Volt power to coolant pump.

✓ 4. Close microprocessor switch to boot up control system.

✓ 5. Check all Input switch positions

Safety Switch	Position	Check
Low Engine Oil Level	On	✓
Low Coolant Pressure	Off	✓
Low Engine Oil Pressure	Off	✓
High Coolant Pressure	On	✓

6. Check all Temperatures

Thermistors	Record
Engine Coolant Temperature	74.4
Engine Oil Temperature	74.3
Ambient Temperature	74.4
~~High Coolant Pressure~~	
Water Temperature In	73.9
Water Temperature Out	73.9

7. Energize Outputs in Calibrate Mode

   a. Coolant System Pump
      i. Open shut-off valves to unit
      ii. Record System Static Pressure: 15 psi
      ✓iii. Energize Main System Circulating Pump
      iv. Record Inlet and Outlet Pressure of Main Pump
         Inlet Pressure: _____
         Outlet Pressure: _____
      v. Check Low Coolant Pressure Switch is "On"

   b. Natural Gas System
      i. Open shut-off valve to unit
      ii. Energize Gas Solenoid
      iii. Bleed Gas Line
      iv. Record Gas Pressure: 12"

   c. Energize Inverter Control Power
      i. Record MAP Pressure: 29.4

   d. Energize Alarm Output

_____ III. Start Engine – No Electric Power Output

✓1. Ensure breaker on cabinet door is still open.

✓2. Ensure system is set to Variable Speed mode.

✓3. Disconnect Field Control (J5).

4. Start engine and verify proper speed loop operation. It should shut down after approximately 10 seconds.

5. Reconnect Field Control.

6. Restart engine.

7. Check and record the following:
   a. Engine Timing: 30°
   b. Engine Oil Pressure: 49
   c. DC Bus Voltage: 432

8. Engine will shut down once PCS is energized.

III. Generate Power using Load Bank (Static Switch Open)

1. Close breaker on cabinet door.
2. Restart Engine
3. Apply 10 kW load. Check the following:
    a. Speed Control
    b. Engine Temperatures
    c. Voltage and Current Output
    d. Verify Emergency Stop button
4. Restart and slowly bring load up to 60 kW. Continuously check the following:
    a. Speed Control
    b. Engine Temperatures
    c. Voltage and Current Output
5. Download 60 kW data with RMCS

IV. Perform Step Load Tests – Refer to Northern Power's Commissioning Plan Section 10

1. 0 – 30 kW ✓
2. 0 - 60 kW ✓
3. 15 - 50 kW ✓
4. 30 - 60 kW ✓
5. 60 - 0 kW ✓
6. 30 - 0 kW ✓

5. CERTS Microgrid Initial Test at AEP (7/26/06 – 7/28/06)

- Fixed unit A1 speed control problem.
- Updated firmware for all 3 units.
- Tested each unit in variable speed mode using Zone 4 load bank.
    - Step up 30KW
    - Step down 30KW
    - Step up 60KW
    - Step down 60KW

- Paralleled A1 and A2 units. Set variable speed mode as initial test, however, engine control failed to handle 60KW step load.
  Changed to fix speed mode, and ran engine at 2070 RPW. Tested A1 and A2 using Zone 4 load bank.
    - Step up 60KW
    - Step down 60KW
    - Step up 90KW
    - Step down 90KW

  After certain run time, Zone 4 load bank was over heat and failed.

- Paralleled all 3 A1, A2 and B1 units together.
  Set engine control as fix speed mode, and engine speed at 2070 RPW. Used the load near the grid input site, and tested
    - Step up 50KW, + 50KW, + 50KW
    - - 50KW, - 50KW, -50KW
    - Step up 100KW
    - Step down 100KW
    - Step up 150KW
      (performed this test few more times as John requested)
    - Step down 150KW
    - Step up 150KW, + 30 KW gradually
    - Step down 180KW
    - Step up 150KW, + 30 KW step, fail

- Turned on grid, turned on static switch.
  Set load bank to 150KW.
  Set all 3 units as power control mode and set power command to 10KW.
  Tied all 3 units to the grid in the sequence of A1, A2, and B1.
  Each unit exported about 10KW.
  Opened the grid switch, all 3 unit ran at micro-grid mode and power 150KW.

- Turned on grid, turned on static switch.
  Set load bank to 150KW.
  Set all 3 units as power control mode and set power command to 50KW.
  Tied all 3 units to the grid in the sequence of A1, A2, and B1.
  Each unit exported about 50KW.
  Opened the grid switch, all 3 unit ran at micro-grid mode and power 150KW.

- Turned on B1, and step 50KW load.
  Ran 30 min.
  Tuned on A1 and A2.
  Set load bank to 150KW.
  Ran 90 min.
  Shuted down all 3 units.

- Turned on B1.
  Set B1 as power control mode, and power command = 10KW.
  Set Zone 5 load bank = 15KW.
  Turned on gird.
  Set load bank near the grid to 50KW.
  Enable the static switch, few minuets later, static switch automatically closed, and B1 tied to the grid successfully.

- Turned on B1.
  Set B1 as power control mode, and power command = 10KW.
  Set Zone 5 load bank = 30KW.
  Turned on gird.
  Set load bank near the grid to 50KW.
  Enable the static switch, few minuets later, static switch automatically closed, and B1 tied to the grid successfully.

6. Test Log for 8-23-06

Time	Test	Unit	Load Bank	Load (kW)
10:06 am	Trigger Test			
10:49 am	I.a.i	A1	3	0-30
10:51 am	I.a.vi	A1	3	30-0
10:56 am	I.a.ii	A1	3	0-60
11:00 am	I.a.v	A1	3	60-0
11:04 am	I.a.iii	A1	3	15-50

Time	Test	Unit	Load Bank	Load (kW)
11:12 am	I.a.i	A2	4	0-30
11:16 am	Ignore data			
11:20 am	I.a.vi	A2	4	30-0
11:24 am	I.a.ii	A2	4	0-60
11:28 am	I.a.v	A2	4	60-0
11:32 am	I.a.iii	A2	4	15-50

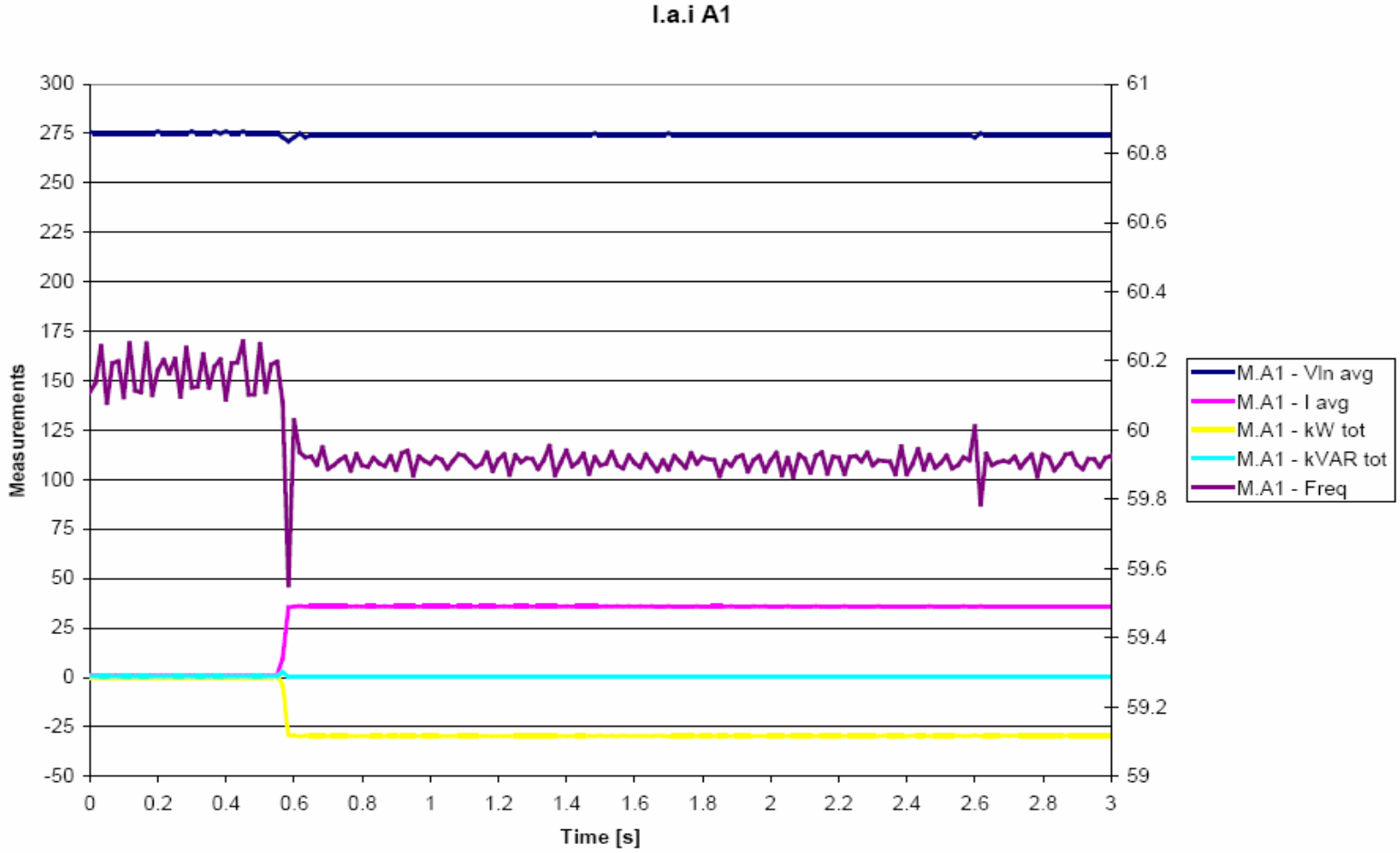
Time	Test	Unit	Load Bank	Load (kW)
11:46 am	Ignore Data (Engine Overspeed)			
11:56 am	I.a.i	B1	5	0-30
12:00 pm	I.a.vi	B1	5	30-0
12:04 pm	I.a.ii	B1	5	0-60
12:08 pm	I.a.v	B1	5	60-0
12:12 pm	I.a.iii	B1	5	15-50

Time	Test	Unit	Load Bank	Load (kW)
01:44 pm	Closed CB41 A1 was running with 50kW on Load Bank 3, No load on Load Bank 4			
02:15 pm	Generator A1 and A2 were load sharing 50kW, Generators carrying 50kW of load at 60Hz frequency, A2 performing as if it were Utility connected. Altering power output command would result in corresponding change in actual power output. We believe event was captured with a manual trigger.			

Note: “cpt” means cycles pre-trigger

03:10 pm	I.I.c.i (part2)(5 cpt)	A1*A2	3 50	
03:16 pm	I.I.c.i (part2)(13 cpt)	A1*A2	3 50	
03:26 pm	I.I.c.i (part3)	A1*A2	#3/50 #4/70	50-120

7. Test Results for 8-23-06



8. Test Log for 8-28-06

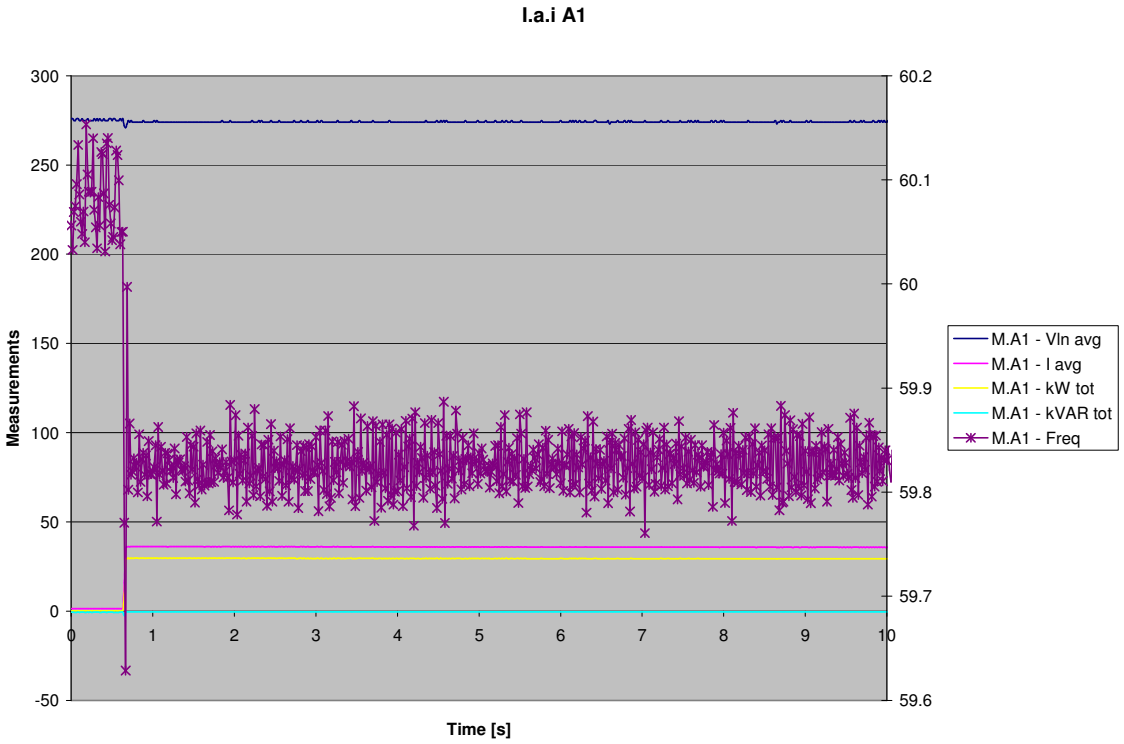
Time	Test		Unit		Load Bank	Load (kW)
Generator A1						
12:44 pm	Trigger Test					
12:58 pm	I.a.i		A1		3	0-30
1:03 pm	I.a.ii	A1		3		0-55
1:06 pm	I.a.iii	A1		3		15-45
1:09 pm	I.a.iv	A1		3		30-55
1:12 pm	I.a.v	A1		3		55-0
1:15 pm	I.a.vi	A1		3		30-0
1:28 pm	I.a.i	A2		4		0-30
1:31 pm	I.a.ii	A2		4		0-55
1:34 pm	I.a.iii	A2		4		15-45
1:37 pm	I.a.iv	A2		4	Genset No Field Sig	30-55
1:42 pm	I.a.iv	A2		4	Genset No Field Sig	30-55
1:46 pm	I.a.v	A2		4		55-0
1:49 pm	I.a.vi	A2		4		30-0
5:04 pm	I.a.i	B1		5	Genset Overspeed	0-30
5:08 pm	I.a.i	B1		5	Genset Overspeed	0-30
5:13 pm	I.a.ii	B1		5		0-55
5:16 pm	I.a.iii	B1		5	Genset No Field Sig	15-45
5:22 pm	I.a.iii	B1		5		15-45
5:25 pm	I.a.iv	B1		5	Genset No Field Sig	30-55
5:29 pm	I.a.iv	B1		5	Genset No Field Sig	30-55
5:37 pm	I.a.v	B1		5		55-0
5:40 pm	I.a.vi	B1		5		30-0

9. Test Log for 8-31-06

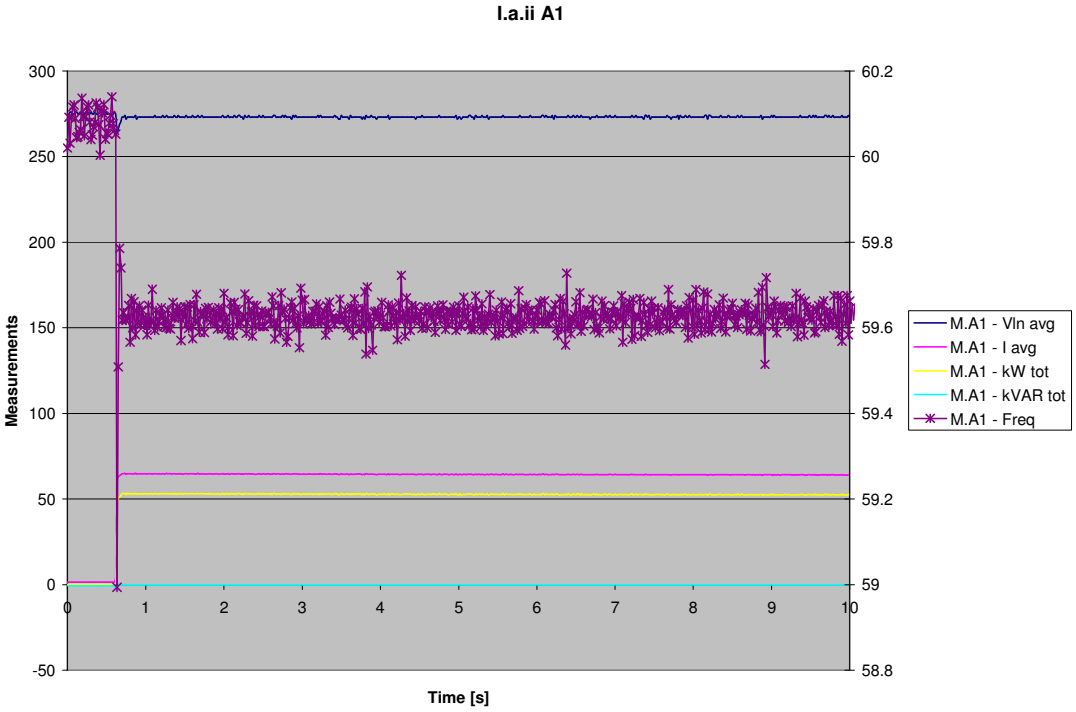
Time	Test	Unit	Load Bank		Load (kW)
Generator A1 and B1 w/out surge module					
8:22 am	II.c.i (Part 2)	A1+B1	3		55
	A1 initially loaded to 50kW, B1 was then connected.				
	Power Command: A1 = 6, B1 = 0				
8:27 am	II.c.i (Part 3)	A1+B1	3+5	Gensets Stalled 55-120	
	A1 and B1 load step together. Power Command: A1 = 6, B1 = 0				
	A1 = No Field Sig, B1 = Boost Fault				
8:38 am	II.c.i (Part 2)	A1+B1	3		55
	A1 initially loaded to 50kW, B1 was then connected.				
	Power commanded: A1 = 0, B1 = 6				
	Repeated due to setpoint mismatch				
8:44 am	II.c.i (Part 3)	A1+B1	3+5	Gensets Stalled 55-120	
	A1 and B1 load step together. Power Command: A1 = 0, B1 = 6				
	A1 = No Field Sig, B1 = Boost Fault				
8:54 am	Custom Test	A1+B1	3+5	Gensets Stalled 55-115	
	A1 and B1 load step together. Power Command: A1 = 0, B1 = 6				
9:01 am	Custom Test	A1+B1	3+5	Gensets Stalled 50-120	
	A1 and B1 load step together. Power Command: A1 = 0, B1 = 6				
	A1 = No Field Sig, B1 = Boost Fault				
9:15 am	II.c.ii	A1+B1	3		95-0
	A1 and B1 load step together. Power Command: A1 = 0, B1 = 6				
	Altered test because a single load step of 95kW is the maximum possible.				
9:49 am	Ignore Data Trigger Test of CB12 Opening				
10:16 am	II.a.i	A1+A2	3+4		30-90
	A1 and A2 load step together. Power Command: A1 = 20, A2 = 40				
10:23 am	II.b.i	A1+A2	3+4		40
	A1 and A2 Island Power Command: A1 = 6, A2 = 54				
11:12 am	II.a.i	A1+B1	3+5		30-90
	A1 and B1 load step together Power Command: A1 = 40, B1 = 20				
11:18 am	II.b.i	A1+B1	3+5	Genset Stalled	40
	B1 and A1 island Power Command: A1 = 54, B1 = 6				
11:35 am	II.b.i	A1+B1	3+5	Genset Stalled	40
	B1 and A1 island Power Command: A1 = 54, B1 = 6				

10. Test Results for 8-31-06

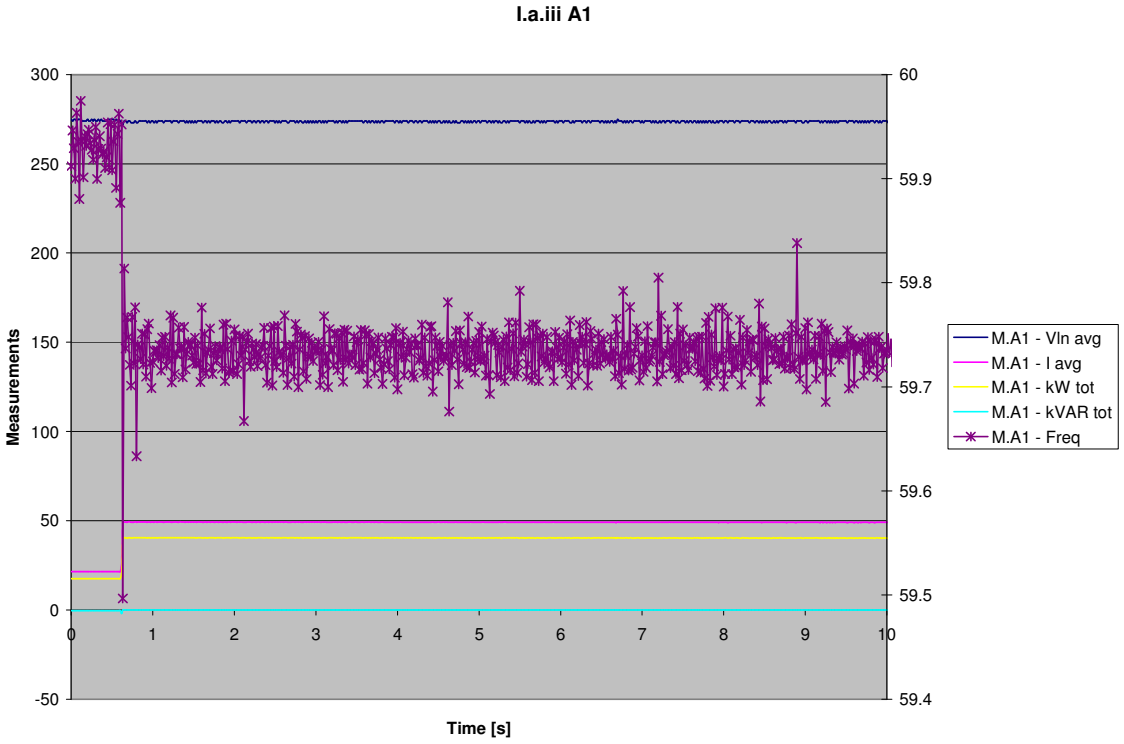
Test I.a.i A1 = 0 – 29.5kW load step



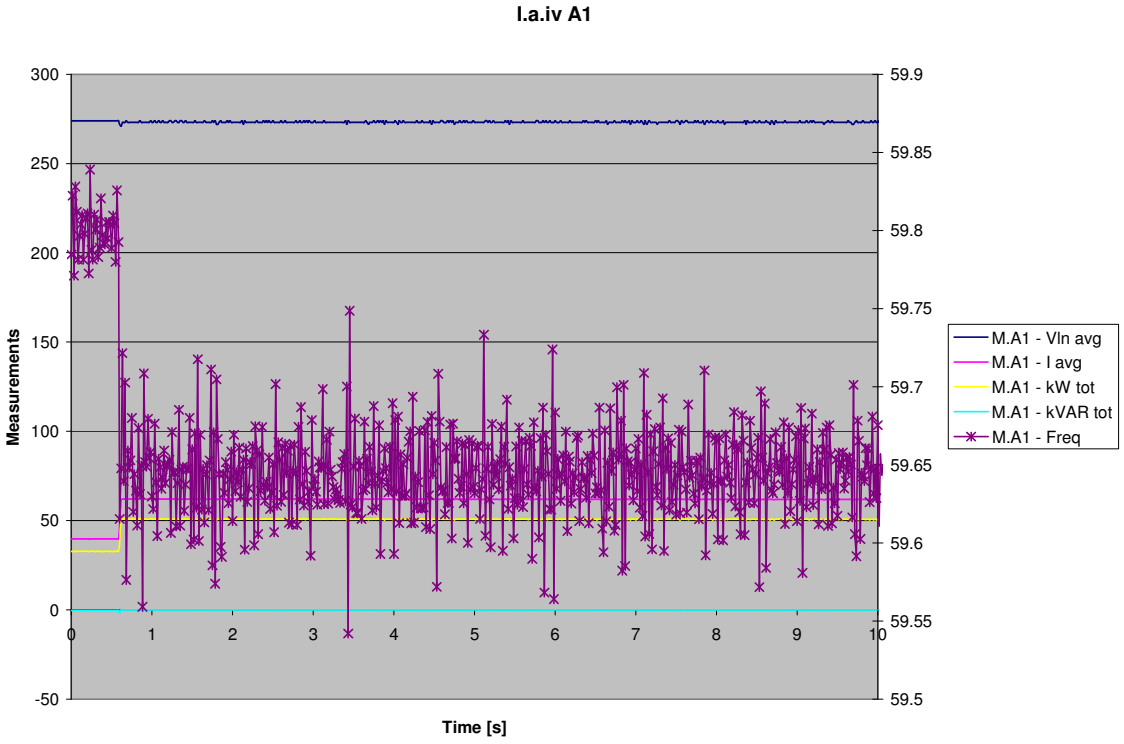
Test I.a.ii A1 = 0 – 53kW load step



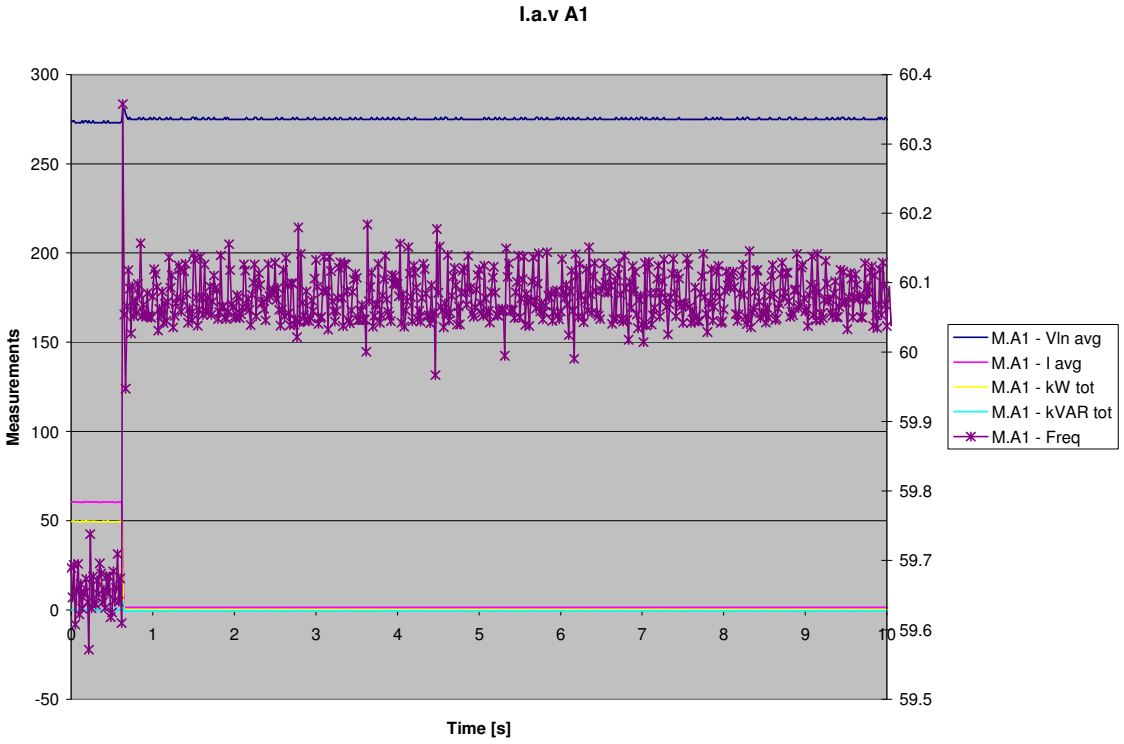
Test I.a.iii A1 = 17.6 – 40.5kW load step



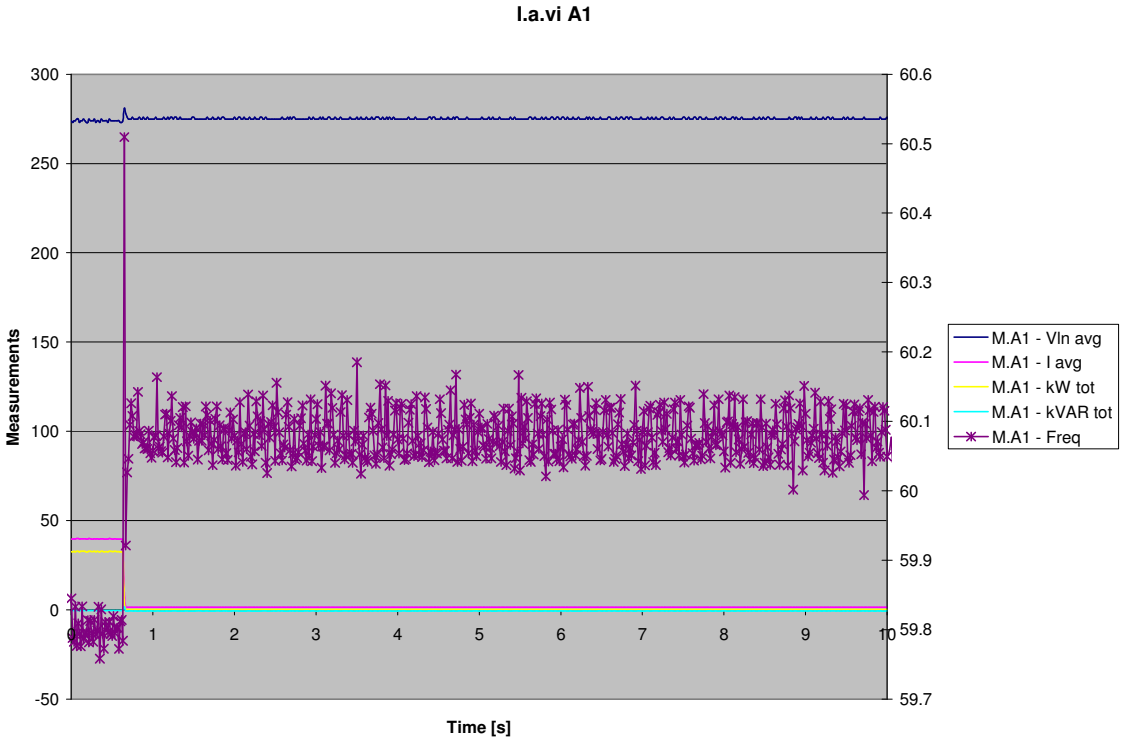
Test I.a.iv A1 = 32.6 – 50.8kW load step



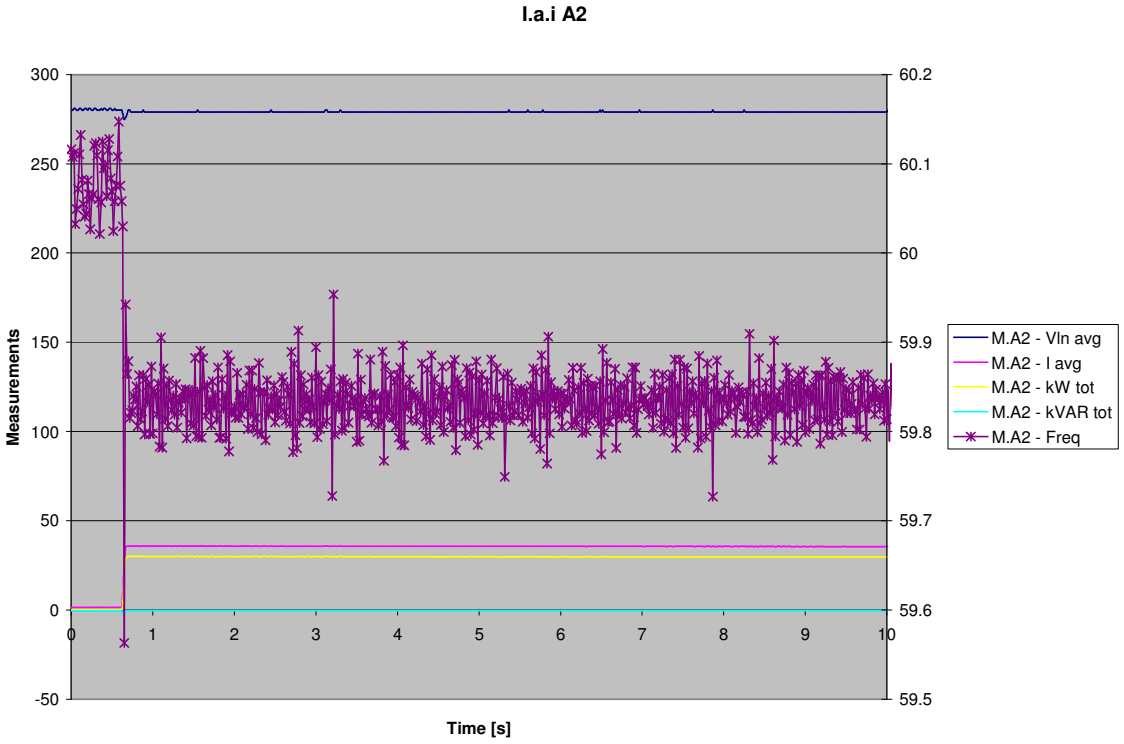
Test I.a.v A1 = 49.5 – 0kW load step



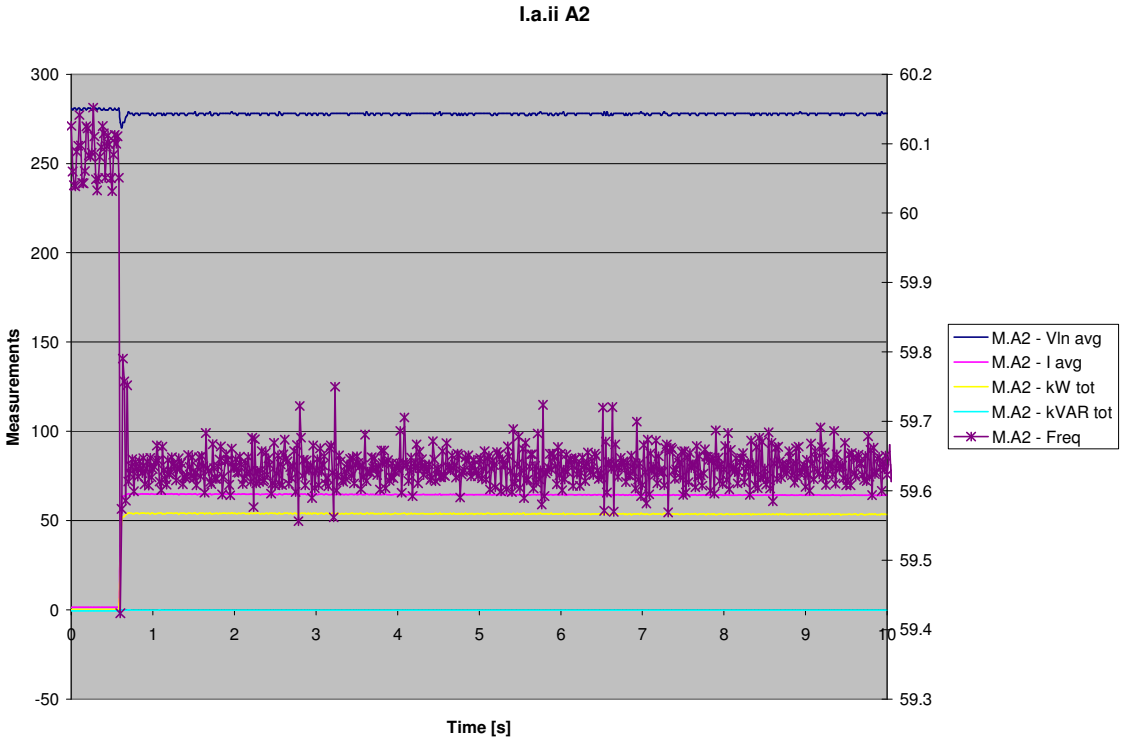
Test I.a.vi A1 = 32.5 – 0kW load step



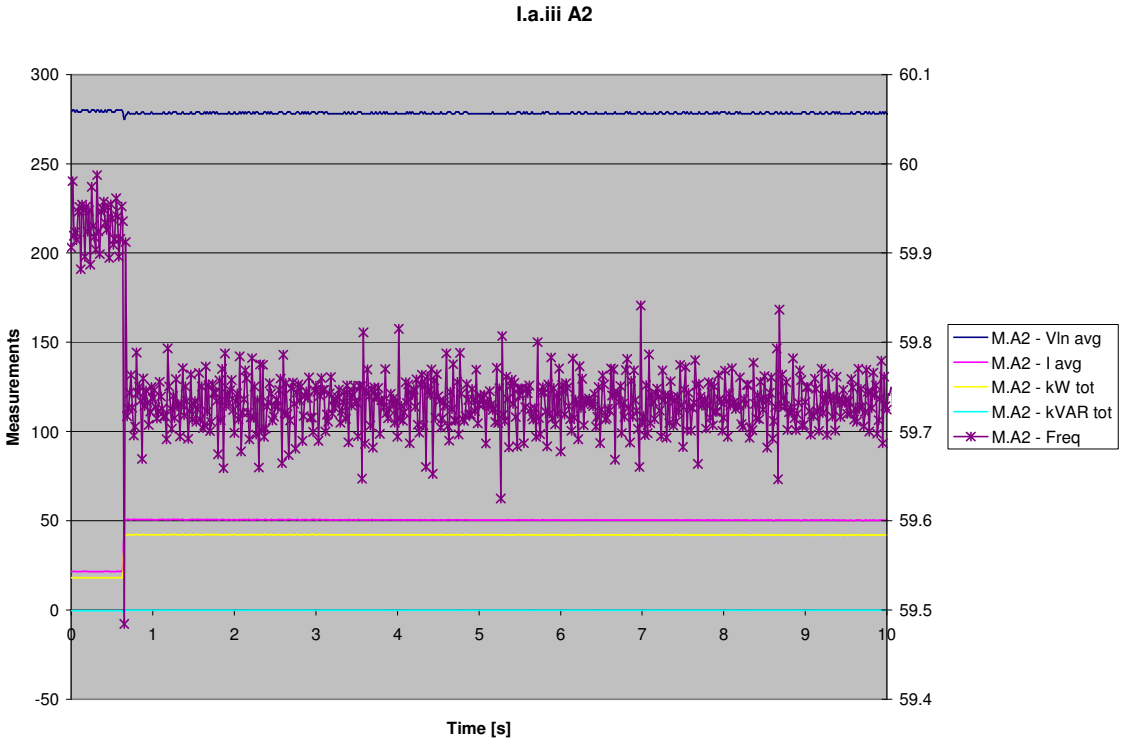
Test I.a.i A2 = 0 – 29.9kW load step



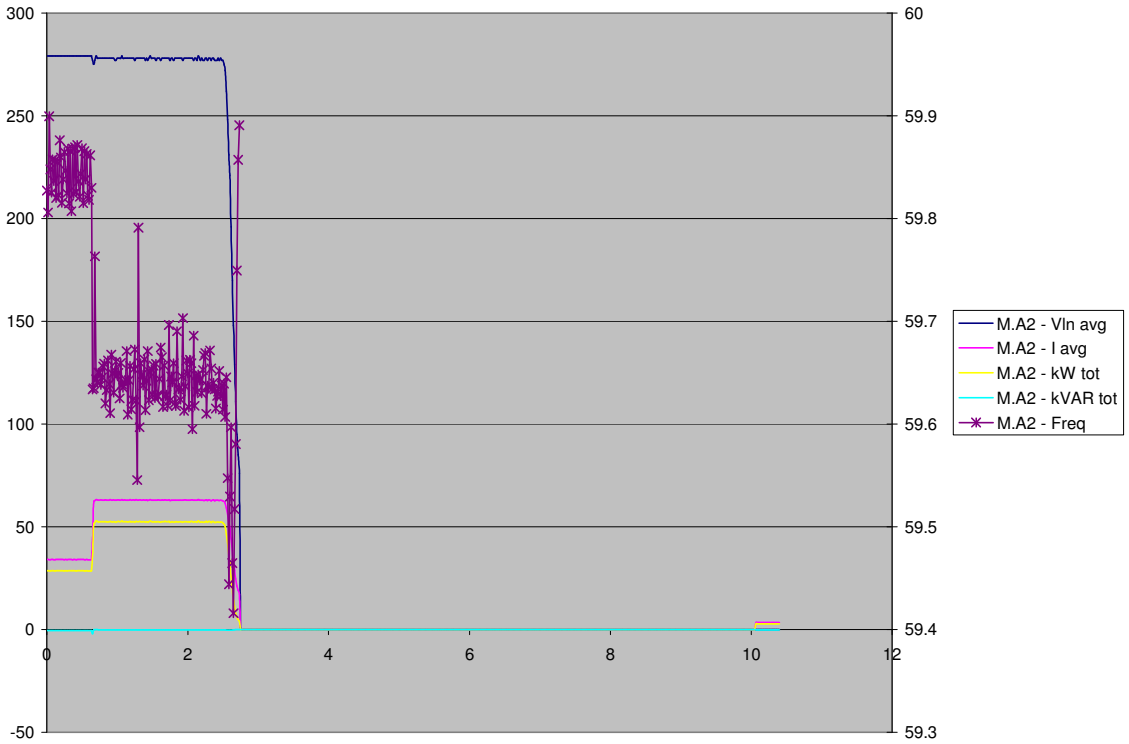
Test I.a.ii A2 = 0 – 53.9kW load step



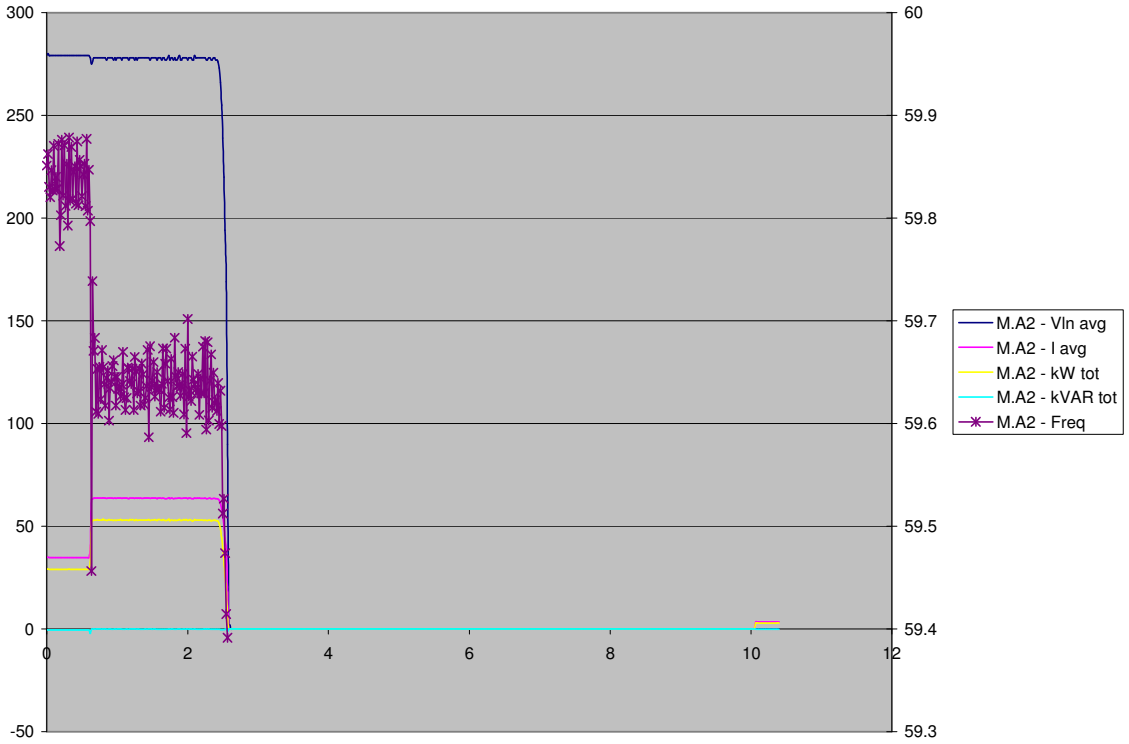
Test I.a.iii A2 = 18 – 42.2kW load step



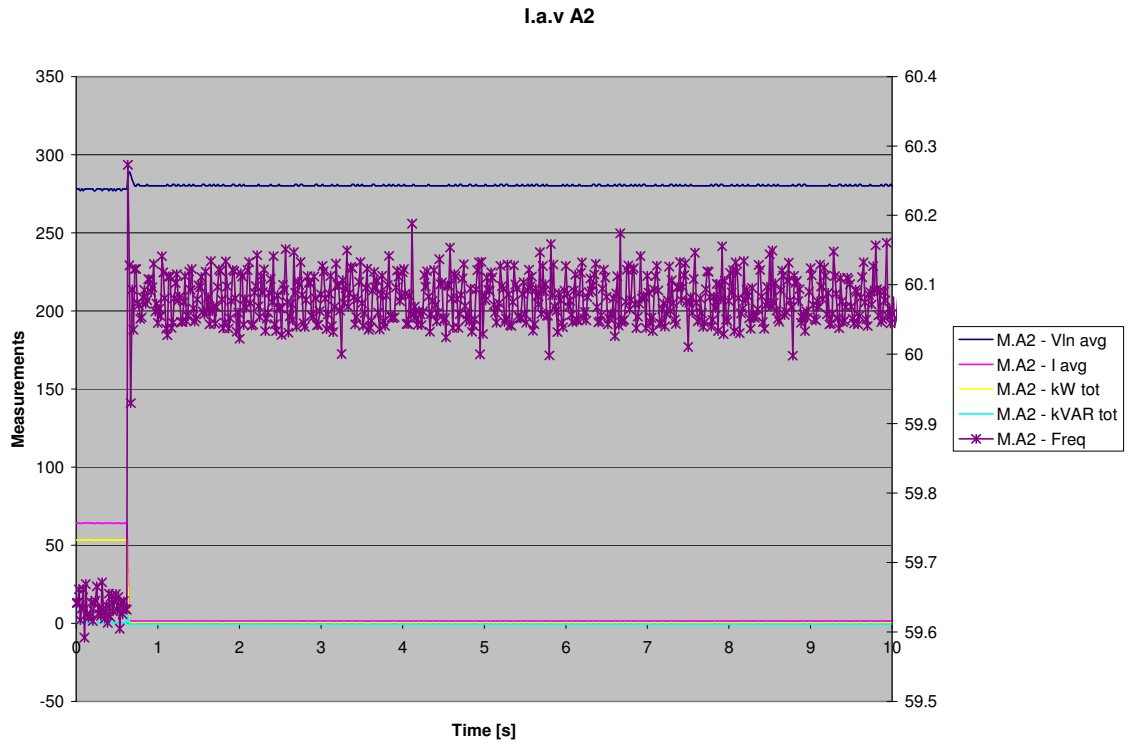
Test I.a.iv A2 = 28.5 – 52.4kW load step, Genset Stalled with No Field Sig



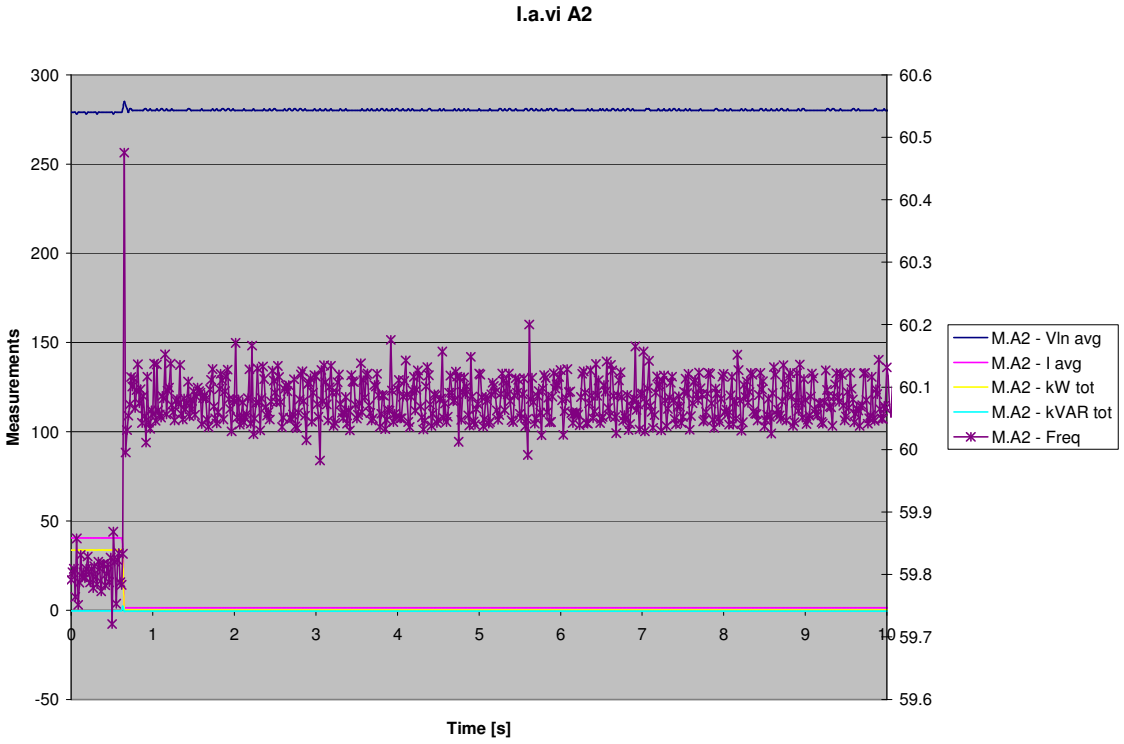
Test I.a.iv A2 = 29 – 51kW load step, Genset Stalled with No Field Sig



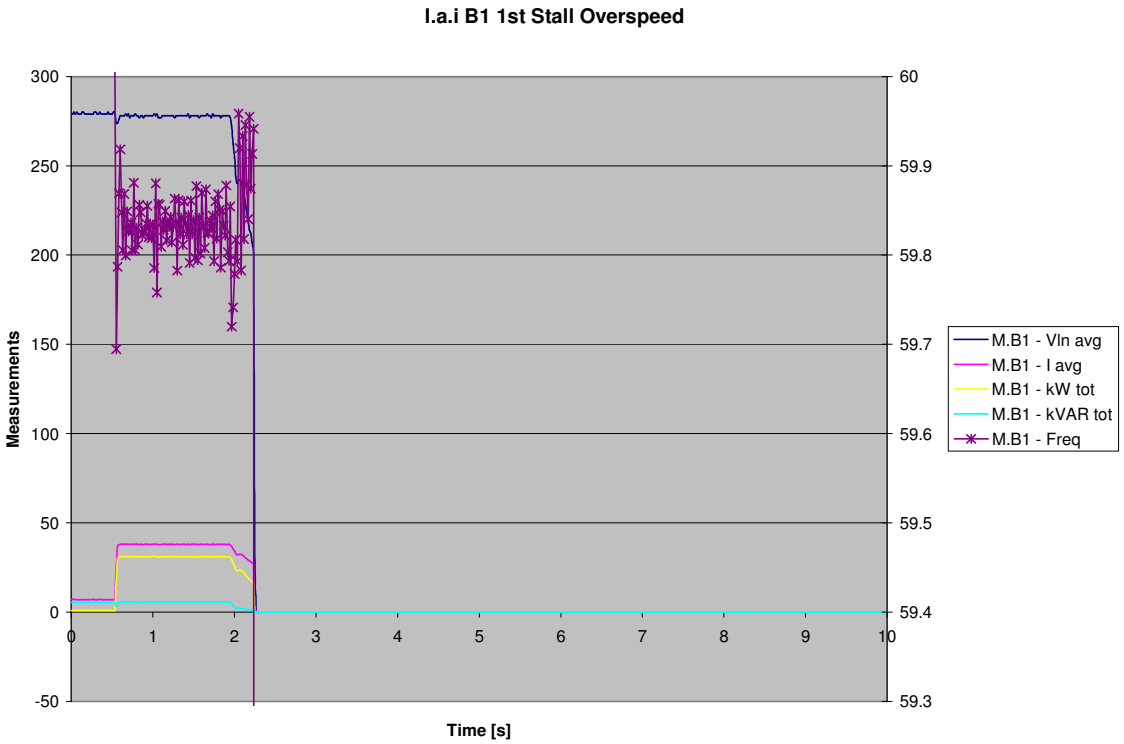
Test I.a.v A2 = 53.5 – 0kW load step



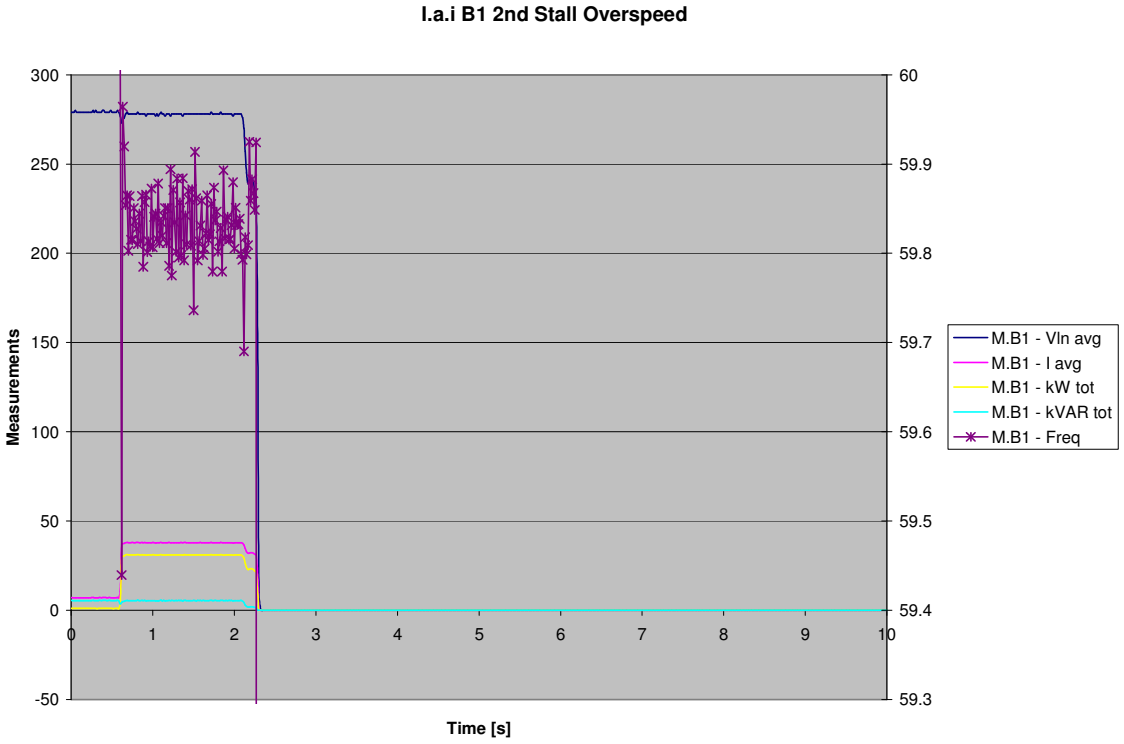
Test I.a.vi A2 = 33.9 – 0kW load step



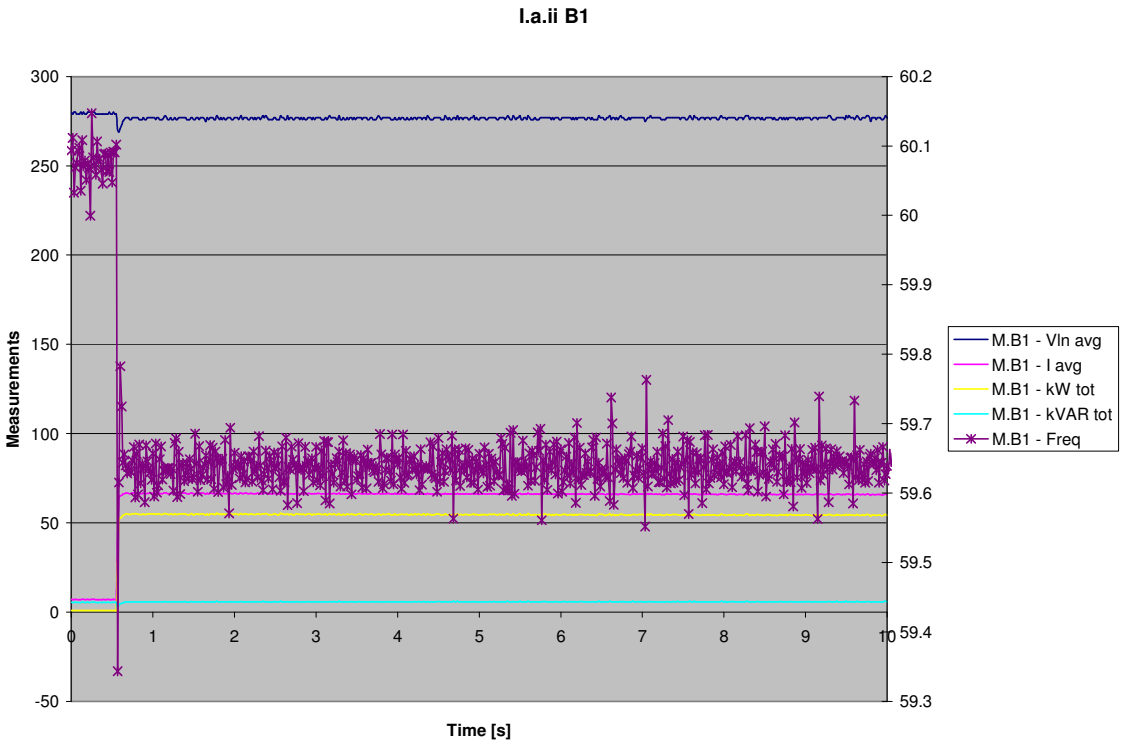
Test I.a.i B1 = 0 – 31kW load step Genset Stalled Overspeed



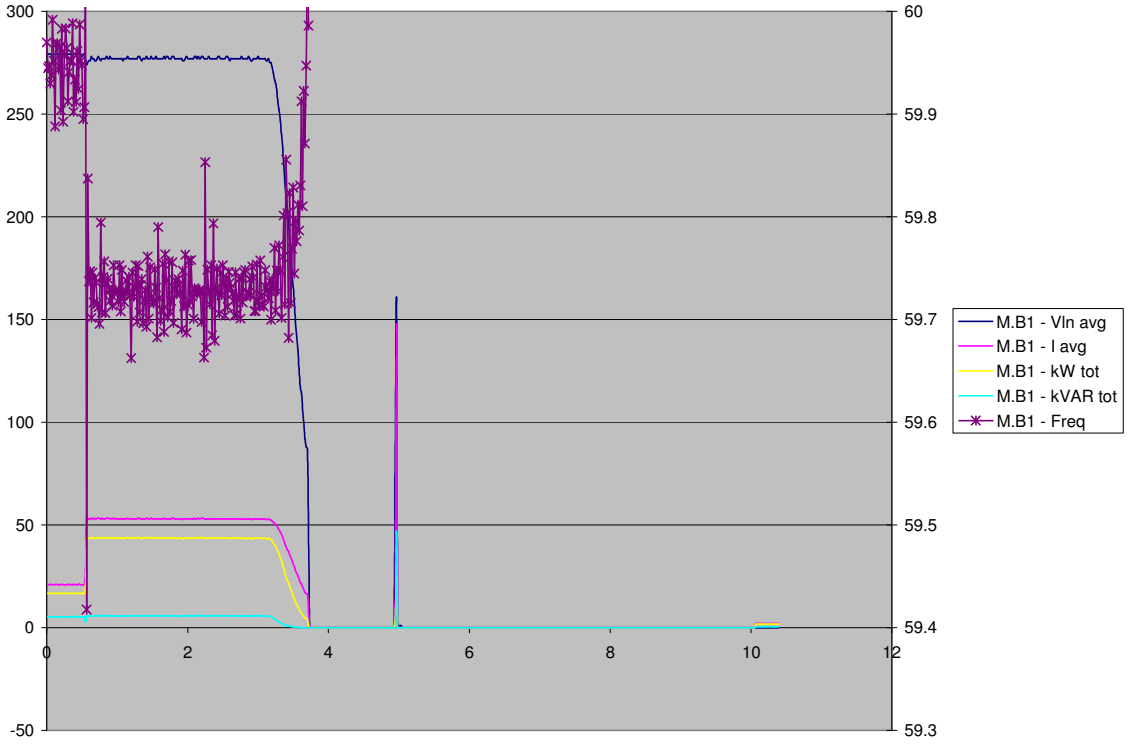
Test I.a.i B1 = 0 – 31kW load step Genset Stalled Overspeed



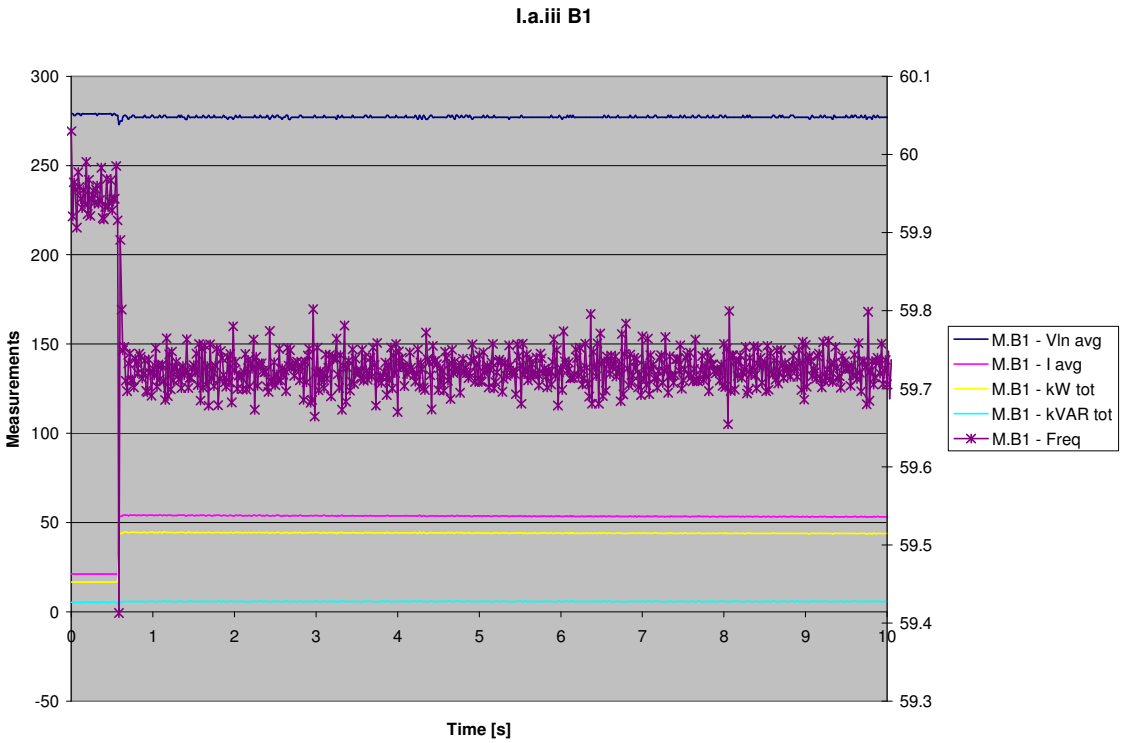
Test I.a.ii B1 = 0 – 54.4kW load step



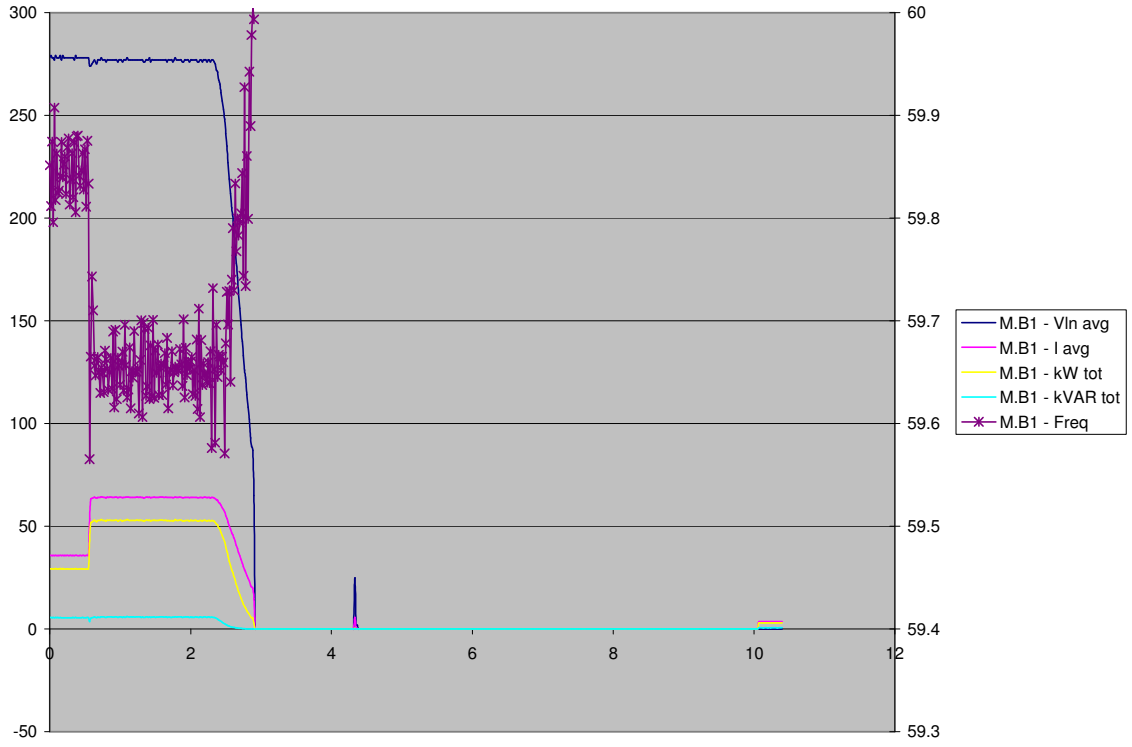
Test I.a.iii B1 = 16.7 – 43.5kW load step Genset Stalled No Field Signal



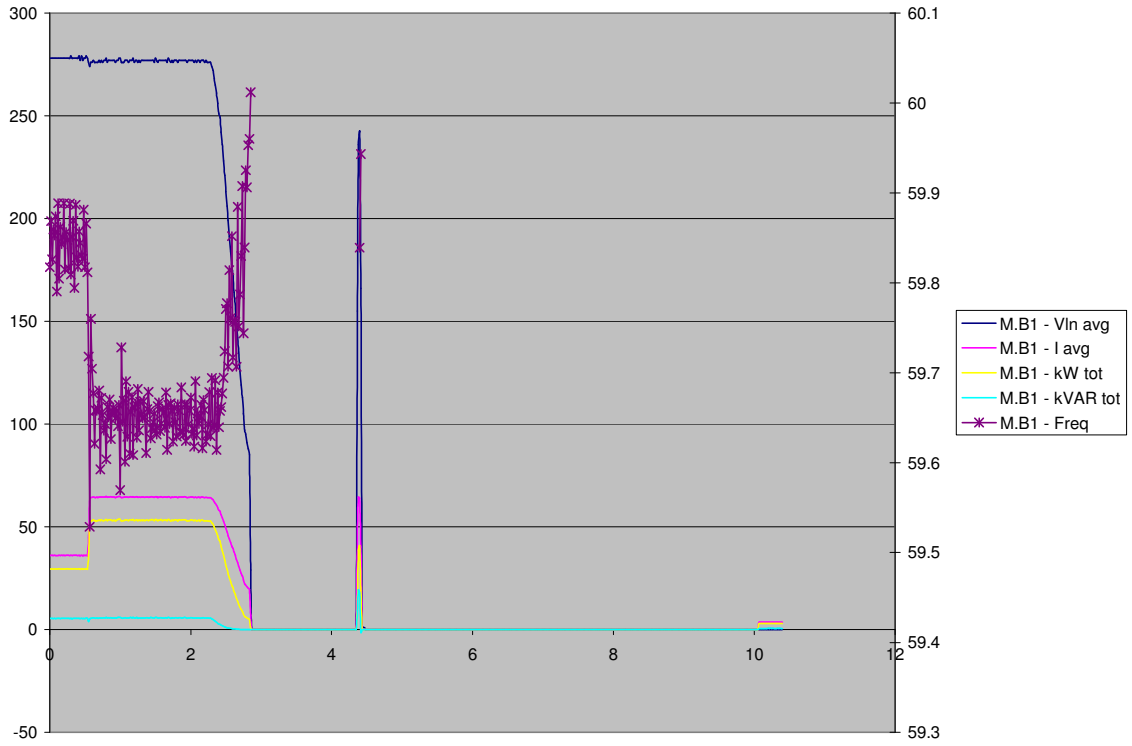
Test I.a.iii B1 = 16.7 – 44.4kW load step



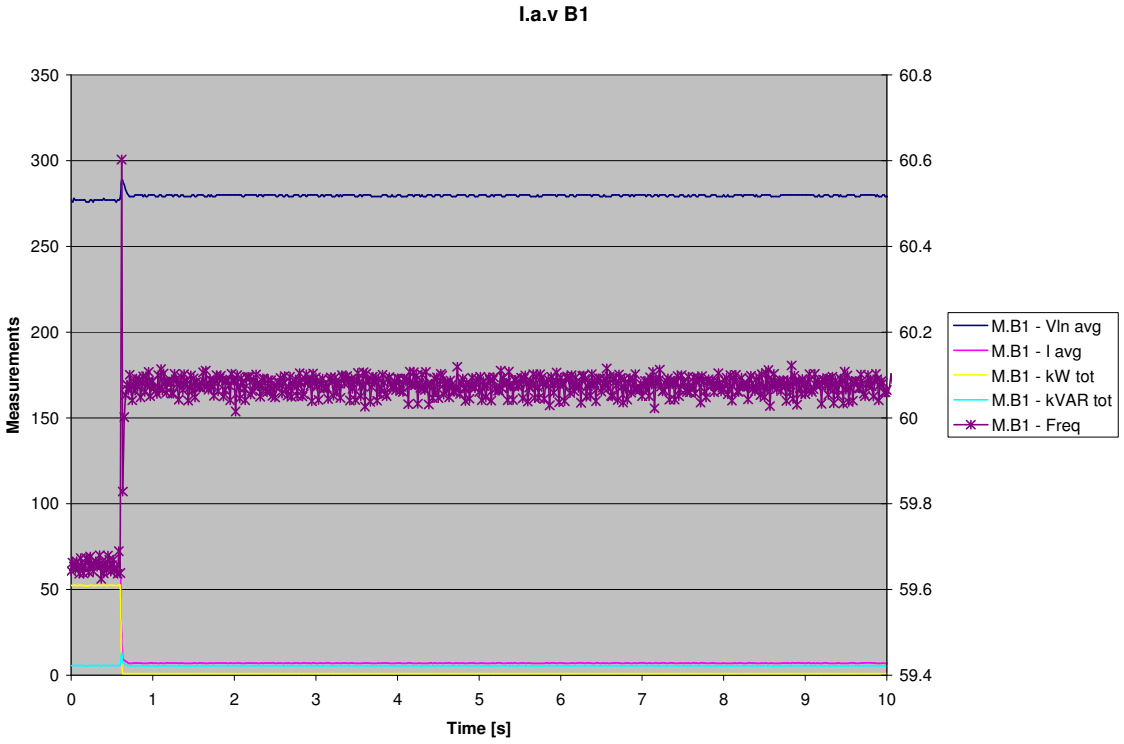
Test I.a.iv B1 = 29.2 – 52.9kW load step No Field Sig



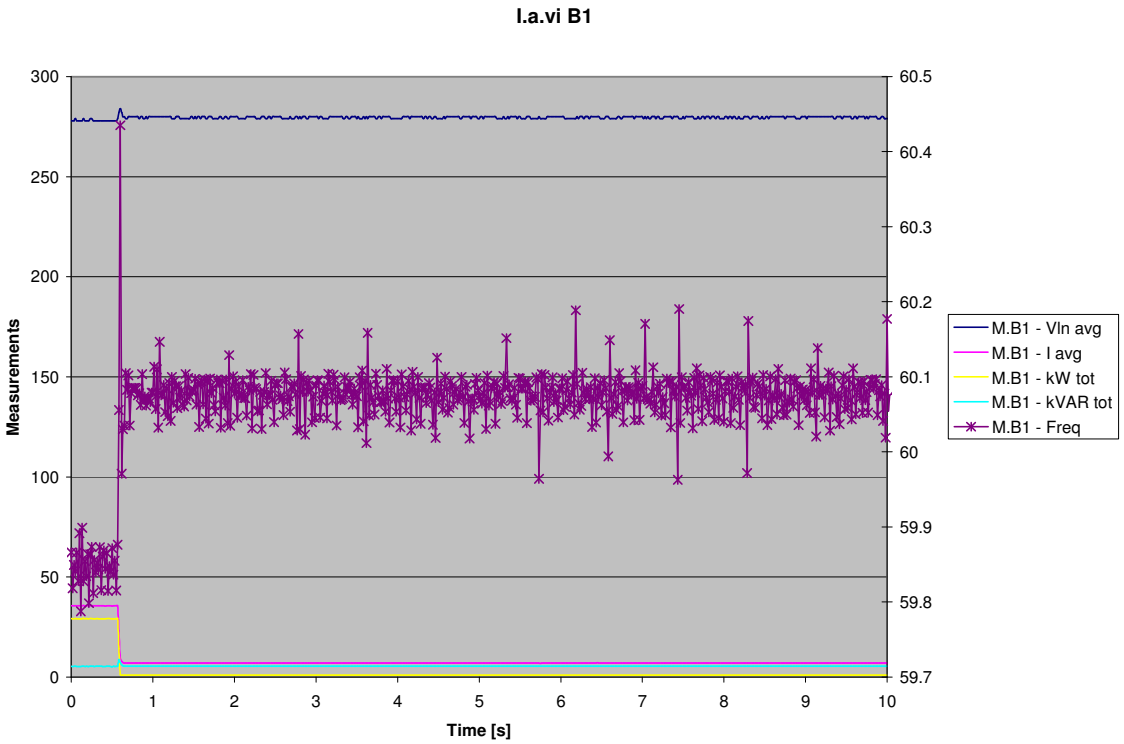
Test I.a.iv B1 = 29.5 – 53.1kW load step No Field Sig



Test I.a.v B1 = 52.2 – 0kW load step



Test I.a.vi B1 = 29.2 – 0kW load step



11. Test Log for 9-20-06

Time	Test	Unit	Load Bank	Load (kW)
Generator B1 with surge module				
1:30 pm	I.a.i	B1	5	0-30
1:33 pm	I.a.ii	B1	5	0-60
1:36 pm	I.a.iii	B1	5	15-50
1:40 pm	I.a.iv	B1	5	30-60
1:43 pm	I.a.v	B1	5	60-0
1:46 pm	I.a.vi	B1	5	30-0
Generator A1 w/out surge module				
1:55 pm	II.c.i (Part 1)	A1	4	50
1:57 pm	A1 Shutdown	A1	4	50
Generator A1and A2 with surge module(s)				
2:01 pm	II.c.i (Part 1)	A1	4	50

12. Test Log for 9-21-06

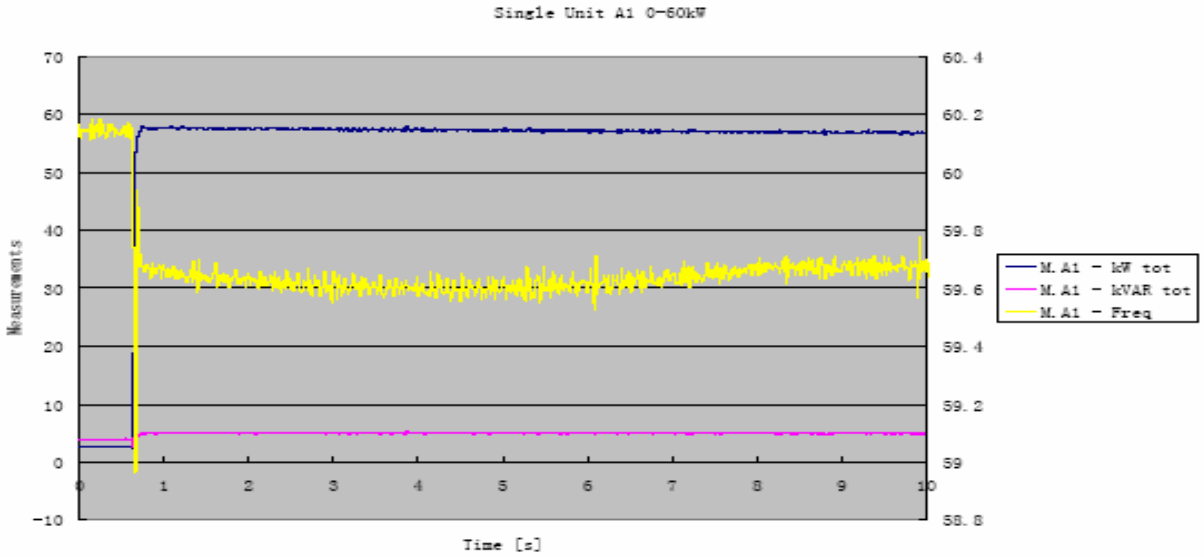
Time	Test	Unit	Load Bank	Load (kW)
Generator A1 with surge module				
7:49 am	I.a.i	A1	3	0-30
8:00 am	I.a.ii	A1	3	0-60
8:03 am	I.a.iii	A1	3	15-50
8:19 am	I.a.iv	A1	3	30-60
8:22 am	I.a.v	A1	3	60-0
8:25 am	I.a.vi	A1	3	30-0
Generator A2 with surge module				
10:18 am	Trigger Test			
10:21 am	I.a.i	A2	4	0-30
10:24 am	I.a.ii	A2	4	0-60
10:28 am	I.a.iii	A2	4	15-50
10:31 am	I.a.iv	A2	4	30-60
10:34 am	I.a.v	A2	4	60-0
10:37 am	I.a.vi	A2	4	30-0

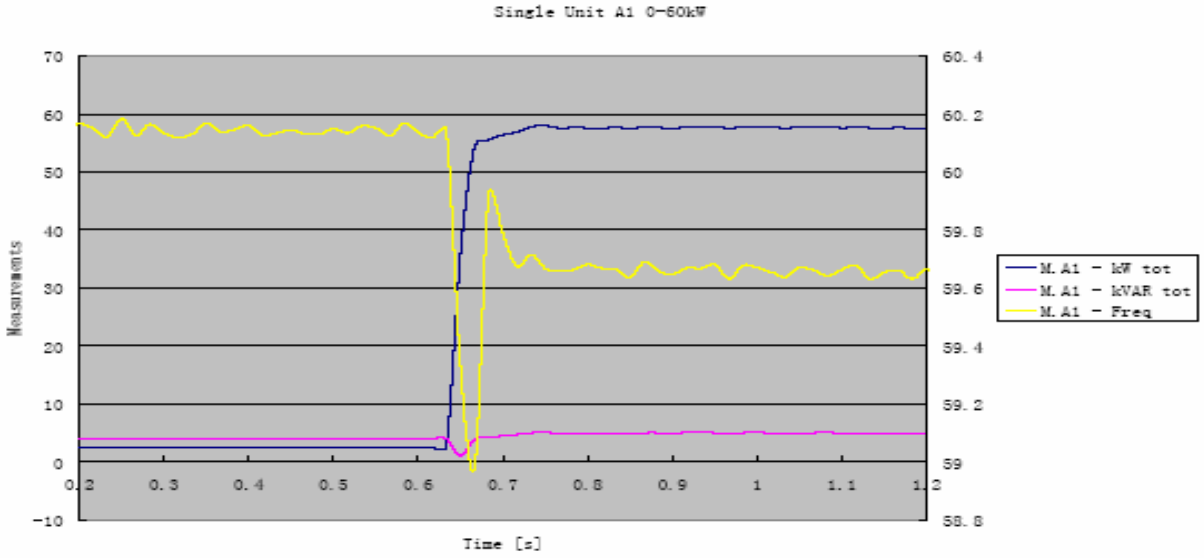
Attachment 13

Test Results for 10-11-06

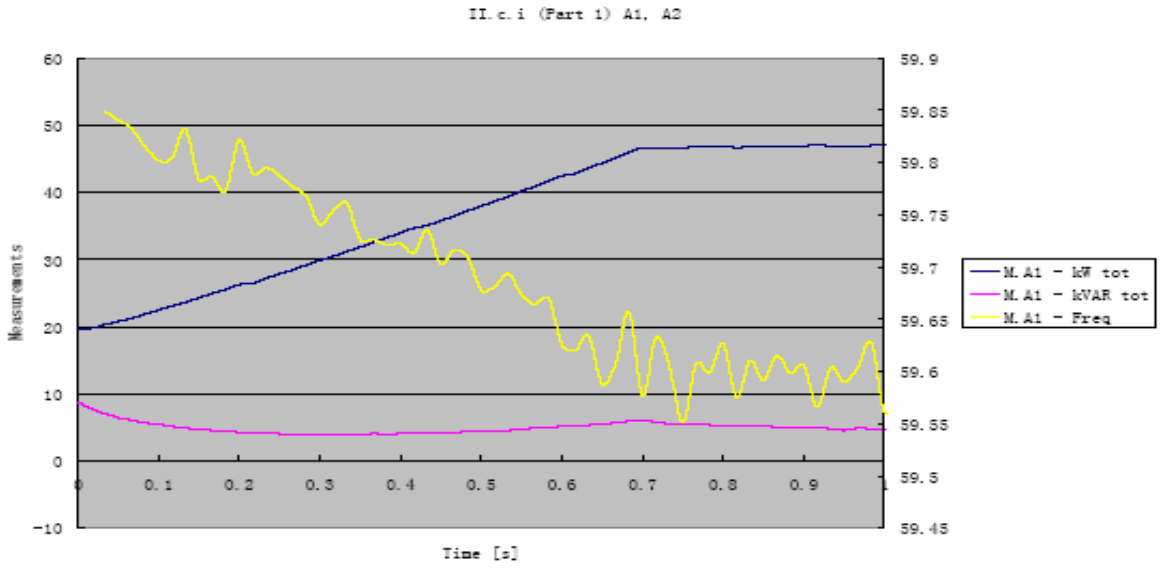
Unit A1, case I.a.ii 2
II.c.i with units A1 and A2 3
II.c.i with units A1 and B1 9
II.c.ii with units A1 and A2 13
II.c.ii with units A1 and B1 15
II.a.i with A1 and A2 17
II.a.i with B1 and A2 19
Event to reach III.a.1 with unit A1 and A2 (connection of A1 in feeder mode) 21
III.a.i with unit A1 and A2 23
II.b.i with unit A1 and A2 25
II.b.i with unit B1 and A2 27
II.b.ii with units A1 and A2 29
II.b.ii with units B1 and A2 31
III.b.i with unit A1 and A2 33

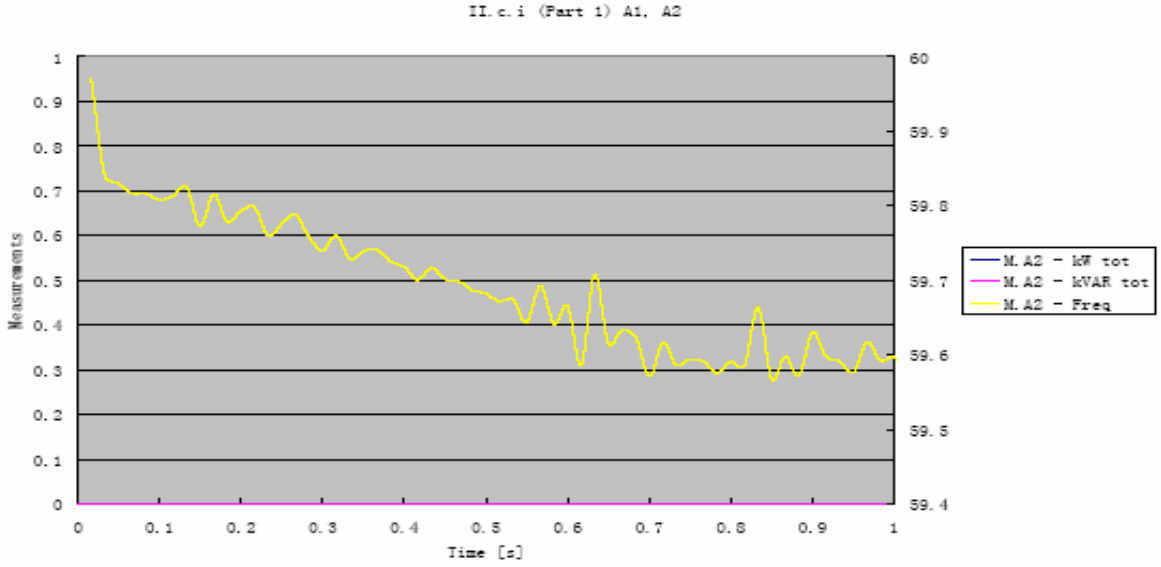
Unit A1, case I.a.ii

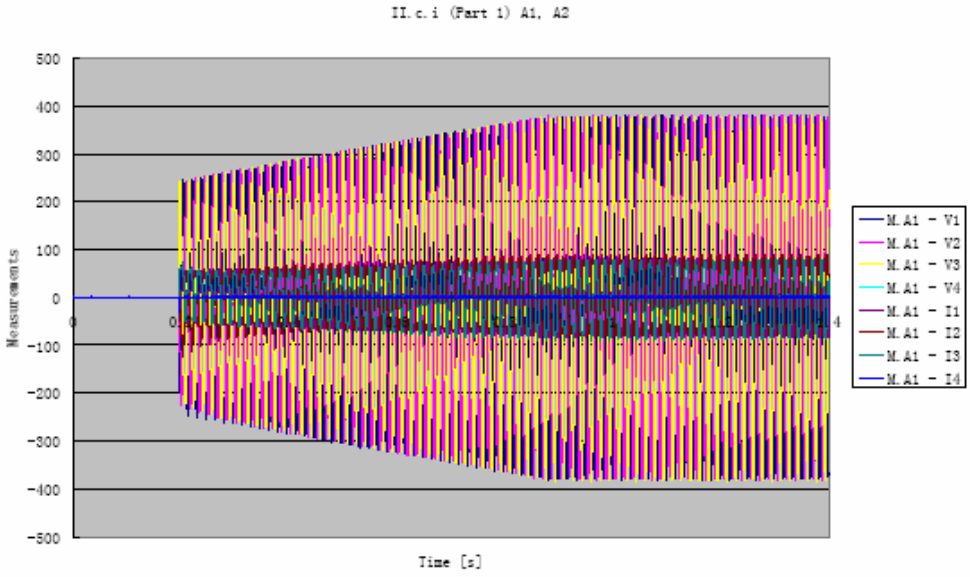


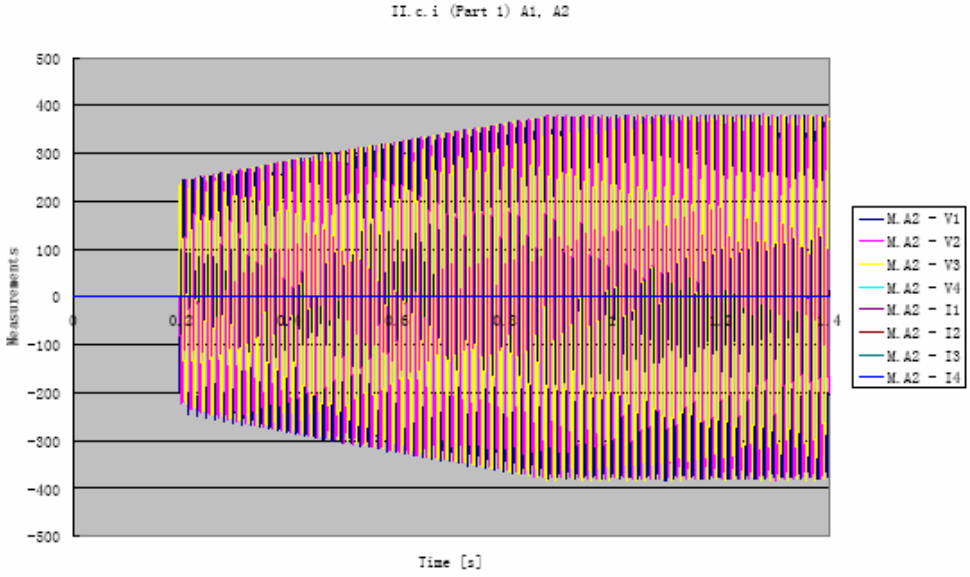


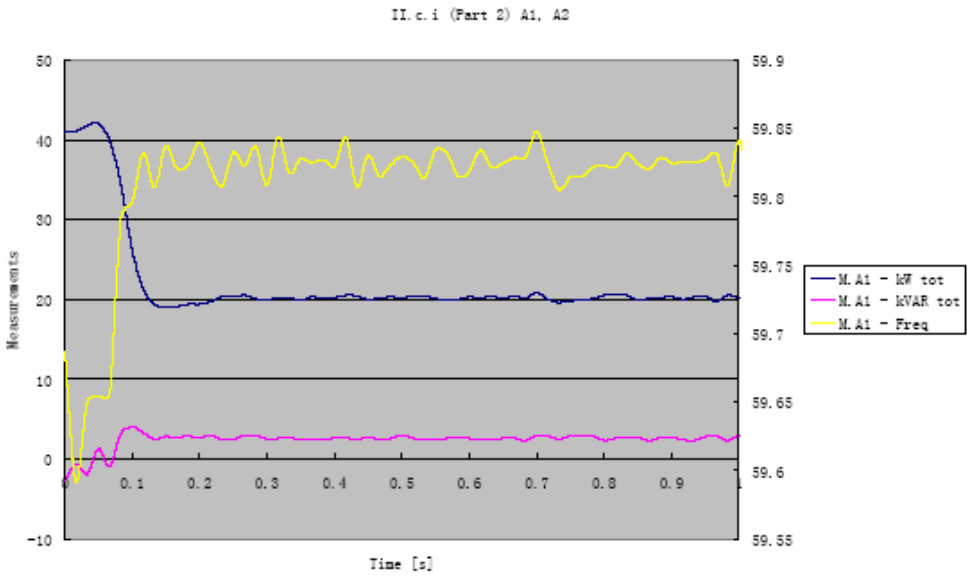
II.c.i with units A1 and A2

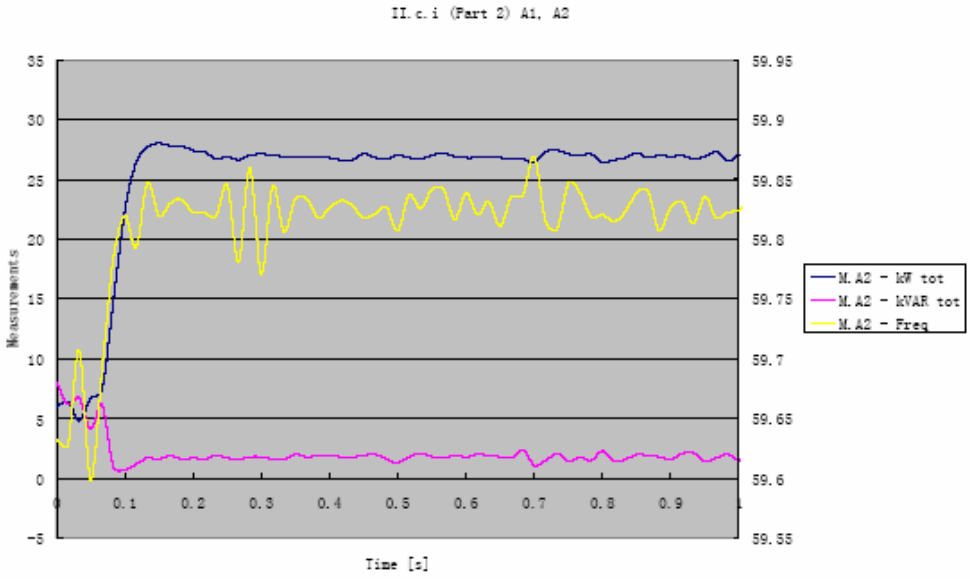


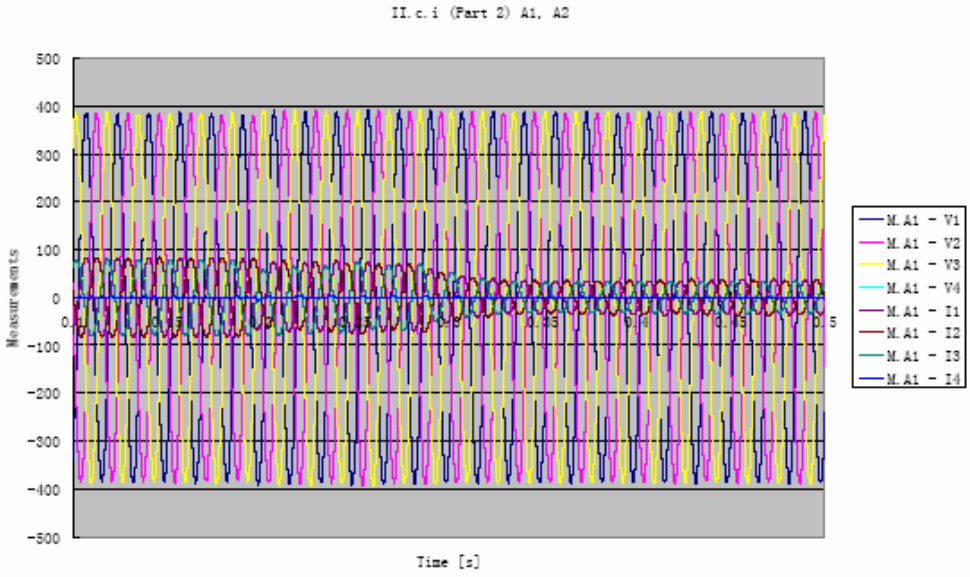


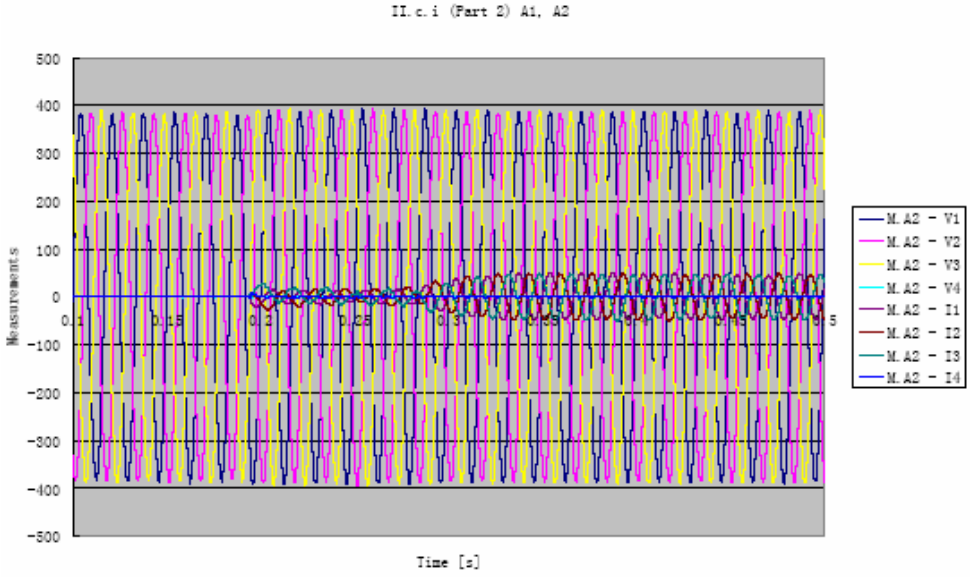

II.c.i (Part 1) A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

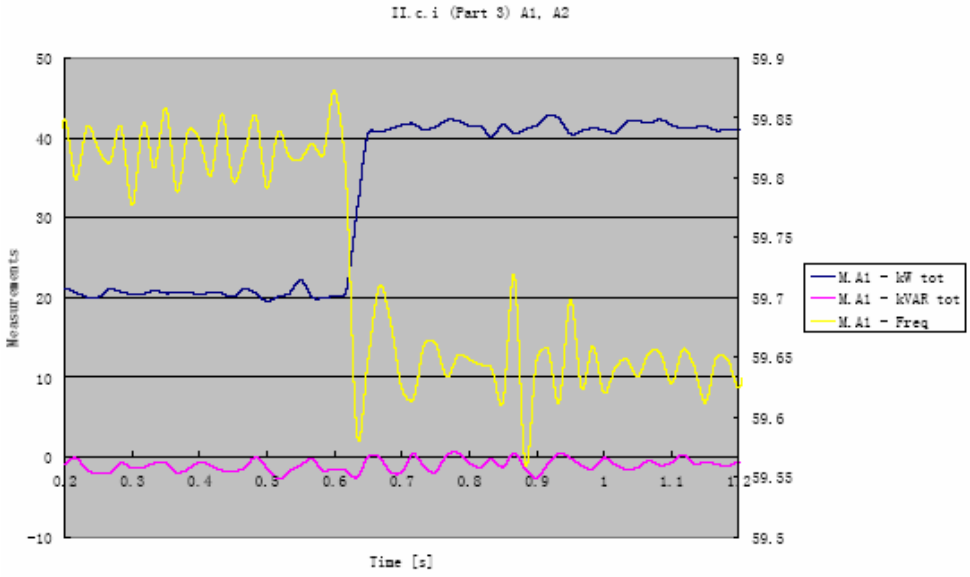

II.c.i (Part 1) A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

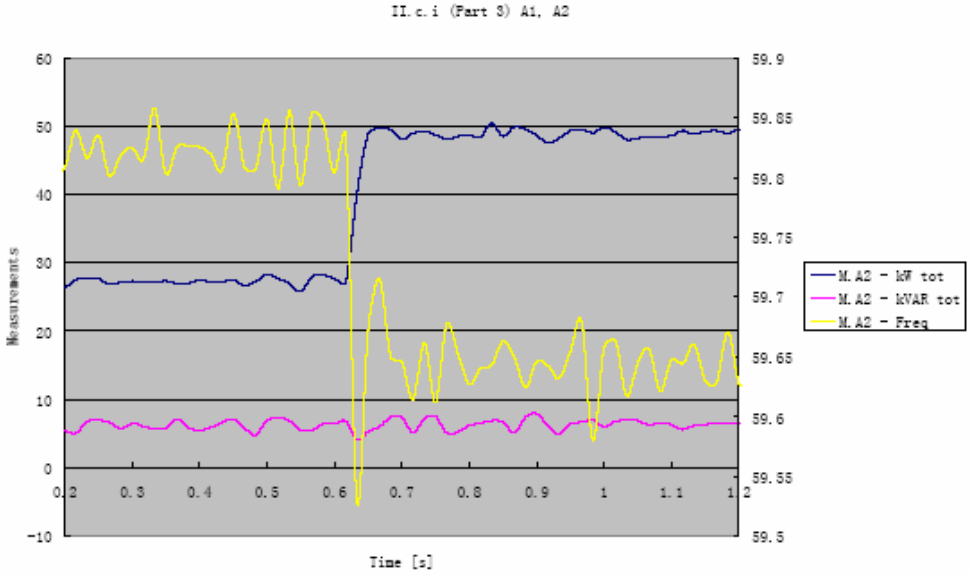

II.c.i (Part 2) A1, A2
Measurements
Time [s]
M.A1 - kW tot
M.A1 - kVAR tot
M.A1 - Freq

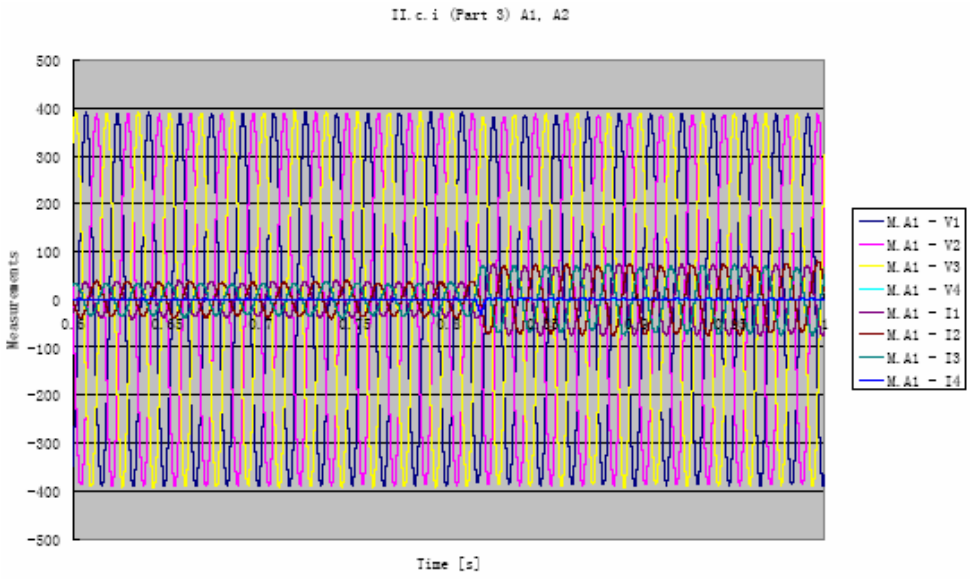

II.c.i (Part 2) A1, A2
Measurements
Time [s]
M.A2 - kW tot
M.A2 - kVAR tot
M.A2 - Freq

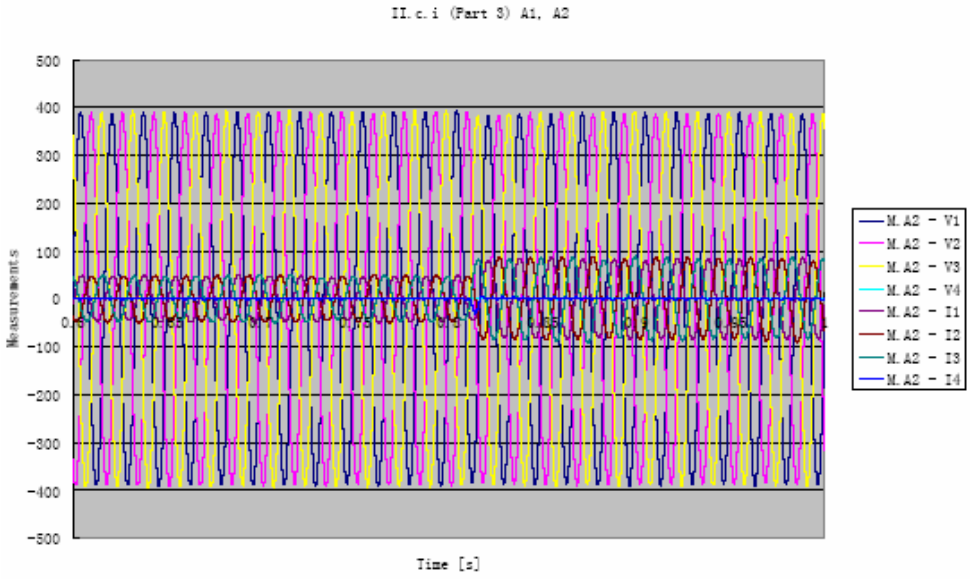

II.c.i (Part 2) A1, A2
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4


II.c.i (Part 2) A1, A2
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

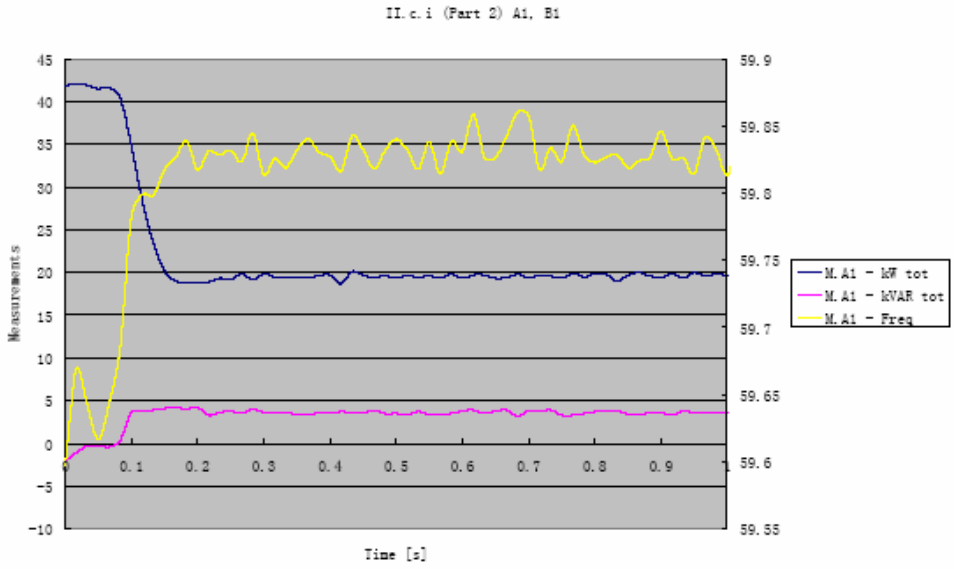

II.c.i (Part 3) A1, A2
Measurements
Time [s]
M.A1 - kW tot
M.A1 - kVAR tot
M.A1 - Freq

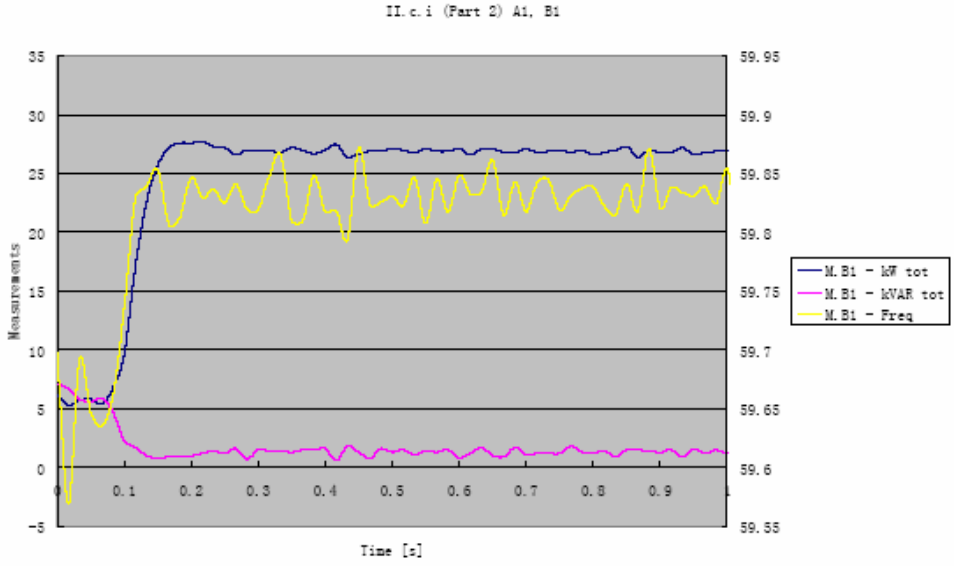

II.c.i (Part 3) A1, A2
Measurements
Time [s]
M.A2 - kW tot
M.A2 - kVAR tot
M.A2 - Freq

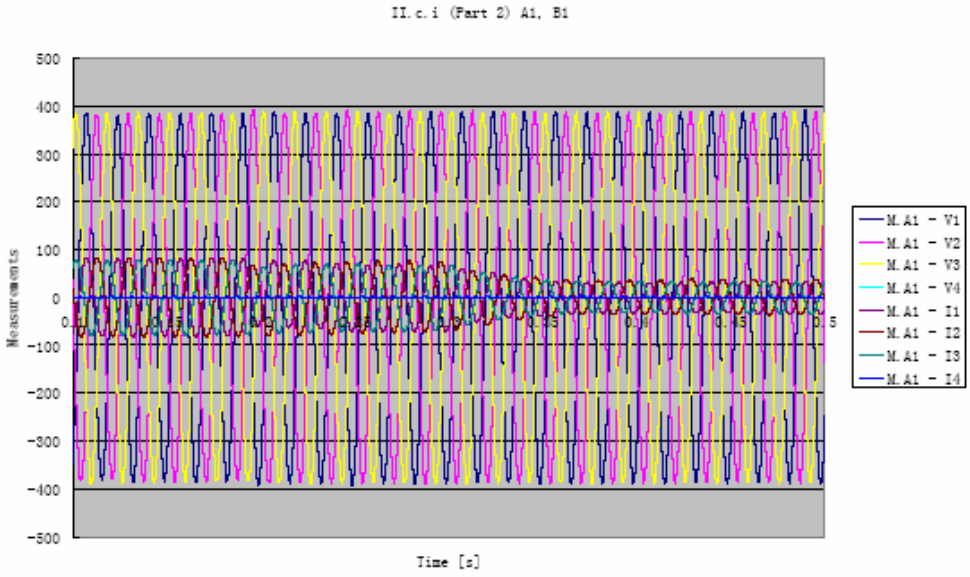

II.c.i (Part 3) A1, A2
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

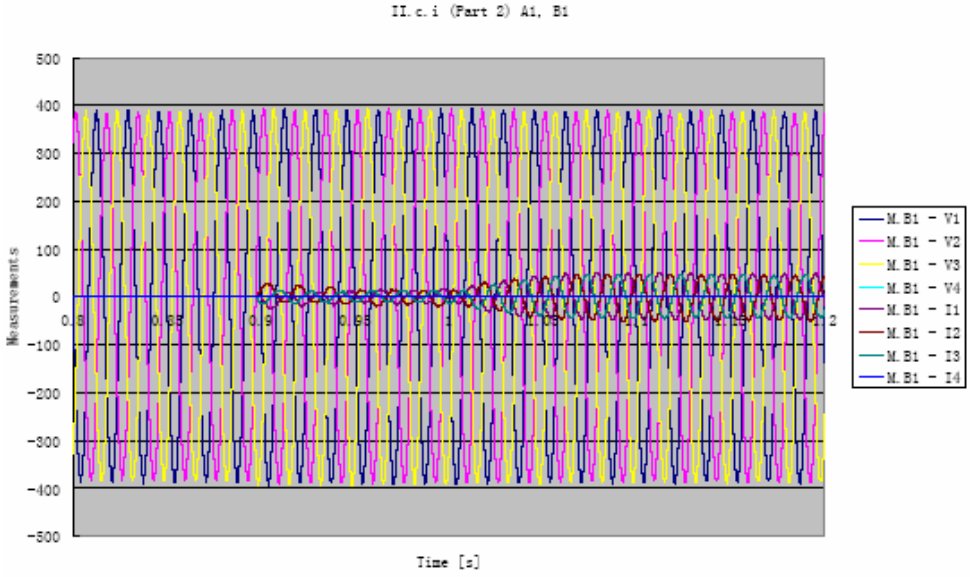

II.c.i (Part 3) A1, A2
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

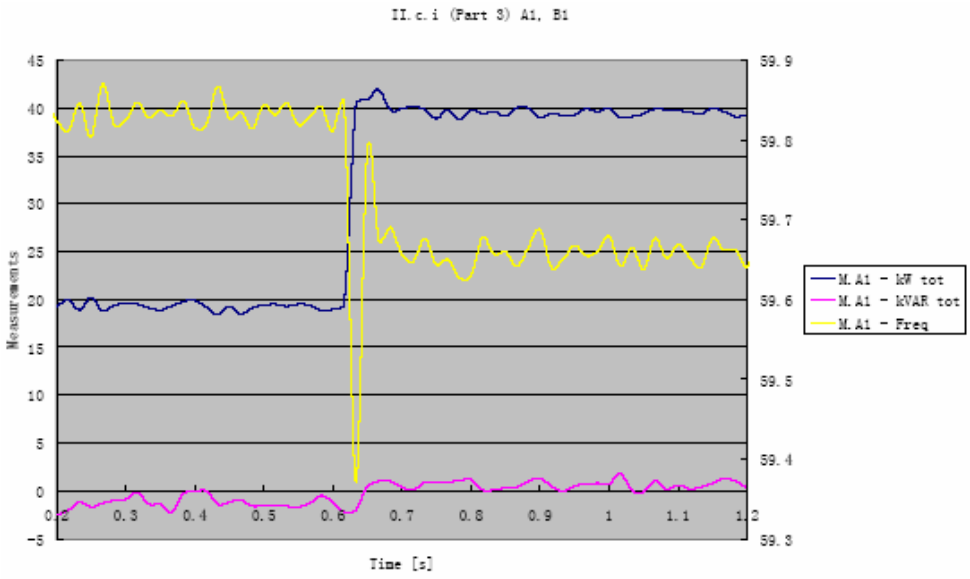
II.c.i with units A1 and B1

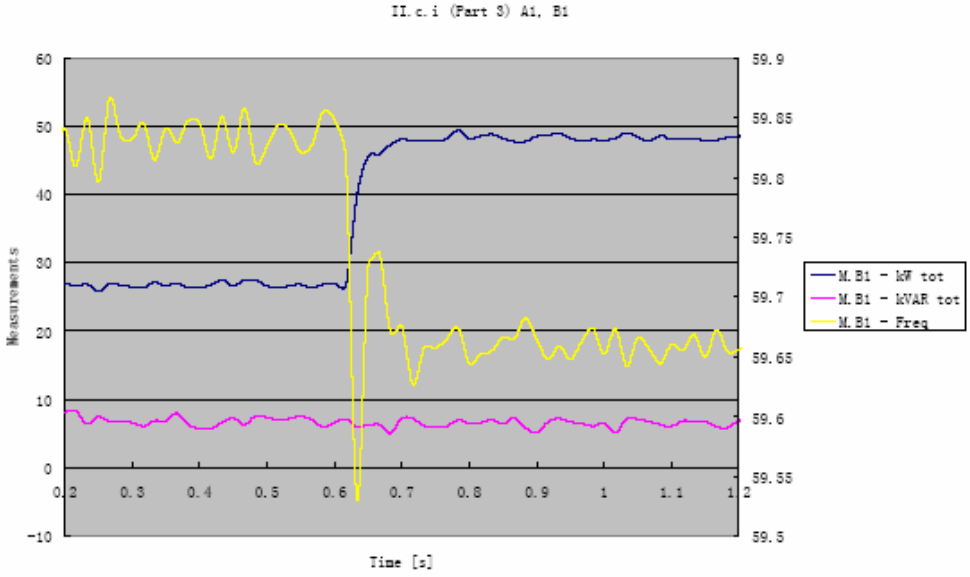


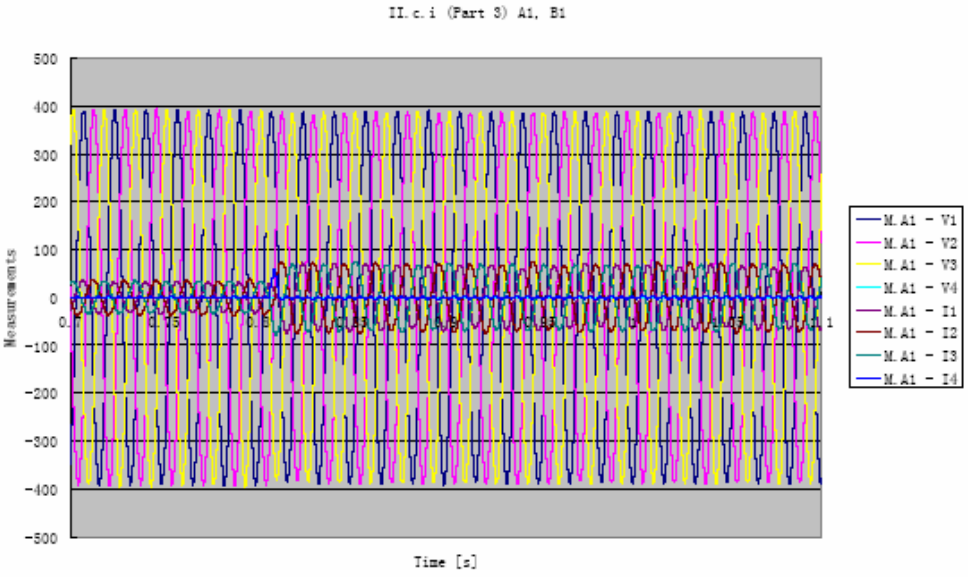



II.c.i (Part 2) A1, B1
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4


II.c.i (Part 2) A1, B1
Measurements
Time [s]
M.B1 - V1
M.B1 - V2
M.B1 - V3
M.B1 - V4
M.B1 - I1
M.B1 - I2
M.B1 - I3
M.B1 - I4

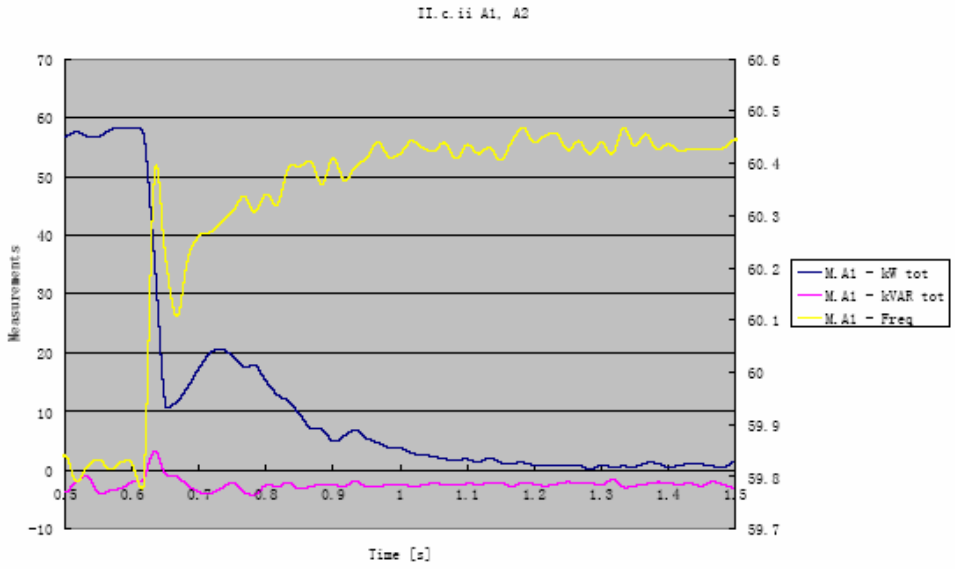

II.c.i (Part 3) A1, B1
Measurements
Time [s]
M.A1 - kW tot
M.A1 - kVAR tot
M.A1 - Freq

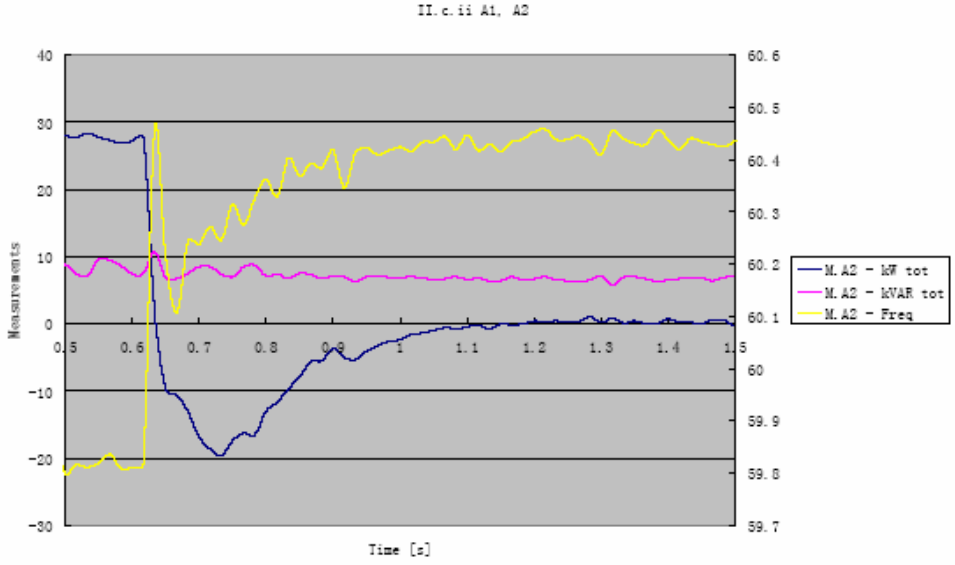

II.c.i (Part 3) A1, B1
Measurements
Time [s]
M.B1 - kW tot
M.B1 - kVAR tot
M.B1 - Freq

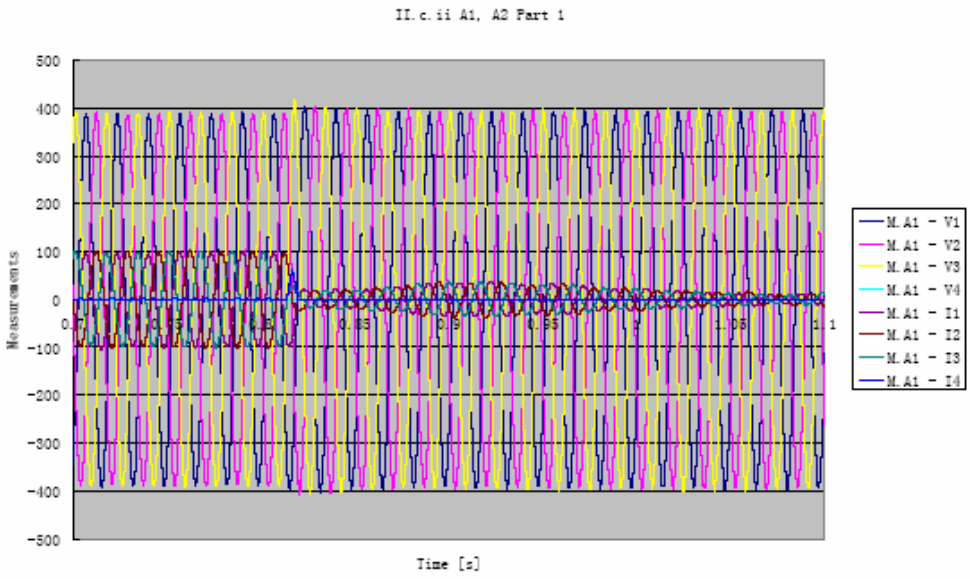


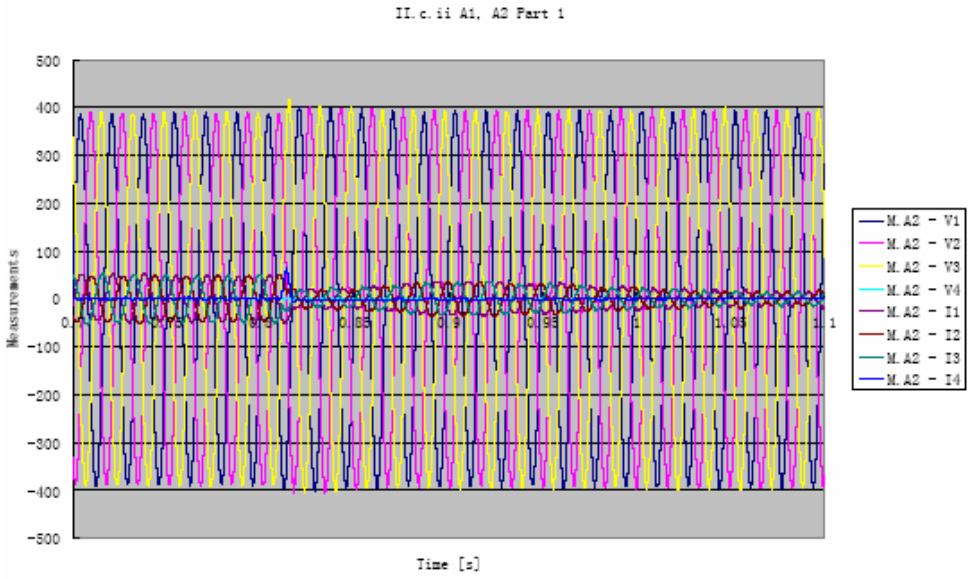
Event non captured

II.c.ii with units A1 and A2

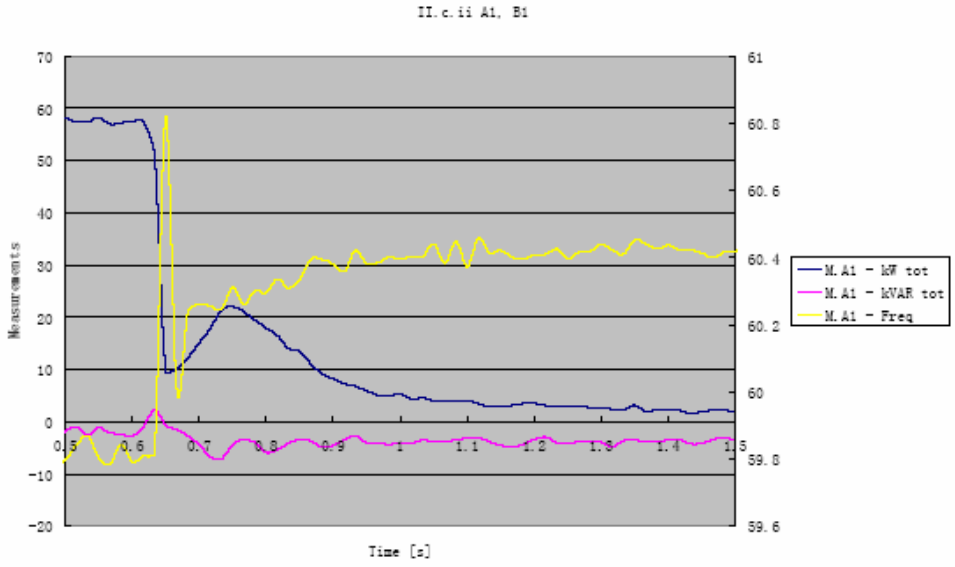


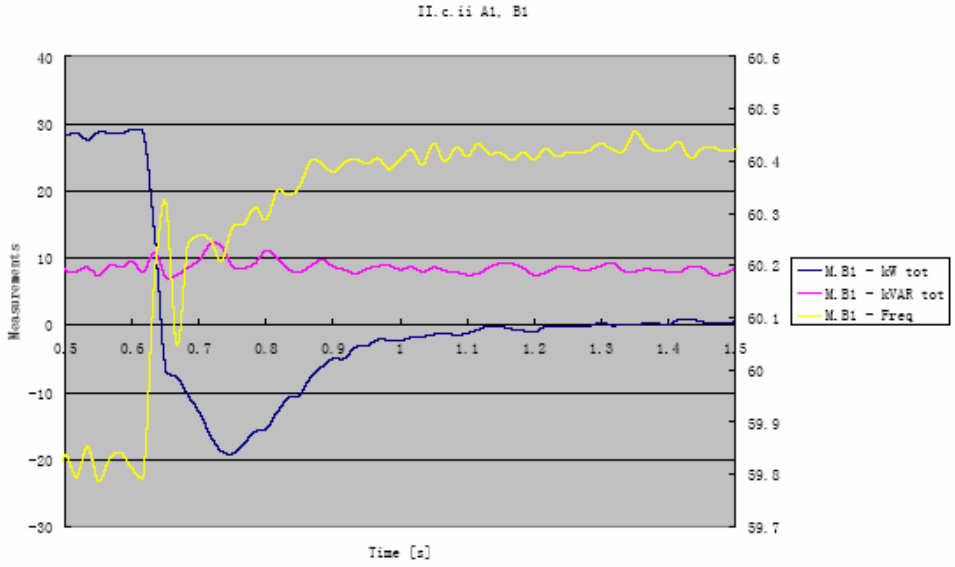


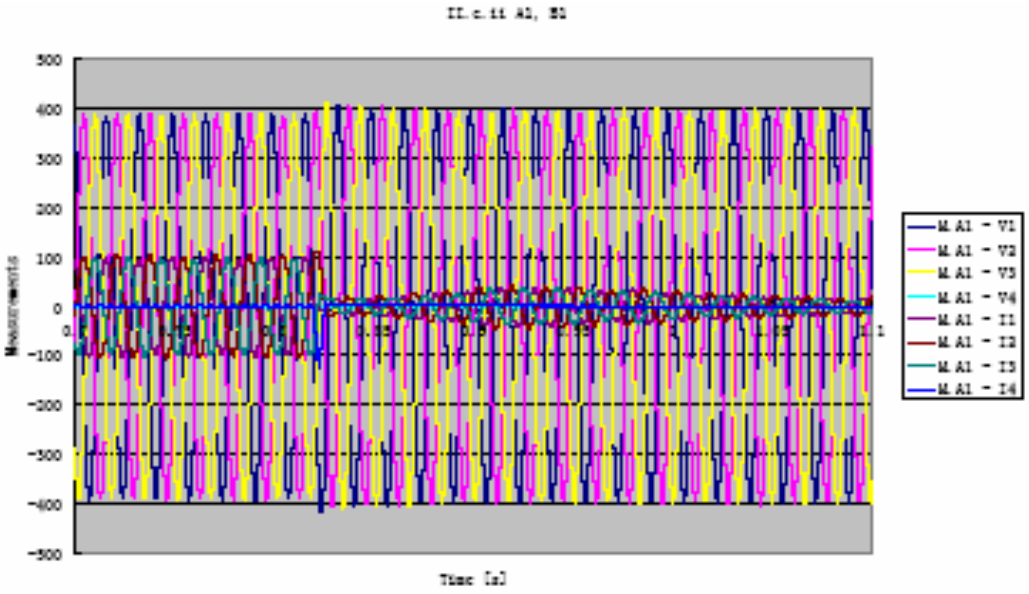

II.c.ii A1, A2 Part 1
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4


II.c.ii A1, A2 Part 1
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

II.c.ii with units A1 and B1

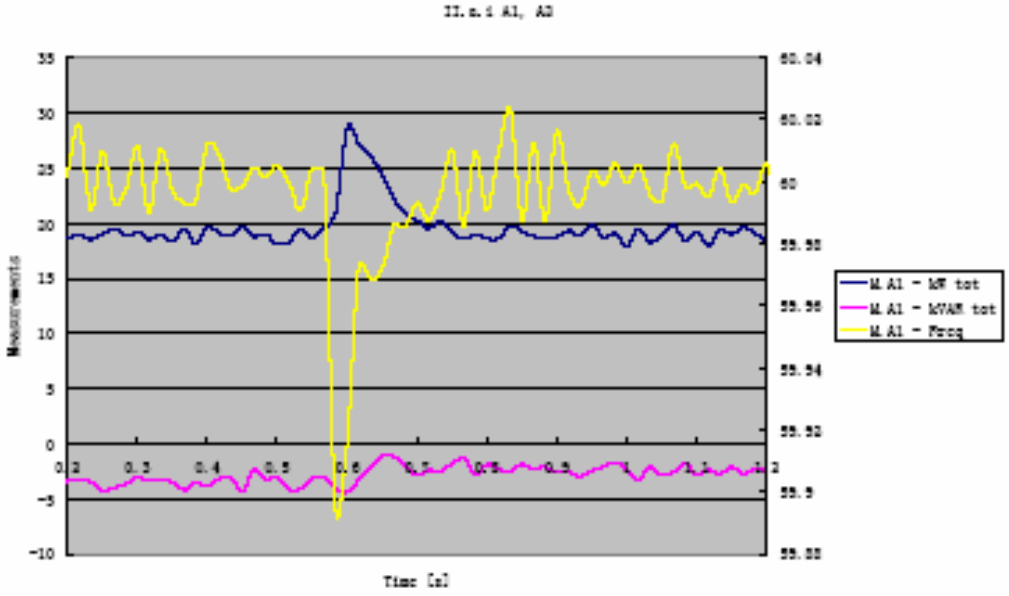


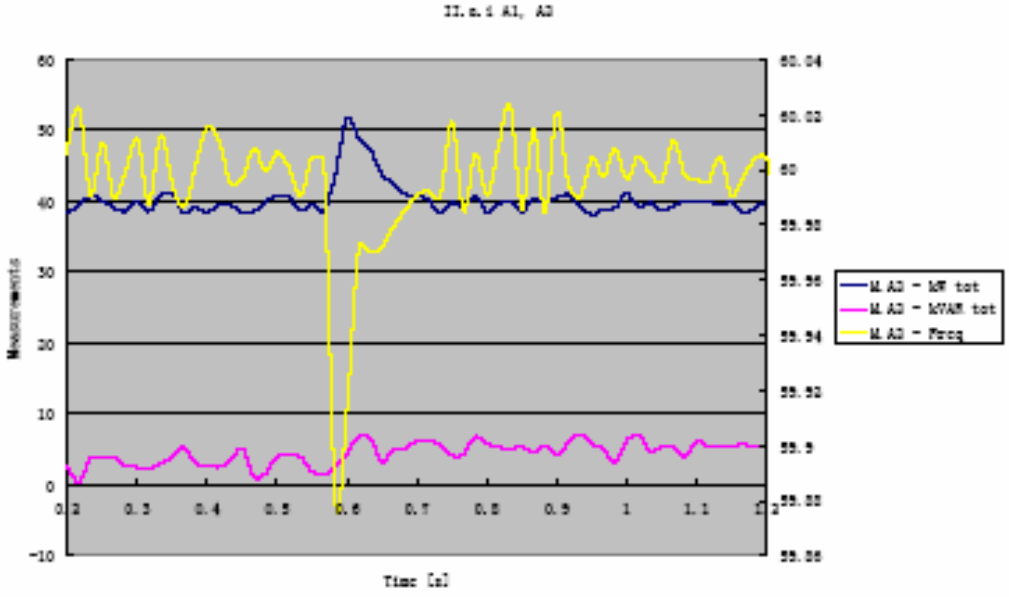


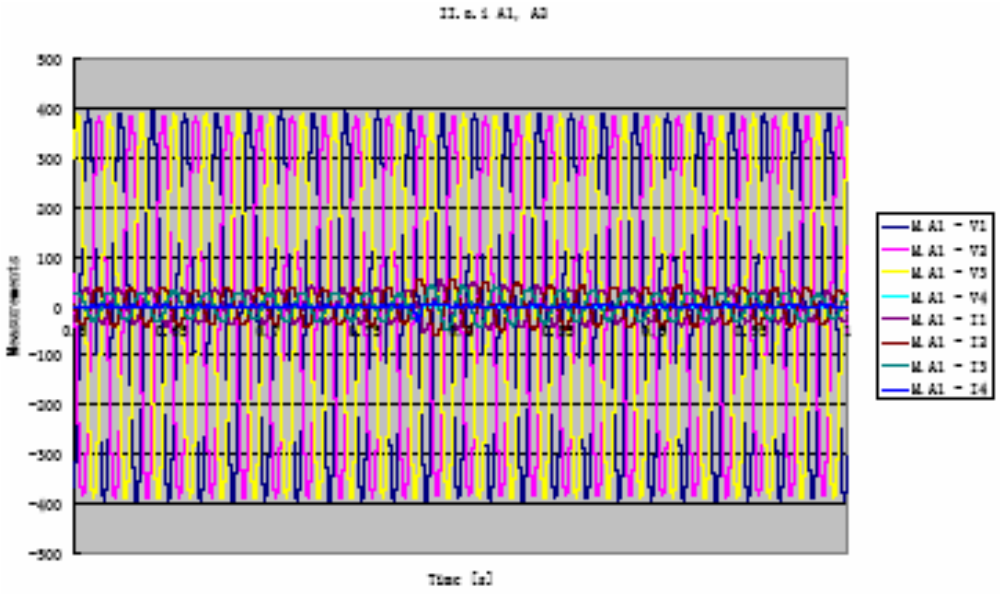


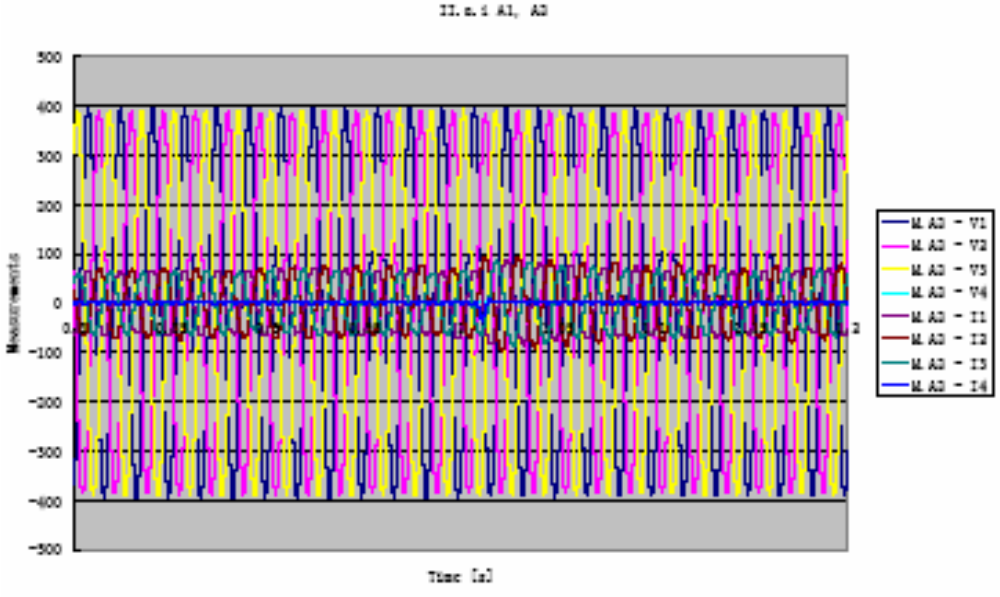
Event not captured

II.a.i with A1 and A2

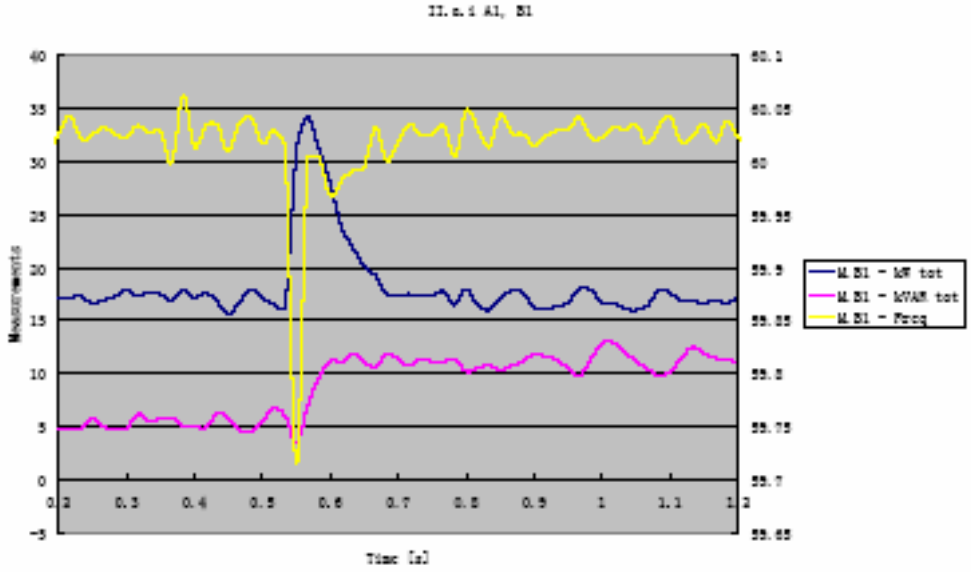


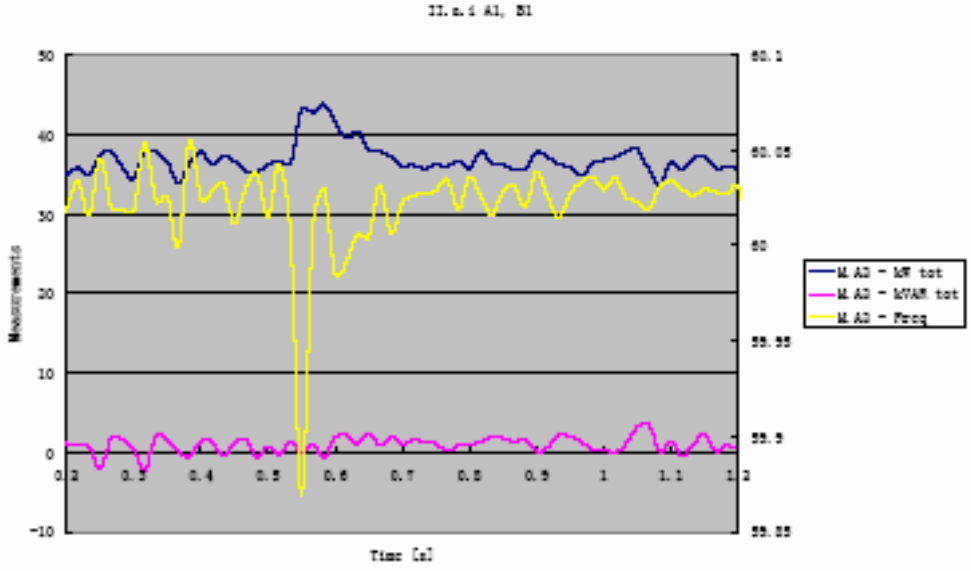



Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

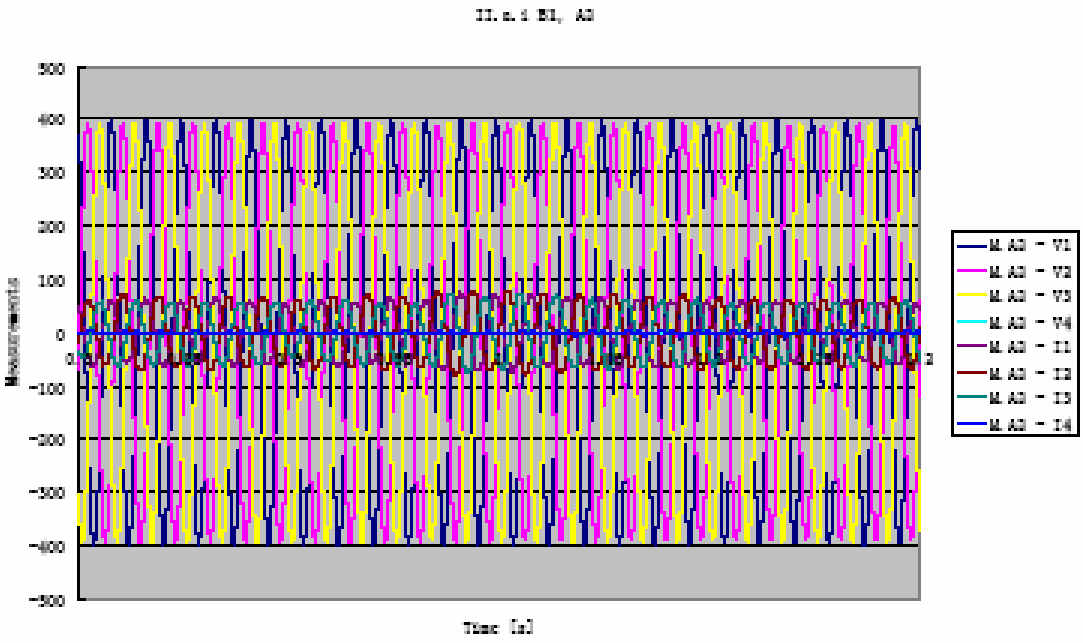

Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

II.a.i with B1 and A2

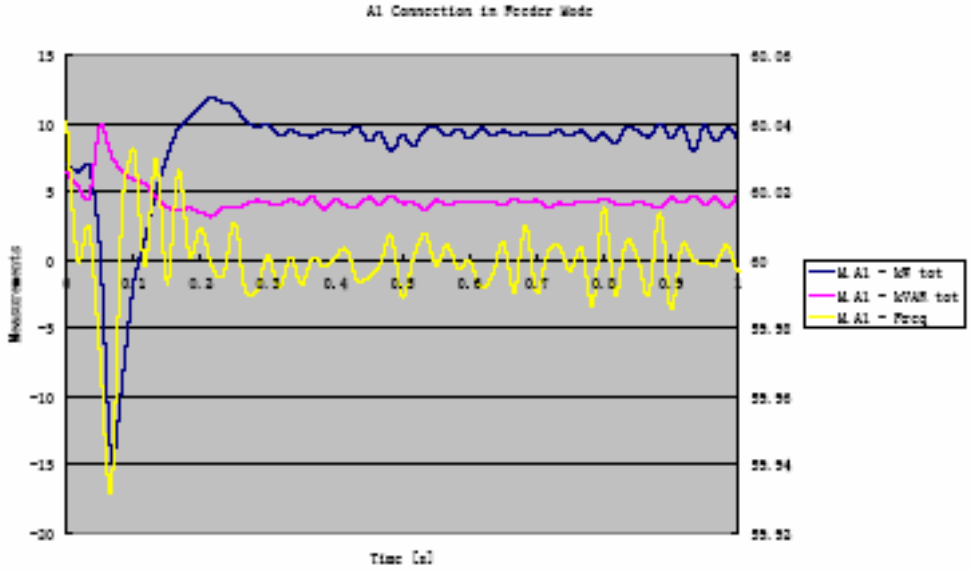


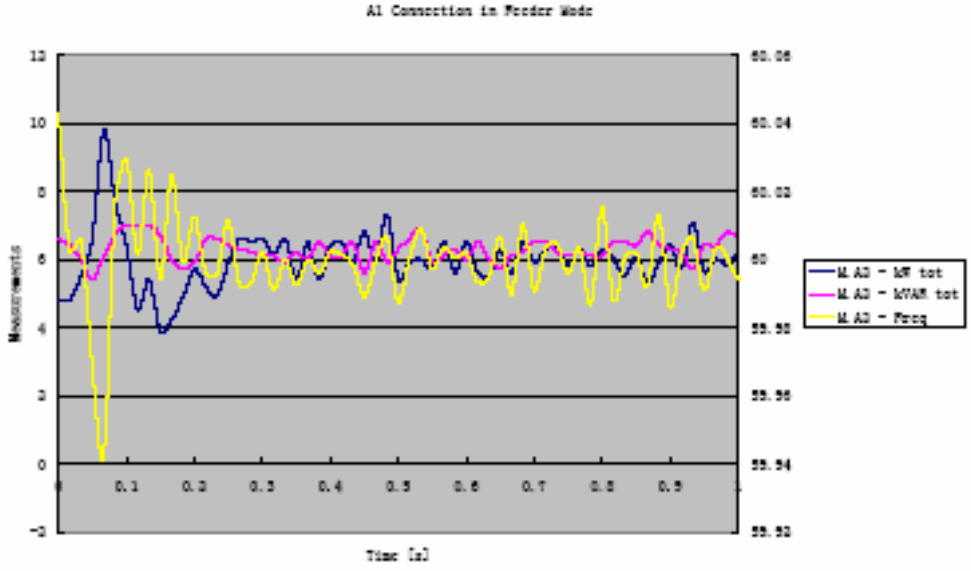


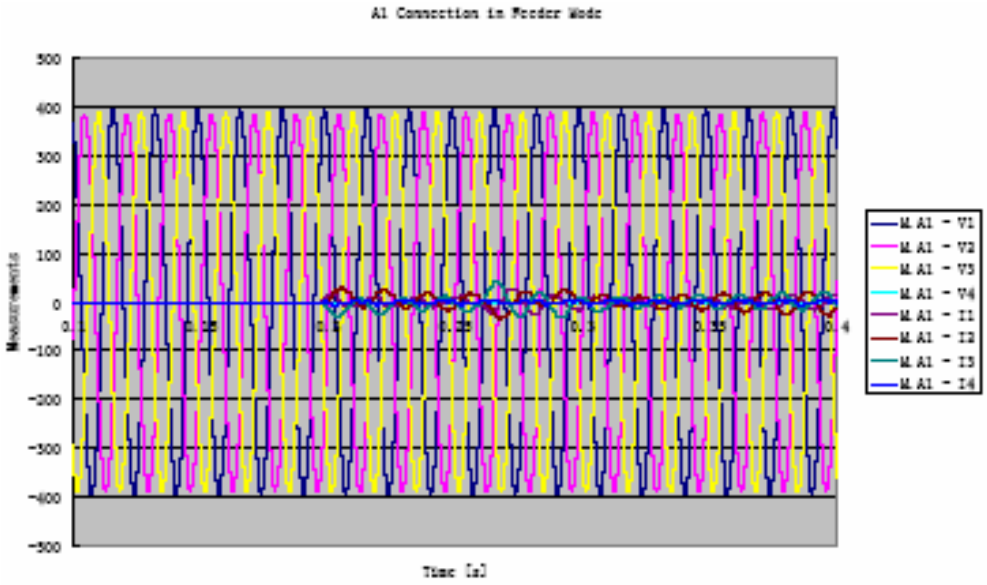
Event not captured

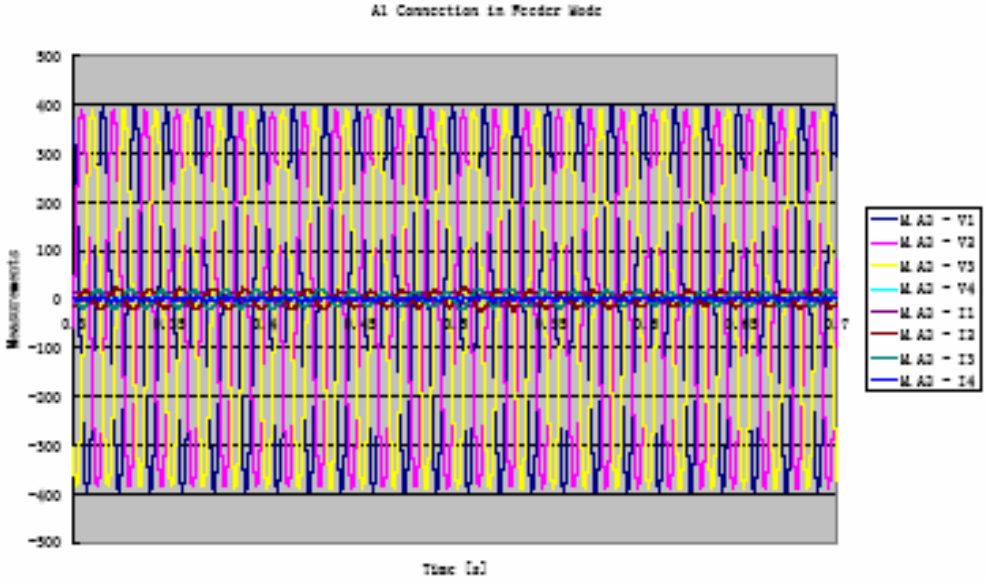


Event to reach III.a.1 with unit A1 and A2 (connection of A1 in feeder mode)

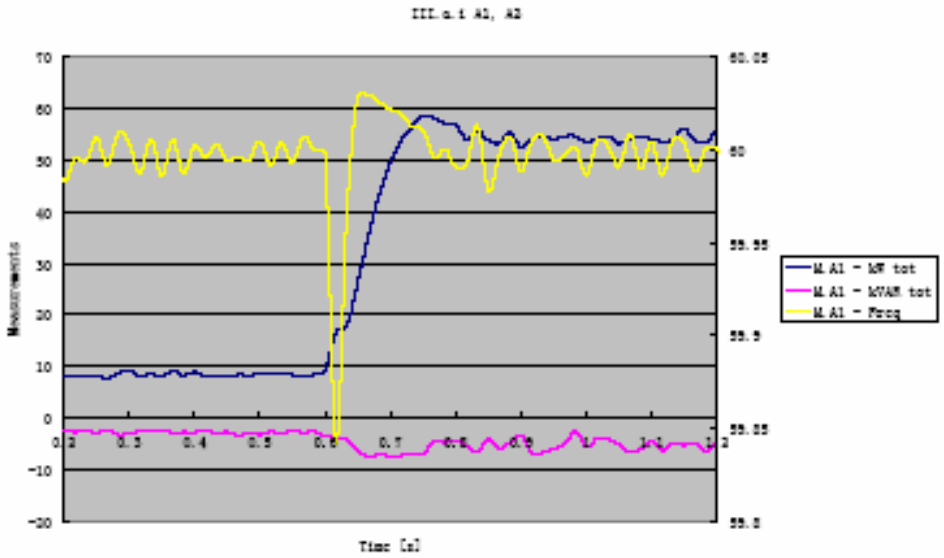


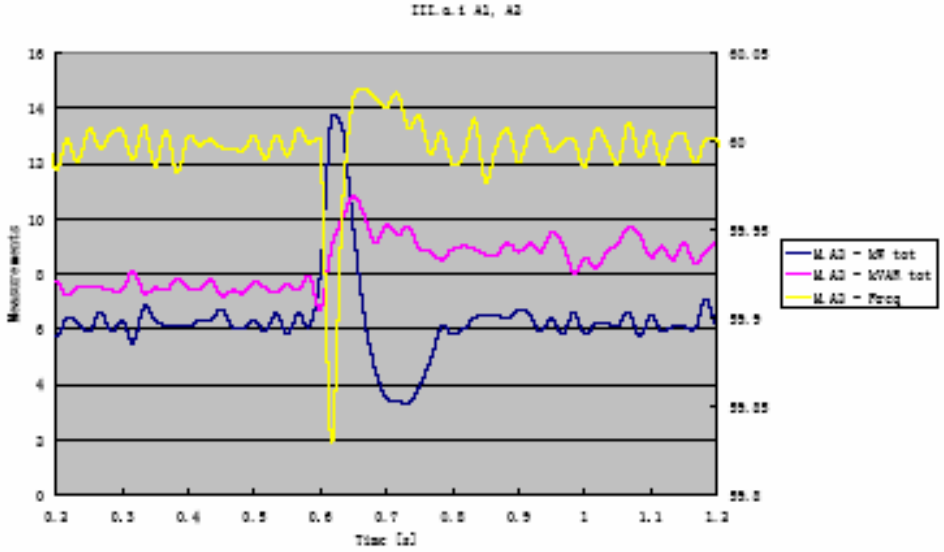


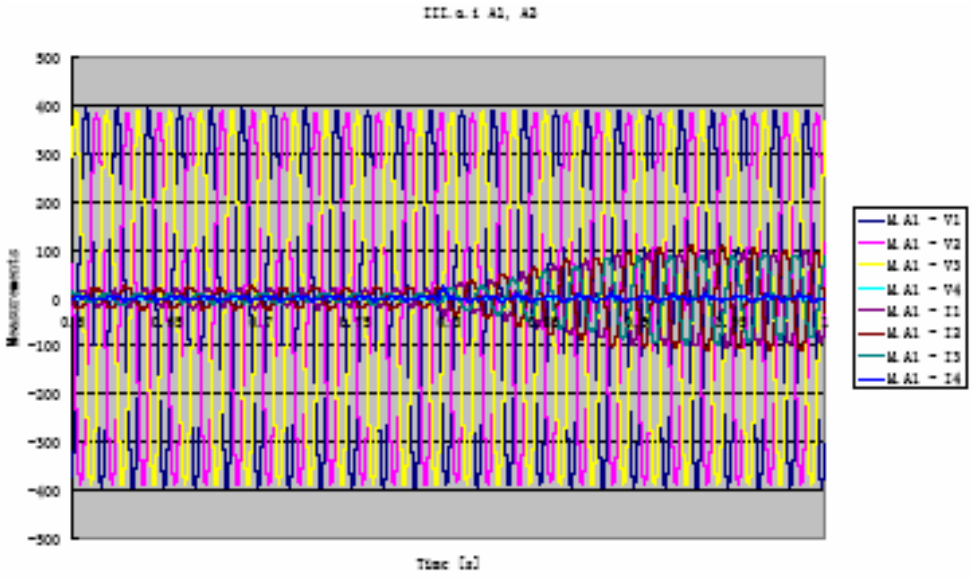

A1 Connection in Feeder Mode
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

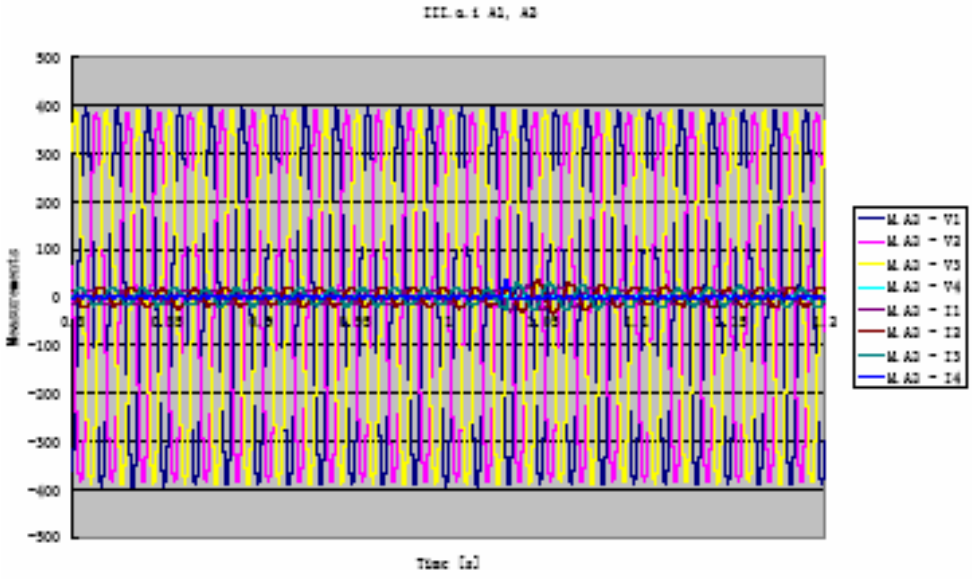

A1 Connection in Feeder Mode
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

III.a.i with unit A1 and A2

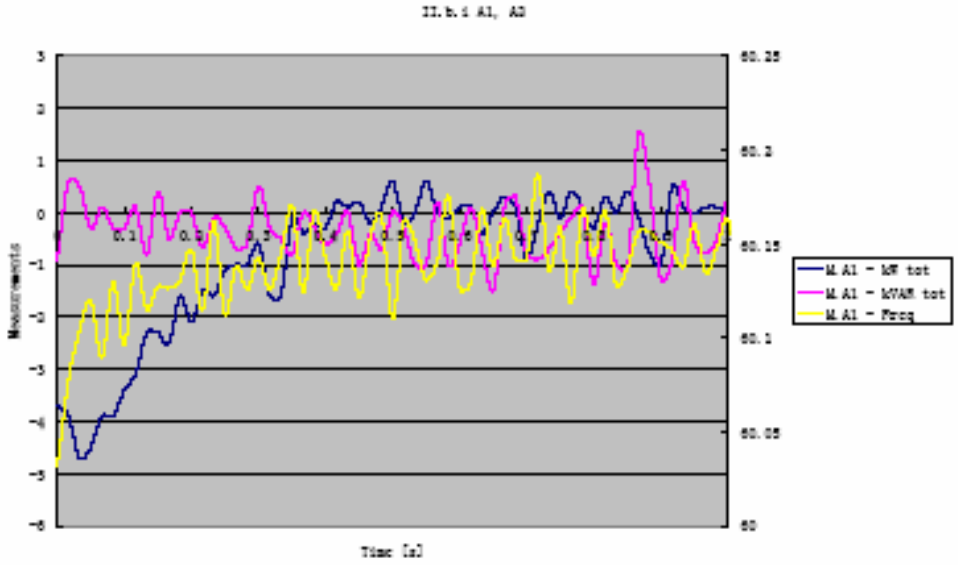


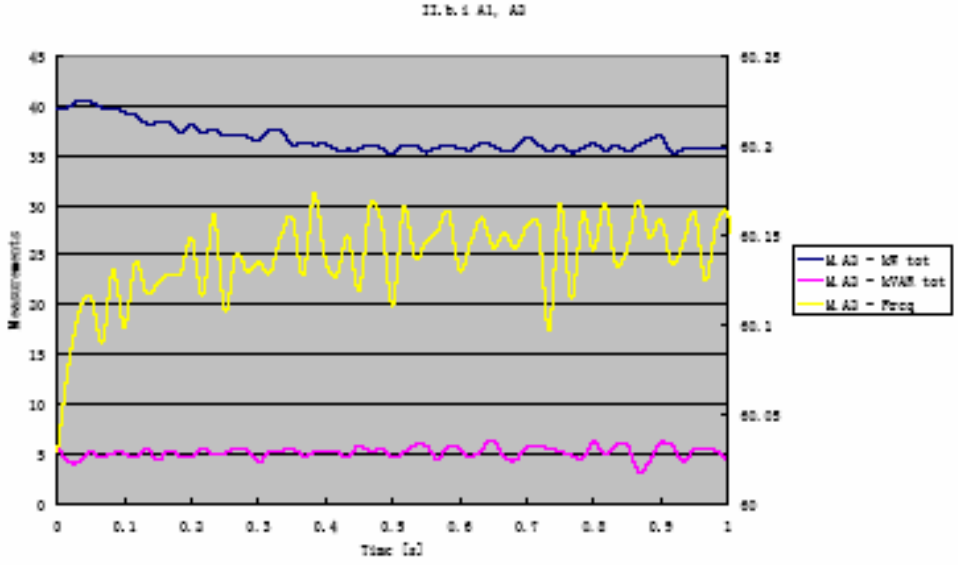


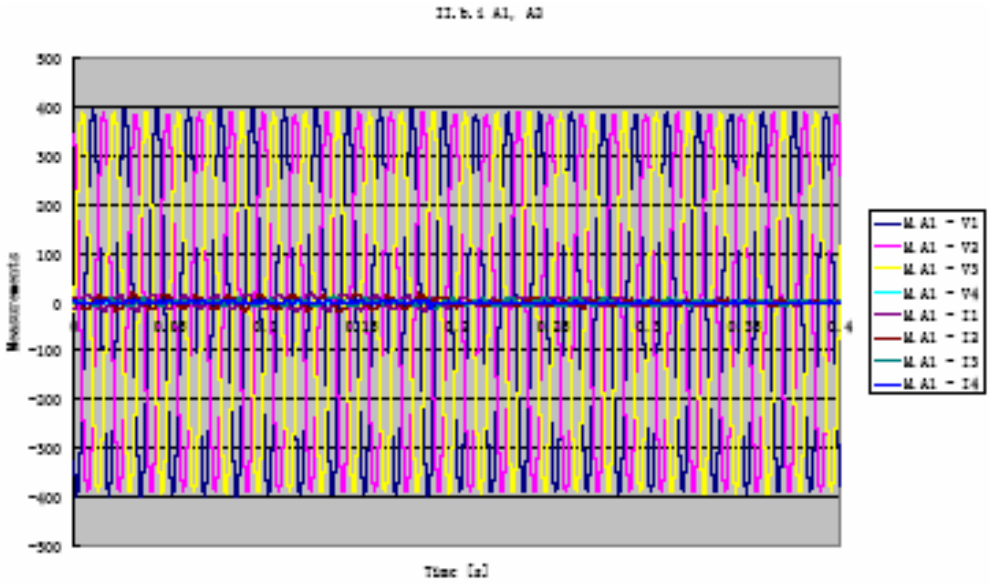

III.n.t A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

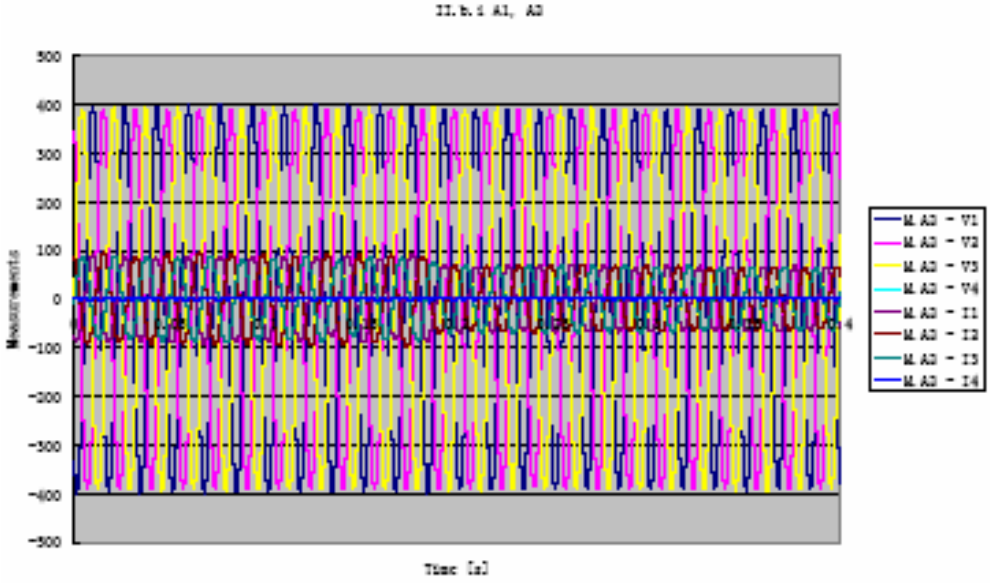

III.n.t A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

II.b.i with unit A1 and A2

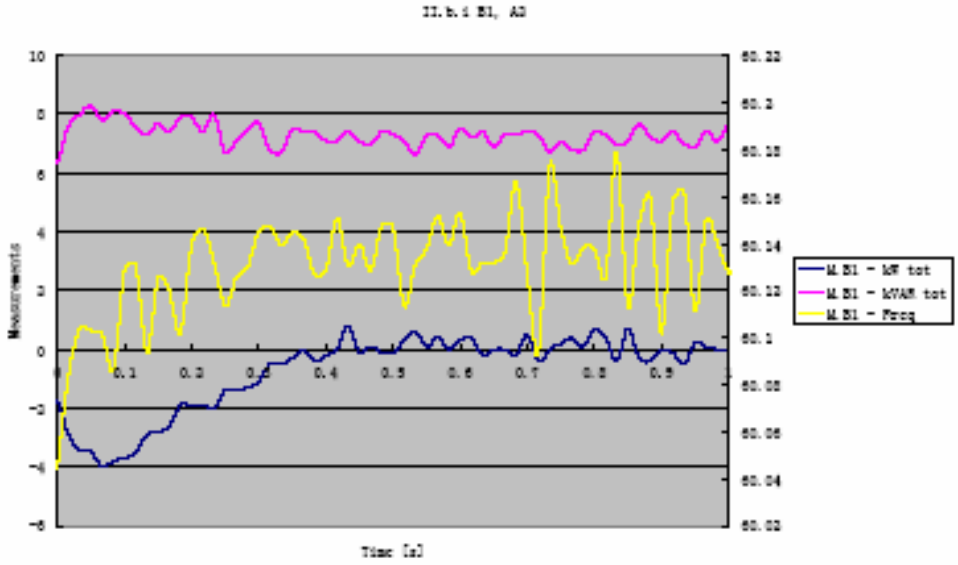


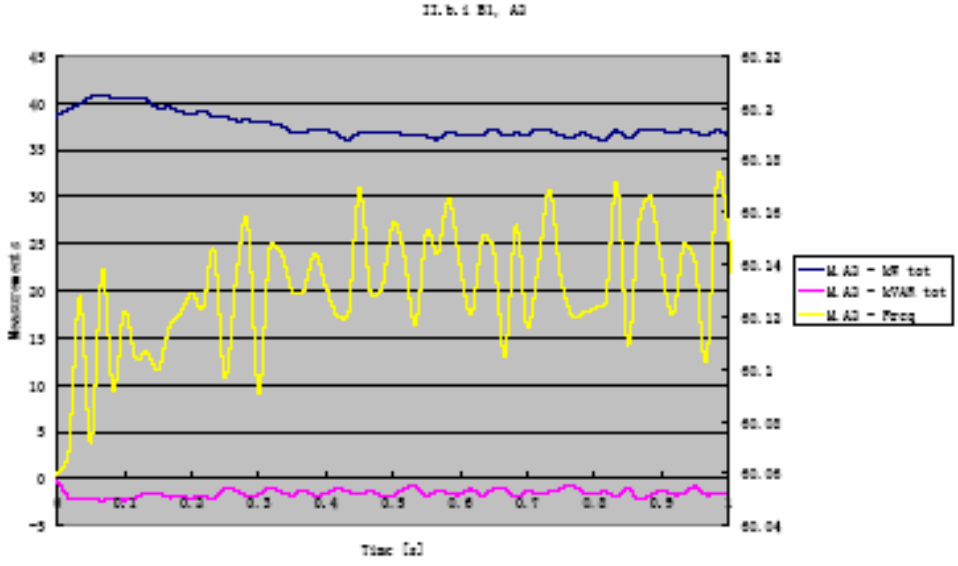


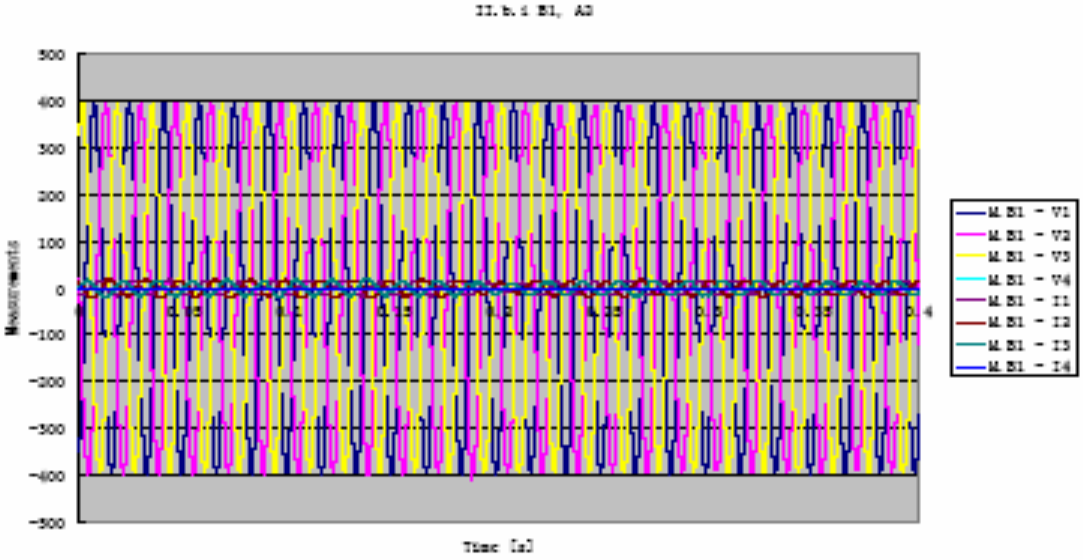

II.b.1 A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
0.1
0.2
0.3
0.4
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4

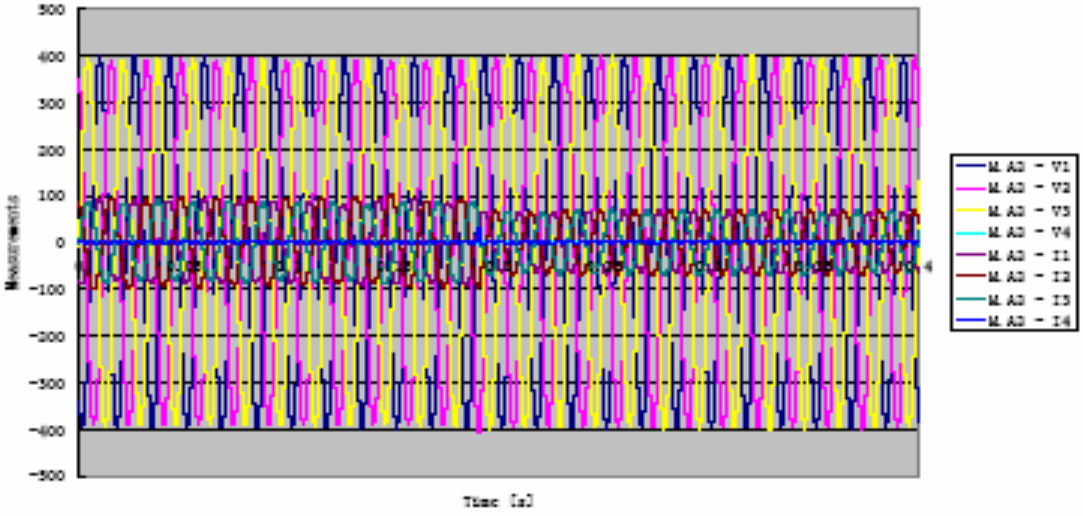

II.b.1 A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
0.1
0.2
0.3
0.4
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

II.b.i with unit B1 and A2

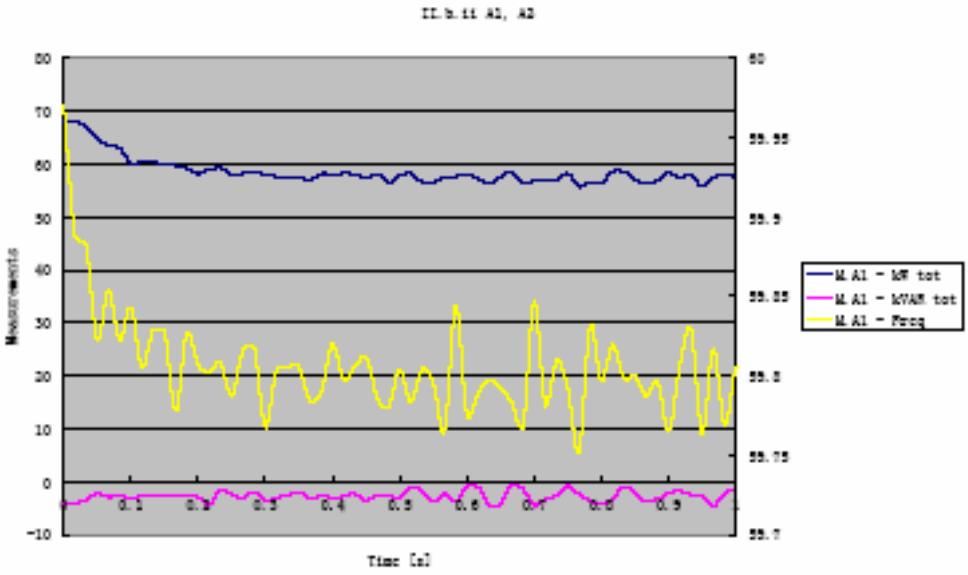


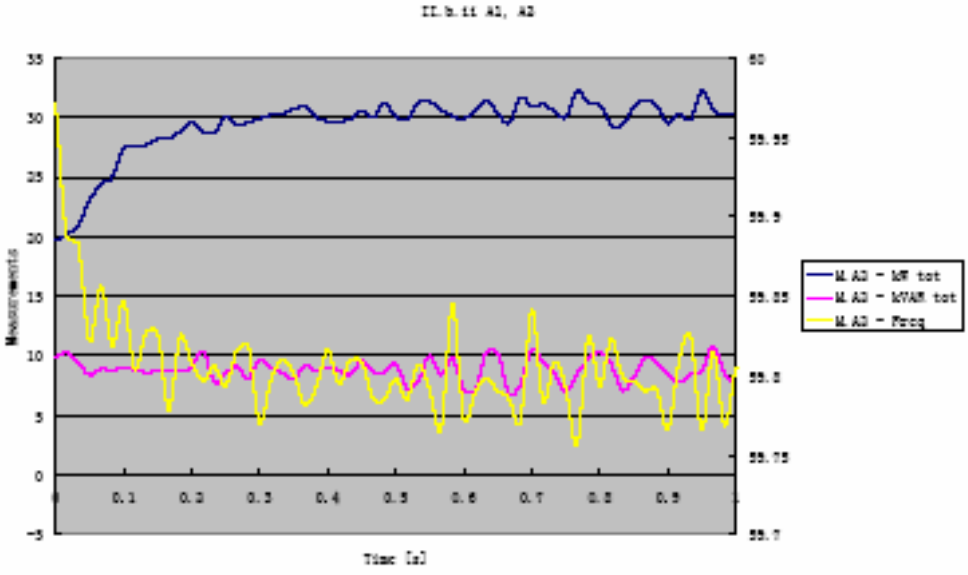


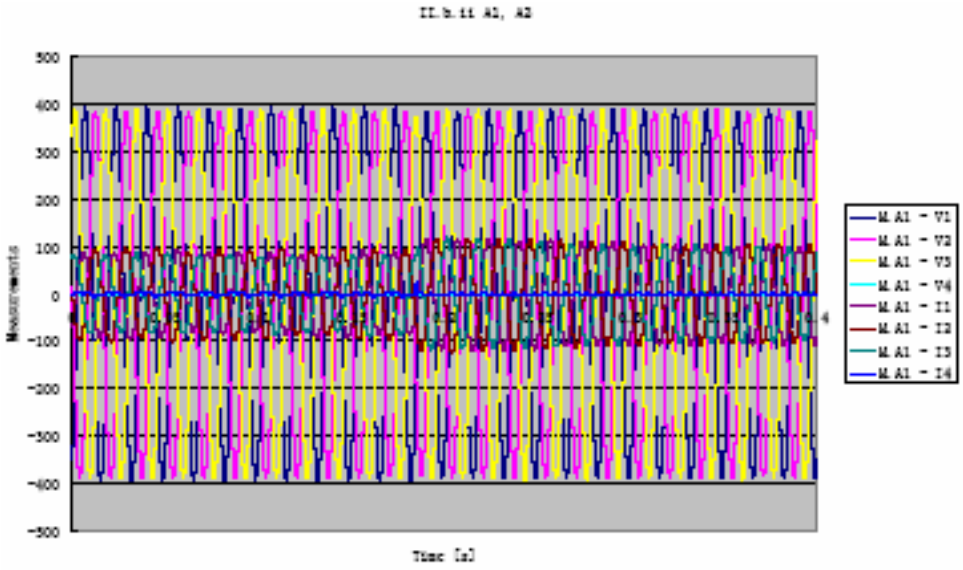

M.B1 - V1
M.B1 - V2
M.B1 - V3
M.B1 - V4
M.B1 - I1
M.B1 - I2
M.B1 - I3
M.B1 - I4
Time [s]

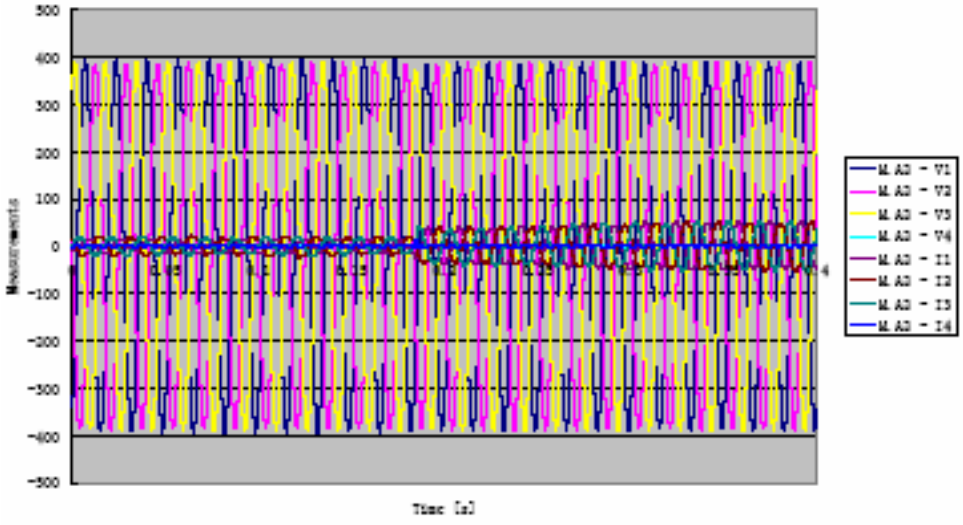

M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4
Time [s]

II.b.ii with units A1 and A2

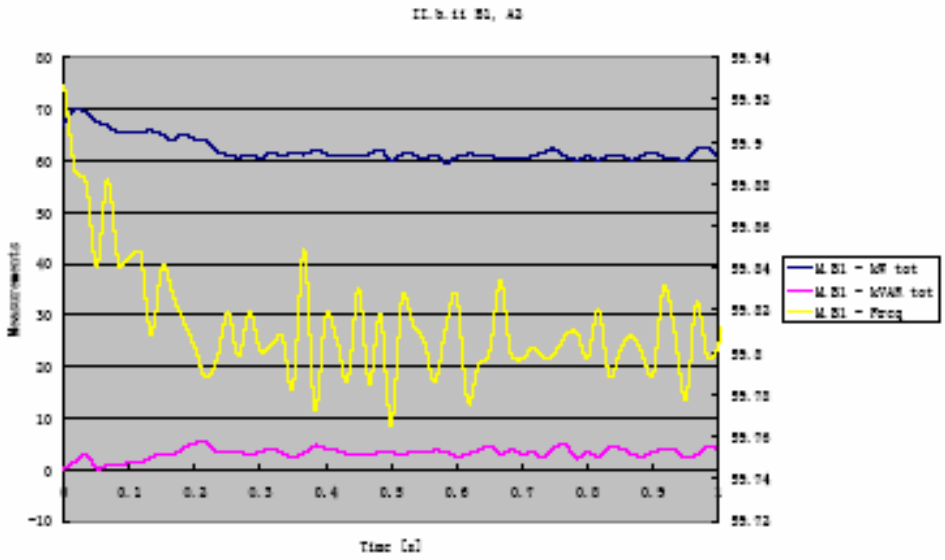


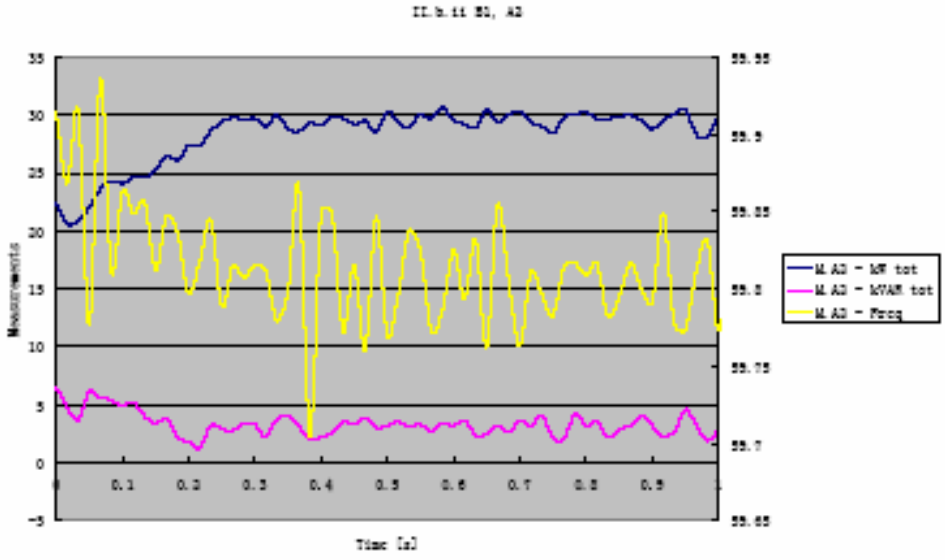


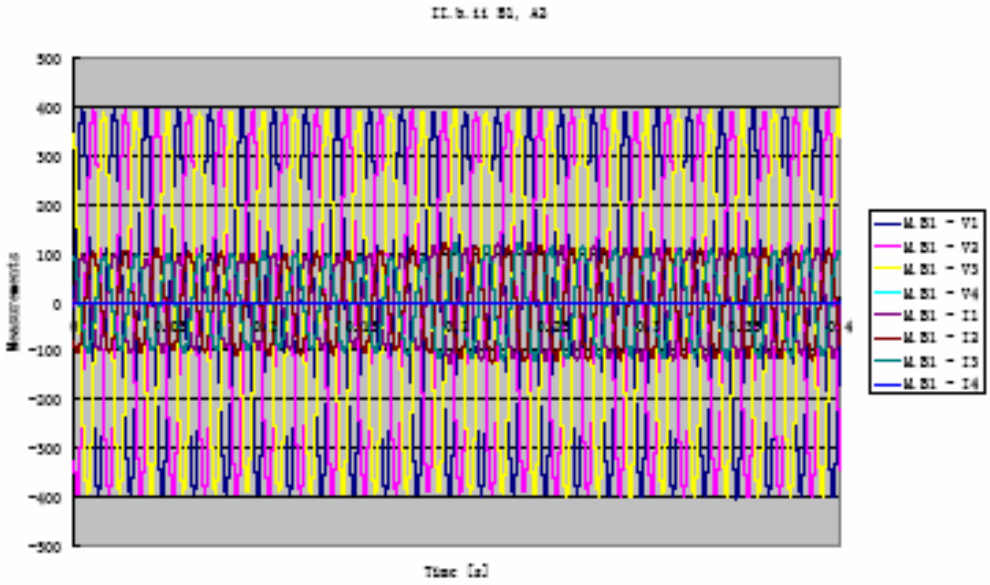

M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4
Time [s]

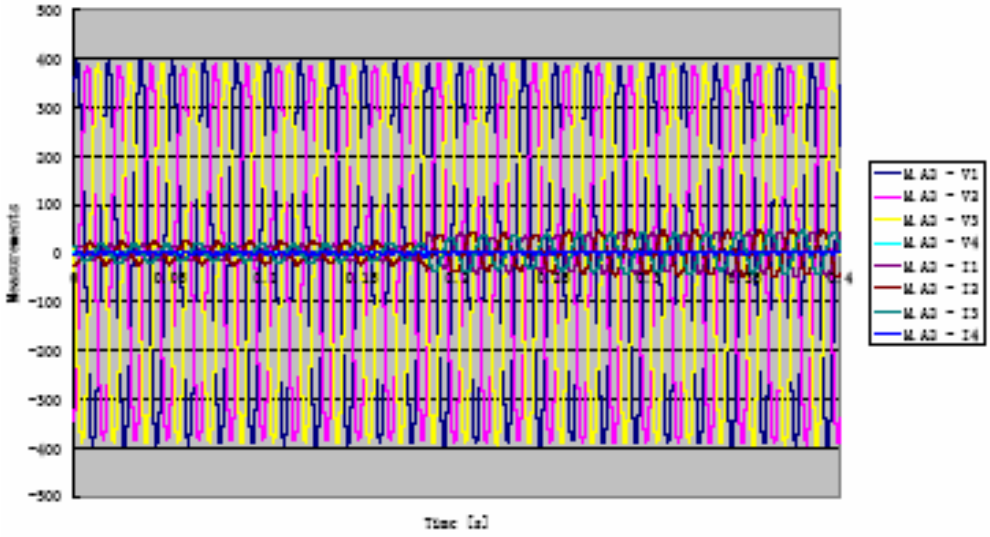

M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4
Time [s]

II.b.ii with units B1 and A2

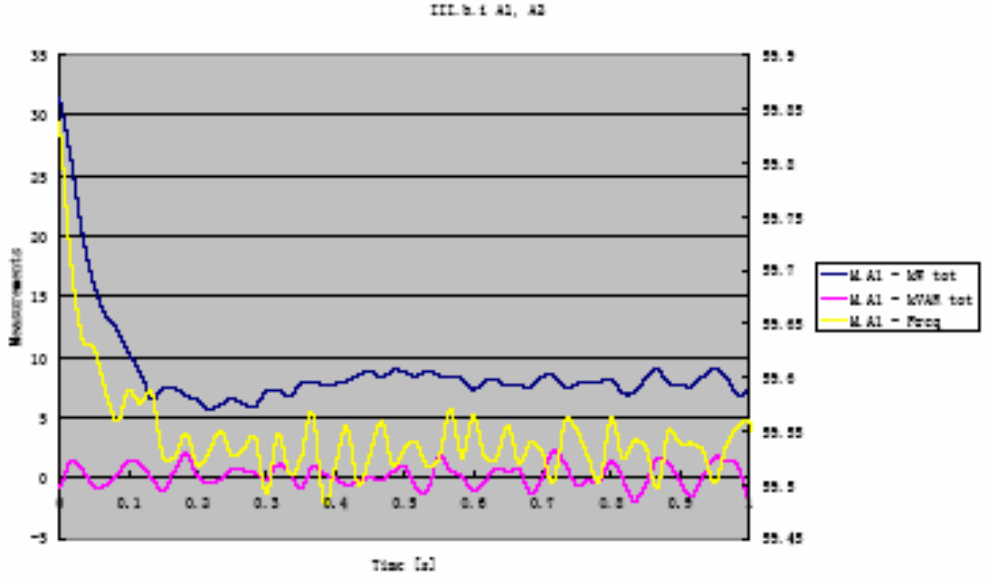


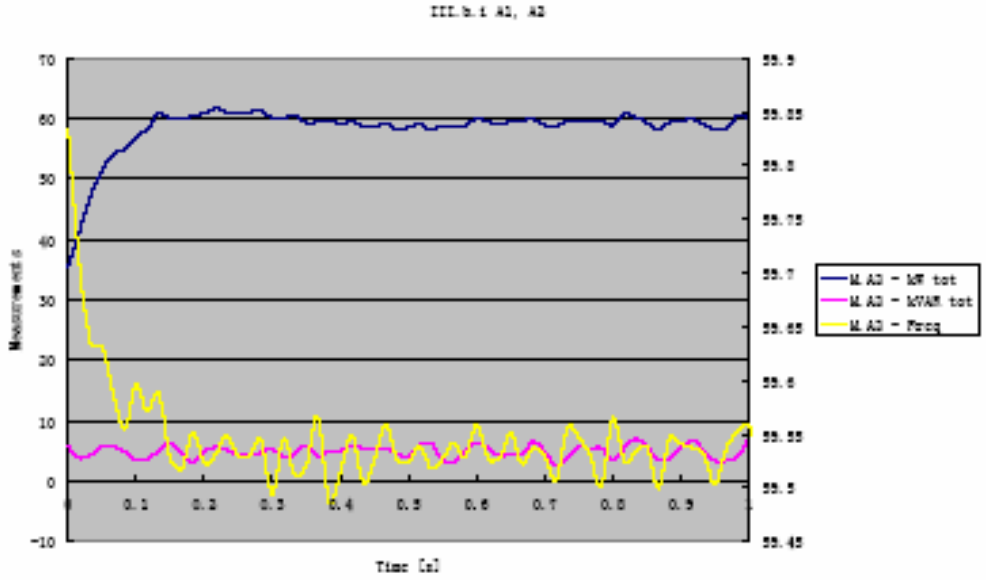


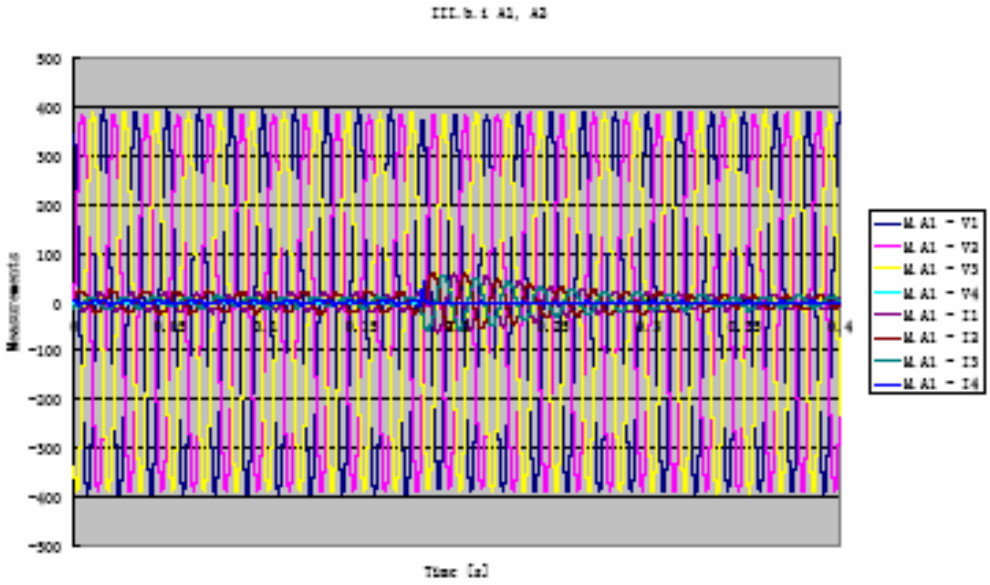

M.B1 - V1
M.B1 - V2
M.B1 - V3
M.B1 - V4
M.B1 - I1
M.B1 - I2
M.B1 - I3
M.B1 - I4
Time [s]

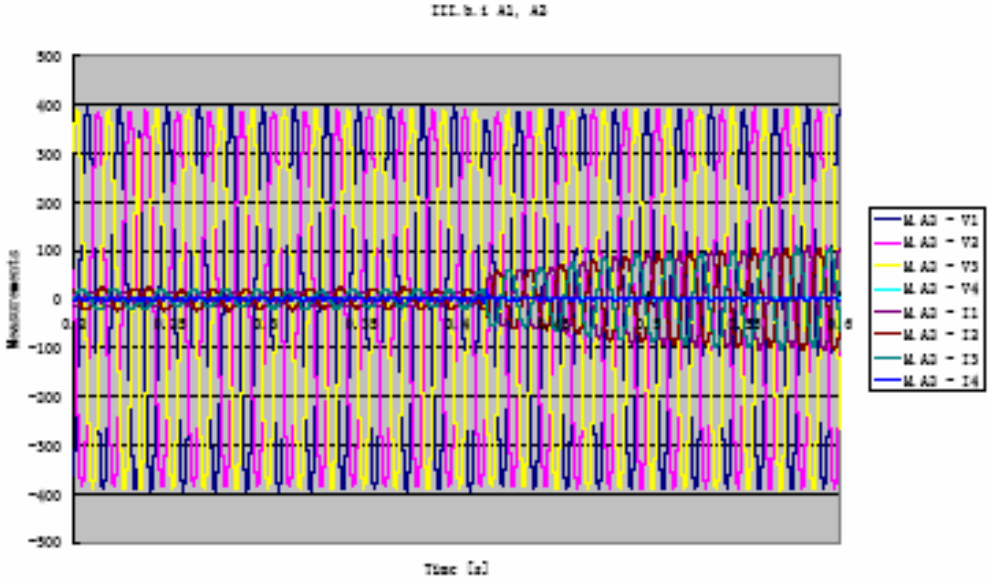

M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4
Time [s]

III.b.i with unit A1 and A2






III.b.i A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A1 - V1
M.A1 - V2
M.A1 - V3
M.A1 - V4
M.A1 - I1
M.A1 - I2
M.A1 - I3
M.A1 - I4


III.b.i A1, A2
500
400
300
200
100
0
-100
-200
-300
-400
-500
Measurements
Time [s]
M.A2 - V1
M.A2 - V2
M.A2 - V3
M.A2 - V4
M.A2 - I1
M.A2 - I2
M.A2 - I3
M.A2 - I4

14. Oscilloscope Waveforms, Unit A2, 10-11-06

Oscilloscope waveforms with and without weakened genset

This report focuses in identifying the contributions of the surge module to the operation of a single genset during several loading and unloading conditions. It was shown that the new stiff engine control would survive all the load changes without the assistance of the surge module. For that, see data in "10_11_06_test_results.pdf", obtained with surge module off and engine running at 2000rpm.

This document shows the oscilloscope traces obtained with the stiff control at unit A1 in two basic series of tests: A) with the engine setpoint 2000rpm and the surge module on at all times; B) with a weakened engine, operating at a 1850rpm setpoint and with the surge module on in some tests and off in others.

The traces show a matrix of plots with DC bus voltage, surge module current, inverter current and voltage, synchronous machine current and engine rpm. The speed was calculated from zero crossing of the synch. mach. current.

The other time (i.e. "Oscilloscope_8_31_06.pdf") the DC bus voltage was obtained from subtracting low rail voltage from the high rail voltage. At this time, only the high rail voltage was captured: the full rail to rail voltage was calculated multiplying by two this available voltage.

The two series of tests can be found:

A) Engine set to run at 2000rpm ……. pg. 2
B) Engine set to run at 1850rpm …… 8

Notes:

i) the current from the surge module (when it is activated) seems to be larger than previously measured in August. I am not sure if before there was a filter in the probe and this time it was without the filtering. Or the issue could be related to the sampling rate. The average current should be equal to 20A.

ii) in the case A) with load from 60kW => 0, (Figure 6) the DC bus exceeds 900V. It could be that the mid point voltage experienced a sag and the high rail was larger than the low rail. Because this plot was obtained by multiplying by two the high rail voltage, it is possible that the actual overall DC bus never exceeded 900V.

iii) I agree with Dave that when the surge module is injecting current, the sychronous machine current has a strong non zero DC offset. This behaviour was identically present also in the August waveforms.

A) Engine at 2000 RPM

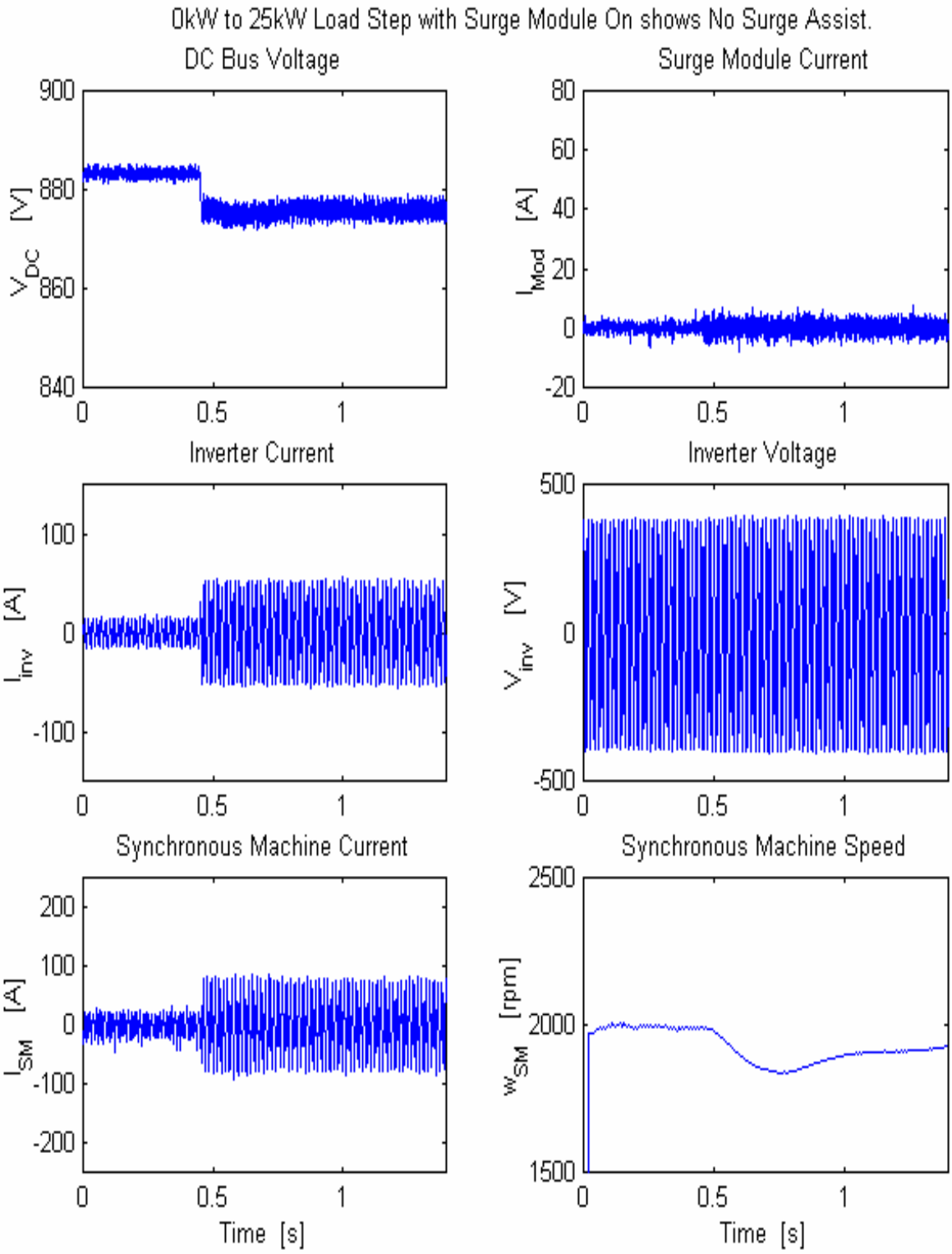


Figure 1.

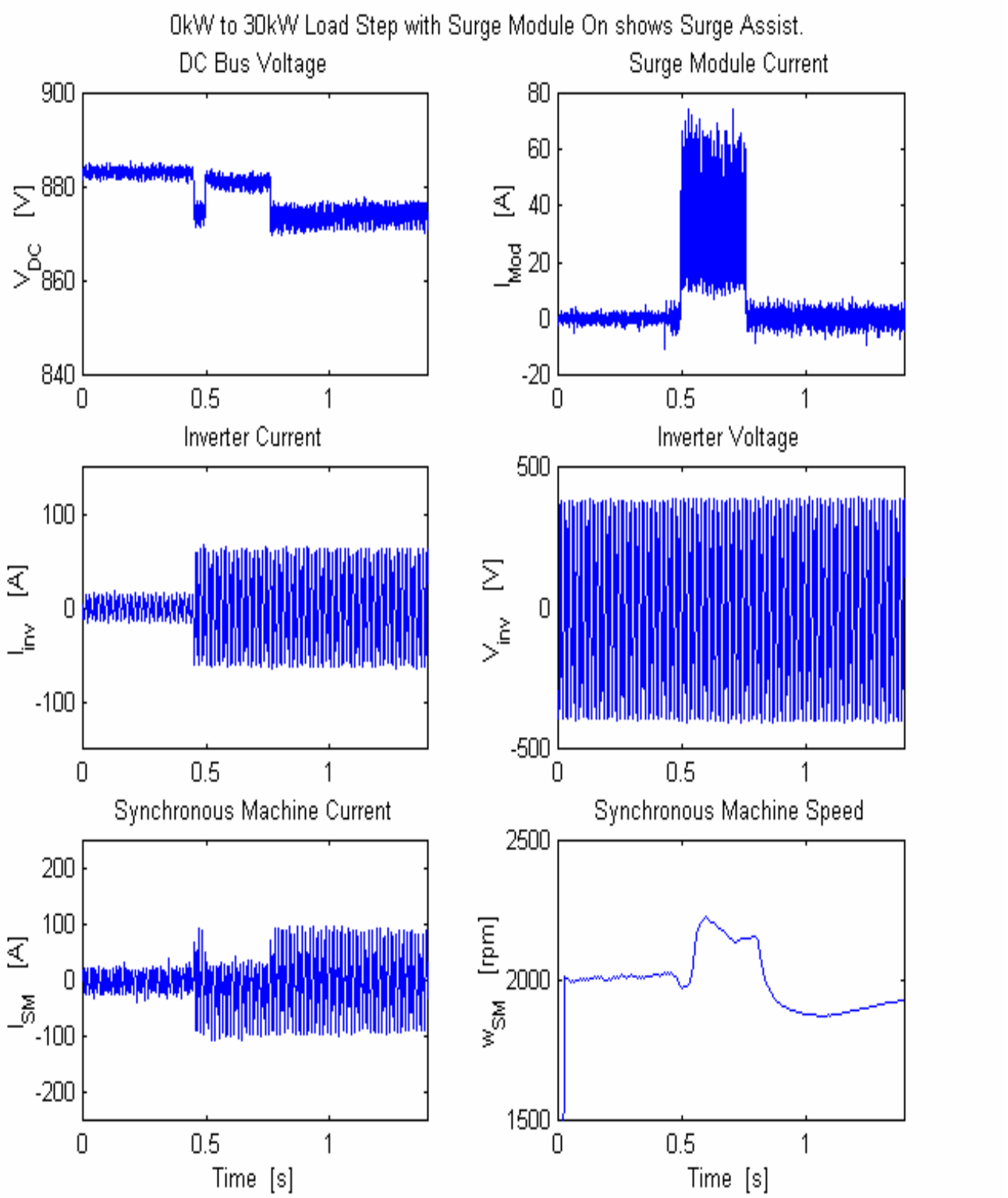

0kW to 30kW Load Step with Surge Module On shows Surge Assist.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
Inverter Current
I_{inv} [A]
100
0
-100
Inverter Voltage
V_{inv} [V]
500
0
-500
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
Time [s]

Figure 2.

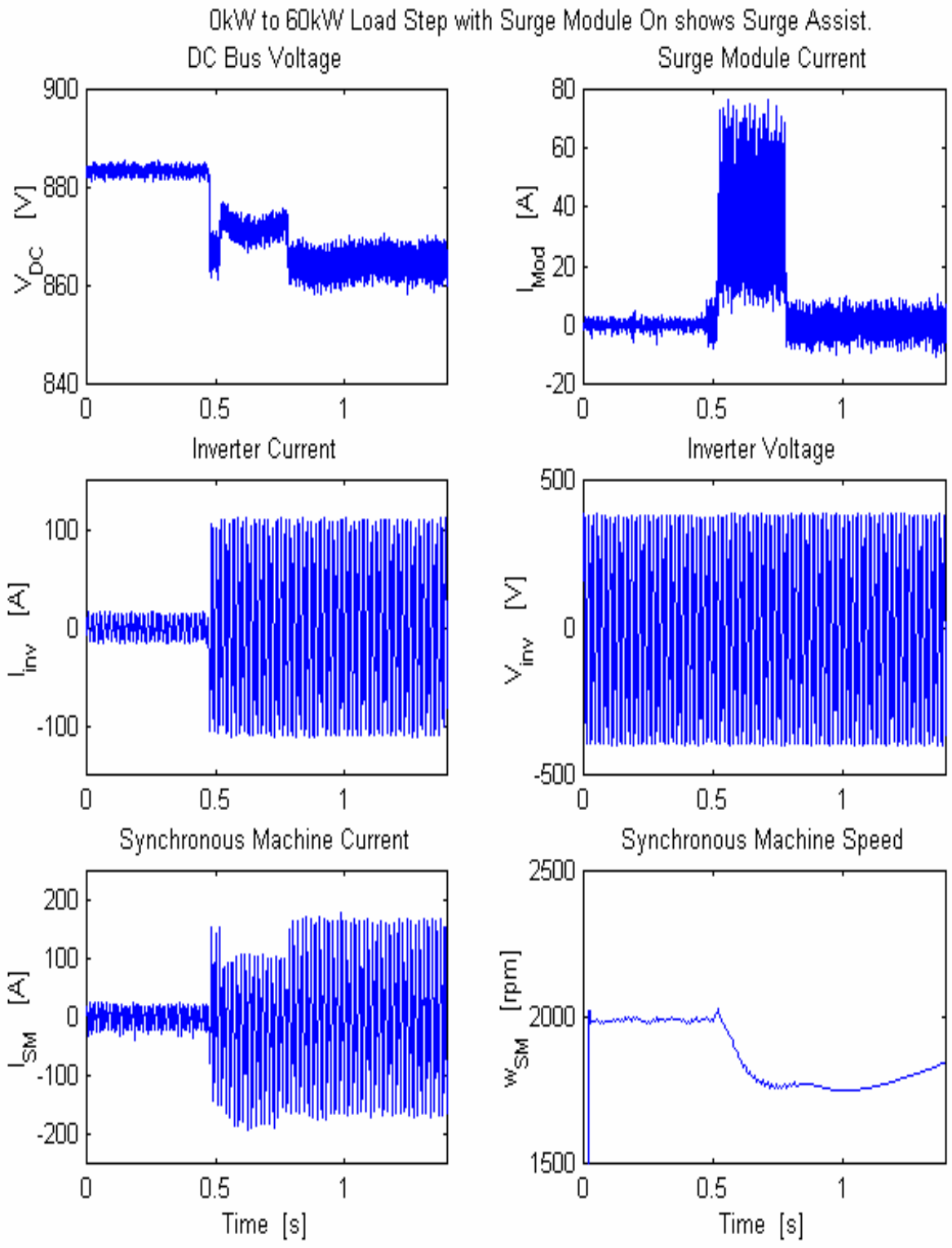

0kW to 60kW Load Step with Surge Module On shows Surge Assist.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
Inverter Current
I_{inv} [A]
100
0
-100
Inverter Voltage
V_{inv} [V]
500
0
-500
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
Time [s]

Figure 3.

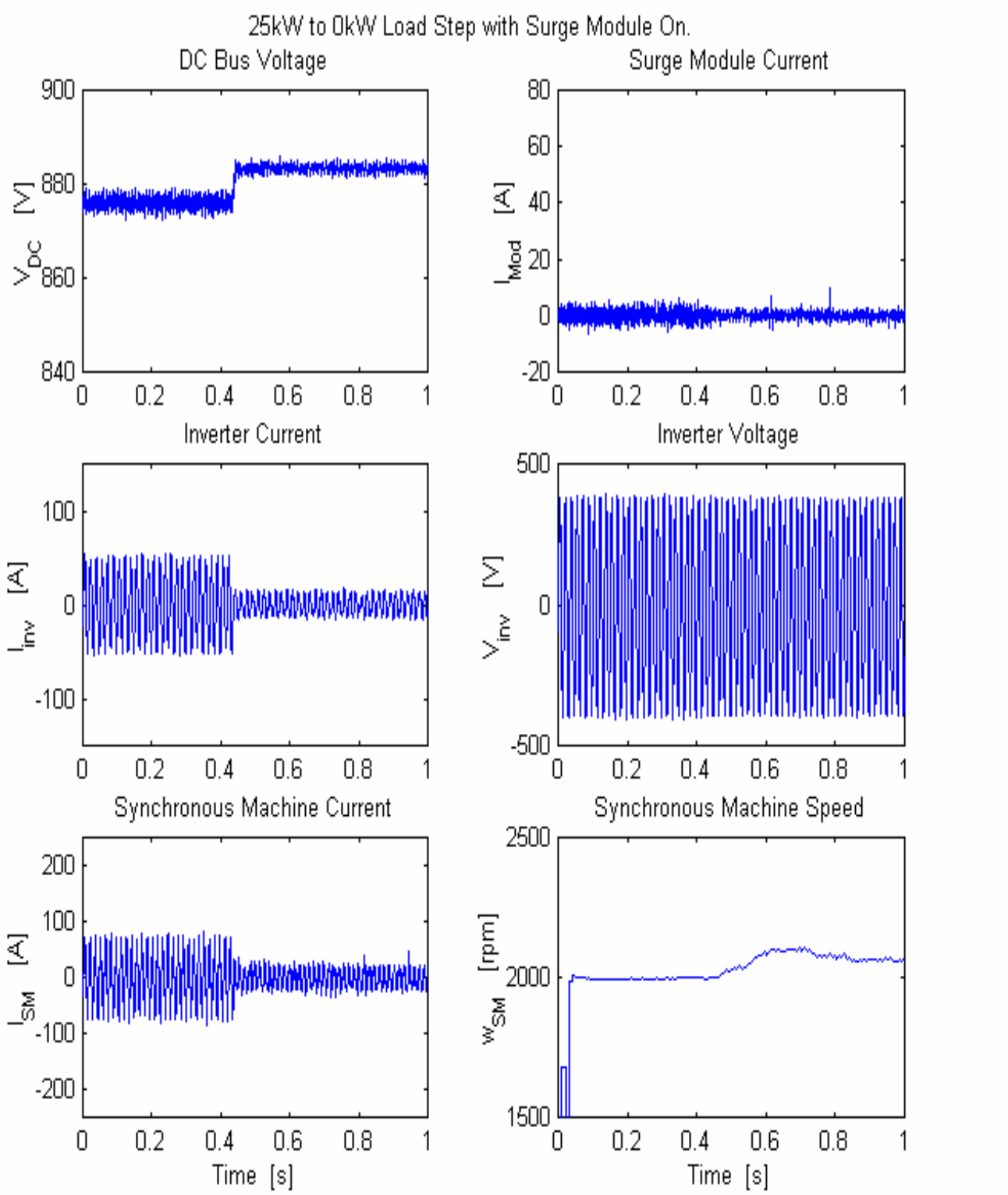

25kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 4.

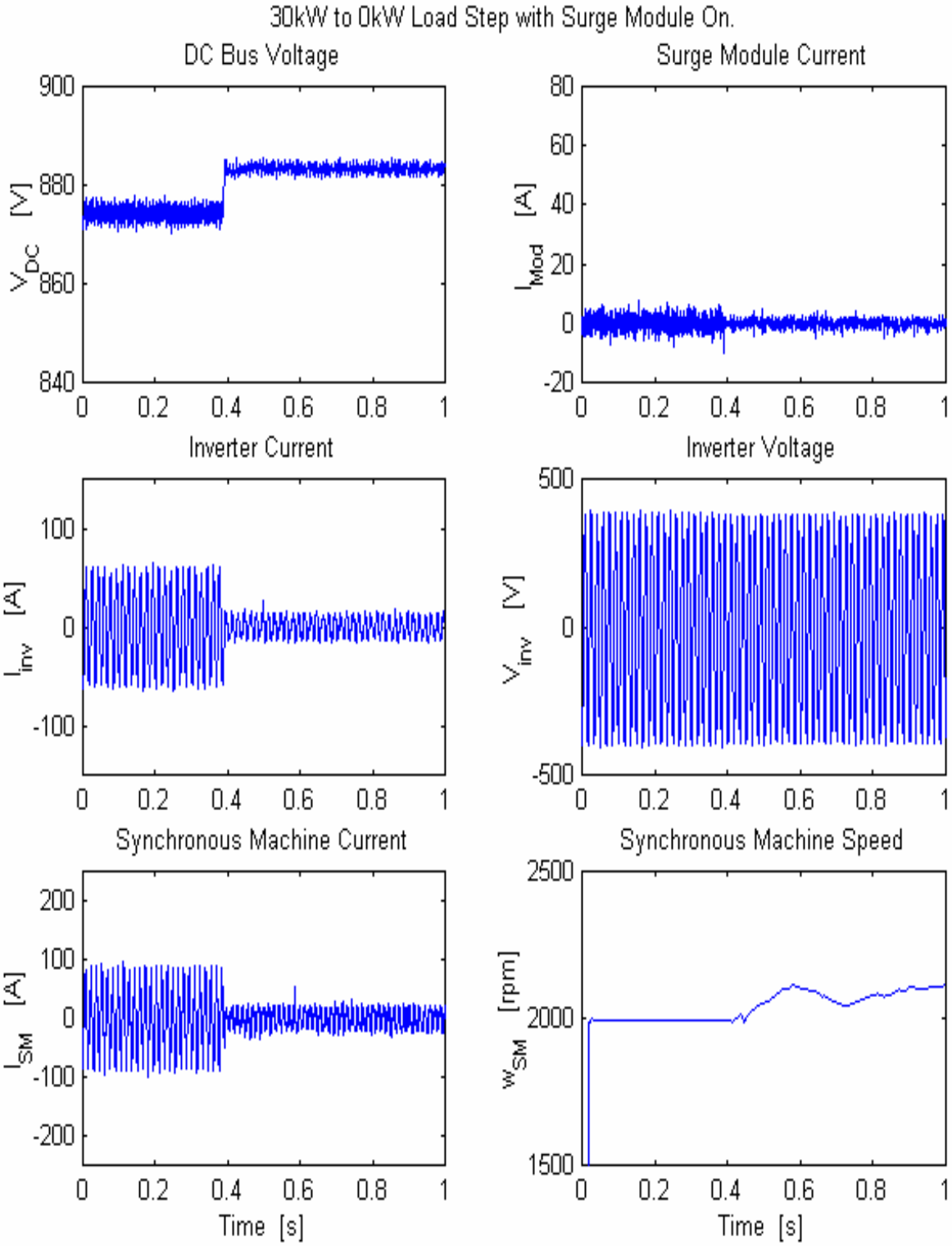

30kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 5.

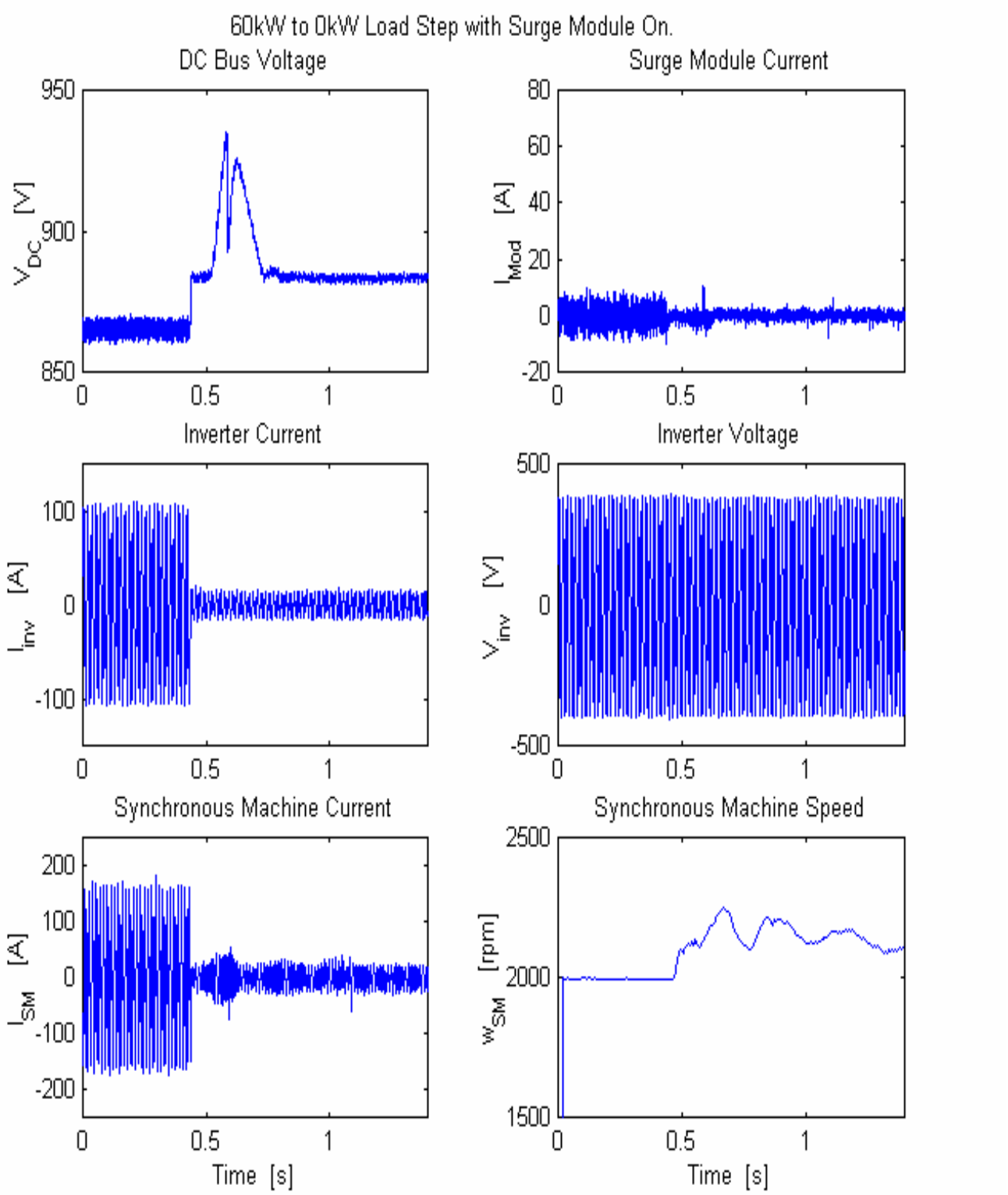

60kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
950
900
850
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
Inverter Current
I_{inv} [A]
100
0
-100
Inverter Voltage
V_{inv} [V]
500
0
-500
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
Time [s]

Figure 6.

B) Engine at 1850 RPM

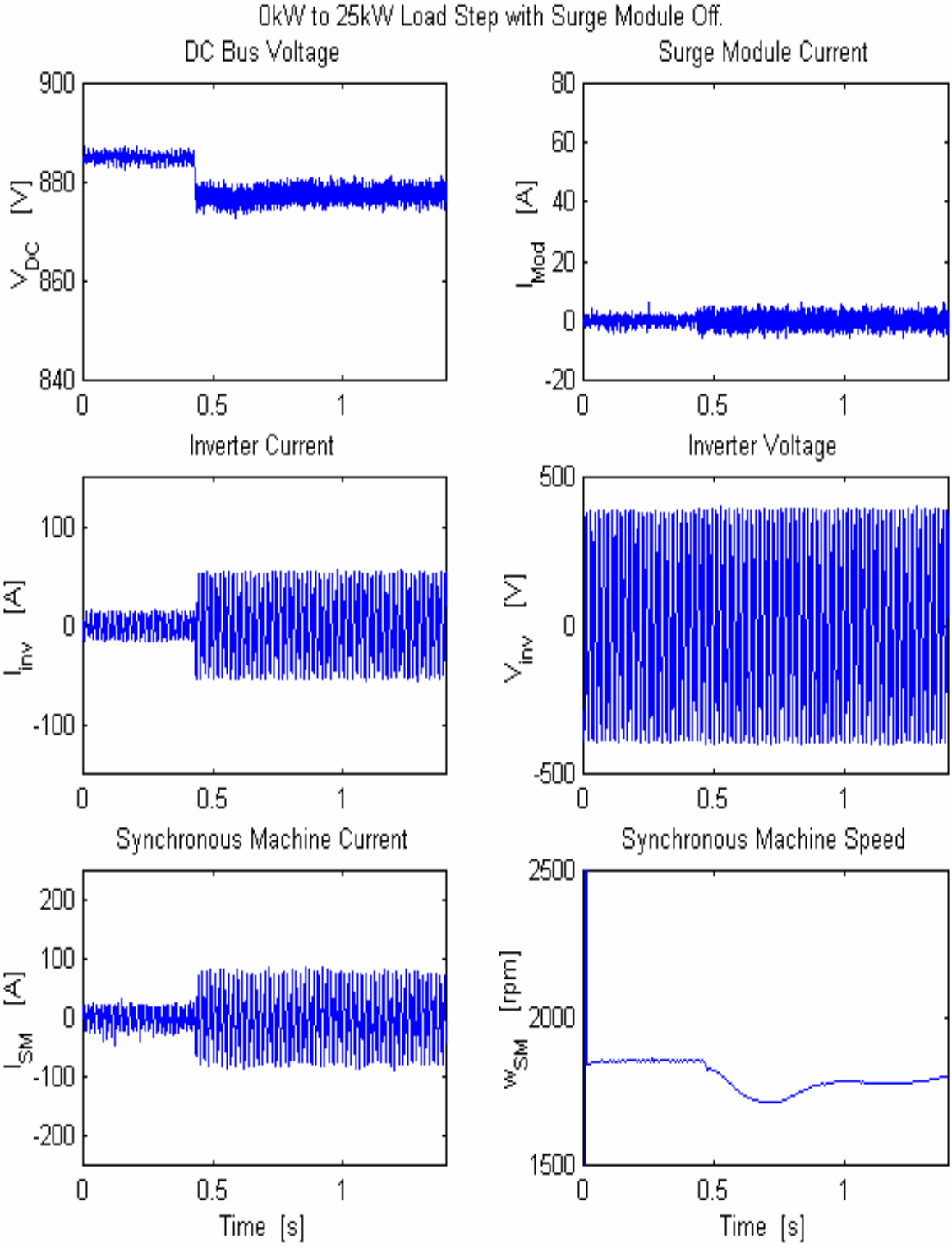


Figure 7.

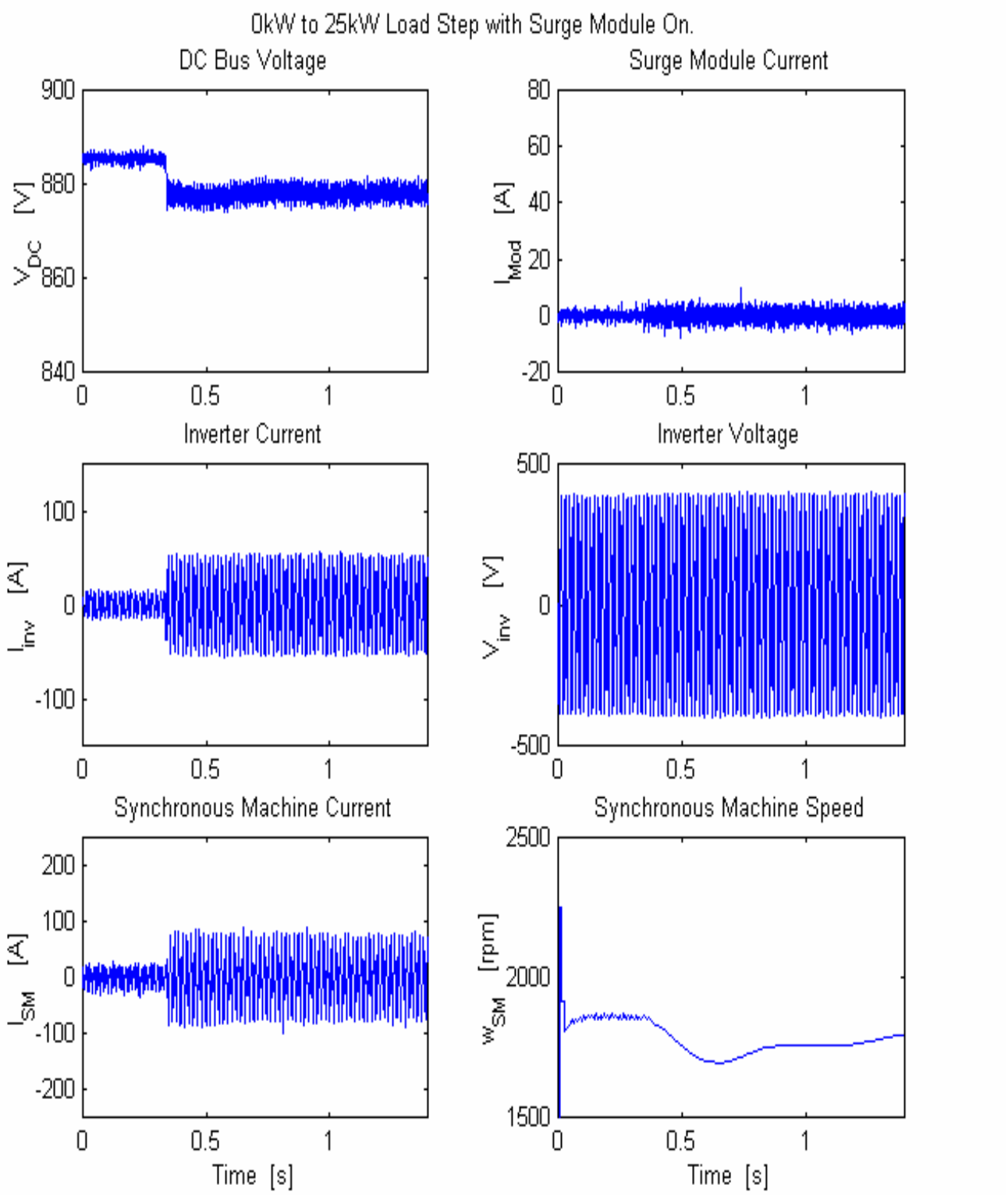

0kW to 25kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
Inverter Current
I_{inv} [A]
100
0
-100
Inverter Voltage
V_{inv} [V]
500
0
-500
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
Time [s]

Figure 8.

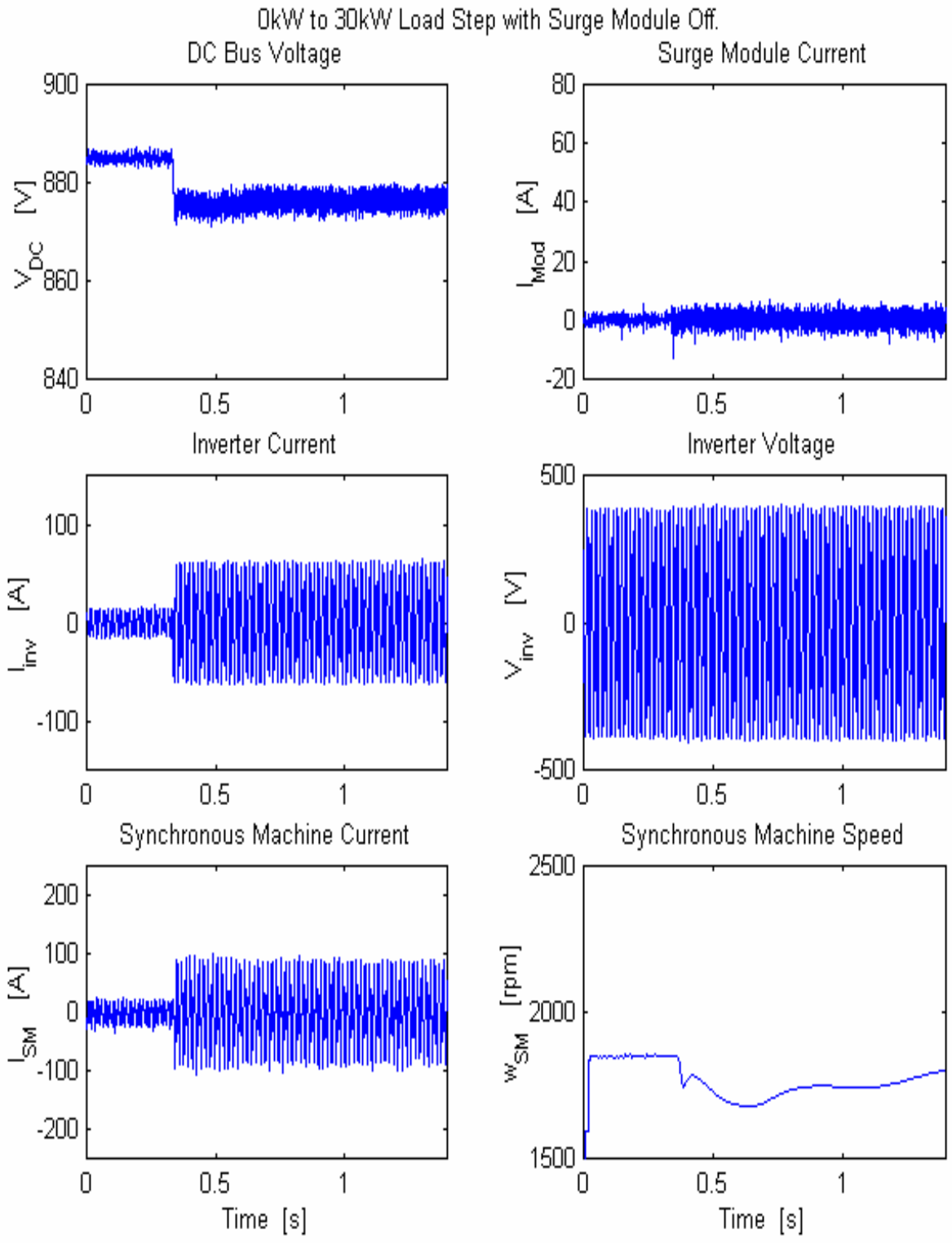

0kW to 30kW Load Step with Surge Module Off.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0
0.5
1
Inverter Current
I_{inv} [A]
100
0
-100
0
0.5
1
Inverter Voltage
V_{inv} [V]
500
0
-500
0
0.5
1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0
0.5
1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0
0.5
1
Time [s]

Figure 9.

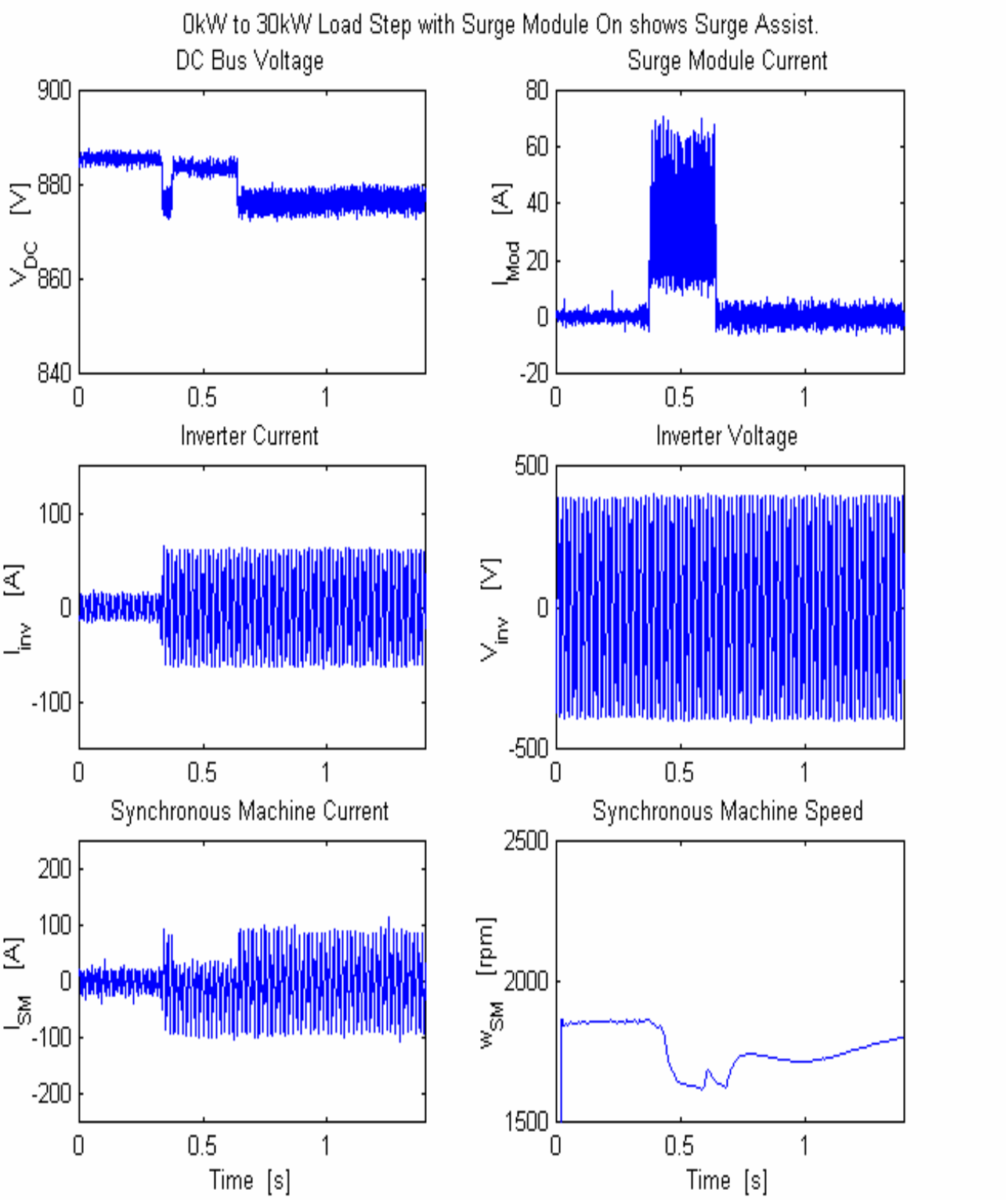

0kW to 30kW Load Step with Surge Module On shows Surge Assist.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0
0.5
1
Inverter Current
I_{inv} [A]
100
0
-100
0
0.5
1
Inverter Voltage
V_{inv} [V]
500
0
-500
0
0.5
1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0
0.5
1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0
0.5
1
Time [s]

Figure 10.

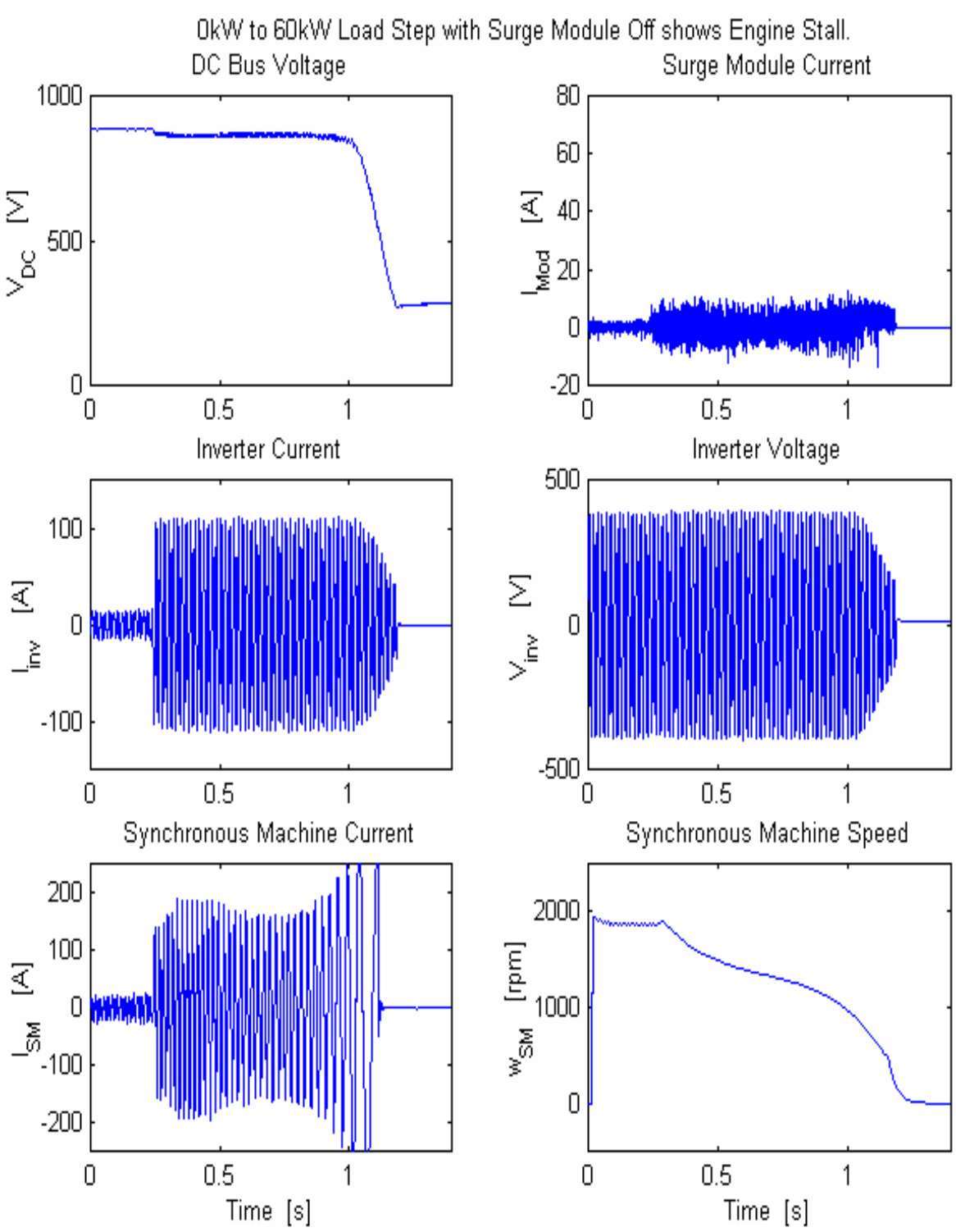

0kW to 60kW Load Step with Surge Module Off shows Engine Stall.
DC Bus Voltage
V_{DC} [V]
Surge Module Current
I_{Mod} [A]
Inverter Current
I_{inv} [A]
Inverter Voltage
V_{inv} [V]
Synchronous Machine Current
I_{SM} [A]
Synchronous Machine Speed
w_{SM} [rpm]
Time [s]
Time [s]

Figure 11.

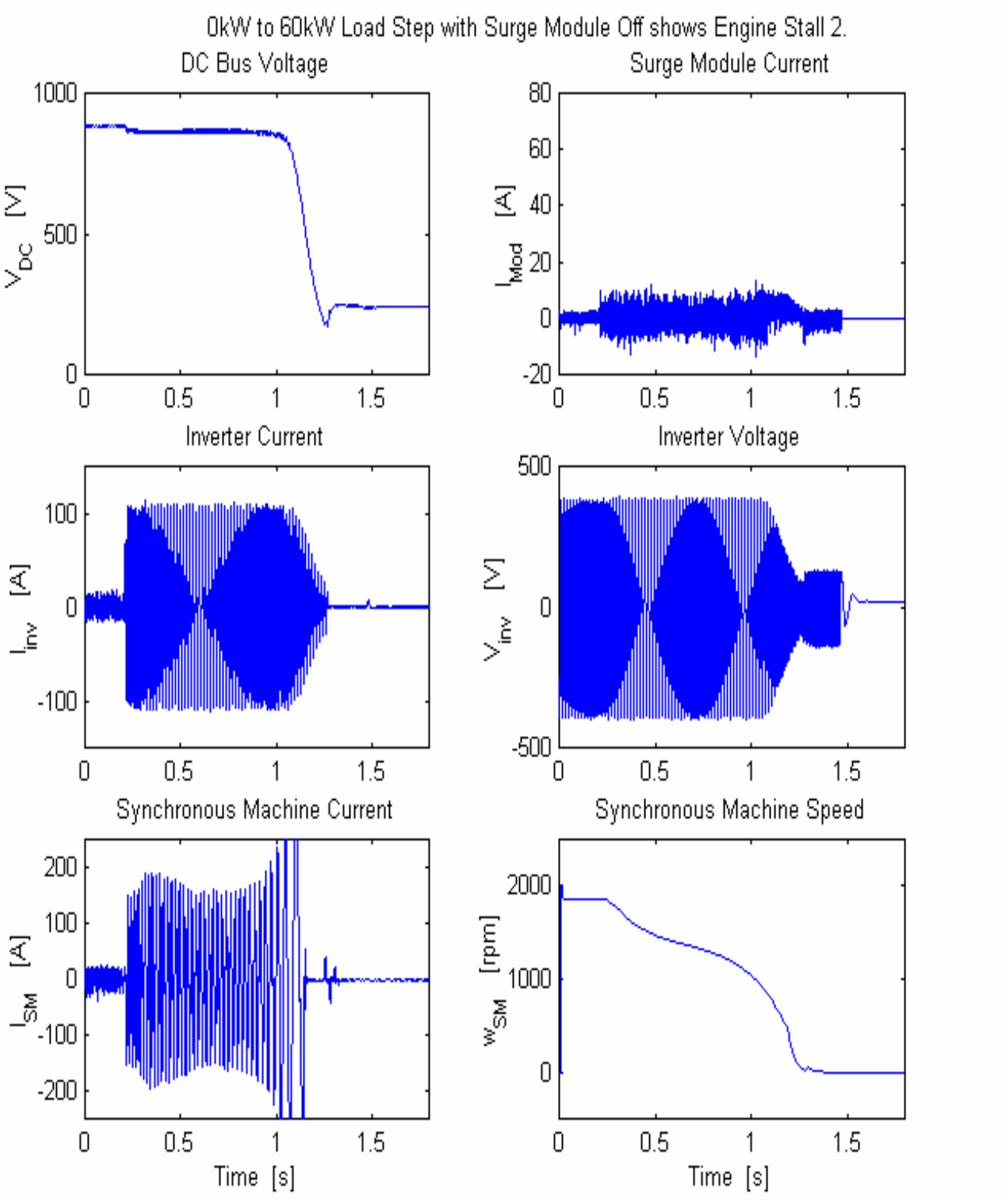

0kW to 60kW Load Step with Surge Module Off shows Engine Stall 2.
DC Bus Voltage
V_{DC} [V]
Surge Module Current
I_{Mod} [A]
Inverter Current
I_{inv} [A]
Inverter Voltage
V_{inv} [V]
Synchronous Machine Current
I_{SM} [A]
Synchronous Machine Speed
w_{SM} [rpm]
Time [s]
Time [s]

Figure 12.

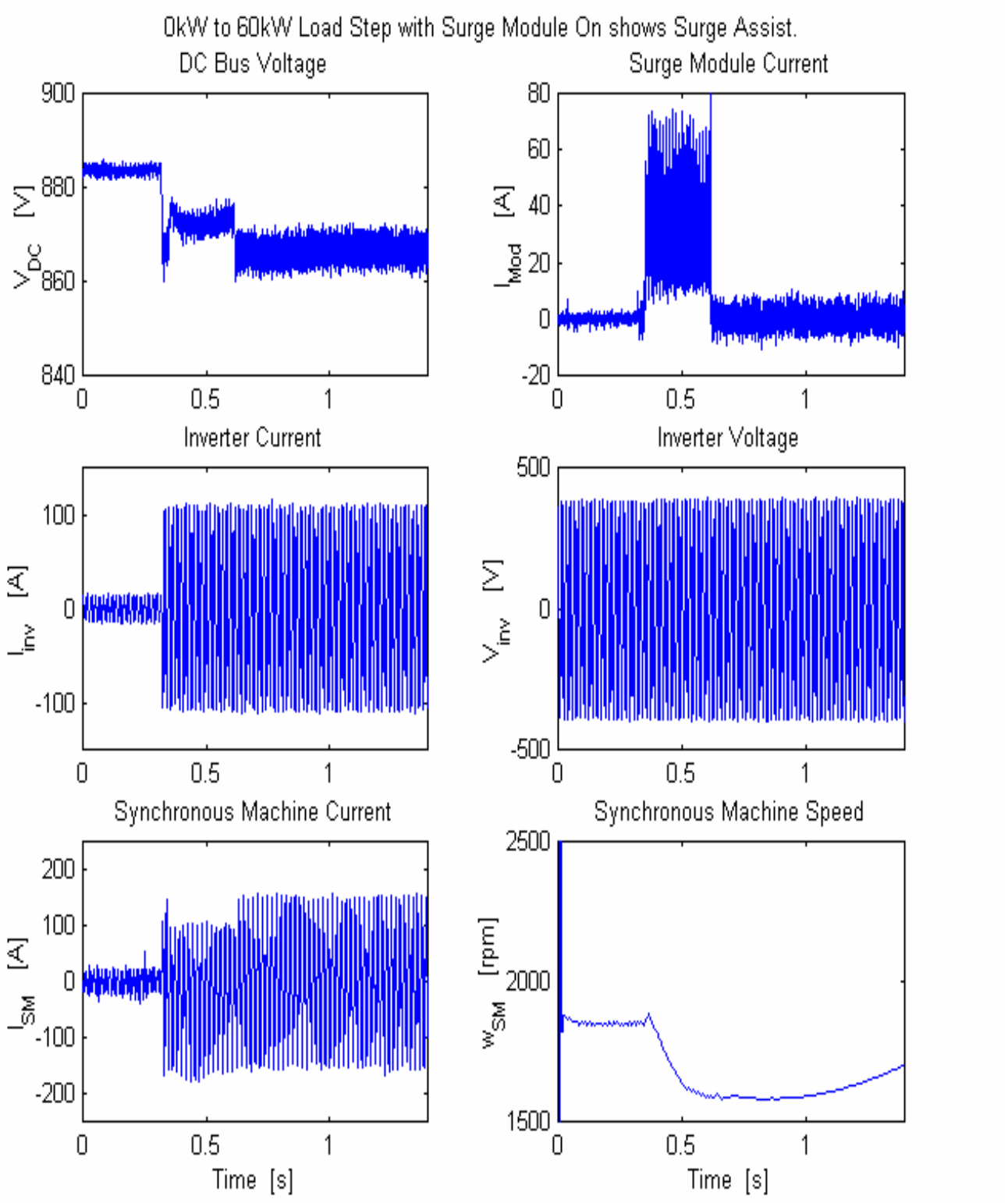

0kW to 60kW Load Step with Surge Module On shows Surge Assist.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0
0.5
1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0
0.5
1
Inverter Current
I_{inv} [A]
100
0
-100
0
0.5
1
Inverter Voltage
V_{inv} [V]
500
0
-500
0
0.5
1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0
0.5
1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0
0.5
1
Time [s]

Figure 13.

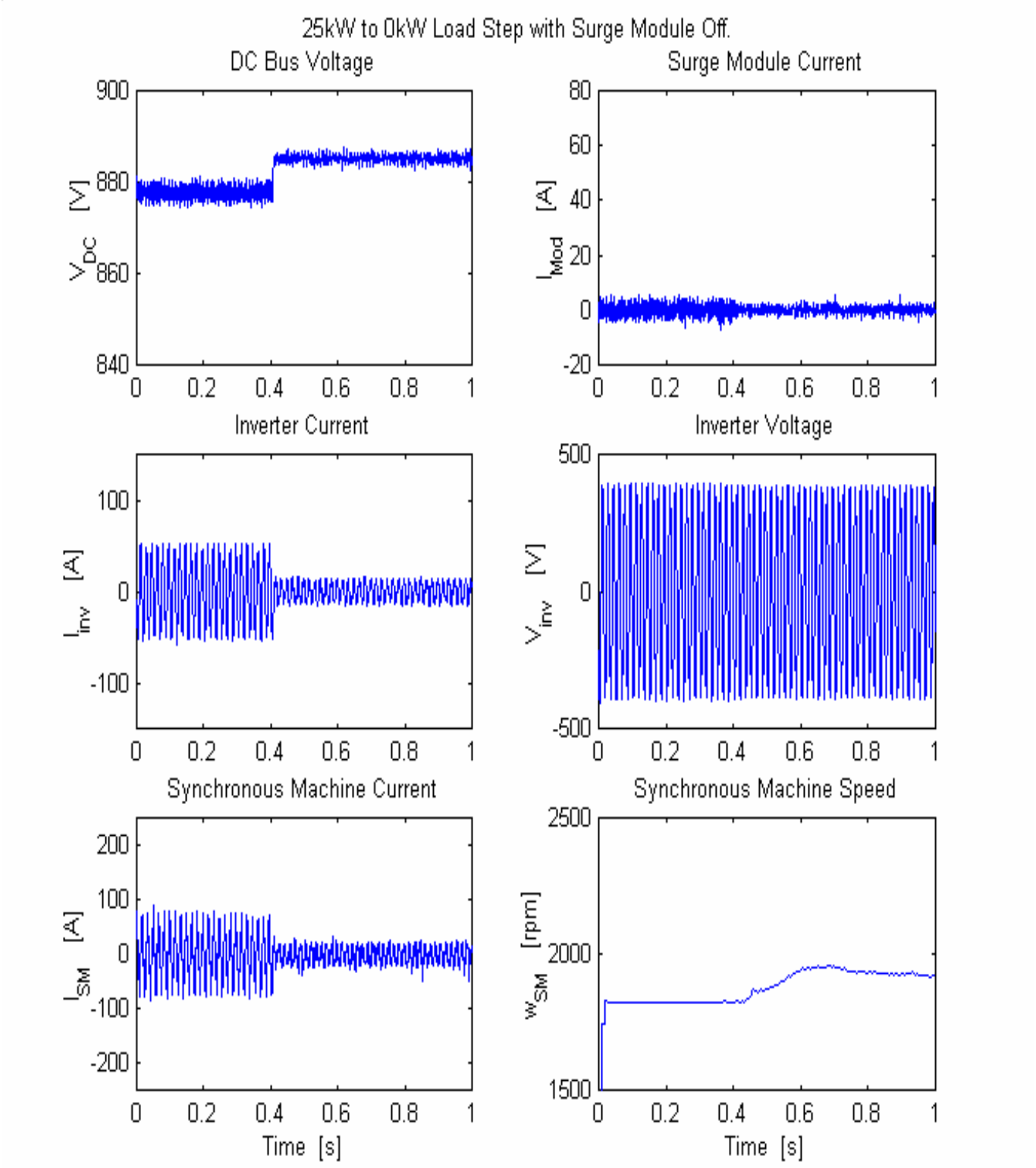

25kW to 0kW Load Step with Surge Module Off.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 14.

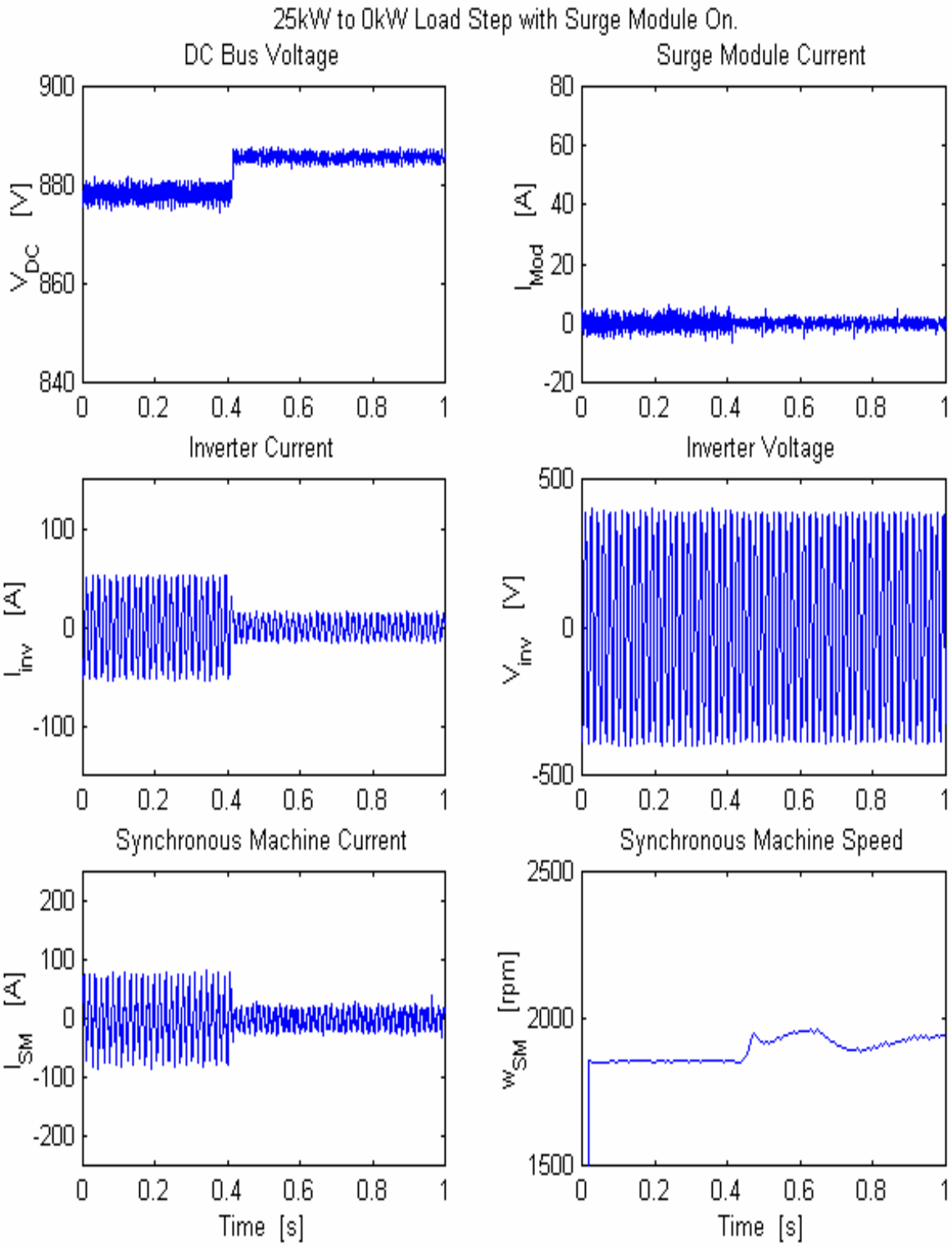

25kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 15.

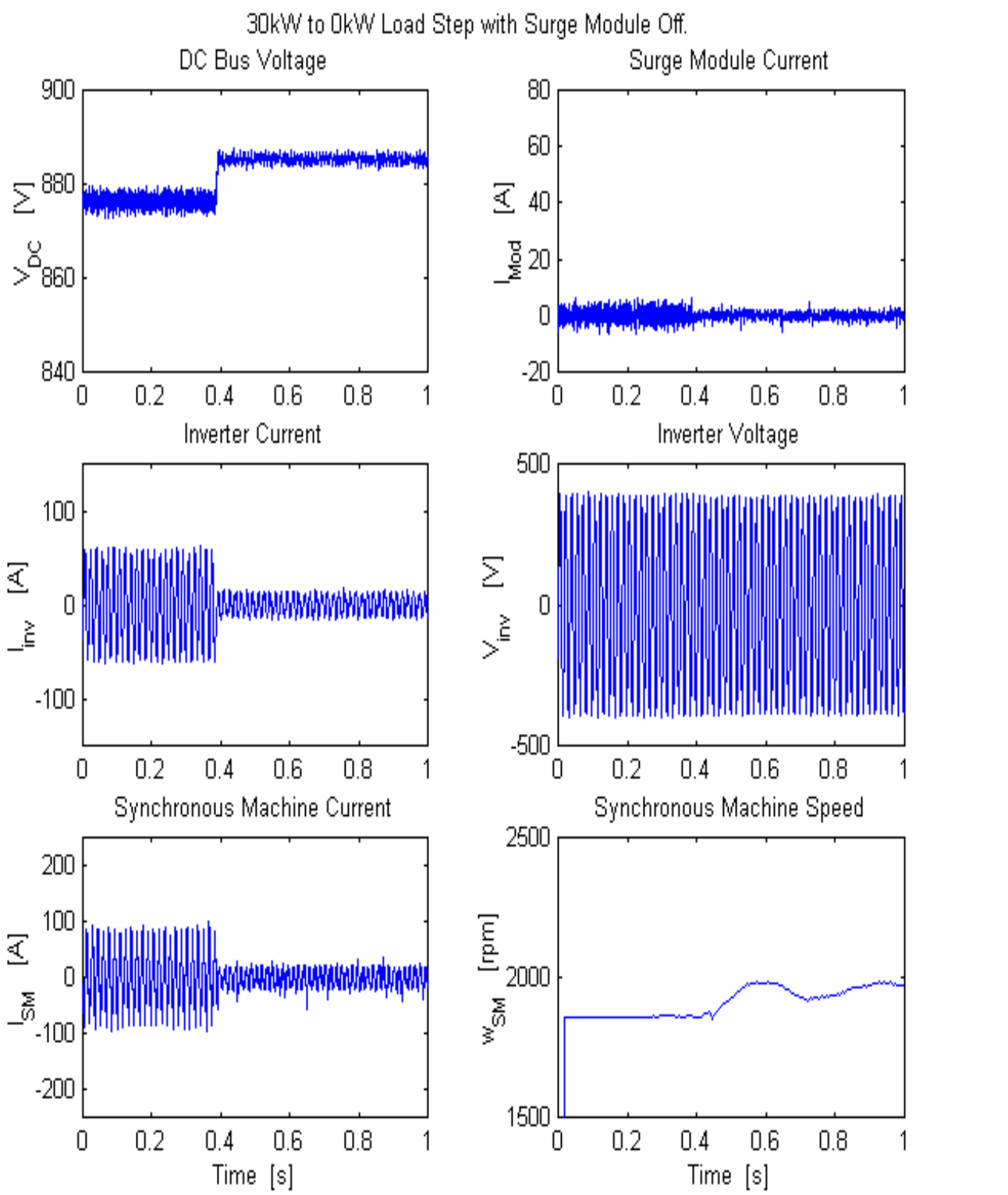

30kW to 0kW Load Step with Surge Module Off.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 16.

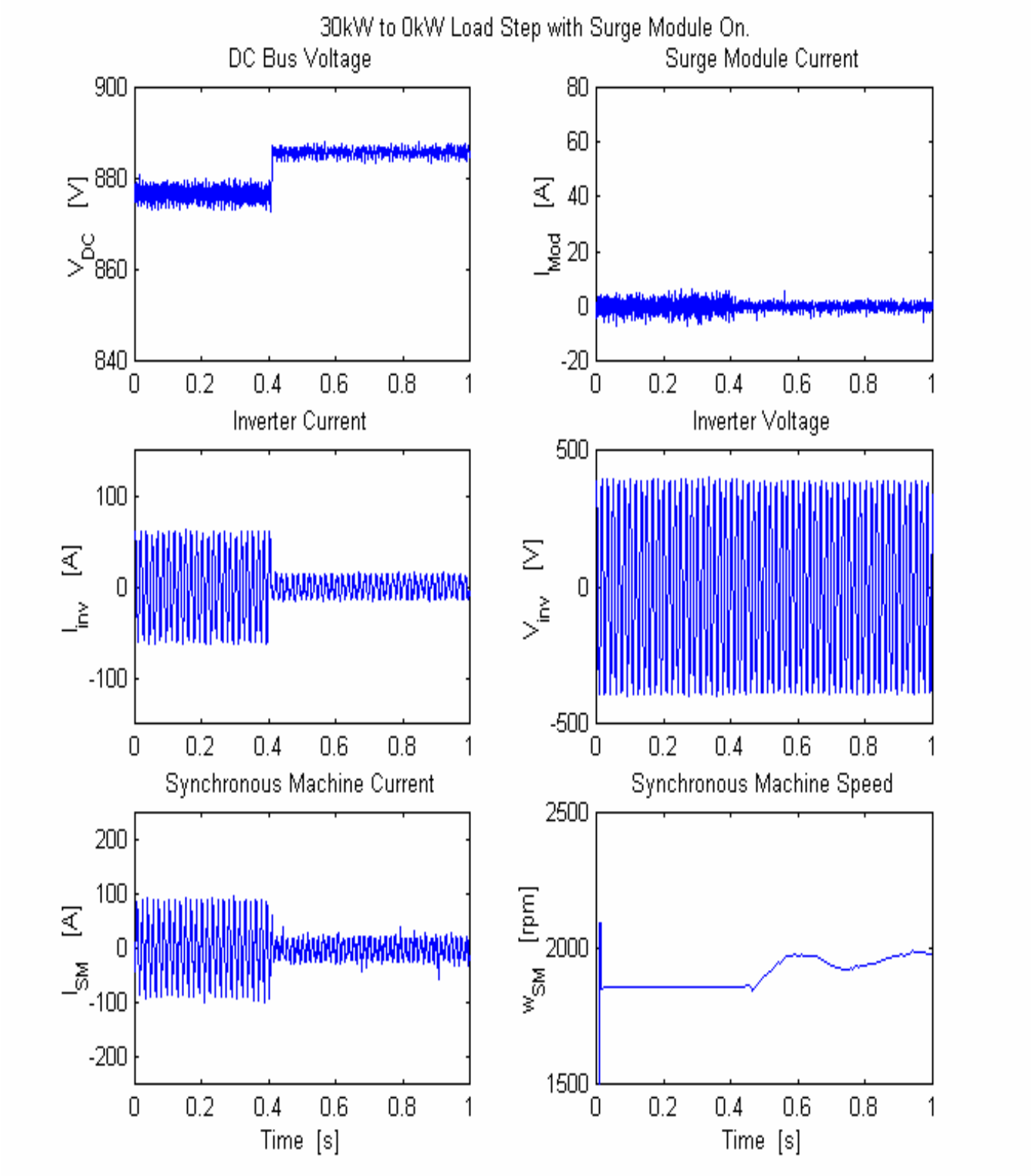

30kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 17.

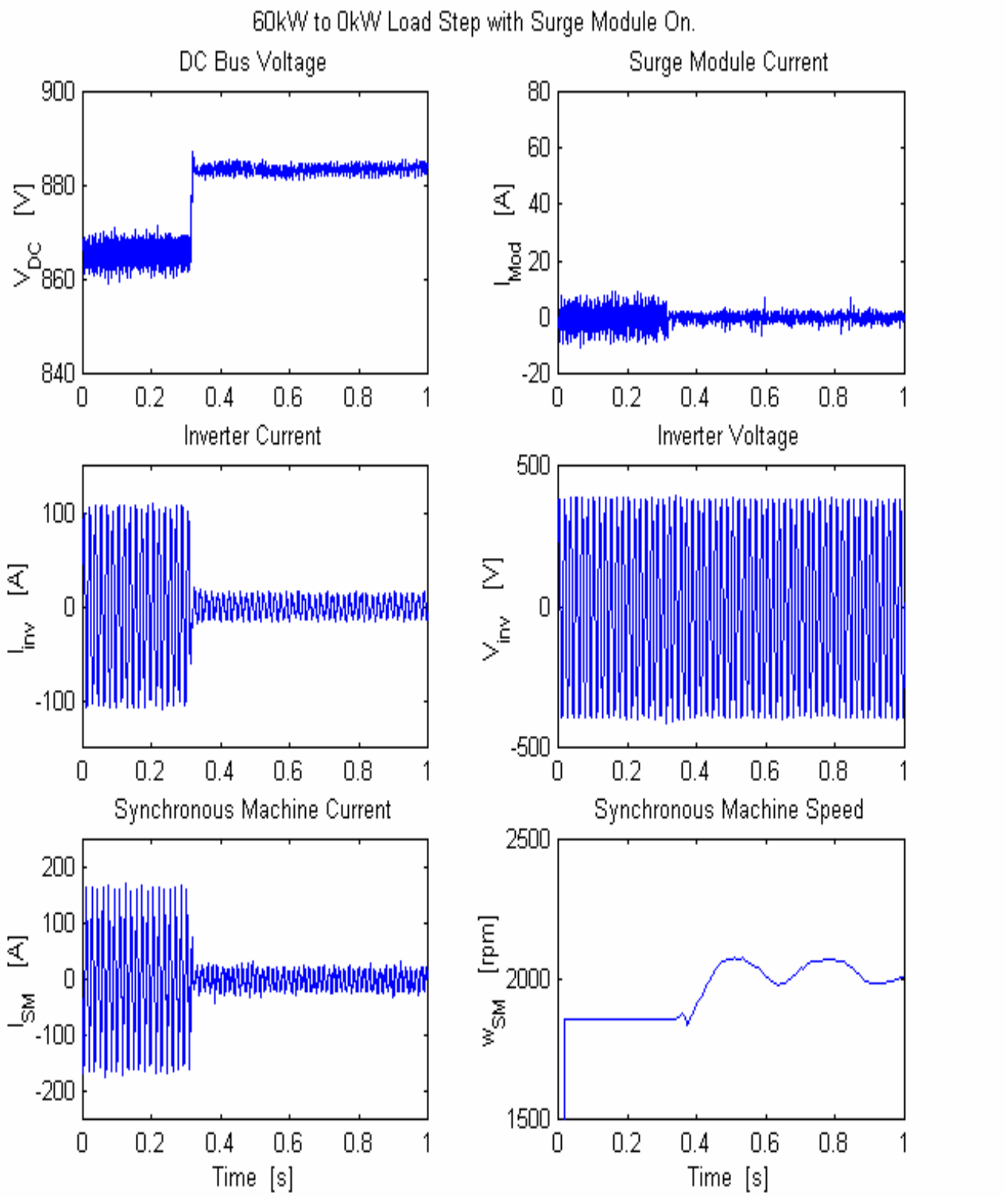

60kW to 0kW Load Step with Surge Module On.
DC Bus Voltage
V_{DC} [V]
900
880
860
840
0 0.2 0.4 0.6 0.8 1
Surge Module Current
I_{Mod} [A]
80
60
40
20
0
-20
0 0.2 0.4 0.6 0.8 1
Inverter Current
I_{inv} [A]
100
0
-100
0 0.2 0.4 0.6 0.8 1
Inverter Voltage
V_{inv} [V]
500
0
-500
0 0.2 0.4 0.6 0.8 1
Synchronous Machine Current
I_{SM} [A]
200
100
0
-100
-200
0 0.2 0.4 0.6 0.8 1
Time [s]
Synchronous Machine Speed
w_{SM} [rpm]
2500
2000
1500
0 0.2 0.4 0.6 0.8 1
Time [s]

Figure 18.

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

CERTS Test Bed CERTEQUIP-V06-002, CERTS Static Switch, Low Power Factory Acceptance Test Report

APPENDIX F

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California Energy Commission
Public Interest Energy Research Program

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Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Executive Director

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Northern
A Distributed Energy Systems Company

CERTS Test Bed
CERTEQUIP-V06-002
CERTS Switch
Low Power Factory Acceptance Test Report

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A Distributed Energy Systems Company

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1 Introduction

1.1 References

- Reference 1: CERTEQUIP-T05-004, “CERTS Test Bed, Factory Acceptance Test, Static Switch Low Power Test Plan”
- Reference 2: CERTEQUIP-H03-002, “CERTS Static Switch Operation & Control”
- Reference 3: “Control and Design of CERTS Microgrid”, R. H. Lasseter and Paolo Piagi, Spetember 28,2005
- Reference 4: "Static Switch Test V2" (2/06), R.H. Lasseter

1.2 Summary

The CERTS Test Bed is designed to test advanced microgrid and distributed generation control concepts developed by Professor Robert Lasseter at the University of Wisconsin. It consists of inverter-coupled generators, loads, low-voltage distribution and data gathering equipment and a static switch to separate the microgrid from the utility. Separation allows the microgrid to operate as an island, protecting its loads when there is a problem with the utility supply. The switch implements IEEE-1547 DG interface requirements, protecting the utility from reverse power and the microgrid from utility power quality issues. Disconnection and reconnection are accomplished smoothly with reduced transients presented to either side.

The switch chosen for the Test Bed was supplied by S&C Electric. It is a 480V, 400A thyristor (SCR) switch with controller, a modified Pure-Wave UPS product without the inverter and battery. To implement the required CERTS function we have added Northern Power’s DSP controller and a programmable SEL-351 protective relay. This assembly was tested at reduced power in our lab. A one-line schematic of the test set up is given in Figure 1 below.

We used an existing inverter development test bed to provide controllable Microgrid and utility sources. The utility side inverter was operated as a voltage source with the ability to control voltage and frequency. The microgrid inverter used the University of Wisconsin control method with power / frequency droop. Control code for this method had been developed under an earlier phase of this CERTS contract. Each inverter was capable of 15 kVA output and included controllable load banks.

The test plan is given in Reference1, test results are detailed in this report. Some revisions were made during testing to meet the capacities of the source inverters and to follow up on discovered issues. S&C provided an applications engineer, Rodger Troyer, for three days on site to rectifying problems found during the initial test runs. Also during testing it was decided to add measurements made by NREL using their Omicron test equipment, applying secondary signal injection to test the IEEE1547 voltage and frequency functions of the DSP Controller. Those measurements, made by Chris Pink of NREL, are included in this report. A final round of static switch testing (Power Quality CBEMA and SEMIF47 events) is planned for the Dolan Labs at AEP before the switch is installed at AEP in the CERTS Test Bed.

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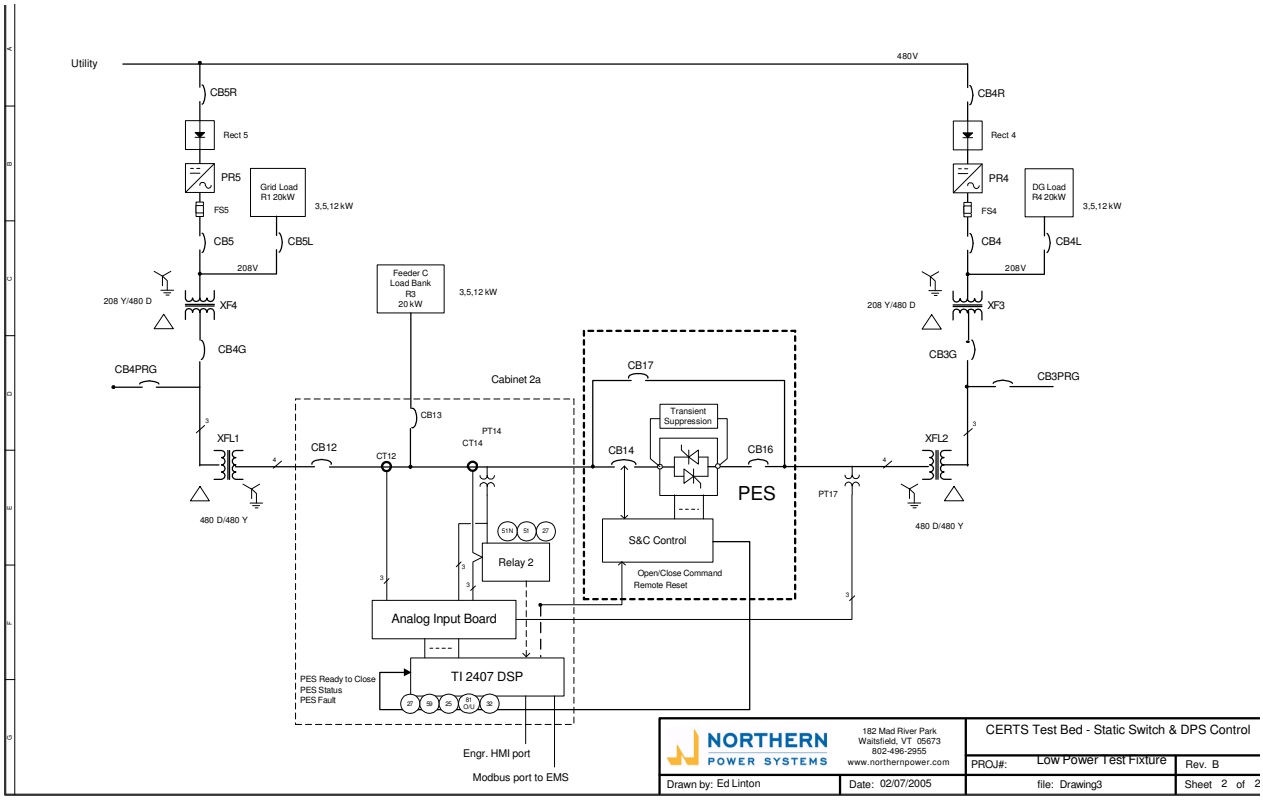

Figure 1. CERTS Switch Low Power test setup 1-line diagram

2 S&C Power Electronic Switch and NPS DSP Controller Functionality

This section is intended to provide a brief description of the control functions that the Northern Power DSP Controller will perform, as well as a description of the interface between the S&C SCR switch control and the DSP Controller. For a complete description of this functionality and Interface, refer to Reference [2].

2.1 S&C Power Electronic Switch

S&C Electric Company was selected as the provider of the SCR-based switch. They provided their 480V, 400A PureWave® Power Electronic Switch (PES), which consists of and SCR-based switch (using Semicron SKKT 250/16E Dual SCR modules) with input, output and bypass breakers, and fuses.

For operation, the PES requires a turn on/off input signal, a Remote reset input for clearing latched alarms and a Remote Disabled (Start/Stop command); these signals are provided by the DSP. It also contains a "Reset" pushbutton for local reset, an "Enable" Selector switch to enable/disable the PES.

Below, is a brief description of the Digital I/O interface of the PES with the Northern Power DSP controller; as well as alarms and operating states that will be available on the LCD display of the PES:

PES Pushbutton/Selector

- Reset (Pushbutton)
- Disable/Enable (Selector)

PES Digital Inputs (24 V, opto-isolated)

- PES Command
- Remote Reset (This reset will come from HMI)
- DSP Fault
- Remote Disable (works as the Start/Stop Command in DSP state machine)

PES Digital Outputs (5-60 V, opto-isolated)

- PES Ready to Close
- PES Over-temperature (Alarm and Pre-alarm)
- PES SCR Failure
- PES Alarm (includes all alarms)
- PES is Closed (PES State)
- PES Disabled (Disable/Enable status)
- Enable/Disable Selector state
- PES Reset Pushbutton state
- PES Warning

PES Alarms (LCD Display in PES)

- SCR failure (PES Open or PES shorted, latching)
- Over-temperature
- Any Alarm (including DSP faults)
- Disable PES
- Warnings

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2.2 CERTS Switch Analog and Digital I/O

The external analog inputs for current measurement assume the use of 1A rms secondary CT. Analog inputs for grid and DG AC voltage measurements are made using 120Vrms nominal at the PT secondary. Sixteen DSP board analog channels that are directly available for high speed sampling are utilized in the controller.

The analog inputs are:

1. Switch Current CTs – (CT14) phase A, B, C (3x)
2. Remote Current CTs – (CT12) phase A, B, C (3x)
3. Grid side sensing – (Vg) phase A, B, C (3x)
4. DG side sensing – (Vdg) phase A, B, C (3x)

Digital inputs to the DSP are opto-isolated and debounced. The 10 mA digital outputs of the DSP are opto-isolated. For a full description of the DSP Controller Digital I/O refer to Reference [2].

2.3 CERTS Switch State Machine

The state machine controls the operation of the CERTS Switch. The primary operating states of the CERTS Switch are to connect or disconnect the grid and Dg sides by closing or opening the switch. A number of the other control states are used for the startup sequence, faults and disable. The behavior of the CERTS Switch when operating in the controller states is described below.

OFF State: The CERTS Switch following power-up and reset of the controls is considered to be the OFF state. The DSP controller conditions for the OFF state are: no faults are latched and all alarms are enabled. To leave the OFF state, a “Start” command is required to be given to the S&C PES; the “Start” command controls the motor operated input breaker.

[STARTUP] Test State: A start command in the Off state initiates the transition to the Test state. Once the Start command is given, the motor operated input breaker as well as the Output Breaker should be close. In the Test State, the DSP Controller checks the “Ready to Close” signal from the PES; if the signal is HIGH, then the system will enter the ON States; if not, it will go back to the OFF state.

[ON] Disconnect State: In the Disconnect state the CERTS Switch checks to see if DG is present in the system using the dead bus relay (27R) function. If synchronization function check evaluates to True or if the Dead Bus Relay check is True (and the operator has enable the “Dead Bus Reclose” Operating Mode) then the switch transitions to the Connect State.

[ON]Connect State: In the Connect state the CERTS Switch checks for power quality, reverse power anti-islanding, SEL Relay and other IEEE1547 functions and fault events. If any of these events are true, the DER Switch transitions to the Disconnect state

Fault State: If there are faults the CERTS Switch can shut down rapidly into a safe state. In this state, the switch is commanded to open, and also the S&C PES is commanded to “Stop”; which opens the motor operated input breaker. The types of faults range from S&C PES internal Alarms (“Fail to Open”, “SCR Failure”, etc) to conditions that require lockout of the system within the DSP Controller (Such as Reverse Power Anti-islanding event).To leave the Fault State, all faults should be reset and cleared.

PES Disable State: The S&C PES has a two-position switch that within its state machine switches the system from Enable to Disable (when Disable, both the motor operated input breaker and the shunt-trip operated output breaker are open). If the DSP Controller receives this signal, it will enter this State, in which an Open command and a “Stop” Command are passed to the PES.

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2.4 CERTS Switch Operating Modes

Auto mode: In this mode, when conditions are appropriate synchronized closing of the switch is attempted; also all events are checked.

Manual Connection Mode: In this mode, the switch can be manually controlled to open or close. Also, during this mode, events are not checked (Except for the "External Relay Trip" event, which in any mode will always open the SCR switch).

Sync Test Bypass: If manual connection mode is enabled, it will try to attempt to close when synchronization conditions are appropriate. However, if the Sync Test Bypass option is also enabled at the same time, then it will skip the synchronization test and force a switch close regardless of the grid and DG conditions.

EFVST (Enable Fast Voltage Sag Trip) Mode: If this operating mode is enable, during "Auto" Mode, Power Quality (CBEMA,SEMIF47) events and trips will be enabled. If disabled, the switch will not be commanded to open is these events occur. This mode can be disabled manually through the EMS; also the EMS may disabled it automatically based on wether there is enough microsources available to cover the microgrid load.

Dead Bus Reclose: If this operating mode is enable, when running in "Auto" Mode, reclosing to a DG side dead bus is allowed in order to perform system black starts. Notice that the operating mode simply allows or blocks the dead bus reclosing; the detection of the dead bus is perform by the relay function "Dead Bus Reclose Relay" described in section 2.5

2.5 CERTS Switch System Control Functions

Several protection, IEE1547, Power Quality and control functions are performed by the CERTS switch; they are listed below:

Synchronism Check: The calculation of this algorithm is performed in the Disconnect state. This function checks to verify that the voltage amplitude (for all three phases), frequency and phase angle are within an acceptable window to enable the closing of the DER Switch. Note that other CERTS Switch control functions may also need to be true to enable the closing.

The voltage magnitude and phase comparison is performed at the high speed ISR rate of the DSP. This ensures that any sudden jump in voltage or magnitude on either side of the CERTS Switch does not cause any false synchronization.

IEEE 1547 Voltage and Frequency Events: The recently approved IEEE 1547 standard contains requirements under certain voltage and frequency events. The levels on these events are fully described in section 3.3.3. If any of these events occur when operating in the "Auto" Mode, the switch will transition from the Connect to the Disconnect State, and if it is already in the Disconnect State, it will prevent the switch from closing.

Relay Trip Signal Event: The SEL-351 Relay (Relay 2) associated with the CERTS Switch will perform protection functions that include phase overcurrent, zero sequence overcurrent and line to line undervoltage. When the Relay detects these conditions, it will provide a trip signal to the CERTS controller so it can command the switch to open.

Dead Bus Reclose Relay: This relay function is provided in the CERTS Switch, so that black start of loads is allowed when there are no microsources present on the DG side.

Phase Sequence Error: This function checks for phase rotation direction, missing phase information or lack of signal on the phase voltage. In addition this function checks if the controller's internal data is

synchronized with the grid and DG operating frequencies. This event in the Connect state will make the CERTS Switch to transition to Disconnect state. An event in the Disconnect state will prevent the operation of synchronization function.

Remote Location RMS Reverse Power (32) and Anti-islanding: The CERTS controller evaluates single and three phase power flow at the remote Current transformer (CT12) location, which is located at the PCC (so its measurement includes protected and unprotected loads of the microgrid). The power measurement is compared with an adjustable threshold and time delay for coordination. If the power flow crosses the threshold then an event is set. An event in the Connect state will cause the CERTS Switch to transition to the Disconnect state. Depending on the state of the grid voltage after transitioning to the Disconnect state (which allows the Controller to decide wether the reverse power event was caused due to grid islanding, open phase or Erroneous Microgrid settings), the Switch may be allowed to reclose when conditions are appropriate (grid islanding, open phase) or the system will enter the fault state and require user intervention (Anti-islanding, Microgrid Settings Reset required).

Controller Digital Event: In addition to the above, functions it is possible to set a bit in the CERTS Switch controller to simulate an event. Also it is possible to use the external digital input to simulate an event occurrence in the controller.

Restoration Timers: IEEE 1547 and Power Quality events will have restoration timers, meaning that once the measured parameters (voltage and frequency) return to normal levels, they should stayed within acceptable limits for at least the time specified in these timers. Two separate timers will exist: one for IEEE 1547 events, which will be a longer time (default 5 minutes) while Power Quality Events will have a faster separate timer (2 seconds). Both timers will be adjustable.

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3 Test Results

This section presents the results of all the tests performed at the Northern Power test facility Below are given some aspects of the general procedure taken in order to perform the low-power test for the CERTS switch. Specific settings for the testing of each kind of event and algorithm are specified in each subsection; notice that some settings used may differ from the original settings in the test plan due to limitations of the source inverters used. The changes are not significant, the intent of the test plan has been maintained.

Figure 1 shows a 1-line diagram of the test setup used for the low-power testing.

Notes about the general test procedure:

1. The CERTS Switch unit was connected to the source inverters and loads, with one inverter and load pair emulating the grid and another pair emulating the DG source. The Grid source operates in open loop mode (Constant voltage magnitude and frequency) while the DG source operates using CERTS microgrid controls (Reference [3]).
2. During the testing of the different types of algorithms, only the event functions under test were enabled, while all other event functions were disabled. The event settings were adjusted to the appropriate values related to the test objective.
3. During the testing of most algorithms and events, the Northern Power Engineering HMI was used as the interface between the user and the DSP. Through this display the operator was able to observe the status of all alarms and events as well as the status of the switch (information from the S&C PES); also the operator was able to adjust any settings on the fly. In section (“EMS testing”) most of these tests are repeated but using the Energy Manager System that will be available at AEP in order to verify required communications.

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3.1 S&C-DSP Interface Commissioning Test [Test Plan Section 2.1]

3.1.1 S&C PES and DSP Controller I/O Interface

The first sets of tests performed are to verify that basic functionality, wiring and interface between the S&C switch and the DSP Controller were working properly. The following steps were performed, and all of them passed successfully.

- Wiring Check: All wiring was verified for proper connection according to schematics, as well as check for mechanical and electrical integrity (DSP Controller only)
- Power Supply: 24V power supply for DSP Controller and Relay2 was checked successfully.
- Digital Inputs and Outputs: Correct operation and logic polarity of all inputs and outputs was verified by simulating several kind of events.
- State Machine: We loop through the state machine as detailed in section 2 of this report several times, and both the S&C and DSP operate as expected. All desired status are communicated between the S&C and the controller
- Alarms: Some of the S&C Alarms were tested; results are detailed in section 3.1.2
- Analog Inputs: All analog inputs (voltage, current) were checked for correct scaling and response. Some calibration was performed to achieve the following accuracies:

  Voltage: < 1% error (2.7 Vrms, measured at rated voltage 277Vrms)

  Current < 2 Arms error (maximum current simulated = 20 Arms, switch rating = 400A)

  Power error < 1 kW (maximum power simulated = 15 kW, switch rating is 330 kVA)

3.1.2 S&C PES Alarms

Some additional simple tests were attempted in order to verify the functionality of the S&C Internal Alarms. A detail description of each of these alarms can be seen in Reference [2]. The status of these alarms is communicated to the DSP controller by the following digital outputs:

PES Alarm: This output includes toggles HIGH if any of the S&C alarms in enabled (Over temperature, Open PES, Shorted PES, PES Fail to Open)
SCR Failure: This output toggles HIGH if either the Open PES or Shorted PES alarms is enabled

3.1.2.1 Fail to Open Alarm

A strategy was devised to test the operation of this alarm. The grid side inverter was set to operate in open loop mode (constant voltage, frequency) while the DG side had only a passive load (5 kW). Also, a single phase contactor across phase A of the SCR switch was connected, but initially left open.

After performing a Manual Connect of the SCR switch with the DSP controller, the single phase contactor was closed. Then, the Manual Connect command was removed; even though the SCR switch opens, the S&C controls will not measure any voltage buildup across the SCR phase A (since the single phase contactor is shorting the connection); thus assuming that the SCR switch has failed to open. When this occurs, the “PES Alarm” digital output goes HIGH, and after the DSP receives this signal, it transfers the CERTS switch to the Fault State and gives a “Stop” command to the S&C PES.

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This response can be observed in Figure 2; this figure shows the voltage across phase A of the SCR switch (channel 1); phase A switch current (channel 2, 20A/division) and the DSP switch command (channel 3). When the DSP command goes Low (to open the switch); the current across the SCR goes to zero (proving that the SCR opened) but the voltage across the SCR terminals is still zero. After approximately 7 cycles, we see the voltage across the switch build up; this is because it takes 2 cycles for the "Fail to Open" detection to operate, and after the Stop command is given, it takes 4-5 cycles for the motor operated input breaker to open. This verifies the correct functionality of the alarm.

This test was repeated, but with the Alarms disabled in the DSP controller; the reason to do this is to verify that the S&C PES will internally open the input breaker if this alarm occurs, independently of wether it receives the Stop Command from the DSP. After repeating the test, the input breaker was open so the S&C PES operates appropriately. Notice that for the other alarms (Open PES, Shorted PES) the DSP needs to provide the Stop command to the S&C PES; it will not open the breaker on its own for these alarms).

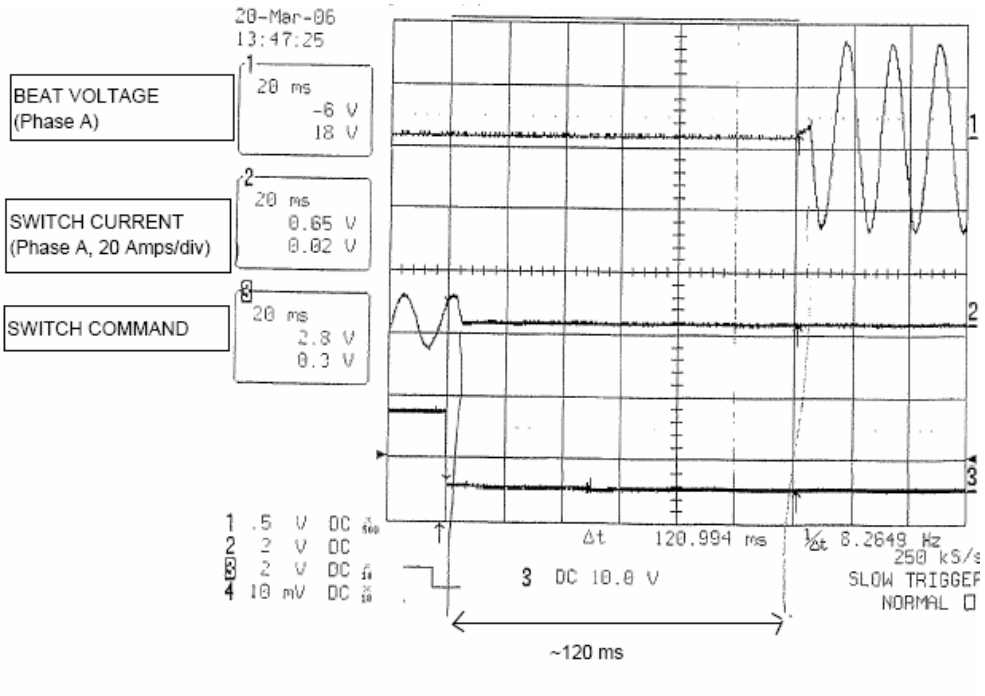

Figure 2: S&C "Fail to Open" Alarm Tests

3.1.2.2 SCR Failure Alarms

The conditions to test these alarms were not possible to be recreated at Northern Power test site.

The "PES Shorted" alarm only operates when the switch current is above 5% SCR rating (400 A); this corresponds to 20A, which can't be output by the inverters at Northern Power's site (max 15 kVA).

The "Open PES" alarm is hard to recreate, although an issue was observed during the whole testing process. After performing several srynchronized closings and manual Opening of the switch, sometimes this alarm will show up when the switch is commanded to open. During Roger Troyer (S&C) visit to the NPS site to resolve some of these issues, the possibility of this issue being a noise problem arose; Northern Power continued the testing since these alarms will not interfere with the test procedure for the control functions; S&C will be visiting the AEP site to resolve the issue of the "Open PES" Alarm.

3.2 *Synchronization* [Test Plan Section 3.1]

The synchronization tests were intended to demonstrate that the CERTS Switch would permit connection between the grid and DG terminals when both systems are synchronized within an allowable window for voltage, frequency and phase.

The following tests were performed to verify the synchronization functionality:

1) Limits Accuracy (using Omicron CMA256-6 secondary injection test set from NREL)
2) Synchronization Time Delay (for Bias Closing)
3) Response to different beat frequencies

3.2.1 Limits Accuracy (using Omicron CMA256-6 secondary injection test set from NREL)

During the time NREL's Omicron Equipment was available at NPS site, calibration tests were performed with secondary level (120V) signals input into the grid and DG PTs (PT14 and PT17 in figure 1). During this test, the CERTS switch was set to "Auto" mode in order to allow synchronized closing when the conditions are appropriate. The DSP limit settings used during testing were as follows:

Frequency Nominal: 60 Hz
Frequency High: 61 Hz
Frequency Low: 59 Hz
Voltage Nominal: 277 Vrms
Voltage High: 305 (+10%) Vrms
Voltage Low: 250 (-10%) Vrms
Phase Upper Band: 10 degrees
Phase Lower Band: -10 degrees
Time delay: 0.0 seconds

It is important to make a few notes about the synchronization settings. First, the reason to allow the larger range for frequency (+/- 1 Hz) is so that the DG side can droop that much if necessary while open and still allow to reclose (the grid side will be limited to the tighter IEEE1547 range 60.5-50.3 Hz since the IEEE1547 events are monitored on the grid side PT only). Also, the phase band settings are simply outer limits to ensure that the switch will not close if the beat voltage is off the zero crossing by this amount; however the DSP control is still trying to reclose it at precisely the zero crossing.

The Omicron equipment performed the calibration test by simulating the grid side voltage to nominal parameters (277Vrms, 60 Hz) and then setting the DG side to a wide range of voltage and frequency deviations. Figure 3 shows the results of this test; the Omicron equipment simulated each of the test conditions for a 1-minute duration and recorded whether the switch closed or not within a 10 degree band of the zero crossing. Figure 3 presents the results in the following format:

- "Failed" test corresponds to a closing outside limits or a failure to close if all conditions are within limits
- "Passed" test corresponds to closing within limits or preventing closing when outside limits

Most of the tests performed gave desired results with the synchronization passing the tests; however, a common "failed test" condition was observed when the DG voltage was just below the upper limit (lower

by 2.7 Vrms (1%)). Is possible that there is a calibration issue with the DG voltage measurements at this level; however, 1% is a relatively acceptable accuracy.

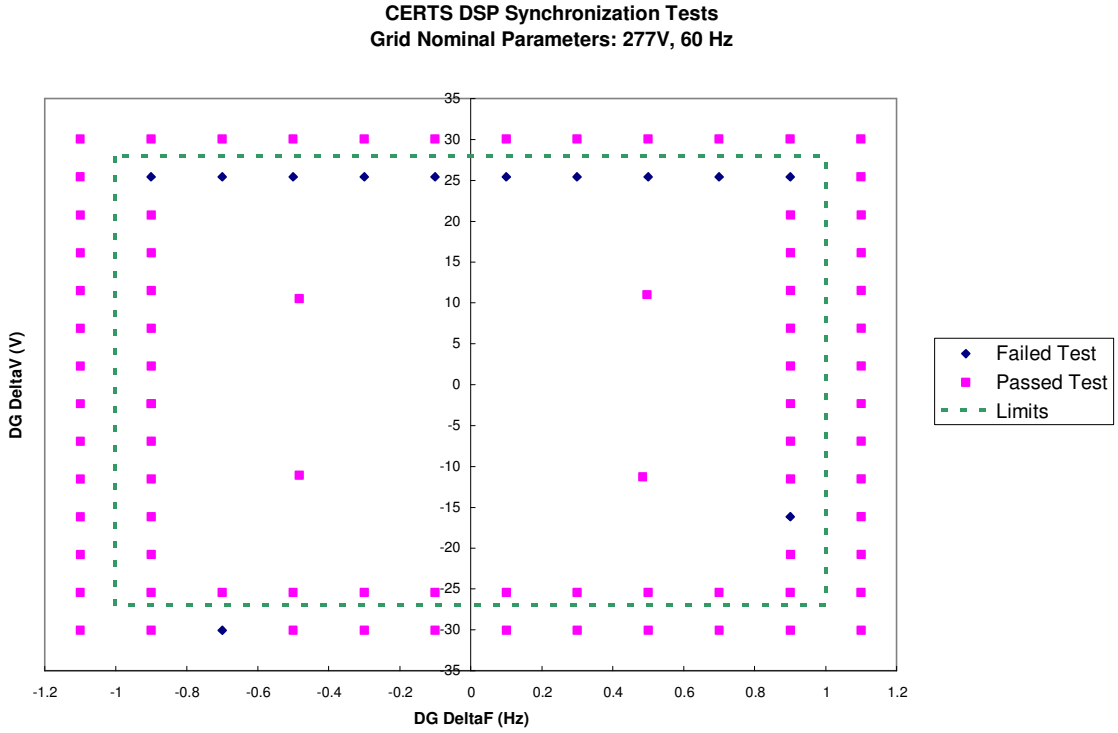

Figure 3: DSP Synchronization Limits Accuracy Test using NREL's Omicron Equipment

3.2.2 Synchronization Time Delay (for Bias Closing)

One of the settings available in Northern Power's DSP Controller is a "time delay" for synchronization closing. The initial purpose of this time delay is to compensate for opening time of devices such as circuit breakers (which typically can take up to 5 cycles to open). However, for the CERTS switch project this time delay can also be used to test the concept of biasing the closing such that switch closes when the fastest rotating voltage must be leading the voltage that rotates slower (check Reference [3]). Without the bias, the controller will try to close when both voltages are on phase (meaning the average phase of the three beat voltages A, B, C is zero).

The bias closing can be achieved by using a positive time delay; a negative time delay will perform the opposite effect (switch closes when the fastest rotating voltage is lagging the voltage that rotates slower). In this situation, the initial direction of power flow will be opposite to the expected steady state power flow direction, thus creating a significant transient response. Also notice that the setting in the Engineering HMI is a time value (in seconds); the equivalent phase bias is obtained by multiplying the beat frequency of the voltage across the switch and this time delay value.

To examine the effect of the bias closing, the following setup was used:

Grid Side:

Voltage: 277Vrms
Frequency: 60 Hz
Grid Load (R1), Feeder C Load (R3) = 0 kW

DG side:
Psetpoint= 6 kW
Dg Load (R4) = 12 kW
Droop: 0.025 Hz/kW
Frequency Measured (before closing): 59.7 Hz

This setup allows us to test an scenario with a beat frequency of 0.3 Hz. When the switch closes, a power flow from the grid side to the DG side of approximately 6 kW results. The following waveforms were recorded:

- Figure 4: Beat Voltage
- Figure 5: Synchronized closing delay= 0 sec (right at zero crossing of beat voltage)
- Figure 6: Synchronized closing delay= +0.25 sec (~27 degrees after zero crossing)
- Figure 7: Synchronized closing delay= -0.25 sec (~27 degrees after zero crossing)

Figures 5-7 show the following measurements:

- Channel 1: Voltage across the switch phase A (Beat Voltage)
- Channel 2: Phase A switch current (20A/division)
- Channel 3: Phase B switch current (20A/division)
- Channel 4: Phase C switch current (20A/division)

Also, the time axis shows an arrow (trigger) which is where the Switch command (open/close) transition from open to close.

These figures show that with a zero delay, the closing transition was very smooth and the current is slowly growing to its steady state value. Also, with the positive time delay, the current is biased in the correct power flow direction, so the transition is also relatively smooth. However, with the negative time delay, we can see that the current in all the phases takes initially the wrong direction, so an unwanted transient is observed. This shows that it is desired to avoid closing of the switch when the fastest voltage is lagging the slower voltage.

Since is shown that the DSP can measure phase very accurately, from here on it is expected that synchronized closing will be performed without any bias (time delay). This setting will be available if desired to test on the field for certain conditions where the phase measurement by the DSP may not be as accurate (harmonic content, significant phase unbalance) and thus the bias could smooth out the transitions.

An important observation to note during this test is that with no delay, we see the switch current is slowly growing to its steady state and taking 8-10 cycles to reach that point. The reason for this behavior is that what we call the Grid side is not really a stiff voltage source because of the impedance of the two transformers (total X~10% at 15kVA, 480V). If this was a stiff source, the current should take ~1 cycle to reach its steady state when closing at exactly the zero crossing; this kind of response will be observed in future synchronization tests, and as explained here it is very probable it occurs due to impedance of the grid connection in the test setup.

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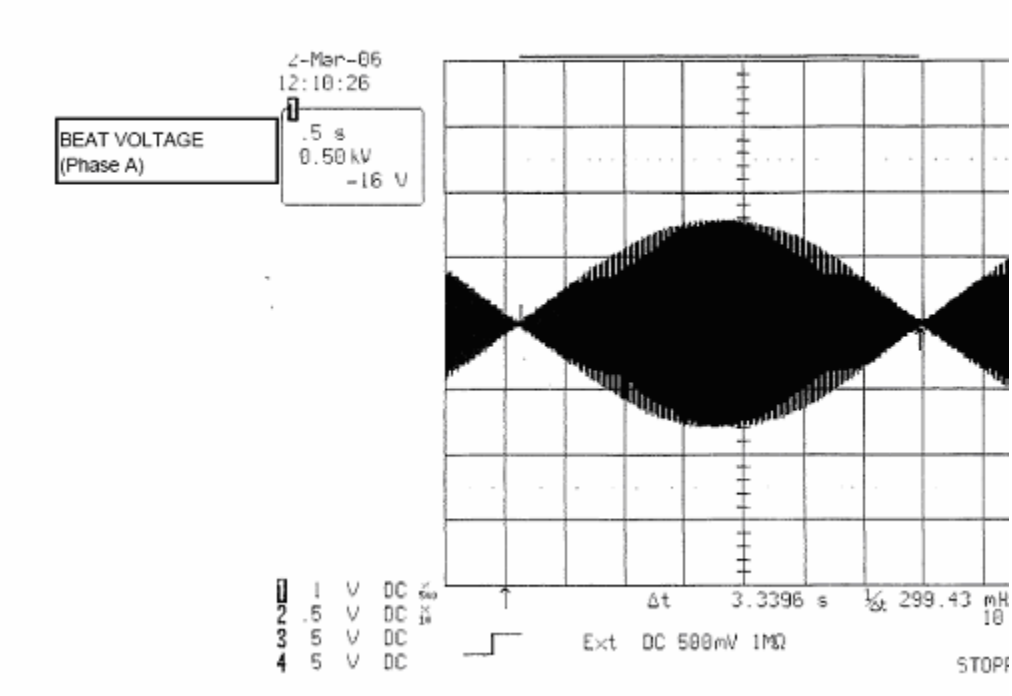

Figure 4: Synchronization Time delay test, Beat Voltage phase A

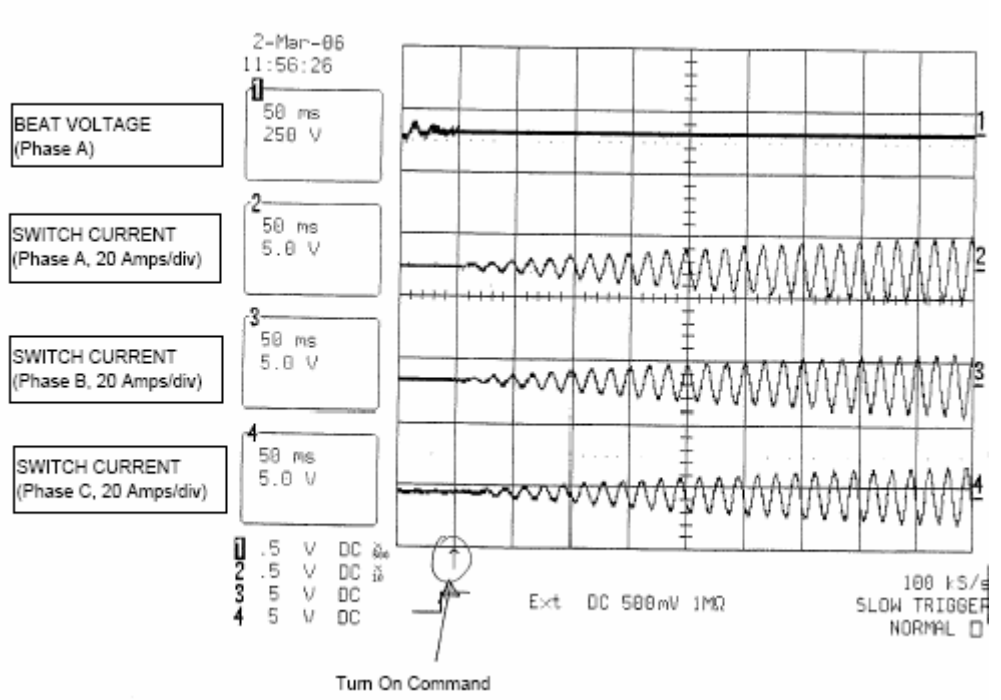

Figure 5: Synchronized closing delay= 0 sec (right at zero crossing of beat voltage)

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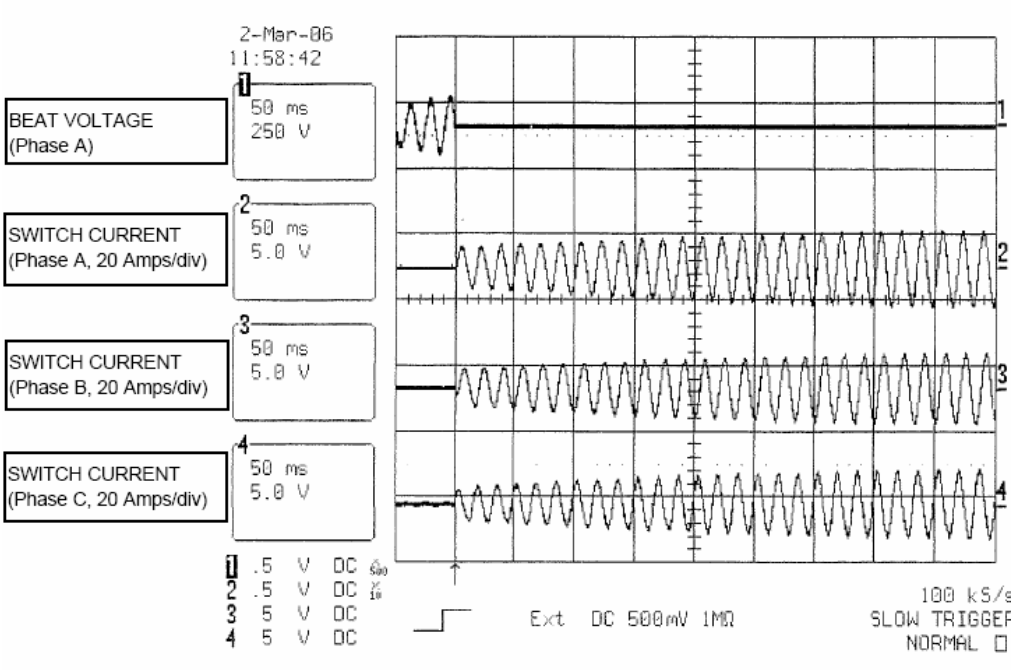

Figure 6: Synchronized closing delay= +0.25 sec (~27 degrees after zero crossing)

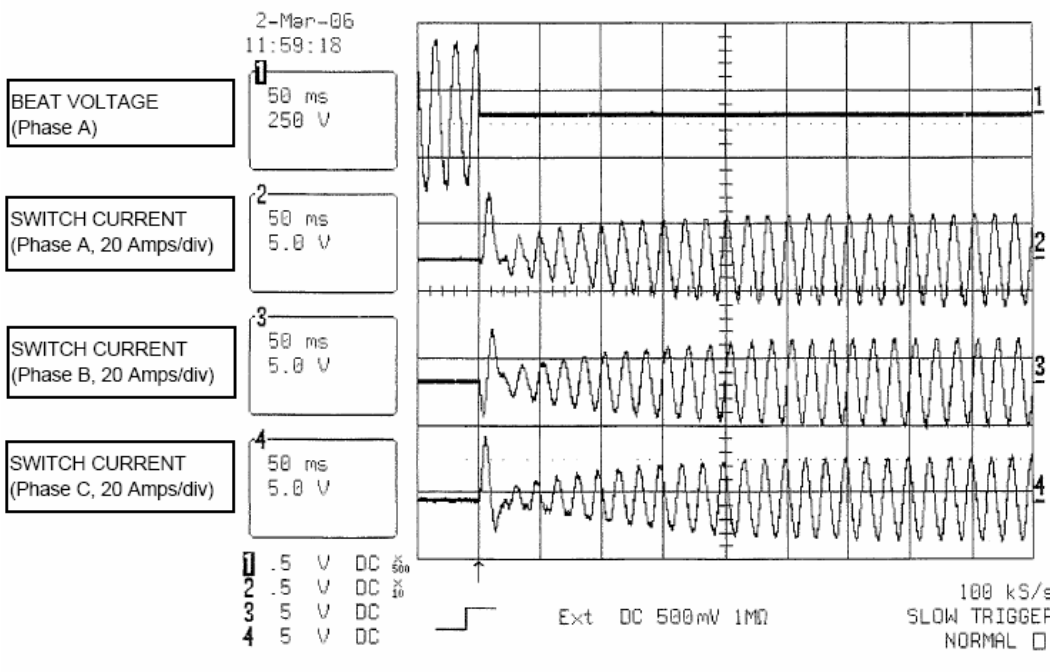

Figure 7: Synchronized closing delay= -0.25 sec (~27 degrees before zero crossing)

3.2.3 Response to different beat frequencies

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The final task of synchronization testing is to evaluate the ability of Northern Power DSP controller to perform the synchronized closing at a wide range of beat frequencies. Table 2 below shows all the different cases that were evaluated. Some important notes about these tests:

1. Table 1 explains the setup used (set points, DG droop, loads, measurements before closing, etc).
2. For all these tests, the grid inverter setpoints were rated values (277Vrms, 60 Hz)
3. The DG voltage droop used for all cases was 2.7 Volts/kVAR. The reasoning behind using this setting is based on the reactive power droop control explained in Reference [3].

   Average Voltage Measured at No Load=277 Vrms

   Average Voltage at DG full load (15kW) = 250Vrms

   Max kVAR output= 10kVAR

   Reactive power droop= (277-250) / (10) = 2.7 V/kVAR
4. Tests 1-9 show cases where the power flow when the switch closes will be from the DG side to the grid side of the switch. Tests 10-12 present cases with the power flow outside of the microgrid side.
5. For Tests 1-6 the real power droop (m) was not selected precisely according to Reference[3]; rather, a fixed droop (0.025 kW/Hz) was used. The purpose during these runs was to artificially create a wide range of beat frequencies without major adjustments in the setup (from 0.1Hz to 0.5 Hz)

6. Tests 7-12 have the droop selected accordingly to the “Control and Design of CERTS Microgrid” document (Reference [3]). The assumption in selecting the droop were:

   Max Power= 15 kW

   Minimum frequency= 59,25 Hz

   M droop= (60 Hz – Minimum Frequency) / (Max Power - Pset)

   The DG power setpoints selected for tests 7-12 were chosen so the beat frequencies obtained will approximately cover the range of frequencies in which the DSP is expected to perform the synchronized closing (0.05Hz-0.5Hz)

Test #	Feeder C R3 (kW)	DG R4 (kW)	DG Pset (kW)	DG droop (Hz/kW)	Vgrid measured (Vrms)	VDG measured (Vrms)	Fgrid measured (Hz)	F_DG measured (Hz)	DeltaF (Hz)

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1	0	12	2.7	0.025	272	275	60	59.5	+0.5
2	0	12	4.2	0.025	272	274	60	59.6	+0.4
3	0	12	6	0.025	272	269	60	59.7	+0.3
4	0	12	7.5	0.025	272	268	60	59.8	+0.2
5	0	12	9.5	0.025	272	265	60	59.9	+0.1
6	0	12	10.5	0.025	272	264	60	59.95	+0.05
7	0	12	6	0.083	272	273	60	59.5	+0.5
8	0	8	4	0.068	272	262	60	59.73	+0.27
9	0	3	1	0.053	272	272	60	59.86	+0.14
10	12	3	8	0.107	272	282	60	60.49	-0.49
11	12	3	6	0.083	273	277	60	60.23	-0.23
12	12	3	4.5	0.071	273	275	60	60.08	-0.08

Table 1: Synchronization Test Runs for range of beat frequencies and power flow direction across switch

For analysis, in this section the results from tests #7 (beat frequency=0.5Hz) and #6 (beat frequency=0.05Hz) are presented since there are the extreme cases of the beat frequencies evaluated. Figures 8 and 9 shows the synchronized closing for both of these tests. Channel 1 shows the voltage across phase A of the SCR switch (refer as “beat voltage” in later figures); Channels 2, 3,and 4 show the SCR switch currents A, B, and C respectively (20 A/division).

It can be seen that both transitions are smooth without any unwanted transients, and that the initial direction of the switch current in all phases is in the same direction as the steady state power flow after closing. These results show the capability of NPS the controller, combined with the DG settings and controls to provide seamless transitions. Notice that, as explained in section 3.2.1, the current slow growth to steady state can be explained by the significant grid impedance in the test setup.

In the appendix section of this report, waveforms are shown for all of these cases. The waveforms for each test include phase A beat voltage, as well as the switch currents A,B,C during synchronized closing and also after a manual opening of the switch.

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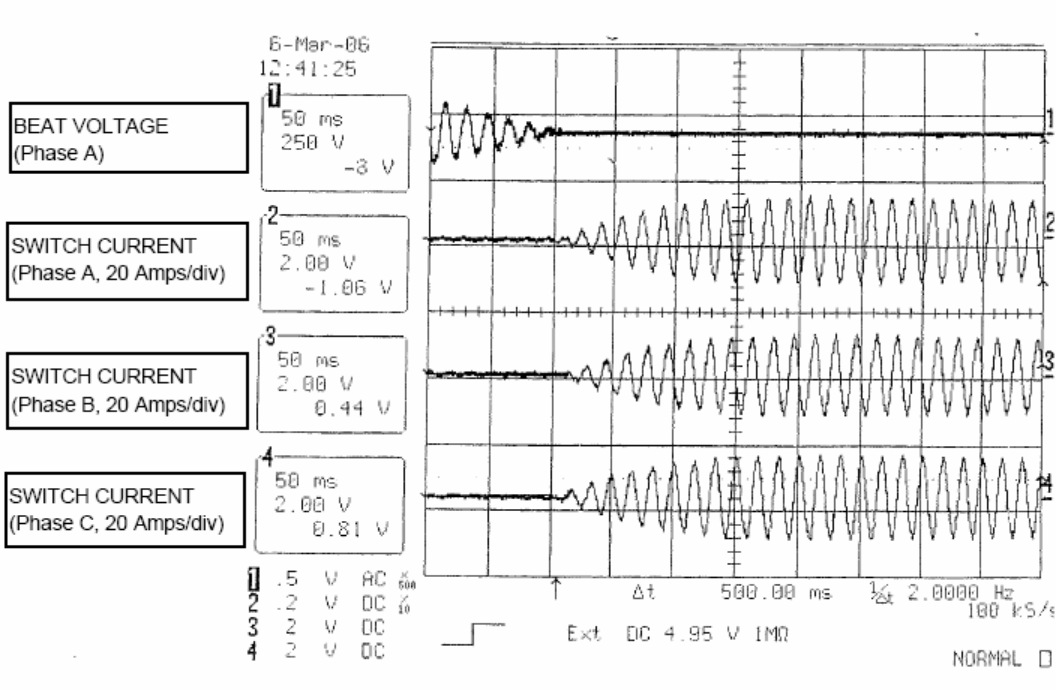

Figure 8: Synchronized Closing for Test #7 (beat frequency= 0.5 Hz)

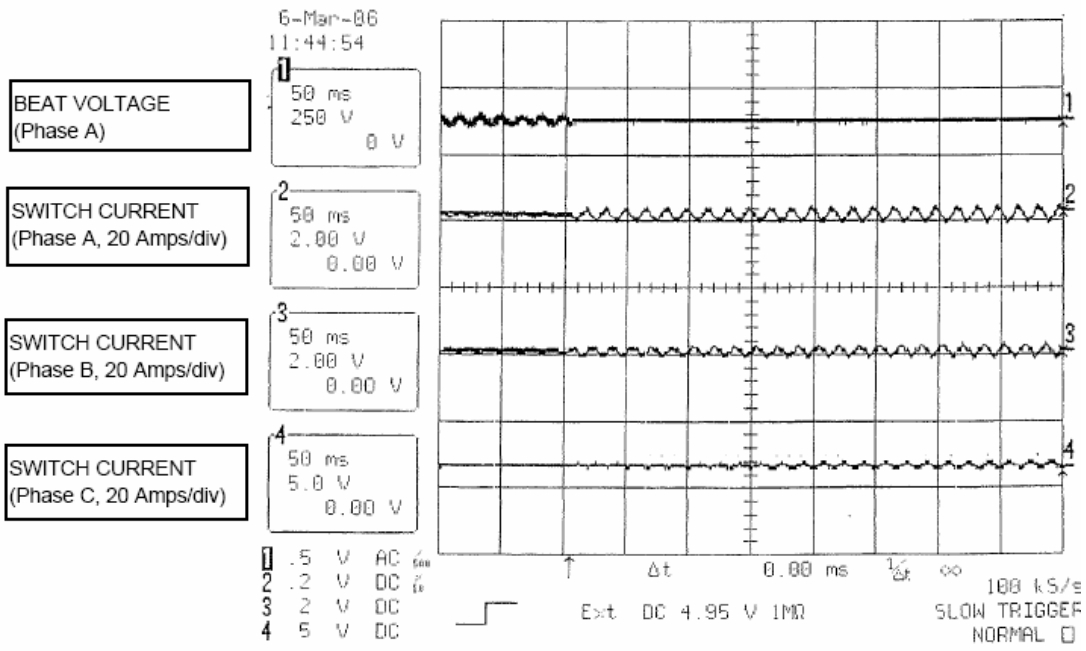

Figure 9: Synchronized Closing for Test #6 (beat frequency= 0.05 Hz)

3.3 *Reverse Power and Anti-Islanding [Test Plan Section 3.3]*

In this section, the reverse power algorithm as well as the functionalities that it is part of will be tested. The reverse power algorithm event will be running when operating in the "Auto" Mode, and if the conditions of the power flow make this event true, then the DSP will command the switch to open.

Additionally, based on the kind of condition that causes the reverse power event, the DSP will take a decision wether to reclose the switch when conditions are appropriate, or simply lockout the system. This decision will be based on what the grid side voltage is after the switch has opened after a reverse power event:

- If after the switch opens on a reverse power event, any of phases of the grid voltage is low (due to a grid upstream islanding or due to an open phase) then, once conditions are normal for synchronization and all events are cleared, the DSP will try to reclose the switch.
- If after the switch opens on a reverse power event, all phases of the grid voltage is normal, then it means that the reverse power condition was created due to incorrect power setpoints in the DG sources (DG Pset > microgrid load); in this situation, then the DSP should create a fault that will be displayed to the user though the Engineering HMI or EMS as "Reverse Power Anti-islanding = Microgrid Settings Reset" and the switch will be lockout (enter the "OFF" state which opens the SCR switch and the input breaker, thus requiring alarms reset and restarting of the system).

3.3.1 Reverse Power (32) magnitude, time test

The first step in testing the reverse power functionality is to test the accuracy the magnitude and time delay of the relay. The settings associated with the reverse power event (which is monitored at the remote location current transformers CT12) are:

- Remote Reverse Power (per phase): In kW; if the reverse power measured at the remote location in any phase is less than this threshold, the "Remote Power connect delay" timer will be triggered. The sign convention is set so that a positive number corresponds to power flow into the microgrid (minimum import convention). The threshold can be set negative or positive (negative settings will allow power export into the grid). The power is measured in every phase so all conditions (including open phase) can be detected.

- Remote Power connect delay timer: In seconds; once the reverse power measurement in any phase is below the threshold, a timer will start to run; if this timer reaches the time delay mentioned here, a "Reverse Power" event will be enabled, which in turn will give an Open command to the SCR switch. This time delay will typically be set to 2 seconds as recommended by utilities on their interconnection agreements.

Two sets of magnitude and time tests were performed: a minimum import case (positive setting) and a maximum export case (negative settings). Recall that during all these tests, all other events (Power Quality, IEEE 1547, etc. were disabled; only Remote reverse power (32) was enabled)

Minimum Import Test Setup

Initial DG Pset: 1 kW
DG load (R4) = 12 kW
Grid Load (R1) = 0 kW
Feeder C Load (R3)= 0 kW
RMS Remote Reverse Power Setting per phase: 1.66 kW (5 kW total)
Remote Power connect delay timer: 2 seconds

To run this test, the DSP controller was set in the Auto Mode and when the conditions were appropriate, the DSP performed a synchronized closing. Once switch closes, initial power flow is approximately ~8kW into the microgrid, which does not trigger the reverse power event. To create the reverse power condition, the DG source Power Setpoint was increased in 1 kW steps (for approximately 10 seconds) until a reverse power trip occurs (this is observed by an open command to the switch and also the Reverse Power event bit is enabled in the Engineering HMI). This test was repeated three times, and the power magnitude and time delay during the trip were recorded; these results are shown in Table 2.

Maximum Export Test Setup
Initial DG Pset: 2 kW
DG load (R4) = 0 kW
Grid Load (R1) = 8 kW
Feeder C Load (R3)= 0 kW
RMS Remote Reverse Power Setting per phase: -1.66 kW (-5 kW total)
Remote Power connect delay timer: 2 seconds

This test was performed in a similar way as the Minimum Import Test. The DG source Power Setpoint was increased in 1 kW steps (for approximately 10 seconds) until a reverse power trip occurs. This test was repeated three times, and the power magnitude and time delay during the trip were recorded; these results are also shown in Table 2.

	Minimum Import (+5kW, 2 seconds)		Maximum Export (- 5kW, 2 seconds)	
Try #	Magnitude (kW)	Time (s)	Magnitude (kW)	Time (s)
1st	4.2	2.16	-4.32	2.13
2nd	4.1	2.11	-4.2	2.23
3rd	4.1	2.07	-4.4	2.2

Table 2: Reverse Power Magnitude and Time tests for Minimum Import and Maximum Export conditions

The results above show a good accuracy for the reverse power detection as well as the time delay; it also shows the capability of the algorithm to work for both power directions (import and export to the grid). Notice that the additional time delay (~0.2 seconds) could be due to the filtering of the RMS power measurement. The power measurement accuracy in our DSP controller is approximately within 1 kW which might explain the trips not occurring at exactly the setpoint (5kW); also recall that the steps performed during this tests were +1 kW, so the resolution of the test wasn't more precise than that.

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3.3.2 Grid islanding and Open Phase [Test Plan Section 3.6]

Using the reverse power algorithm tested in 3.3.1, an upstream grid islanding as well as an open phase condition can be detected. If this conditions occurs, it is expected that at least one phase of the grid voltage will be dead after the switch opens on the reverse power event; if the DSP controller observes this condition, then it will decide not to lockout the system, and thus allow to reclose when conditions are appropriate.

For the tests described above, and during normal operation, an additional setting is required:

- Voltage test delay timer: In seconds; once the reverse power event is enable, this new timer starts to run, and after it expires it looks at the voltage on the grid side (the switch should still be open from the reverse power event); if all the three phases voltages are normal, then it will create a fault and lockout the system, requiring user intervention; but if any of the phases voltage is low (grid islanding upstream or open-phase) then it will simply keep the switch open until conditions are appropriate for reclosing. For testing purposes, this timer will be set to 1 second.

Grid islanding and Open Phase Test Setup
Initial DG Pset: 1 kW
DG load (R4) = 8 kW
Grid Load (R1) = 0 kW
Feeder C Load= 0 kW
RMS Remote Reverse Power Setting per phase: 1.66 kW (5 kW total)
Remote Power connect delay timer: 2 seconds

The test setup described above was used for both the grid-islanding and the Open phase test. The grid islanding test condition was created by disconnecting the grid side inverter, thus no power flow exist across the switch which enables the reverse power event. The open-phase condition was created by disconnecting one of the phases on the grid side.

Figures 10 and 11 show the response of the controller and the switch to the grid upstream islanding test. These figures show the following:

Channel 1: beat voltage across phase A of the SCR

Channel 2: phase A switch current (20A/division)

Channel 3: DSP switch command

In Figure 10 it can be observed when the grid islanding condition occurs by disconnecting the grid inverter; the switch current is reduced to almost zero (the small current is due to the S&C control load), and after approximately 2 seconds, the switch is commanded to open (this can be seen by the switch command going HIGH, and also by the beat voltage going from zero when the switch is still closed to rated voltage once the switch opens). More than 1 second elapses, and the system is still running in the “Disconnect” mode, waiting for the right synchronization conditions to close.

In figure 11, the grid side is reconnected at approximately 0.25 seconds in the oscilloscope plot; after the grid is reconnected, the voltage across the switch now changes from rated voltage to a beat voltage waveform, and once synchronization conditions are appropriate (phase of beat voltage at zero) the DSP commands the switch to reclose. This is the desired behavior.

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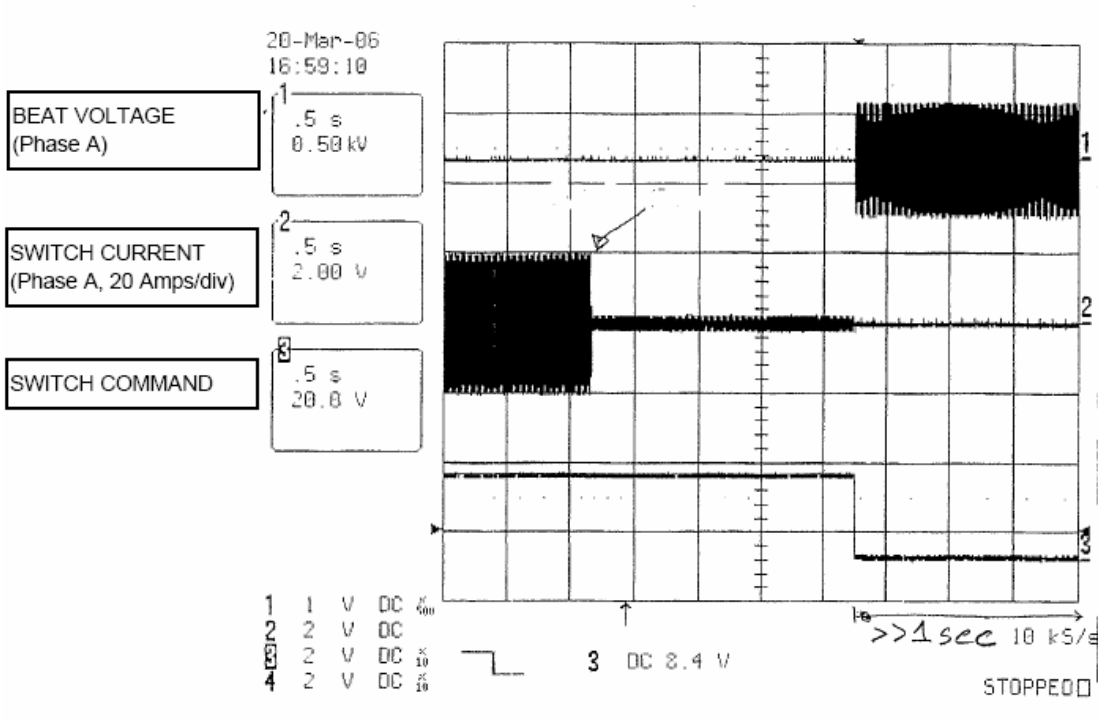

Figure 10: Grid Islanding Test, Disconnection after reverse power event

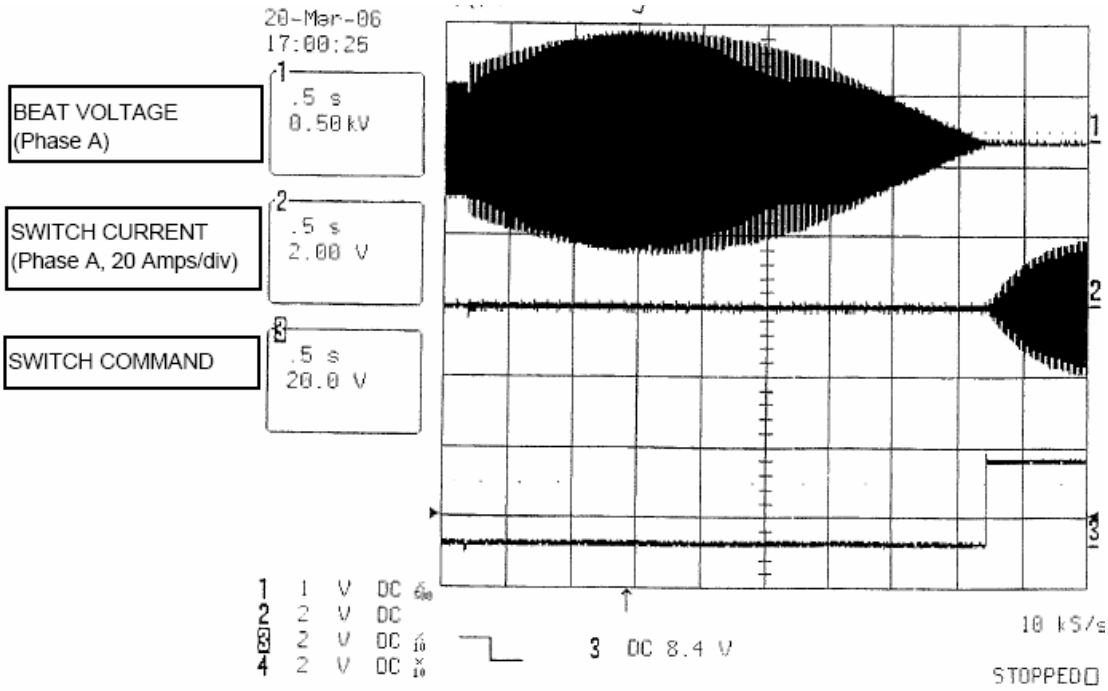

Figure 11: Grid Islanding Test, Reconnection

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In figure 12, the response to an open phase condition is observed. This figure shows the following:

Channel 1: beat voltage across phase A of the SCR

Channel 2: phase A switch current (20A/division)

Channel 3: phase B switch current (20A/division)

Channel 4: DSP switch command

Phase C switch current isn't shown due to oscilloscope channel limitations. This figure verifies that an open-phase condition was created by showing the phase A switch current going to zero while phase B (and phase C) still supply the load. After ~ 2 seconds, the reverse power event requires the DSP to open the switch without locking out the system. Just like the previous test, when synchronization conditions are appropriate, the DSP will attempt to reclose the switch.

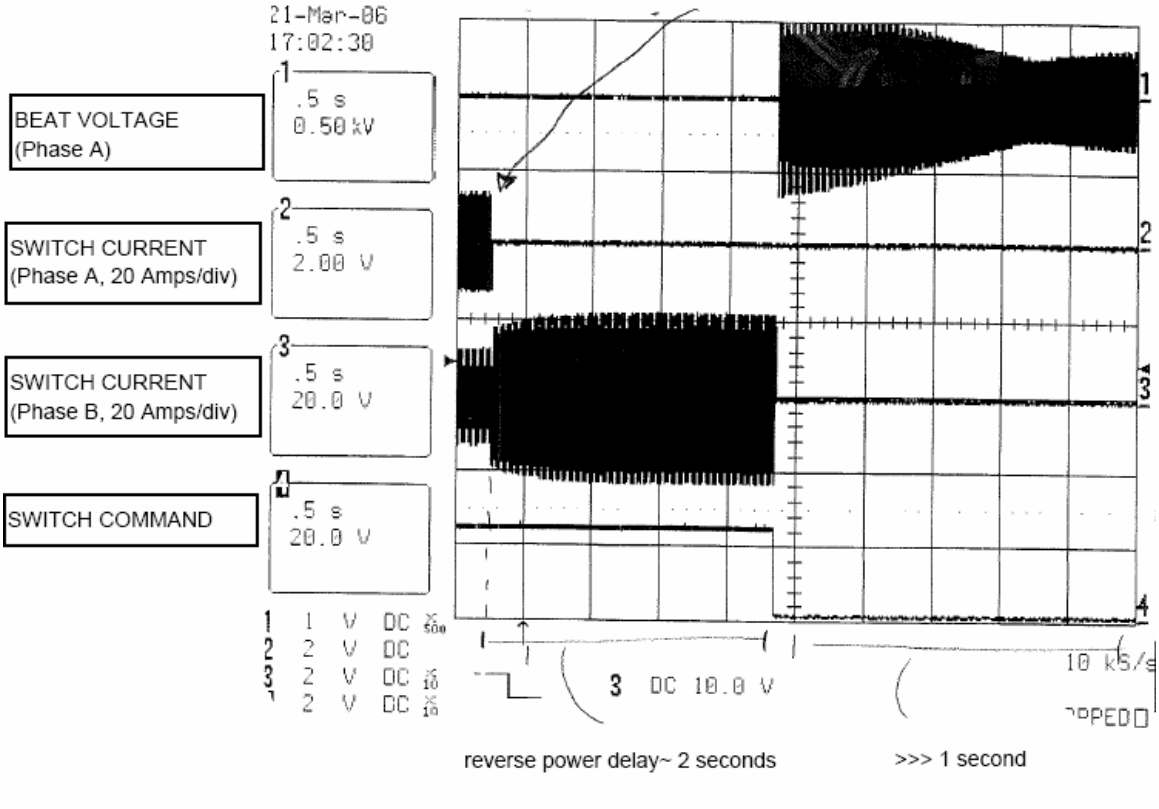

Figure 12: Open Phase Test

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3.3.3 Anti-islanding, Microgrid Settings Reset (Lockout)

The final reverse power test in this section involves the possible islanding condition of the microgrid due to a reverse power event created by erroneous microgrid settings (power setpoints larger than microgrid load). If this occurs, once the switch opens, the voltages on the grid and DG sides will all be normal, and it is expected that by detecting this condition, the DSP controller will lockout the system. The lockout occurs by creating a fault, transferring switch to the "Fault State" which opens the input breaker and requires user interface to restart the system.

The setup used for this test is the same setup as the grid islanding and open phase tests in section 3.3.2. Once the switch has done the synchronized closing and reach steady state, the power flow into the microgrid is approximately 7 kW (over the reverse power threshold). Then, the DG load bank (R4) is reduced from 8 kW to 3 kW, reducing the power flow into the microgrid side to 2kW, which will enable the reverse power event. Figure 13 shows the system response to this test:

Channel 2: phase A switch current (20A/division)

Channel 3: DSP Switch command

Channel 4: "Start/Stop" Command

After approximately 2 seconds after the load reduction, the DSP switch command opens the SCR switch as expected, but 1 second after that, the "Start/Stop" command goes low, which stops the S&C PES by opening the input breaker.

In the Engineering HMI, it was observed that the system entered the "Fault" state, which will require user interface. The alarm displayed in the HMI is "Reverse Power Anti-islanding, Microgrid Settings Reset" which should inform the operator that adjustments in the power setpoints of the microsources is required.

For future consideration it is possible that rather than locking out the system when this condition occurs, the EMS will automatically update the microsource settings to eliminate the reverse power condition, but this was not considered for this project.

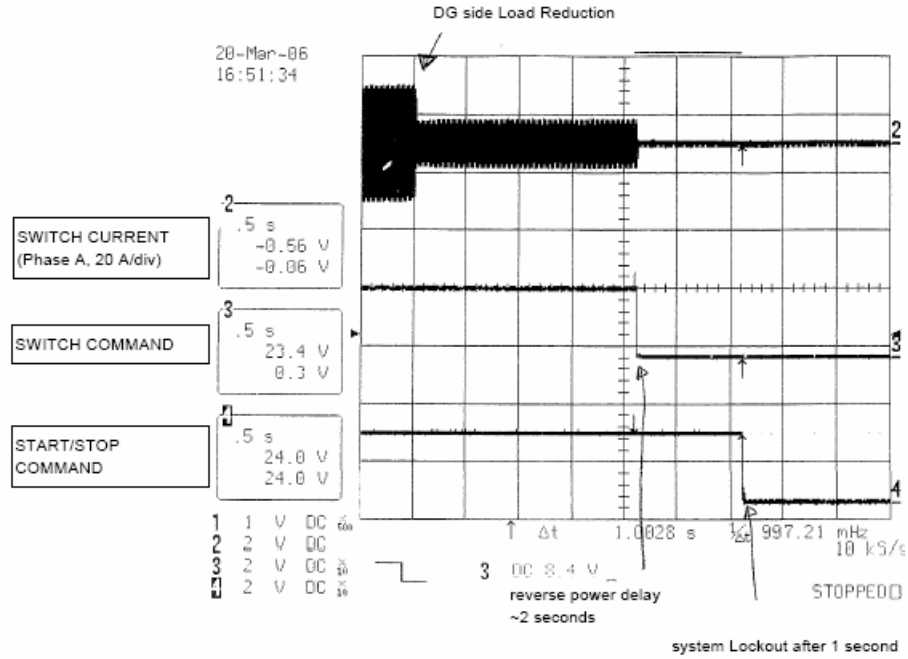

Figure 13: Anti-islanding, Microgrid Settings Reset Test

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3.4 IEEE 1547 Voltage and Frequency Tests

The IEEE 1547 standard specifies the voltage ranges and clearing times for over-voltage, under-voltage, over-frequency and under-frequency events. The values specified in the standard are repeated in each section for reference.

NREL's Omicron CMA256-6 secondary injection test set was used to perform the IEEE 1547 voltage and frequency tests. These tests closely reflect the method required by the IEEE 1547.1 standard, where tests are repeated 5 times to get more accurate results. Two types of tests are performed:

- Magnitude Test: The Omicron equipment ramps the voltage or frequency up or down (depending on the setpoint tested) at a relatively slow rate, and stays at each level long enough to allow the DSP to give the trip command if necessary. The magnitude at which the trip occurs is recorded.
- Time test: The Omicron equipment ramp the voltage or frequency from rated level to just above or below the magnitude of the setpoint that is tested, and records the time delay of the switch command to trip.

As explained before, all these tests are run in the "Auto" model the Omicron Equipment simulates appropriate synchronization conditions on both the DG and Grid side PT secondary signals. After the DSP switch command goes high (close), it performs the tests mentioned above.

Also, it is important to note that these tests are performed at low power, so the S&C switch is off during this test; the time delays recorded relate to the DSP switch command, and does not include the opening time of the SCR (which is expected to be up to ½ cycles). The next subsection shows some tests that were done to verify the SCR opening time.

3.4.1 Over/Under Voltage tests [Test Plan Section 3.5]

In this subsection, a summary of the results of the voltage tests (magnitude and time) is presented. Tables 3 and 4 show the specified responses in the IEEE1547.1 standard to over and under-voltage event.

Table 3. IEEE 1547 specification for interconnection response to over-voltages

Voltage range (% of base voltage)	Clearing time (s)
110 < V < 120	1
V ≥ 120	0.16

Table 4. IEEE 1547 specification for interconnection response to under-voltages

Voltage range (% of base voltage)	Clearing time (s)
V < 50	0.16
50 ≤ V < 88	2

Tables 5 and 6 below shows a summary of the tests that were performed; it presents average results of the 5 tries that were run for each voltage setpoint compared to the actual setting that was set in the DSP controller while running the test. Notice that for all setpoints, three phase tests were performed. However, for single phase tests different phases were alternated for different setpoints; this procedure was done this way because due to limited availability of the Omicron Equipment at Northern Power's facility, there would not have been time to perform all single-phase tests for all the different setpoints. However, by alternating the phases with different setpoints we were able to obtain a good picture of the overall accuracy of the controller.

For the voltage magnitude tests, the magnitude was ramped with 0.1 V steps. Also, for the time tests, the steps were done from rated voltage (277 V) to 5 V above or below the setpoint.

IEEE 1547 VOLTAGE MAGNITUDE TESTS (AVERAGES FROM 5 TRIES)			
Test	**Setting (V)**	**Average Trip Magnitude (V)**	**Average Deviation (V)**
Under-voltage 50%, Three Phase	138.5	139.00	0.50
Under-voltage 50%, Phase A	138.5	138.98	0.48
Under-voltage 88%, Three Phase	243.8	244.02	0.22
Under-voltage 88%, Phase C	243.8	243.78	-0.02
Over-voltage 110%, Three Phase	304.7	305.08	0.38
Over-voltage 110%, Phase A	304.7	306.24	1.54
Over-voltage 110%, Phase B	304.7	305.08	0.38
Over-voltage 110%, Phase C	304.7	305.66	0.96
Over-voltage 120%, Three Phase	332.4	332.50	0.10
Over-voltage 120%, Phase B	332.4	332.50	0.10

Table 5. Summary of IEEE 1547 voltage magnitude tests

IEEE 1547 VOLTAGE TIME TESTS (AVERAGES FROM 5 TRIES)			
Test	**Setting (ms)**	**Actual Trip Time (ms)**	**Average Deviation (ms)**
Under-voltage 50%, Three Phase	167	181.94	14.94
Under-voltage 50%, Phase A	167	181.68	14.68
Under-voltage 50%, Phase B	167	181.84	14.84
Under-voltage 88%, Three Phase	2000	2014.98	14.98
Under-voltage 88%, Phase C	2000	2015.16	15.16
Over-voltage 110%, Three Phase	1000	1008.48	8.48
Over-voltage 110%, Phase A	1000	1015.34	15.34
Over-voltage 120%, Three Phase	167	181.70	14.7
Over-voltage 120%, Phase B	167	178.68	11.68

Table 6. Summary of IEEE 1547 voltage time tests

The results in Table 5 show a very good accuracy for the voltage magnitude tests. The maximum deviation occurred at the 110% over-voltage setting for a single phase (A) test; the deviation for this test was 1.54V, which corresponds to 0.55% of rated voltage.

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The results in Table 6 also show good accuracies for the voltage time delays; the maximum deviation for the faster trips (167 ms) was less than 1 cycle (14.98 ms).

The IEEE 1547 under and over-voltage function tests results confirmed that the controller achieved its software programmed functionality.

3.4.2 Over/Under Frequency tests [Test Plan Section 3.4]

In this subsection, a summary of the results of the frequency tests (magnitude and time) is presented. Tables 7 and 8 show the specified responses in the IEEE1547.1 standard to over and under-frequency events.

Table 7. IEEE 1547 specification for interconnection response to over-frequency

Frequency range (Hz)	Clearing time (s)
> 60.5	0.16

Table 8. IEEE 1547 specification for interconnection response to under-frequency

Frequency range (Hz)	Clearing time (s)
< 57.0	0.16
59.8 > freq > 57	Adjustable 0.16-300 seconds*

* The IEEE 1547.1 standard specifies this time setting to be adjustable, and does not provide an actual value. For this testing it will be set to 1 second, and if necessary it can be adjusted in the microgrid test site using the EMS.

Tables 9 and 10 show the summary results for the frequency magnitude and time tests. The frequency magnitude tests were ramped at a rate of 10 milliHertz per step; for the time tests, Table 10 describes precisely to what frequency was the step done for each of the tests.

IEEE 1547 FREQUENCY MAGNITUDE TESTS (AVERAGES FROM 5 TRIES)			
Test	**Setting (V)**	**Average Trip Magnitude (Hz)**	**Average Deviation (Hz)**
Over-frequency 60.5 Hz	60.50	60.51	0.01
Under-frequency 59.3 Hz	59.30	59.30	0.00
Under-frequency 57 Hz	57.00	57.00	0.00

Table 9. Summary of IEEE 1547 frequency magnitude tests

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IEEE 1547 FREQUENCY TIME TESTS (AVERAGES FROM 5 TRIES)			
Test	**Setting (ms)**	**Actual Trip Time (ms)**	**Average Deviation (ms)**
Over-frequency 60.5Hz (step:60.0 to 60.55 Hz)	167	266.06	99.06
Over-frequency 60.5Hz (step:60.45 to 60.55 Hz)	167	202.66	35.66
Over-frequency 60.5Hz (step:60.40 to 60.70 Hz)	167	183.04	16.04
Over-frequency 60.5Hz (step:60.0 to 60.55 Hz)	100	186.56	86.56
Under-frequency 59.3Hz (step:60.0 to 59 Hz)	1000	1069.54	69.54
Under-frequency 57Hz (step:60.0 to 56 Hz)	167	251.08	84.08

Table 10. Summary of IEEE 1547 frequency time tests

The magnitude tests in Table 9 show that the maximum deviation was 0.01 Hz, therefore the frequency magnitude trips are extremely accurate.

However, some issues were observed for the frequency time tests in Table 10; longer time delays than expected were observed. Notice that for the frequency time tests, rather than simply doing a large step from 60 Hz to just above or below the thresholds, also smaller steps were taken.

Similar results were obtained from the testing of Northern Power Controller for the DER Switch project (another NREL subcontract) The investigation of this issue shows that when a large frequency step change was applied, it can also cause a large PLL transient response, possibly large enough to briefly break the lock detector. In reality, a power system would not be subjected to instant frequency swings so drastic. In order to obtain the expected time response with a more realistic test condition, the frequency tests were repeated for smaller step changes centered at the threshold (see Table 10); these tests provides much better time responses.

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3.5 SCR Switch Opening Time

In the IEEE 1547 section, the trip time measurement only monitored the opening command from the DSP Controller, and does not include the opening time of the switch (since the S&C PES was not powered). It was considered important to perform some runs and verify that unless an asymmetrical component is present in any of the switch currents, the SCR switch will open on approximately ½ cycles (8 ms).

To perform this test, a very simple test setup was used. The inverter side of the switch was setup as an open-loop source (constant voltage and frequency; 277V,60 Hz) while the other side of the switch was set to an 8 kW resistive load.

The test was operated in the "Manual" mode and "Sync Test Bypass", so the switch could be manually opened and close. With this setup, the switch was cycled 20 times, and the opening time was recorded (from when the DSP command to open is given until all the phase currents go to zero).

The results are presented in Table 11. Figure 14 shows the oscilloscope waveforms (switch currents A,B,C and DSP switch command) for try#4 in table 11. The average opening time from these results was 8.13 ms, which verifies the expected performance of the SCR switch.

Try#	Opening Time (ms)
1	7.96
2	7.67
3	8.96
4	7.62
5	8.25
6	7.31
7	7.38
8	8.07
9	7.92
10	9.18
11	7.59
12	9.00
13	8.39
14	8.73
15	8.57
16	8.56
17	7.95
18	8.85
19	7.03
20	7.68
Average (ms)	8.13

Table 11. SCR Opening Time Test Results

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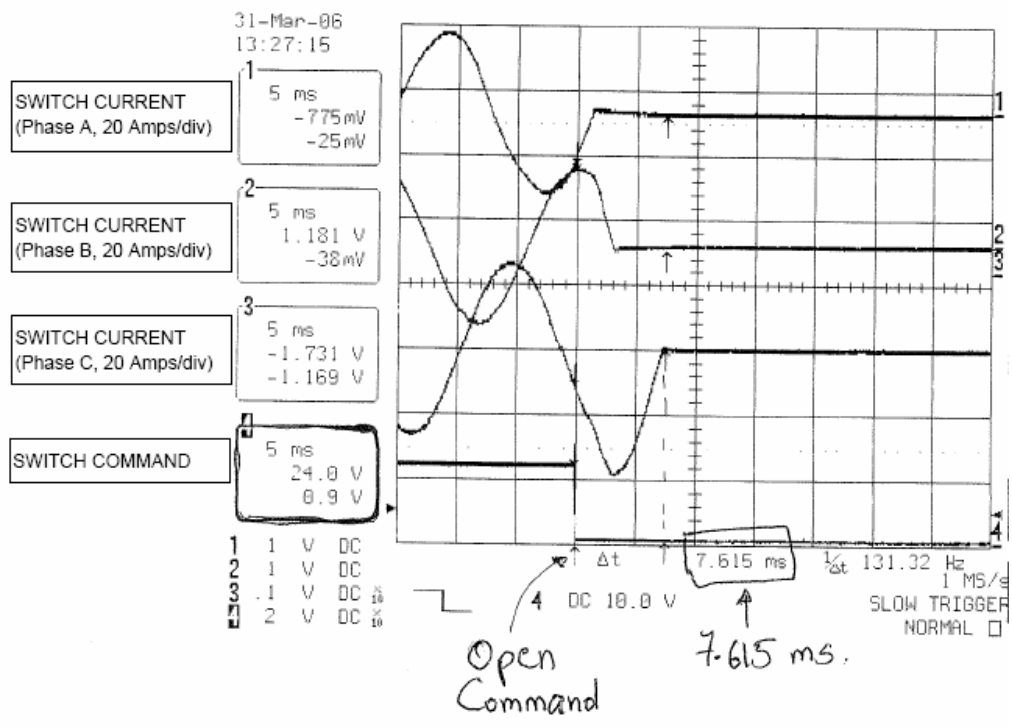

Figure 14. SCR Opening Time Test; Try #4

3.6 SEL-351 Relay – DSP Controller Functionality [Test Plan Section 4]

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Several tests were performed to verify the basic functionality of the SEL-351 relay and its interaction with the Static Switch DSP control. The Relay input is considered an “Event” in the DSP controller; anytime the Relay communicates a trip to the DSP Controller, the DSP will give an opening command to the switch, no matter what the control mode is (recall that for the other events, such IEEE1547, Power Quality and Reverse Power, the DSP Controller opens the switch only in the “Auto” Mode)

As explained before, the Static Switch SEL 351 Relay (Relay2) is expected to perform the following protection functions:

- Phase overcurrent protection (instantaneous and time-overcurrent)
- Line to Line undervoltage protection (on the grid side of the switch PT14)
- Zero Sequence Current (using the neutral current input)

However, notice that for this set of tests, the programming of the SEL-351 relay was set to very simple trip levels and timers so that the trip conditions could be created based on the capabilities of the NPS test setup. The purpose is to test the interaction of Relay-DSP and not the trip accuracies of the Relay. The accuracies of the SEL-351 Relays can be trusted due to their wide use in the industry.

The tests performed in this section attempted to verify the following:

1) SEL Relay TRIP output logic
2) SEL Relay minimum opening time and associated DSP reconnection timer and reclosing
3) Relay to DSP delay

Settings

To perform the testing of this simple functionality, the Relay was programmed to the following settings (given in primary values):

- 50P1 (Instantaneous overcurrent): 15A
- 27PP (Line-Line undervoltage): 50%
- SV1 = 27PP (SV1 logic associated with line-line voltage)
- SV1 Pickup time: 0 cycles
- SV1 Dropout time: 5 seconds
- Relay minimum opening time: 20 seconds
- TRIP= 50P1+ SV1
- OUT101 =! TRIP (OUT101 is the output that will give the command to DSP)

3.6.1 SEL Relay TRIP output logic

The purpose of this test is to verify the output logic of the SEL-351. The DSP is expected to open the switch whenever the relay gives a trip command to it. There is no reconnection timers in the DSP associated with the Relay input (the final programming of the Relay will have its minimum opening time ~20 seconds in order to allow utility protection equipment to reclose first under fault conditions).

OUT101 has been programmed with an inverse logic to the trip condition (!TRIP); also the DSP was programmed to the following logic:

- If input from Relay is HIGH (24V); keep switch closed
- If input from Relay is LOW (0V); open switch

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The reason for this is to have a fail-safe mode; if for some reason communication is lost between the Relay and the DSP, the input to the DSP from the Relay will go low, thus providing the trip and making the operator aware that something wrong has occurred.

To verify this functionality, a test was done creating and under-voltage condition. The grid side inverter was disconnected, dropping the voltage below 50% and thus creating an under-voltage trip condition (27PP). The inverter was kept disconnected for about 1 minute (to allow minimum opening time to run off); then, the inverter is turned on again.

Figure 15 shows the response to the test described above:

Channel 1: Grid Voltage Phase A
Channel 4: Relay output signal to the DSP

We can see that the relay signal is initially low as expected; once the grid voltage has recovered, approximately 5 seconds after (dropout time) it can be seen that the Relay signal goes high (+24 V), which means the relay trip conditions are cleared and now the DSP can turn on the switch when synchronization conditions allow it.

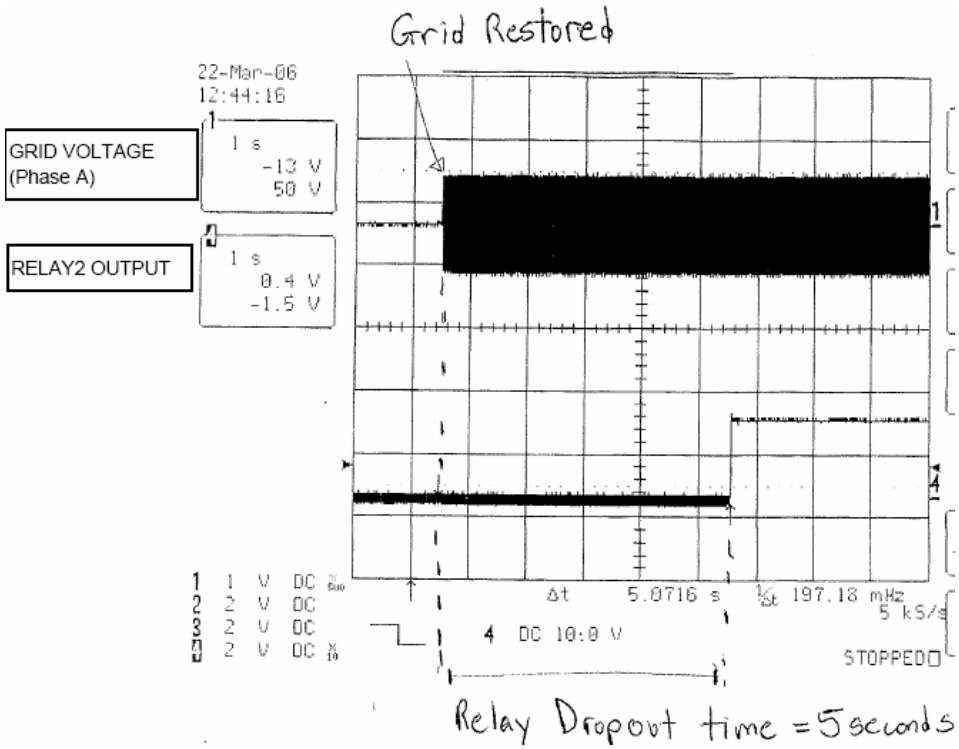

Figure 15. SEL Relay Trip Output Logic Test

3.6.2 SEL Relay minimum opening time and associated DSP reclosing

The second test performed verifies that the DSP opens the static switch on the Relay input signal going Low, and that once the command goes High again; the DSP closes the switch once synchronization conditions are appropriate.

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For this test, both the grid and DG power routers are on, and their initial conditions and loads were set such that the beat frequency of the voltage across the switch before closing is approximately 0.08 Hz. Once the switch performs synchronized closing, the grid supplies 12 kW of the DG load (~ 14 Arms).

To test the interaction of DSP and Relay, an over-current condition was created. On the DG side, the load was increased from 12kW to 15 kW. This will increase the current measured by the Relay from 14Arms to approximately 18 Arms, thus requiring an instantaneous current trip (recall threshold was set to 15A).

Figure 16 shows the response to this test; it shows the following waveforms:

Channel 1: switch phase A beat voltage
Channel 2: phase A switch current (20 A/division),
Channel 3: Switch Command
Channel 4: Relay output signal to the DSP

The switch current curve shows when the over-current condition is created, and it can be seen that, instantaneously, the Relay signal goes Low thus requiring the DSP command to open the switch. The switch opens, which can be observed by the formation of the beat voltage across the switch phase A.

The load is immediately reduced back to 12 kW (to avoid any overcurrent condition when reconnecting). After ~20 seconds (minimum opening time), the Relay signal goes back High (+24V), but the DSP does not attempt to reclose the switch right away because synchronization conditions are not appropriate. Once synchronization conditions are appropriate, the DSP switch command closes the switch again for normal operation.

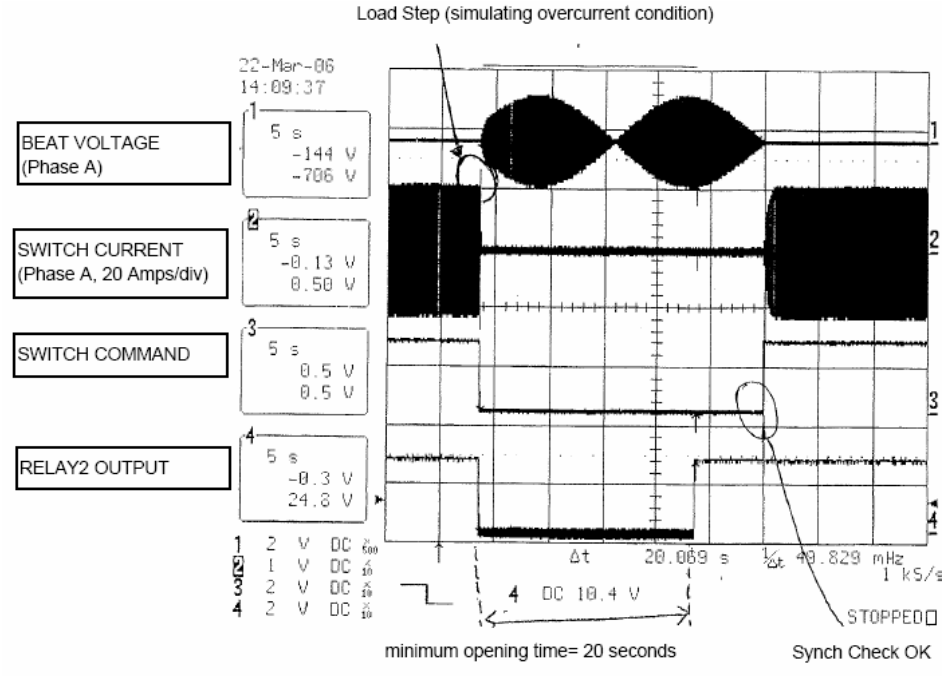

Figure 16. SEL Relay minimum opening time and associated DSP reclosing Test

3.6.3 Relay to DSP delay

The final Relay functionality test was performed in order to have an estimation of time delays between the Relay trip signal and the DSP switch command when required to open the switch. Five tries were run, creating the same over-current condition as in section 3.6.2, recording the time delay between the two signals. Table

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12 below shows the data collected. On average, the time delay was 1.1 ms, which is not significant and does not provide any concerns.

Relay to DSP Delay	
Try#	**Time (ms)**
1	1.22
2	0.975
3	1.52
4	1.19
5	0.81
Average	**1.143**

Table 12. Relay to DSP time delay Test data

3.7 Dead Bus Reclosing [Test Plan Section 3.5.3]

This section presents results of testing the accuracy and operation of the Dead Bus Reclosing functionality of the DSP. The purpose of this algorithm is to allow for reclosing to a dead bus on the DG side to allow for black starts of loads. The test will be divided in two sections:

1) DG Bus LO (27R) magnitude test

2) DG Bus LO (27R) time test; “Dead Bus Reclose” operating mode

The settings for the algorithm during this test are:

Dead Bus 27R Magnitude: 15Vrms

Dead Bus 27R Time constant:: 1 second

3.7.1 DG Bus LO (27R) magnitude test

The first step is to test the accuracy of the DG Bus LO (27R) relay function, which toggles HIGH if ALL phases of the DG side voltage are below the threshold. This test was performed with voltage on the DG side only; no attempt to reclose the switch was done, only the 27R relay event was checked to see when it detects the Dead Bus.

The test was performed in each test by setting the voltage in two of the phases (B,C for the first test) close to zero volts, and setting the remaining phase (A for the first test) just above the threshold (set it to 25 Vrms). At this point, the 27R event should be Low since one phase is above the threshold. Then, in 0.5V steps, the phase A voltage was reduced and settle at that level for 5 seconds until the 27R relay event toggles High. Results for the test performed on each phase were recorded and shown in table 13:

Dead Bus Reclose Magnitude Test Threshold= 15 Vrms	
Phase Tested	**Voltage at Trip (Vrms)**
A	14.33
B	14.23
C	14.34

3.7.2 DG Bus LO (27R) time test; “Dead Bus Reclose” operating mode

This test will verify the Dead Bus reclosing Logic and the time delay in the 27R LO relay. The setup used for this test was:

Operating Mode: Auto

Grid Side Voltage: 277 Vrms

DG Side Voltage: 25 Vrms

Dead Bus Reclose Mode: Enabled

Figure 17 shows the response for this test. This waveform shows:

Channel 1: DG side voltage

Channel 2: Grid side Voltage

Channel 3: Switch command

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Once the system is started, the system remains in the Disconnect state because synchronization conditions are not appropriate since the DG side voltage is well below the limits, and also it doesn't attempt to reclose since the voltage is not below the Dead Bus Relay threshold. To achieve the dead bus reclose, the DG side inverter was disconnected, dropping the DG voltage to zero. After a 0.944 seconds time delay (very close to the 1 second setting) the Switch Command goes high, closing the SCR switch; the fact that the switch closes can be observed since the grid and DG voltages are now equal.

The test was repeated, but disabling the operating mode "Dead Bus Reclose" in the HMI. With this change, even after disconnecting the DG inverter, closing of the switch did not occur; this verifies that the operator can control through the HMI (or EMS) whether Dead Bus Reclosing is allowed or not.

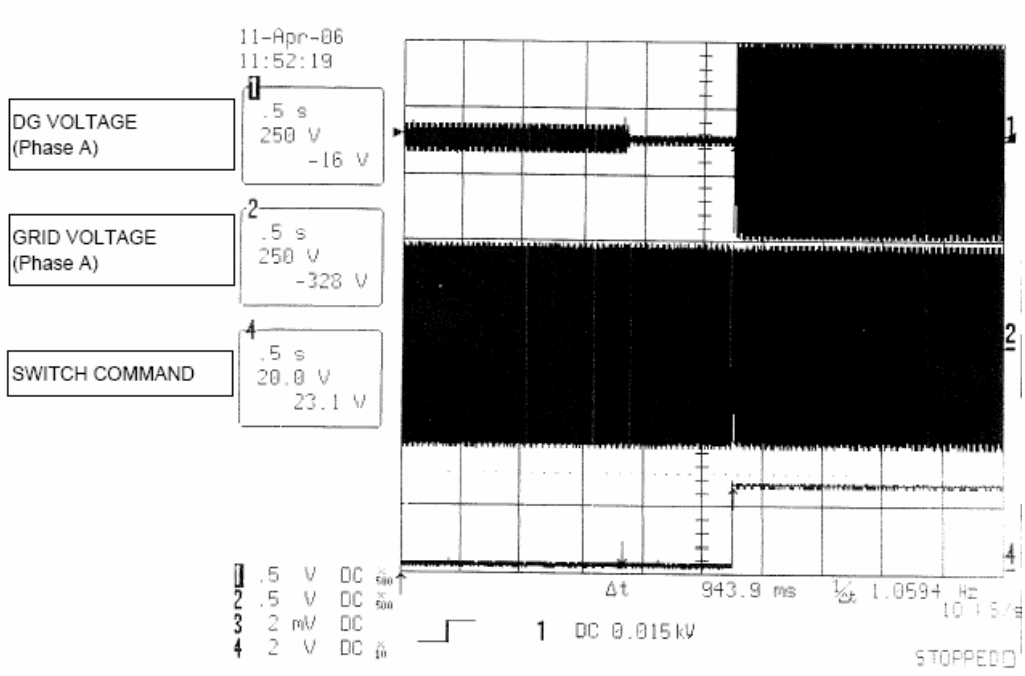

Figure 17. Dead Bus Reclosing Test

3.8 Restoration Timers

In this section, the accuracy of the restoration timers was tested. There are two separate restoration timers:

IEEE 1547 restoration timer: This restoration timer is used whenever a IEEE 1547 voltage or frequency event occurs. The timer is adjustable, and it will be set by default to 300 seconds (5 minutes) as recommended in the IEEE1547.1 standard.

PQ restoration timer: This restoration timer is used whenever a Power Quality event occurs. The timer is adjustable, and is set by default to 2 second.

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Additionally, it is important to mention that a “Disconnect” timer also exist in the DSP controller, this timer is not related to restoration conditions but rather to a minimum opening time for the switch. This timer is set by default to 1 second.

To test the IEEE1547 timer, a reverse power event due to a grid upstream was created (similar to section 3.3.2). Once the switch opens, since there is no voltage in the grid side, an IEEE1547 and a Power Quality event occur (this was verified by observing the alarms displayed in the Engineering HMI).

Figure 18 shows the response to this event. This figure shows the following waveforms:

Channel 1: grid voltage phase A

Channel 2: Switch command

After a couple of minutes, the grid was reconnected (as seen in figure 18, channel 1 the grid voltage recovers). However, the switch is not commanded to reconnect after the voltage has returned within limits for approximately 300 seconds, verifying the functionality of the IEEE1547 restoration timer. This test was repeated, but after approximately 2 minutes of restoring the grid, the grid was disconnected again; then the grid was brought back to normal conditions again, and it took and additional 300 seconds to reconnect (as expected).

To test the PQ restoration timer, the 90% under-voltage point in the CBEMA curve was simulated (this is the only event that can be simulated with the test setup without triggering other events). Initially, the grid is supplying 8 kW load to the DG side.

Figure 19 shows the response to this event. This figure shows the following waveforms:

Channel 1: grid voltage phase A

Channel 2: phase A beat voltage

Channel 3: Switch command

Approximately 4 seconds into the time axis of the plot, a voltage drop can be observed occurring in the grid voltage; this drop is an 11% drop (from 277V to 247V) which after 10 seconds (time delay setting for 90% undervoltage), enables a Power Quality event. After the 10 seconds, the switch is commanded to open. Once the switch opens, due to the load reduction, the voltage grows up above the 90% threshold, but it takes at least 2 seconds (PQ restoration timer) before it attempts to close. It actually closed at precisely 3.7 seconds. The reason why it didn’t close at 2 seconds is because at that time, synchronization conditions were not optimum for reclosing (see channel 2).

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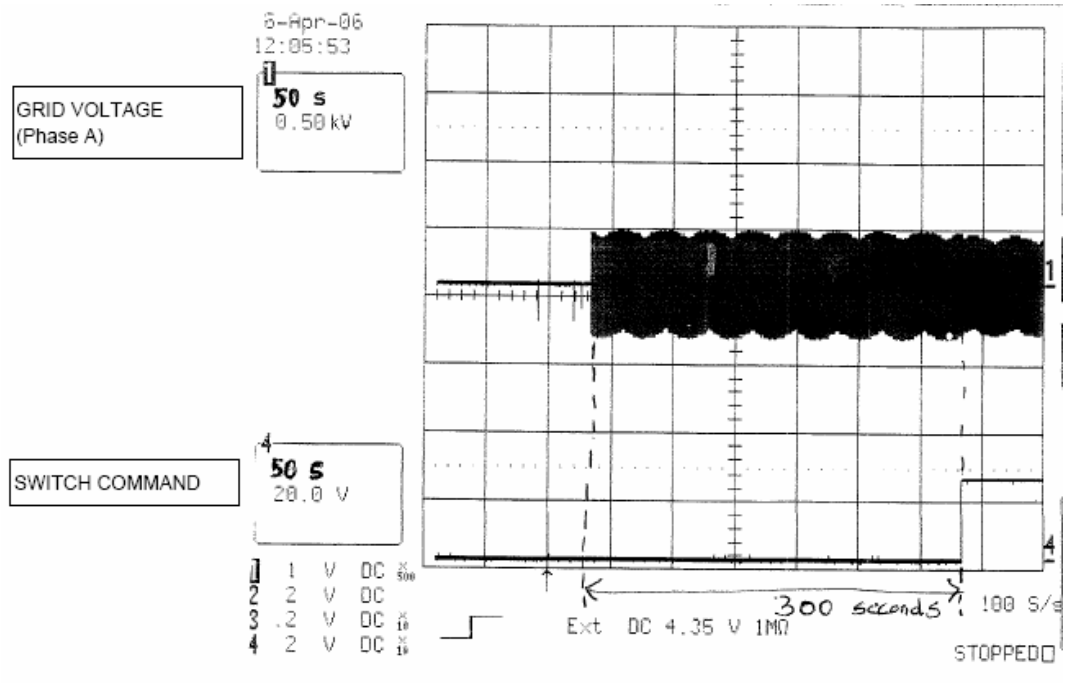

Figure 18. IEEE 1547 Restoration Timer test

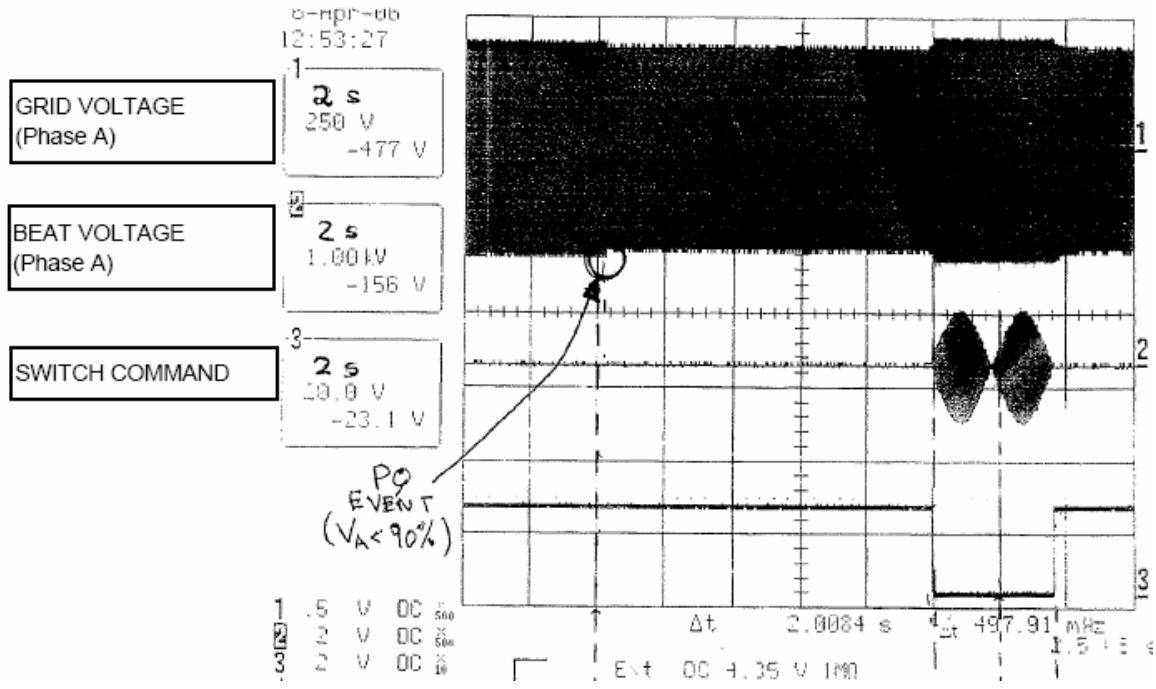

Figure 19. Power Quality Restoration Timer Test

3.9 Energy Manager System (EMS)

All the functionality tests so far have been performed using Northern Power Engineering HMI. However, at the AEP site, control and monitoring of the Static Switch (as well as the operation of the rest of the zones in the testbed) is performed using an Energy Manager System (EMS) developed with LABVIEW™.

For control and monitoring of the Static Switch, the EMS will have two windows associated to this feature:

Static Switch Control: This window includes the information of the operating status of the switch, status and enabling control of all alarms and events, interface with the switch control (Start, Stop, Reset commands) as well as overview of measurements (Remote location and Switch RMS power, DG and Grid voltages). Figure 20 shows a snapshot of this display in the EMS.

Static Switch Parameters: This window includes all the necessary setpoints that can be adjusted by the user for the different kind of events:

- IEEE 1547 events (magnitude and time delay)
- Power Quality events (magnitude and time delay)
- Reverse Power
- Synchronization Limits
- Dead Bus Reclose
- Reconnection Timers

The complete list of settings can be observed in Appendix.

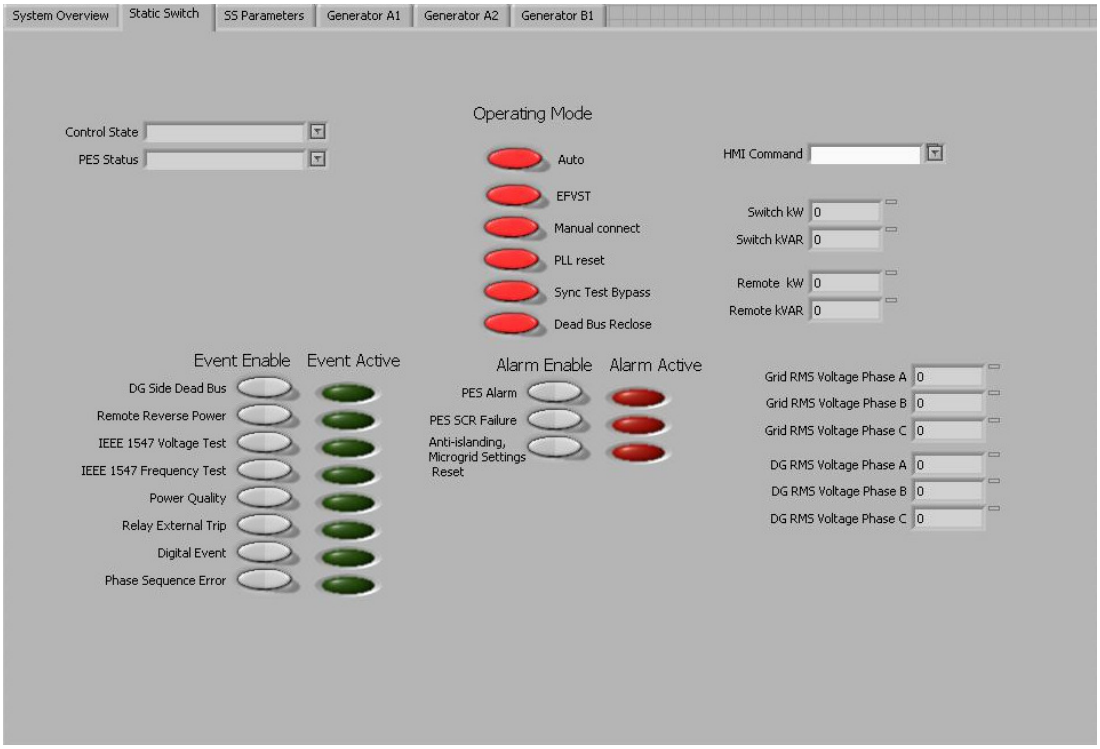

Figure 20. EMS "Static Switch Control" Window Display

As part of this Factory Acceptance Test procedure, a set of simplified tests were preformed:

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HMI Command: The HMI Command includes the “Start”, “Stop” and “Reset” command. These commands were cycled around about 5 times, and the expected response of switch was observed (by opening and closing the input breaker, or by Resetting any alarms that appear).

Control State: The Control State window display in which state of the DSP Controller State Machine the system is at the moment. These states include:

- OFF
- FAULT
- DISABLE
- TEST
- CONNECT, DISCONNECT

To test this feature, some simple functionality tests from the previous sections were performed, and it was observed that this display will show the correct state in which the switch was at the moment (which was also the case when using the Engineering HMI).

PES Status: The Control State window display in which state of the S&C PES is at the moment. These states include:

- PES OK (running, no alarms, but the switch open)
- PES Closed
- PES Alarm
- PES SCR failure
- PES Warning

To test this feature, several open/close of the switch as well as alarm conditions were created, and the expected display was observed. To understand in full detail the meaning of each of this alarm, check Reference [2].

Events and Alarms: All the events and alarms that the DSP Controller will be monitoring have to bit associated with them:

- Enable: When this event is on, the switch will be checking this event, if not, the event is disabled
- Active: Indicator that tells whether conditions that create this event or alarm are present at the moment.

To test the “Enable” bit, overcurrent condition was created (same as section 3.6.2) which requires and External Relay trip; it was observed that, with the “External Relay Trip” event enabled, the Active indicator for this event was on, and the switch goes to disconnect state on this event. Then, the test was repeated but the “Relay trip event” was disable, and in this condition no opening of the switch occurs as expected.

To test the “Active” bit, a reverse power condition requiring anti-islanding lockout (section 3.3.3); once the switch command the system to “Stop” the “Anti-islanding Microgrid Settings Reset” indicator turns on as expected, communicating the operator that adjustments of power setpoints in the DG sources is required.

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3.10 CERTS Switch Full Functionality Test

The purpose of these section is to verify the complete functionality of CERTS switch Controller by creating events that will simulate all the conditions tested previously, but while having all the functions Enabled (with all the default functions and settings when the Switch goes to the AEP site). Also, during all these tests, the interface between the operator the DSP controller will be the Energy Manager System (EMS) only.

Below, a description of all the tests performed is included. All the tests were run continuously without stopping the system (unless required by the control logic); during all these tests, all signals and alarms are checked in the EMS to see if it operates as expected. In each of the tests below, a brief summary with observations of the CERTS switch response is presented.

CERTS Switch Full Functionality Test

Initial System Setup

Grid side
- Grid inverter voltage setpoint: 277V
- Grid inverter Frequency: 60 Hz
- Grid Load (R1) = 0 kW

DG side
- DG inverter Power Setpoint= 1 kW
- DG inverter droop= 0.05 Hz/kW (assuming Fmin=59.3Hz, Pmax=15 kW)
- DG Load (R4)= 12kW
- Frequency (before closing) ~ 59.45 Hz

DSP Default Setpoints

- Synchronization frequency limits: (Nominal= 60Hz, Freq min= 59Hz, Freq max= 61 Hz)
- Synchronization voltage limits: (Nominal = 277V,Voltage min= 305V (110 %), Voltage max= 250V (90%)
- Synchronizations phase outer limits: 10, -10 degrees

- Reverse power per phase= 3.33 kW (10 kW total)
- Reverse power time delay= 2 seconds
- Reverse power voltage test delay (for lockout decision) = 0.5 seconds

- IEEE 1547 voltage, frequency points: based on IEEE 1547.1 standard (same settings tested in section 3.4; tables 4,5,8,9)

- Power Quality: Based on CBEMA, SEMIF47 standard (4 undervoltages and 3 overvoltages; check Reference [2]). The testpoint that will be tested in this process is:
    - Voltage #7 (sag): magnitude=90% (249.3 Vrms), time delay= 10 seconds

- Dead Bus reclose test voltage: 15 V
- Dead bus reclose test time delay: 1 second

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- Reconnection timer for PQ events: 2 seconds
- Reconnection timer for IEEE1547 events: 300 seconds
- Disconnect timer: 1 second

SEL 351 Relay2 Settings

- 50P1 (Instantaneous overcurrent): 15A
- Relay minimum opening time: 20 seconds
- TRIP= 50P1+ SV1
- OUT101 =! TRIP (OUT101 is the output that will give the command to DSP)

Note: under-voltage protection was not included in the Relay programming for this test so it wouldn't interfere with the IEE1547 and Power Quality voltage tests.

Test #1: Start up system, Synchronized Closing

The initial setup of the DG and grid side will provide a beat frequency of about 0.55 Hz.. Also all voltages should be within the default synchronization limits so system should be ready to automatically performed a synchronized closing.

- Measurements were setup to observe:
- Voltage across phase A of the switch
- Phase A switch current.

The following steps were performed:

1) Make sure all alarms are reset on both the S&C PES and DSP, and that system is ready to start. (S&C PES should be in "Output disconnect" mode)
2) Start the system with the "Start" command. The system should enter the "Disconnect" State on the DSP, and we should observe the beat voltage with a frequency of approximately ~0.2 Hz.
3) After passing through a zero crossing in the beat voltage, the DSP should provide a "Close" command to the PES and the switch will close. Should see the beat voltage drop to approximately zero Volts, and the switch current should increase to approximately 14Arms (the Grid needs to supply 12 of the 15kW in the DG side)

Observations: The response of the CERTS switch during this test was as expected; once the system was started, synchronization closing occurred with a very smooth transition. After waiting a few minutes, the switch remaining closed without any alarms or events, meaning the system is in normal operation.

When the switch closes, "CONNECT" is displayed in the Control State block of the EMS, and "PES OK" is displayed in the PES Status block.

Test #2: Reverse power due to grid islanding (Check for IEEE1547 voltage event)

For this test, monitor:

- Switch command
- Grid side voltage phase A
- Voltage across phase A of the switch
- Switch current phase A

1) Disconnect grid side inverter from system. The switch current should drop from 14Arms to zero since the grid is gone and won't be providing any power (in any of the phases) to the DG side of the switch.

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2) After two seconds, the DSP should provide an open command to the S&C PES due to a reverse power event. The beat voltage in Phase A should change from zero to approximately rated voltage (since DG side: rated voltage and Grid side: 0 V). Switch current remains zero since switch is opened.
Observe the "Events Active" list in the EMS. Once the switch opens, verify that the "IEEE1547 voltage type test" turn on, due to the fact that once the switch opens, the voltage on the grid side PT drops to zero.(Notice that the "Power Quality Function" event also should turn on)
3) Wait for ~20-30 seconds, and observe that the "IEEE1547 voltage type test" event remain high.
4) Reconnect the grid inverter to bring the grid voltage back. The "IEEE1547 voltage type test" event should toggle back low since the grid voltage is back to normal, but switch shouldn't try to reclose due to IEEE1547 reconnection timer being 300 seconds.
5) Observe the beat voltage of the switch phase A (which should again be a beat waveform with ~0.2Hz frequency). After approximately 5 minutes, once synchronization conditions are appropriate, it should reclose. Switch current should go back to ~14 Arms.

Observations: The response of the CERTS switch during this test was as expected; the switch is disconnected 2.05 seconds after the reverse power event occurs.

When the switch opens, "DISCONNECT" is displayed in the Control State block of the EMS, and "PES OPEN" is displayed in the PES Status block. In the Events list, the "IEEE1547 voltage type test" and "Power Quality Function" events are on.
Once the grid was reconnected, it took over 300 seconds (~305 seconds) for the switch to reclose. The Control State and PES Status block returned to "CONNECT" and "PES CLOSED" respectively.

Test #3: Reverse power due to open phase (Also check for IEEE1547 voltage event)

For this test, monitor:

- Switch command
- Grid side voltage phase A
- Voltage across phase A of the switch
- Switch current phasse A and B

1) Disconnect grid side phase A from system by using a single phase contactor. Phase A current should drop from ~14Arms to zero while phase B (and C) currents increase a bit. Also, grid Phase A to neutral voltage should drop to zero, but phase B (and C) will remain approximately at rated voltage.
2) After two seconds, the DSP should provide an open command to the PES due to a reverse power event (setting is at 3.3kW per phase). The beat voltage in Phase A should change from zero to approximately rated voltage (since DG=rated voltage and Grid=0 V). Now both phase A and B switch current drop to zero since switch is opened.
3) Observe the "Alarms" menu in the HMI display. Once the switch opens, we
should see the "IEEE1547 voltage type test" event go high, due to the fact that one of the phases (phase A) the voltage on the grid side PT drops to zero.
4) Wait for ~20-30 seconds, and observe that the "IEEE1547 voltage type test" event remains high
5) Close the single-phase contactor to bring phase A grid voltage back. The "IEEE1547 voltage type test" event should toggle back low since the grid voltage is back to normal, but switch shouldn't try to reclose due to IEEE1547 reconnection timer being 300 seconds.
6) Observe the beat voltage A (which should again be a waveform with ~0.2Hz frequency). After approximately 5 minutes, once synchronization conditions are appropriate, it should reclose. Switch current should go back to ~14 Arms.

Observations: Same as Test #2

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Test #4: Reverse power Anti-islanding, Microgrid Settings Reset (Check Anti-islanding lockout logic)

For this test, monitor:

- Switch command
- Start/Stop Command
- Grid side Voltage phase A
- Switch Current phase A

1) Currently, the grid is supplying ~11 kW to the DG side (monitored by the remote CT12 current transformers).
2) Change the DG setpoint from 1 kW to 4 kW. This will require the grid to supply a per phase power of ~2.66 kW, just below the threshold (3.3 kW per phase).
3) After 2 seconds, a reverse power event occurs, so the Switch command should open the S&C PES.
4) Approximately 0.5 seconds after the trip, the reverse power voltage test algorithm will see that all the voltages on the grid side are normal. This will create a fault condition that requires the switch to lockout. The DSP will provide a “Stop” command to the PES, opening the input breaker and keeping the DSP state machine in the “Fault” state.
5) Restart the system. The switch should performed automatically a synchronized closing, but two seconds fter that it will see the reverse power condition again, and lockout the system
6) Change the microgrid setpoint back to 3kW.
7) Restart the system. The system should perform the synchronized close. Wait for 1 minute, and we should see no alarms or events come on.

Observations: The CERTS Switch controller responded as expected; the reverse power event transition the switch to the “DISCONNECT” State, but after 0.5 seconds, the switch was commanded to Stop and the input breaker was Open. The Control State Block display “Fault- Anti-islanding Microgrid Settings Reset”.

Faults were cleared and the switch Started. After attempting the first switch reclosing (without adjusting the DG setpoint back to 1 kW) the switch closed by opened and Stop again. Once the DG setpoint was adjusted back to 1 kW, the switch closed and remained in the “CONNECT” State.

Test #5: Power Quality Event

- For this test, monitor:
- Switch command
- Grid side Voltage phase A
- Voltage across switch phase A

1) Drop all phases of the grid side voltage from rated voltage to 91% (252Vrms)
2) Drop phase A by 0.5% (1.38V). Wait for ~ 30 seconds; no events should occur.
3) Repeat step 2 until a PQ event (and no IEEE1547) occurs. The event should occur approximately 10 seconds after the voltage step is performed.
4) Once the event occurs, the Switch Command should open the switch.

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5) Observe the “Power Quality” event go high. No other events should be enabled at this point.
6) Wait for ~ 1 minute.
7) Step the phase A voltage back to 100% (277Vrms). Approximately two seconds (PQ reconnection timer) after the step, the switch should attempt to reclose (once synchronization conditions are acceptable)
8) System goes back to normal, no alarms present.

Observations: CERTS Switch responded appropriately; in the events list on the EMS, the “Power Quality Function” event turn on, and after 9.7 seconds of the voltage step, the switch was commanded to open and transitioned to the “DISCONNECT” state. The voltage came back within the Power Quality thresholds (>90%) almost immediately (since there is no voltage drop across the grid inverter transformers). The switch reconnected after 3.7 seconds rather than 2 seconds (PQ restoration timer) because synchronization conditions were not appropriate yet.

Test # 6: SEL351 Relay2 Event

For this test, monitor:

- Switch command
- Relay Output Signal
- Switch Current Phase A
- Voltage across switch phase A.

1) After the switch recloses in the final step of test #5, the switch current is approximately ~14 A rms (12 kW supplied by grid).
2) Check the Relay current readings (in the display panel); the three phases should be approximately 14 Arms.
3) Increase the DG side load to 15 kW.. The current now will increase to ~18 Arms. Since the overcurrent level in the relay was set to 15 Arms, then the relay should provide a trip command to the DSP, and the DSP should command the switch to open instantaneously. Reduce the DG load back to 12 kW.
4) Check that the “Relay Trip event” alarm goes high.
5) After ~20 seconds (relay minimum opening time) the relay trip signal will go off, and the DSP will immediately try to reclose the switch.

Observations: The CERTS Switch controller responded as expected; when the DG side load was increased, the Relay Output signal went Low, and the Switch command immediately opened the switch. At this time, the “Relay External Trip” event turned on, and all other alarms and events remained off. After 20 seconds, the Relay Output signal toggle HIGH again, and after an additional ~1.8 seconds, the DSP reclosed the switch (once synchronization conditions were appropriate).

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4 Appendix

4.1 Appendix 1: IEEE1547 Tests Results with NREL's Omicron Equipment (Section 3.3)

Table 1 - Under-voltage Magnitude Test Results

SUMMARY OF IEEE 1547 UNDERVOLTAGE MAGNITUDE TESTS

UNDERVOLTAGE 50%, Three Phase

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
138.50	139.00	500.00
138.50	139.00	500.00
138.50	139.00	500.00
138.50	139.00	500.00
138.50	139.00	500.00

Avg: 139.00 V

UNDERVOLTAGE 50%, Phase A

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
138.50	139.00	500.00
138.50	139.00	500.00
138.50	138.90	400.00
138.50	139.00	500.00
138.50	139.00	500.00

Avg: 138.98 V

UNDERVOLTAGE 88%, Three Phase

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
243.80	244.00	200.00
243.80	244.00	200.00
243.80	244.10	300.00
243.80	244.00	200.00
243.80	244.00	200.00

Avg: 244.02 V

UNDERVOLTAGE 88%, Phase C

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
243.80	243.80	0.00
243.80	243.80	0.00
243.80	243.80	0.00
243.80	243.80	0.00
243.80	243.70	-100.00

Avg: 243.78 V

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Table 2 - Over-voltage Magnitude Test Results

SUMMARY OF IEEE 1547 OVERVOLTAGE MAGNITUDE TESTS

OVERVOLTAGE 110%, Three Phase

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
304.70	305.10	400.00
304.70	305.10	400.00
304.70	305.10	400.00
304.70	305.10	400.00
304.70	305.00	300.00

Avg: 305.08 V

OVERVOLTAGE 110%, Phase A

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
304.70	306.20	1500.00
304.70	306.20	1500.00
304.70	306.20	1500.00
304.70	306.30	1600.00
304.70	306.30	1600.00

Avg: 306.24 V

OVERVOLTAGE 110%, Phase B

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
304.70	305.00	300.00
304.70	305.10	400.00
304.70	305.10	400.00
304.70	305.10	400.00
304.70	305.10	400.00

Avg: 305.08 V

OVERVOLTAGE 110%, Phase C

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
304.70	305.60	900.00
304.70	305.70	1000.00
304.70	305.60	900.00
304.70	305.70	1000.00
304.70	305.70	1000.00

Avg: 305.66 V

OVERVOLTAGE 120%, Three Phase

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
332.40	332.50	100.00
332.40	332.40	0.00
332.40	332.60	200.00
332.40	332.50	100.00
332.40	332.50	100.00

Avg: 332.50 V

OVERVOLTAGE 120%, Phase B

dV/dT=	0.10	V/s
dT per step	1.00	s

Nominal (V)	Actual (V)	Deviation (mV)
332.40	332.60	200.00
332.40	332.40	0.00
332.40	332.50	100.00
332.40	332.50	100.00
332.40	332.50	100.00

Avg: 332.50 V

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Table 3 - Under-voltage Time Test Results

SUMMARY OF IEEE 1547 UNDERVOLTAGE TIME TESTS

UNDERVOLTAGE 50%, Three Phase

Ramp from	277.00	V
Ramp to	130.00	V

Tnominal (ms)	Tactual (ms)	Tdev (ms)
167	176.6	9.60
167	181.6	14.60
167	183.8	16.80
167	183.8	16.80
167	183.9	16.90
Avg:	**181.94**	**msec**

UNDERVOLTAGE 50%, Phase A

Ramp from	277.00	V
Ramp to	130.00	V

Tnominal (ms)	Tactual (ms)	Tdev (ms)
167	175.4	8.40
167	183.6	16.60
167	183.9	16.90
167	183.7	16.70
167	181.8	14.80
Avg:	**181.68**	**msec**

UNDERVOLTAGE 50%, Phase B

Ramp from	277.00	V
Ramp to	130.00	V

Tnominal (ms)	Tactual (ms)	Tdev (ms)
167	176.1	9.10
167	183.7	16.70
167	181.8	14.80
167	183.8	16.80
167	183.8	16.80
Avg:	**181.84**	**msec**

UNDERVOLTAGE 88%,Three Phase

Ramp from	277.00	V
Ramp to	238.00	V

Tnominal (ms)	Tactual (ms)	Tdev (ms)
2000	2009.60	9.60
2000	2016.70	16.70
2000	2016.90	16.90
2000	2016.80	16.80
2000	2014.90	14.90
Avg:	**2014.98**	**msec**

UNDERVOLTAGE 88%, Phase C

Ramp from	277.00	V
Ramp to	238.00	V

Tnominal (ms)	Tactual (ms)	Tdev (ms)
2000	2008.30	8.30
2000	2016.70	16.70
2000	2016.90	16.90
2000	2016.90	16.90
2000	2017.00	17.00
Avg:	**2015.16**	**msec**

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Table 4 - Over-voltage Time Test Results

SUMMARY OF IEEE 1547OVERVOLTAGE TIME TESTS

OVERVOLTAGE 110%, Three Phase

Ramp from 277.00
Ramp to 310.00

Tnominal (ms)	Tactual (ms)	Tdev (ms)
1000	1009.7	9.70
1000	1017.0	17.00
1000	1015.0	15.00
1000	1000.3	0.30
1000	1000.4	0.40

Avg: 1008.48 msec

OVERVOLTAGE 110%, Phase A

Ramp from 277.00
Ramp to 310.00

Tnominal (ms)	Tactual (ms)	Tdev (ms)
1000	1008.8	8.80
1000	1016.8	16.80
1000	1017.1	17.10
1000	1017.1	17.10
1000	1016.9	16.90

Avg: 1015.34 msec

OVERVOLTAGE 120%, Three Phase

Ramp from 277.00
Ramp to 340.00

Tnominal (ms)	Tactual (ms)	Tdev (ms)
167	175.4	8.40
167	183.6	16.60
167	183.9	16.90
167	183.8	16.80
167	181.8	14.80

Avg: 181.70 msec

OVERVOLTAGE 120%, Phase B

Ramp from 277.00
Ramp to 340.00

Tnominal (ms)	Tactual (ms)	Tdev (ms)
167	175.0	8.00
167	166.9	-0.10
167	183.9	16.90
167	183.8	16.80
167	183.8	16.80

Avg: 178.68 msec

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Table 5 - Over-frequency Magnitude Test Results

SUMMARY OF IEEE 1547 OVERFREQUENCY MAGNITUDE TESTS

OVERFREQUENCY 60.5 Hz

dV/dT=	10.00	mHz/s
dT per step	1.00	s

Nominal (Hz)	Actual (Hz)	Deviation (Hz)
60.50	60.51	0.01
60.50	60.51	0.01
60.50	60.51	0.01
60.50	60.51	0.01
60.50	60.51	0.01

Avg: 60.51 Hz

Table 6 - Under-frequency Magnitude Test Results

SUMMARY OF IEEE 1547 UNDERFREQUENCY MAGNITUDE TESTS

UNDERFREQUENCY 57 Hz

dV/dT=	10.00	mHz/s
dT per step	1.00	s

Nominal (Hz)	Actual (Hz)	Deviation (Hz)
57.00	57.00	0.00
57.00	57.00	0.00
57.00	57.00	0.00
57.00	57.00	0.00
57.00	57.00	0.00

Avg: 57.00 Hz

UNDERFREQUENCY 59.3 Hz

dV/dT=	2.00	mHz/s
dT per step	1.00	s

Nominal (Hz)	Actual (Hz)	Deviation (Hz)
59.30	59.30	0.00
59.30	59.30	0.00
59.30	59.30	0.00
59.30	59.30	0.00
59.30	59.30	0.00

Avg: 59.30 Hz

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Table 7 - Over-frequency Time Test Results

SUMMARY OF IEEE 1547 OVERFREQUENCY TIME TESTS

OVERFREQUENCY 60.5 Hz_TEST # 1

Ramp from 60.00 Hz

Ramp to 60.55 Hz

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
167.00	274.20	107.20
167.00	263.00	96.00
167.00	265.00	98.00
167.00	265.00	98.00
167.00	263.10	96.10

Avg: 266.06 msec

OVERFREQUENCY 60.5 Hz_TEST # 2

Ramp from 60.45 Hz

Ramp to 60.55 Hz

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
167.00	203.00	36.00
167.00	190.10	23.10
167.00	206.70	39.70
167.00	206.80	39.80
167.00	206.70	39.70

Avg: 202.66 msec

OVERFREQUENCY 60.5 Hz_TEST # 3

Ramp from 60.40 Hz

Ramp to 60.70 Hz

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
167.00	190.40	23.40
167.00	181.70	14.70
167.00	181.80	14.80
167.00	179.50	12.50
167.00	181.80	14.80

Avg: 183.04 msec

OVERFREQUENCY 60.5 Hz_TEST # 4

Ramp from 60.00 Hz

Ramp to 60.55 Hz

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
100.00	207.80	107.80
100.00	198.40	98.40
100.00	165.10	65.10
100.00	165.10	65.10
100.00	196.40	96.40

Avg: 186.56 msec

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Table 8 - Under-frequency Time Test Results

SUMMARY OF IEEE 1547 UNDERFREQUENCY TIME TESTS

UNDERFREQUENCY 59.3 Hz

Ramp from	60.00	Hz
Ramp to	59.00	Hz

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
1000.00	1077.20	77.20
1000.00	1066.50	66.50
1000.00	1068.70	68.70
1000.00	1068.70	68.70
1000.00	1066.60	66.60

Avg: 1069.54 msec

UNDERFREQUENCY 57 Hz

Ramp from	60.45	mHz/s
Ramp to	60.55	s

Nominal Time (ms)	Actual Time (ms)	Deviation (ms)
167.00	255.60	88.60
167.00	250.40	83.40
167.00	248.40	81.40
167.00	250.40	83.40
167.00	250.60	83.60

Avg: 251.08 msec

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4.2 Appendix 2: List of DSP Controller settings in EMS (Section 3.9)

Table 9 - Static Switch DSP Controller Settings

Control Constants

Type	Event	Value	unit
Filter time constant	27R (Dead Bus Relay)	1.00	sec
Timeout	1547 voltage deep sag	0.17	sec
Timeout	1547 voltage shallow sag	2.00	sec
Timeout	1547 voltage swell	1.00	sec
Timeout	1547 voltage over	0.17	sec
Timeout	1547 frequency high swing	0.17	sec
Timeout	1547 frequency low droop	1.00	sec
Timeout	1547 frequency critically low	0.17	sec
Time delay	Reverse power test delay	2.00	sec
Time delay	Reverse power voltage fault time delay	0.50	sec
CBEMA time constant	#1, instantaneous voltage	0.02	sec
CBEMA time constant	#2, instantaneous voltage	0.00	sec
CBEMA time constant	#3,filtered med speed voltage	0.20	sec
CBEMA time constant	#4,filtered med speed voltage	0.50	sec
CBEMA time constant	#5,filtered int speed voltage	0.50	sec
CBEMA time constant	#6,filtered int speed voltage	0.50	sec
CBEMA time constant	#7,filtered low speed voltage	10.00	sec

Setpoints

Type	Event	Value	unit
Event 25	Sync voltage HH	305.00	V
Event 25	Sync Voltage LL	250.00	V
Event 25	Sync voltage nominal	277.00	V
Event 25	Sync frequency HH	61.00	Hz
Event 25	Sync Frequency LL	59.00	Hz
Event 25	Sync frequency nominal	60.00	Hz
Event 25	Sync Phase HH	10.00	degrees
Event 25	Sync Phase LL	-10.00	degrees
Event 25	Time advance	0.00	sec

State Controller

Timer	Value	unit
Time disconnect	1	sec
Restoration 1547	2	sec
Restoration PQ	300	sec

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Table 10 - Static Switch DSP Controller Parameters

DSP Controller - Parameters

Event Levels

Filtered

Event	Value	unit
27R (rms dead DG bus)	15	V
AC Remote Power per Phase	3.333	kW
1547 voltage deep sag	50	% of rated
1547 voltage shallow sag	88	% of rated
1547 voltage swell	110	% of rated
1547 voltage over	120	% of rated
1547 frequency high swing	60.50	Hz
1547 frequency low droop	59.30	Hz
1547 frequency critically low	57.00	Hz
RMS CBEMA voltage #3	194	V
RMS CBEMA voltage #4	332	V
RMS CBEMA voltage #5	222	V
RMS CBEMA voltage #6	332	V
RMS CBEMA voltage #7	249	V

Instantaneous

Event	Value	unit
Instantaneous CBEMA voltage #1	196	V
Instantaneous CBEMA voltage #2	548	V

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4.3 Appendix 3: Synchronization Tests (Section 3.2) plots

In this appendix, a complete set of waveforms for the synchronization tests that were performed in Section 3.2 is presented. Results in this appendix include all the cases that are described in Table 1 (Section 3.2.3).

The results for each of the 12 tests include three figures:

1) Phase A Voltage Across Switch (Beat Voltage) before closing
2) Response to a “Manual Opening” of the switch
3) Response to a “Synchronized Closing” of the switch

For figures 2) and 3), the following channels represent:

Channel 1: Phase A Switch Current (20 Amps per division)

Channel 2: Phase B Switch Current (20 Amps per division)

Channel 3: Phase C Switch Current (20 Amps per division)

For figures 2) and 3), the vertical arrow in the time axis represents the transition of the switch command from open-to-close or close-to-open (the switch command was used to trigger the oscilloscope plots).

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Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Summary of CERTS Microgrid Static Switch Power Quality Tests at AEP Dolan, CERTS Microgrid Static Switch Testing

APPENDIX G

Prepared For:
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Public Interest Energy Research Program

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CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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AEP DTC Proposed Test Plan – CERTS Micro-grid Static Switch

Project Engineer: David A. Klapp

Date: March 3, 2006

Background

The Static Switch (SS) will be the power gateway between the protected and unprotected portions of the Microgrid Test Bed. This gateway is required to incorporate many different functions in order that the Microgrid will seamlessly transition from grid connection to grid disconnection for certain reasons. These reasons include, but aren't limited to, Power Quality Events and Power Export to the utility grid. This gateway must also handle the seamless reconnection of the Microgrid following any of these events. Originally, it was discussed that the SS would meet IEEE Standard 1547 for interconnecting DR with electric power systems. Since these tests are not trying to qualify the SS at this time, some portions of testing will be left for a later date (i.e. Thermal, EMI, Harmonics, etc). Therefore, DTC testing will focus on how the SS disconnects and reconnects to the utility grid. Although the SS function may not completely fit into IEEE Standard 1547, it does not cause any problems for the intended testing of the Microgrid, however testing of the SS needs to incorporate this knowledge. A brief example of the differences and a suggested test plan at AEP's DTC follows.

From a protection point of view the SS can be setup to meet the IEEE 1547 criteria or more stringent criteria, such as ITIC, CBEMA, etc. The deviation from standard deals primarily with reconnection to the utility grid. Briefly, IEEE 1547 has windows for frequency difference, voltage difference, and phase angle difference between the two electrical buses. It is understood that there are possible operating points under which the Microgrid would not reconnect to the utility grid, if the SS strictly followed IEEE Standard 1547. Therefore, the SS will have somewhat looser criteria under which it is acceptable to reconnect to the utility grid and will be tested in the Microgrid Test Bed to see what the results show.

1.0 Proposed DTC Test Plan

The proposed DTC tests are designed to test the functionality of the protection portion of the SS. For example, does the switch open when out of voltage, current, and frequency criteria, etc. From discussions with Ed, Northern Power Systems (NPS) has put together a good basic test sequence for SS functionality. This is appropriate, as any system debugging will be easiest to perform at the NPS site. Thus, more advanced testing of the SS will be performed at the DTC, primarily dealing with power quality events. Examples would be sags, swells, switching transient events, etc. It is our intention to treat this SS as a protection relay and test it similarly. To achieve this, we will inject various stimuli and capture the SS's response. This stimulus is best kept low power in nature as larger power may cause damage to the SS. It is also appropriate for the team to agree on what the stimulus should be prior to testing. Currently, AEP budgeted/scheduled 10 days to setup and test the SS at the DTC site and we must make the most of it without delaying the project schedule.

Originally, we discussed testing the SS with high power stimuli, such as fault currents. Because the SS is likely to be the most critical path device during Microgrid installation, it would cause large delays in the project schedule if damage to the SS occurred during DTC tests. Also, there is adequate secondary protection within the Walnut Test Site, so that this high power testing may take place on site. We believe power fault tests would be more appropriately tested once in the Microgrid. However, we would like to simulate faults at the DTC site both in the utility system and faults within the Microgrid to determine if the SS reacts properly. This testing would inject voltage and current signals into the sensing portion of the SS and capture its response.

Based on the above information, we recommend the following tests take place at the DTC site.

- Ramp testing of Over/Under Voltage, and Over/Under Frequency protection. This protection is part of IEEE Standard 1547, which may be somewhat difficult for NPS to complete. Currently, NPS is performing the step technique portion of this test. The ramp test technique will complete the test requirements.
- Synchronization to the utility grid. As mentioned, above, the criterion for synchronization is likely to be different to IEEE Standard 1547; however, it should be tested to the CERTS Microgrid criteria set-points, i.e., Frequency, Voltage, and Phase Angle. Currently, NPS is testing the SS with an inverter source, mimicking the Tecogen generator devices. This testing needs further verification to demonstrate that the SS alone meets its design criteria.
- Power Quality Events.
    - Sags/Swells in Voltage, reflecting ITIC, CBEMA, and/or SEMI
    - Sags/Swells in Frequency
    - Switching/Line Transients
    - Simulated Utility/Microgrid Faults

We also recommend the following tests take place at NPS.

- Open phase combinations

  We recommend this test be done as this can be a common occurrence in the utility system. This testing can be satisfied, if the minimum import relay is tested successfully.

- SCR failure to "Open"

  We recommend this test be done to satisfy concerns that the SS may be unable to "Open" under asymmetrical faults. This testing can take place at either NPS or DTC; however, AEP will need more detail of this functionality if done here.

Most, if not all, of this testing can be accomplished with the capabilities of a single set of test equipment. This includes a 480volts 3-phase variac, an Elgar SW 5250A Smart Wave, an Elgar SS-66 3-phase power supply, a Manta MTS 1710 relay test set, and a Wavetek Datron Model 195 Universal Waveform Generator.

2.0 DTC Test Details

For all of the following tests the SCR switches will be disconnected from the circuit. This is to prevent any stress on the SCR switches and damage to any test equipment. The stimuli will be injected into the sensing PTs and CTs with the resultant response measured on the signal that "opens" and "closes" the SCR switches.

1) **Ramp testing of Over/Under Voltage and Over/Under Frequency protection.** This testing is used to determine if the SS meets the design criteria for voltage and frequency protection. Specifically, ramping the voltage and frequency will allow accurate measurement of where the trip points are set. This test setup will require only the Manta 1710 Relay Test Set (Manta) and shown in Figure 1. The measurement PTs of the SS will be disconnected and the Manta connected in their place. The Manta will be configured to deliver the same stimuli to both sides of the switch. These stimuli will be the ramping functions as laid out in IEEE Standard 1547.1. Individual tests for voltage and frequency will be performed. The SS will be energized to nominal conditions and then ramped from them. The magnitude of the ramp at the command to "open" the SS will be recorded for 5 test runs. For voltage each phase will be tested, individually, as well as all three phases together. For frequency all three phases will be tested together.

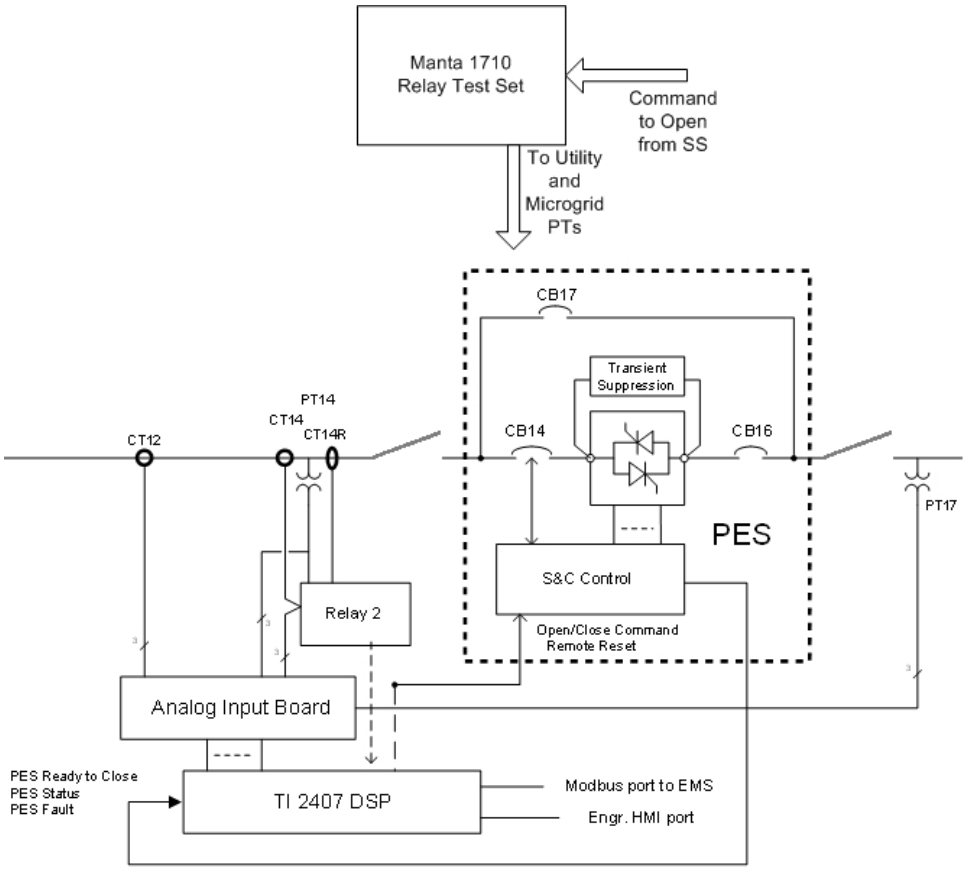

Figure 1: Ramp Test Setup for Over/Under Voltage & Over/Under Frequency.

2) **Synchronization to the utility grid.** This testing is used to determine if the SS meets the CERTS Microgrid criteria for synchronizing to the utility grid. Specifically, this test will allow us to test the each condition for acceptable synchronization, individually, instead of as a combined process. This test setup will require both the Manta 1710 Relay Test Set and a 3-phase variac, as shown in Figure 2. The Manta will provide stimulus to the Microgrid side of the SS. The 3-phase variac will connect to the Utility side of the SS and will primarily correct the utility voltage, if other than nominal.
   a. For testing the synchronization of voltage, the SS will be energized on the utility side through the variac to nominal voltage. The Manta will energize the Microgrid side of the SS with a frequency and phase locked voltage. This voltage magnitude will be ramped from out of tolerance to in to tolerance. The magnitude of the ramp at the command to "close" the SS will be recorded for 5 test runs. Each phase will be tested, individually, as well as all three phases together.
   b. For testing the synchronization of frequency and phase angle, the SS will be energized on the utility side through the variac to nominal voltage. The Manta will energize the Microgrid side of the SS with the nominal voltage and a frequency that is outside the synchronization criteria. The frequency will then be ramped from out of tolerance and

in to tolerance. The magnitude of the ramp and the phase angle at the command to "close" the SS will be recorded for 5 test runs. All three phases will be tested together.

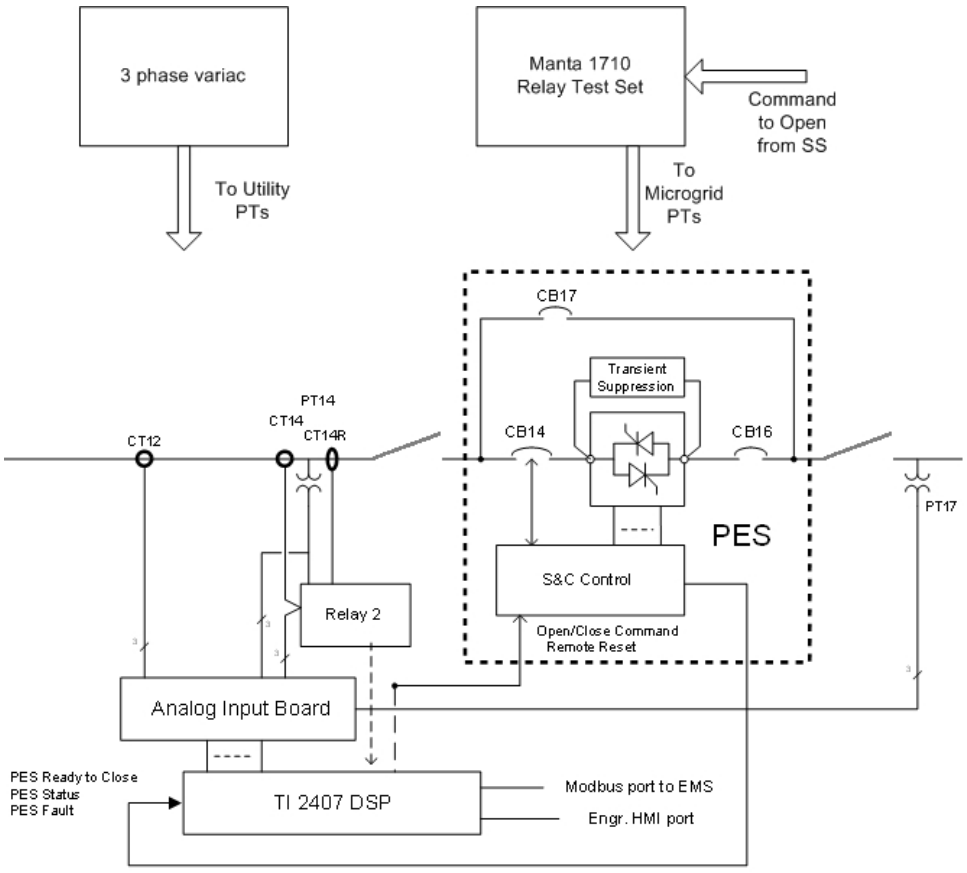

Figure 2: Test Setup for Synchronization to the utility grid.

3) **Power Quality Events.** This testing is used to determine how the SS will respond to power quality events within the utility system. The test setup for both sags and swells in voltage and frequency, as well as switching and line transients will be similar to the voltage and frequency ramp testing, described above. This will require only the Manta 1710 Relay Test Set. The measurement PTs of the SS will be disconnected and the Manta connected in their place. The Manta will be configured to deliver the same stimuli to both sides of the SS. These stimuli will need to be decided, prior to testing. A recommendation follows:

   a. Voltage sags and swells for at least 7 points on the ITIC or CBEMA curve
   b. If desired, voltage sags at 3 points for the SEMIF47 curve.
   c. Frequency sags and swells for at least 3 points to meet IEEE Standard 1547.

d. At least 6 switching and line transients to be decided upon.

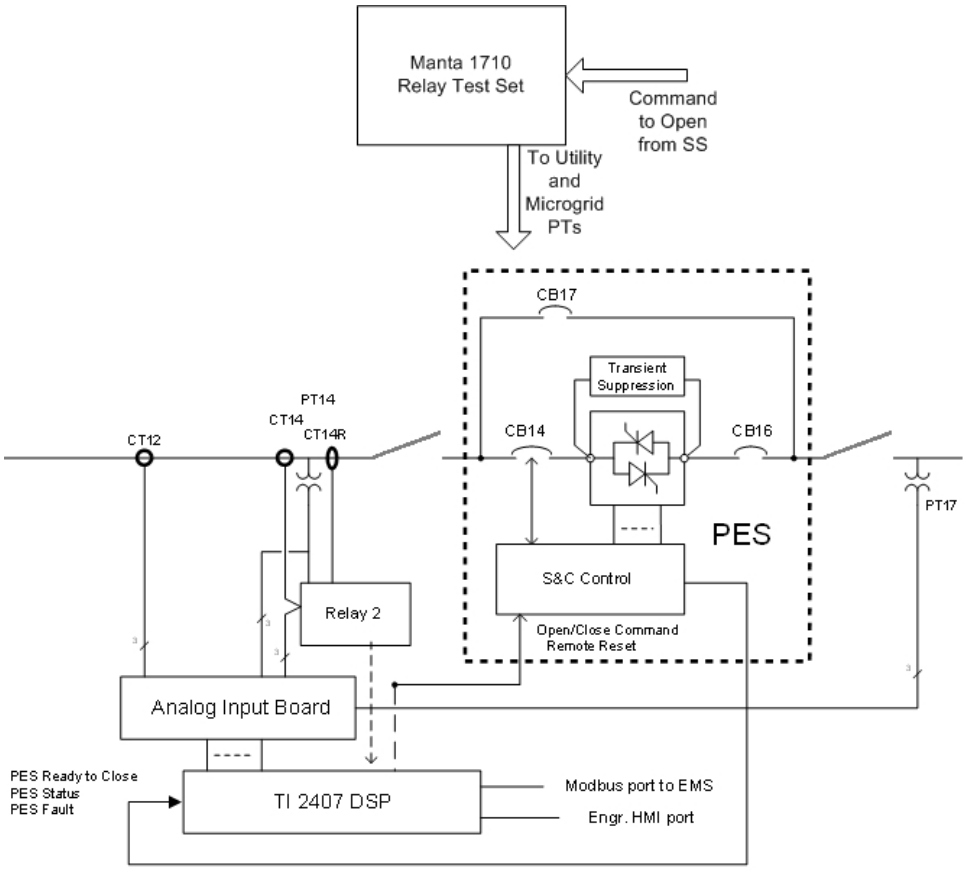

Figure 3: Test Setup for Power Quality Events.

4) **Utility and Microgrid Faults.** Test setup for simulated Utility and Microgrid Faults will be similar to the sag and swell testing above, except the measurement CTs of the SS will also be disconnected and the Manta connected in their place. This test setup is shown in Figure 4. The Manta will be configured to deliver the same voltage stimuli to both sides of the SS and current stimuli to the utility side. The stimulus will match what the anticipated faults will look like within the Microgrid. Testing of each type of fault, as well as three different levels of fault currents will be performed. For simulating the utility faults, data from past test and

the simulation of the Microgrid Test bed will be used to design the stimuli. This test will take into account the effect of the Reverse power relay.

The SS will be energized to nominal conditions and then the power quality event will be triggered. The event details (type, magnitude, duration, etc.) and the response of the SS will be recorded for each of the 5 test runs.

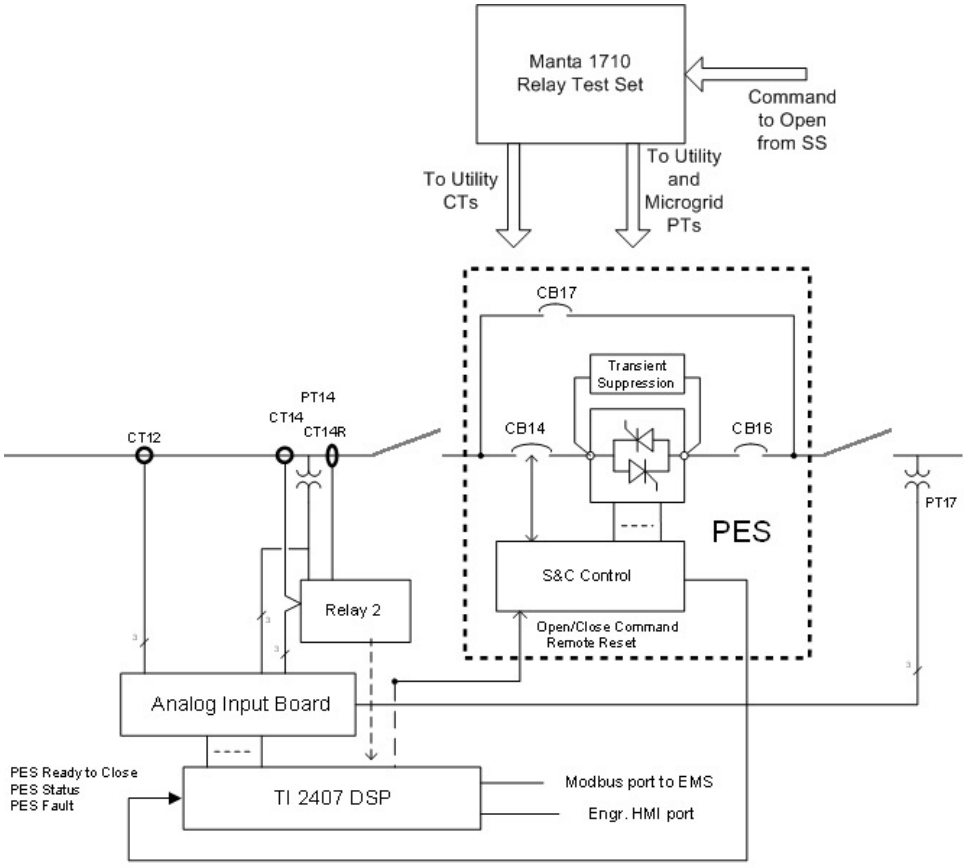

Figure 4: Test Setup for Utility and Microgrid Faults.

SUMMARY OF CERTS MICROGRID STATIC SWITCH POWER QUALITY TESTS @ AEP DOLAN
Notes: AEP EMS is setup with only PQ Events Enableded, The SS Parameters for CBEMA#7 Time was changed to 3.0223 and CBEMA#2 Voltage was changed to 470 Volts

The Manta has been setup to deliver secondary voltages and currents to the DSP and Relay 2

CBEMA/ITIC/SEMI VOLTAGE SAG/SWELL TESTS (AVERAGES FROM 5 TRIES)					
Test	**Voltage**	**Cycles**	**Average Trip Time (ms)**	**Standard Deviation (ms)**	**Pass / Fail**
Undervoltage 0%, Three Phase	0.0 Peak	0.5	N/A	N/A	Pass
Undervoltage 0%, Three Phase	0.0 Peak	2	N/A	N/A	Fail
Undervoltage 30%, Three Phase	117.5 Peak	5	N/A	N/A	Fail
Undervoltage 67%, Three Phase	262.5 Peak	15	0.2084	0.0004	Pass
Undervoltage 73%, Three Phase	286.0 Peak	3	N/A	N/A	Pass
Undervoltage 77%, Three Phase	213.3 RMS	35	0.4582	0.0008	Pass
Undervoltage 83%, Three Phase	229.9 RMS	45	N/A	N/A	Pass
Overvoltage 107%, Three Phase	296.4 RMS	60	N/A	N/A	Pass
Overvoltage 113%, Three Phase	313.0 RMS	45	N/A	N/A	Fail
Overvoltage 117%, Three Phase	458.3 Peak	20	N/A	N/A	Pass
Overvoltage 123%, Three Phase	481.8 Peak	10	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	0.5	N/A	N/A	Pass
Undervoltage 45%, Single Phase B	176.3 Peak	20	0.1415	0.0006	Pass
Undervoltage 67%, Single Phase C	185.6 RMS	40	0.1848	0.0004	Pass
Undervoltage 77%, Single Phase A	213.3 RMS	45	0.4376	0.0004	Pass
Undervoltage 83%, Single Phase B	229.9 RMS	70	N/A	N/A	Pass
Undervoltage 0%, Single Phase A	0.0 Peak	2	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	3	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	4	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	5	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	6	N/A	N/A	Fail
Undervoltage 0%, Single Phase A	0.0 Peak	7	0.1077	0.0006	Pass
Undervoltage 0%, Single Phase A	0.0 Peak	8	0.1081	0.0010	Pass
Undervoltage 0%, Single Phase A	0.0 Peak	9	0.1082	0.0004	Pass
Undervoltage 0%, Single Phase A	0.0 Peak	10	0.1079	0.0008	Pass
Overvoltage 120%, Three Phase	470.1 Peak	20	N/A	N/A	Fail

SUMMARY OF CERTS MICROGRID STATIC SWITCH POWER QUALITY TESTS @ AEP DOLAN
Notes: AEP EMS is setup with only PQ Events Enableded, The SS Parameters for CBEMA#7 Time was changed to 3.0223 and CBEMA#2 Voltage was changed to 470 Volts

The Manta has been setup to deliver secondary voltages and currents to the DSP and Relay 2

Overvoltage 121%, Three Phase	474.0 Peak	20	N/A	N/A	Fail
Overvoltage 122%, Three Phase	477.9 Peak	20	N/A	N/A	Fail
Overvoltage 123%, Three Phase	481.8 Peak	20	N/A	N/A	Fail
Overvoltage 124%, Three Phase	485.8 Peak	20	N/A	N/A	Fail
Overvoltage 125%, Three Phase	489.7 Peak	20	N/A	N/A	Fail
Overvoltage 126%, Three Phase	493.6 Peak	20	N/A	N/A	Fail
Overvoltage 127%, Three Phase	497.5 Peak	20	N/A	N/A	Fail
Overvoltage 128%, Three Phase	501.4 Peak	20	0.3248	0.0008	Pass
Overvoltage 129%, Three Phase	505.3 Peak	20	0.3253	0.0004	Pass
Overvoltage 130%, Three Phase	509.3 Peak	20	0.3083	0.0008	Pass

Table 1: Voltage Sag/Swell Test Results

SIMULATED FAULT TESTS (AVERAGES FROM 5 TRIES)					
Test	**Current**	**Cycles**	**Average Trip Time (ms)**	**Standard Deviation (ms)**	**Pass / Fail**
Phase A to B, Bolted Fault		300	0.0231	0.0002	Pass
Phase A to Ground, Bolted Fault		300	0.0214	0.0005	Pass
Phase A to B to Ground, Bolted Fault		300	0.0224	0.0012	Pass
Phase A to B to C to Ground, Bolted Fault		300	0.0212	0.0010	Pass
Phase A to B to Ground, High Impedance Fault		300	0.0235	0.0006	Pass
Phase A to B to C to Ground, High Impedance Fault		300	0.0214	0.0007	Pass

Table 2: Simulated Fault Test Results

OPEN PHASE TESTS (AVERAGES FROM 5 TRIES)					
Test		**Cycles**	**Average Trip Time (ms)**	**Standard Deviation (ms)**	**Pass / Fail**
Open Phase A in Delta-Delta Feed		300	0.1582	0.0006	Pass
Open Phase A in Wye Secondary Feed		300	0.1074	0.0005	Pass
Open Phase A and B in Wye Secondary Feed		300	0.1075	0.0008	Pass

Table 3: Open Phase Test Results

SUMMARY OF CERTS MICROGRID STATIC SWITCH POWER QUALITY TESTS @ AEP DOLAN
Notes: AEP EMS is setup with only PQ Events Enableded, The SS Parameters for CBEMA#7 Time was changed to 3.0223 and CBEMA#2 Voltage was changed to 470 Volts

The Manta has been setup to deliver secondary voltages and currents to the DSP and Relay 2

VOLTAGE TRANSIENT/DISTORTION TESTS (AVERAGES FROM 5 TRIES)					
Test	**Cycles**	**Trip**	**Average Trip Time (ms)**	**Standard Deviation (ms)**	**Pass / Fail**
Lightning Surge 1.2-50us	<1	No	N/A	N/A	N/A
900 MVar Capacitor Switch	<1	No	N/A	N/A	N/A
Motor Start Non-CBEMA/ITIC/SEMI Violation	40	Yes	0.4749	0.0007	N/A
Motor Start CBEMA/ITIC/SEMI Violation	40	Yes	0.1918	0.0010	Pass
Six Pulse Bridge Load	300	No	N/A	N/A	N/A
Harmonic Distortion	240	No	N/A	N/A	N/A

Table 4: Voltage Transient/Distortion Test Reults

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

UNDERVOLTAGE SAG 0%, Three Phase, 0.5 Cycle

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Three Phase, 2 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 30%, Three Phase, 5 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 67%, Three Phase, 15 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.2085	Pass
Test 2	Trip Open	Trip Open	0.208	Pass
Test 3	Trip Open	Trip Open	0.2085	Pass
Test 4	Trip Open	Trip Open	0.208	Pass
Test 5	Trip Open	Trip Open	0.209	Pass

AVERAGE TRIP TIME 0.2084 **ST DEV** 0.0004

UNDERVOLTAGE SAG 73%, Three Phase, 3 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain	Remain	N/A	Pass

UNDERVOLTAGE SAG 77%, Three Phase, 35 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.4585	Pass

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

	Online	Online		
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

Test 2	Trip Open	Trip Open	0.4575	Pass
Test 3	Trip Open	Trip Open	0.4575	Pass
Test 4	Trip Open	Trip Open	0.4595	Pass
Test 5	Trip Open	Trip Open	0.458	Pass

AVERAGE TRIP TIME 0.4582 **ST DEV** 0.0008

UNDERVOLTAGE SAG 83%, Three Phase, 45 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SURGE 107%, Three Phase, 60 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SURGE 113%, Three Phase, 45 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail

OVERVOLTAGE SAG 117%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 123%, Three Phase, 10 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 0.5 Cycle

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 45%, Single Phase B, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.142	Pass
Test 2	Trip Open	Trip Open	0.142	Pass
Test 3	Trip Open	Trip Open	0.1405	Pass
Test 4	Trip Open	Trip Open	0.1415	Pass
Test 5	Trip Open	Trip Open	0.1415	Pass

UNDERVOLTAGE SAG 67%, Single Phase C, 40 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.18425	Pass
Test 2	Trip Open	Trip Open	0.185	Pass
Test 3	Trip Open	Trip Open	0.185	Pass
Test 4	Trip Open	Trip Open	0.1845	Pass
Test 5	Trip Open	Trip Open	0.185	Pass

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

AVERAGE TRIP TIME 0.1415 **ST DEV** 0.0006

UNDERVOLTAGE SAG 77%, Single Phase A, 45 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.4375	Pass
Test 2	Trip Open	Trip Open	0.438	Pass
Test 3	Trip Open	Trip Open	0.437	Pass
Test 4	Trip Open	Trip Open	0.4375	Pass
Test 5	Trip Open	Trip Open	0.438	Pass

AVERAGE TRIP TIME 0.4376 **ST DEV** 0.0004

AVERAGE TRIP TIME 0.1848 **ST DEV** 0.0004

UNDERVOLTAGE SAG 83%, Single Phase B, 70 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Remain Online	Remain Online	N/A	Pass
Test 2	Remain Online	Remain Online	N/A	Pass
Test 3	Remain Online	Remain Online	N/A	Pass
Test 4	Remain Online	Remain Online	N/A	Pass
Test 5	Remain Online	Remain Online	N/A	Pass

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 2 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 3 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 4 Cycles

UNDERVOLTAGE SAG 0%, Single Phase A, 5 Cycles

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 6 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

UNDERVOLTAGE SAG 0%, Single Phase A, 7 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.108	Pass
Test 2	Trip Open	Trip Open	0.1075	Pass
Test 3	Trip Open	Trip Open	0.107	Pass
Test 4	Trip Open	Trip Open	0.1085	Pass
Test 5	Trip Open	Trip Open	0.1075	Pass

AVERAGE TRIP TIME 0.1077 **ST DEV** 0.0006

UNDERVOLTAGE SAG 0%, Single Phase A, 8 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.108	Pass

UNDERVOLTAGE SAG 0%, Single Phase A, 9 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.108	Pass

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

Test 2	Trip Open	Trip Open	0.107	Pass
Test 3	Trip Open	Trip Open	0.1085	Pass
Test 4	Trip Open	Trip Open	0.1075	Pass
Test 5	Trip Open	Trip Open	0.1095	Pass

AVERAGE TRIP TIME 0.1081 **ST DEV** 0.0010

Test 2	Trip Open	Trip Open	0.108	Pass
Test 3	Trip Open	Trip Open	0.108	Pass
Test 4	Trip Open	Trip Open	0.108	Pass
Test 5	Trip Open	Trip Open	0.109	Pass

AVERAGE TRIP TIME 0.1082 **ST DEV** 0.0004

UNDERVOLTAGE SAG 0%, Single Phase A, 10 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.1085	Pass
Test 2	Trip Open	Trip Open	0.109	Pass
Test 3	Trip Open	Trip Open	0.1075	Pass
Test 4	Trip Open	Trip Open	0.107	Pass
Test 5	Trip Open	Trip Open	0.1075	Pass

AVERAGE TRIP TIME 0.1079 **ST DEV** 0.0008

OVERVOLTAGE SAG 120%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 121%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain	N/A	Fail

OVERVOLTAGE SAG 122%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain	N/A	Fail

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

Test 5	Trip Open	Online Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

Test 5	Trip Open	Online Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 123%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 124%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 125%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

OVERVOLTAGE SAG 126%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

SUMMARY OF CBEMA/ITIC/SEMI VOLTAGE SAG/SURGE TESTS

AVERAGE TRIP TIME N/A **ST DEV** N/A

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 127%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Remain Online	N/A	Fail
Test 2	Trip Open	Remain Online	N/A	Fail
Test 3	Trip Open	Remain Online	N/A	Fail
Test 4	Trip Open	Remain Online	N/A	Fail
Test 5	Trip Open	Remain Online	N/A	Fail

AVERAGE TRIP TIME N/A **ST DEV** N/A

OVERVOLTAGE SAG 128%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.325	Pass
Test 2	Trip Open	Trip Open	0.326	Pass
Test 3	Trip Open	Trip Open	0.3245	Pass
Test 4	Trip Open	Trip Open	0.3245	Pass
Test 5	Trip Open	Trip Open	0.324	Pass

AVERAGE TRIP TIME 0.3248 **ST DEV** 0.0008

OVERVOLTAGE SAG 129%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.3255	Pass
Test 2	Trip Open	Trip Open	0.3255	Pass
Test 3	Trip Open	Trip Open	0.3245	Pass
Test 4	Trip Open	Trip Open	0.3255	Pass
Test 5	Trip Open	Trip Open	0.3255	Pass

AVERAGE TRIP TIME 0.3253 **ST DEV** 0.0004

OVERVOLTAGE SAG 130%, Three Phase, 20 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.3075	Pass
Test 2	Trip Open	Trip Open	0.3075	Pass
Test 3	Trip Open	Trip Open	0.309	Pass
Test 4	Trip Open	Trip Open	0.309	Pass
Test 5	Trip Open	Trip Open	0.3085	Pass

AVERAGE TRIP TIME 0.3083 **ST DEV** 0.0008

Table 5: Detailed Voltage Sag/Swell Test Results

SUMMARY OF SIMULATED FAULT TESTS

PHASE A TO B, BOLTED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.0235	Pass
Test 2	Trip Open	Trip Open	0.023	Pass
Test 3	Trip Open	Trip Open	0.023	Pass
Test 4	Trip Open	Trip Open	0.023	Pass
Test 5	Trip Open	Trip Open	0.023	Pass

AVERAGE TRIP TIME 0.0231 **ST DEV** 0.0002

PHASE A TO GROUND, BOLTED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.022	Pass
Test 2	Trip Open	Trip Open	0.021	Pass
Test 3	Trip Open	Trip Open	0.021	Pass
Test 4	Trip Open	Trip Open	0.022	Pass
Test 5	Trip Open	Trip Open	0.021	Pass

AVERAGE TRIP TIME 0.0214 **ST DEV** 0.0005

PHASE A TO B TO GROUND, BOLTED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.021	Pass
Test 2	Trip Open	Trip Open	0.023	Pass
Test 3	Trip Open	Trip Open	0.024	Pass
Test 4	Trip Open	Trip Open	0.0215	Pass
Test 5	Trip Open	Trip Open	0.0225	Pass

AVERAGE TRIP TIME 0.0224 **ST DEV** 0.0012

PHASE A TO B TO C TO GROUND, BOLTED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.0205	Pass
Test 2	Trip Open	Trip Open	0.02	Pass
Test 3	Trip Open	Trip Open	0.0225	Pass
Test 4	Trip Open	Trip Open	0.022	Pass
Test 5	Trip Open	Trip Open	0.021	Pass

AVERAGE TRIP TIME 0.0212 **ST DEV** 0.0010

PHASE A TO B TO GROUND, HIGH IMPEDANCE, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.0235	Pass
Test 2	Trip Open	Trip Open	0.024	Pass
Test 3	Trip Open	Trip Open	0.024	Pass
Test 4	Trip Open	Trip Open	0.0235	Pass
Test 5	Trip Open	Trip Open	0.0225	Pass

AVERAGE TRIP TIME 0.0235 **ST DEV** 0.0006

PHASE A TO B TO C TO GROUND, HIGH IMPEDANCE, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.0205	Pass
Test 2	Trip Open	Trip Open	0.022	Pass
Test 3	Trip Open	Trip Open	0.021	Pass
Test 4	Trip Open	Trip Open	0.0215	Pass
Test 5	Trip Open	Trip Open	0.022	Pass

AVERAGE TRIP TIME 0.0214 **ST DEV** 0.0007

SUMMARY OF OPEN PHASE TESTS

OPEN PHASE A IN DELTA-DELTA FEED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.158	Pass
Test 2	Trip Open	Trip Open	0.1585	Pass
Test 3	Trip Open	Trip Open	0.159	Pass
Test 4	Trip Open	Trip Open	0.1575	Pass
Test 5	Trip Open	Trip Open	0.158	Pass

AVERAGE TRIP TIME 0.1582 **ST DEV** 0.0006

OPEN PHASE A IN WYE SECONDARY FEED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.107	Pass
Test 2	Trip Open	Trip Open	0.108	Pass
Test 3	Trip Open	Trip Open	0.108	Pass
Test 4	Trip Open	Trip Open	0.107	Pass
Test 5	Trip Open	Trip Open	0.107	Pass

AVERAGE TRIP TIME 0.1074 **ST DEV** 0.0005

PHASE A AND B IN WYE SECONDARY FEED, 300 Cycles

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.107	Pass
Test 2	Trip Open	Trip Open	0.1085	Pass
Test 3	Trip Open	Trip Open	0.108	Pass
Test 4	Trip Open	Trip Open	0.1075	Pass
Test 5	Trip Open	Trip Open	0.1065	Pass

AVERAGE TRIP TIME 0.1075 **ST DEV** 0.0008

Table 6: Detailed Simulated Fault Test Results

SUMMARY OF SIMULATED FAULT TESTS

LIGHTNING SURGE 1.2-50us

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	???	Remain Online	N/A	N/A
Test 2	???	Remain Online	N/A	N/A
Test 3	???	Remain Online	N/A	N/A
Test 4	???	Remain Online	N/A	N/A
Test 5	???	Remain Online	N/A	N/A

AVERAGE TRIP TIME N/A **ST DEV** N/A

900 MVAR CAPACITOR SWITCH

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	???	Remain Online	N/A	N/A
Test 2	???	Remain Online	N/A	N/A
Test 3	???	Remain Online	N/A	N/A
Test 4	???	Remain Online	N/A	N/A
Test 5	???	Remain Online	N/A	N/A

AVERAGE TRIP TIME N/A **ST DEV** N/A

MOTOR START NON-CBEMA/ITIC/SEMI VIOLATION

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	???	Trip Open	0.476	Pass
Test 2	???	Trip Open	0.475	Pass
Test 3	???	Trip Open	0.4745	Pass
Test 4	???	Trip Open	0.474	Pass
Test 5	???	Trip Open	0.475	Pass

AVERAGE TRIP TIME 0.4749 **ST DEV** 0.0007

MOTOR START CBEMA/ITIC/SEMI VIOLATION

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	Trip Open	Trip Open	0.1925	Pass
Test 2	Trip Open	Trip Open	0.1925	Pass
Test 3	Trip Open	Trip Open	0.191	Pass
Test 4	Trip Open	Trip Open	0.1925	Pass
Test 5	Trip Open	Trip Open	0.1905	Pass

AVERAGE TRIP TIME 0.1918 **ST DEV** 0.0010

SIX PULSE BRIDGE LOAD

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	???	Remain Online	N/A	N/A
Test 2	???	Remain Online	N/A	N/A
Test 3	???	Remain Online	N/A	N/A

HARMONIC DISTORTION

Name	Anticipated Reaction	Actual Reaction	Reaction Time	Pass / Fail
Test 1	???	Remain Online	N/A	N/A
Test 2	???	Remain Online	N/A	N/A
Test 3	???	Remain Online	N/A	N/A

Test 4	???	Remain Online	N/A	N/A
Test 5	???	Remain Online	N/A	N/A
AVERAGE TRIP TIME	N/A	**ST DEV**	N/A	

Test 4	???	Remain Online	N/A	N/A
Test 5	???	Remain Online	N/A	N/A
AVERAGE TRIP TIME	N/A	**ST DEV**	N/A	

Table 7: Detailed Miscellaneous Test Results

Notes
Motor Start Non CBEMA/ITIC/SEMI Violation: The DSP tripped open even though this motor start does not violate CBEMA/ITIC/SEMI Curves
Motor Start CBEMA/ITIC/SEMI Violation: The DSP properly tripped open and reclosed after the event, but then tripped open again for unknown reasons

DTC Registered Test Procedure CERTS Microgrid Static Switch Testing		
Dolan Technology Center	Document No: DTC212812.206	
Written by: David A. Klapp	Effective Date: April 04, 2006	Target Group: Assigned
Approved by: K. P. Loving, P.E.	Procedure Review Date: As Needed	

Revision #	Date	Revision Description
0	04/04/06	Original

Team Members and Roles

3.0 Name	4.0 Group	5.0 Primary Roles
David Klapp	Operations	Test Engineer
Kevin Loving	Operations	Test Coordinator
CERTS	CERTS	Sponsor

6.0 Purpose, References, Definitions

Purpose: The purpose of this document is to define the procedure for testing the CERTS Microgrid Static Switch DSP and SEL-351 Relay for detection and reaction to various power quality events and simulated faults (see Figure 5).

This procedure defines the functional requirements for testing and documenting the results.

Criterion: The CERTS Microgrid Static Switch DSP or SEL-351 Relay should correctly identify and respond to predetermined power quality events and simulated faults, demonstrating its ability to island the Microgrid and properly protect the load.

Materials to be used include, but are not limited to; an Manta MTS 1710 relay test set, an Elgar SW 5250A Smart Wave, an Elgar SS-66 3-phase power supply, a 480 volt 3-phase variac, and a Wavetek Datron 195 Universal Waveform Generator.

Definition: The CERTS Microgrid Static Switch DSP and SEL-351 Relay located in Cabinet 2a.

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Reference documents:

DTC Standard Operating Procedures
SOP – Barricades, Barriers and Guards, 204-DTC-011
SOP – Personal Protective Equipment, 204-DTC-032
SOP – Job Safety Analysis, 204-DTC-070

7.0 Responsibilities

Scheduling:	Test Coordinator
Parameter Specification:	Sponsor, Test Engineer
Setup:	Test Engineer
Execution:	Test Engineer
Report:	Test Engineer

2.1 The Test Engineer shall comply with all the appropriate DTC operating procedures that are listed above in Clause 1.6.

2.2 The Test Engineer in charge during a test must be familiar with the test plan.

2.3 All persons who are directly involved during the execution of the tests shall wear the appropriate personal protective equipment.

2.4 The Test Coordinator shall ensure the required qualifications of all participants are met.

2.5 The Test Coordinator shall be responsible for approving this procedure and any revisions to it.

8.0 Procedure

General Safety Requirements

Testing in Test Cell A shall be in accordance with:
SOP 204-DTC-011, Barricades, Barriers and Guards.
SOP 204-DTC-032, Personal Protective Equipment.

The proper operation of any associated test equipment based on the manufacturer's operator's manual.

A Job Safety Briefing shall be performed prior to testing.

<u>Test Setup</u>

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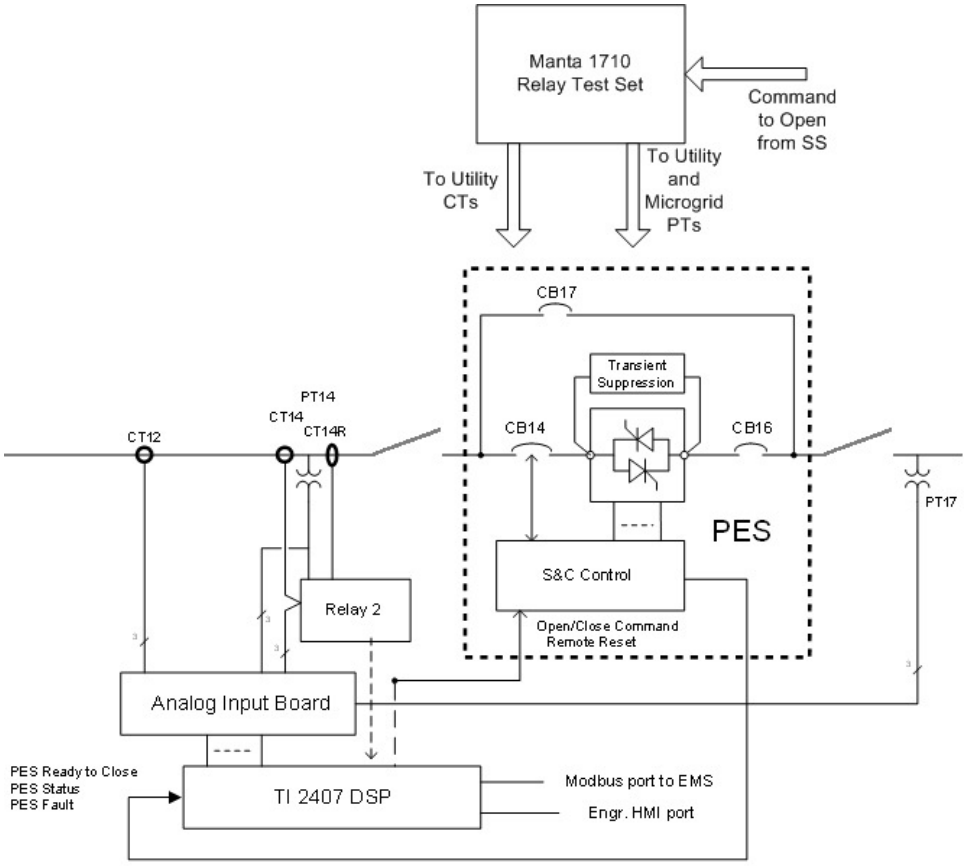

Figure 5: Test setup for Power Quality and Simulated Fault Testing.

All testing will be preformed at low power to reduce the possibility of damage to the SS and test equipment.

The SS should be assembled and connected to all of the appropriate control cabinets as needed for functionality.

The measurement PTs and CTs of the SS will be disconnected and the Manta relay test set will be connected in their place.

The reverse power relay will either be disabled or will be connected to a source to simulate continuous power import.

Test Procedure

The Manta will be configured to deliver the same stimulus to both sides of the SS.

Each individual test will consist of three parts, a pre-fault, a fault, and a post-fault. Note: the word "fault" as referred to above means the condition of abnormality under test. This is not solely limited to electrical faults but also includes the power quality events of interest.

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The pre-fault configuration which will lie within the normal operation conditions where the Microgrid can be connected to the utility.

The fault configuration will consist of the desired power quality or simulated fault event

The post-fault configuration will return to the normal operation conditions where the Microgrid is connected to the utility.

The Manta will be set to the pre-fault configuration and the SS will be commanded closed.

The Manta will then be triggered into the fault configuration.

Once the SS responds to the fault configuration the Manta move to the post-fault configuration.

The SS response to the fault and the time for the response will be recorded in the results form, CERTS Static Switch PQ Results.xls.

This testing will not be concerned with whether or not the SS resynchronizes with the utility source once the Manta is in post-fault configuration.

The power quality and simulated fault tests in CERTS Static Switch PQ Tests.doc will be performed.

All results shall be recorded in the results form, CERTS Static Switch PQ Results.xls.

9.0 Hazards & Mitigation

Hazards that exist during testing of the "Purple Power Cleaner" include dangerous voltage levels and electrical flashover. These hazards are mitigated by the following measures:

Compliance with all applicable SOP's, including

204-DTC-11 Barricades, Barriers, and Guards
204-DTC-32 Personal Protective Equipment
204-DTC-70 Job Safety Analysis

10.0 Quality Assurance

Quality assurance is maintained by ensuring that:

The measurement equipment used is within the specified calibration interval.

Measurement uncertainty is appropriate to the needs of the test.

All appropriate information on the test results form is filled in.

All setup parameters, calculations and assumptions are fully documented.

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Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

CERTS Test Bed Design and Commissioning Lessons Learned Summary

APPENDIX H

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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CERTS Test Bed
Design and Commissioning
Lessons Learned Summary

Date: December 11, 2006

This document is intended to summarize some of the most important issues that were found during the design stage of the Testbed as well as during commissioning at the AEP site. The document includes a range of issues that go from safety, control, protection and data acquisition; the correspondent solutions implemented are also described. Safety Review recommendations were obtained via outside safety review of the design by Jim Daley, P.E., DGCP

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1. Zone Breakers:

Initially, Molded-Case circuit breakers (ABB Isomax) were selected based on the CERTS Testbed criteria. However, due to the multiple fault testing that is expected for this project, these breakers were replaced in the design with Insulated-Case breakers (ABB Emax). Molded-Case breakers are not adequate for the following reasons:

a. They are not built to withstand repeated fault currents. Expected life would be 2 or 3 faults and they would have to be replaced. The molded-case design is not conducive to inspection and maintenance between test runs. Subsequent failures could be explosive and could damage other equipment.

b. Nuisance trips can be expected at ~10 times the continuous current rating due to the magnetic release mechanism in spite of the rapid static switch opening. This may interfere with testing the intended protection scheme. For example, in the current CERTS Tesbed design Strong Grid Case, the fault current in Zone 2 (just downstream of the Static Switch) was calculated to be ~8000A sym. Zone Breaker CB31 would require a continuous rating larger than 800A. ABB Isomax S7 would have meet that requirement (In=1200A; S6 would have been borderline In=800A); however, the CT ratings and microprocessor unit available in S7 would only allow for a minimum overload setting of 400A, which is much larger than the rated load in Zone 3 (~225A) so proper time-overcurrent protection wouldn't be possible. For CERTS Testbed testing this issue could be avoided by using the external protection CTs and SEL-351 Relays available at each zone, but for a commercial design or the next phase of CERTS testing (where these relays and CTs will not be present) careful evaluation of the rated load and fault currents of each zone breaker would be required to verify is Molded-Case breakers are appropriate.

Insulated-Case breakers were recommended for the following reasons:

a. They can handle much higher fault currents without damage

b. They can be more easily inspected and rebuilt.

c. They can stand much higher short time (6 to 18 cycles) currents without tripping, allowing the static switch time to act.

Other recommendations that were provided in the Safety Review include:

2. Other Safety Review Issues:

Fault contactors (K22, K32, K42, K52, K62): should be insulated-case circuit breakers with latching spring driven actuators. A common contactor may not be able to stay closed under fault currents due to high magnetic fields. This recommendation has been implemented in the CERTS Testbed.

Cable trays are preferred over conduit. The insulation on cable in conduit may be worn and may fail due to conductor whip under fault conditions and resulting magnetic forces. Conductors should be tied down on every rung of the cable trays. On the longer power cables, outbound conductor runs should be separated from returns to mitigate magnetic forces at fault current levels. Phase and neutral conductors should be tightly bundled.

AEP reviewed this safety comment and decided that significant forces are not expected, so in the present CERTS Testbed, conduit was used.

Power conductor termination lugs should be crimp type and not mechanical type. This recommendation has been implemented in the CERTS Testbed.

3. Energy Manager System

AEP made several recommendations that were implemented to the Energy Manager System (EMS) program that includes the following:

a. In the System Overview Display, status (Open/Closed) of all zone breakers was added to the already present information (Static Switch Status, power flows, etc).

b. Remote Operation of Breaker CB12 was added to the Energy Manager System; this breaker is used to backup the rest of the system and also its disconnection provides a testing condition for reverse power alarms. This option was added to avoid the operator from having to open CB12 locally.

c. Emergency Stop was added to the EMS. Every tab (window) in the EMS includes and E-Stop button that remotely shuts down every microsource and also opens CB12 to disconnect the microgrid from the utility.

4. Load Control Software and Zone/Fault Loads

a. The Load Control Labview Software initialization was modified so that upon initialization (Powering up computer/ Starting Program) all initial settings that are displayed in the screen are uploaded from the PLCs or DSP boards (this fix was also implemented in the EMS software). Before this correction, if the computers were restarted, the programs will be showing initial values that may not match the current controls, thus providing a confusing picture to the operator.

b. Remote Operation of Breaker CB12 was added to the Energy Manager System; this breaker is used to backup the rest of the system and also its disconnection provides a testing condition for reverse power alarms. This option was added to avoid the operator from having to open CB12 locally.

c. AEP recommended that an Emergency Stop be added to the EMS. Presently, every tab (window) in the EMS includes and E-Stop button that remotely shuts down every microsource and also opens CB12 to disconnect the microgrid from the utility.

d. A Load Bank as originally designed had temperature issues when running at full load. Post-Glover recommended the addition of ventilation on top of the load bank to improve the airflow.

5. Data Acquisition System:

a. PML ION 7650 Meters are used as the data acquisition equipment at every important location of the Testbed (Zones, Loads, Static Switch). These meters have fast sampling (up to 3 cycles 1024 samples/cycle; 96 cycles at 16 samples/cycles). It also includes a 1cycle-RMS calculation for the variables that are required to be monitored in CERTS (Real Power, Reactive Power, Voltage, Current, Frequency). Initially during commissioning, several data collection tests were performed with waveform resolution of 128 samples/cycle and 10-second duration RMS calculations at 1cycle sampling. The waveform collection was optimum; however, the RMS collection had issues because the ION 7650 does not include a pre-trigger option for this type of calculation (which the waveform collection does). This is an important requirement since it is useful to know the initial state of the system before step loads or switch transitions occur in order to understand the response of the inverter-gensets. Several solutions were attempted, such as implementing pre-triggering signals directly from the EMS-DAS Labview programs, however, this provided

mismatching between the starting times of the waveform and RMS data, which added confusion in interpreting the data. Also, with this strategy, a Software “Manual Trigger” from the operator would have been required, thus adding further complication to the system.

b. To eliminate this problem, the approach taken was to use the meters only as a front-end data acquisition system (waveform data collection) and allow external software to download the data and process it and perform the RMS calculation. By taking this approach, any pre-triggering mismatches are eliminated (every meter gets the same trigger signal, and each meter has a #cycles pre-trigger setting). PQView, software developed by Electrotek Concepts, will be used as the processing tool and also as a Database Management System to share data in the internet (PQWeb). Setup of PQ View is currently under way.

6. Protection:

a. In the original design, neutral point the Y-side of every microsource transformer was connected to a ground-conductor that will run from the neutral point of the microgrid main transformer (T11) through the length of all feeders. However, due to a safety recommendation from AEP, the microsource transformers Y-side neutral is now tied to a neutral conductor that runs back to the neutral point of T11, where it is solidly grounded. These change affected the original intent of the differential current (CT around phase and neutral conductors) scheme; now, this scheme will only detect ground faults that are downstream of the microsource (rather than independent on location). Professor Lasseter investigated and provided recommendations to implement additional zero-sequence and negative sequence current elements to the protection scheme. The addition of these elements is possible due to the flexibility provided by the SEL-351 Relays.

7. S&C Power Electronic Switch (PES)

During Low-Power Testing of the Static Switch (at NPS Lab), some issues were found with nuisance alarms from the S&C PES (power electronic switch) local controls:

a. When the Switch was commanded to Open, with a source only on the “Input” (Grid) side, the system will “Stop”, opening the input CB. The

reasoning behind was that control power is usually taken from the "Output" (DG) side, thus when the switch opens, control power is lost temporarily, which sent the system "Stop". This issue was verified by performing a similar test but with the source connected to the "output" side, so control power was always available; during this test, the problem disappear. Roger Troyer from S&C visited the AEP Dolan Lab and performed modifications to the control power circuit of the S&C to eliminate this problem.

b. The PES also includes a "Fail to Open" Alarm, which will Stop the system (open the input breaker) in the switch if the switch is still closed (measured >15Vpk across any phase of the SCR switch) after 2-cycles of being commanded open. This issue was found sporadically during low power testing at NPS, and was replicated during the first visit of Roger Troyer to the AEP site. This issue occurs because this method of detection is not design to account for having sources of approximately the same frequency on both sides of the switch (if this is the case, then voltage will not develop, or will take time to develop, across the switch when it has opened). Based on the CERTS microsource control, this situation will occur when the power across the switch is zero or very low (there is usually at least some real power taken by the PES controls). To fix this issue, Roger Troyer provided a modification in the PES code so the "Fail to Open" detection will only occur if the current across the switch has fallen below ~20A after 2 cycles.

8. TECOGEN Engine Control-Communications

During the commissioning process, it was noticed that communications between the EMS computer and the TECOGEN inverter controls was very slow; commands for frequency-voltage-power were modified from the EMS computer, and it will take approximately 20 seconds until values were updated on the Engine Control side.

Modifications to the communications between gensets and EMS computer were required. Initially, the gensets were connected together (2-wire duplex) using RS-485 connection to the EMS.

This setup was replaced with an Ethernet connection from the EMS to the gensets; on the genset side, an Ethernet serial switch is used to split the Ethernet link into 4 COM ports; three of these are used to communicate with each genset, using RS-232. With this setup, each generator will be polled individually, thus speeding up communications.

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 6.0
Microgrid Test Bed System Checkout
(Static Switch)

APPENDIX I

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CERTS MICROGRID TEST REPORT

SECTION 6.0

"Microgrid Test Bed System Checkout
(Static Switch)"

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as "islanded" from it. This paper describes the tests that were performed in Section 6.0 "Procedure – Microgrid Test Bed System Checkout" of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility's distribution system, isolating the microgrid's load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility's electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to an 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

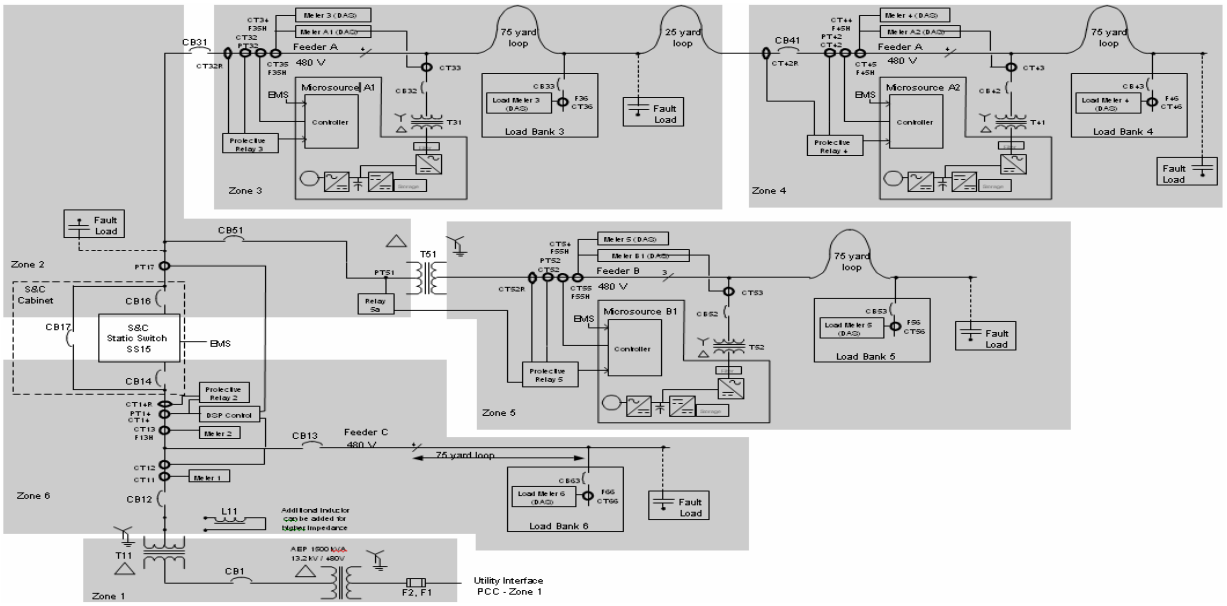

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

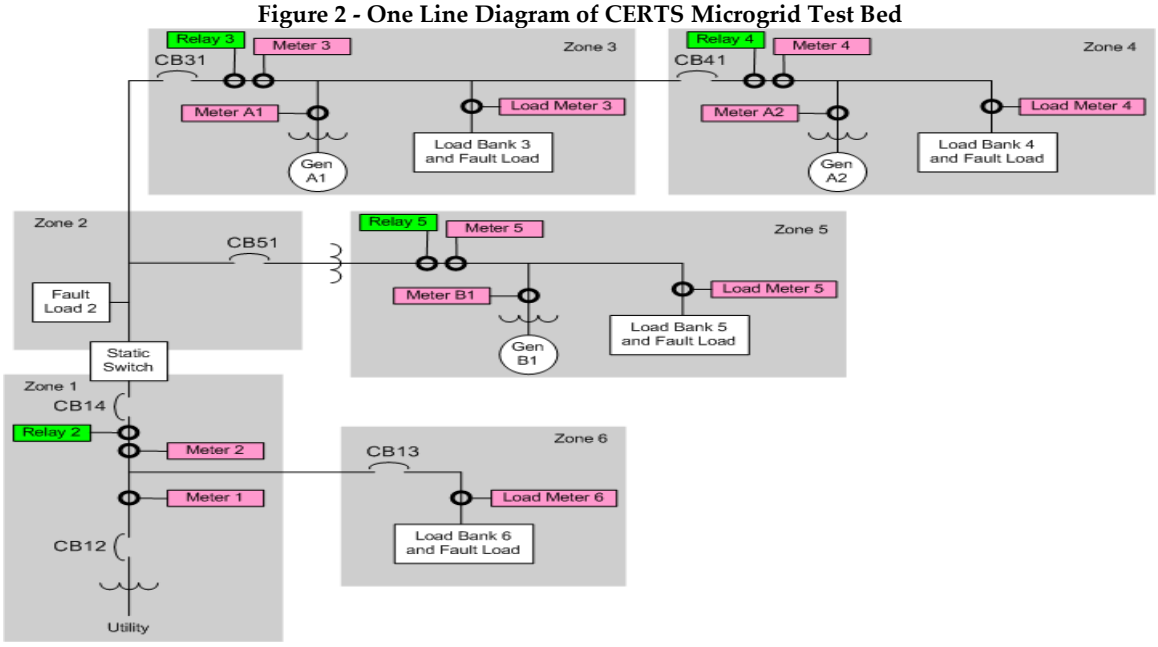

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

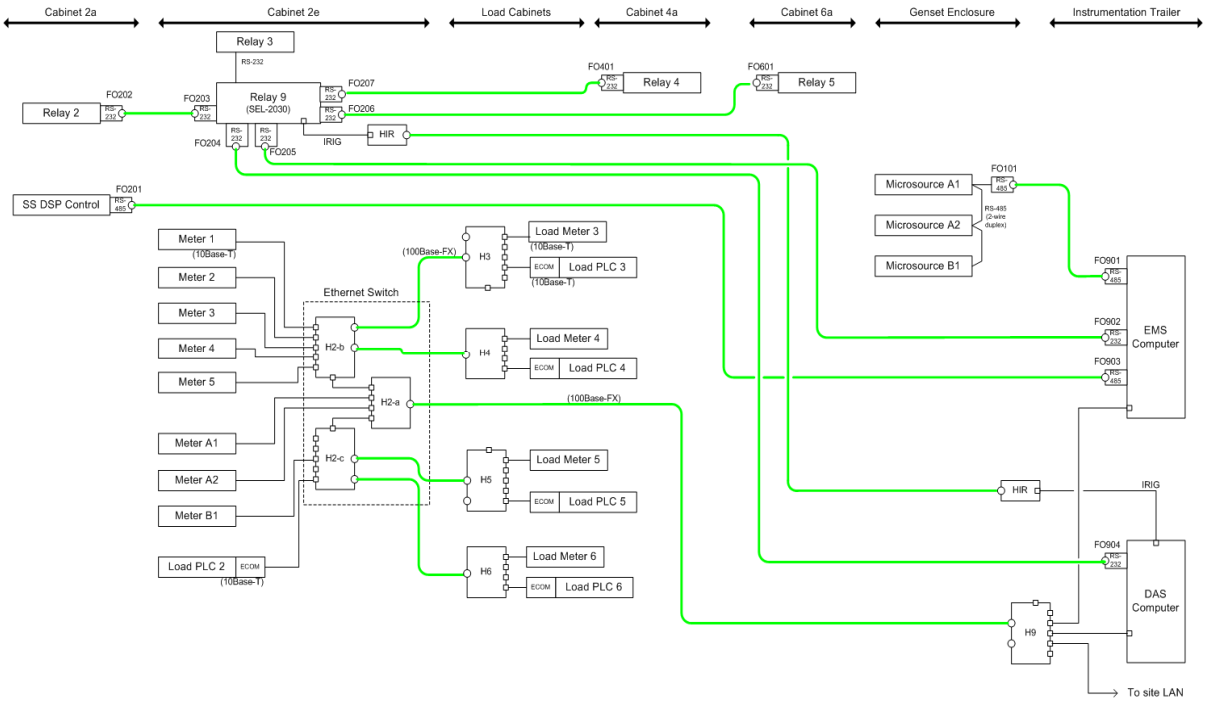

Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – "Purpose, References, and Definitions" describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – "Responsibilities" informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.

- Section 3 – "Training - Team Members" lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.

- Section 4 – "Procedure – CERTS Microgrid Test Bed Lockout/Tagout" entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.

- Section 5 – "Procedure – General" is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.

- Section 6 – "Procedure – Microgrid Test Bed System Checkout" was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.

- Section 7 – "Validate Protection Settings & Initial Fault Testing" is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.

- Section 8 – "Procedure – Reduced System Tests" is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.

- Section 9 – "Procedure – Demonstration Tests of Control Power Flow" demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – "Procedure – Test Difficult Loads" determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.

- Section 11 - "Hazards & Mitigation" informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.

- Section 12 – "Quality Assurance" ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 6.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a "Red" plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

The first sets of tests came from section 6.0 where the static switch's controls and operation were checked, all three Gen-sets basic power and voltage controls were verified for correct operation, and a preliminary check of the protection scheme that was later tested in section 7.0. The static switch function tests checked the operation of the static switch, to assure it and its DSP control were operating as designed. This section included tests of dead-bus and synchronized closing, reverse power, and IEEE 1547 protective relay functions.

A synchronized closing test of the static switch was required to verify that when conditions were within synchronization limits set in the EMS, the static switch performed a synchronized close and thus provided a smooth connection transition. The de-energized bus (dead-bus) reclose test's goal was to verify that the static switch can close when de-energized bus conditions exist on the Gen-set side of the static switch; and that the dead-bus reclose algorithm requires user intervention (i.e., Operator needs to "Enable" the dead-bus reclose using pushbutton in the EMS).

The reverse power tests consisted of three tests: three-phase reverse power condition test, single-phase reverse power condition test, and anti-islanding Micro-grid settings reset test. Both three-phase and single-phase reverse power condition tests were required to verify the reverse power functionality of the static switch and confirm that the static switch islands the microgrid for a three-phase or single-phase reverse power condition The anti-islanding Micro-grid settings reset test was needed to verify that if a reverse power event occurred, due to a mismatch of Gen-set settings (i.e., total Gen-set power is greater than Microgrid load), the static switch will lockout and go to the "Fault" state, where user intervention is required.

The next goal was to verify the reconnection timers of the static switch (i.e., set by default at 300 seconds based on IEEE Standard 1547-2003). The length of time is programmed into the control system and designed to prevent reconnection from island to utility-connected mode until after the utility source voltage returns to nominal steady state conditions.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 6 – MICROGRID TEST BED SYSTEM CHECKOUT

6.1.1 System Start-Up and Synchronized Closing of Static Switch

Performance Goal:

Verify that when conditions are appropriate (within synchronization limits set in the EMS), the switch can perform a synchronized closing and thus give smooth closing transitions.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833Hz/kW

MG Voltage Command = 277V

Load Bank 3 = 40kW (13.3kW per phase)

Load Bank 6 = 40kW (13.3kW per phase)

After Gen-set A1 was running for a few minutes and supplied power to Load Bank 3, the test was started with a "Start" command from the EMS.

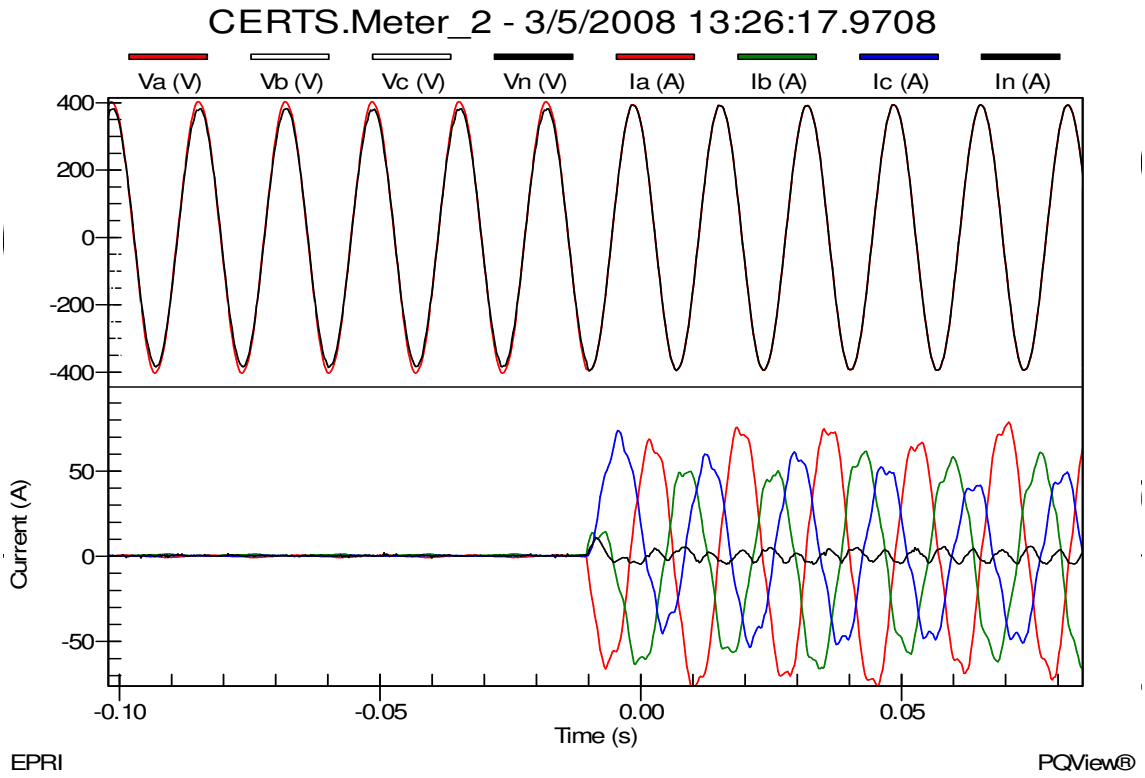

Figure 5a - A phase voltage waveforms and current at Meter 2 on the Microgrid during a synchronized "Close" of the static switch

When electrical system conditions met established criteria, the static switch did a synchronized "Close". A smooth voltage transition occurred from island to utility-connected mode. This transition occurred relatively quickly, after the "Start" command with the A-phase voltage waveforms at Meter 2 shown in Figure 5a. It can be seen that the utility A-phase voltage (red) closely matches the microgrid A-phase voltage (black) prior to synchronization. The transition occurred at approximately minus 0.01 seconds.

After the static switch closed and steady state conditions were established, the power flow at Meter 1, Meter 2, and Meter A1 was approximately 52kW, 16kW, and 20kW, respectively and the frequency stabilized, as shown in Figure 5b from 59.86Hz to the grid frequency of 60.01Hz.

The resistive load banks in each test zone were nominally rated with deviations from nominal expected due to changes in ambient temperature, per phase voltages, heat rise based on duration of test, etc. Thus, during this test the load banks were set at 13.3kW

per phase (i.e., approximately 40kW), but in reality the actual kW value recorded at Load Meter 3 and at load Meter 6 was approximately 36kW.

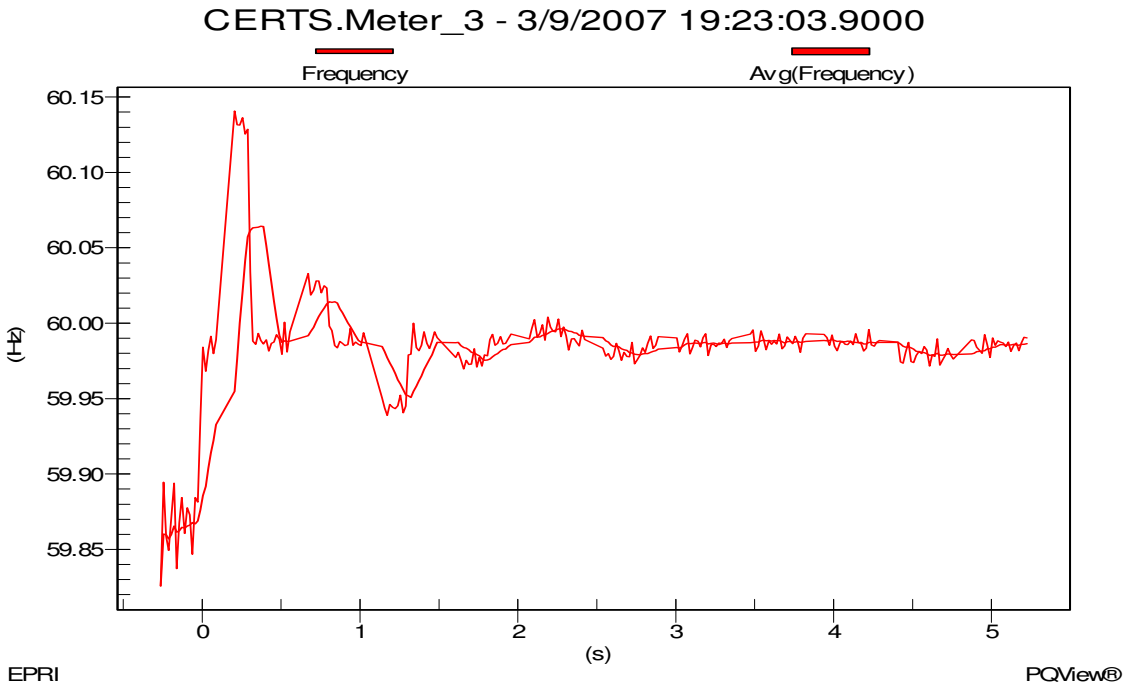

Figure 5b - Change in frequency during a synchronized close of the static switch, during the transition from island to utility-connected mode.

The first full scale test on the Microgrid Test Bed and synchronizing an islanded microgrid to the utility required a thorough review of the electrical conditions and affects of the corresponding algorithms designed into the CERTS Microgrid Concept. Thus, the following paragraphs provide a more extensive review and focus-in on the kW and kVAr load flows in Test Zone 3 which occurred before and after the transition from island to utility-connected mode.

Figure 5c includes the single-phase and three-phase load being served in Zone 3 of the microgrid. When in island mode and prior to synchronization, Gen-set A1 at Load Meter 3 was serving 33.75kW with A, B and C phases being 11.15kW, 11.35kW and 11.25kW, respectively. After synchronizing to the utility grid, the load at Load Meter 3 increased to 35.4kW with A, B and C phases being 11.95kW, 11.75kW and 11.70kW, respectively.

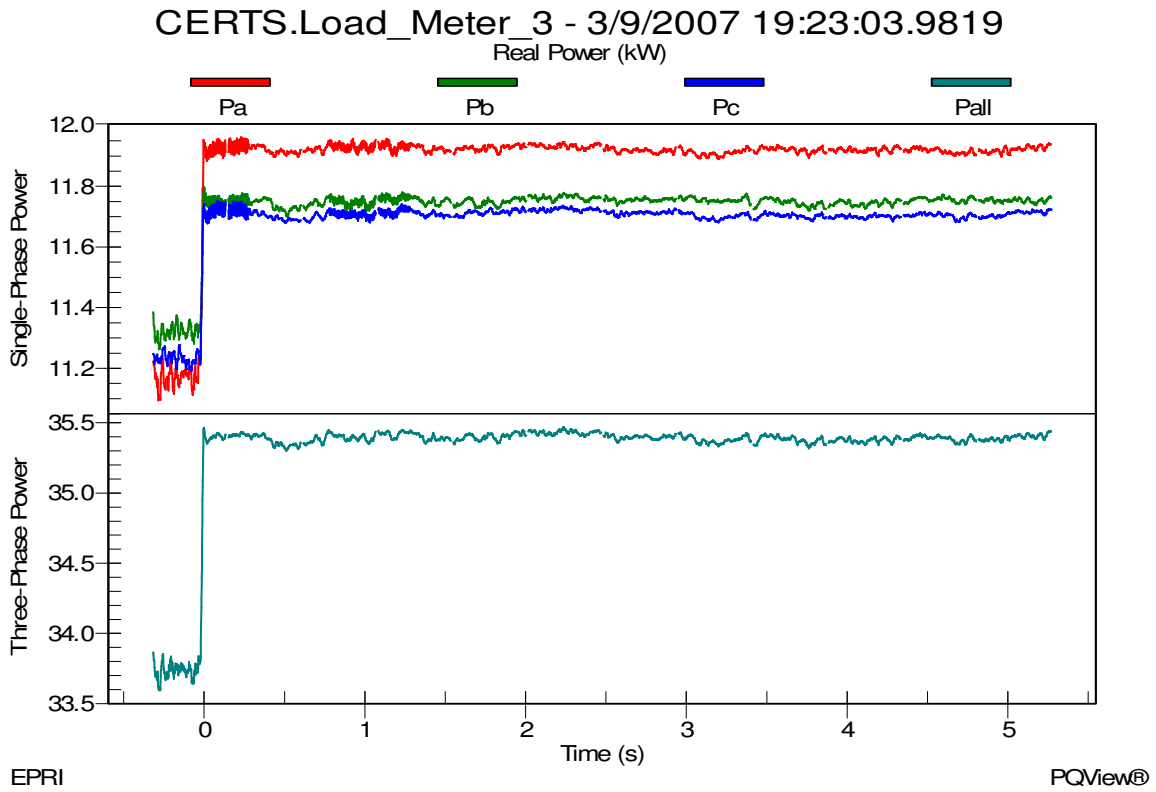

Figure 5c - Single and three phase kW load in Zone 3 at Load Meter 3

The increase in kW load at Load Bank 3 can be attributed to the slight change in the per phase voltages when interconnected to the utility grid. As illustrated in Figure 5d, A-phase RMS voltage was below B and C phases when the microgrid was in island mode, but is above B and C phase voltages when connected to the utility grid.

Prior to synchronization, Figure 5e show A-phase voltage at the point of common coupling (PCC) being higher at 283V with B and C phase voltages at 280V. After the microgrid synchronized to the utility grid, each of the phase voltages dropped at the PCC with A-phase reducing to approximately 280V, and B and C phases reducing to approximately 277V. These voltages are similar to the voltages at Meter 2 and closely match the voltage change at Load Bank 3.

With the slight change in kW load explained at Load Bank 3, the question remains as to how much of the microgrid's protected load is being served from the Gen-set A1 and how much is being served from the utility grid.

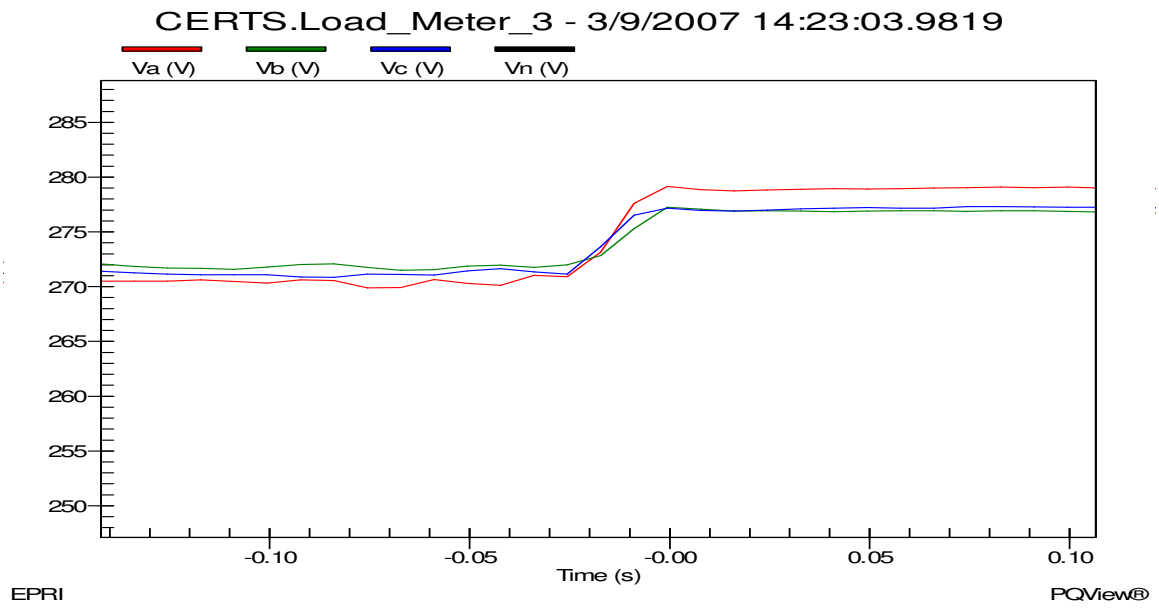

Figure 5d - RMS voltage at Load Bank3, during the transition from island to utility-connected mode.

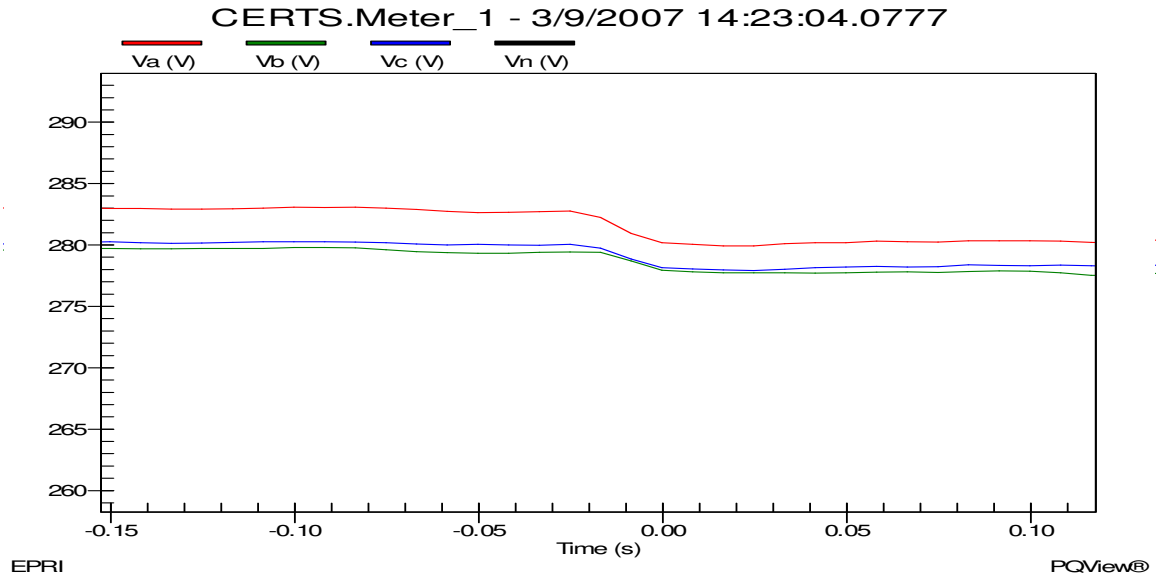

Figure 5e - RMS voltage on grounded-wye, 480/277 volts, side of T11 transformer during the transition from island to utility-connected mode

Figure 5f shows the change in kW load being served from the utility at Meter 2 when the microgrid is interconnected to the utility grid. As indicated, after the static switch closed, the total three phase load increased from 0kW to 16kW with A, B and C phase loads increasing from 0 to approximately 5.5kW, 4.0kW and 6.5kW, respectively.

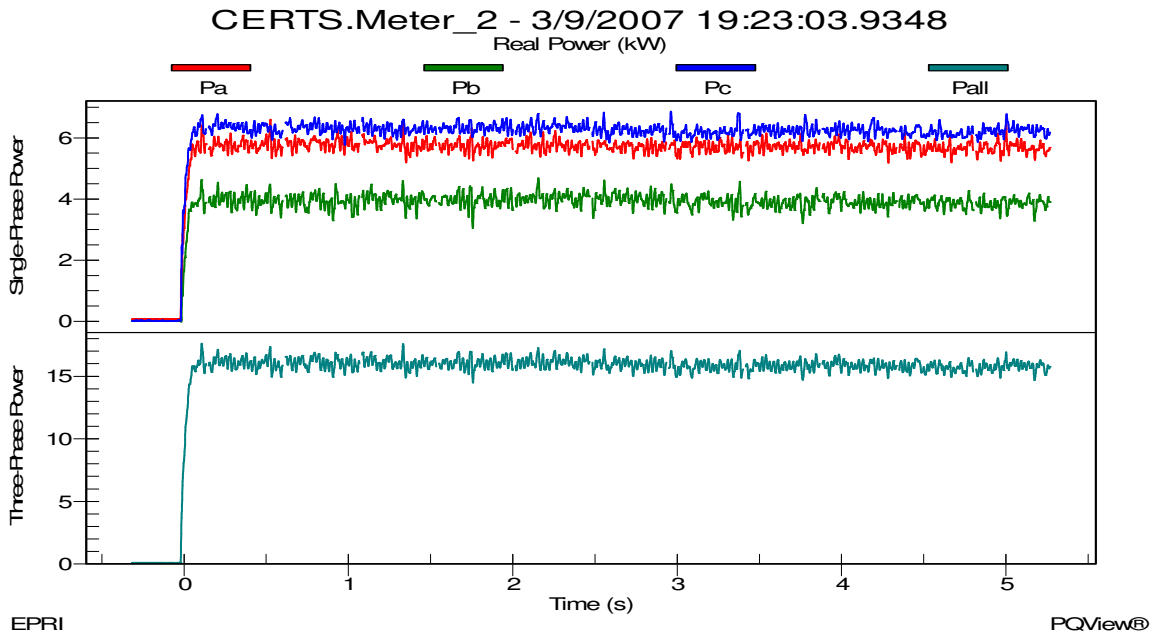

Figure 5f - The kW change at Meter 2 when served from the utility grid

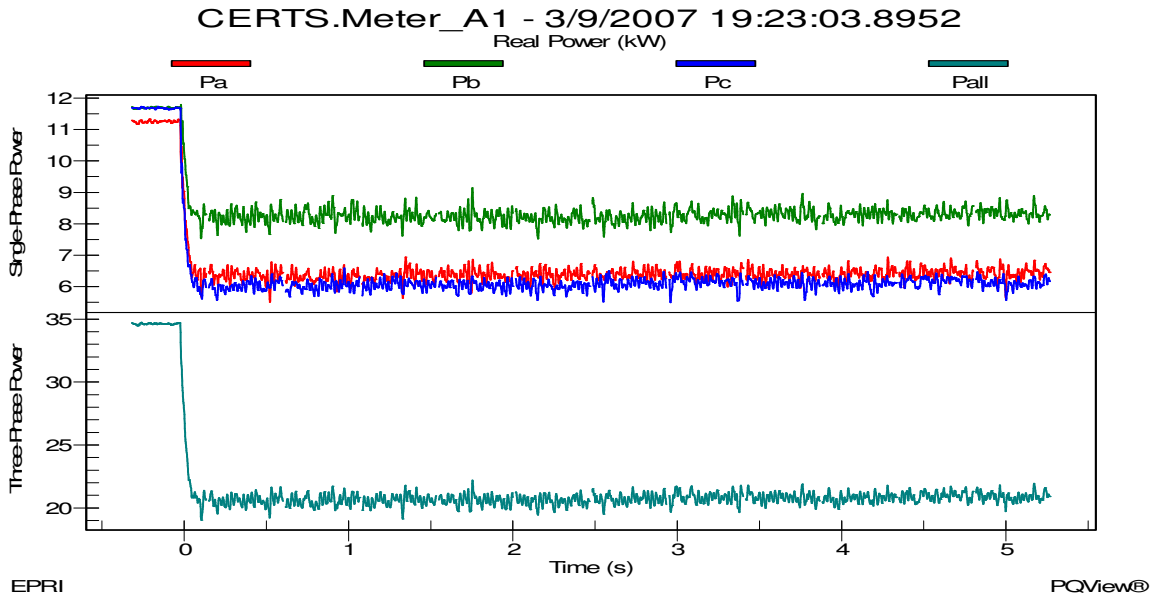

Figure 5g - The kW change at Meter A1 on the output of Gen-set A1

Figure 5g shows the corresponding change in kW output of Gen-set A1 at Meter A1, after the transition from island mode to utility-connected mode. As illustrated, the three-phase kW output of Gen-set A1 changed from approximately 34.6kW to 20kW with A-phase changing from approximately 11.2kW to 6kW; B-phase changing from 11.7kW to 8kW, and C-phase changing from 11.7kW to 6kW.

Note the 20kW value was the original Unit Power output set point in the controller of Gen-set A1. When in island mode, Gen-set A1 had sufficient capacity to serve the 35kW of load in Zone 3; and when the static switch synchronized with the utility grid, Gen-set A1 reduced its kW output to the selected set-point value.

Once the synchronization criteria were within limits, the static switch closed, connecting the microgrid to the utility. After this connection Gen-set A1 adjusted its frequency to match that of the utility grid, as shown in Figure 5b. This increase in frequency caused Gen-set A1 to reduce its real power output to the unit power mode set-point of 20kW, as shown in Figure 5g. Finally, Gen-set A1 reactive power output transitioned from producing to absorbing power in response to the increased voltage of the utility in an attempt to lower the microgrid nominal voltage of 277 volts, as shown in Figure 5h.

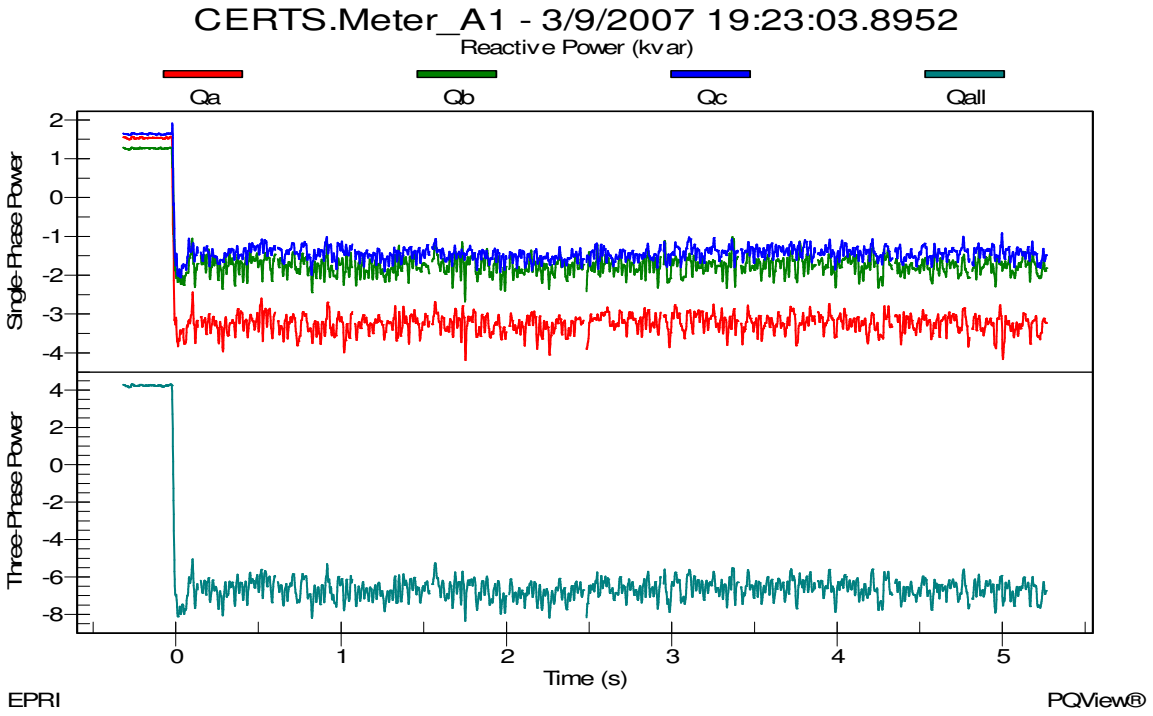

Figure 5h - The kVAr change at Meter A1 on the output of Gen-set A1

Figure 5h shows the inverter adjusting the total kVAr value at Gen-set A1 from +4kVAr when in island mode to approximately -7kVAr when utility-connected. For the static switch to synchronize with the utility grid, A-phase voltage needed to be raised high on the Microgrid than the voltages on phases B and C. This is evident in Figure 5h, where the kVAr change in A-phase was much greater (i.e., almost twice the kVAr change) than in phases B and C. Thus, the voltages raised and frequency adjusted on the Microgrid,

as designed in the algorithm (i.e., MG Power/Frequency Droop setting), for the static switch to synchronize with the utility grid.

6.1.2 Loss of Utility Source Test

Performance Goal:

Verify that the microgrid detects and islands itself upon the loss of the utility source upstream of the PCC. This is detected in two ways: first, for a large load loss on the utility system an under-voltage event will occur; and second, for a small load loss a reverse power event will occur. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standards).

Initial Setup for large loss on utility system:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Load Bank 3 = 40kW

Load Bank 6 = 20kW

AEP Load Bank = 500kW

After Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized "Close" of the static switch was initiated. Once synchronized, the microgrid was connected to the utility grid with a separate AEP Load Bank connected to the electrical system between transformer T11 and circuit breaker CB1 with 500 kW of additional load being served from the utility through breaker CB1.

Figure 6a shows the voltage waveform results when breaker CB1 to the utility grid was "Opened/Tripped". It can be seen that the voltage collapses quickly causing the static switch to open and the microgrid load remains served by the Gen-set A1. Likewise, Figure 6b shows the current waveforms at Meter A1 when breaker CB1 was opened, the microgrid islanded in approximately 2 cycles. Note, Gen-set A1 current waveform increased to approximately 500 amperes, peak, which is well beyond its design rating. The EMS indicated that an under-voltage PQ event did occur and that a static switch

opened, successfully. During this event the under-voltage relay of CB-51 operated, de-energizing Zone 5 in the test bed.

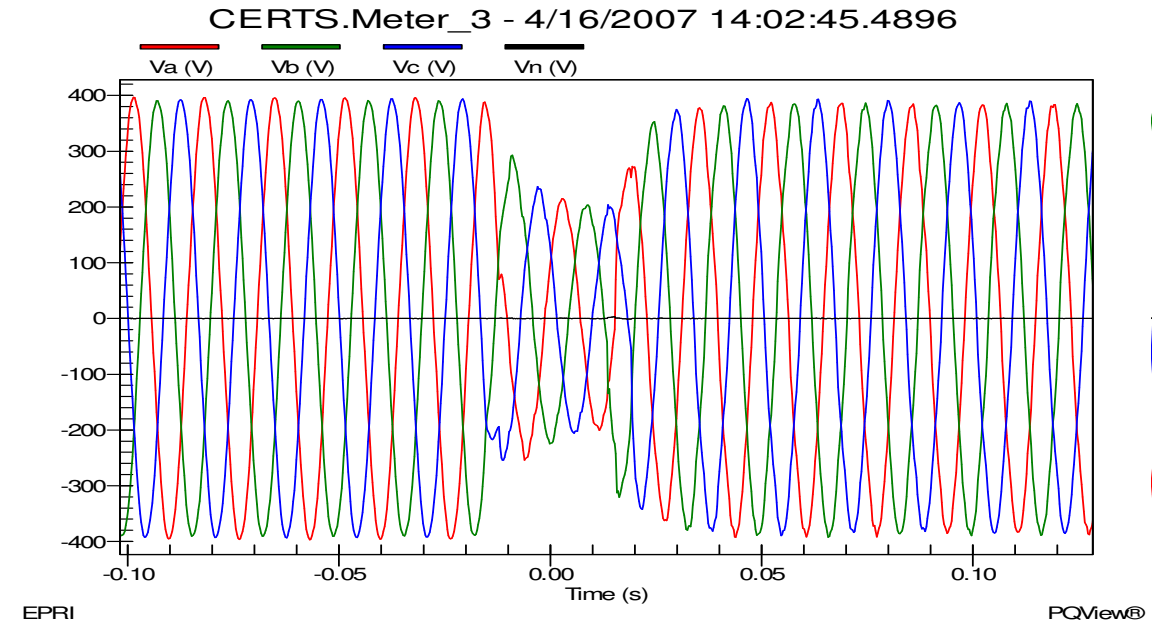

Figure 6a - Meter 3 voltage waveform during breaker CB1 opening and the microgrid islanded within 2 cycles

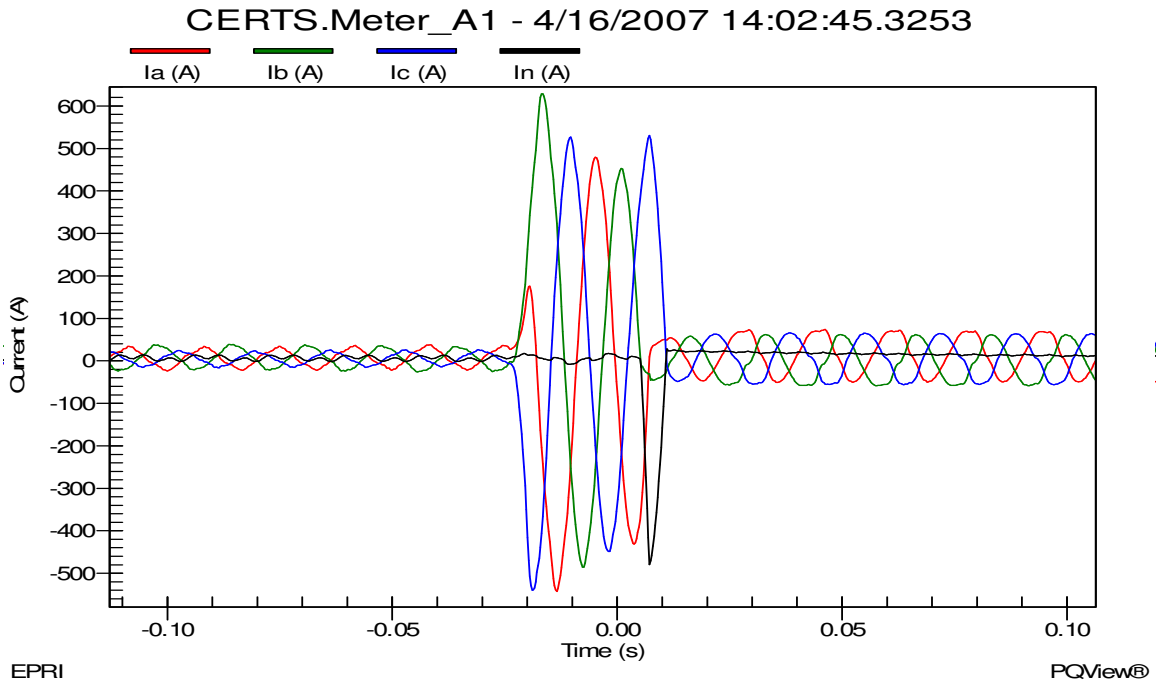

Figure 6b - Current waveforms at Meter A1 during breaker CB1 opening

Load on the AEP Load Bank was reduced to 0kW and the utility grid was reconnected by a manual "Close" of breaker CB1. After CB1 was closed, the IEEE 1547 voltage test did shut-off and the static switch did not immediately attempt to reconnect, since the reconnection timer was set to 300 seconds. After 300 seconds, the static switch did a synchronized "Close" and the microgrid transitioned from island mode to utility-connected mode of operation. Figure 6c shows kW load at Meter 2 increasing from 0kW to approximately 28kW from the utility grid. Coincidently, kW load at Meter A1 decreased from 34.5kW to 10kW, as shown in Figure 6d.

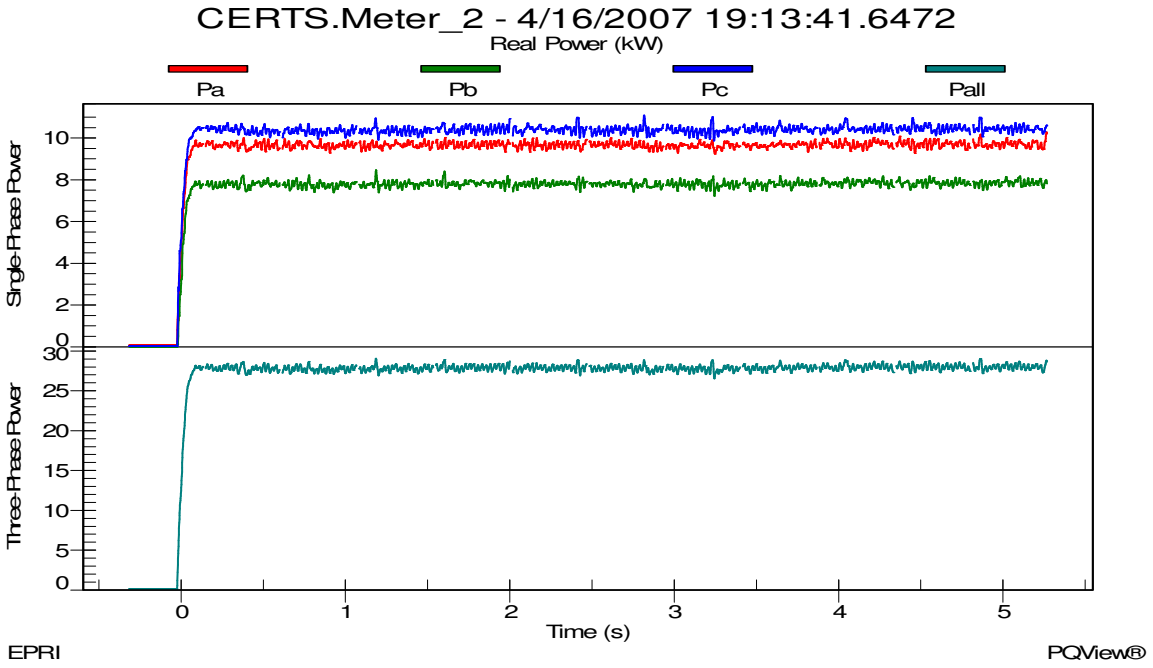

Figure 6c - Meter 2 load during synchronized close of the static switch

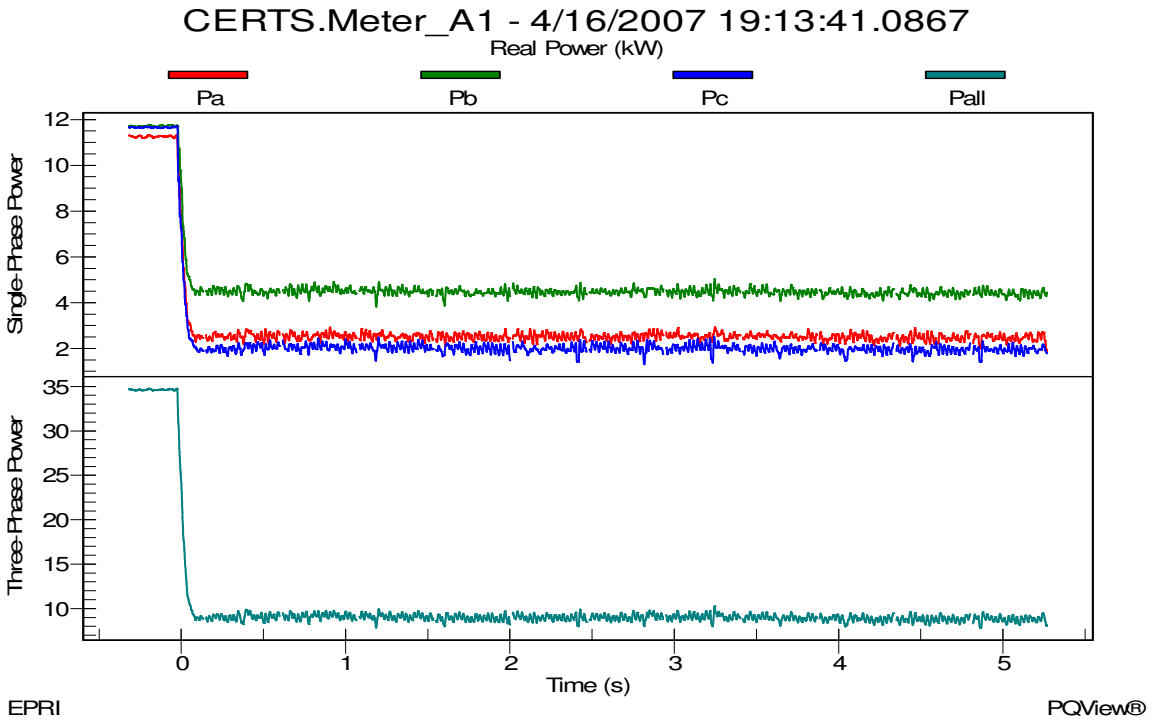

Figure 6d - Meter A1 load when microgrid transitioned from island mode to utility-connected mode

Figures 6e and 6f show the kW load changes in Zone 3 at Load Meter 3 and kVAr changes at Meter A1, respectively, when the microgrid transitioned from island mode to utility-connected mode.

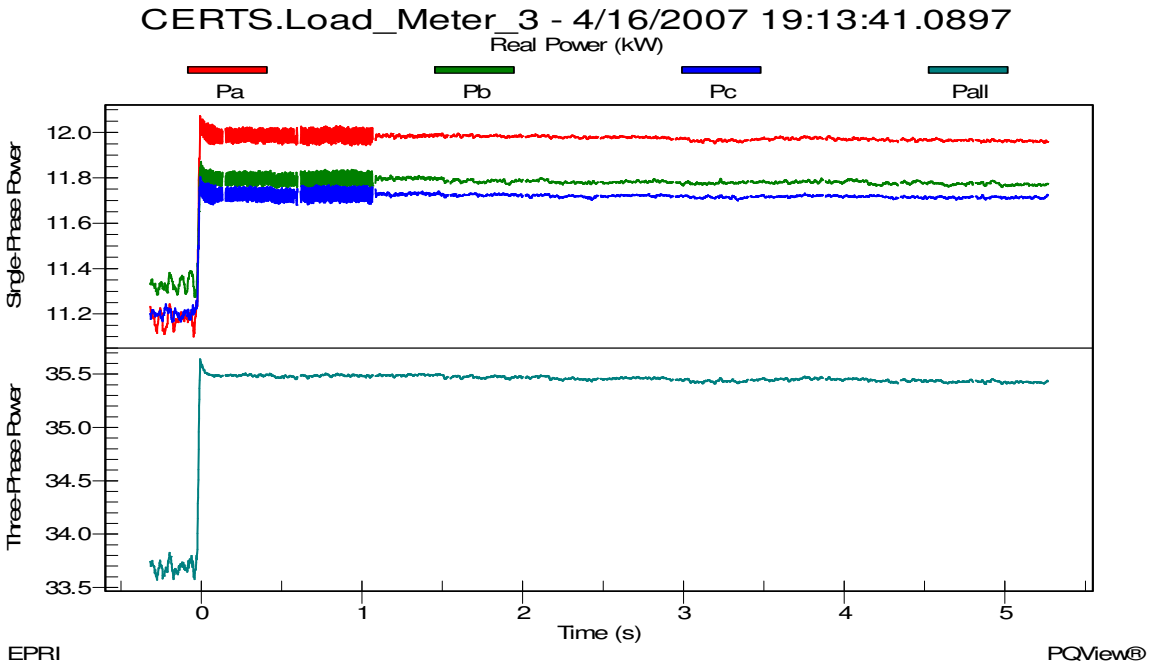

Figure 6e - Zone 3 load when microgrid transitioned from island mode to utility-connected mode

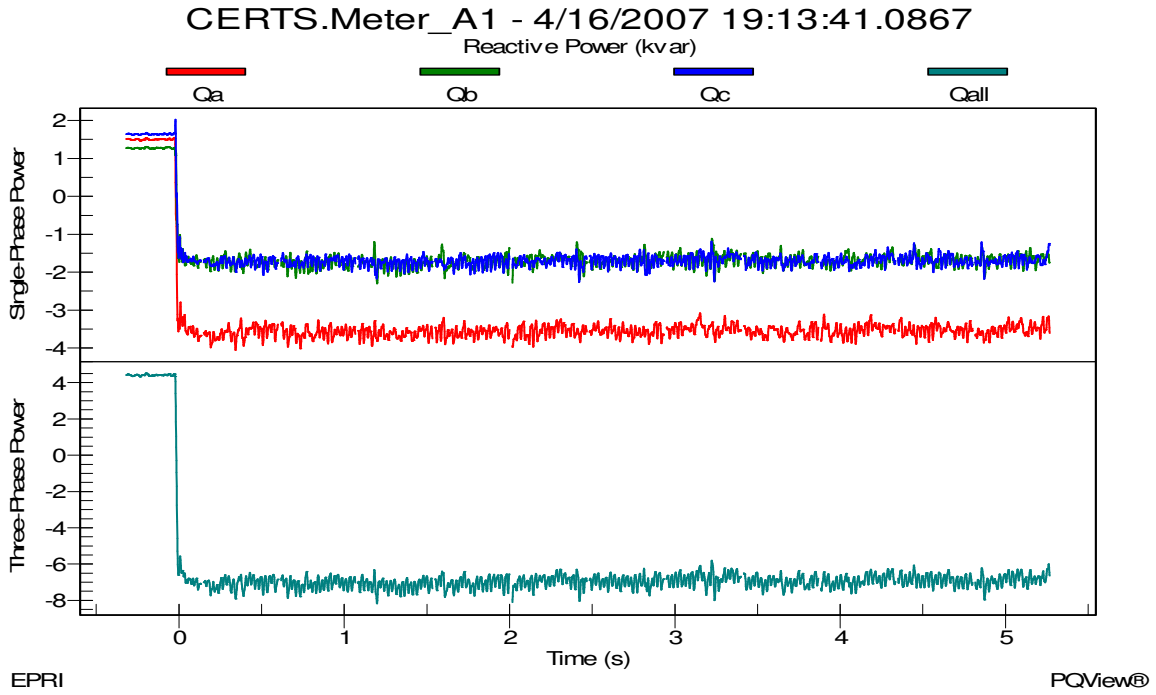

Figure 6f - kVAr changes in Zone 3 when Microgrid transitioned from island mode to utility-connected mode.

Figure 6f shows the inverter adjusting the total kVAr value at Gen-set A1 from +4.5kVAr when in island mode to -7kVAr when utility-connected. For the static switch to synchronize with the utility grid, A-phase voltage on the microgrid needed to be raised higher than the voltages on phases B and C. In Figure 6f the kVAr change in A-phase was much greater than in phases B and C. Thus, the voltages raised and the frequency adjusted on the microgrid, as designed in the algorithm, for the static switch to synchronize with the utility grid.

The test below verifies that the microgrid detected and islanded itself upon the loss of the utility source upstream of the PCC for a small load loss with a reverse power event occurring.

Initial Setup for small loss on utility system:

Overload-Load Bank = 85kW

Load Bank 4 = 60kW

Load Bank 6 = 10kW

Reverse Power Set-point = 10kW (i.e., import 3.33kW per phase)

In Figure 6g a large load of approximately 135kW is removed from the microgrid. Only a small amount of load remains beyond the PCC (i.e., actually less than 10kW) in Load Bank 6. After two seconds a reverse power event occurs and the static switch opens. This demonstrates that any load below the reverse power set-point for more than two seconds will initiate an anti-islanding event.

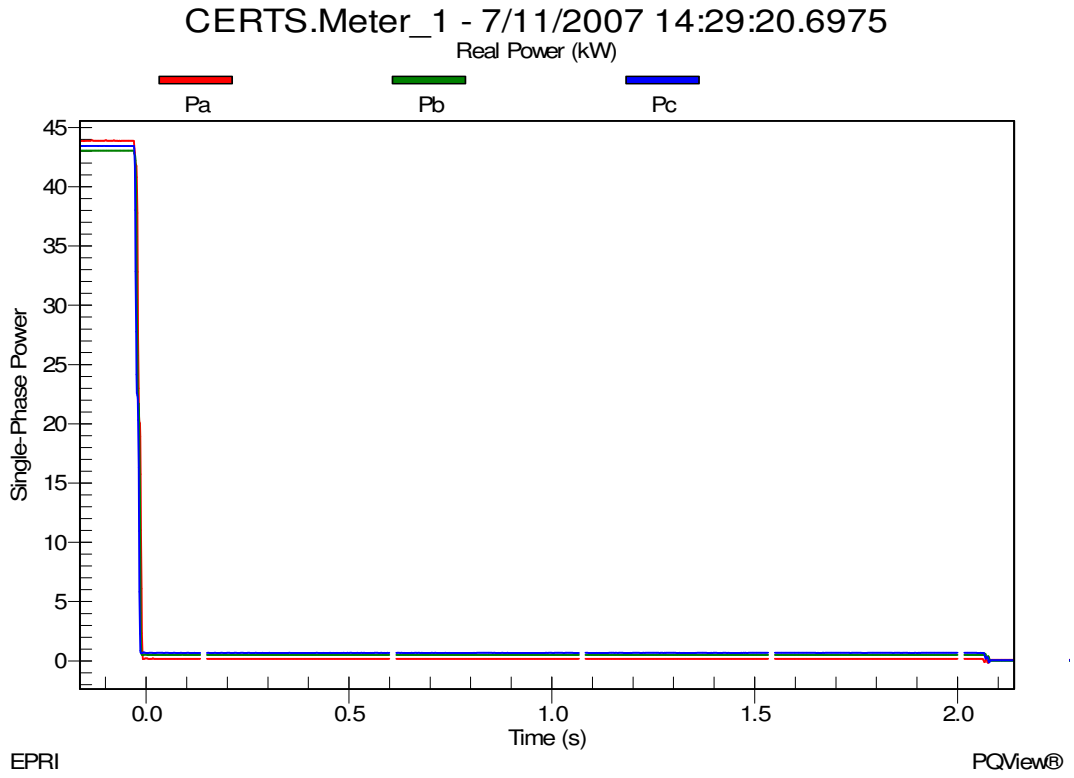

Figure 6g – Single-phase kW at PCC when microgrid load was below reverse power set-point of 10kW.

6.1.3 Single-Phase Reverse Power Test (Simulate Loss of Phase)

Performance Goal:

Verify that the static switch islands the microgrid when a reverse power condition, due to an open-phase occurs.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Reverse Power Setting = 10kW

Load Bank 3 = 40kW

Load Bank 6 = 40kW

After the Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized "Close" of the static switch was initiated. After the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid.

This test began by removing the load on A-phase of Load Bank 6, shown in Figure 7a, with approximately 23.7kW remaining (i.e., 11.85kW in each of the two phases). While maintaining 0kW on A-phase of Load Bank 6, the kW load on A-phase of Load Bank 3 was reduced from approximately 11.8kW to 4kW, which in turn reduced the kW load on the A-phase at Meter 1 at the PCC to below the set threshold of 3.3kW, shown in Figure 7b. This created a reverse power condition on A-phase and opened the static switch.

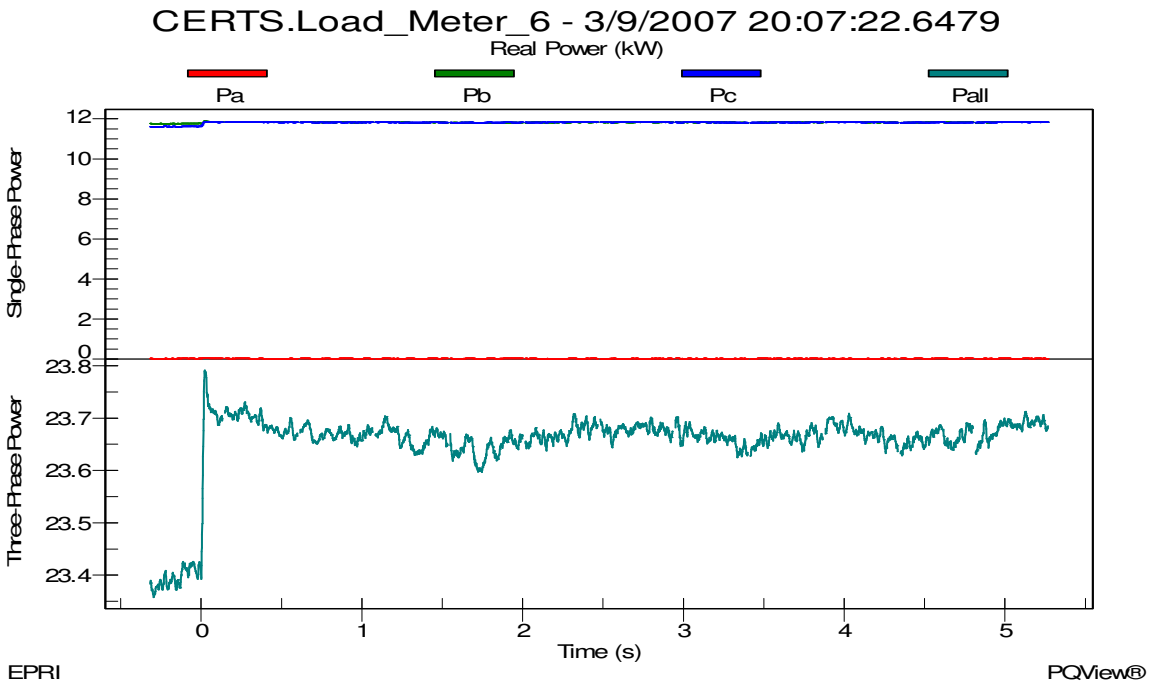

Figure 7a - Load Bank 6 real power before and after the static switch opened.

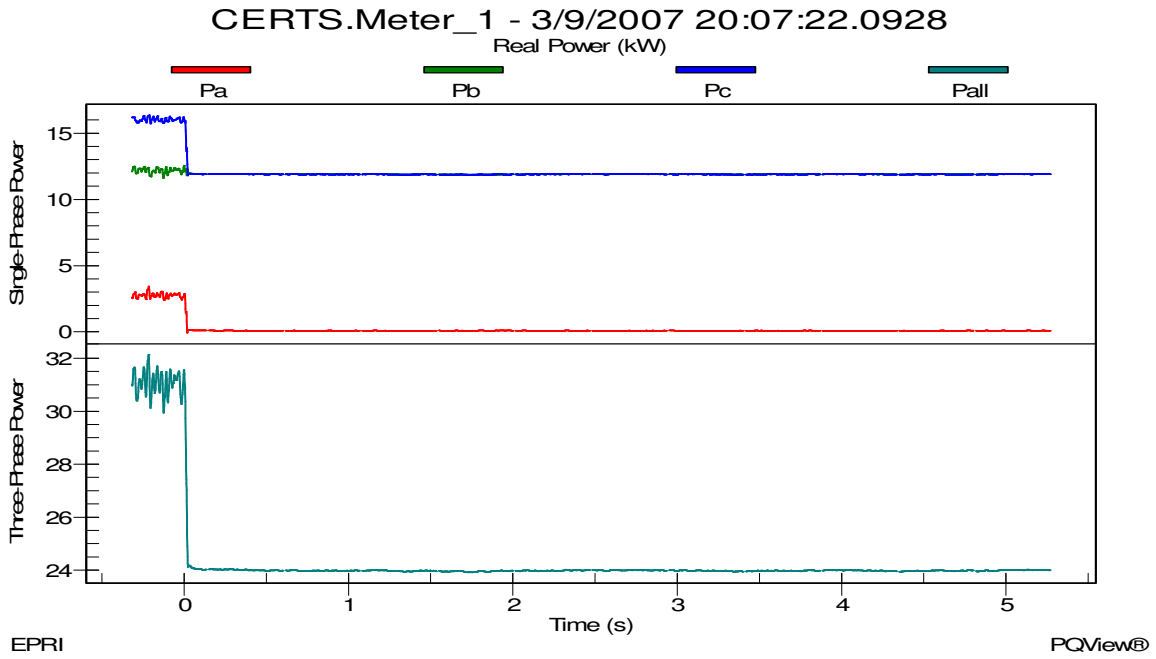

Figure 7b - Load change at Meter 1 when static switch opened on reverse power

Once the static switch opened and voltage remained on the utility side of the switch, the load at Meter 1 decreased from approximately 31kW to 24kW, serving only Load Bank 6. A review of the sequence of actions which took place revealed that the static switch went to a lockout condition and fault condition in EMS (i.e., the DSP stopping the S&C PES switch and opening CB14). The EMS did indicate a "Fault" condition and the "Reverse power Anti-islanding Alarm did turn "On".

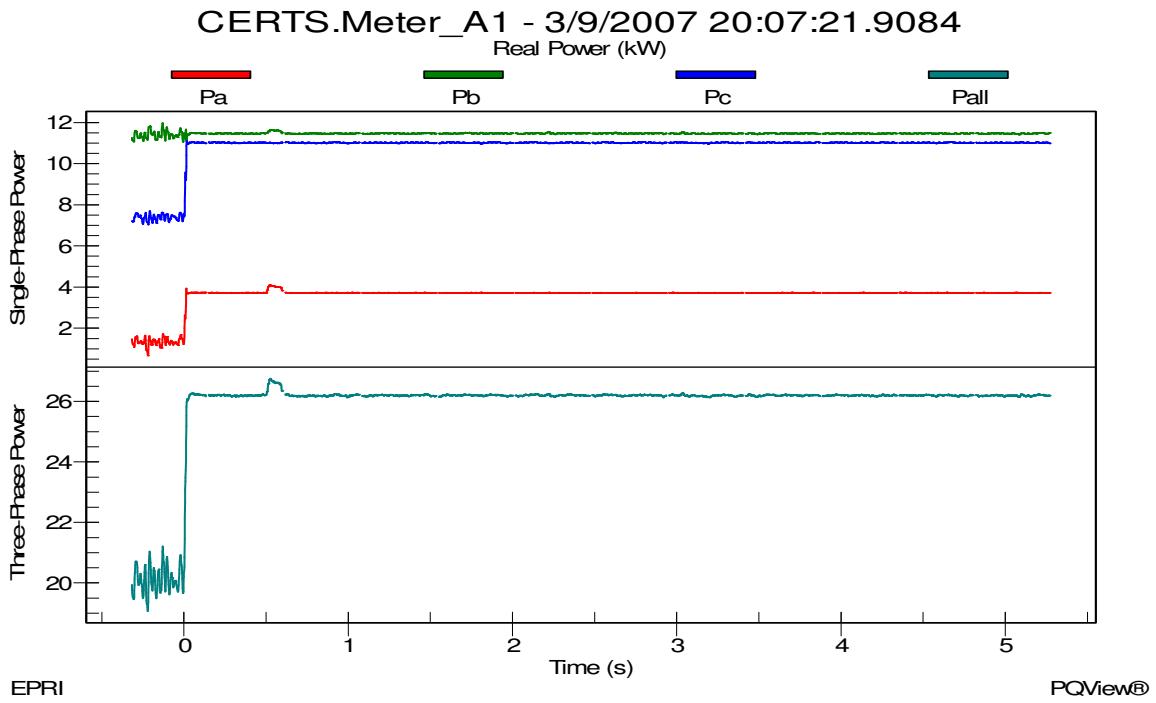

Figure 7c - Gen-set A1 kW load change when Microgrid was islanded

After the static switch opened, Gen-set A1 successfully picked up the Microgrid load remaining in Load bank 3. Figure 7c shows the change in kW load at Meter A1 when the static switch opened. Note, even though the Gen-set setting was 20kW, generator output was unbalanced on a per phase basis. This could lead to complication when operating the microgrid near the reverse power set-point at the PCC.

Monitoring Location	**Phase-A (kW) Before/After**	**Phase-B (kW) Before/After**	**Phase-C (kW) Before/After**
Meter 1	3.0/0	12.0/12.0	16.0/12.0
Load Meter 6	0/0	11.8/12.0	11.6/11.8
Meter 3	2.5/0	0.5/0	4.2/0
Meter A1	1.5/3.8	11.5/11.7	7.5/11.2
Load Meter 3	3.8/3.5	11.8/11.5	11.6/11.0

Table 1 - Microgrid kW loading before/after the static switch opened

Although the output power set-point of Gen-set A1 was set at 20kW, the remaining load on the microgrid was approximately 26kW. Table 1 shows the relative change in kW load beyond the static switch before and after the static switch opened. Note the kW difference between Meter A1 and Load Meter 3 can be attributed to the voltage drop and electrical loss in the 225 feet of conductor between Load Bank 3 and A1 source, as well as

transformer T51. In addition to kW load and voltage changes, the change in frequency when the microgrid was islanded is shown in Figure 7d. This figure shows the frequency changed from approximately 59.99 Hz to 59.95 Hz after the microgrid was islanded.

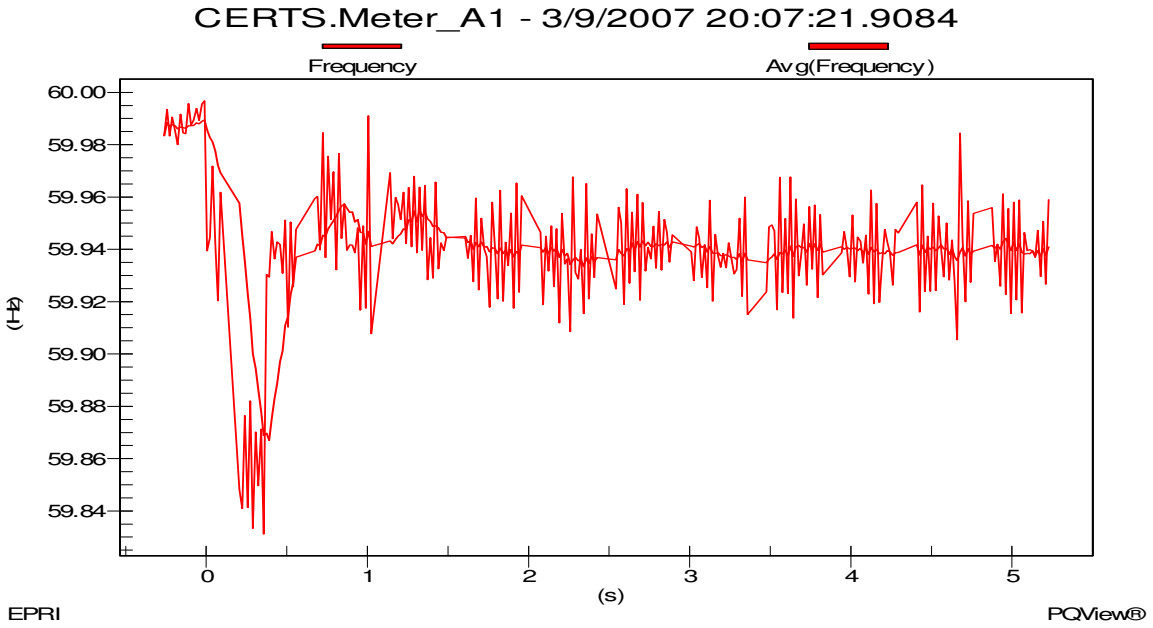

Figure 7d - Frequency change on the Microgrid after being islanded

The reverse power single phase condition was removed by bringing all A-phase loads at Zone 6 and at Zone 3 back to pretest conditions (i.e., 40kW each). The reverse power anti-islanding Alarm was turned "Off". Note the static switch needed to be "Reset" to return it to service, because to the EMS this was a mis-dispatch of the generation within the microgrid. Also, the static switch did not wait for the 300 seconds to reconnect to the utility grid, since voltage remained on the utility side of the static switch. Once all event and alarms were cleared, a "Start" command was initiated on the EMS and a synchronized closing of the static switch was observed. (Note the 300 seconds reconnect time was proven during later tests on the microgrid, satisfying this requirement.)

6.1.4 Reverse Power, Anti-Islanding Microgrid Setting Reset Test

Performance Goal:

Verify that if a reverse power event occurs, due to a mismatch of Gen-set settings (Total Gen-set power > microgrid load), the static switch will lockout and go to the "Fault" state, where user intervention is required.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Reverse Power Setting = 10kW

Load Bank 3 = 40kW

After Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized "Close" of the static switch was initiated. As soon as the static switch closed and steady-state conditions established, the microgrid was connected to the utility grid with the total power flow at Meter 1 approximately 18kW.

When the test began the power measurement at Meter 1 was 18kW. Waited 5 seconds with no reverse power trip occurring (i.e., value was above the minimum 10kW threshold value). Then, reduced load at Load Bank 3 by 5kW, waited about 5 seconds and no reverse power trip occurred. Reduced load at Load Bank 3 by an additional 5kW and the static switch opened, after the second 5kW load reduction. Once the static switch opened, shown in Figure 8a, the Event Logger recorded a reverse power event, DAS was triggered and data was recorded. The EMS entered a "Fault" state, opening CB14, and the "Reverse Power Anti-islanding Microgrid Settings Reset" alarm turned "On".

Although the output power set-point of Gen-set A1 was set at 20kW, the remaining load on the microgrid was approximately 28.5kW, which was successfully served by Gen-set A1. Table 2 shows the relative change in kW load per phase in the microgrid before and after the static switch opened. As mentioned earlier, the kW differences can be attributed to the voltage drop and electrical loss in the microgrid. In addition to load and voltage changes, the frequency changed from approximately 59.99 Hz to 59.95 Hz after the Microgrid was islanded.

Monitoring Location	**Phase-A (kW) Before/After**	**Phase-B (kW) Before/After**	**Phase-C (kW) Before/After**
Meter 1	3.2/0	2.0/0	4.0/0

Meter 3	3.0/-0.2	1.3/-0.5	3.4/-0.5
Meter A1	6.7/9.3	8.2/9.6	6.2/9.6
Load Meter 3	9.6/9.0	9.4/9.1	9.4/9.1

Table 2 - Microgrid kW loading before/after the static switch opened

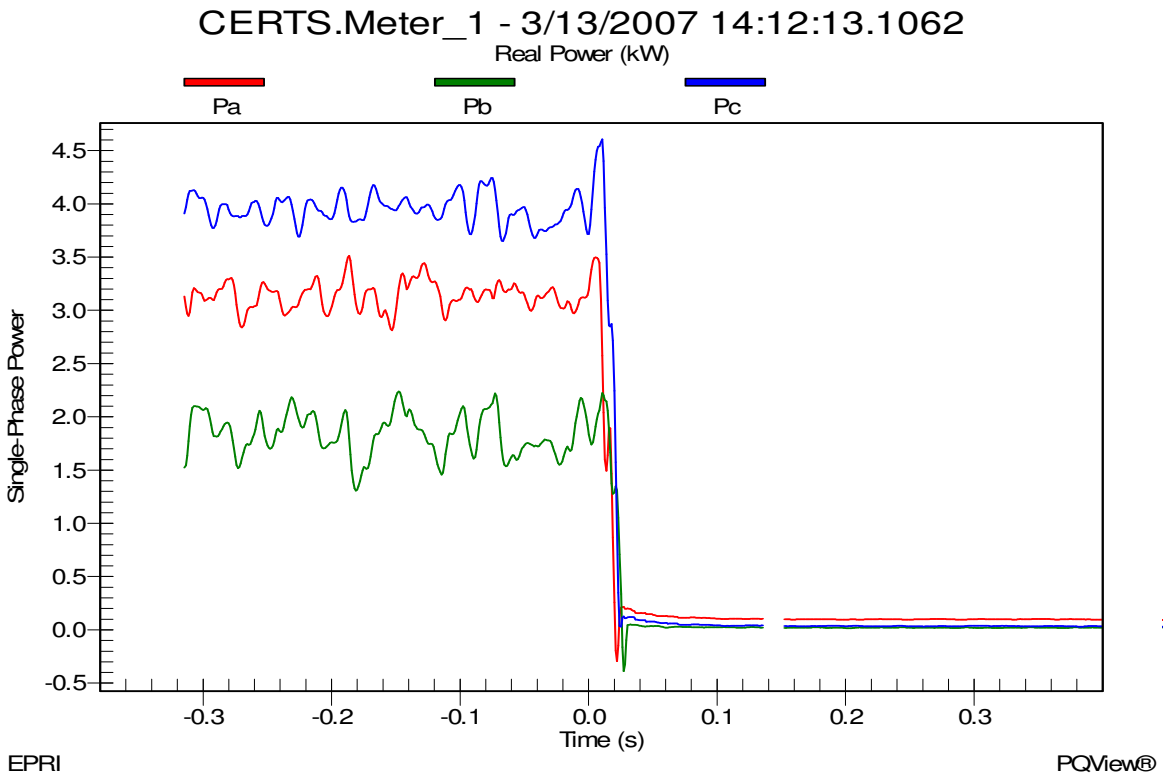

Figure 8a – Meter 1 load decrease after the static switch opened.

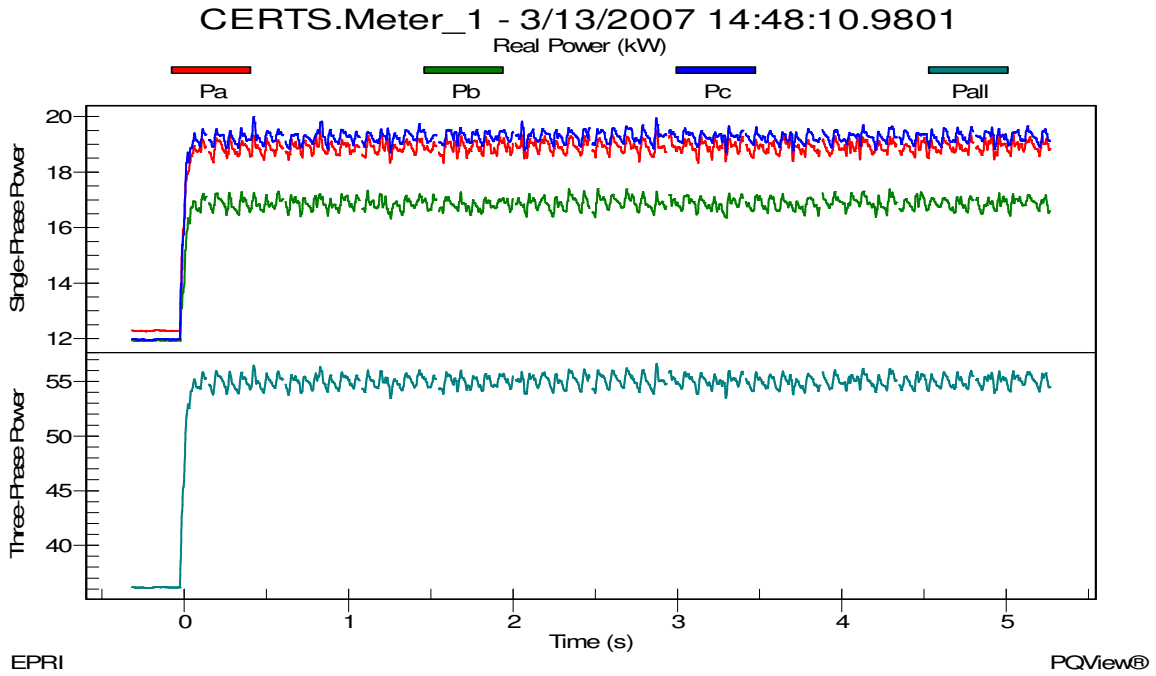

Figure 8b – Load increase at Meter 1 during synchronized close of static switch.

Load Bank 3 and 6 were each set at 40kW. All events and alarms were cleared. The static switch successfully synchronized and reconnected after the "Start" command was initiated with load at Meter 1 increasing from approximately 36kW to 55kW, shown in Figure 8b. During this test the first trigger was noted on reset of the static switch, and the second trigger was caused after the static switch was issued the start command and successfully closed. Likewise, during this transition from island to grid-connected mode, Gen-set A1 decreased its output from 35kW to 18kW, shown in Figure 8c, and frequency increased from 59.86 Hz to 60.01 Hz shown in Figure 8d.

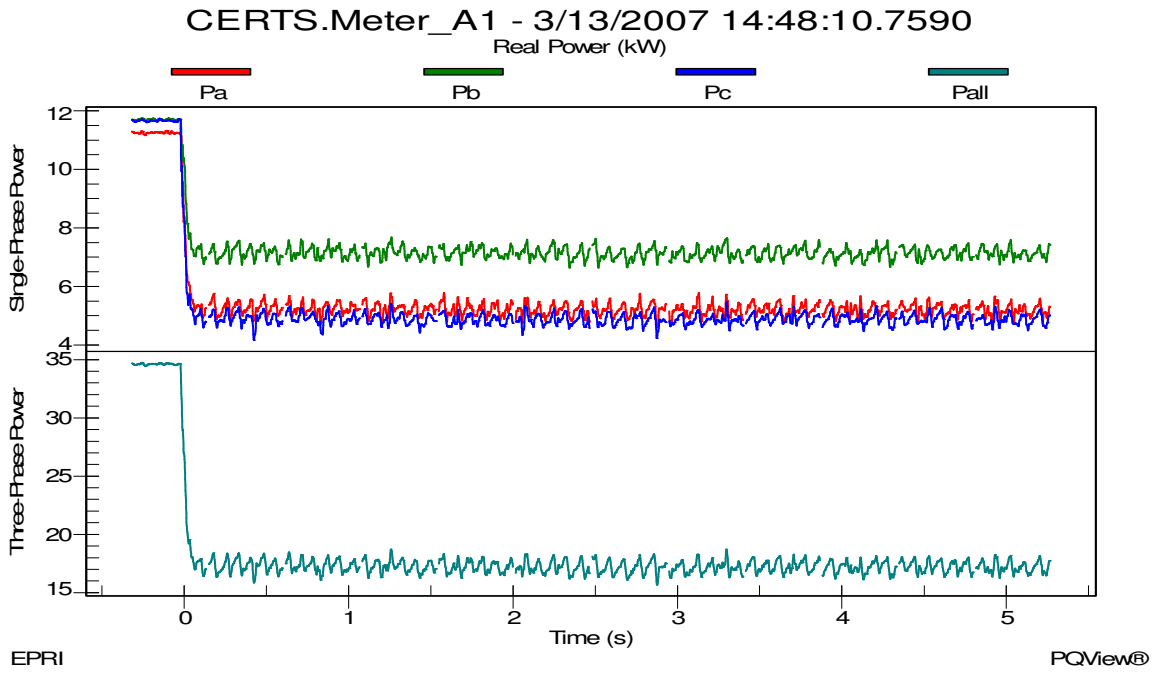

Figure 8c - Gen-set A1 output during synchronized close of static switch

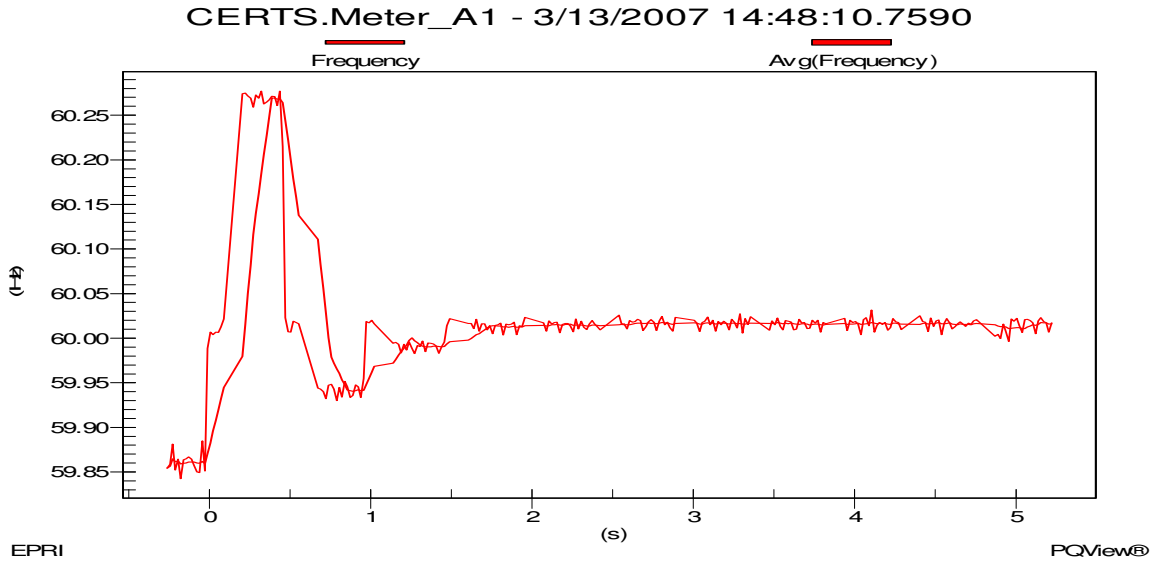

Figure 8d - Frequency on the Microgrid during synchronized close of static switch

6.1.5 De-energized Bus (Dead Bus) Reclose Test

Performance Goal:

Verify that the static switch can close when de-energized bus conditions (< 15V) on the DG side are measured and that the Dead Bus Reclose algorithm requires user intervention (i.e. Operator needs to "Enable: the Dead Bus Reclose using pushbutton in the EMS).

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command =20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = A (Delayed)

Load Bank 3 = 40kW

Load Bank 6 = 40kW

After a few minutes, the "Manual Open" command was removed in the EMS and the static switch remained in the "Open" position. Then a "Dead-Bus Reclose". This Dead-Bus Reclose event was captured in the Event Logger with the change in load at Meter 1 increasing from 36kW to 75kW, shown in Figure 9a. Note, prior to the static switch closing, Meter 1 is serving Load Bank 6 in Zone 6.

During the Dead-Bus Reclose of the microgrid, Figure 9a shows the expected kW inrush, due to transformer T51 (i.e., 112.5kVA rated) which is connected within the microgrid.

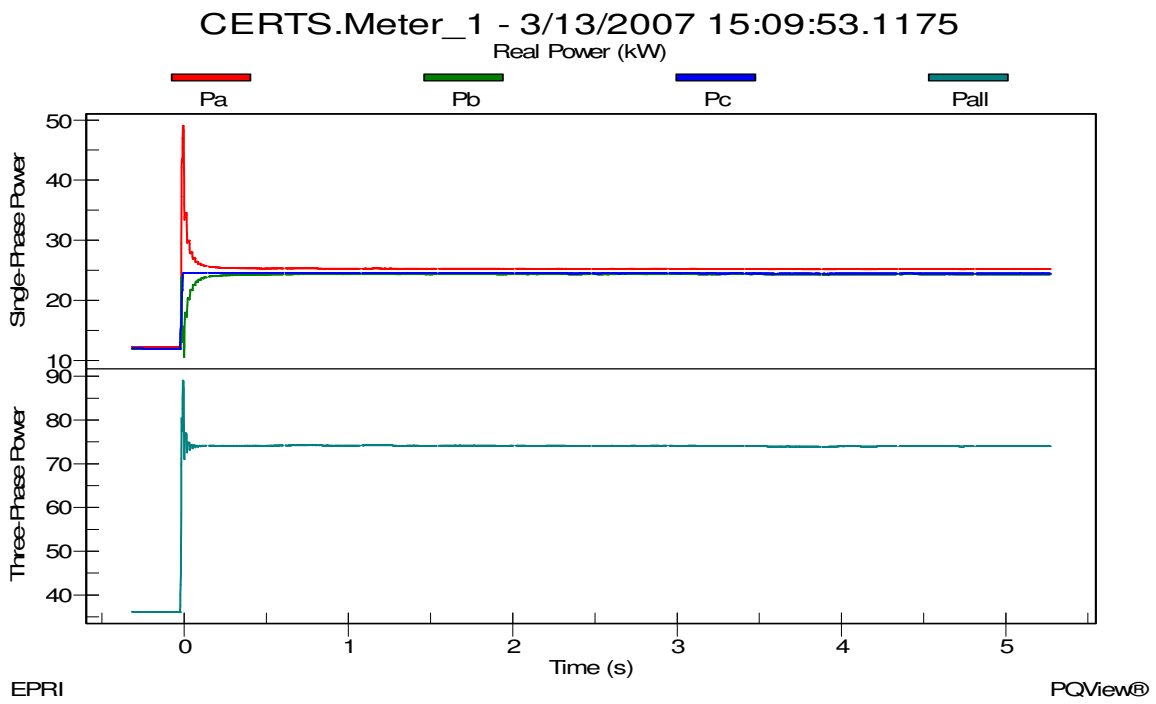

Figure 9a - Load increase at Meter 1 (PCC) during a Dead-Bus Reclose of the static switch

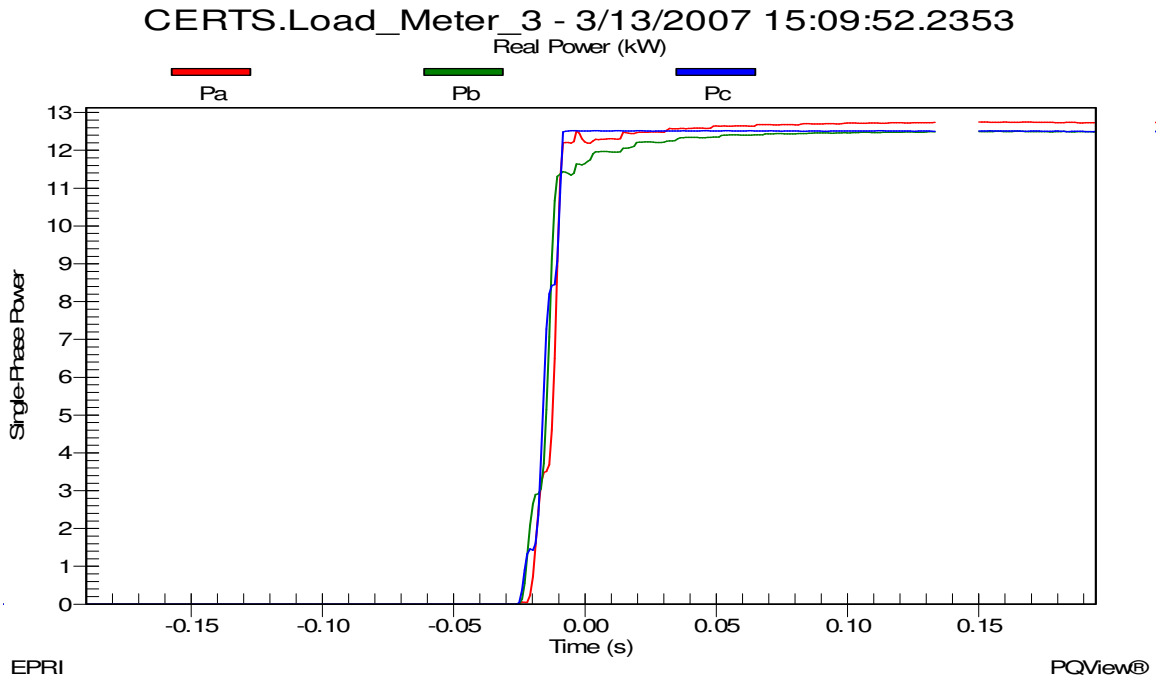

Figure 9b - Load Bank 3 connected in the Microgrid during a Dead-Bus Reclose of the static switch

Load Bank 3 was also connected in the microgrid and set at 40kW (i.e., 13.3kW per phase), but the actual load was approximately 38kW with minimal inrush, shown in Figure 9b, when energized and connected to the utility grid.

After this testing was performed the protection settings were revised, increasing their sensitivity. The updated protection settings no longer allow for a Dead-Bus close to take place successfully, due to the transformer inrush currents.

7.0 CONCLUSION

The series of tests performed in section 6.0 validated the proper control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. These tests provided confidence that the static switch would provide protection and fast disconnect from the utility for the CERTS microgrid during a disturbance for future tests.

One interesting test came during the large load condition in the "Loss of Utility Source Test" in section 6.1.2 where 6 p.u. current was recorded before the Gen-set turned off which seems high but was expected. The inverters on the Gen-sets are 125kVA rated which is twice the rating of the Gen-sets but were artificially limited to half. Also, the inverters were set up to deliver 2.5 p.u. fault current which is approximately 550A peak. This is the close to the 6 p.u. current recorded during the test.



Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 7.0
Validate Protection Settings and Initial Fault Testing

APPENDIX J

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CERTS
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CERTS MICROGRID TEST REPORT

SECTION 7.0

"Validate Protection Settings and Initial Fault Testing"

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as "islanded" from it. This paper describes the tests that were performed in Section 7.0 "Validate Protection Settings & Initial Fault Testing" of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility's distribution system, isolating the microgrid's load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility's electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating

adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to a 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

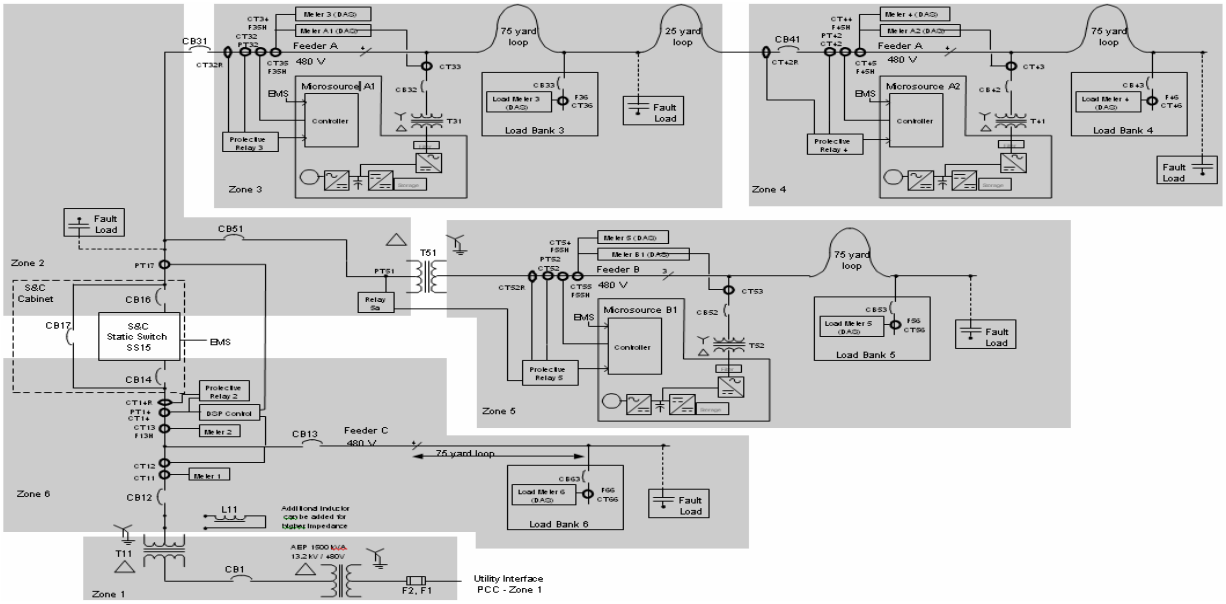

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

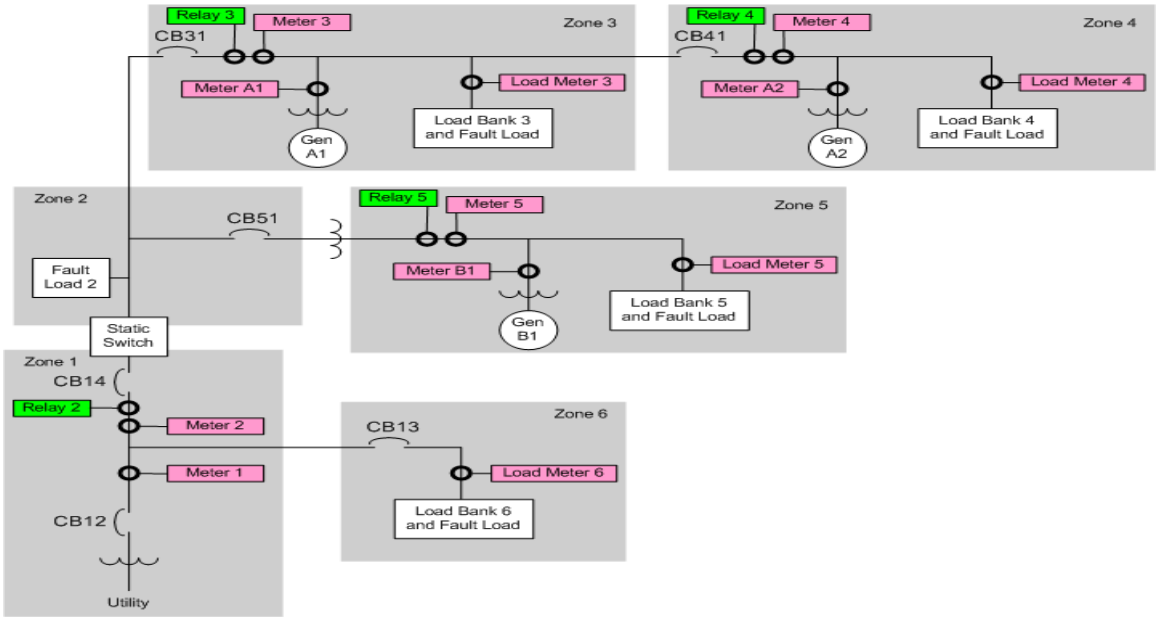

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

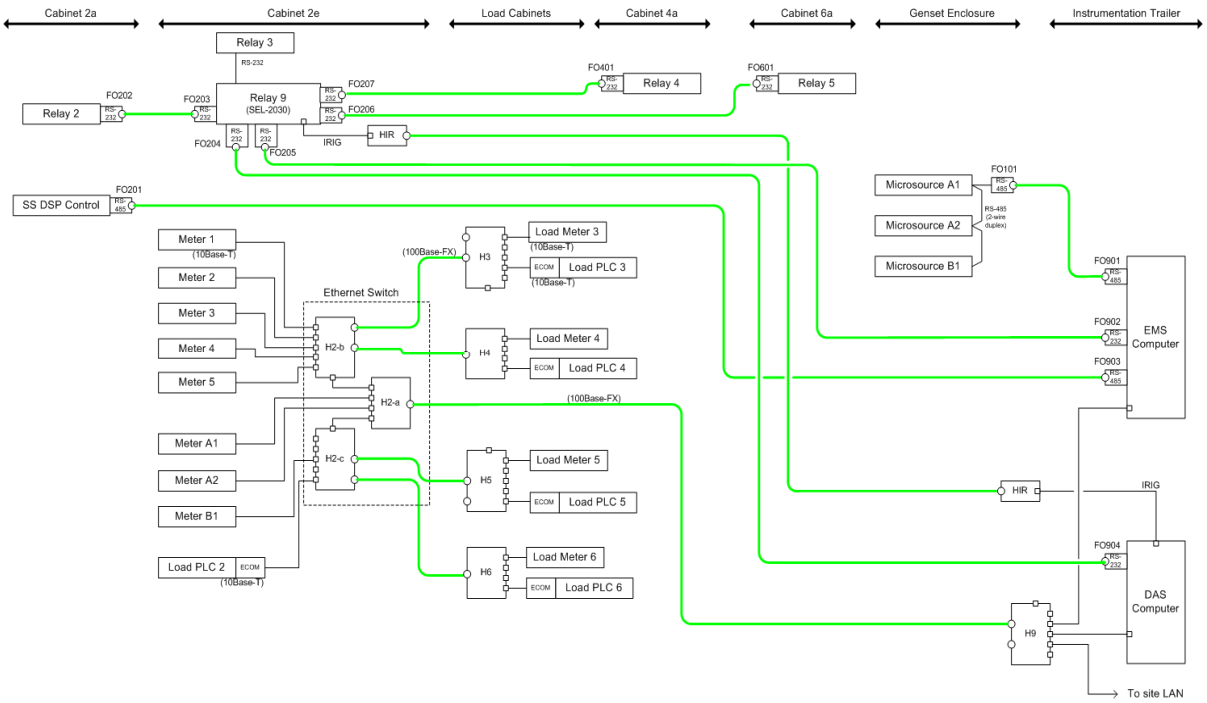

Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – "Purpose, References, and Definitions" describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – "Responsibilities" informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.

- Section 3 – "Training - Team Members" lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.

- Section 4 – "Procedure – CERTS Microgrid Test Bed Lockout/Tagout" entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.

- Section 5 – "Procedure – General" is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.

- Section 6 – "Procedure – Microgrid Test Bed System Checkout" was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.

- Section 7 – "Validate Protection Settings & Initial Fault Testing" is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.

- Section 8 – "Procedure – Reduced System Tests" is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.

- Section 9 – "Procedure – Demonstration Tests of Control Power Flow" demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – "Procedure – Test Difficult Loads" determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.

- Section 11 - "Hazards & Mitigation" informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.

- Section 12 – "Quality Assurance" ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 7.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a "Red" plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

Section 7 was the next set of tests that were developed to demonstrate the CERTS Microgrid protection scheme while connected to the grid and islanded under different overload fault conditions. During each overload fault test event, waveforms of phase currents and line-to-neutral voltages were recorded in DAS at all meter locations and at all relay locations (i.e., Relays 2, 3, 4, & 5). In addition, the relay element that caused the "TRIP" was recorded with trip times for each relay relative to when the fault condition was applied. Tests performed in this section included inductor L11 in the circuit, reflecting weak utility grid conditions.

Test 7.1 induced a three-phase-to-ground balanced overload fault condition in Zone 4 to verify the I^2t protection and a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection. Zone 3 and Zone 5 were tested similar to Zone 4 by introducing a three-phase-to-ground balanced overload fault and a single line-to-ground fault conditions in the zones, verifying the protection scheme in Test 7.2 (Zone 3) and Test 7.3 (Zone 5). During the 7.1, 7.2 and 7.3 tests, all three Gen-sets were off-line and the CERTS Microgrid was connected to the utility. Test 7.4 tested a three-phase-to-ground balanced overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus to confirm a reverse power event after the zone breaker "opens".

Test 7.5 through Test 7.10 involved applying a single line-to-ground overload fault condition in each Zone, located beyond the static switch, while connected to the utility grid. Each one of the six tests differs from one another by which Gen-sets are on-line during the fault, which phase is faulted, and in which zone the fault is applied. These tests were designed to verify zero-sequence, negative-sequence or residual over-current protection settings. Test 7.5 verified the protection in Zone 3 by applying a single line-to-ground overload fault condition with Gen-sets A1 operating in parallel with the utility grid. Test 7.6 tested a single line-to-ground overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.7 tested a single line-to-ground overload fault condition in Zone 5 with Gen-set B1 operating in parallel with the utility grid. Test 7.8 tested a single line-to-ground overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid. Test 7.9 tested a single line-to-ground overload fault condition in Zone 4 with Gen-sets

A1 and A2 operating in parallel with the utility grid. Test 7.10 tested a single line-to-ground overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in parallel with the utility grid.

Tests 7.11 and 7.12 both applied a single line-to-ground overload fault condition in Zone 6 while connected to the utility. Test 7.11 involved only Gen-set A1 operating in parallel with the grid; and Test 7.12 involved Gen-sets A1 and B1 operating in-parallel with the grid. Both tests were designed to verify the I^2t protection of the breaker in Zone 6.

The four tests, 7.13 – 7.16, applied a line-to-line overload fault condition in one of the five zones beyond the static switch with a combination of two Gen-sets, operating in parallel with the utility grid. These tests were designed to test negative-sequence, I^2t protection or residual over-current protection settings. Test 7.13 tested a phase-to-phase overload fault condition in Zone 3 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.14 tested a phase-to-phase overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in parallel with the utility grid. Test 7.15 tested a phase-to-phase overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid. Test 7.16 tested a phase-to-phase overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in parallel with the utility grid.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 7 – VALIDATE PROTECTION SETTINGS & INITIAL FAULT TESTING

6.1.1 Zone 4 Circuit Breaker Settings and Utility Connected

Performance Goal:

Initially test a three-phase-to-ground balanced overload fault in Zone 4 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 4 to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Relay Settings = A (Delayed)

Load Bank 4 = 60kW

Load Bank 6 = 10kW

To simulate a high impedance three-phase-to-ground fault in Zone 4, the

Overload Load Bank of 85kW was connected by cable/plug into the exterior receptacle of Cabinet 5a. This would add an additional 85kW to Zone 4 when initiated, causing an overload because the load is currently set at 60kW from Load Bank 4.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 55kW at Meter 2. A simulated fault (i.e., Overload Load Bank of 85kW) with a duration set for 99 seconds was initiated to Zone 4 from the DAS Load Control Program. Figure 10a shows when the overload bank was initiated and the load in Zone 4 increased from approximately 55kW to 130kW.

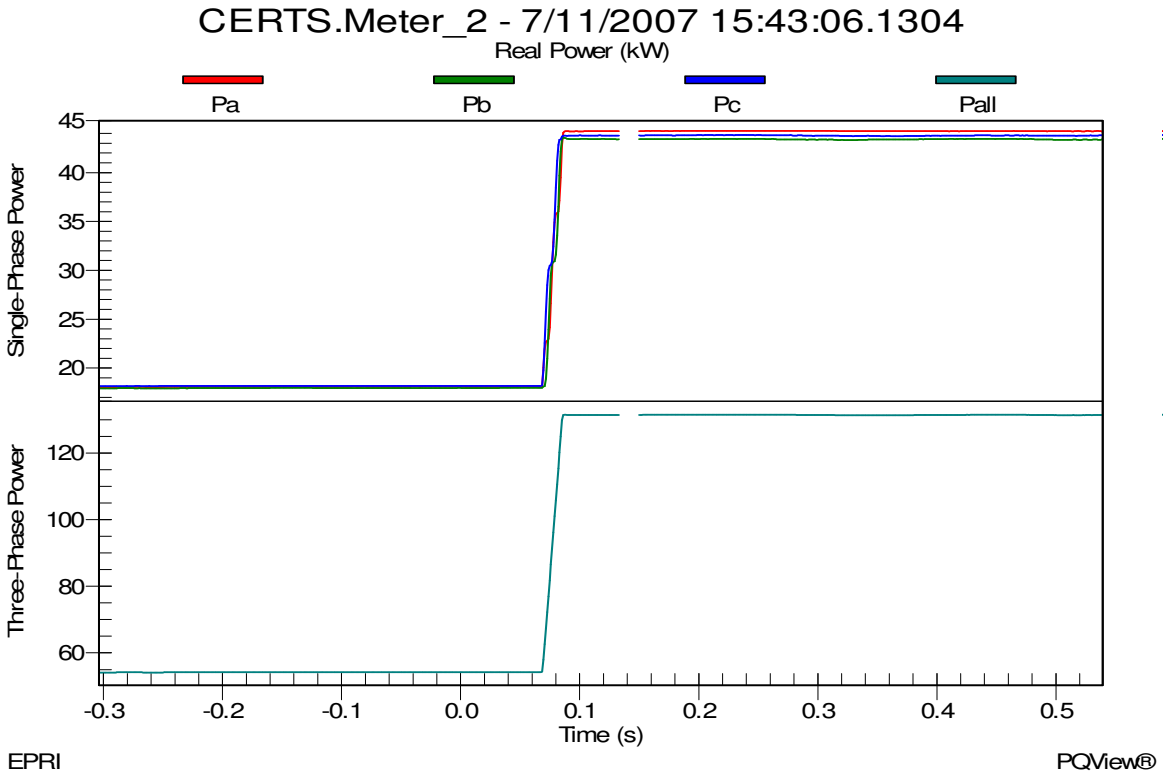

Figure 10a - Load in Zone 4 when the overload fault is initiated

When the load increased in Zone 4, CB41 internally detected an I^2t protection event and opened after 71.3 seconds, clearing the fault from Zone 4, shown in Figure 10b.

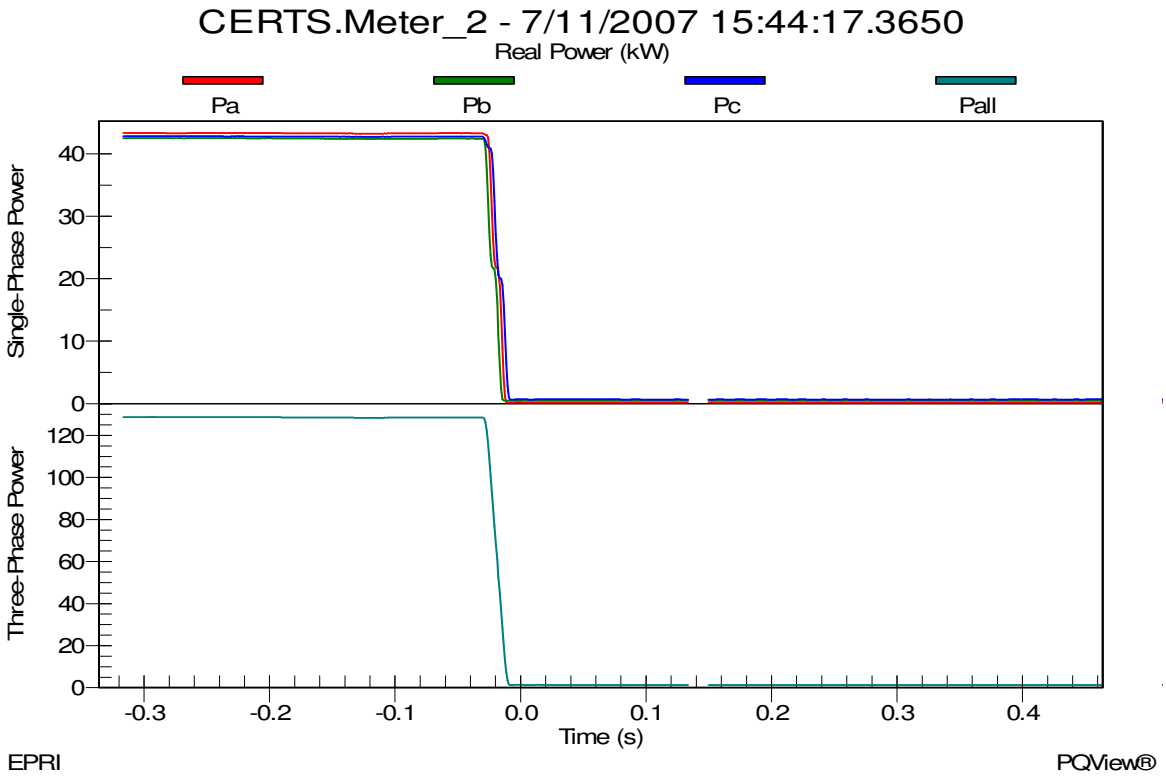

Figure 10b - Load in Zone 4 after circuit breaker CB41 "Opens" to isolate and clear the fault

The static switch, nor any of the other breakers, opened up at the time the fault was initiated. The main purpose of this test was designed for CB41 to isolate the fault and then clear it.

Once the fault was cleared and all the alarms and circuit breakers were reset and brought back to the initial setup, the Overload Load Bank in Cabinet 5A was reconfigured from a three-phase-to-ground fault into a single phase-to-ground fault. This was accomplished by removing phases B and C from the Overload Load Bank cabling which leaves approximately 28.3kW on A-phase when the fault is initiated.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 51kW at Meter 2. A simulated overload fault (i.e., Overload Load Bank of 28.3kW on A-phase) with a duration set for 10 seconds was initiated to Zone 4 from the DAS Load Control Program. Figure 10d shows when the overload bank was initiated and load in Zone 4 increased from approximately 52kW to 75kW three-phase power and approximately 17.5kW to 41kW on A-phase. Also in Figure 10d, you can see where the fault is cleared and the load is reduced to 0kW.

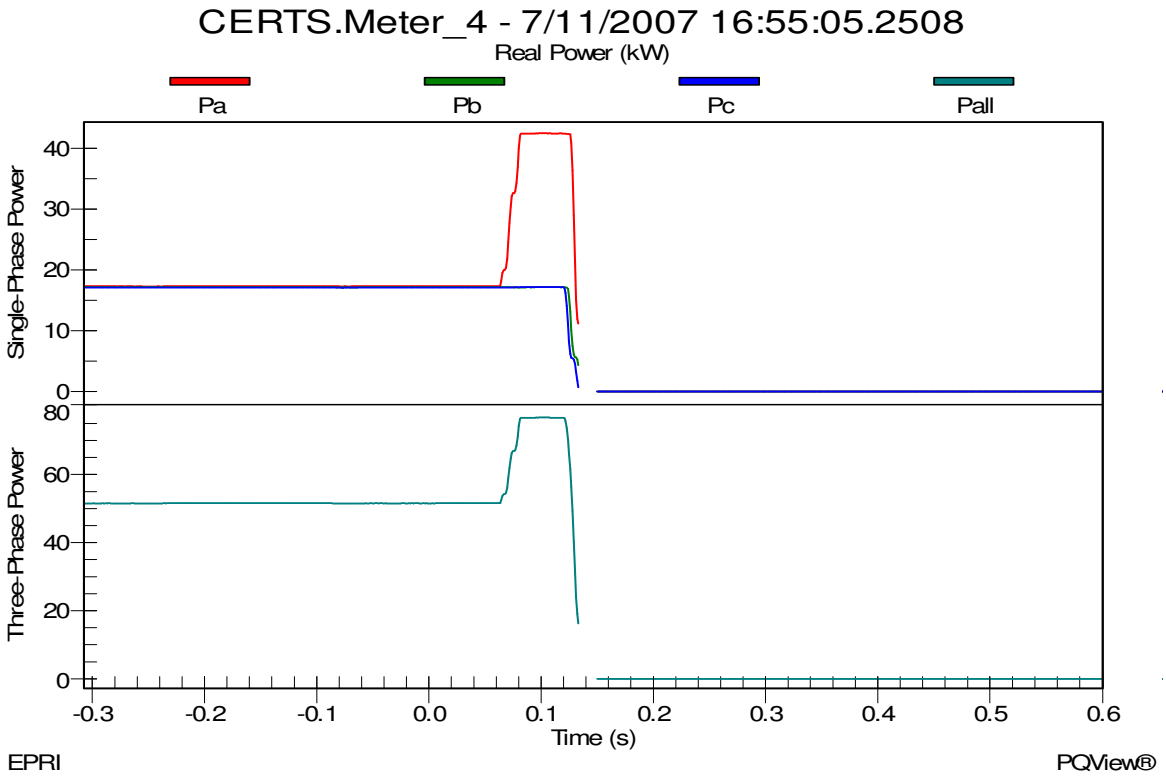

Figure 10d - Load in Zone 4 before/after the single phase-to-ground fault is applied

It's important to note that all four protection relays (i.e., relays 2 through 5) have residual CT's wired to the neutral input of the relay. Thus, any neutral current measurements are actually measurements of ground current.

When the load increased in Zone 4, the static switch (i.e., Relay 2) detected a ground over-current (67N1T), shown in Figure 10e. The static switch opened after 0.023 seconds (1.5 cycles) clearing the fault from Zone 4, shown in Figures 10d and 10e.

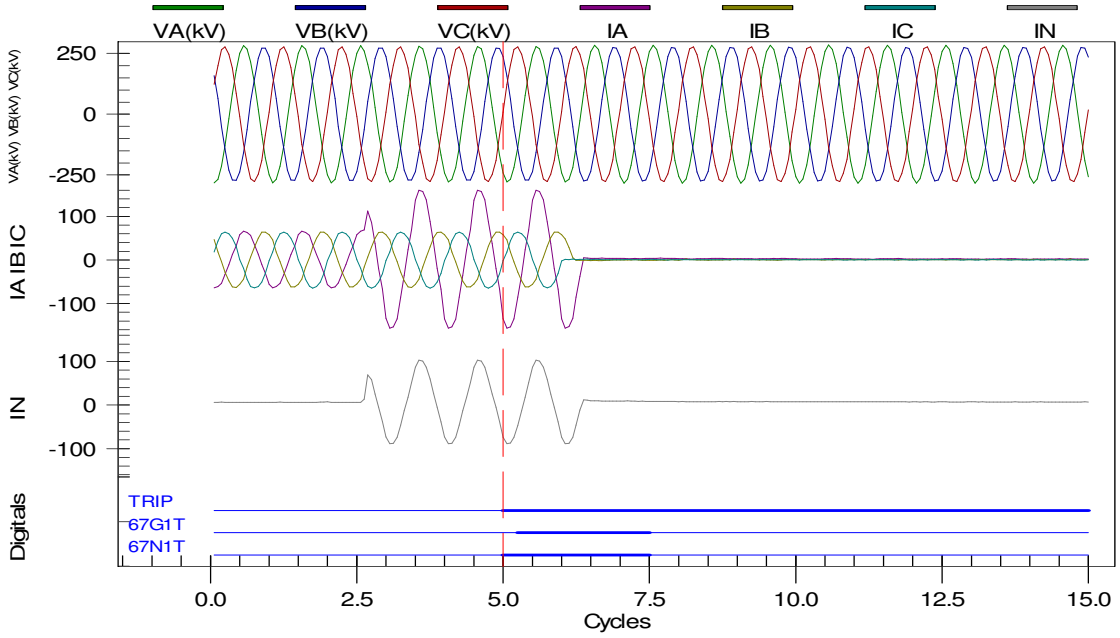

Figure 10e - Voltages, Currents, and Ground Current (IN) at Relay 2 when the fault is detected and cleared by the static switch.

After the static switch opened, the breakers in protection zones (i.e., CB31 in Zone 3, CB41 in Zone 4 and CB51 in Zone 5) remained closed. This was expected since the fault was isolated and cleared by the static switch.

The electrical system was stable in both the microgrid and utility grid, after CB41 opened for the three-phase-to-ground fault. In addition the static switch opened for a single phase-to-ground fault condition in Zone 4, separating the microgrid from the utility system. All loads and alarms were reset and equipment was prepared for the next test.

6.1.2 Zone 3 Circuit Breaker Settings and Utility Connected

Performance Goal:

Initially test a three-phase-to-ground balanced overload fault condition in Zone 3 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 3 to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Relay Settings = A (Delayed)

Load Bank 3 = 75kW

Load Bank 4 = 75kW

Load Bank 6 = 10kW

To simulate a high impedance three-phase-to-ground fault in Zone 3, the

Overload load Bank of 85kW was connected by cable/plug into the exterior receptacle of Cabinet 3a. This additional 85kW of load in Zone 3 when initiated would cause an overload in Zone 3, because load is currently set at 75kW in Load Bank 3 and in Load Bank 4.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 140kW at Meter 2**.** A simulated fault (i.e., Overload Load Bank of 85kW) with a duration set for 99 seconds was initiated to Zone 3 from the DAS Load Control Program. Figure 11a shows when the overload bank was initiated and load in Zone 3 increased from approximately 140kW to 220kW.

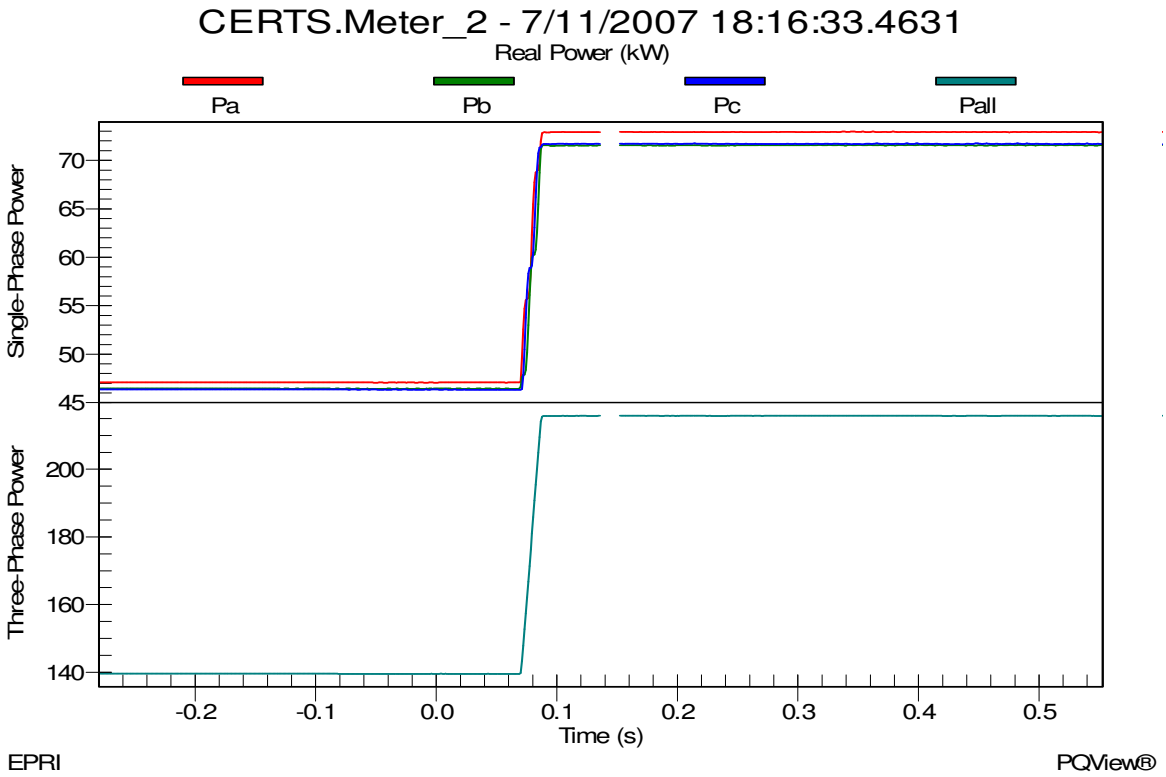

Figure 11a – Load change due to Zone 3 when the overload fault was initiated

When the load increased in Zone 3, CB31 internally detected an I^2t protection event and opened after 84 seconds, clearing the fault from Zone 3, as shown in Figure 11b.

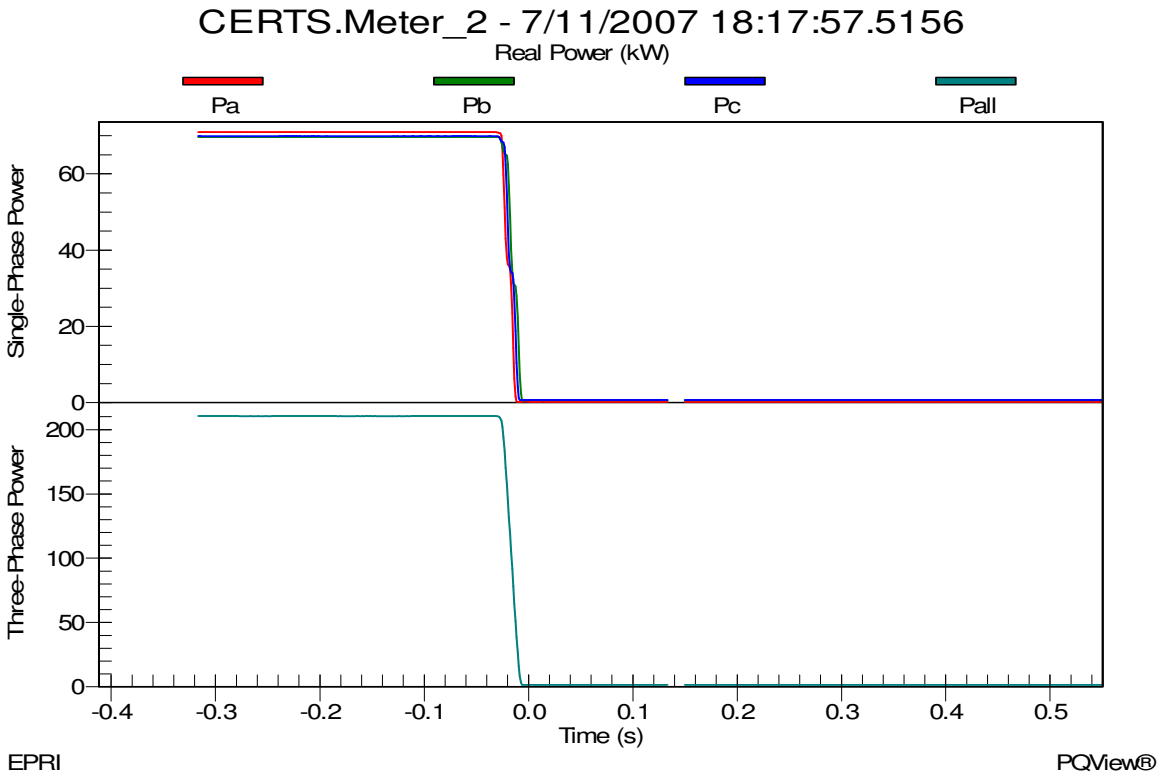

Figure 11b - Load change in Zone 3 after CB31 opened" to isolate and clear the fault

The static switch, nor any of the other breakers, opened at the time when the fault was initiated. The main purpose of this test was designed for CB31 to isolate the fault in Zone 3 and then clear it.

Once the fault was cleared, all alarms and circuit breakers were reset and brought back to the initial setup. In addition, the load in Load Bank 3 and in Load Bank 4 was reset to 60kW. The Overload Load Bank in Cabinet 3 was reconfigured from a three-phase-to-ground fault into a single phase-to-ground fault. This was accomplished by removing phases A and C from the Overload Load Bank cabling which leaves approximately 28.3kW on B-phase when the fault is initiated.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 111kW at Meter 2. A simulated fault (i.e., Overload Load Bank of 28.3kW on B-phase) with a duration set for

10 seconds was initiated to Zone 3 from the DAS Load Control Program. Figure 11c shows when the overload bank was initiated and load in Zone 3 increased from approximately 111kW to 133kW three-phase power and approximately 35kW to 60kW on B-phase. Also, Figure 11c, shows where the fault is cleared and load is reduced to 0kW.

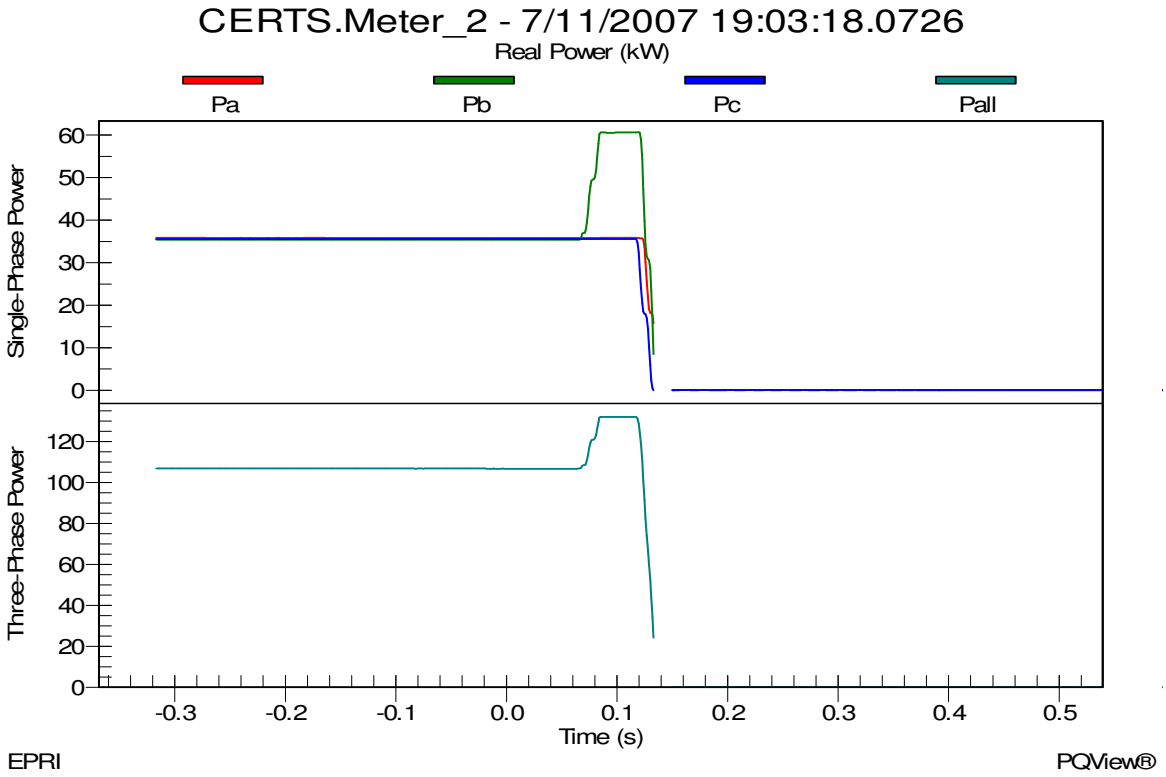

Figure 11c - Load change before/after the single phase-to-ground fault was applied in Zone 3.

When load increased in Zone 3, the static switch (Relay 2) detected a ground over-current (67N1T) shown in Figure 11d. The static switch then "Opens" after 0.016 seconds (1 cycle) clearing the fault from Zone 3 shown in Figures 11c and 11d.

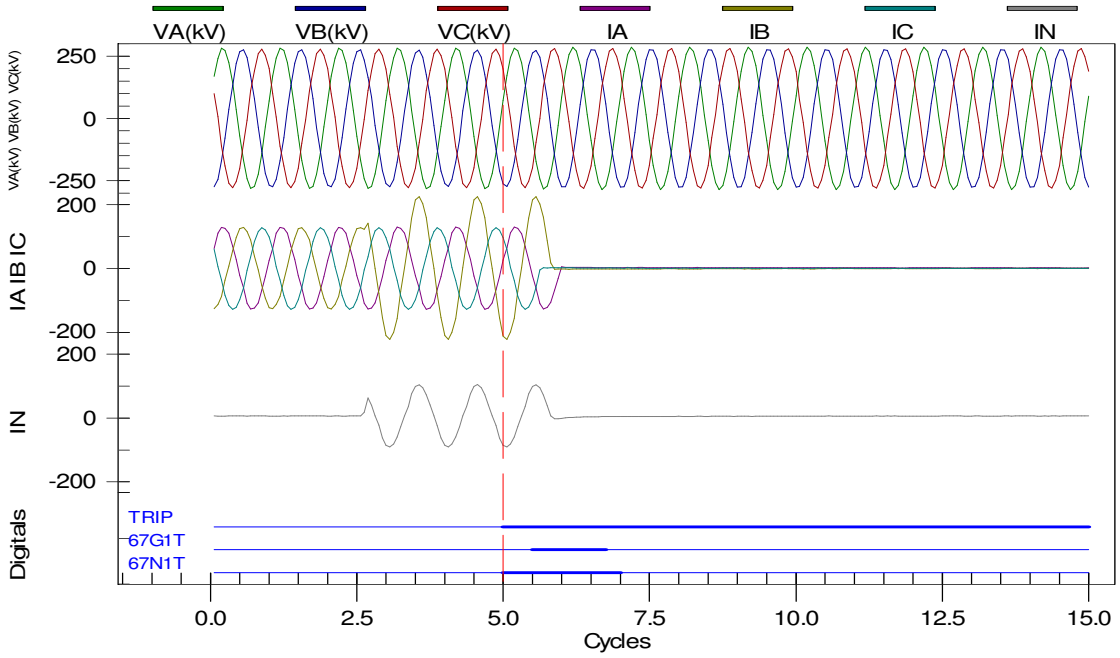

Figure 11d - Voltages, Currents, and Ground current (IN) at Relay 2 when the fault is detected and cleared by the static switch

After the static switch opened, the breakers in the protection zones (i.e., CB31 in Zone 3, CB41 in Zone 4 and CB51 in Zone 5) remained closed. This was expected, since the fault was isolated and cleared by the static switch.

The electrical system was stable in both the microgrid and utility grid, after circuit breaker CB31 opened for the three-phase-to-ground overload fault. In addition, the static switch opened for a single phase-to-ground fault condition in Zone 3, separating the microgrid from the utility system. All loads and alarms were reset and equipment was prepared for the next test.

6.1.3 Zone 5 Circuit Breaker Settings and Utility Connected

Performance Goal:

Initially test a three-phase-to-ground balanced overload fault condition in Zone 5 to verify I^2t protection. Then test a single line-to-ground fault condition in Zone 5 to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Relay Settings = A (Delayed)

Load Bank 5 = 60kW

To simulate a high impedance three-phase-to-ground fault in Zone 5, the

Overload Load Bank of 85kW was connected by cable/plug into the exterior receptacle of Cabinet 7a. This additional 85kW of load in Zone 5 when combined with the 60kW in Load Bank 5 causes an overload condition.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 55kW at Meter 2**.** A simulated fault (i.e., Overload Load Bank of 85kW) with the duration set for 99 seconds was initiated in Zone 5 from the DAS Load Control Program. Figure 12a shows when the overload bank was initiated and load in Zone 5 increased from approximately 55kW to 130kW.

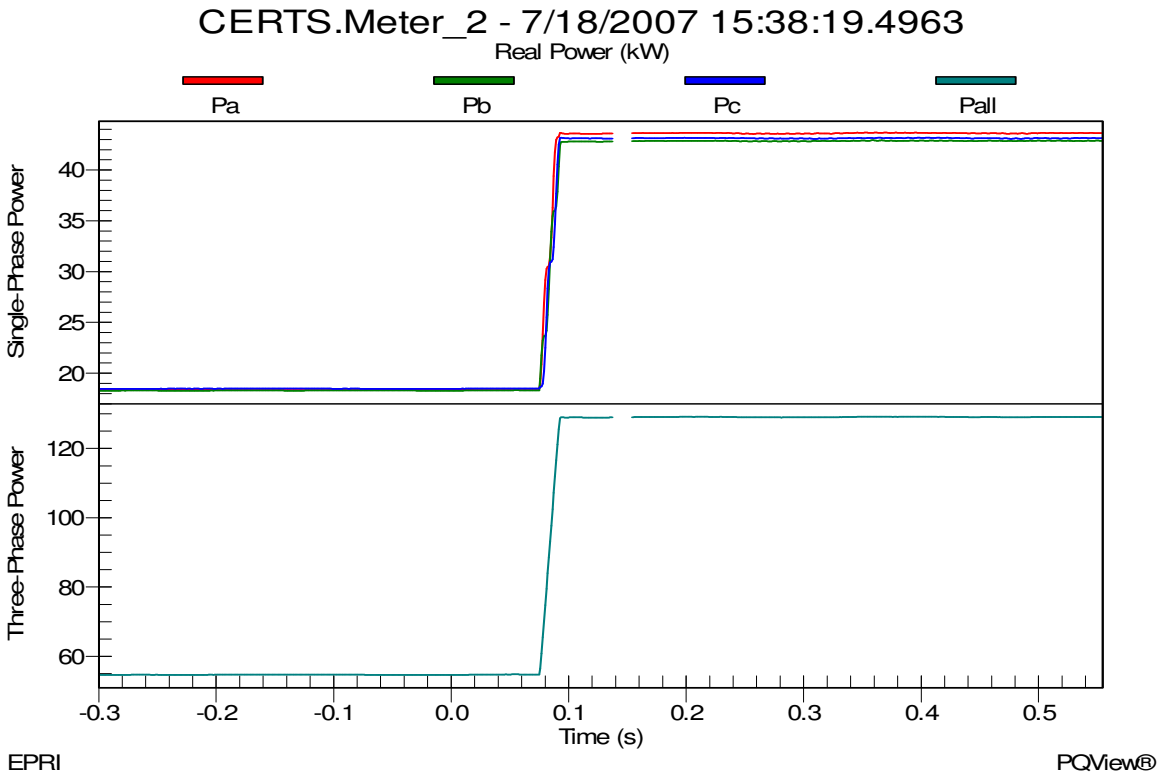

Figure 12a - Load change when the overload fault was initiated in Zone 5.

When the load increased in Zone 5, CB51 internally detected an I^2t protection event and opened after 72.8 seconds, clearing the fault from Zone 5, as shown in Figure 12b.

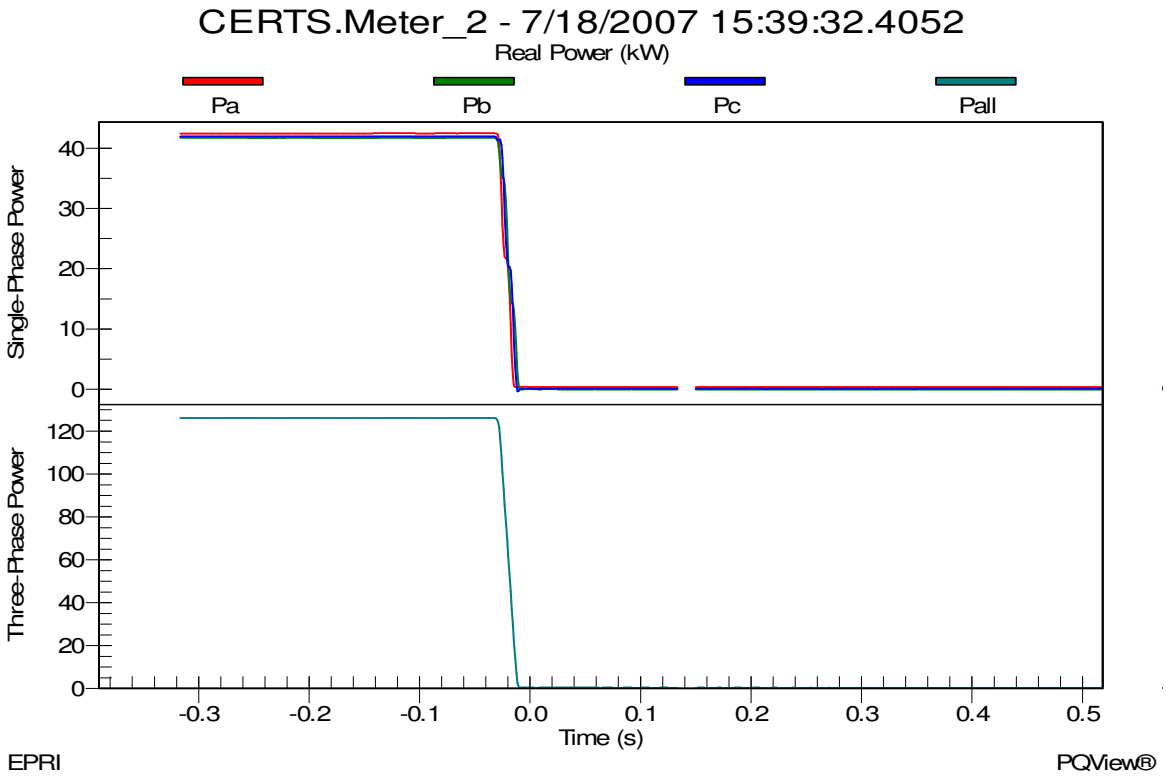

Figure 12b - Load change before/after CB51 opened to isolate and clear the fault in Zone 5.

The static switch, nor any of the other breakers, opened at the time the fault was initiated. The main purpose of this test was designed for CB51 to isolate the fault in Zone 5 and then clear it.

Once the fault was cleared and all the alarms and circuit breakers were reset and brought back to the initial setup, the Overload Load Bank in Cabinet 7a was reconfigured from a three-phase-to-ground fault into a single phase-to-ground fault. This was accomplished by removing phases A and B from the Overload Load Bank cabling which leaves approximately 28.3kW on the C-phase when the fault is initiated.

After the dead-bus closing of the static switch from the EMS, the Microgrid Test

Bed was connected to the utility grid with approximately 54kW at Meter 2. A simulated fault (i.e., Overload Load Bank of 28.3kW on C-phase) with a duration set for 10 seconds was initiated to Zone 5 from the DAS Load Control Program. Figure 12c shows when the overload bank was initiated and the load in Zone 5 increased from approximately 51kW to 74kW three-phase power and approximately 16.5kW to 40kW on C-phase. Also, Figure 12ce, shows where the fault is cleared and the load is reduced to 0kW.

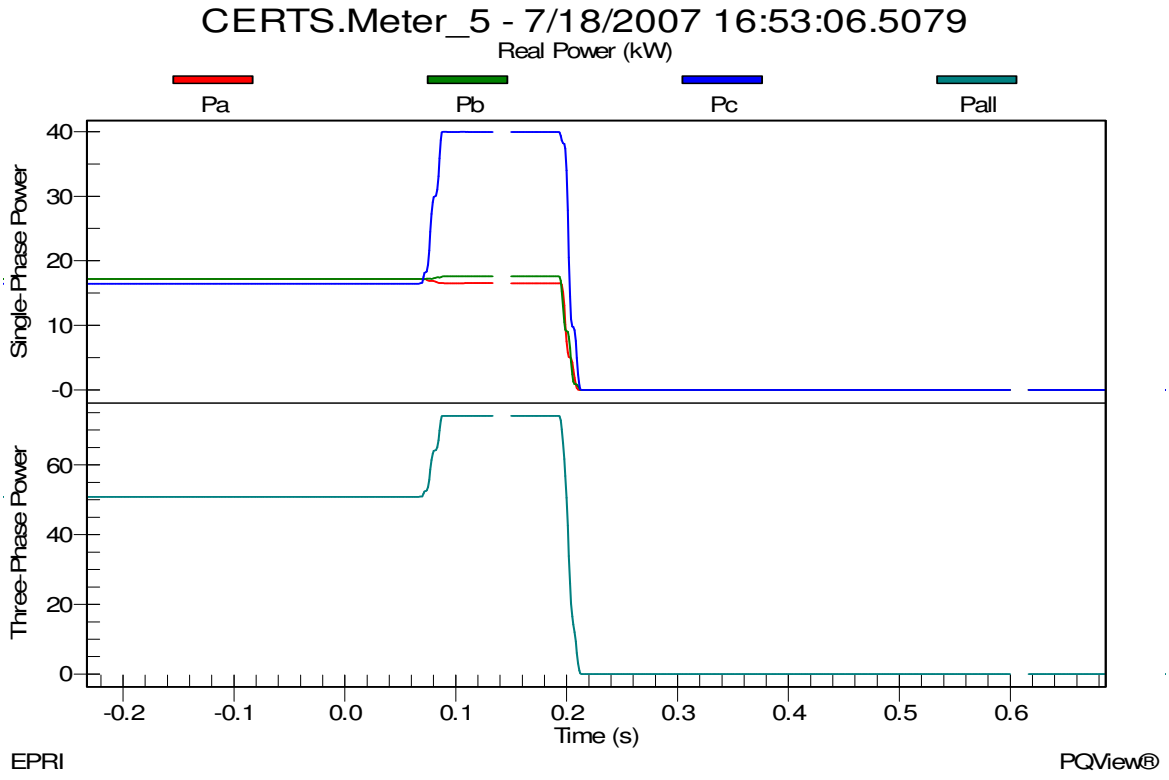

Figure 12c - Load in Zone 5 before/after the single phase-to-ground fault was applied.

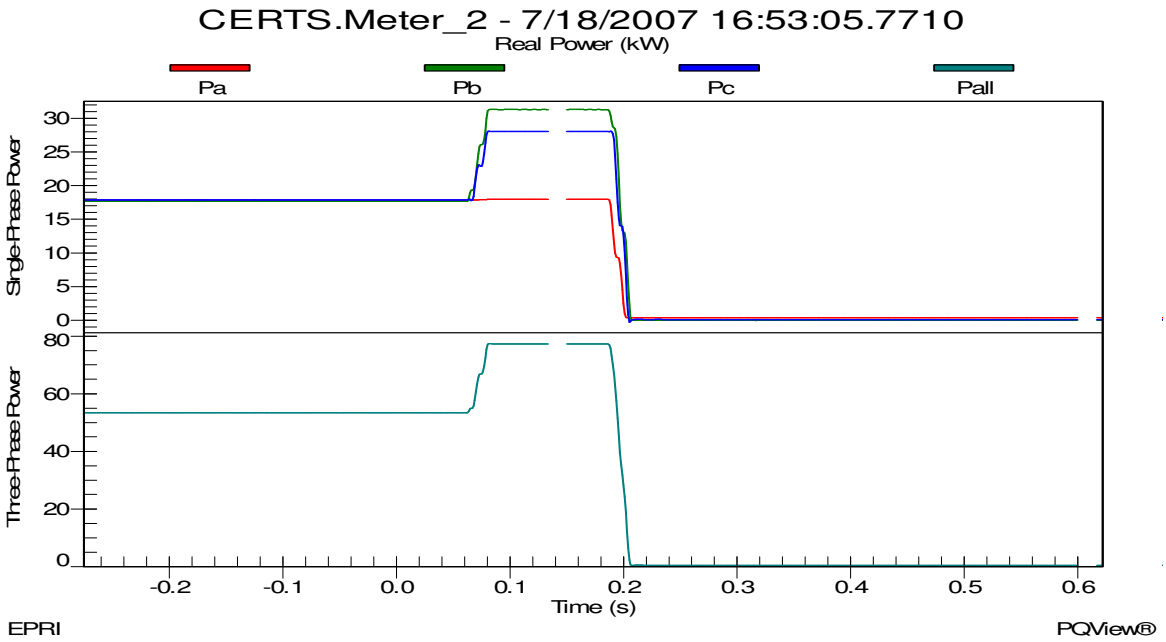

Figure 12d - Load change before/after the single phase-to-ground fault was applied in Zone 5.

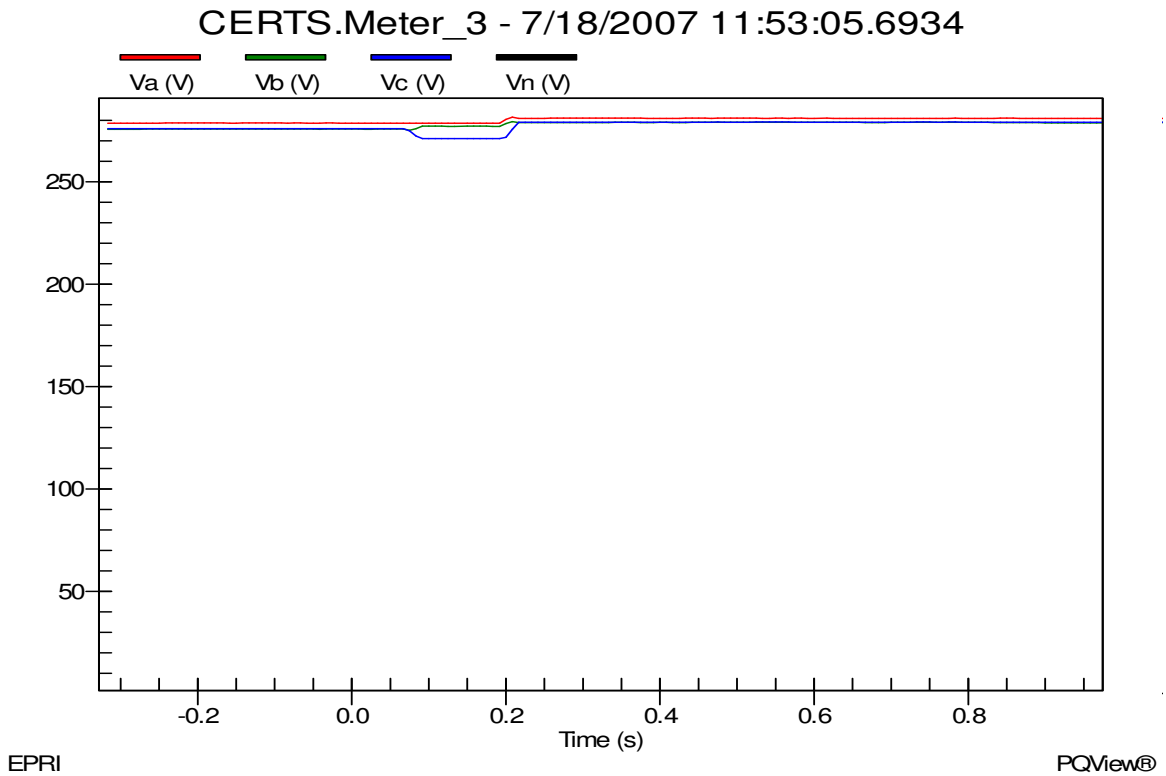

Figure 12e – RMS Voltage in Zone 3 before/after the single phase-to-ground fault was applied

From Figure 12d it can be seen at the static switch that the phase C real power appears reduced in magnitude and distributed over both phases B and C. This reduces the sensitivity of the static switch to this type of fault in Zone 5. From Figure 12e it is apparent that the static switch did not operate, since the RMS voltage never collapsed.

When the load increased in Zone 5, Relay 5 detected a negative-sequence over-current (67Q1T) event, shown in Figure 12f. CB51 opened and cleared the fault from Zone 5 shown in Figure 12f. The opening of CB51 was past the end of the recorded relay waveform, but it can be seen that the real power at Meter 5 reduces to zero, shown in Figure 12c.

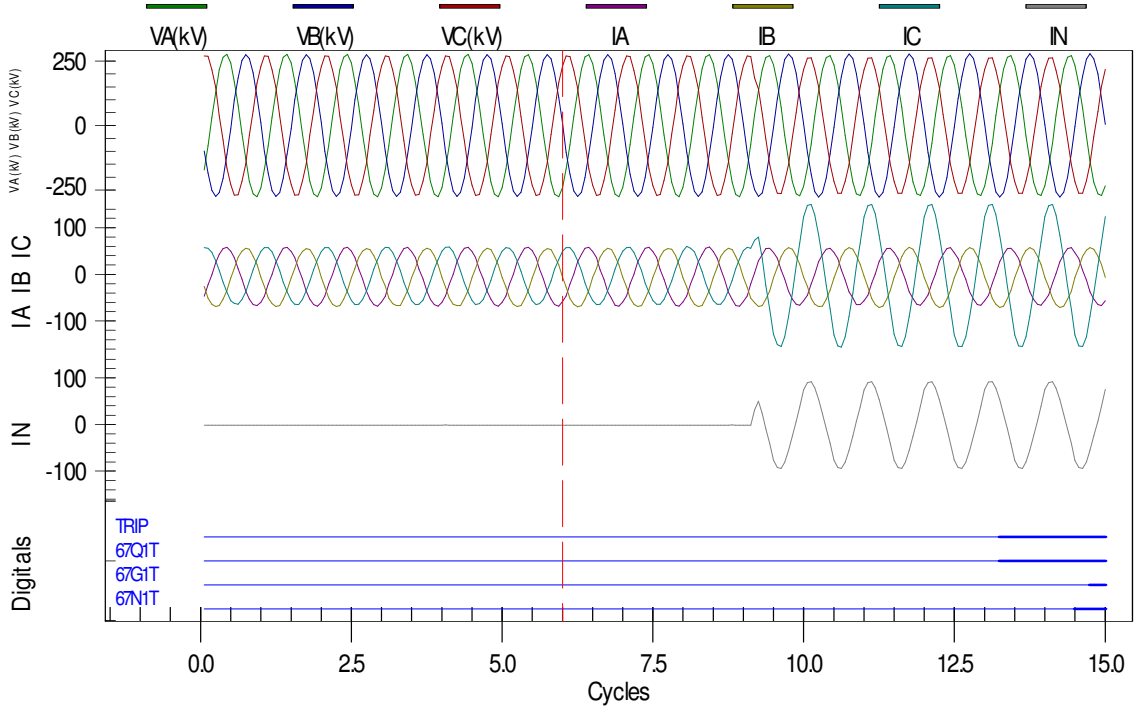

Figure 12f - Voltages, Currents, and Sequence Currents at Relay 2 when the fault was detected and cleared by the static switch.

After circuit breaker CB51 opened, the breakers in other protection zones, (i.e., CB31 in Zone 3 and CB41 in Zone 4) and the static switch remained closed. This was expected since the fault was isolated and cleared by CB51 in Zone 5.

The electrical system was stable in both the microgrid and utility grid after CB51 opened for both single phase-to-ground and three-phase-to-ground fault conditions in Zone 5. All loads and alarms were reset and equipment was prepared for the next test.

6.1.4 Zone 4 Three-Phase Grounded Fault, Gen-sets (A1+A2) and Utility Connected

Performance Goal:

Test a three-phase-to-ground balanced overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify I^2t protection, plus confirm a reverse power event after the Zone breaker "Opens".

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set A1 Output Power Command = 50kW

Gen-set A2 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833Hz/kW

MG Voltage Command = 277V

Reverse Power Set-point = 0kW

Load Bank 3 = 10kW

Load Bank 6 = 40kW

Load Bank 4 = 65kW

To simulate a high impedance three-phase-to-ground fault in Zone 4, the

Overload Load Bank of 85kW was connected by cable/plug into the exterior receptacle of Cabinet 5a. This additional 85kW of load in Zone 4 when initiated and combined with the 65kW in Load Bank 4 would cause an overload condition.

After both Gen-sets A1 and A2 were running for a few minutes and supplied power to Load Bank 3 and Load Bank 4, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid was connected to the utility grid with total power flow at Meter 1 equaling approximately 45kW and approximately 5kW at Meter 2. Figure 13a shows when the

overload fault was applied in Zone 4, the load increased from 45kW to approximately 125kW at Meter 1.

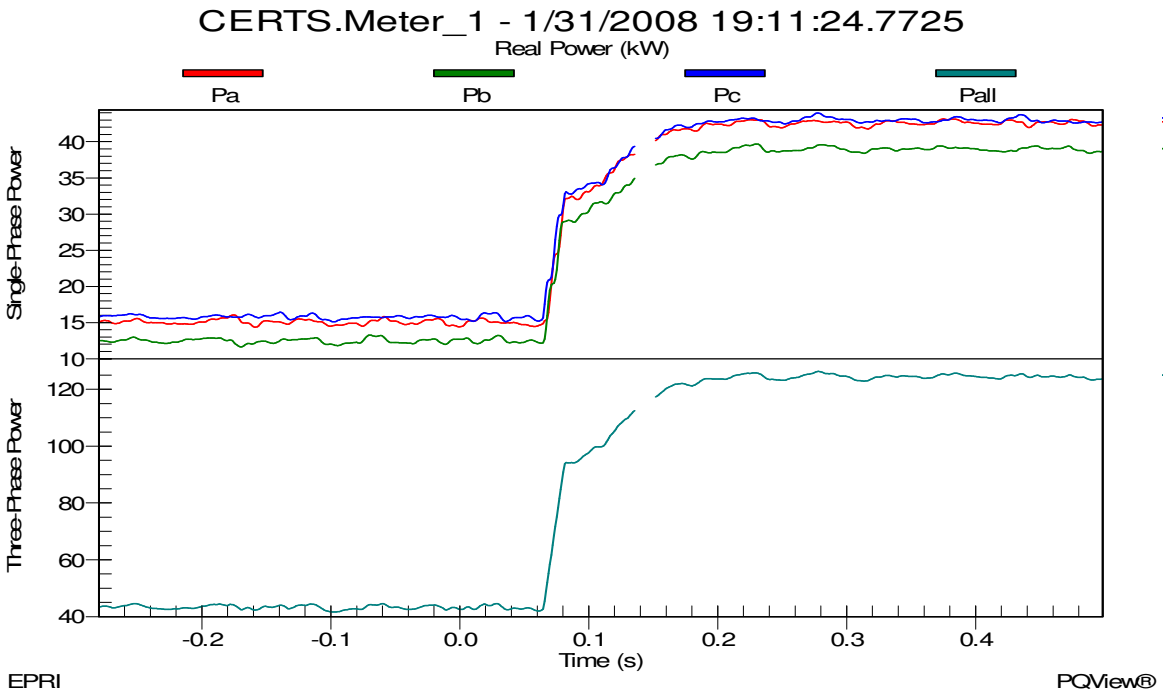

Figure 13a - Power flow at Meter 1 before/after the overload fault was applied.

Using the DAS Load Control program, the three-phase ground fault was set for a duration of 99 seconds and then initiated. CB41 tripped on an I^2t protection event in 86 seconds, shown in Figures 13b, which isolated and cleared the fault as expected in Zone 4. Zone 3 and Gen-set A1 remained connected, displacing the load in Zone 6, as shown in Figure 13b with minus 37kW through the static switch. This results in approximately zero load at the PCC, which in-turn caused the static switch to open after 30 seconds due to a reverse power event.

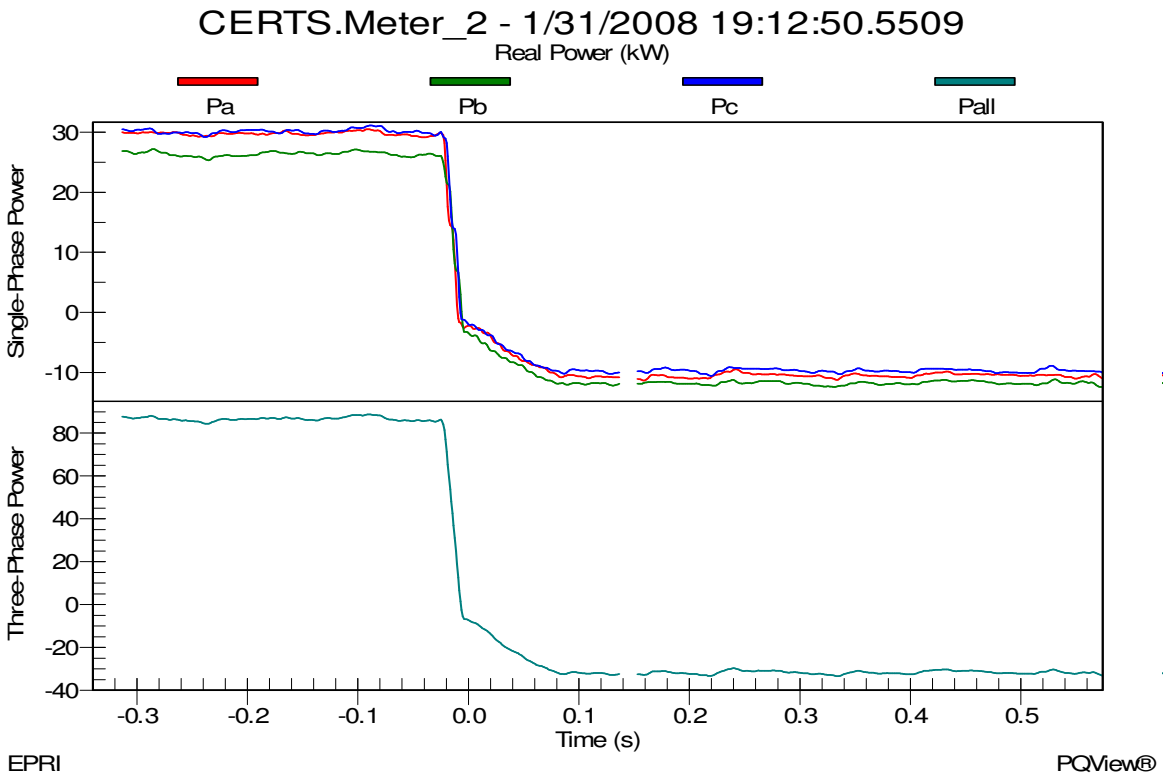

Figure 13b - Power flow at Meter 2 before/after CB41 opened.

Gen-set A2 shut down 0.2619 seconds (~16 cycles) after CB41 opened to clear the fault, shown in Figure 13c. Gen-set A1 remained online after Gen-set A2 shutdown producing approximately 47kW. Note, in Figure 13d there is an instance where Gen-set A1 drops from approximately 47kW to 22kW, which is due to Load Bank 4 being disconnected

from the microgrid. Since Gen-set A1 was set for a Unit Power Control of 50kW and there was only 10kW worth of load from Load Bank 3 within the microgrid a reverse power flow occurred opening the static switch islanding it from the utility grid. The static switched opened approximately 56.2 seconds after CB41 opened and Gen-set A1 remained online, serving the microgrid load. Figure 13e shows Gen-set A1 picking up the load from Load Bank 3, approximately 12kW after the static switch opened.

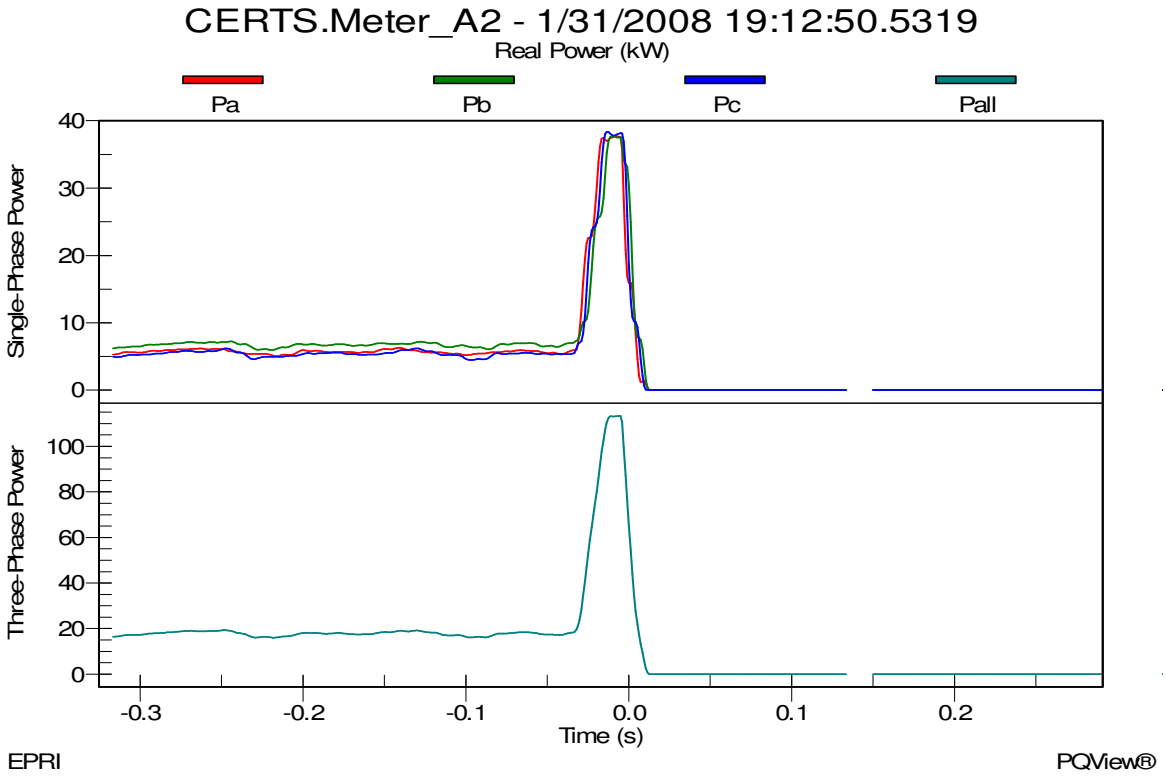

Figure 13c - Gen-set A2 shutting down after CB41 opens

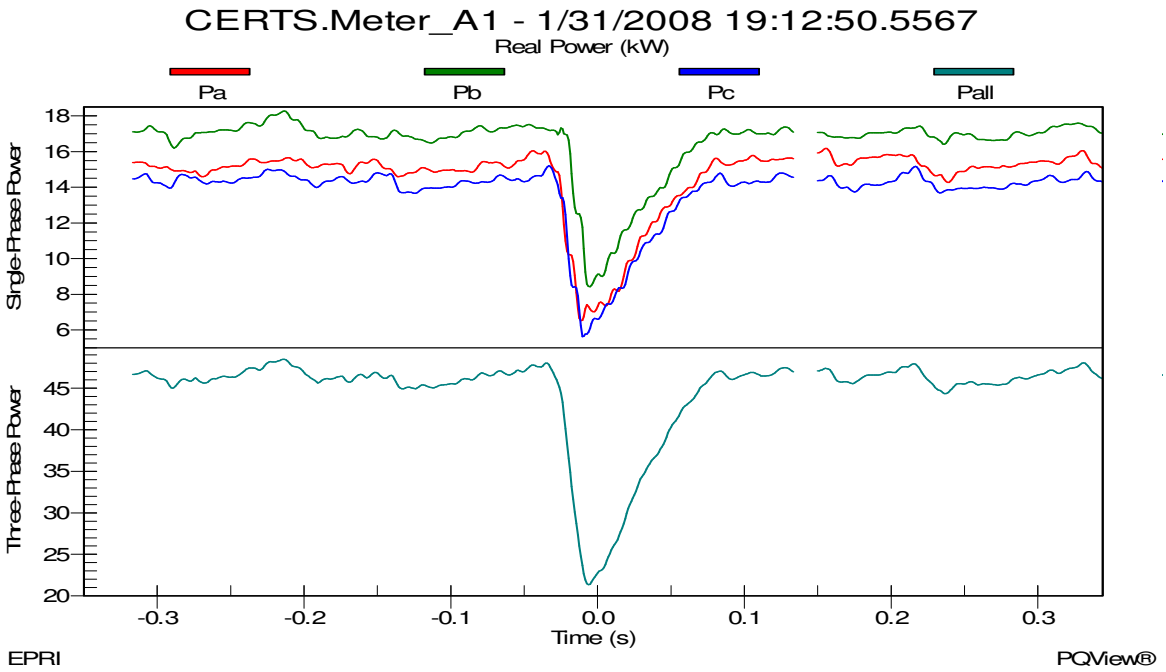

Figure 13d - Gen-set A1 power flow before/after CB41 opened.

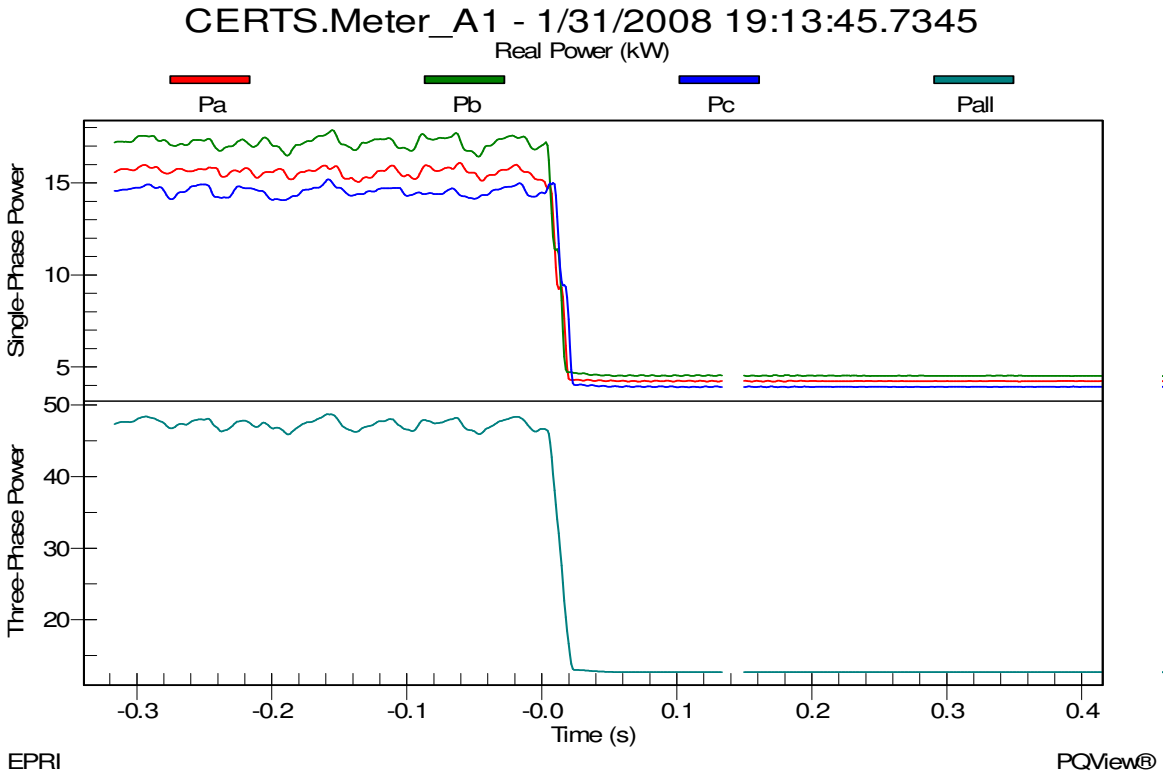

Figure 13e - Gen-set A1 power flow reducing its output power to approximately 12kW after the static switch opens from a reverse power condition.

Gen-set A1 dropped its output power from 50kW to 12kW to satisfy the load requirement. The electrical system was stable in both the microgrid and utility grid after CB31 opened and Gen-set A2 shutdown. Gen-set A1 was manually shutdown, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.5 Zone 3 A-Phase Line-to-Ground Fault, Gen-set A1 and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 3 with Gen-sets A1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control Mode

Output Power Command = 20kW

MG Power /Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B(Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance single phase-to-ground fault in Zone 3 on the A-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 3a with phases B and C disconnected. This, when combined with the load in Load Bank 3 of 40kW (approximately 13.3kW per phase), added 28.3kW to A-phase of Zone 3 causing an overload condition.

After Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, the test was started with a "Start" command from the EMS. As soon as the static switch

closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 equaling approximately 57.5kW, shown in Figure 14a, and 21kW at Meter 2 shown in Figure 14b before the fault was applied.

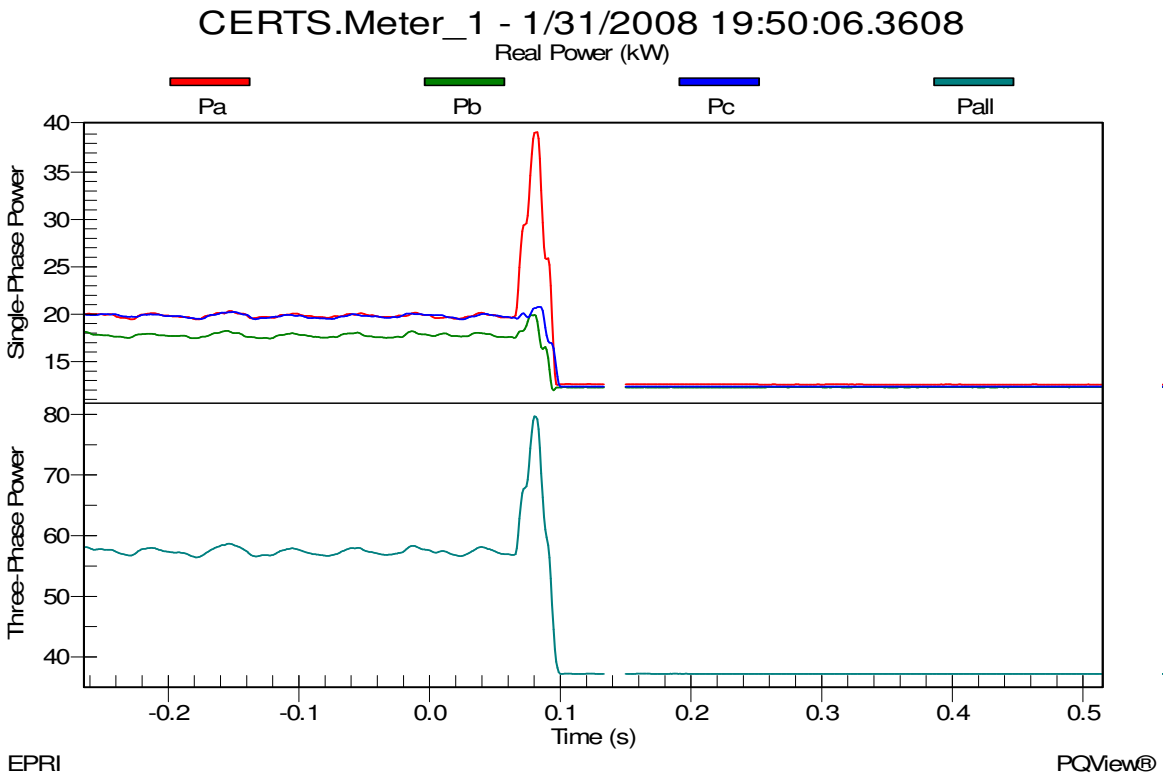

Figure 14a - Power flow in Meter 1 before/after the fault was cleared in Zone 3.

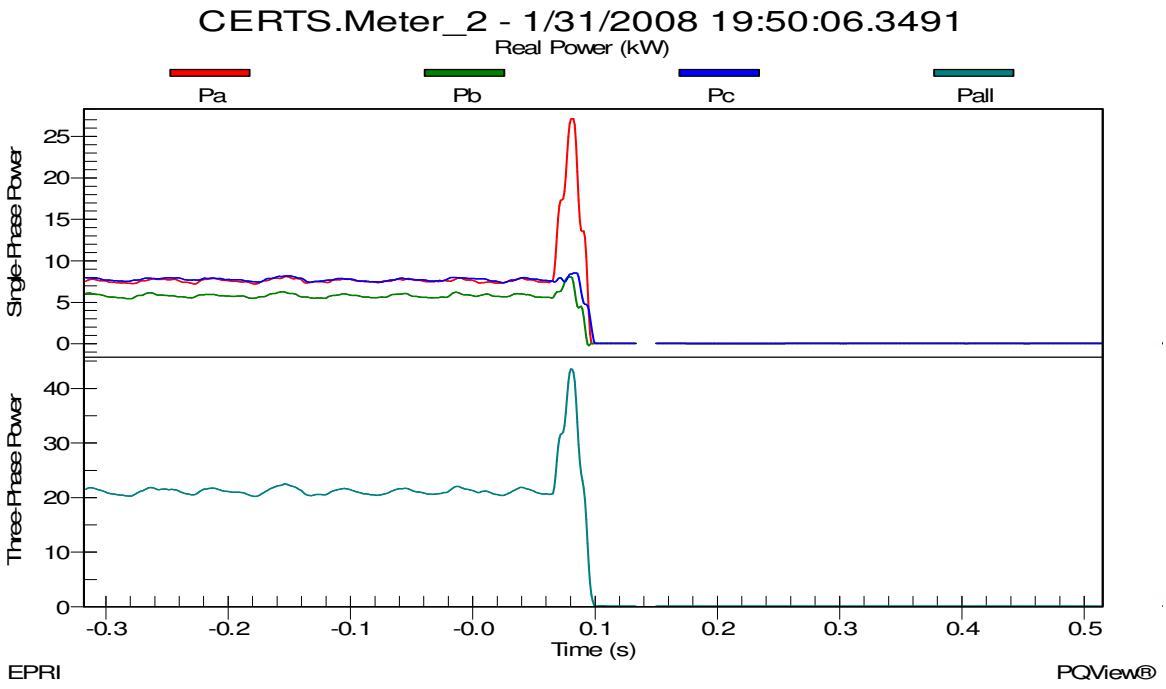

Figure 14b - Power flow in Meter 2 before/after the fault was cleared in Zone 3.

Using the DAS Load Control program, the single phase-to-ground fault on A-phase was set for 10 seconds and then initiated. The static switch tripped first in approximately 0.016 seconds (~1 cycle) from a ground over-current (67N1T), shown in Figure 14c, isolating the microgrid from the utility grid. Relay 3 tripped CB31, opening in 0.15 seconds (~9 cycles) after the static switch opened due to a ground over-current (67N1T), shown in Figure 14d, isolating Zones 3 and 4 from the rest of the microgrid and shutting down Gen-set A1. It is also worth noting that once the static switch opens the phase currents measured by the relay reduce to zero. However, because of the grounding layout, ground current from the fault, fed by Gen-set A1, is still measured and tripped. Once CB31 opens Zones 3 and 4 are isolated, no longer being satisfied by the grid or Gen-set A1 as shown by the collapsed voltage in Figure 14d. The approximate 39kW load in Load Bank 6 is still being satisfied by the grid as shown in Figure 14a.

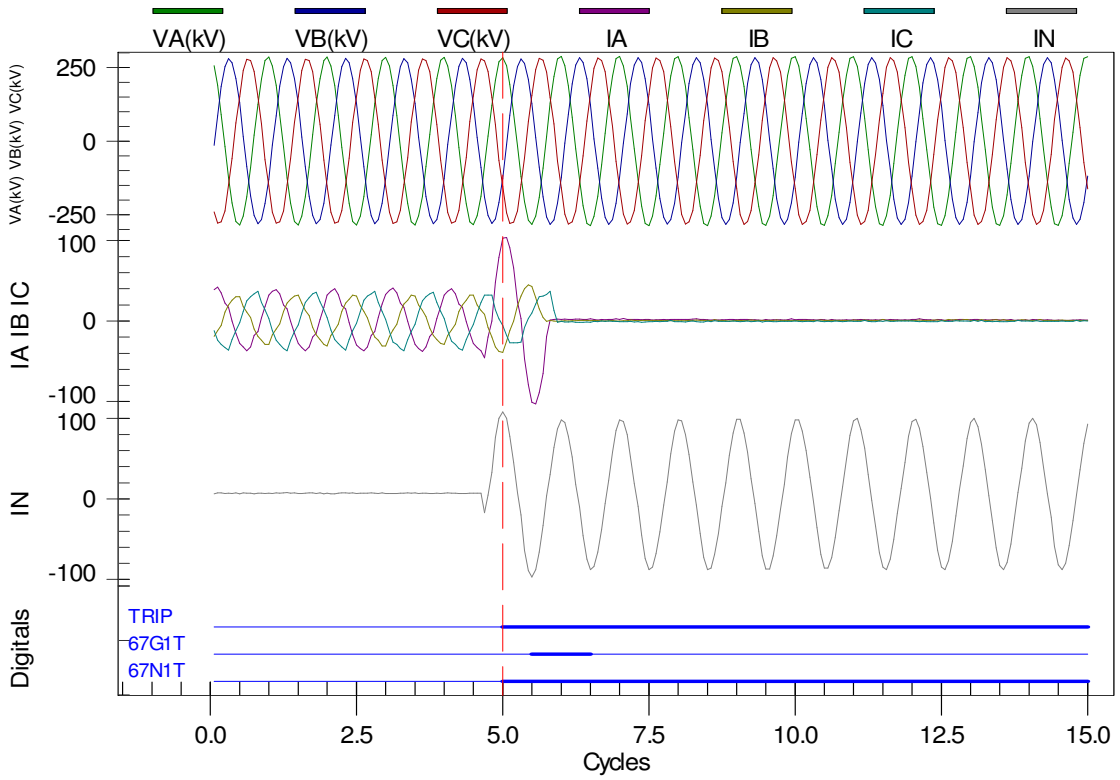

Figure 14c - Relay 2 (static switch) tripped due to ground over-current (67N1T) in 1 cycle after the single phase-to-ground fault was applied in Zone 3.

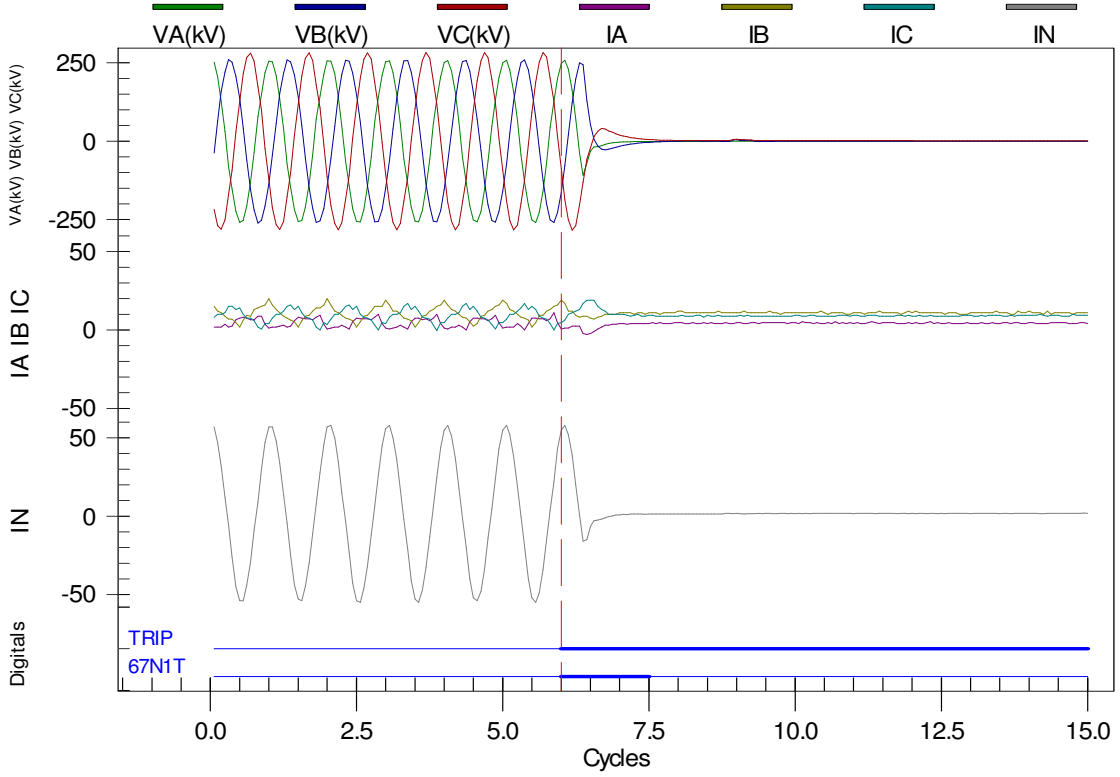

Figure 14d - Relay 3 (CB31) tripped on a ground over-current (67N1T) after the single phase-to-ground fault was applied in Zone 3.

Gen-set A1 shutdown 0.166 seconds (~10 cycles) after Zones 3 and 4 were separated when CB31 opened. Figure 14e shows Gen-set A1 produced approximately 19kW before the single phase-to-ground fault was initiated, increased to approximately 57kW to satisfy Load Bank 3 when the static switch opened and shutdown when CB31 separated Zones 3 and 4.

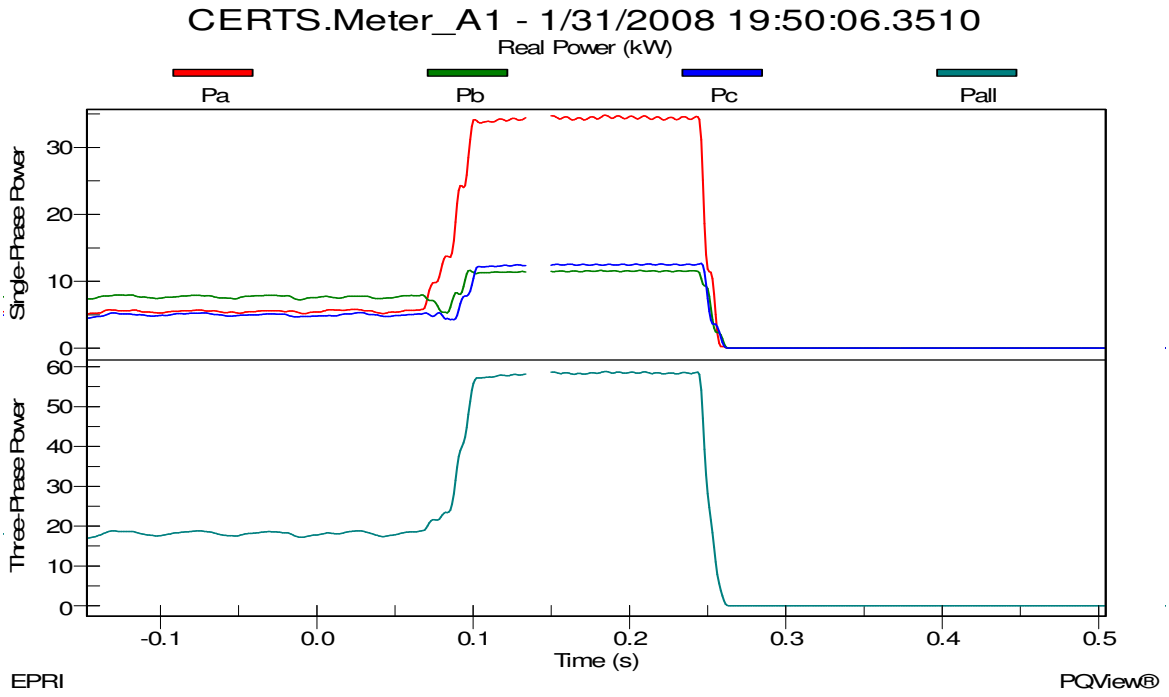

Figure 14e - Gen-set A1 output power before/after the static switch opens and then when Zones 3 and 4 are isolated from the rest of the Microgrid.

The electrical system was stable in the microgrid and utility grid after the static switch opened, CB31 opened and Gen-set A1 shutdown. All loads and alarms were reset and equipment was prepared for the next test.

6.1.6 Zone 3 A-Phase Line-to-Ground Fault, Gen-sets (A1+A2) and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 3 with Gen-sets A1 and A2, operating in-parallel with the utility grid, to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set A2 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set A2 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance single phase-to-ground fault in Zone 3 on A-phase, the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 3a with phases B and C disconnected. This, when combined with the load in Load Bank 3 of 40kW (approximately 13.3kW per phase), added 28.3kW to A-phase when initiated and caused an overload condition in Zone 3.

After both Gen-sets A1 and A2 were running for a few minutes and supplying power to Load Banks 3 and 4, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid. Before the fault was applied the total power flow at Meter 1 was approximately 72.5kW shown in Figure 15a and approximately 35kW at Meter 2 shown in Figure 15b.

Using the DAS Load Control program, the single phase-to-ground overload fault on A-phase was set for 10 seconds and then initiated. The static switch tripped first in approximately 0.02 seconds (~1.3 cycles) from a ground over-current (67N1T), shown in Figure 15c, islanding the microgrid from the utility grid.

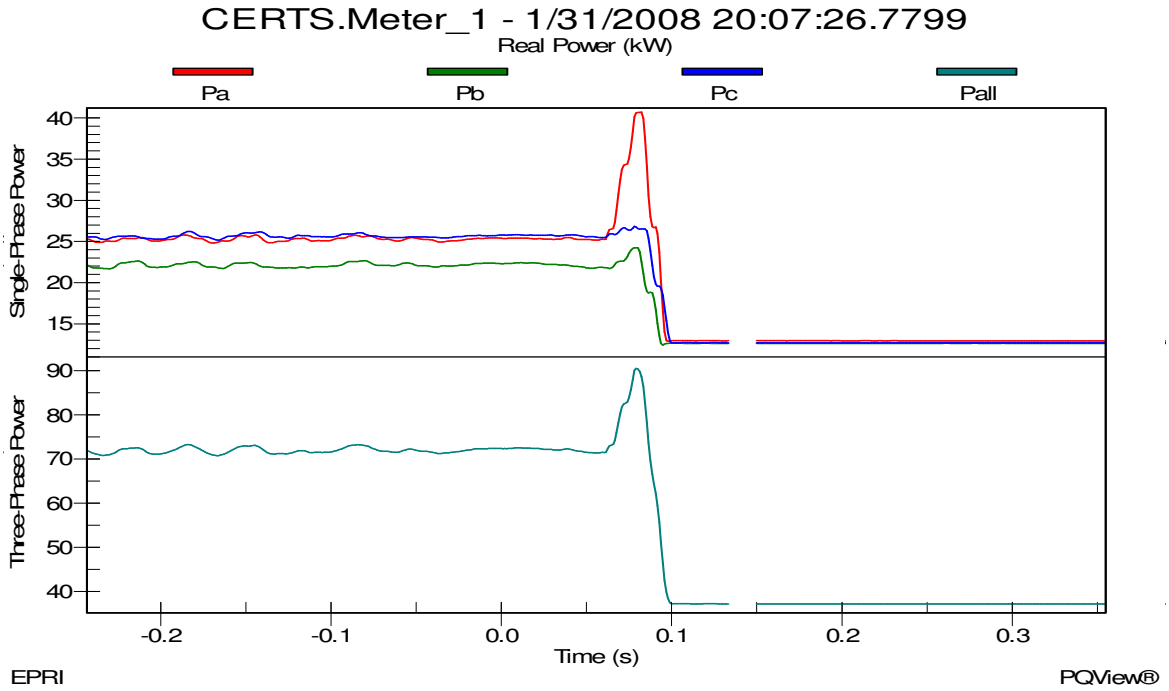

Figure 15a - Meter 1 power flow before/after the static switch opens, islanding the microgrid from the utility grid after a single phase-to-ground fault was applied to Zone 3.

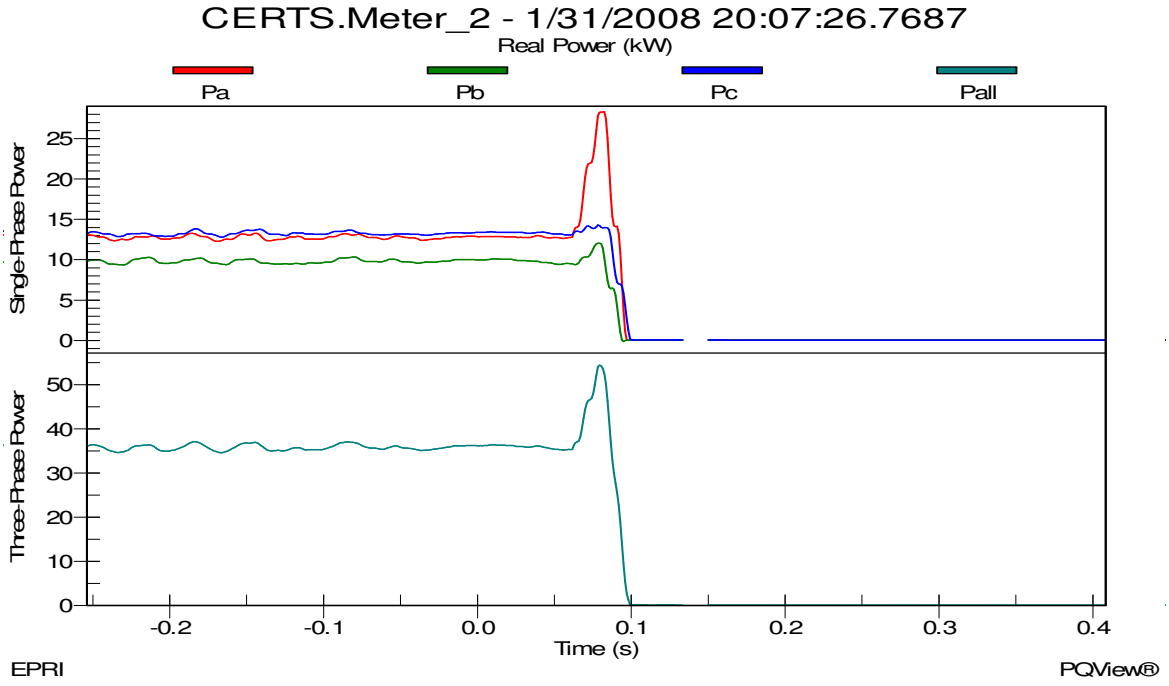

Figure 15b - Meter 2 power flow before/after the static switch opened, isolating the microgrid from the utility grid after a single phase-to-ground fault was applied to Zone 3.

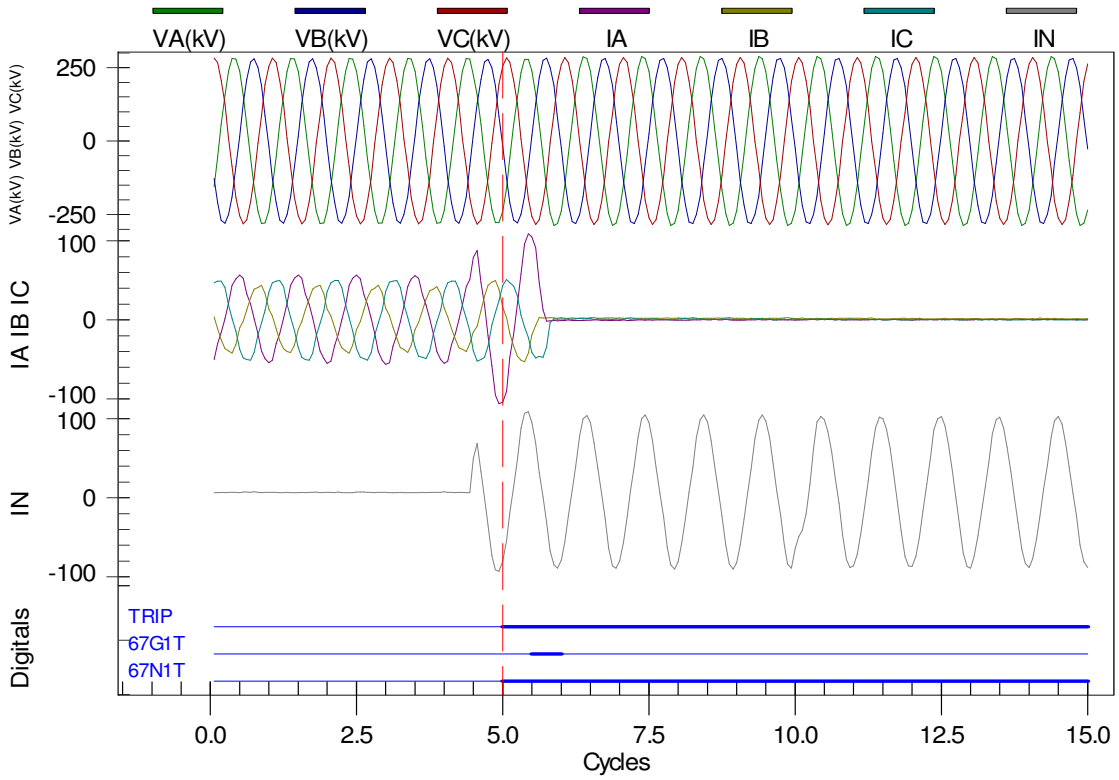

Figure 15c - Relay 2 (static switch) tripped after the single phase-to-ground fault was applied in Zone 3.

Relay 4 trips 0.07 seconds (~4.3 cycles) after the static switch opened due to a neutral over-current (67G1T), shown in Figure 15d, separating Zone 4 from the rest of the microgrid.

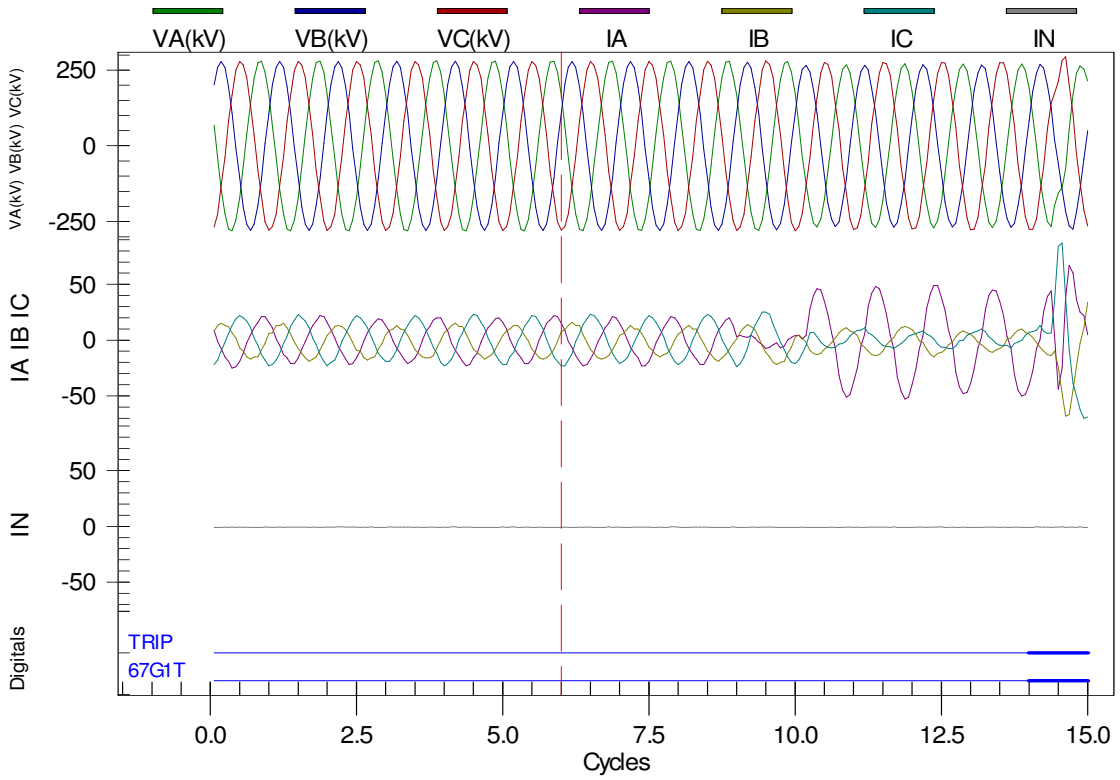

Figure 15d - Relay 4 (CB41) tripped after the single phase-to-ground fault was applied in Zone 3.

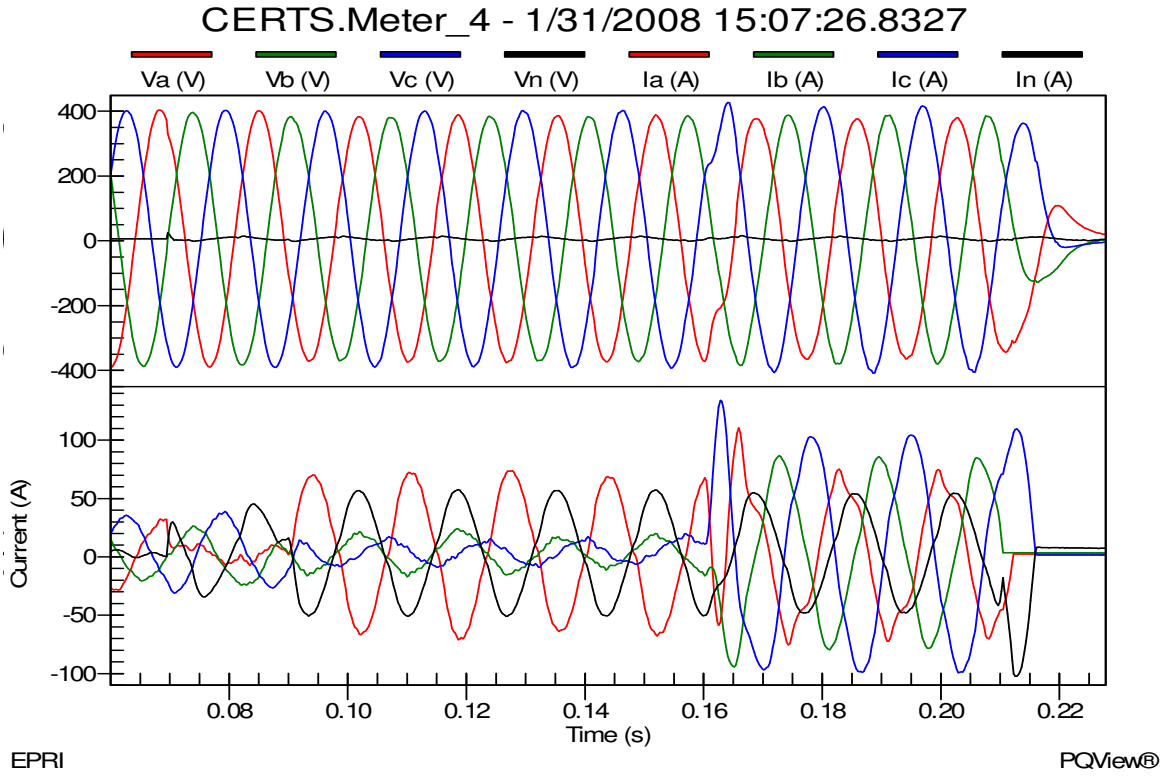

Figure 15e - Meter 4 (CB41) voltage and current for a single phase-to-ground fault applied in Zone 3.

A complex situation took place in Figures 15e, 15f and 15g. The fault was applied at 0.07 seconds which caused the static switch to open at 0.09 seconds. This was followed by a short period where both Gen-sets A1 and A2 were supporting the microgrid load, as well as the fault overload, shown in Figures 15f and 15g between 0.09 and 0.16 seconds. At 0.16 seconds Relay 4 commanded Gen-set A2 to shutdown and CB41 to open. Gen-set A2 first stopped delivering power to the microgrid, as seen by the sudden increase of current at Meter 4, Figure 15e, and Meter A1, Figure 15g. Even though Gen-set A2 stopped switching the inverter output, its interface transformer remained connected to the microgrid. This is evident by the continued current flow though Meter A2 after 0.16 seconds, Figure 15f, due to the Wye/Delta transformation, and also evident in the real power transferred from B and C phases to A phase at Meter A2 in Figure 15h. At 0.215 seconds CB41 opened reducing the current through CB41 to zero and denergizing Zone 4 of the microgrid.

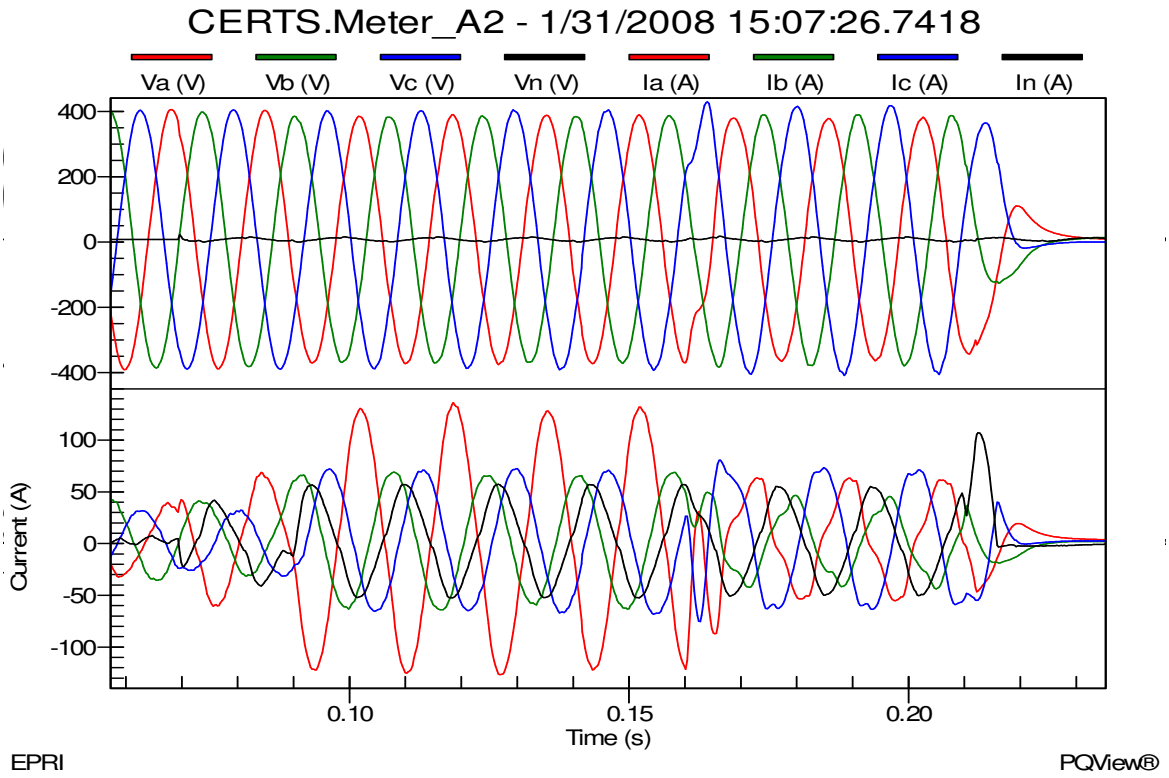

Figure 15f - Meter A2 voltage and current for a single phase-to-ground fault applied in Zone 3.

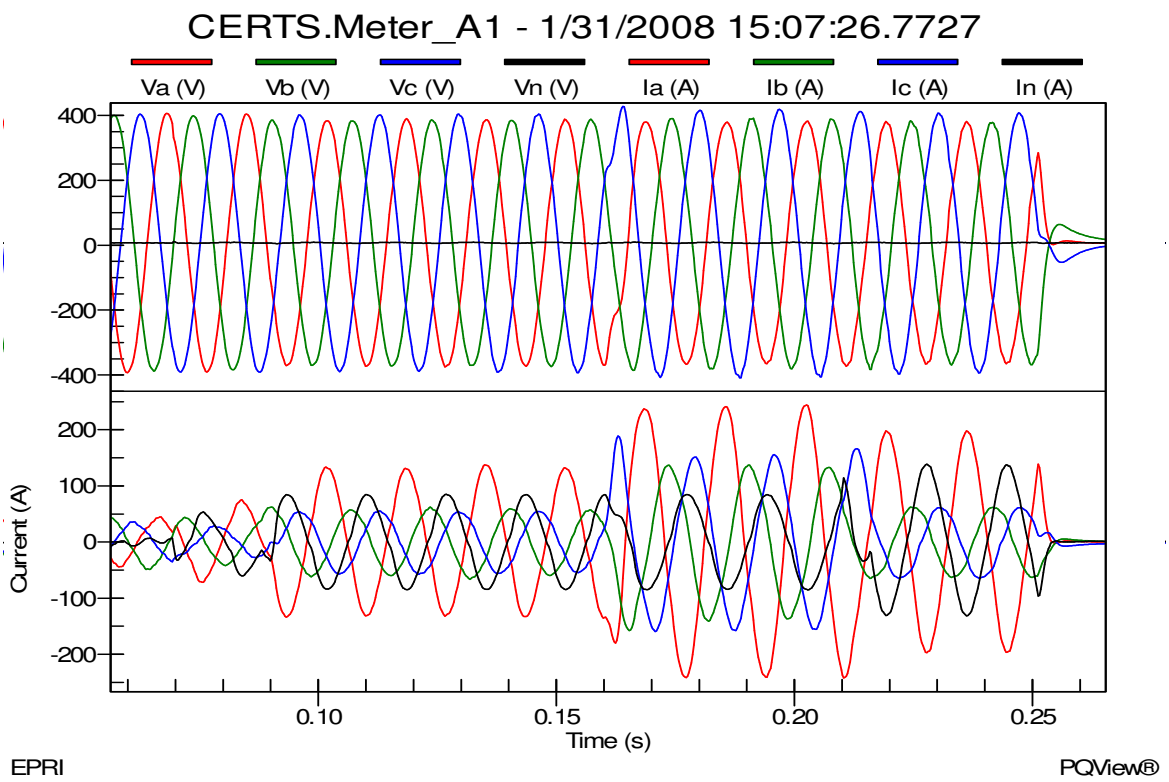

Figure 15g - Meter A1 voltage and current for a single phase-to-ground fault applied in Zone 3.

Relay 3 tripped Gen-setA1 and opened CB31 0.04 seconds (~2.3 cycles) after CB41 opened, due to ground over-current (67N1T), shown in Figure 15i, separating Zone 3 from the rest of the microgrid. In Figure 15j Gen-set A1 produced approximately 20kW before the single phase-to-ground fault was initiated and increased to approximately 48.5kW to satisfy Load Banks 3 and 4 along with generation from Gen-set A2 once the static switch opened. Output power for Gen-set A1 also increased to approximately 100kW for a brief period of time due to Gen-set A2 shutting down while the 40kW of Load Bank 3 and 4 remained connected.

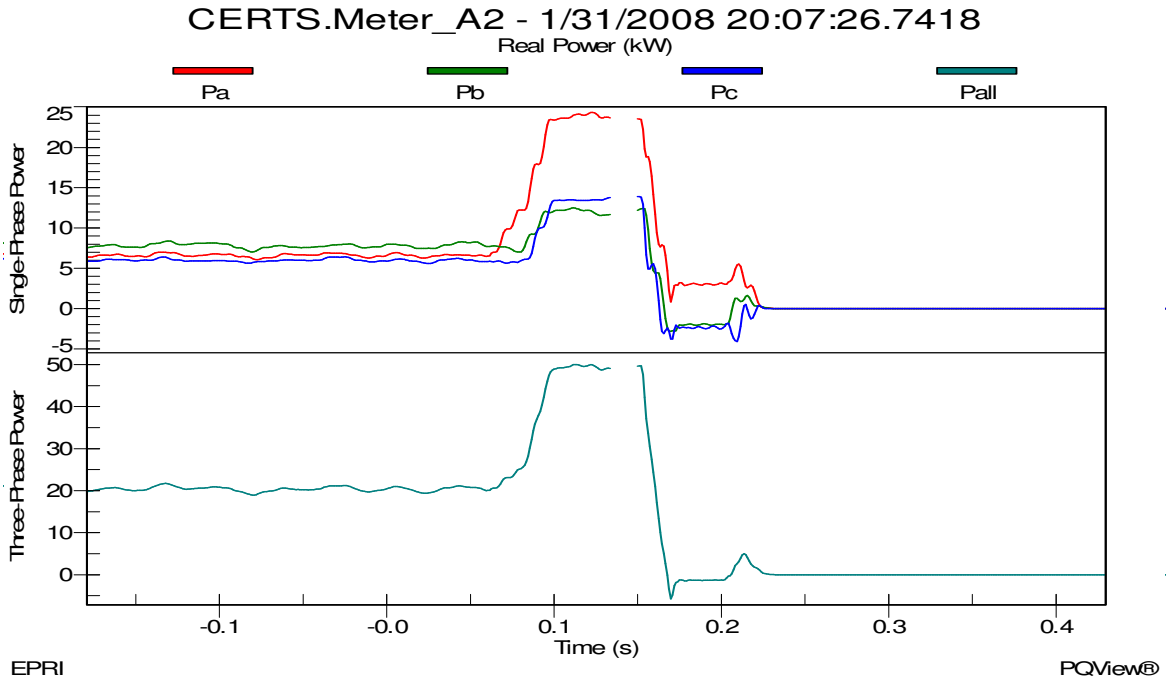

Figure 15h - Gen-set A2 output power before/after the static switch "Opens" and when Zone 4 is separated from the rest of the microgrid.

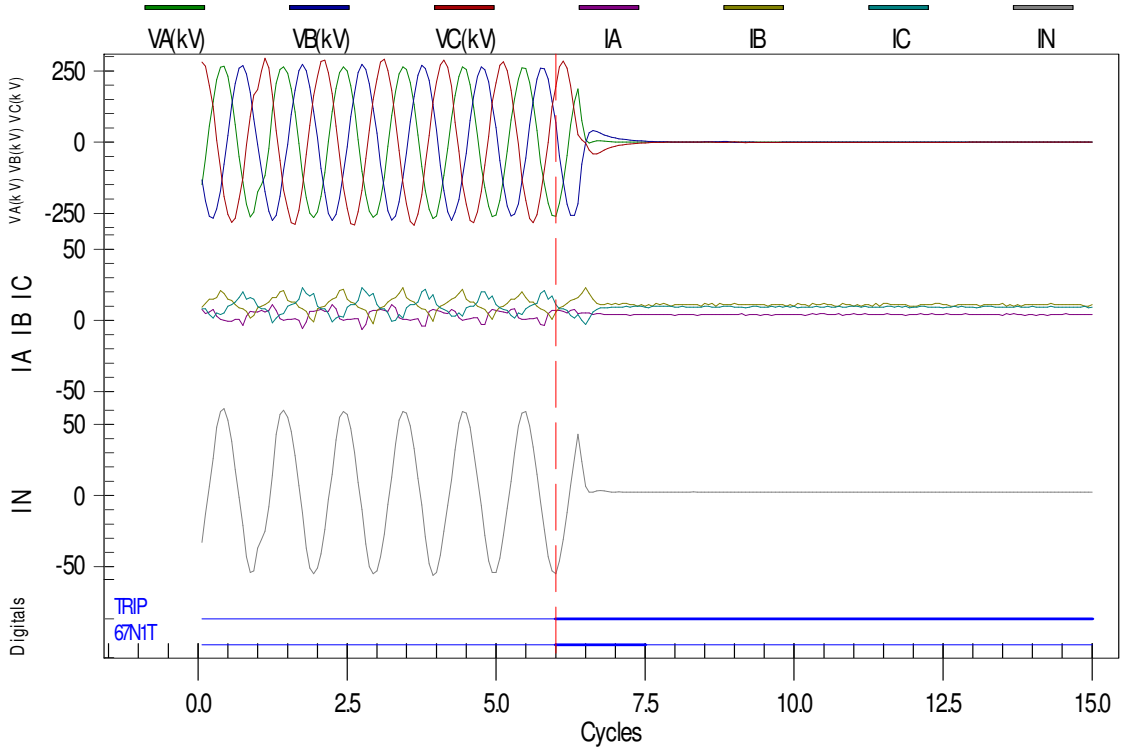

Figure 15i - Relay 3 (CB31) tripped due to a ground over-current (67N1T) when the single phase-to-ground fault was initiated in Zone 3

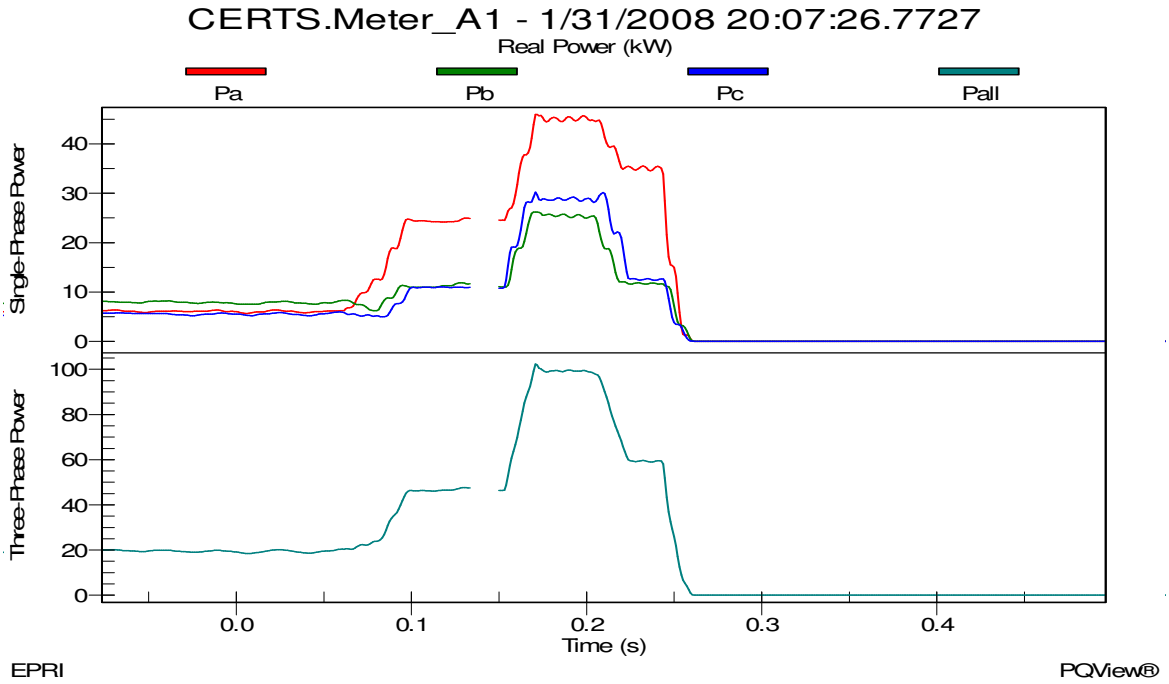

Figure 15j - Gen-set A1 output power before/after the static switch opened, when CB41 opens isolating Zone 4, and when Zone 3 is isolated from the rest of the microgrid.

The electrical system was stable in both the microgrid and utility grid after the static switch had opened, circuit breakers (i.e., CB31, CB41 andCB51) had opened, and Gen-sets A1 and A2 shut down. All loads and alarms were reset and equipment was prepared for the next test.

6.1.7 Zone 5 B-Phase Line-to-Ground Fault, Gen-set B1 and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 5 with Gen-sets B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set B1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance single phase-to-ground fault in Zone 5 on the B-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 7a with phases A and C disconnected. When initiated, this 28.3kW on B-phase, with the 40kW in Load Bank 3 of Zone 3, causes an overload.

After Gen-set B1 was running for a few minutes and supplying power to Load Bank 3, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with total power flow at Meter 1 being approximately 54kW, shown in Figure 16a, and approximately 17.5kW at Meter 2 shown in Figure 16b before the fault was applied.

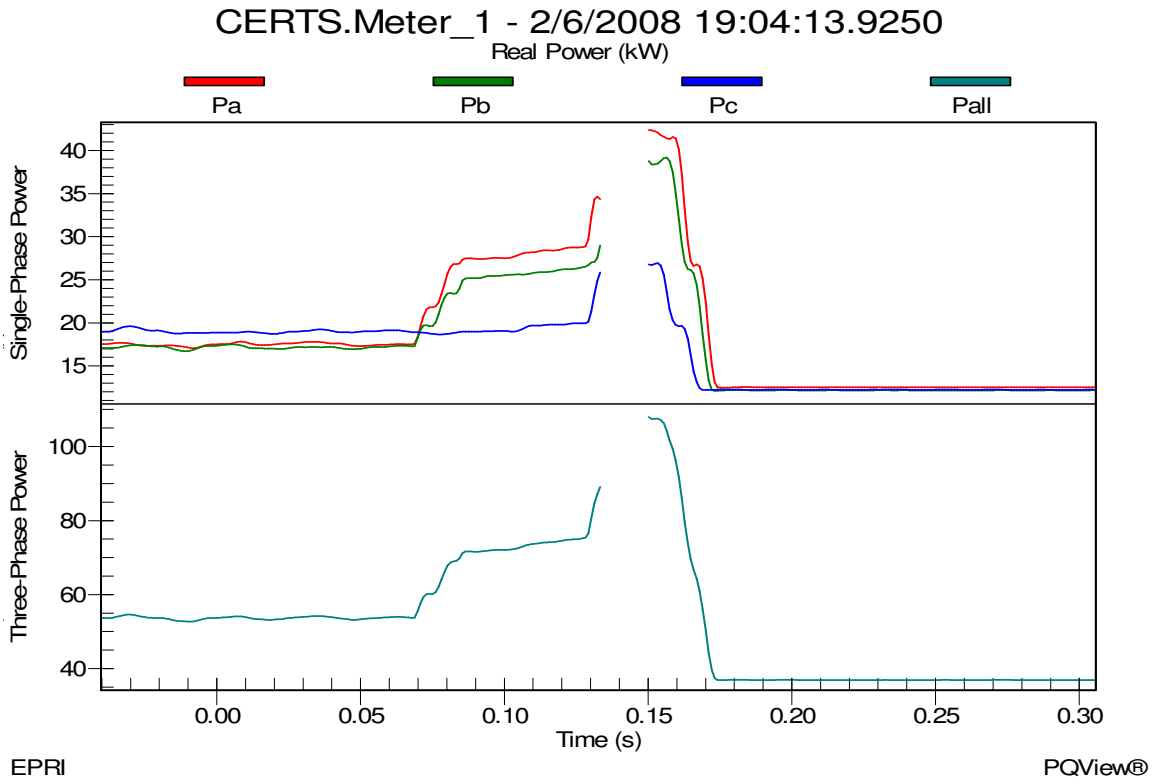

Figure 16a – Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 5.

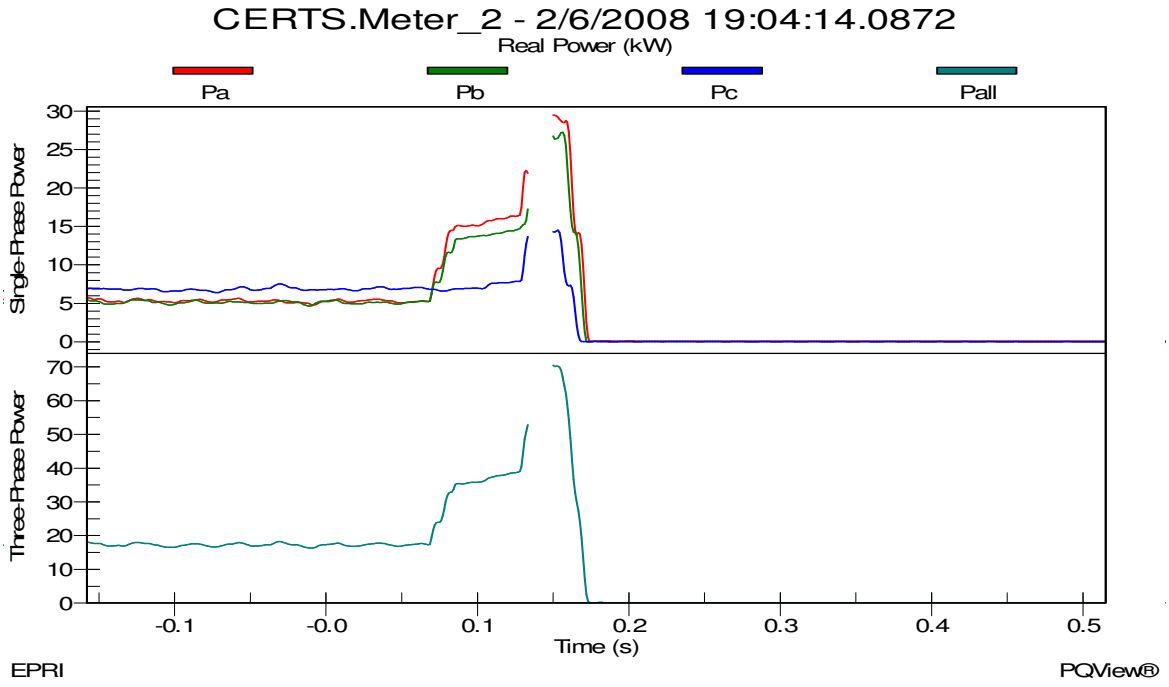

Figure 16b – Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 5.

Using the DAS Load Control program, a single phase-to-ground overload fault on B-phase was set for 10 seconds and then initiated. The protection coordination for this event appears to be different than expected. After the fault is initiated Relay 5 first trips shutting down Gen-set B1 and opening CB51, Figure 16c. The Gen-set stops switching the inverter output, however its transformer contactor and CB51 remains closed for a brief period of time, Figure 16d. After the Gen-set stops switching the fault current at the static switch becomes large enough to cause Relay 2 to trip on negative sequence (67Q1T), Figure 16e. Relay 5 tripped first approximately 0.07 seconds (~4.2 cycles) separating Zone 5 from the rest of the microgrid. The static switch opened 0.03 seconds (~1.75 cycles) after Relay 5 tripped, islanding the microgrid from the utility.

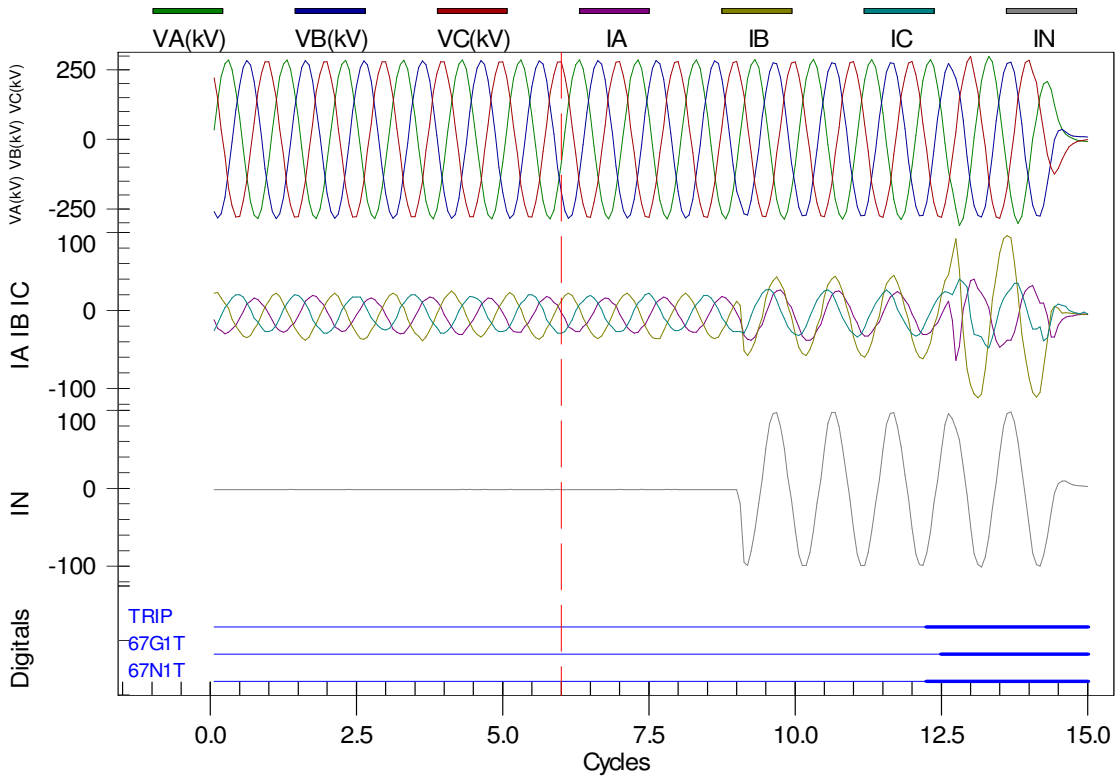

Figure 16c – Relay 5 (CB51) tripped due to ground over-current (67N1T) after the single phase-to-ground fault was initiated in Zone 5.

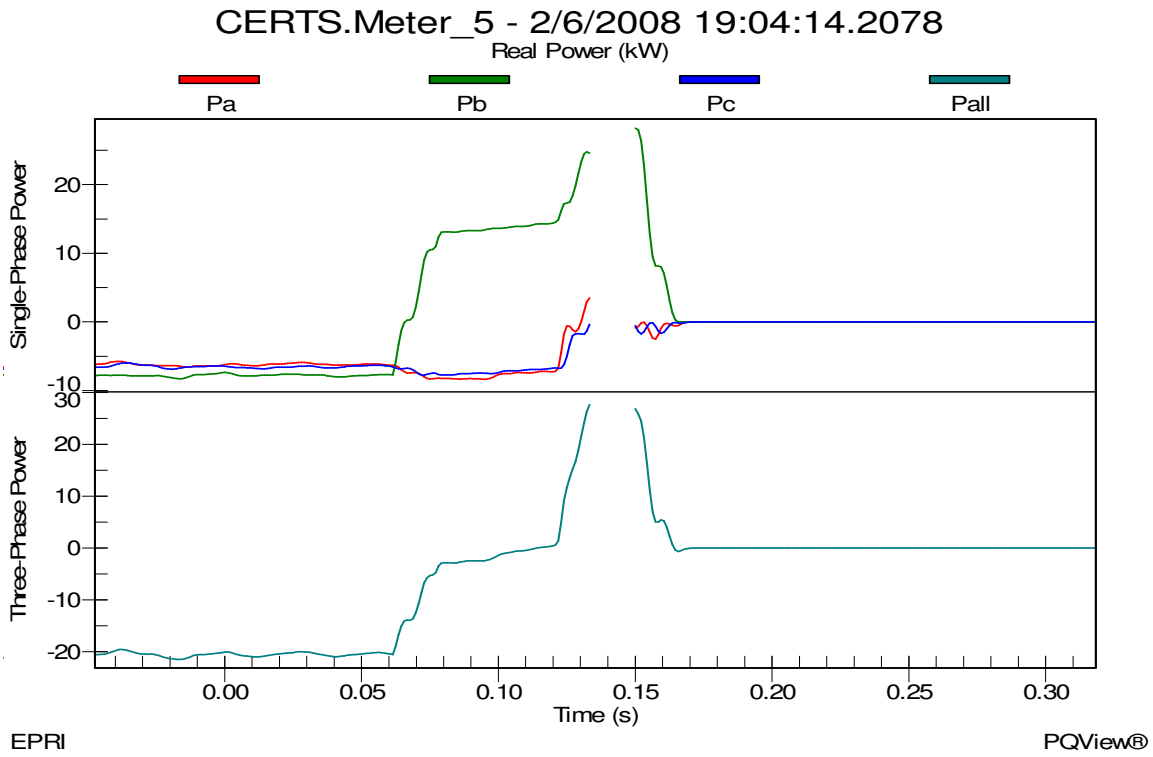

Figure 16d – Meter 5 power flow for a single phase-to-ground fault applied in Zone 5.

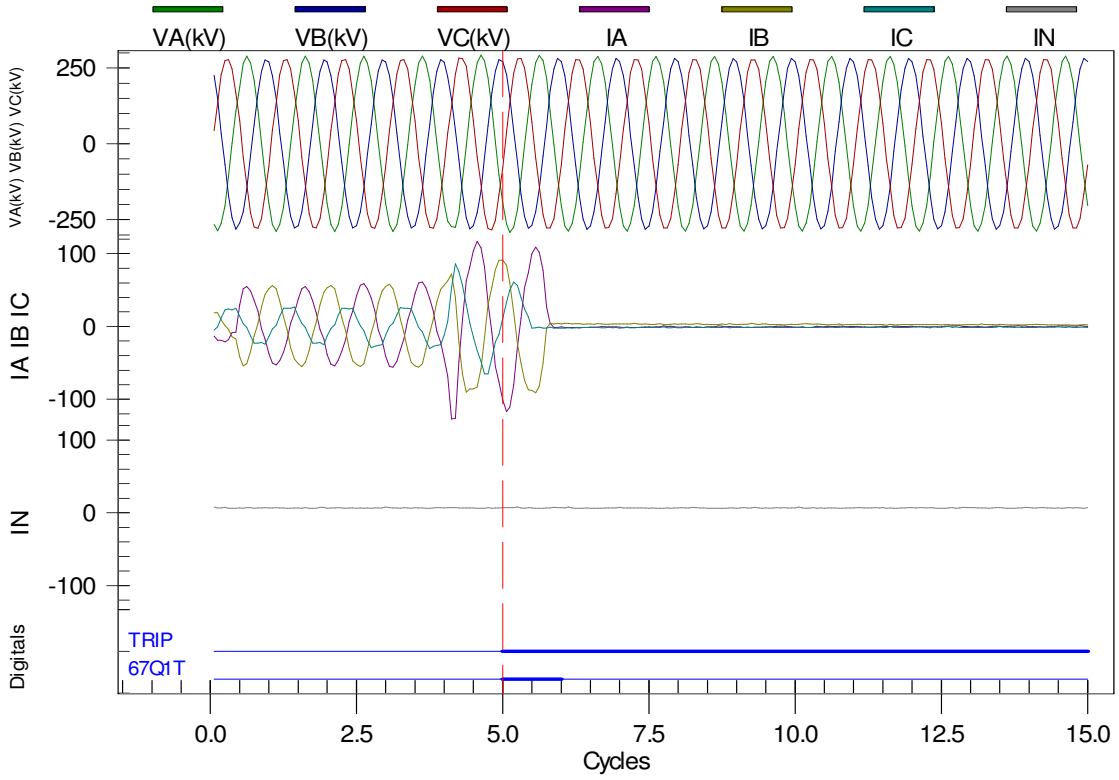

Figure 16e - Relay 2 (static switch) tripped due to negative sequence (67Q1T) after the single phase-to-ground fault was applied in Zone 5.

The electrical system was stable in the microgrid and utility grid after the static switch opened, CB51 opened, and Gen-set B1 shut down. All loads and alarms were reset and equipment was prepared for the next test.

6.1.8 Zone 5 B-Phase Line-to-Ground Fault, Gen-sets (A1+B1) and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 5 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set B1 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set B1 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance single phase-to-ground fault in Zone 5 on B-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 7a with phases A and C disconnected. When initiated, this 28.3kW on B-phase, with the 40kW in Load Banks 3 and 4, causes an overload.

After both Gen-sets A1 and B1 were running for a few minutes and supplying power to Load Banks 3 and 4, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 75kW, shown in Figure 17a, and approximately 40kW at Meter 2, shown in Figure 17b. Gen-sets A1 and B1 were producing between 17 to 18kW each, shown in Figures 17c and 17d, before the overload fault was applied.

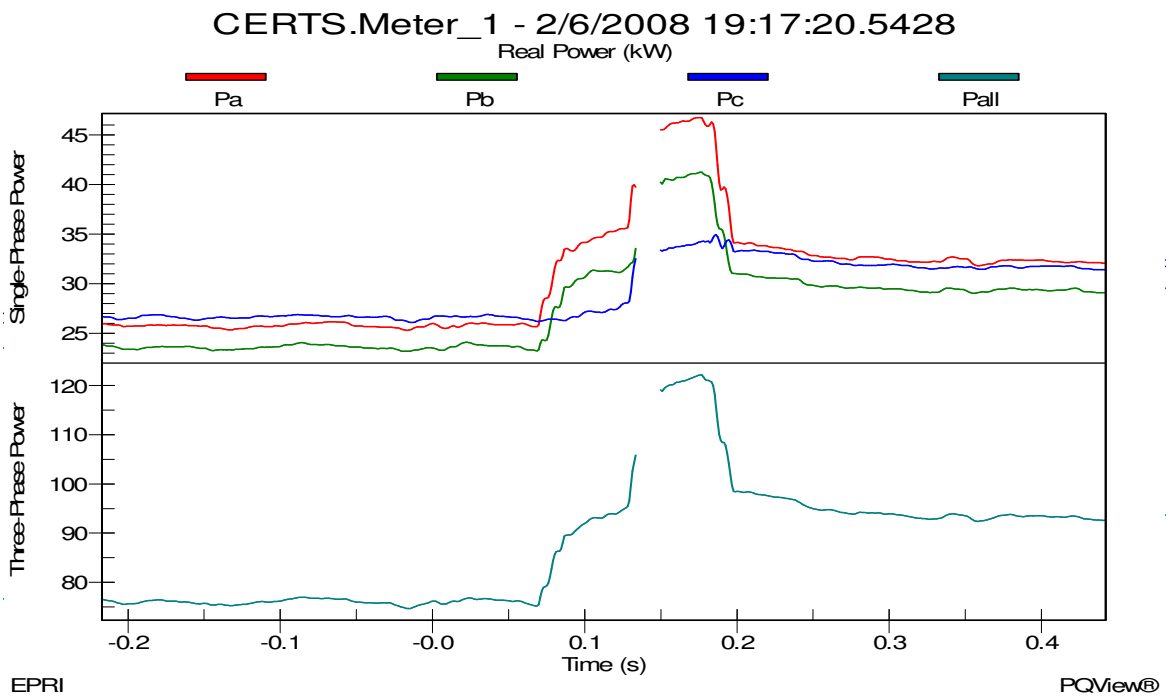

Figure 17a – Meter 1 power flow for a single phase-to-ground fault applied in Zone 5.

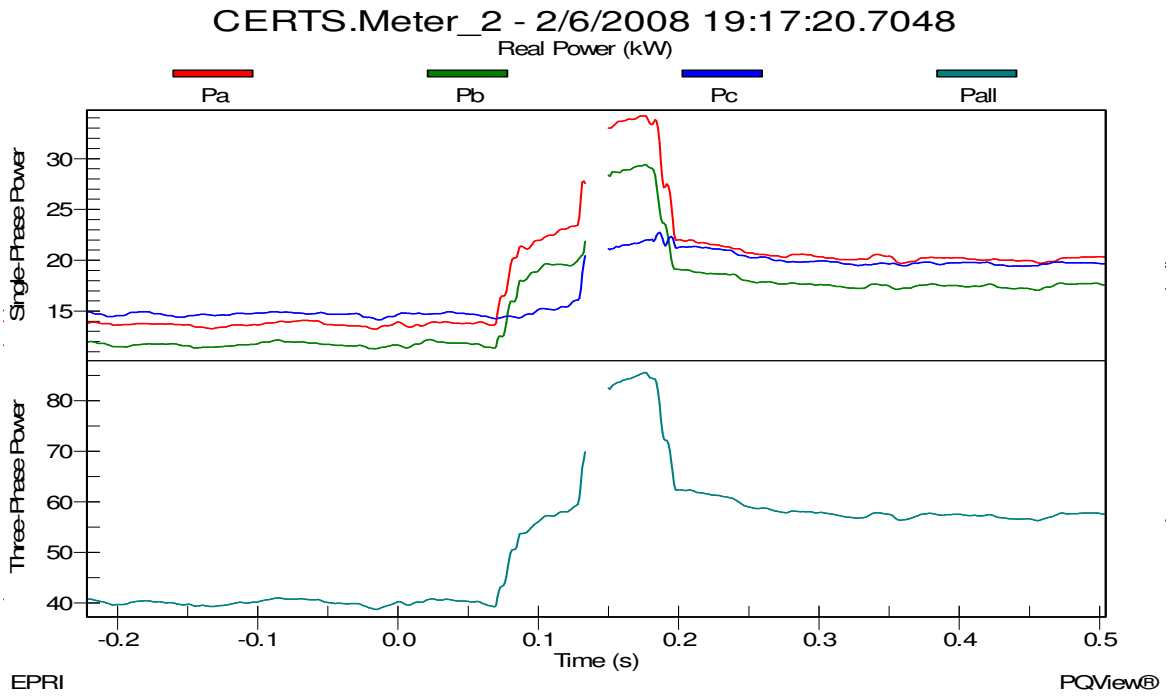

Figure 17b Meter 2 power flow for a single phase-to-ground fault applied in Zone 5.

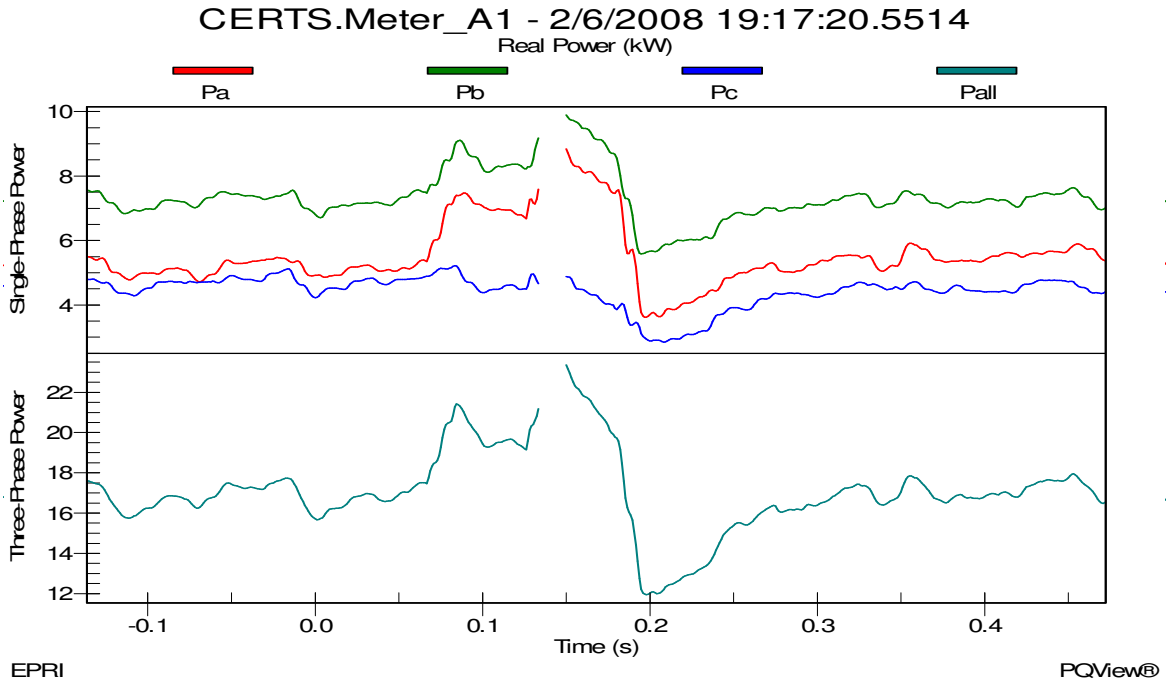

Figure 17c - Power produced by Gen-set A1 before/after a B-phase phase-to-ground fault in Zone 5.

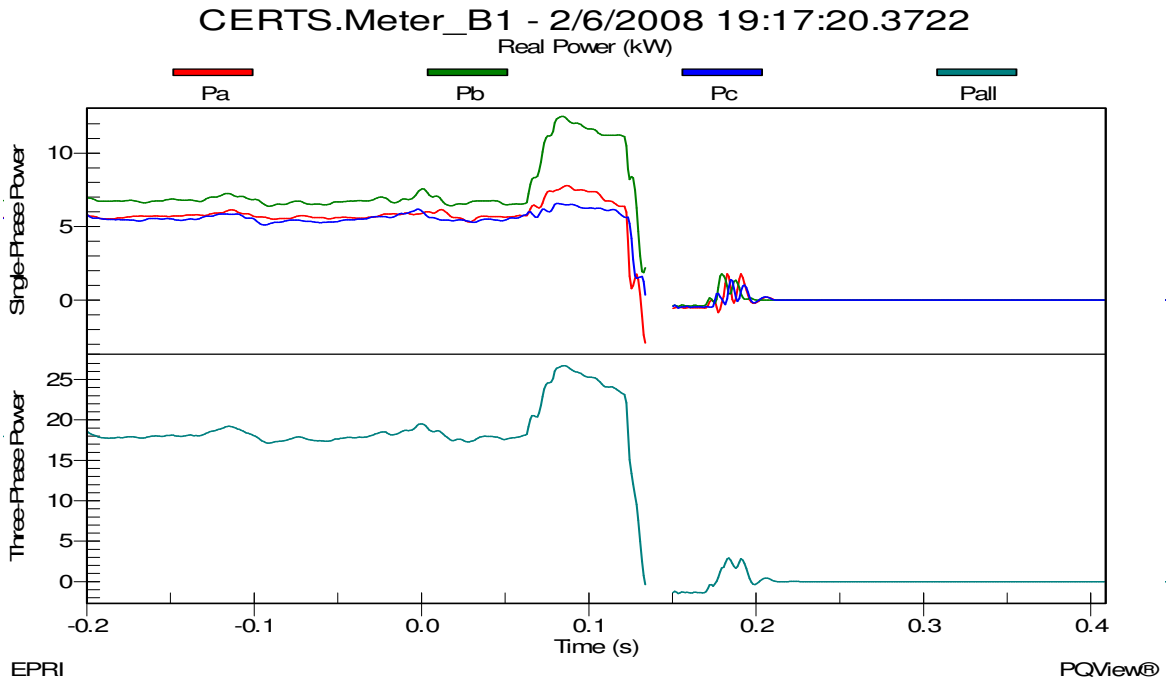

Figure 17d - Power produced by Gen-set A2 before/after a B-phase phase-to-ground fault in Zone 5

Using the DAS Load Control program, the single phase-to-ground fault on B-phase was set for 10 seconds and then initiated.

The protection coordination for this event appears to be different than expected but similar to the previous test. After the fault was initiated, Relay 5 tripped on ground over-current (67N1T), shutting down Gen-set B1 and opening CB51, Figures 17d and 17e. The Gen-set stopped switching the inverter output; however, its transformer contactor and CB51 remained closed for a brief period of time, Figure 17f. Once CB51 cleared 0.06 seconds (3.8 cycles) later the fault was removed and Zone 5 was de-energized, Figure 17g. The static switch and remaining zones of the microgrid remained online and connected.

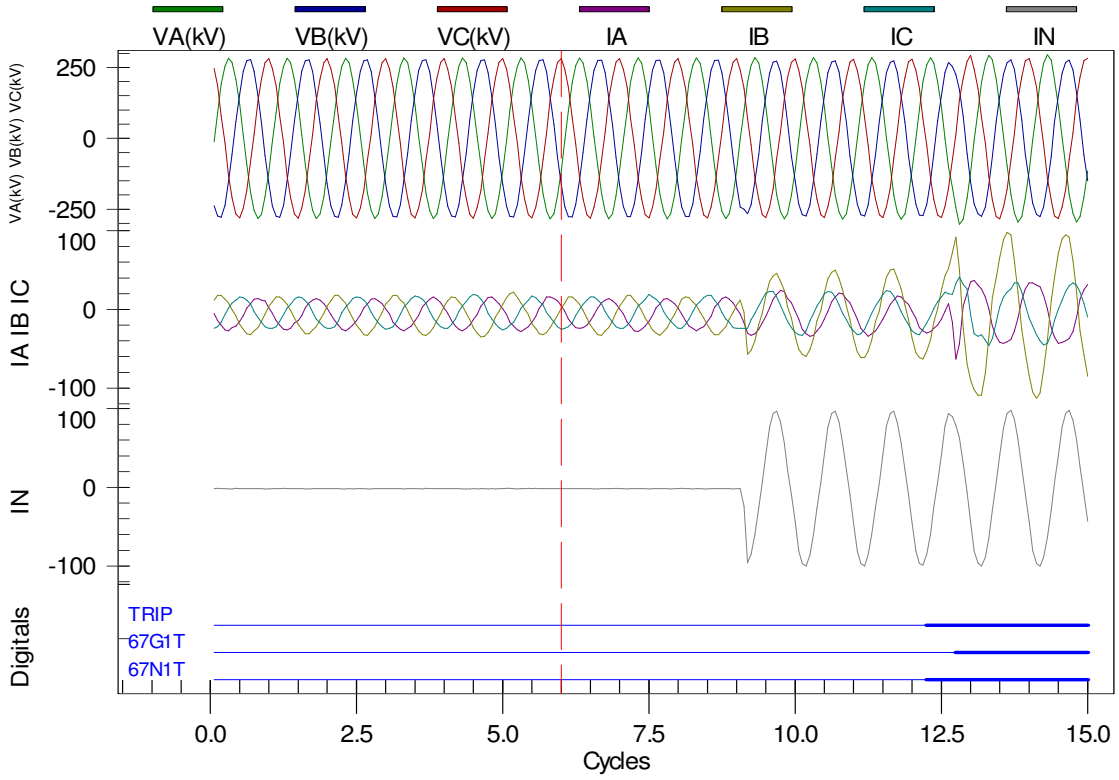

Figure17e - Relay 5 (CB51) tripped due to a ground over-current (67N1) after the single phase-to-ground fault was initiated in Zone 5.

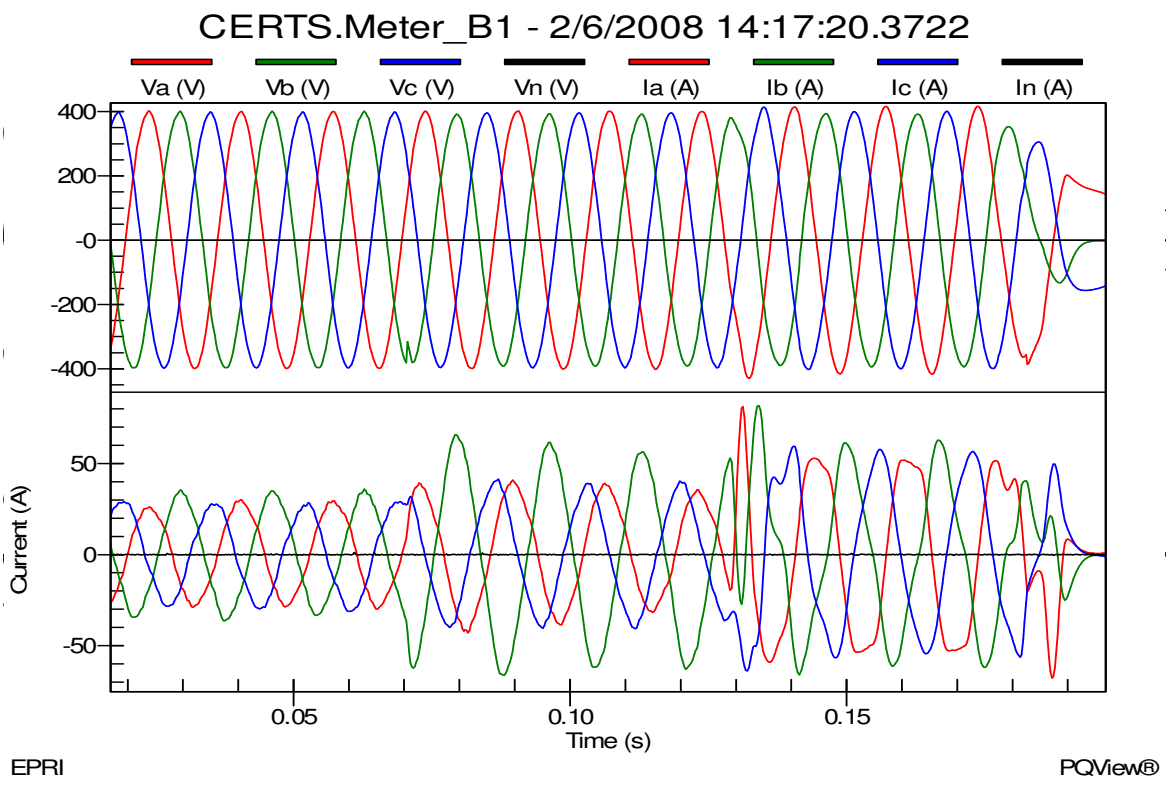

Figure17f – Meter B1 voltage and current for a single phase-to-ground fault applied in Zone 5.

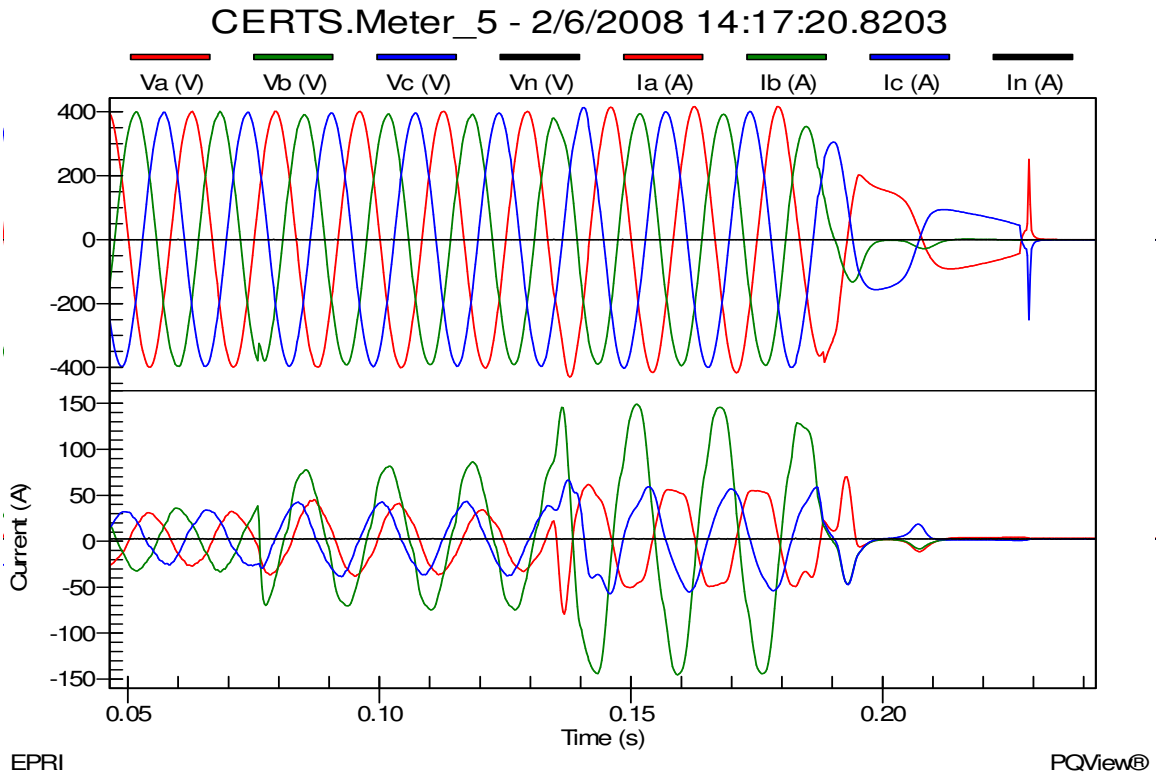

Figure17g- Meter 5 (CB51) voltage and current for a single phase-to-ground fault applied in Zone 5

The electrical system was stable in both the microgrid and utility grid after CB51 opened and Gen-set B1 shut down. Gen-set A1 was shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.9 Zone 4 B-Phase Line-to-Ground Fault, Gen-sets (A1+A2) and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 4 with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set A2 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set A2 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40 kW

To simulate a high impedance single phase-to-ground fault in Zone 4 on B-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 5a with phases A and C disconnected. This, when combined with the load in Load Bank 4 of 40kW (approximately 13.3kW per phase), added 28.3kW to B-phase of Zone 4, causing an overload condition in Zone 4.

After both Gen-sets A1 and A2 were running for a few minutes and supplying power to Load Banks 3 and 4, the test was started with a "Start" command from the EMS. As

soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 74kW, shown in Figure 18a, and approximately 36kW at Meter 2, shown in Figure 18b. Gen-sets A1 and A2 were producing about 20kW each, shown in Figures 18c and 18d before the fault was applied after 0 seconds.

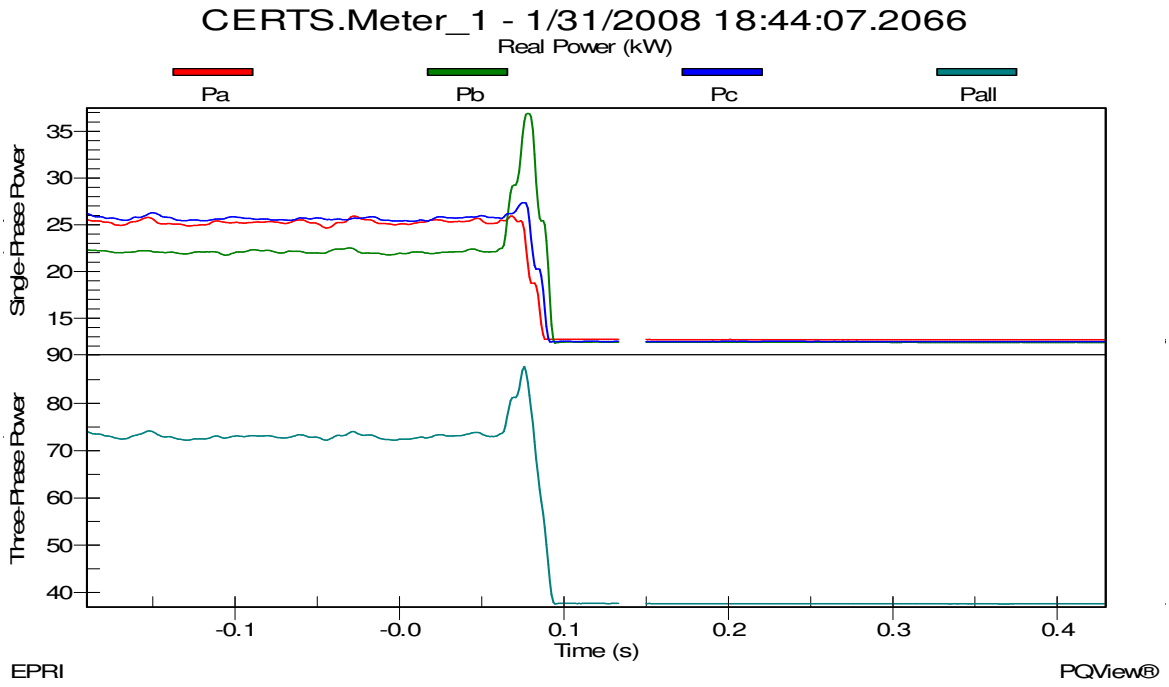

Figure 18a Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 4.

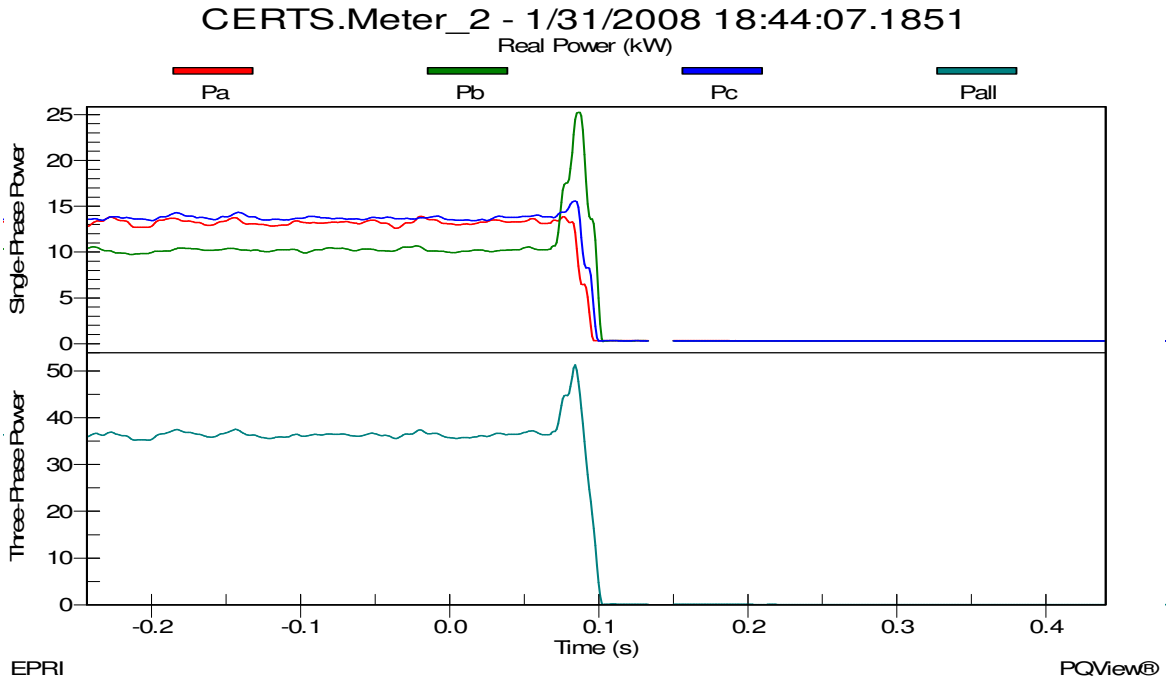

Figure 18b Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 4.

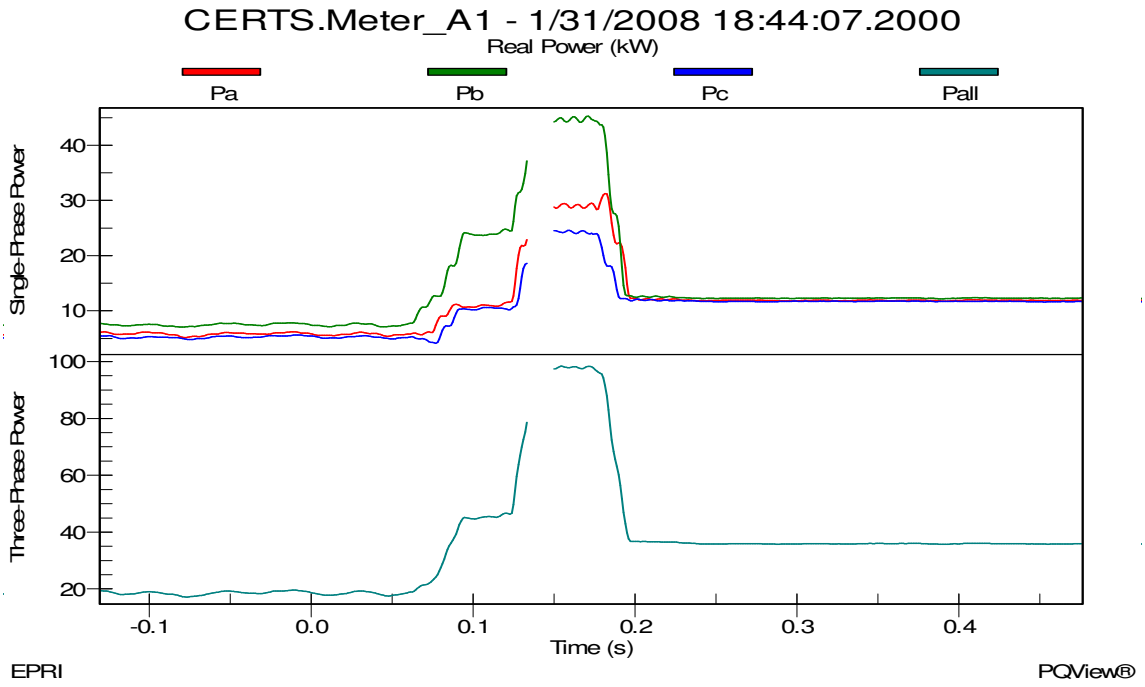

Figure 18c - Power produced by Gen-set A1 before/after the static switch and CB41 opened when a B-phase-to-ground fault was applied in Zone 4.

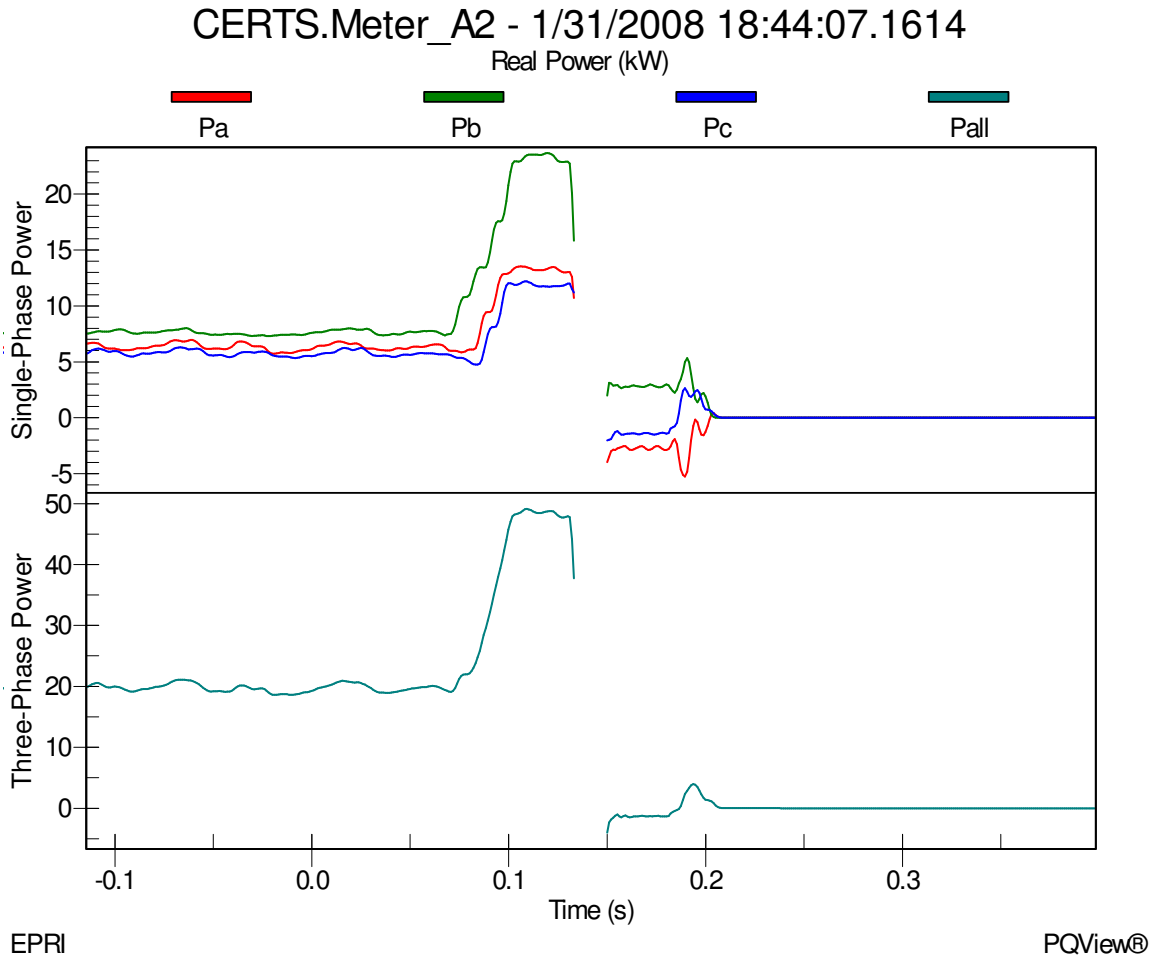

Figure 18d - Power produced by Gen-set A2 before/after the static switch and CB41 opened when a B-phase-to-ground fault was applied in Zone 4.

Using the DAS Load Control program, the single phase-to-ground fault on B-phase was set for 10 seconds and then initiated. The static switch tripped in approximately 0.007 seconds (~0.4 cycles) from a ground over-current (67N1T), shown in Figure 18e, islanding the microgrid from the rest of the utility grid. Relay 4 tripped after approximately 0.058 seconds (~3.5 cycles) on a ground over-current (67N1T) signal, isolating Zone 4 from the rest of the microgrid, shown in Figure 18f.

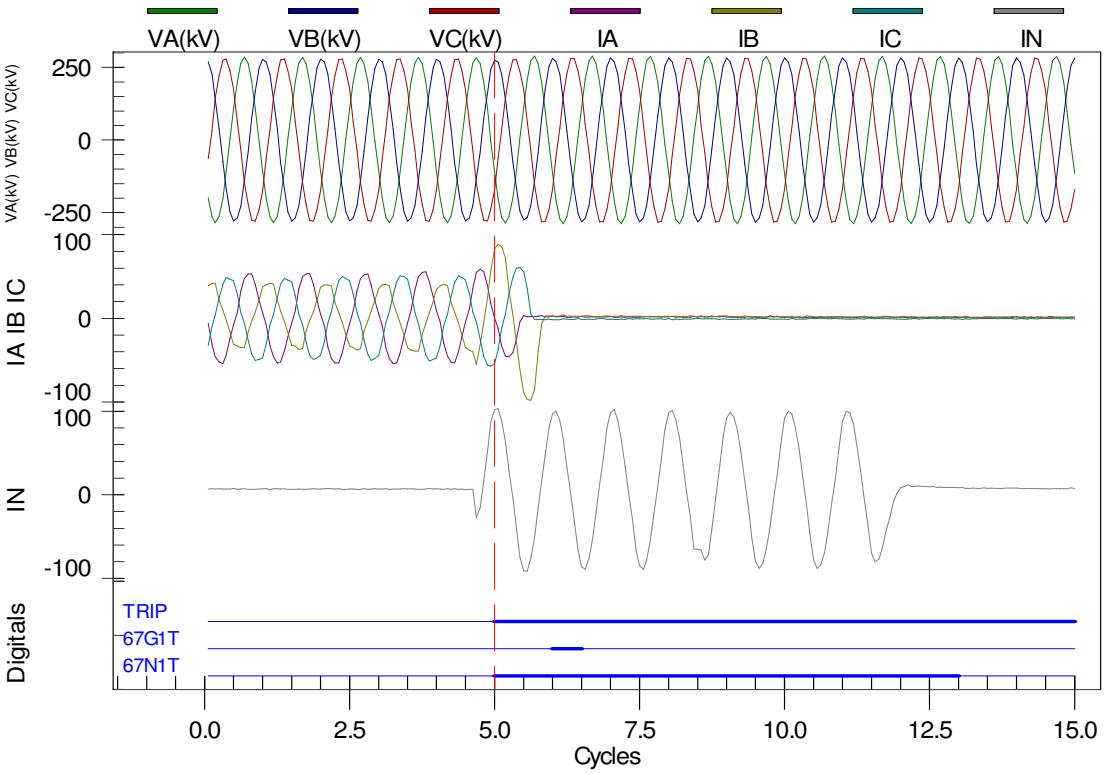

Figure 18e - Relay 2 (static switch) tripped due to a ground over-current (67N1T) when the single phase-to-ground fault is applied in Zone 4.

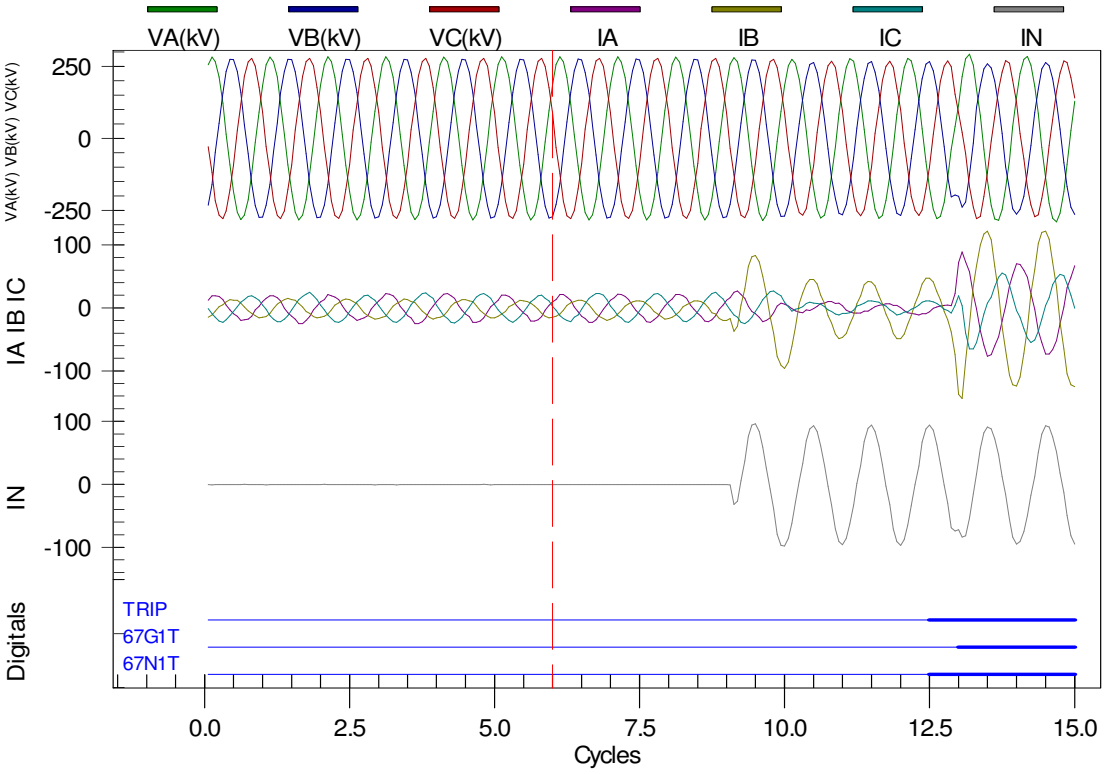

Figure 18f – Relay 4 (CB41) tripped due to a ground over-current (67N1T) when the single phase-to-ground fault was initiated in Zone 4

Gen-set A2 stopped switching approximately 0.008 seconds (~0.5 cycles) after Relay 4 tripped; however, its transformer contactor and CB41 remained closed for a short period. In Figures 18a and 18b power flow through Meter 1 was approximately 37.5kW, supplying only the load in Load Bank 6 from the utility. Load Bank 3 was supplied power from Gen-set A1, within the islanded microgrid, with output power raised from approximately 20kW to about 36kW to meet the load demand, Figure 18c. CB31 and CB51 remained closed throughout the entire test.

The electrical system was stable in both the microgrid and utility grid after the static switch opened, CB41 opened and Gen-set A2 shut down. A short duration later the static switch performed a synchronized close and reconnected the microgrid to the utility grid. Gen-set A1 was shutdown manually, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.10 Zone 2 C-Phase Line-to-Ground Fault, Gen-sets (A1+B1) and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 2 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify zero-sequence, negative-sequence or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set B1 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set B1 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40 kW

To simulate a high impedance single phase-to-ground fault in Zone 2 on C-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 2d with phases A and B disconnected. This, when combined with the load in Load Banks 3 and 4 of 40kW each (each at approximately 13.3kW per phase), added 28.3kW to C-phase in Zone 2 and caused an overload condition in Zone 2.

After both Gen-sets A1 and B1 were running for a few minutes and supplied power to Load Banks 3 and 4, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 68kW, shown in Figure 19a, and approximately 32kW at Meter 2, shown in Figure 19b. Gen-sets A1 and B1 were producing about 20kW each, shown in Figures 19c and 19d before the fault was applied after 0 seconds.

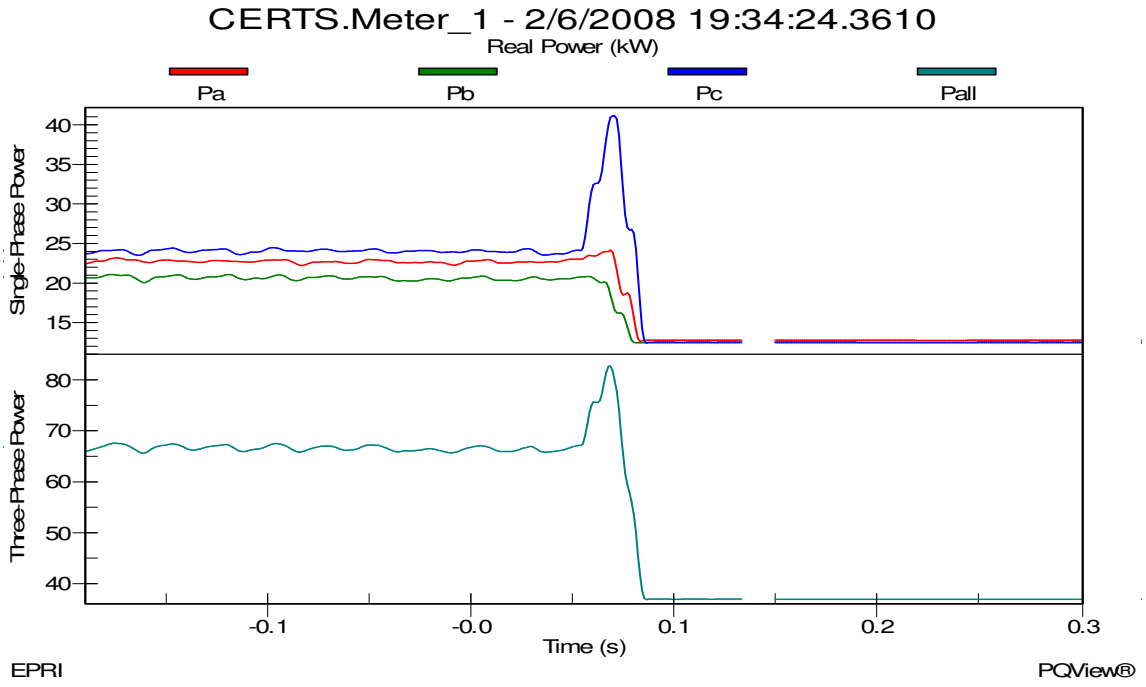

Figure 19a Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 2.

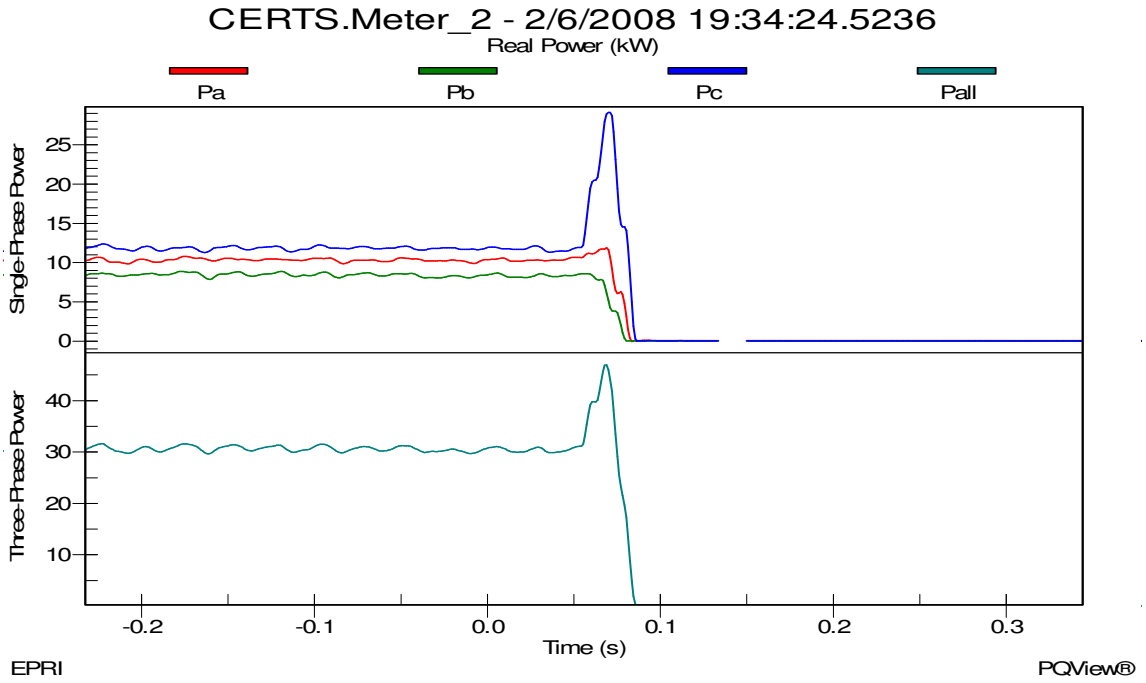

Figure 19b – Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 2.

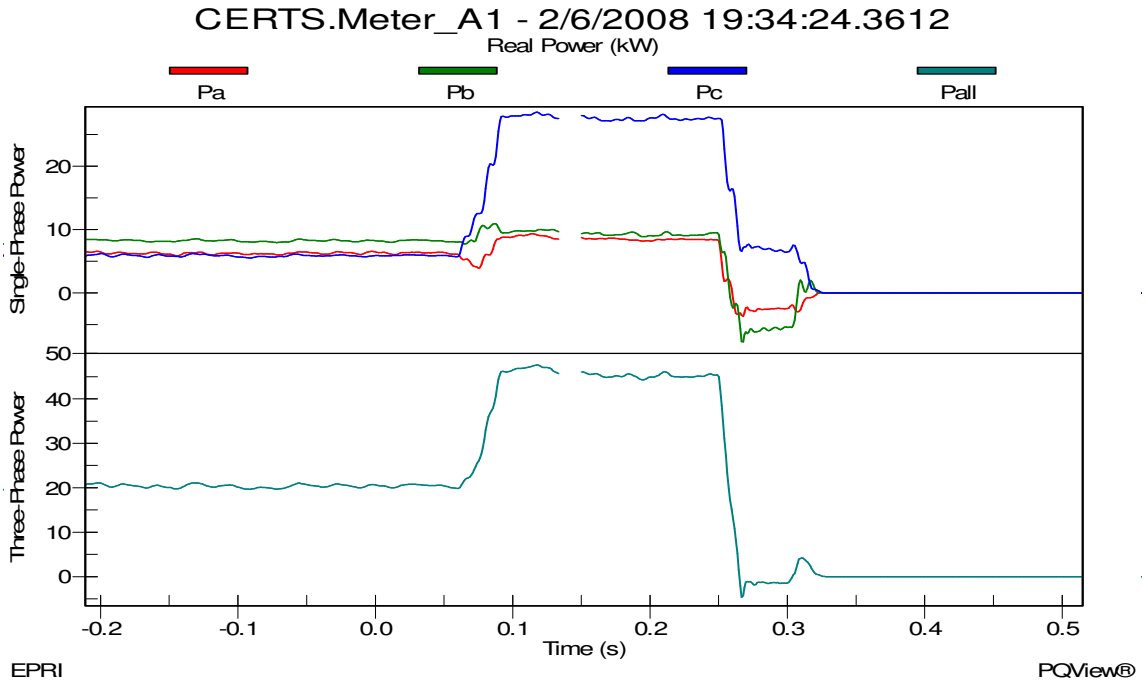

Figure 19c - Power produced by Gen-set A1 before/after the static switch opened from a C-phase-to-ground fault in Zone 2.

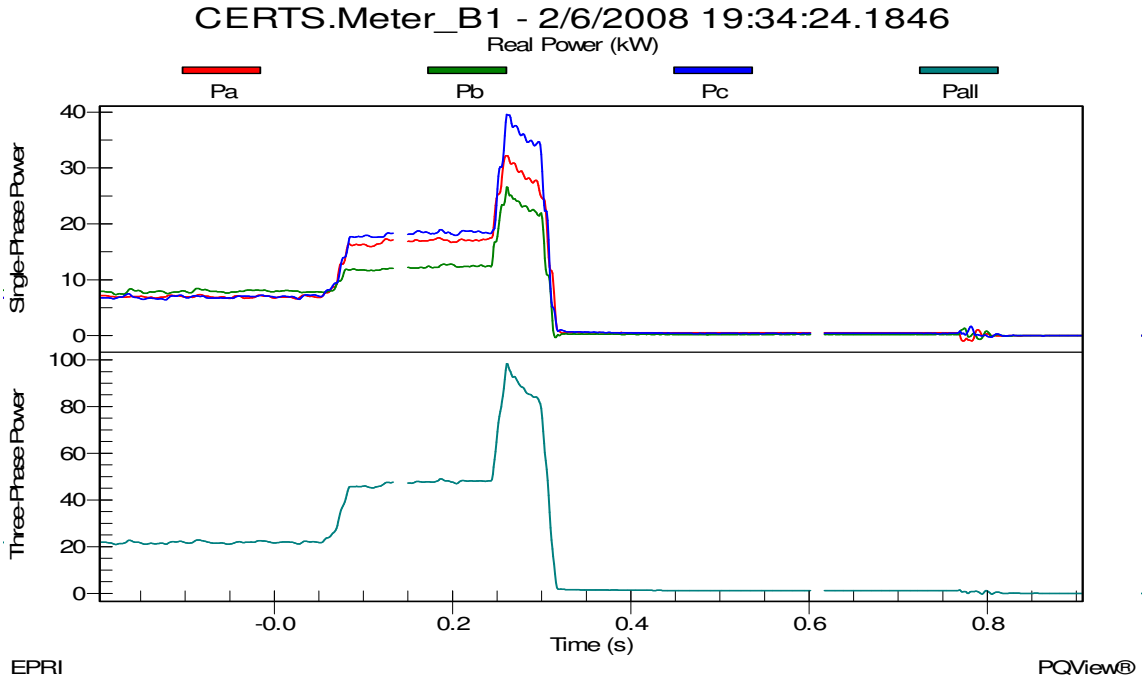

Figure 19d - Power produced by Gen-set B1 before/after the static switch opened from a C-phase-to-ground fault in Zone 2.

Using the DAS Load Control program, the single phase-to-ground fault on C-phase was set for 10 seconds and then initiated. Relay 2 tripped the static switch first on ground over-current (67N1T) in approximately 0.02 seconds (1 cycle) after the fault was applied, Figure 19e. Both Gen-sets A1 and B1 ramped up carrying Load Banks 3 and 4, as well as the C phase overload fault. Relay 3 tripped approximately 0.17 seconds (10.4 cycles) after the static switch opened, causing Gen-set A1 to stop switching its output, although its transformer contactor and CB31 remained closed for a few cycles longer. This can be seen by the reverse power on A and B phases supplying C phase even though the net three phase power remains zero, Figure 19c. CB31 opened 0.046 seconds (2.75 cycles) after receiving the trip signal from Relay 3, separating Zones 3 and 4 from the microgrid.

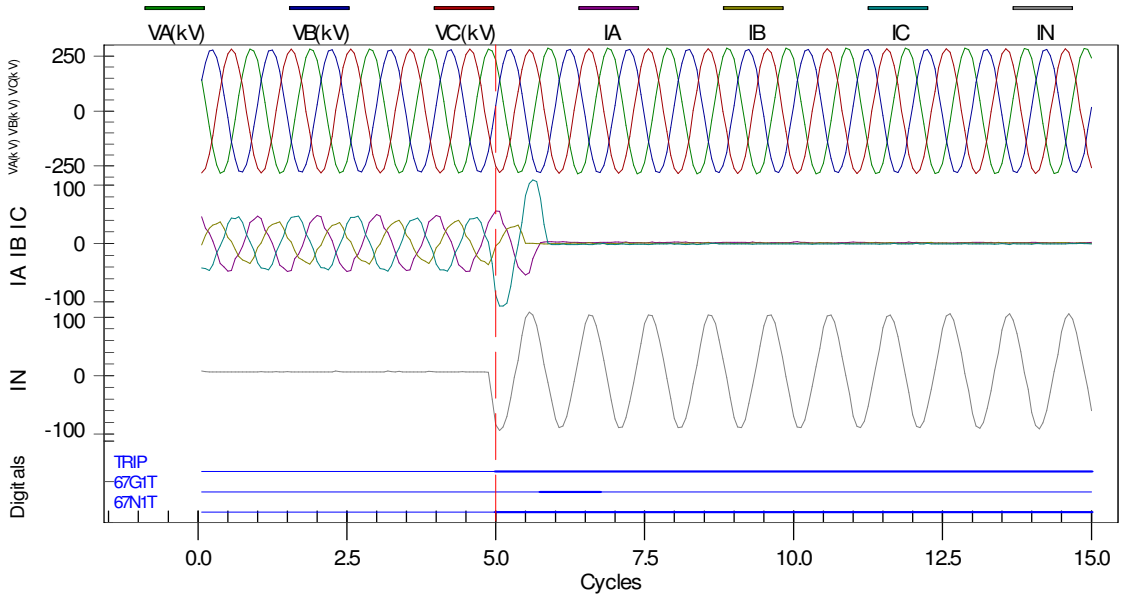

Figure 19e - Relay 2 (static switch) tripped due to a gournd over-current (67N1T) when the single phase-to-ground fault was initiated in Zone 2.

Gen-set B1 remained on-line supporting the fault load bank in Zone 2, Figure 19f. Because the static switch and CB31 were now open, Zone 2 was dominated by the Delta winding of T51 and effectively turned the entire zone into a 3-wire system. However, the measurement transformers which feed the DSP controller and the under-voltage relay 5a were connected wye-wye and likely experienced a full phase to phase voltage (480V) across their primary windings (277V), Figure 19g. Because only high impedance measurement equipment was connected to the secondaries of these transformers, negligible fault current flowed through them. Since the fault was applied from C phase-to-ground there remained no path for current flow and the fault was effectively removed.

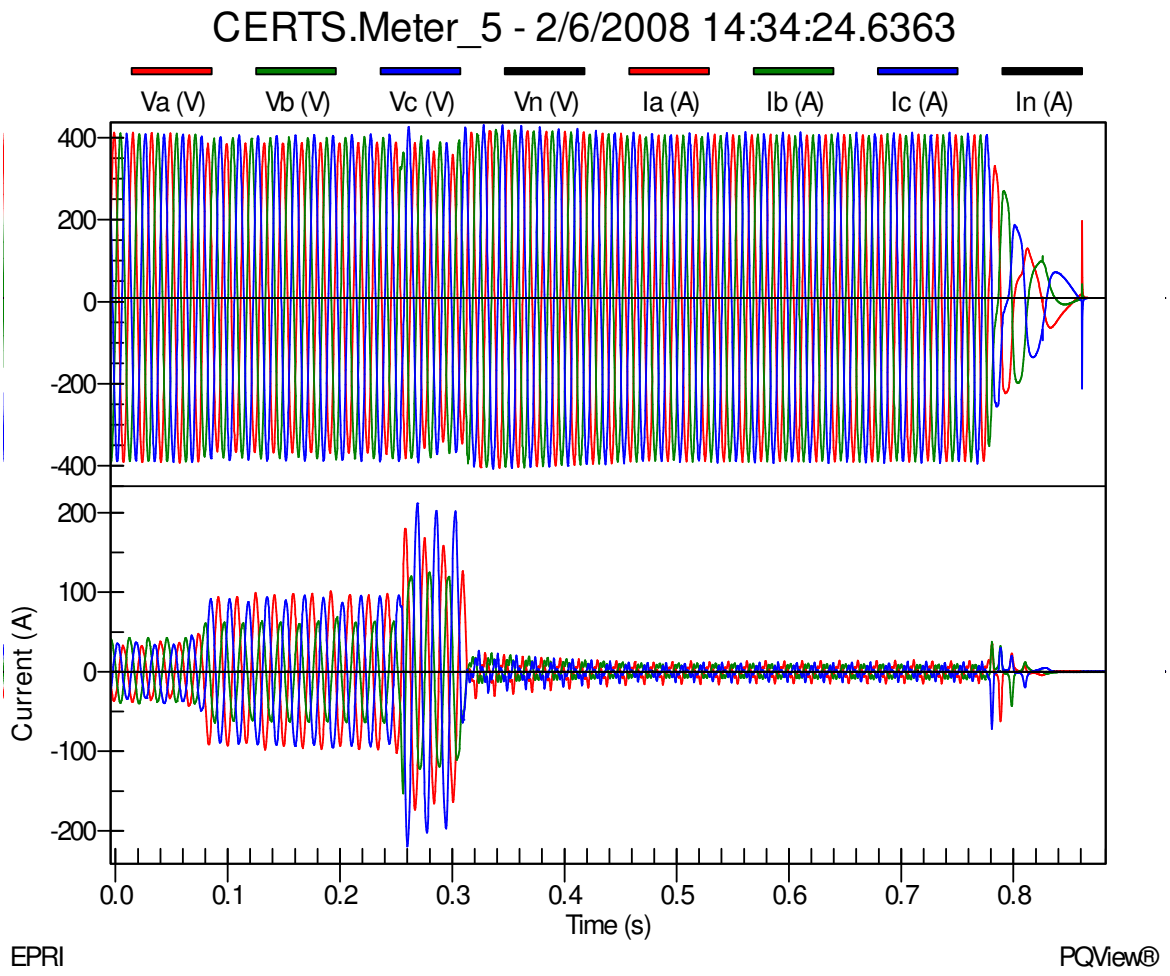

Figure 19f - Meter 5 voltage and current during the applied single-phase-to-ground fault in Zone 2.

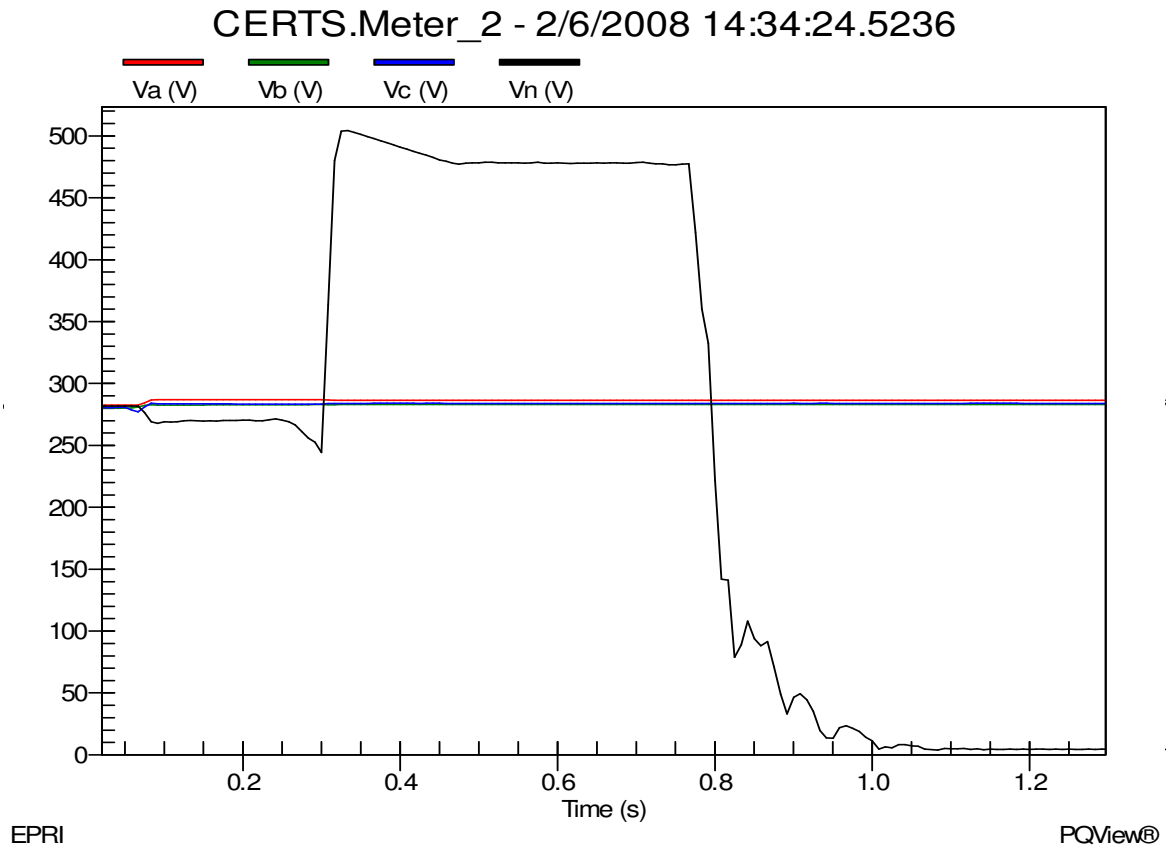

Figure 19g – Meter 2 RMS voltage before/after CB31 opened.

Finally Gen-set B1 was tripped off-line by under-voltage Relay 5a (SV4T) as can be seen in Relay 5, Figure 19h. As mentioned above, voltage remained within Zone 2 after the static switch and CB31 opened, therefore it must be assumed that either the fusing on Relay 5a operated or that it was damaged by excessive voltage that occurred during the fault. This was interpreted as an under-voltage and caused Relay 5 to trip incorrectly, shutting down Gen-set B1 and opening CB51. Relay 5 tripped approximately 0.5 seconds (30 cycles) after CB31 opened.

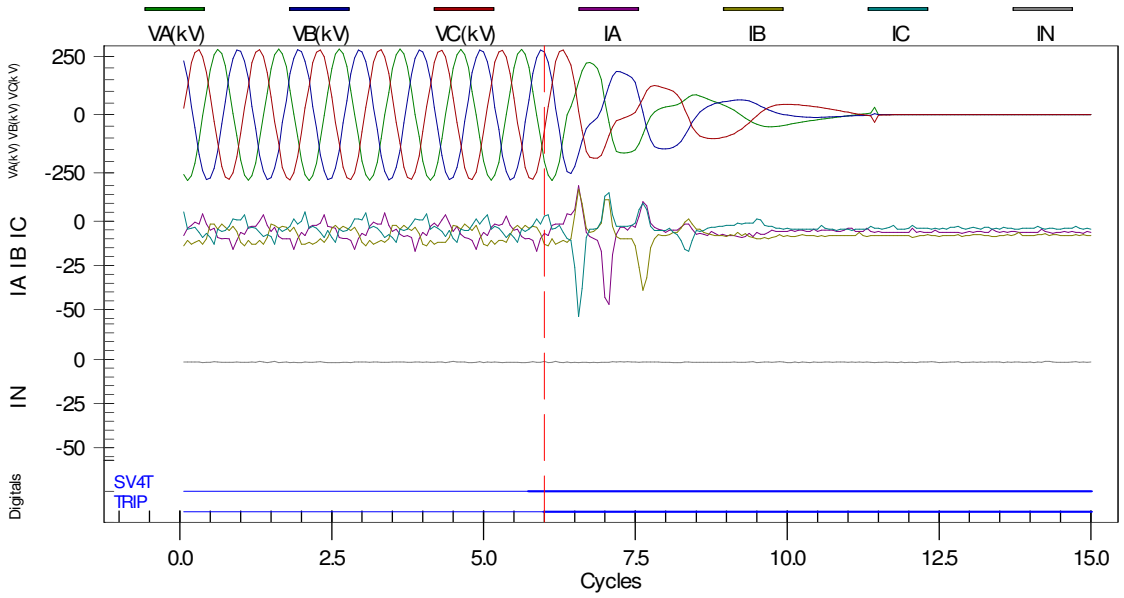

Figure 19h - Relay 5 (CB51) tripped due to an undervoltage at T51 when the single phase-to-ground fault was initiated in Zone 2.

The electrical system was stable in both the microgrid and utility grid after the static switch opened, CB31 and CB51 opened, and Gen-sets A1 and B1 shut down. All loads and alarms were reset and equipment was prepared for the next test.

6.1.11 Zone 6 C-Phase Line-to-Ground Fault, Gen-set A1 and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 6 with Gen-set A1 operating in-parallel with the utility grid to verify I^2t protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = A (Delayed)

Load Bank 3 = 40kW

Load Bank 6 = 60kW

To simulate a high impedance single phase-to-ground fault in Zone 6 on C-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 8a with phases A and B disconnected. This, when combined with the load in Load Bank 6 of 60kW (20kW per phase), added 28.3kW to C-phase in Zone 6 and caused an overload condition.

After Gen-set A1 was running for a few minutes and supplied power to Load Bank 3, the test was started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 68.5kW, shown in Figure 20a, and approximately 16kW at Meter 2, shown in Figure 20b. Gen-set A1 was producing about 20.5kW, shown in Figures 20c before the fault was applied after 0 seconds.

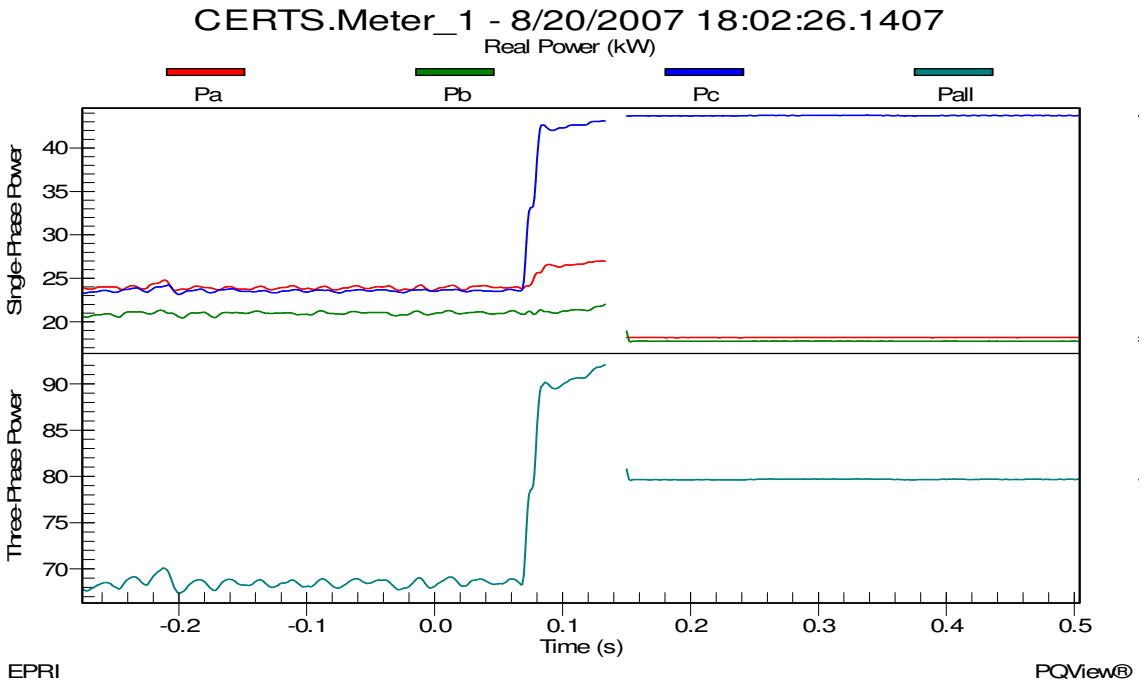

Figure 20a - Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 6.

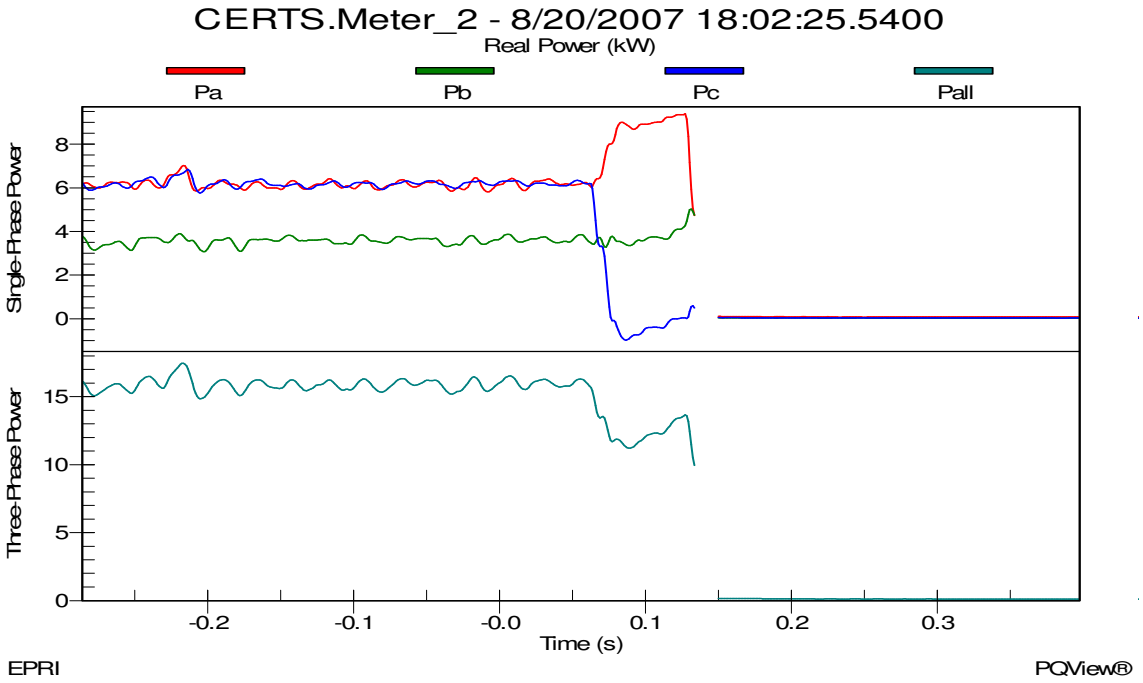

Figure 20b - Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 6.

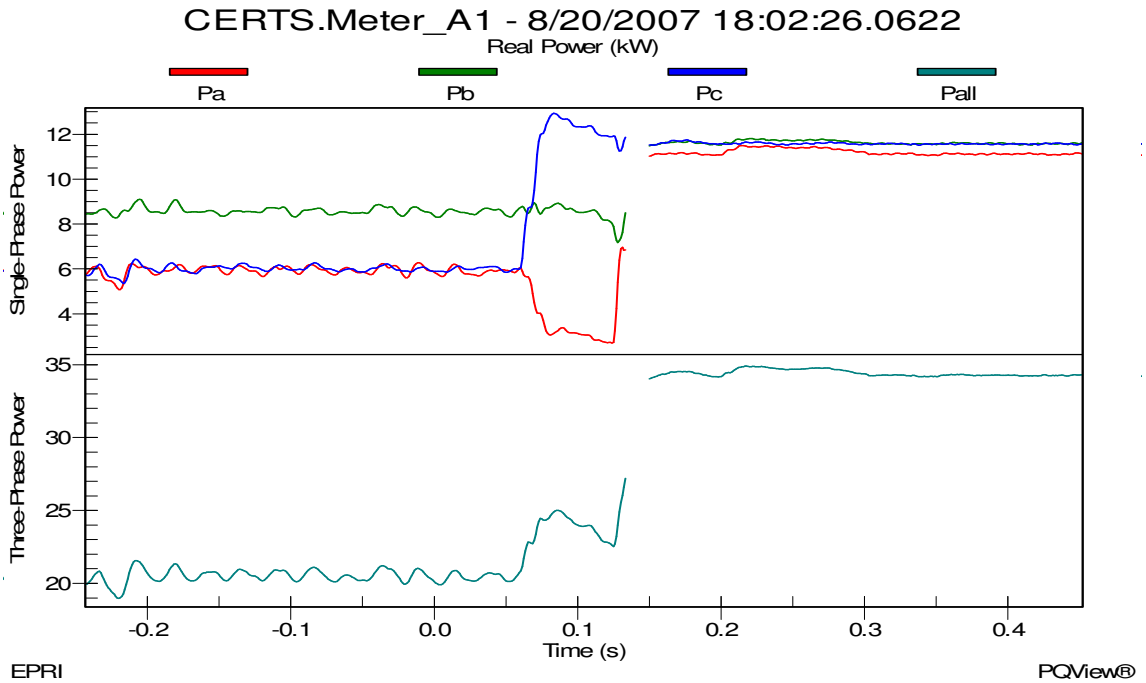

Figure 20c - Power produced by Gen-set A1 before/after the static switch opened from a C-phase phase-to-ground fault in Zone 6.

Using the DAS Load Control program, the single phase-to-ground fault on C-phase was set for 10 seconds and then initiated. The static switch tripped in approximately 0.07 seconds (~4.3 cycles) from a neutral over-current (67G1T), shown in Figure 20d, islanding the microgrid from the utility grid. Following the static switch operation, CB13, which provides protection to Zone 6, tripped on I^2t protection with CB31, CB41 and CB51 remaining closed, since the overload fault was not part of the microgrid, located beyond the static switch.

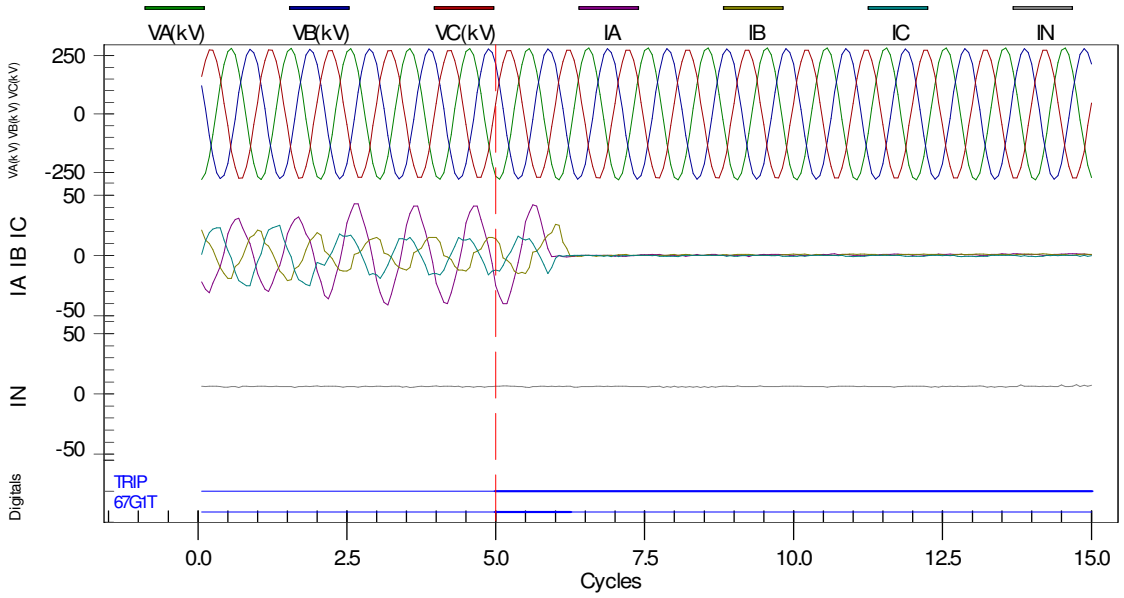

Figure 20d - Relay 2 (static switch) tripping due to a ground over-current (50GR) when the single phase-to-ground fault was initiated in Zone 6.

The electrical system was stable in both the microgrid and utility grid after the static switch opened and CB13 opened. Gen-set A1 was manually shut down with all loads and alarms reset and equipment was prepared for the next test.

A few points of interest for this test include the Gen-set contribution to the fault and the sensitivity of the static switch to an unbalanced load within the unprotected portion (i.e., Zone 6) of the microgrid. In Figure 20c it can be seen that at Meter A1, just after the fault was applied, three phase power increased slightly from 20kW to 25kW, with C-phase output increasing and A-phase output decreasing. Because the three phase power increased by approximately 5kW, it must be concluded that Gen-set A1 did increase its power output. The reduction in A-phase power which contributed to the C-phase

increase in power is likely due to the delta winding of the inverter transformer, which cannot be confirmed, since there are no meter provisions on that side.

The second point of interest for this test is that the static switch is sensitive to load unbalance in Zone 6 of the microgrid. In this test, had the unbalance not tripped CB13, removing it from the system, the static switch after a short period of time would have reconnected to the utility briefly before tripping off again. This process would have continued indefinitely or until some other system parameter was altered. In future installations, consideration must be given to this to prevent unattended operation in this manner.

6.1.12 Zone 6 C-Phase Line-to-Ground fault, Gen-sets (A1+B1) and Utility Connected

Performance Goal:

Test a single line-to-ground overload fault condition in Zone 6 with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify I^2t protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set B1 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set B1 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = A (Delayed)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 5 = 40kW

Load Bank 6 = 60 kW

To simulate a high impedance single phase-to-ground fault in Zone 6 on C-phase the Overload Load Bank of 85kW (approximately 28.3kW per phase) was connected by cable/plug into the exterior receptacle of Cabinet 8a with phases A and B disconnected.

This, when combined with the load in Load Bank 6 of 60kW (approximately 20kW per phase), added 28.3kW to C-phase in Zone 6 and caused an overload condition in Zone 6.

After both Gen-sets A1 and B1 were running for a few minutes and supplied power to Load Banks 3 and 5, the test started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 89kW, shown in Figure 21a, and approximately 35kW at Meter 2, shown in Figure 21b. **B**efore the overload fault was applied, Gen-set A1 was producing approximately 17kW and Gen-set B1 was producing approximately 19kW, shown in Figures 21c and 21d, respectively.

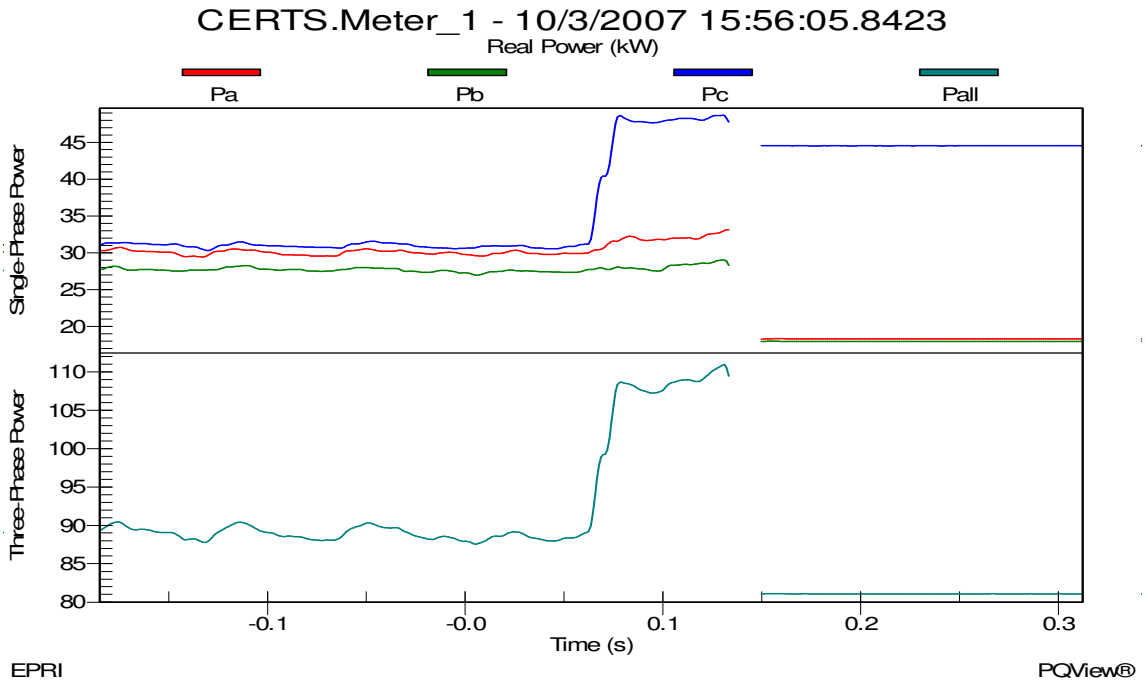

Figure 21a Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 6.

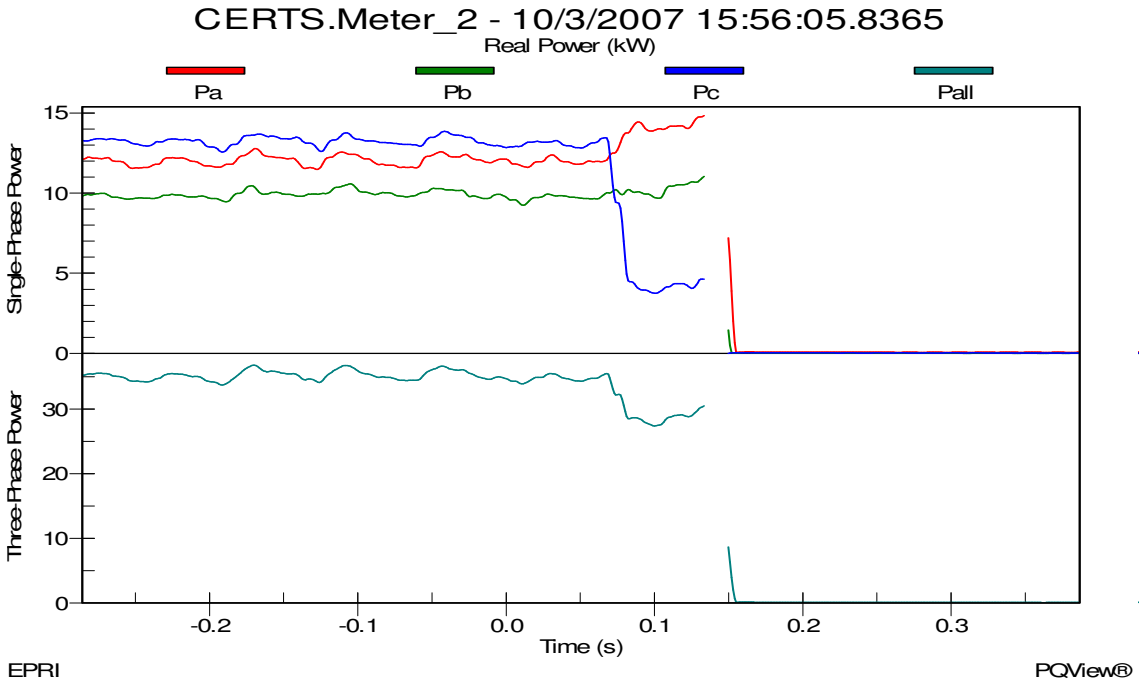

Figure 21b Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a single phase-to-ground fault was applied in Zone 6.

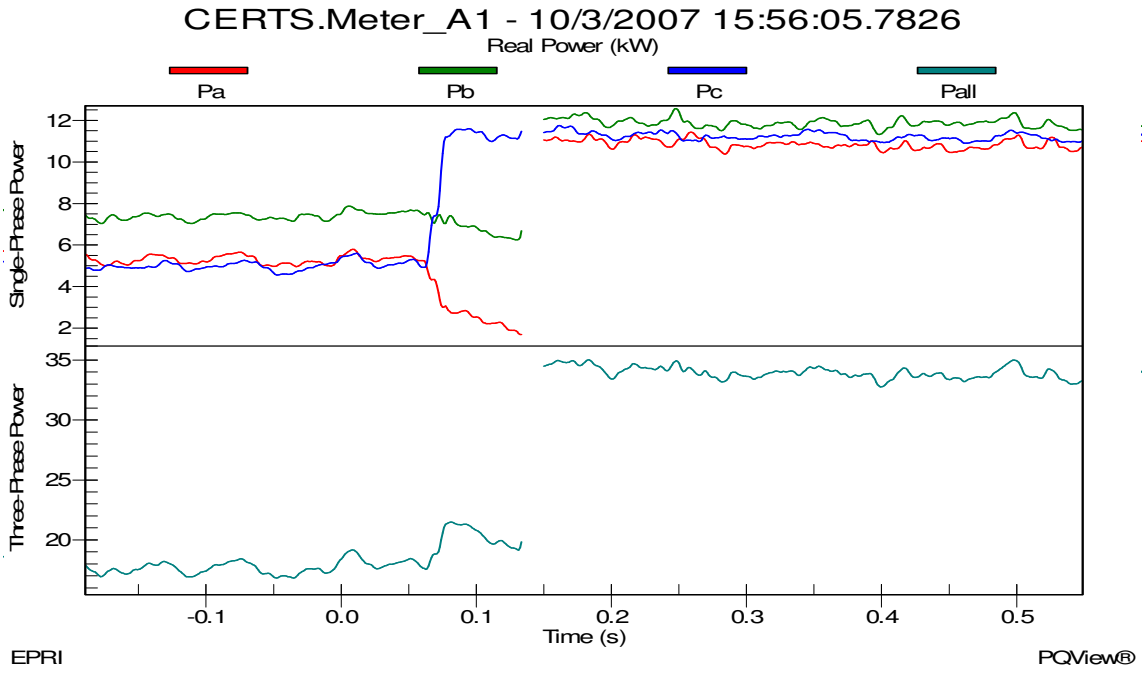

Figure 21c - Power produced by Gen-set A1 before/after the static switch opened from a C-phase-to-ground fault in Zone 6.

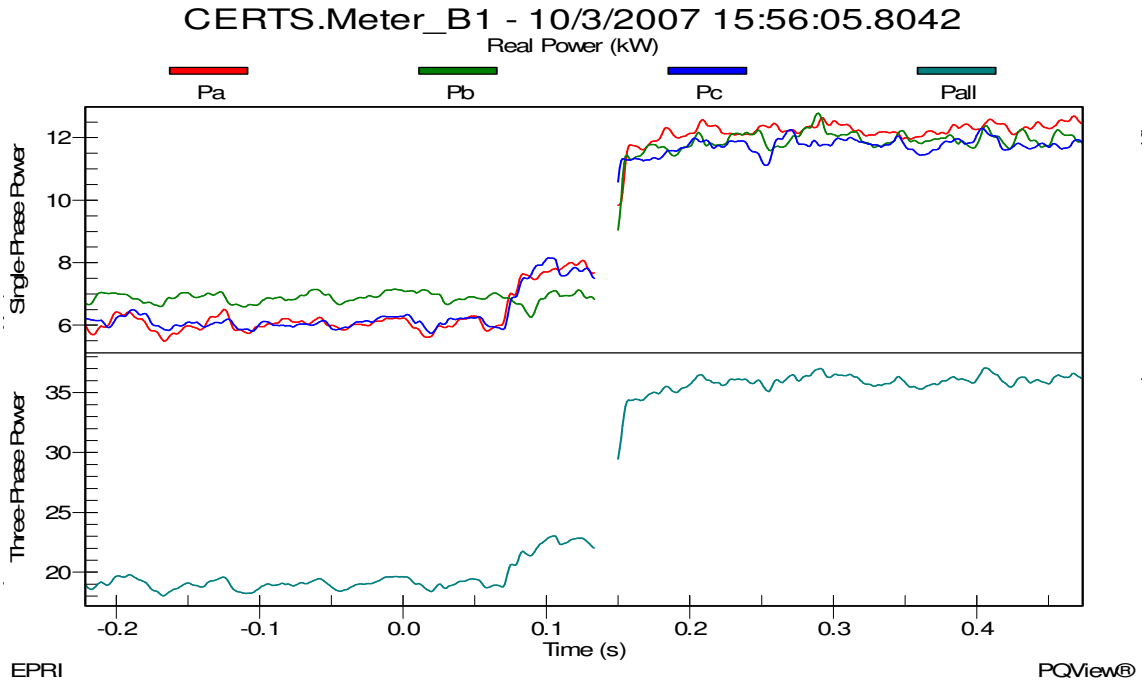

Figure 21d - Power produced by Gen-set B1 before/after the static switch opened from a C-phase-to-ground fault in Zone 6.

Using the DAS Load Control program, the single phase-to-ground fault on C-phase was set for 10 seconds and then initiated. The static switch tripped in approximately 0.07 seconds (~4.3 cycles) from a neutral over-current (67G1T), shown in Figure 21e, islanding the microgrid from the utility grid. Following the static switch operation, CB13, which provides protection to Zone 6, tripped on I^2t protection with CB31, CB41 and CB51 remaining closed, since the overload fault was not part of the microgrid, located beyond the static switch.

Within the islanded microgrid, Gen-sets A1 and B1 increased their output power to Load Banks 3 and 5. Gen-set A1 increased its output power from approximately 17kW to 34kW, and Gen-set B1 increased its output power from approximately 19kW to 36kW, shown in Figures 21c and 21d, respectively. Meter 2 (i.e., Figure 21b) power flow decreased to 0kW after the fault was initiated and the static switch opened. After the overload fault was cleared from the electrical system, Meter 1 (i.e., Figure 21a) power flow decreased to 80kW from the utility grid. The utility grid and microgrid remained in this stable state until the fault was removed.

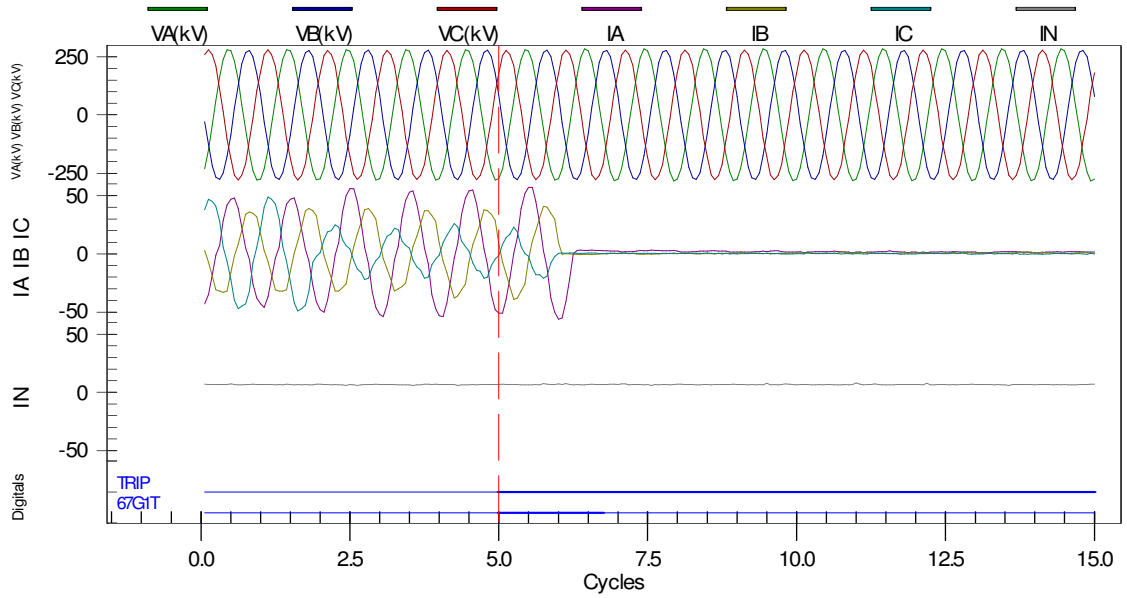

Figure 21e - Relay 2 (static switch) tripped due to a neutral over-current (67G1T) when the single phase-to-ground fault was initiated in Zone 6.

This test also produced the two points of interest mentioned in the previous test. These tests were similar with the exception that Gen-set B1 was less affected by the phase-to-ground fault due to transformer T51. Gen-set B1 did increase its power output by approximately 2kW; however, it was spread more evenly across A- and C-phases. Also, both A- and C-phases increased in power output instead of A-phase reducing as in the last test. The static switch still remains sensitive to unbalanced load within Zone 6 of the microgrid.

A third point of interest developed in this test, while waiting for the data to finish being collected from the metering equipment. Both Gen-set A1 and B1 shut down prematurely after the test was completed. This shutdown was captured by the metering equipment and can be used as insight into what caused the shutdown. Gen-set A1 reported a "No Field Fault" and B1 reported a "Boost Fault". Figure 21f indicated Gen-set A1 produced a 150kW increase of power for a short period of time. This matched up with Figure 21g indicating Gen-set B1 draws-in a large amount (i.e., 95kW) of power for a short period of time. These Gen-sets were not designed to absorb power, thus, it can be assume that the cause for this premature shutdown was attributed to Gen-set B1.

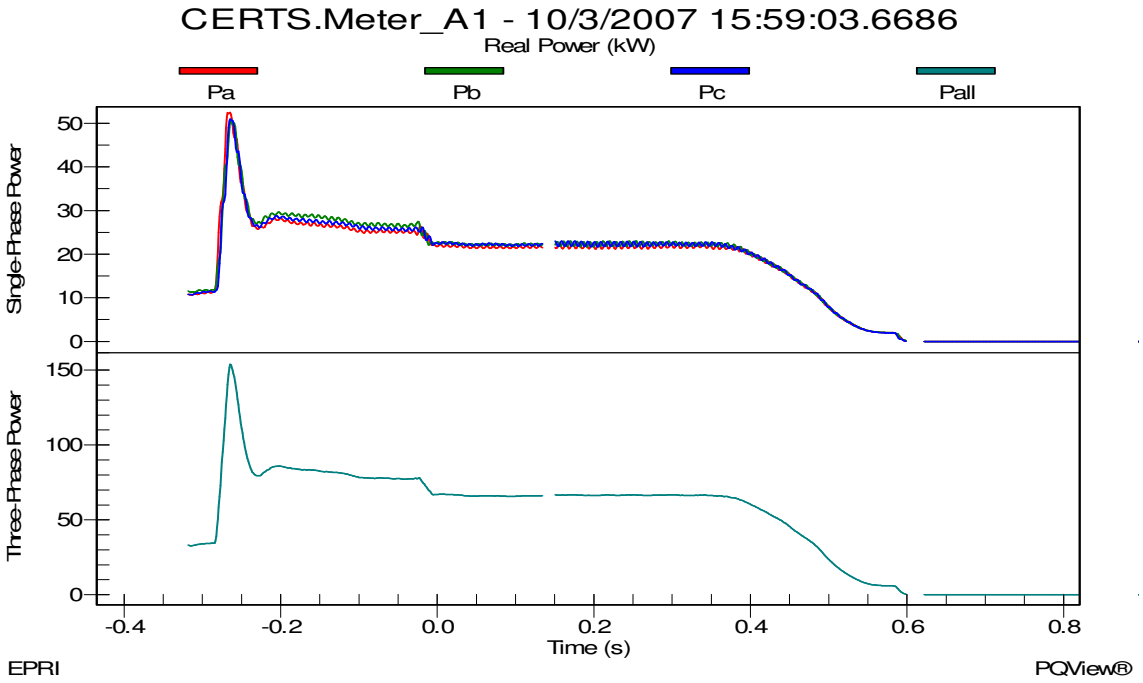

Figure 21f – Gen-set A1 shutting down due to a "No Field" fault.

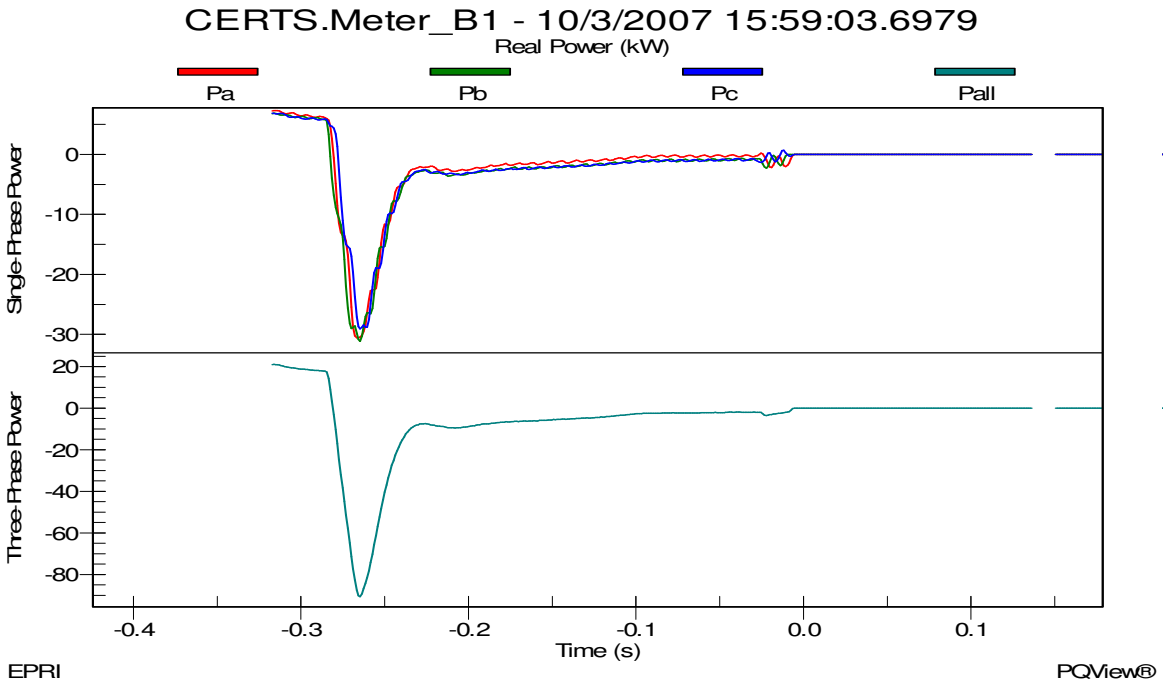

Figure 21g – Gen-set B1 shutting down due to a "Boost" fault

In Figure 21h, voltage at Gen-set A1 suddenly dropped to 245V and current increased to approximately 200A. After a short period of time, 0.28 seconds, Gen-set B1 was removed from the system and Gen-set A1 remained on-line, now serving both Load Banks 3 and 5, measured at approximately 65kW. Gen-set A1 continued to serve this load for approximately 0.38 seconds and then shut down, unexpectedly. Two conditions need be examined; the sudden import of power into Gen-set B1 which initiated the problem, and the short duration of Gen-set A1 operation afterwards which should have been within its overload envelope capability. These problems need to be corrected, as they unintentionally lead to a decrease in reliability.

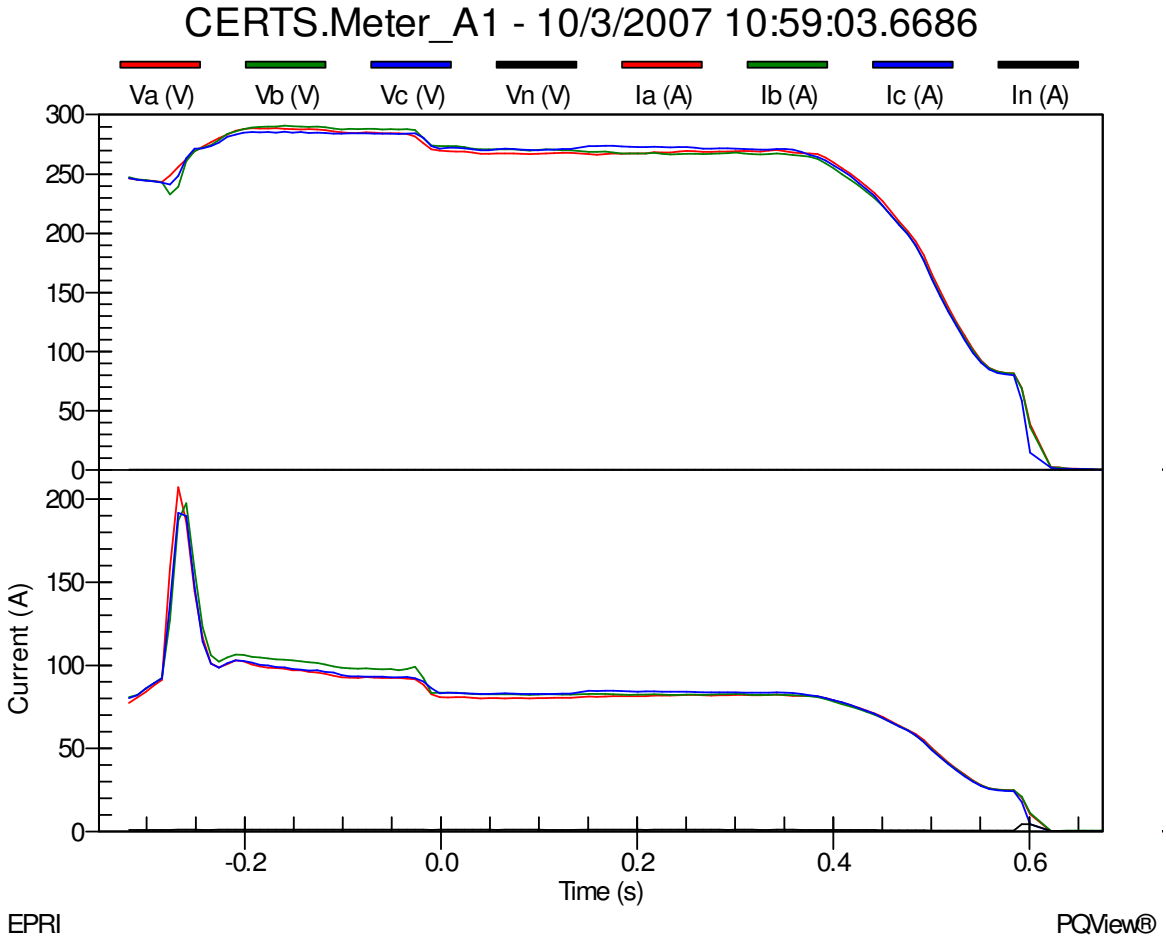

Figure 21h – Gen-set A1 shutting down due to a "No Field" fault.

6.1.13 Zone 3 A-to-B Phase Fault, Gen-sets (A1+A2) and Utility Connected

Performance Goal:

Test a phase-to-phase overload fault condition in Zone 3 on A- and B-phases with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set A2 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set A2 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance phase-to-phase fault in Zone 3 on A-B phases the Overload Load Bank of 85kW (i.e., approximately 42.5kW phase-to-phase) was connected by cable/plug into the exterior receptacle of Cabinet 3 with C-phase disconnected. This, combined with load in Load Banks 3 and 4, added an additional 21.2kW on A- and B phases of Zone 3 when initiated causing an overload.

After Gen-sets A1 and A2 were running for a few minutes and supplied power to Load Banks 3 and 4, the test started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with power flow at Meter 1 being approximately 74kW, shown in Figure 22a, and approximately 38kW at Meter 2, shown in Figure 22b. Before the overload fault was applied, Gen-sets A1 and A2 were producing about 19kW, shown in Figures 22c and 22d.

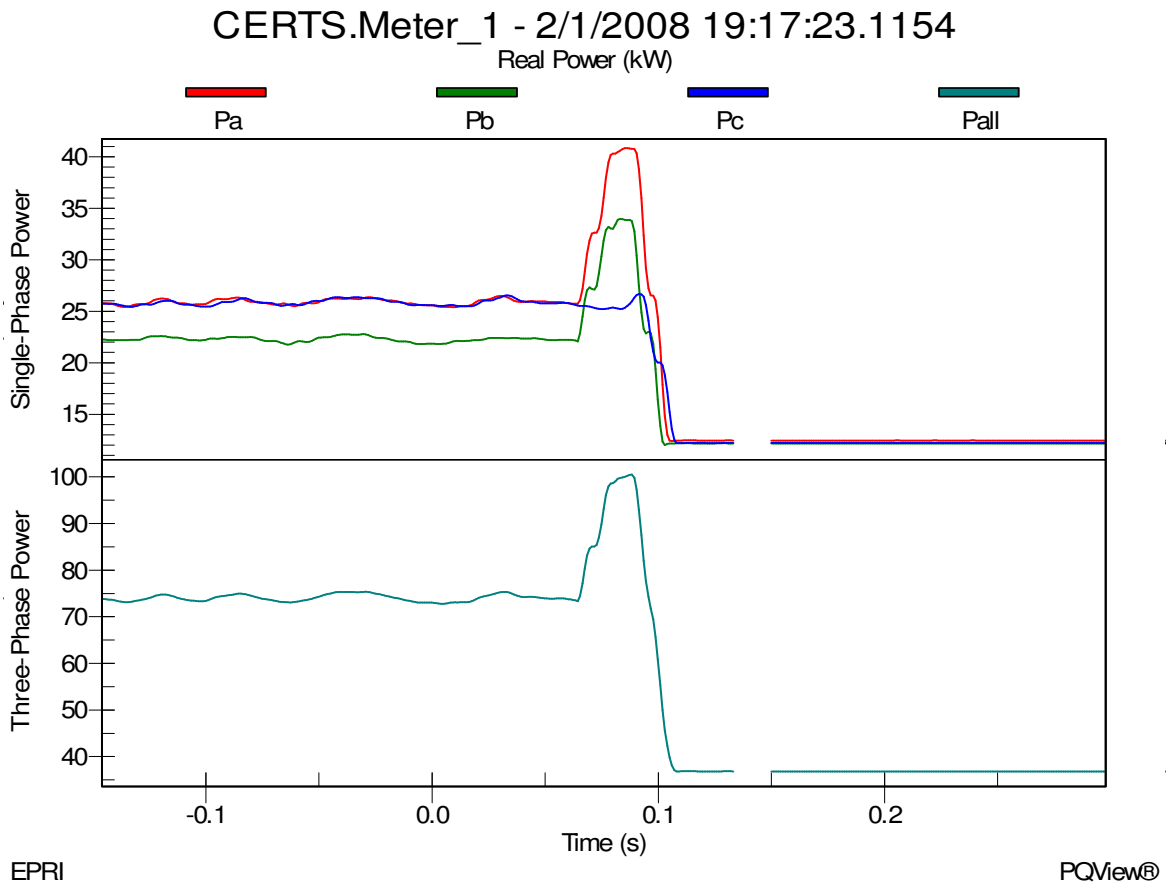

Figure 22a – Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when the phase-to-phase fault was applied in Zone 3.

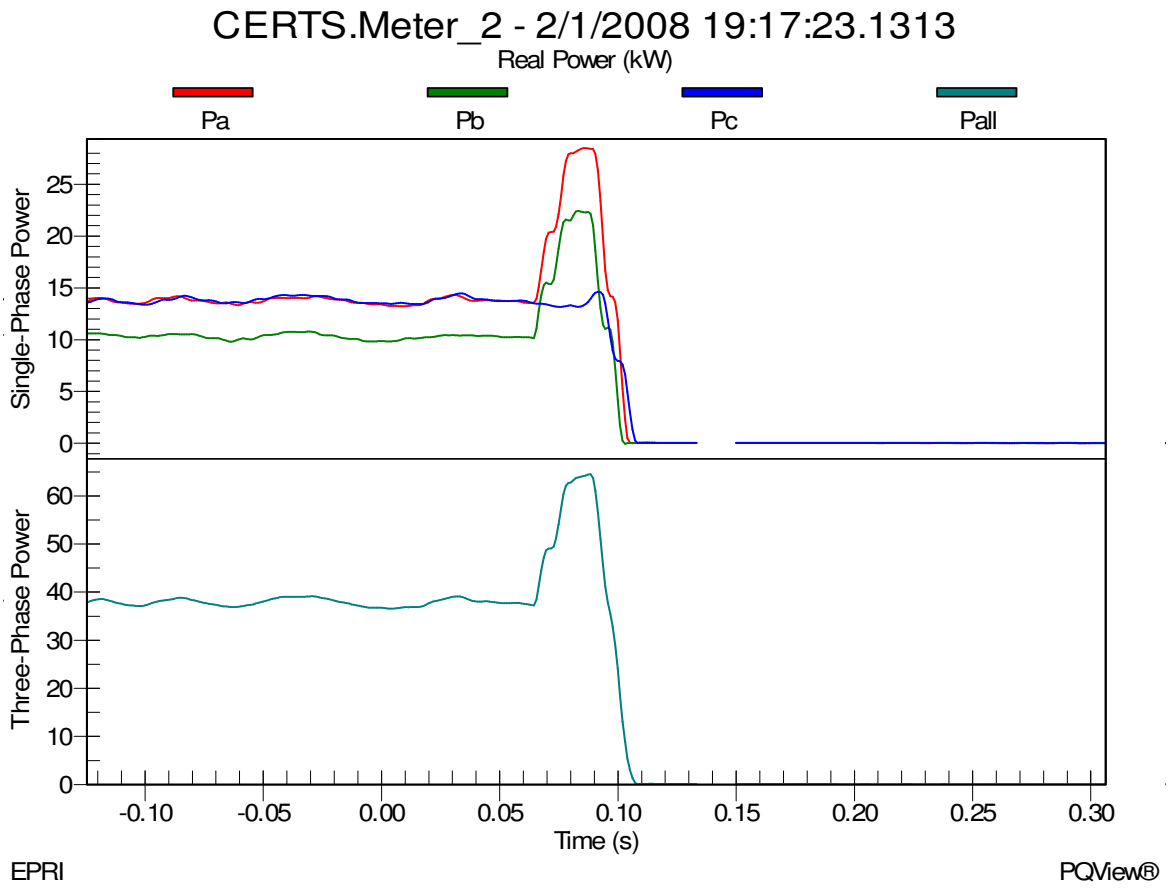

Figure 22b – Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a phase-to-phase fault was applied in Zone 3.

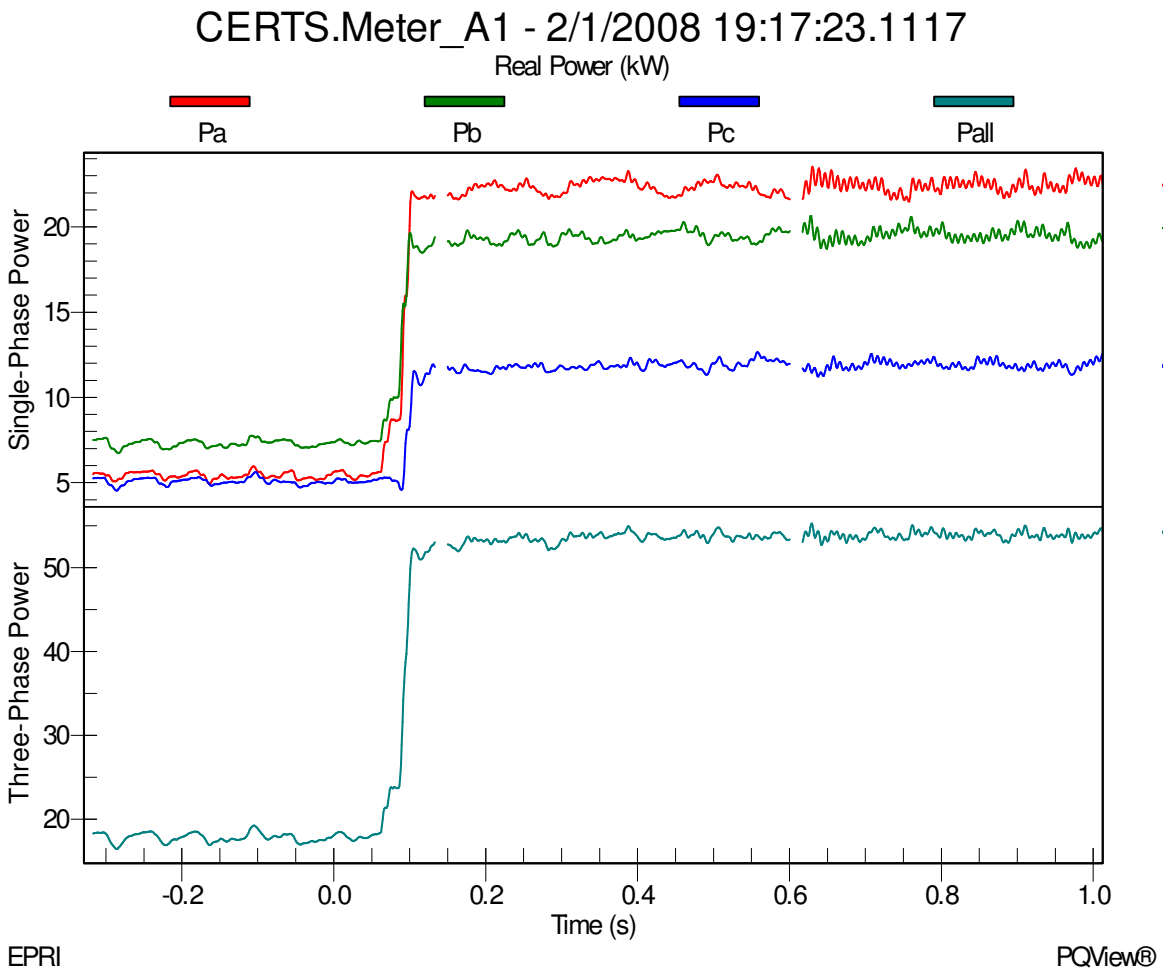

Figure 225c - Power produced by Gen-set A1 before/after the static switch opened when an A-to-B phase fault was applied in Zone 3.

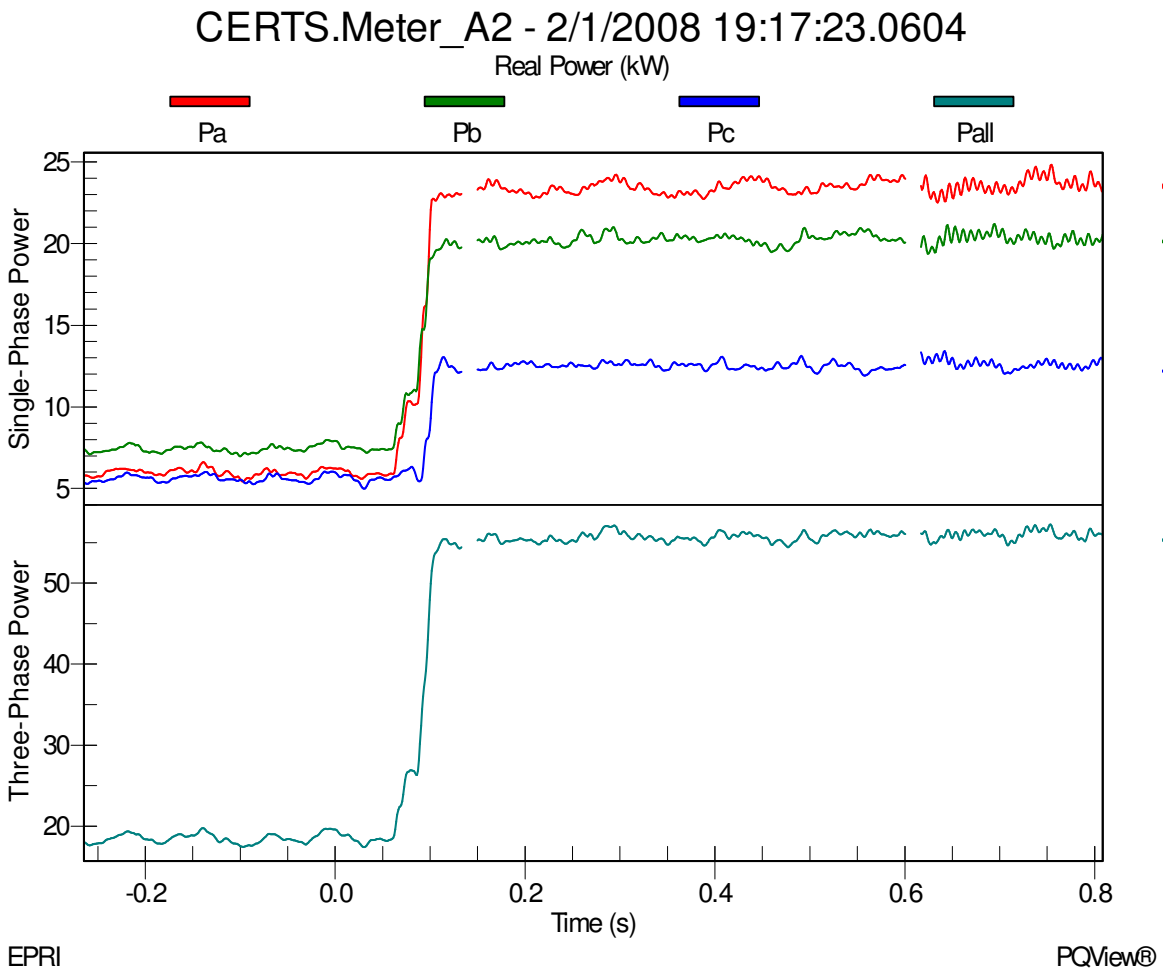

Figure 22d - Power produced by Gen-set A2 before/after the static switch opened when an A-to-B phase fault was applied in Zone 3.

Using the DAS Load Control program, the phase-to-phase fault on A and B phases was set for 10 seconds and then initiated. The static switch tripped in approximately 0.028 seconds (~1.7 cycles) from a negative-sequence over-current (67Q1T), shown in Figure 22e, islanding the microgrid from the utility grid. CB31, CB41 and CB51 remained closed throughout the 10 second phase-to-phase fault. Gen-sets A1 and A2 increased their output power from approximately 19kW to 54kW, each shown in Figures 22c and 22d supplying power to Load Banks 3 and 4. Load Bank 6 was supplied power from the utility grid, shown in Figure 22a.

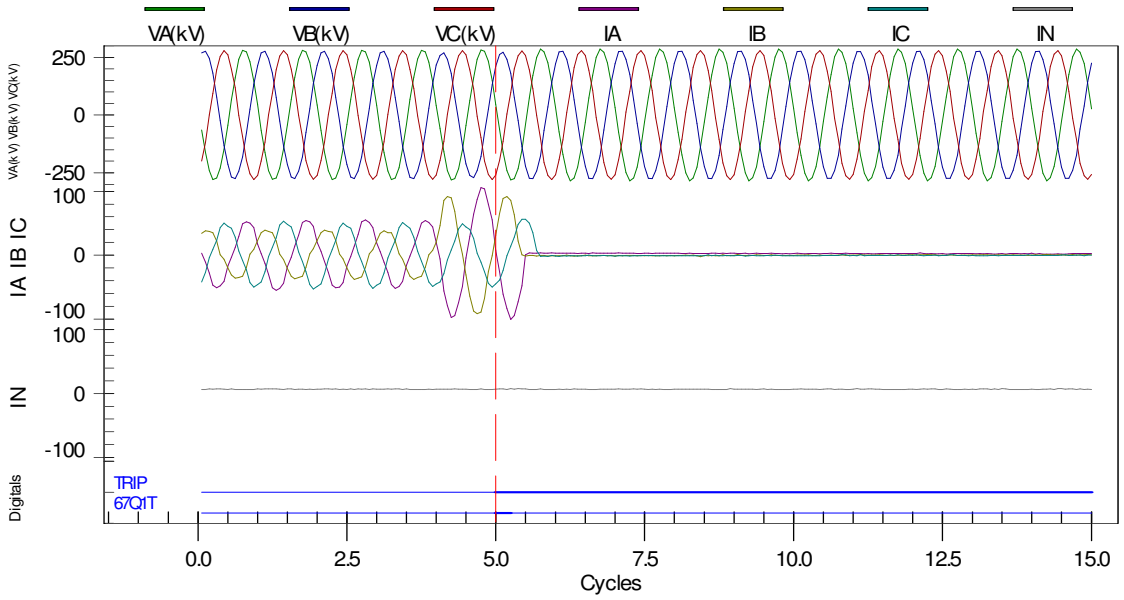

Figure 22e - Relay 2 (static switch) tripped due to a negative-sequence over-current (67Q1T) when the phase-to-phase fault was initiated in Zone 3.

After the fault was removed from Zone 3, the static switch was synchronized and shortly closed back into the utility grid. The electrical system was stable in both the microgrid and utility grid after the static switch opened and then when it closed. Gen-sets A1 and A2 were shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.14 Zone 4 A-to-B Phase Fault, Gen-sets (A1+A2) and Utility Connected

Performance Goal:

Test a phase-to-phase overload fault condition in Zone 4 on A- and B-phases with Gen-sets A1 and A2 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set A2 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set A2 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 4 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance phase-to-phase fault in Zone 4 on A-and B-phases, the Overload Load Bank of 85kW (i.e., approximately 42.5kW phase-phase) was connected by cable/plug into the exterior receptacle of Cabinet 5a with C-phase disconnected. This, combined with Load Bank 4 load, added 21.2kW on both A and B phases in Zone 4, when initiated, causing an overload.

After Gen-sets A1 and A2 were running for a few minutes and supplied power to Load Banks 3 and 4, the test started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with power flow at Meter 1 being approximately 67.5kW, shown in Figure 23a, and approximately 36kW at Meter 2, shown in Figure 23b, Before the overload fault was applied, Gen-sets A1 and A2 were producing about 20kW, each shown in Figures 23c and 23d .

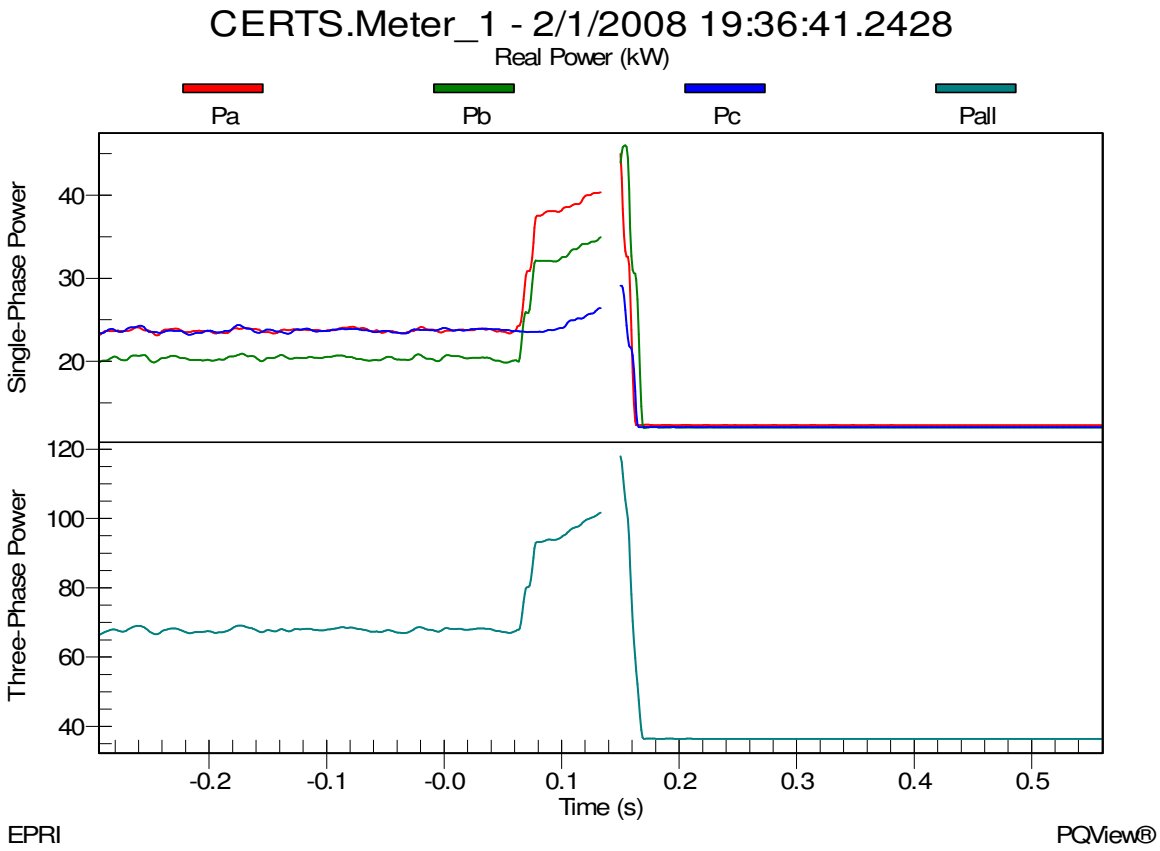

Figure 23a – Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a phase-to-phase fault was applied in Zone 4.

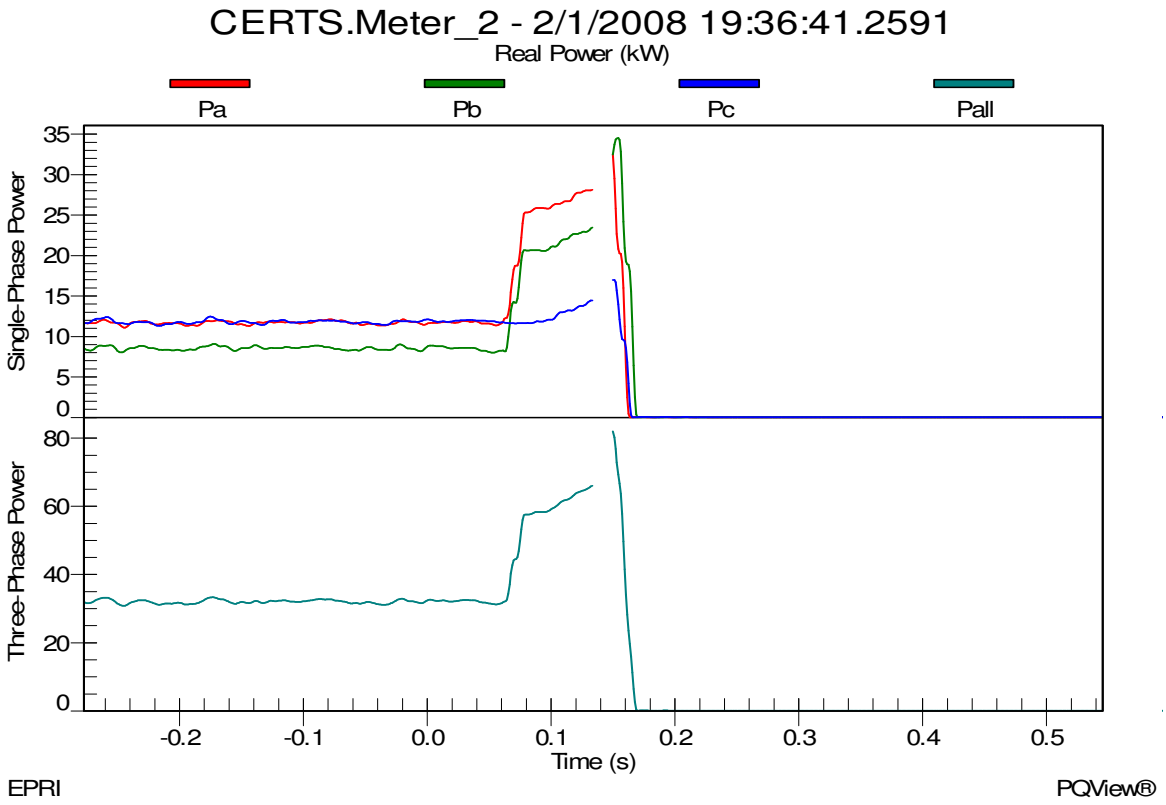

Figure 23b – Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a phase-to-phase fault was applied in Zone 4.

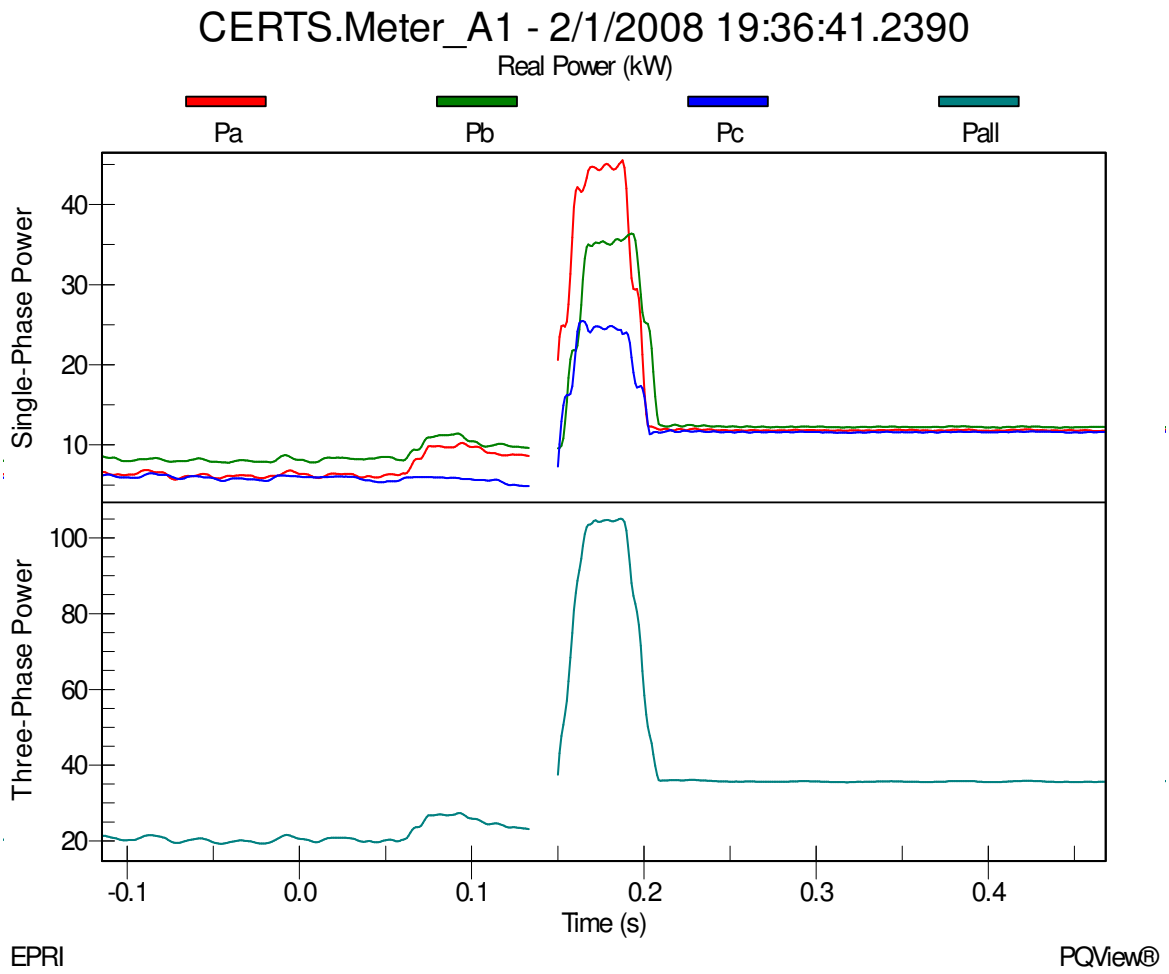

Figure 23c - Power produced by Gen-set A1 before/after the static switch opened when an A-phase to B-phase fault was applied in Zone 4.

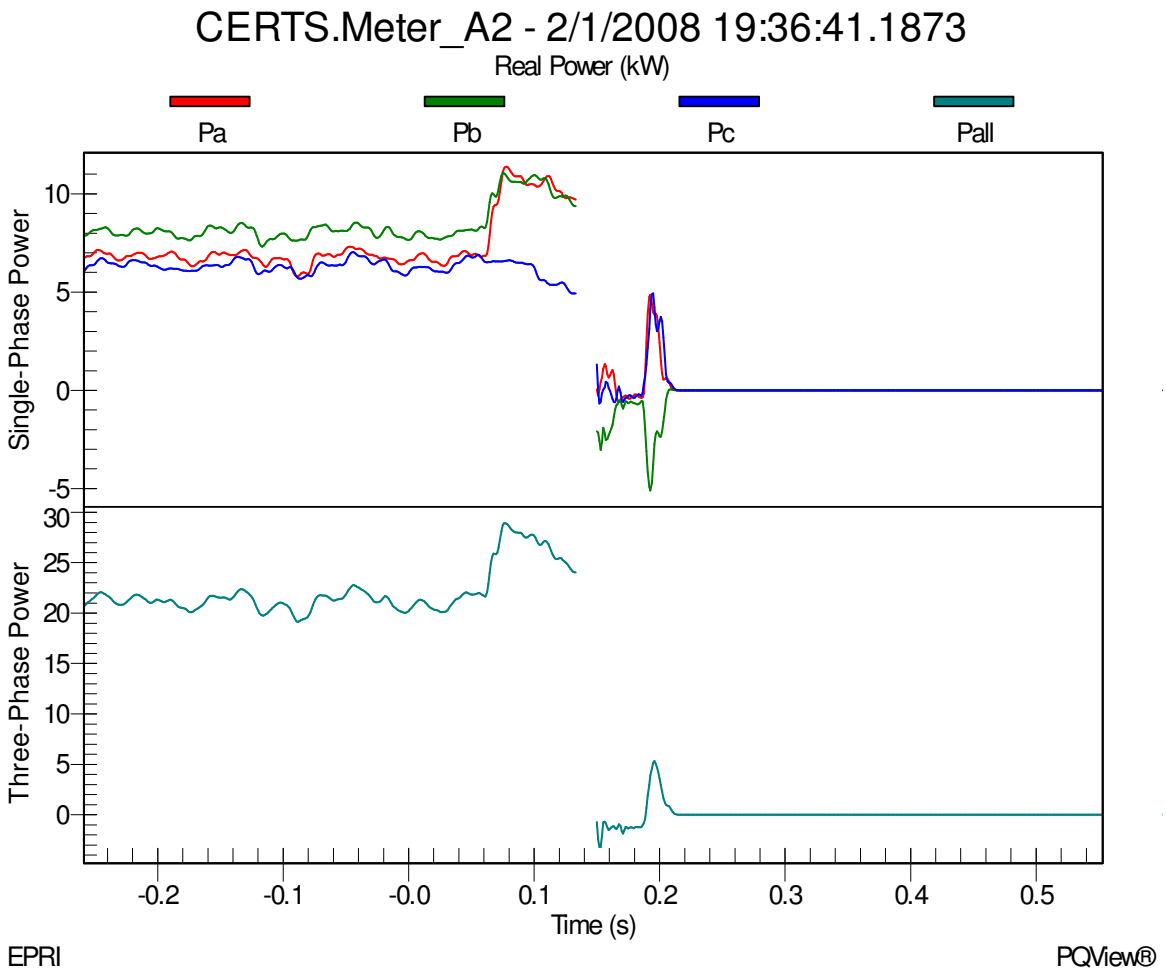

Figure 23d - Power produced by Gen-set A2 before/after the static switch opened when an A-phase toB-phase fault was applied in Zone 4.

Using the DAS Load Control program, the phase-to-phase fault on A and B phases was set for 10 seconds and then initiated. The static switch tripped in approximately 0.078 seconds (~4.7 cycles) from a negative-sequence over-current (67Q1T), shown in Figure 23e, islanding the microgrid from the utility grid. CB41 tripped, after the static switch opened, due to a negative-sequence over-current (67Q1T) isolating Zone 4 from the rest of the microgrid, and shutting down Gen-set A2, shown in Figures 23d and 23f. CB31 and CB51 remained closed throughout the 10 second phase-to-phase fault. Gen-set A1 increased its output power from approximately 20kW to 35kW, shown in Figure 23c, supplying power to Load Bank 3. Load Bank 6 was supplied power from the utility grid, shown in Figure 23a.

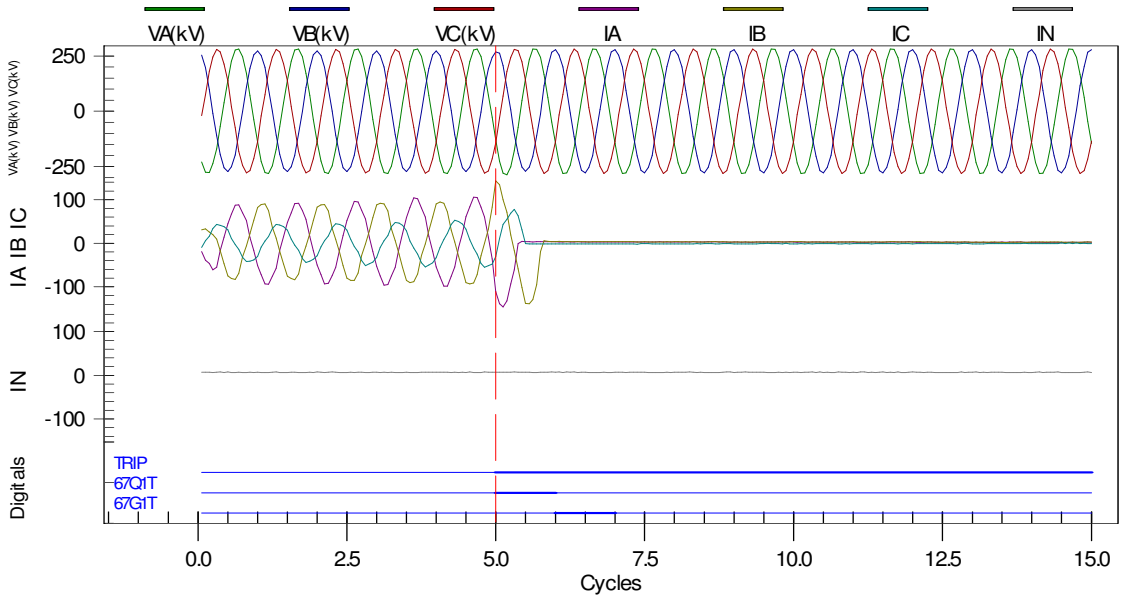

Figure 23e - Relay 2 (static switch) tripped due to a negative-sequence over-current (67Q1T) when the phase-to-phase fault was initiated in Zone 4.

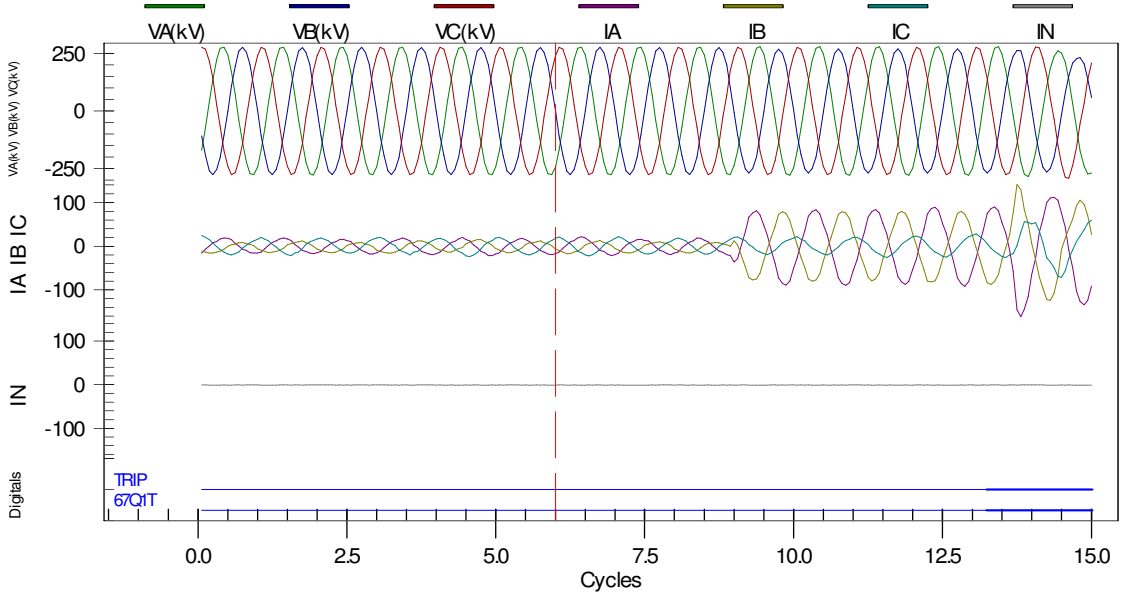

Figure 23f - Relay 4 (CB41) tripped due to a negative-sequence over-current (67Q1T) when the phase-to-phase fault was initiated in Zone 4.

After the fault was removed in Zone 4, the static switch was synchronized and shortly closed back into the utility grid. The electrical system was stable in the microgrid and utility grid after the static switch opened, CB41 opened, and Gen-set A2 shutdown. Gen-set A1 was shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.15 Zone 2 A-to-B Phase Fault, Gen-sets (A1+B1) and Utility Connected

Performance Goal:

Test a phase-to-phase overload fault condition in Zone 2 on A- and B-phases with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set B1 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set B1 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 5 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance phase-to-phase fault in Zone 2 on A- and B- phases, the Overload Load Bank of 85kW (i.e., approximately 42.5kW phase-phase) was connected by cable/plug into the exterior receptacle of Cabinet 2d with C-phase disconnected. This, when combined with load of Load Banks 3 and 5, added 21.2kW on A and B phases of Zone 2, when initiated, causing an overload.

After Gen-sets A1 and B1 were running for a few minutes and supplied power to Load Banks 3 and 5, the test started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 70kW, shown in Figure 24a, and approximately 34kW at Meter 2, shown in Figure 24b. Before the overload fault was applied, Gen-sets A1 and B1 were producing about 20kW each, shown in Figures 24c and 24d.

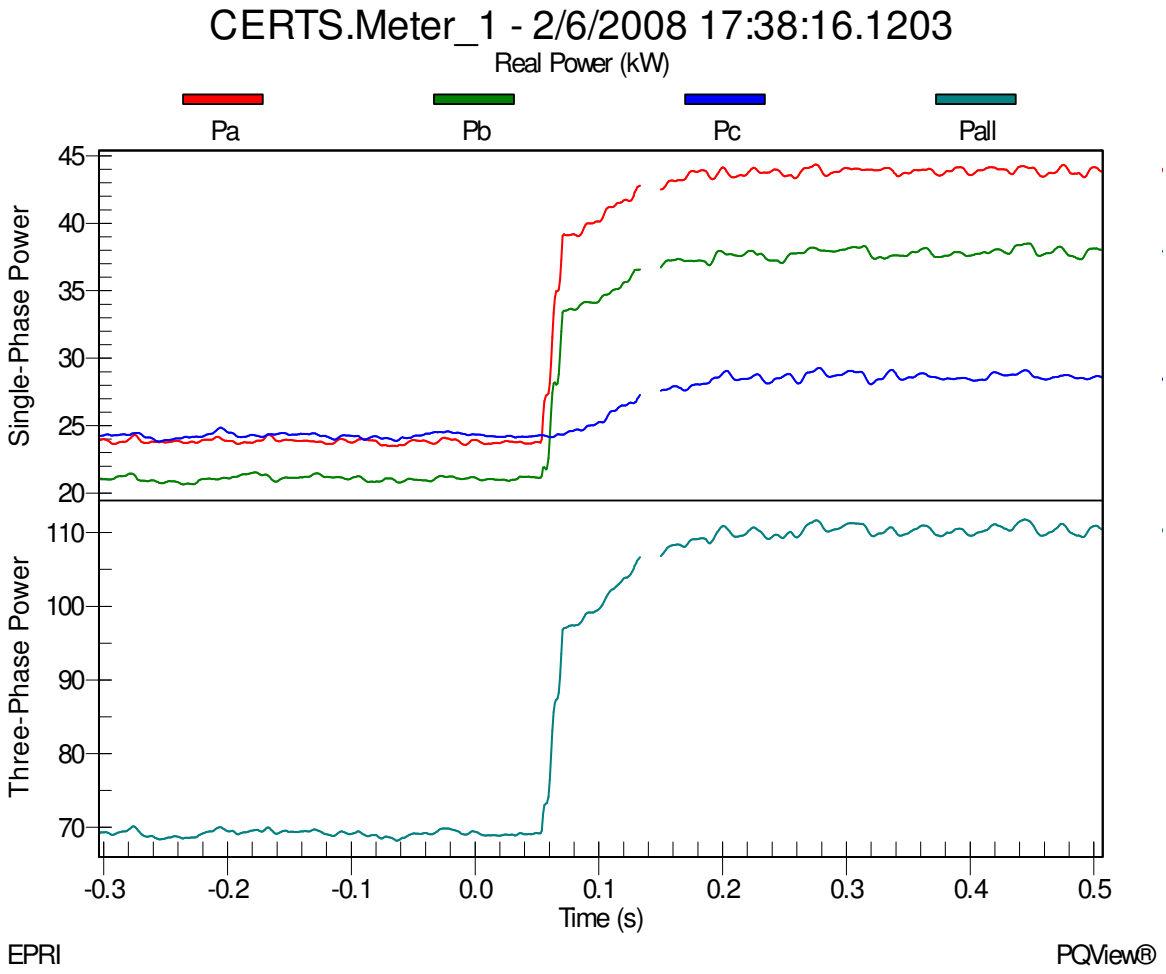

Figure 24a – Meter 1 power flow before/after the phase-to-phase fault was applied in Zone 2.

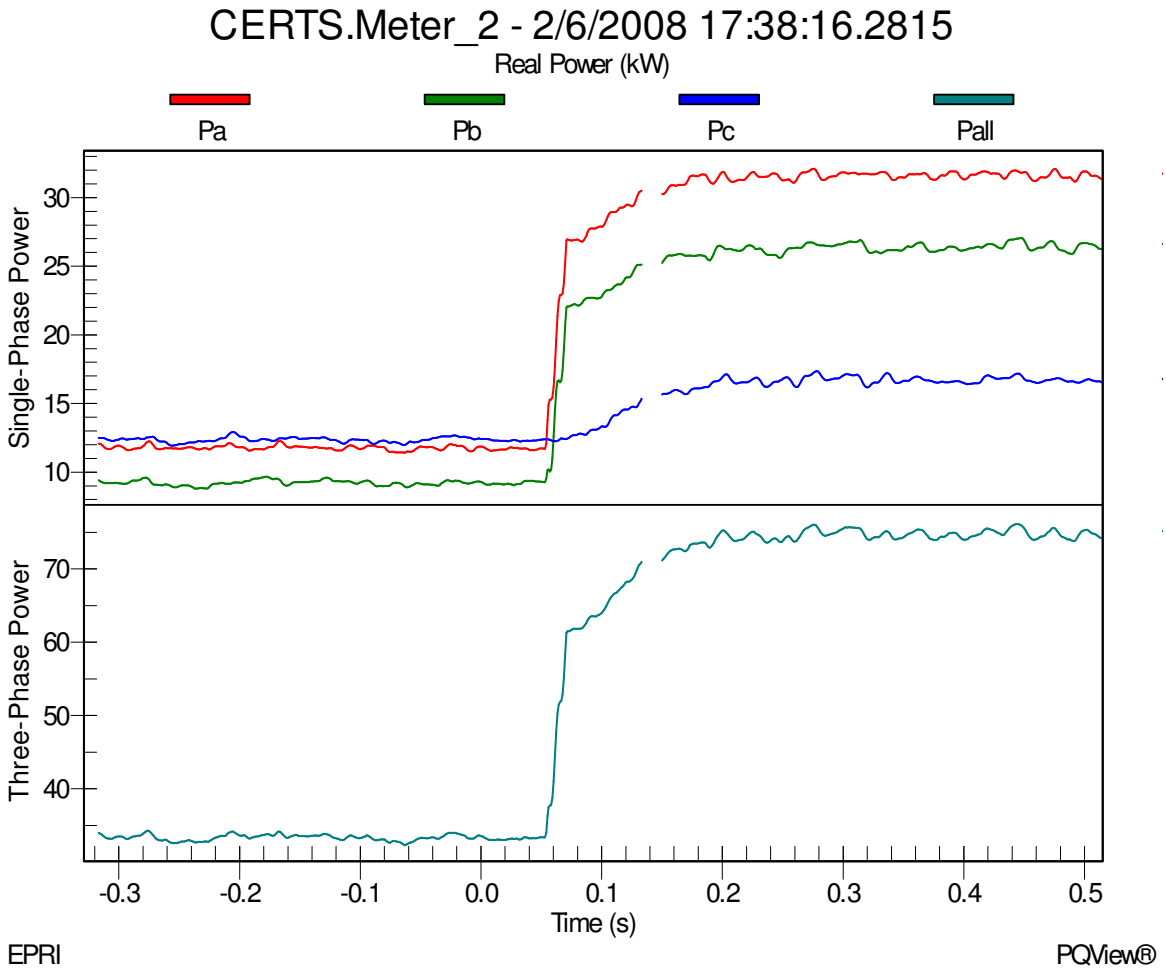

Figure 24b – Meter 2 power flow before/after the phase-to-phase fault was applied in Zone 2.

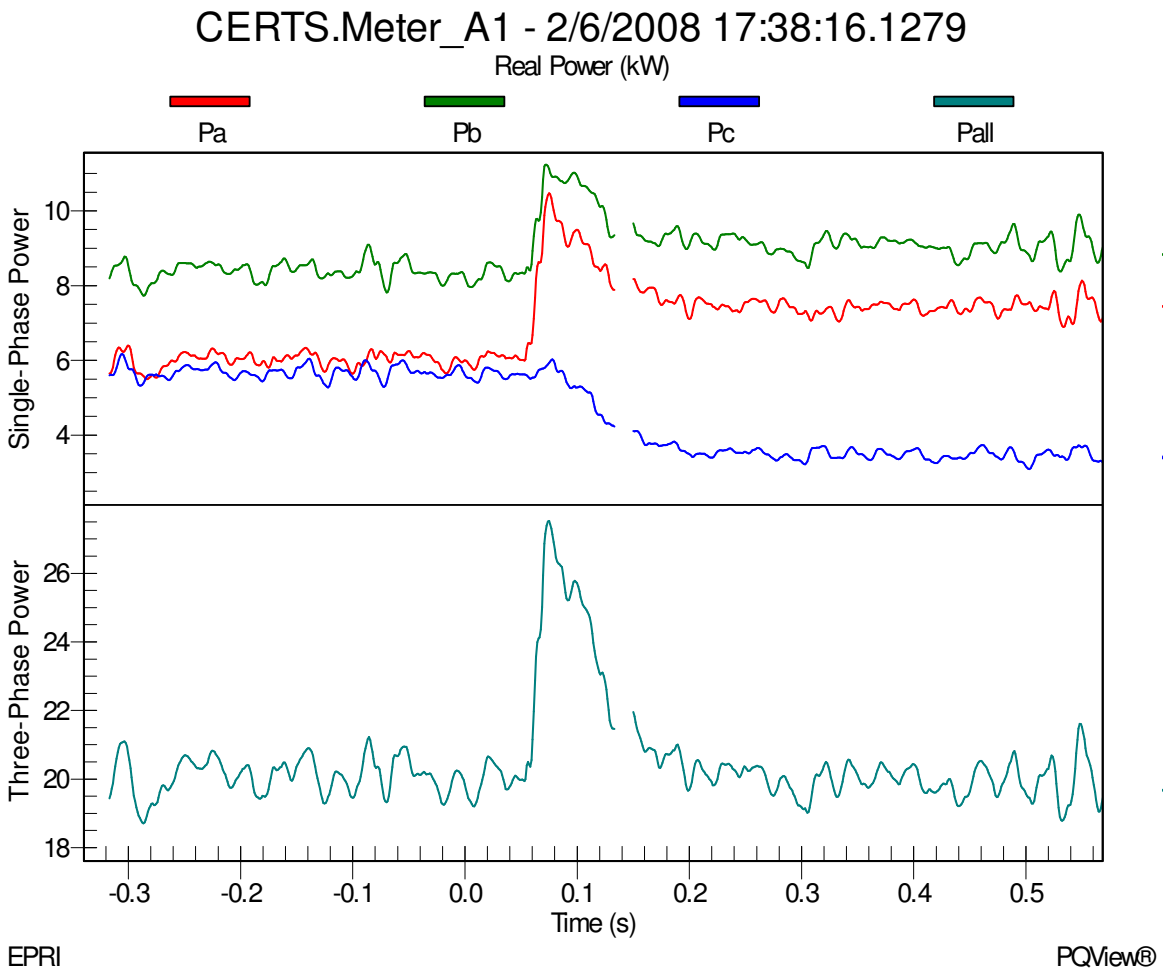

Figure 24c - Power produced by Gen-set A1 before/after an A-phase to B-phase fault was applied in Zone 2.

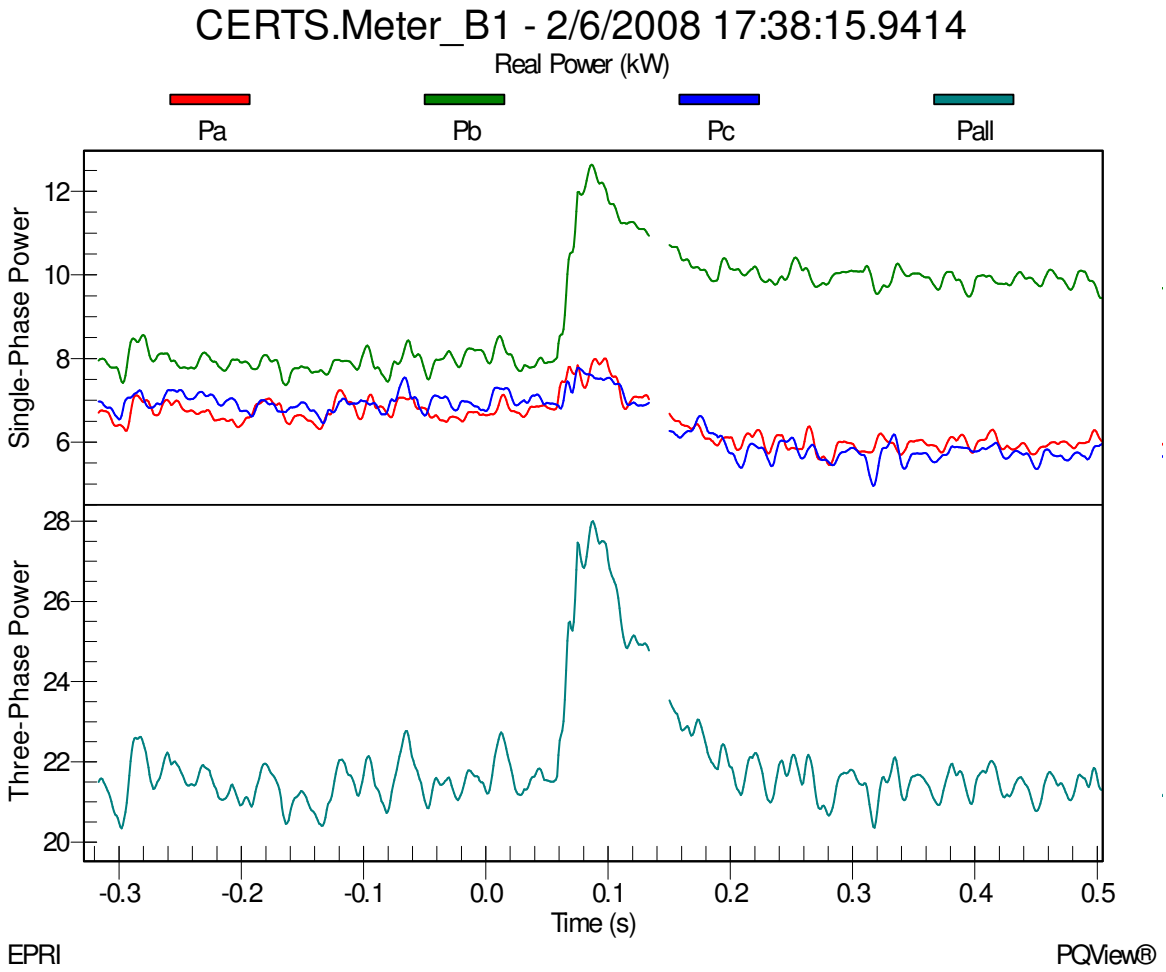

Figure 24d - Power produced by Gen-set B1 before/after an A-to-B phase-to-phase fault in Zone 2 is applied

Using the DAS Load Control program, the phase-to-phase fault on A- and B- phases was set for 10 seconds and then initiated. The static switch, CB31, CB41 and CB51 did not detect enough current from Zone 2 to trip. Power flow in Meter 1, Figure 24a, increased from approximately 70kW (i.e., A-phase = 24kW, B-phase = 22kW and C-phase = 24kW) to 110 kW (i.e., A-phase = 44kW, B-phase = 38kW and C-phase = 28kW) when the fault was initiated in Zone 2. A-phase increased by approximately 20kW and B-phase by 26kW, due to the overload bank connected in Zone 2. The microgrid treated this as an unbalanced load and supplied it power by the utility grid, since both Gen-sets were set for unit power control.

The Overload Load Bank was on-line for the allotted time of 10 seconds and then was removed. The electrical system was stable in both the microgrid and utility grid through the entire duration of the fault with no tripping of the static switch or circuit breakers.

Gen-sets A1 and B1 were shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

6.1.16 Zone 5 A-to-B Phase Fault, Gen-sets (A1+B1) and Utility Connected

Performance Goal:

Test a phase-to-phase overload fault condition in Zone 5 on A- and B-phases with Gen-sets A1 and B1 operating in-parallel with the utility grid to verify negative-sequence, I^2t protection or residual over-current protection.

Initial Setup:

Gen-set A1 = Unit Power Control

Gen-set B1 = Unit Power Control

Gen-set A1 Output Power Command = 20kW

Gen-set B1 Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = B (Inst)

Reverse Power Set-point = 0kW

Load Bank 3 = 40kW

Load Bank 5 = 40kW

Load Bank 6 = 40kW

To simulate a high impedance phase-to-phase fault in Zone 5 on A and B phases, the Overload Load Bank of 85kW (i.e., approximately 42.5kW phase-phase) was connected by cable/plug into the exterior receptacle of Cabinet 7a with C-phase disconnected. This, combined with Load Bank 5 load, added 21.2kW on A and B phases of Zone 5 when initiated causing an overload.

After Gen-sets A1 and B1 were running for a few minutes and supplied power to Load Banks 3 and 5, the test started with a "Start" command from the EMS. As soon as the static switch closed and steady-state conditions established, the microgrid and Load

Bank 6 were connected to the utility grid with the total power flow at Meter 1 being approximately 69kW, shown in Figure 25a, and approximately 34kW at Meter 2, shown in Figure 25b. Before the overload fault was applied, Gen-sets A1 and B1 were producing about 20kW and 22kW, respectively, with each shown in Figures 25c and 25d.

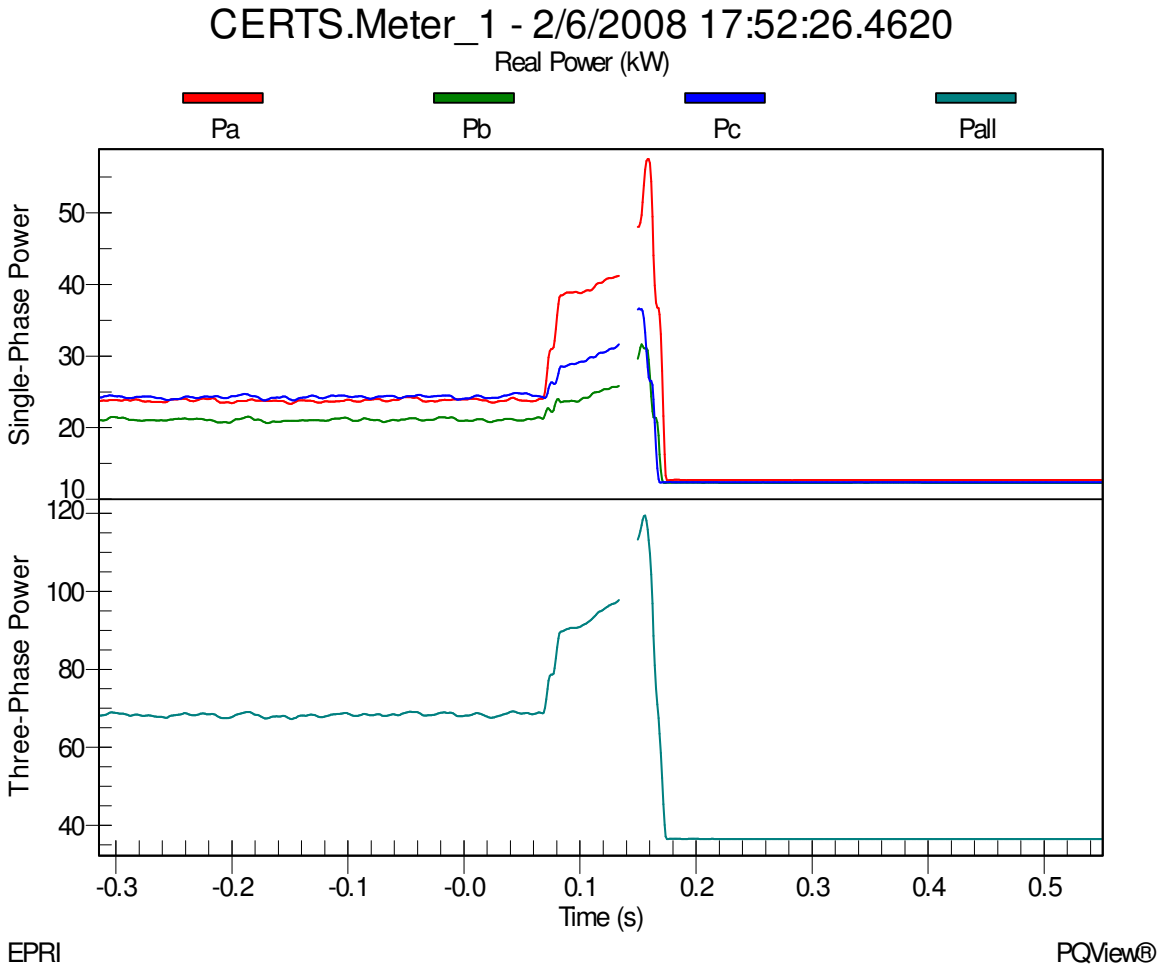

Figure 25a – Meter 1 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a phase-to-phase fault was applied in Zone 5.

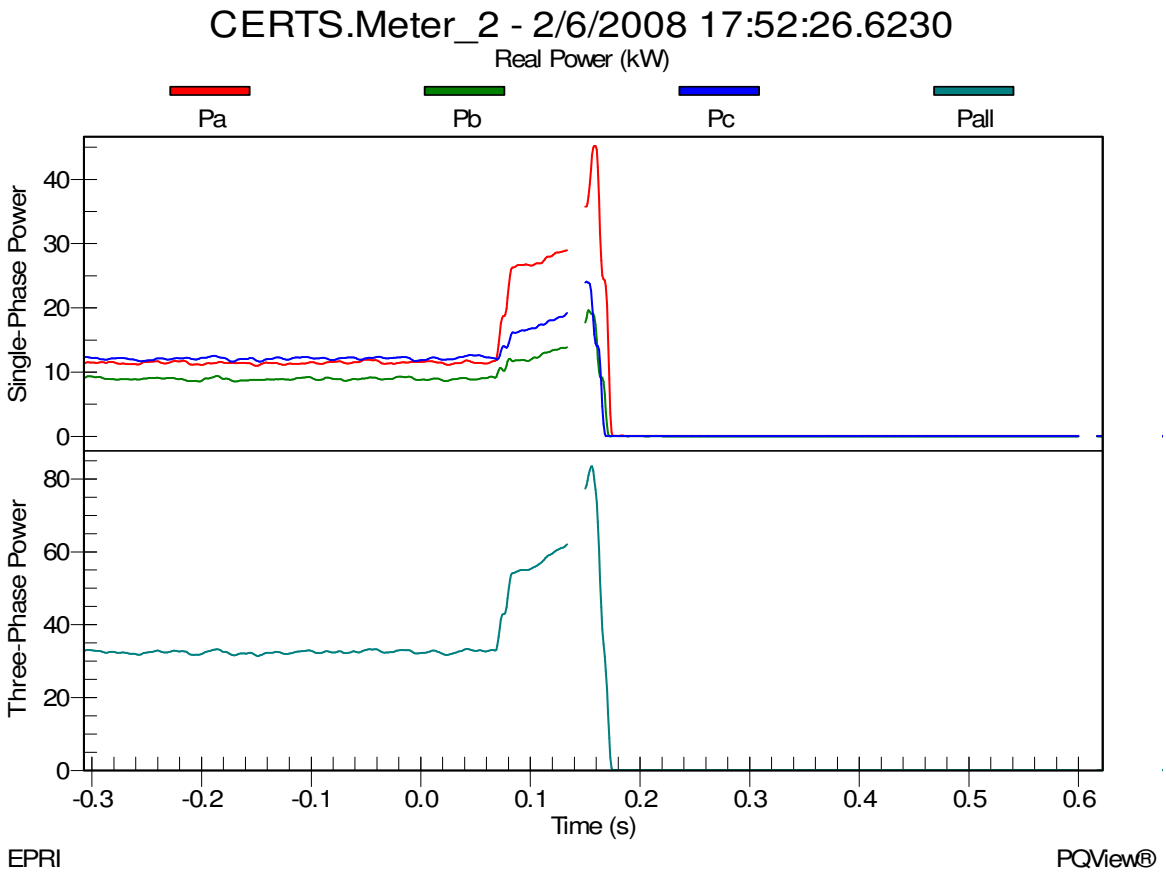

Figure 25b – Meter 2 power flow before/after the static switch opened, islanding the microgrid from the utility grid when a phase-to-phase fault was applied in Zone 5.

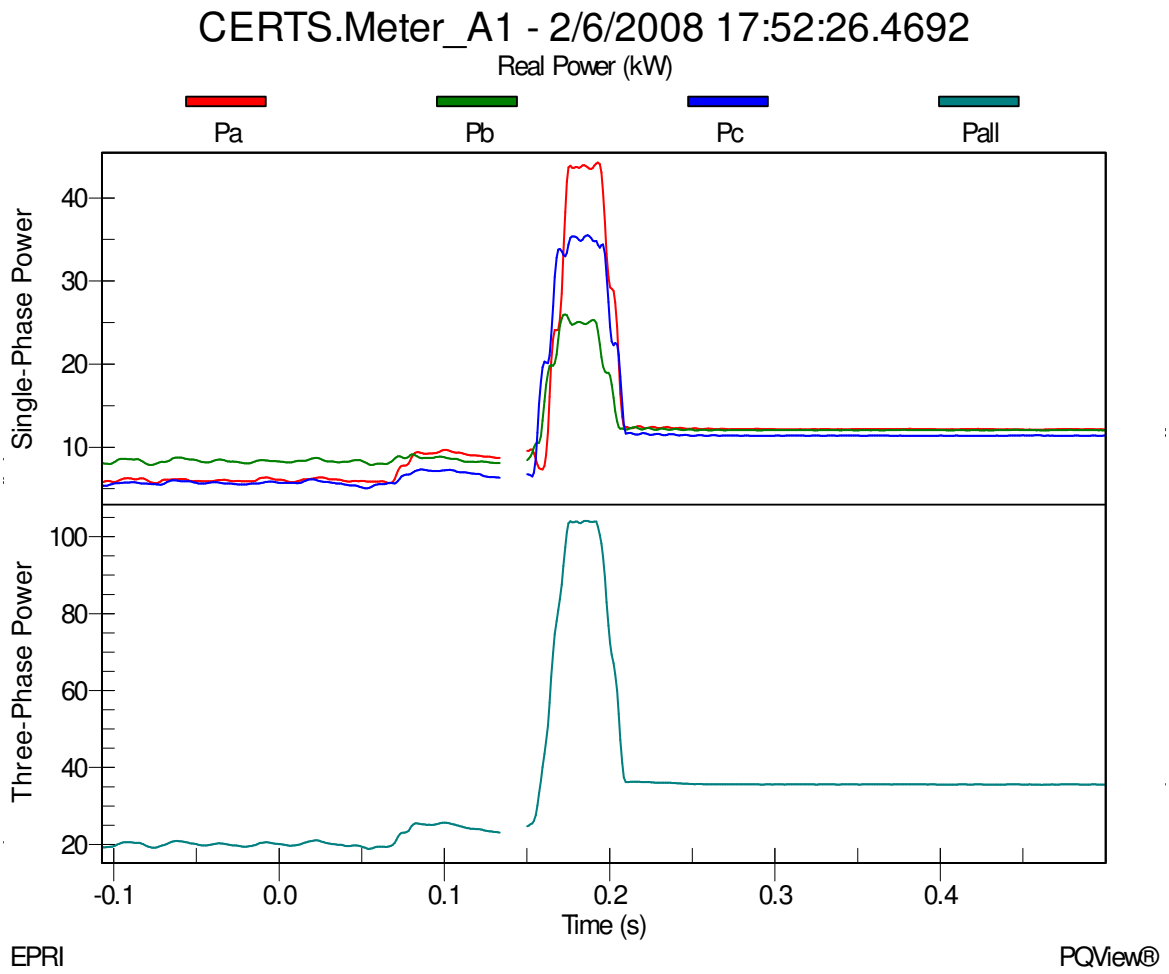

Figure 25c - Power produced by Gen-set A1 before/after the static switch opened from an A-phase to B-phase fault in Zone 5.

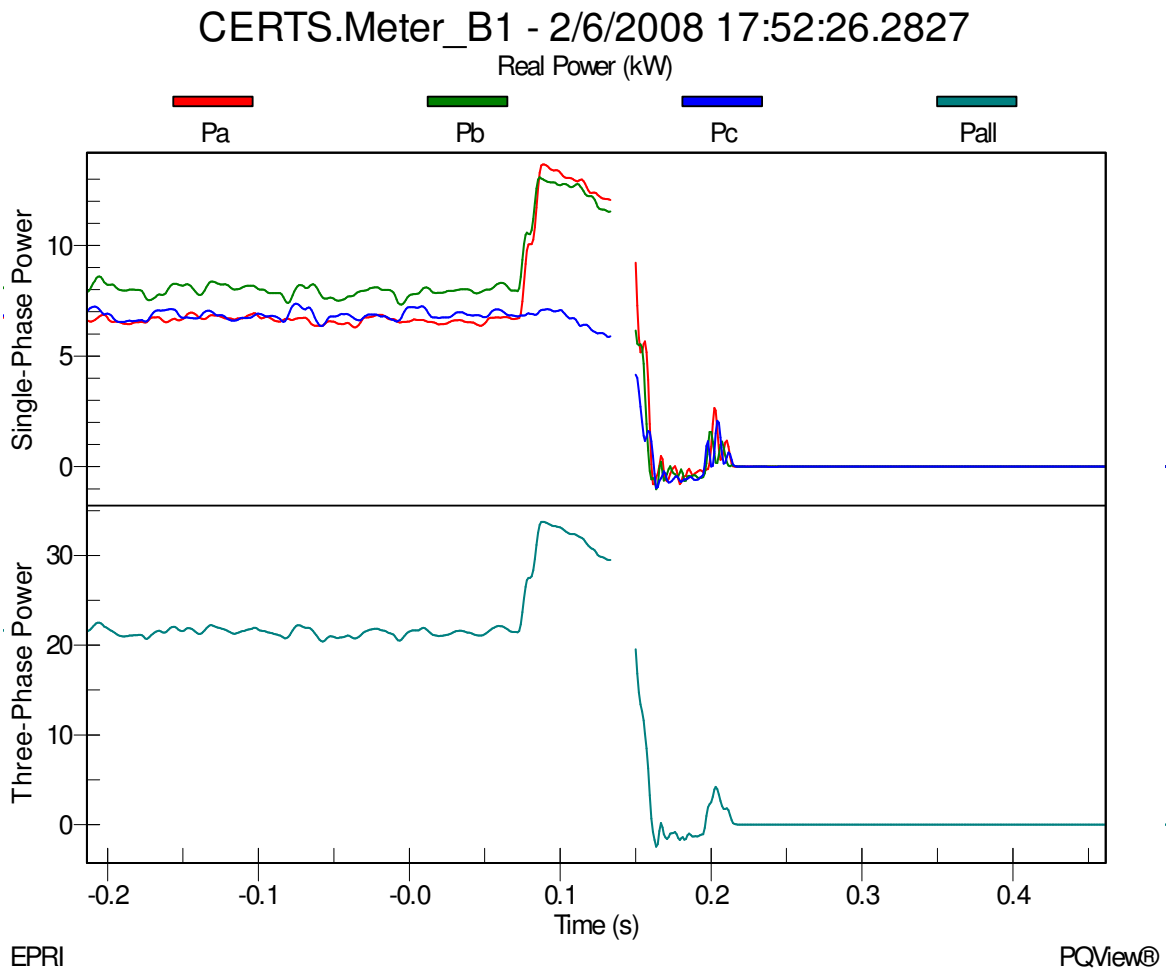

Figure 25d - Power produced by Gen-set B1 before/after the static switch opened from an A-phase to B-phase fault in Zone 5.

Using the DAS Load Control program, the phase-to-phase fault on A- and B-phases was set for 10 seconds and then initiated. Relay 5 tripped in approximately 0.075 seconds (~4.5 cycles) from a negative-sequence over-current (67N1T), shown in Figure 25f. Gen-set B1 stopped switching its output even though its transformer contactor and CB51 remained closed, shown in Figure 25g. This loss of generation increased the negative sequence current seen by the static switch enough to cause it to trip within approximately 0.016 seconds (~1 cycle), shown in Figure 25e. Gen-set A1 increased its output briefly to support the load in Load Banks 3 and 5, as well as the overload fault. After approximately 0.043 seconds (~2.5 cycles) CB51 cleared and Gen-set A1 remained on-line, supplying power to loads in zones 2, 3, and 4.

CB31 and CB41 remained closed throughout the 10 second phase-to-phase fault. Gen-set A1 increased its output power from approximately 21kW to 36kW, shown in Figure

25c, supplying power to Load Bank 3. Load Bank 6 was supplied by the utility grid, shown in Figure 25a.

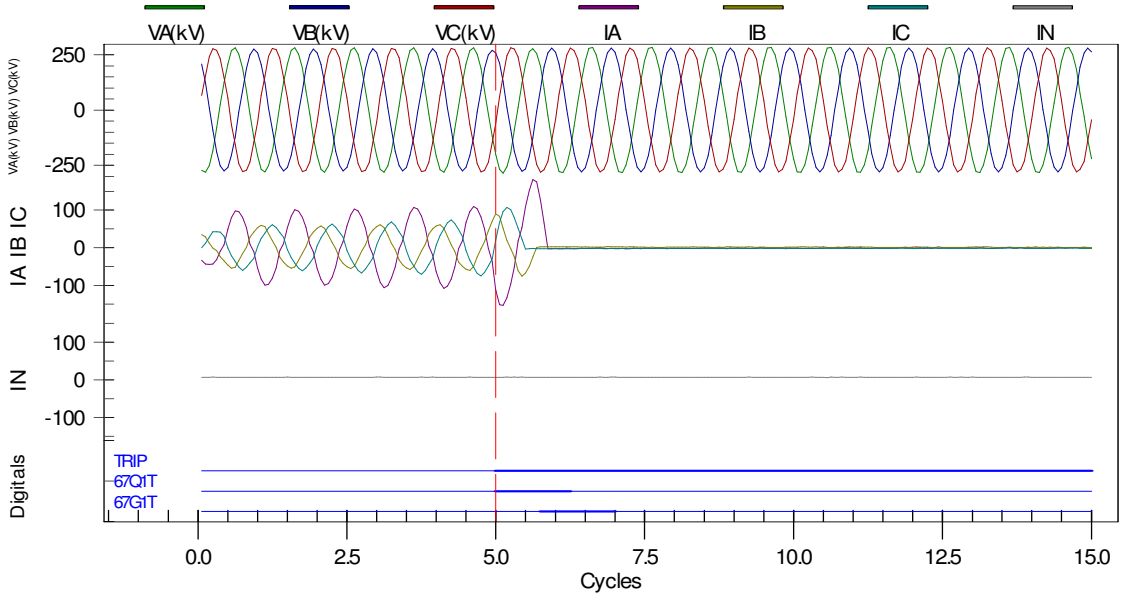

Figure 25e - Relay 2 (static switch) tripped due to a negative-sequence over-current (67N1T) when the phase-to-phase fault was initiated in Zone 5.

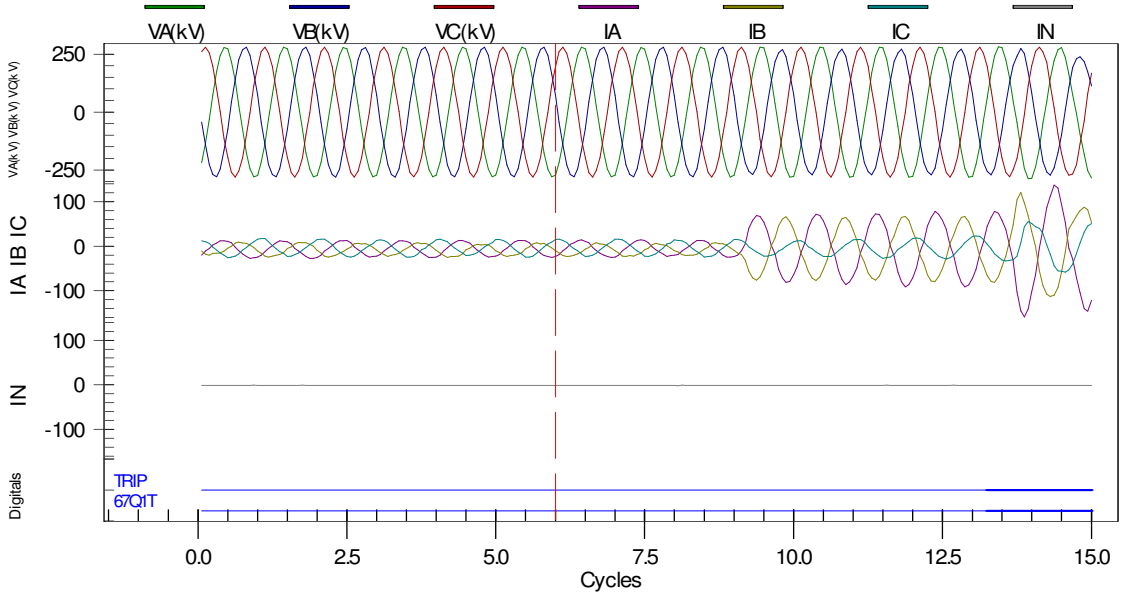

Figure 25f – Relay 5 (CB51) tripped due to a negative sequence over-current (67N1T) when the phase-to-phase fault was initiated in Zone 5.

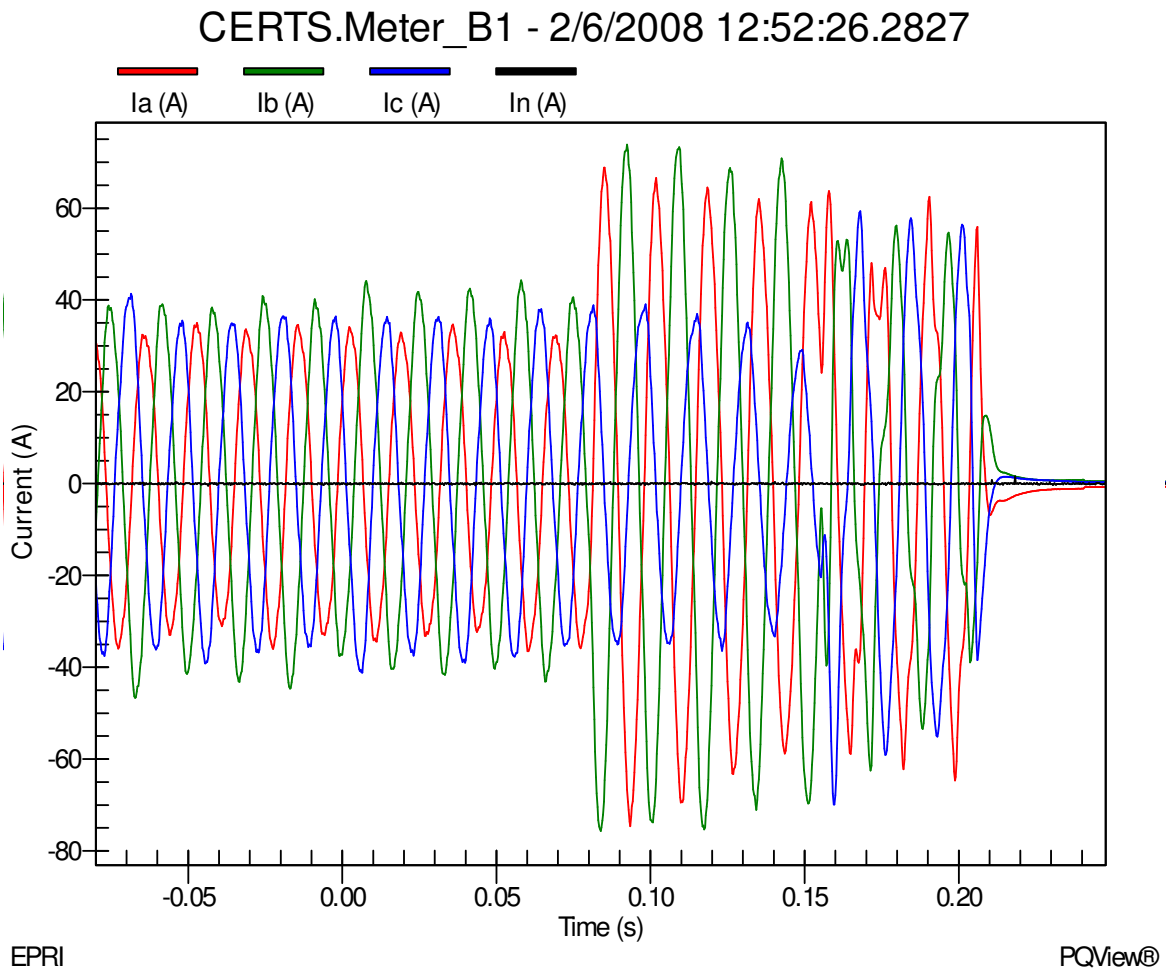

Figure 25g – Gen-set B1 current before/after a phase-to-phase fault was initiated in Zone 5.

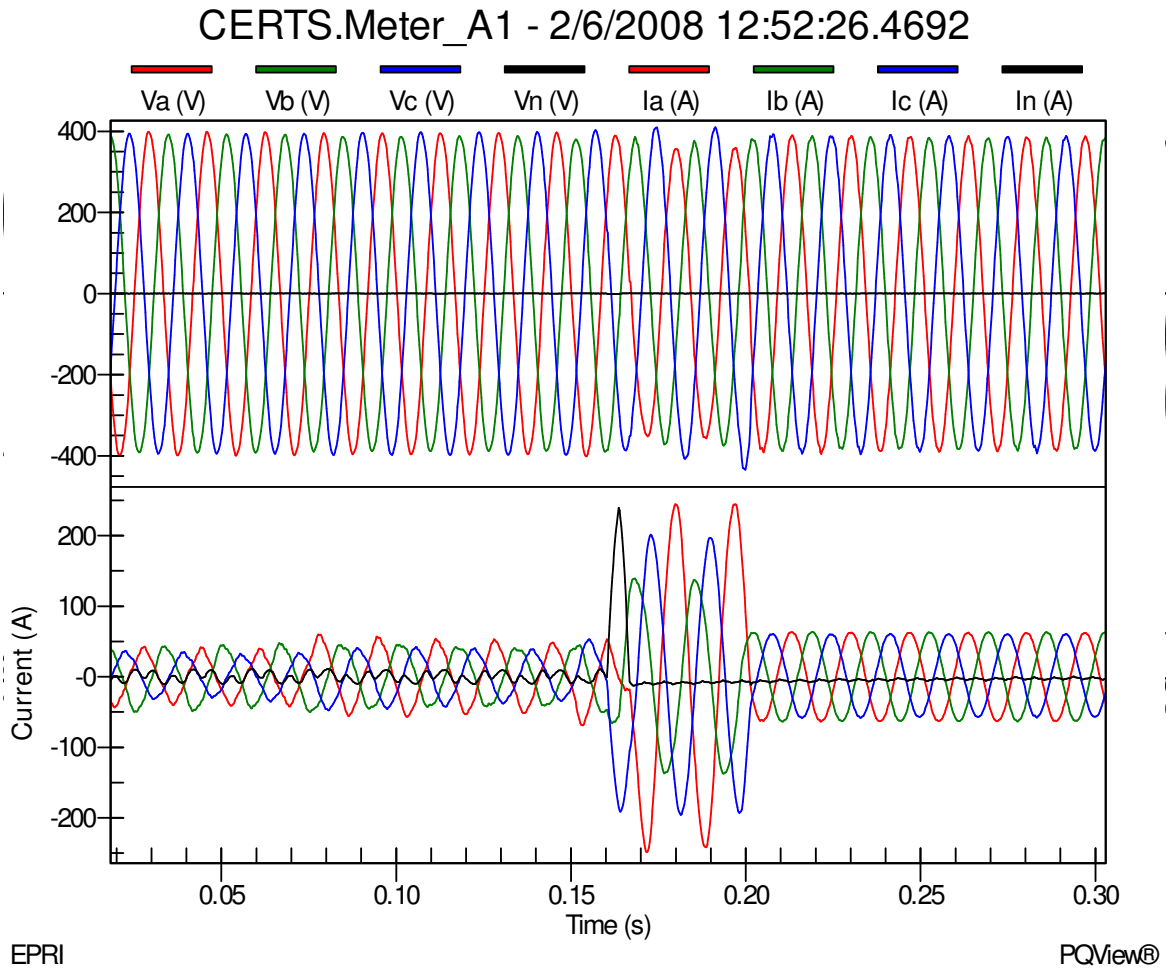

Figure 25h – Gen-set A1 current before/after a phase-to-phase fault was initiated in Zone 5.

The electrical system was stable in both the microgrid and utility grid, after the static switch opened, CB51 opened, and Gen-set B1 shut down. All loads and alarms were reset and equipment was prepared for the next test.

7.0 CONCLUSION

The tests performed in section 7.0 were performed to validate the protection settings for various combinations of type of faults, placement of faults, and amount of real power provided by the Gen-sets. In the first three sub-sections of section 7.0 (7.1, 7.2 and 7.3) the delays were increased from the initial values to avoid the transformer inrush current which was causing nuisance tripping of the relays. In the remaining tests of section 7.0, the Gen-sets were allowed to warm up before the faults were applied to the CERTS microgrid which allowed the delay settings in the relays to be reset to the initial values. The protection settings in the relays proved to be sufficient for protecting the microgrid

during single line-to-ground, three phase-to-ground and line-to-line faults downstream of the PCC.

One test that was not performed during this section was a fault on the utility side of the PCC. This test was not performed due to the utility not allowing intentional faults to be applied to their system, but will be performed in future tests.

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 8.0
Reduced System Tests

APPENDIX K

Prepared For:
California Energy Commission
Public Interest Energy Research Program

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CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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CERTS MICROGRID TEST REPORT

SECTION 8.0

"Reduced System Tests"

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as "islanded" from it. This paper describes the tests that were performed in Section 8.0 "Reduced System Tests" of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility's distribution system, isolating the microgrid's load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility's electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to a 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

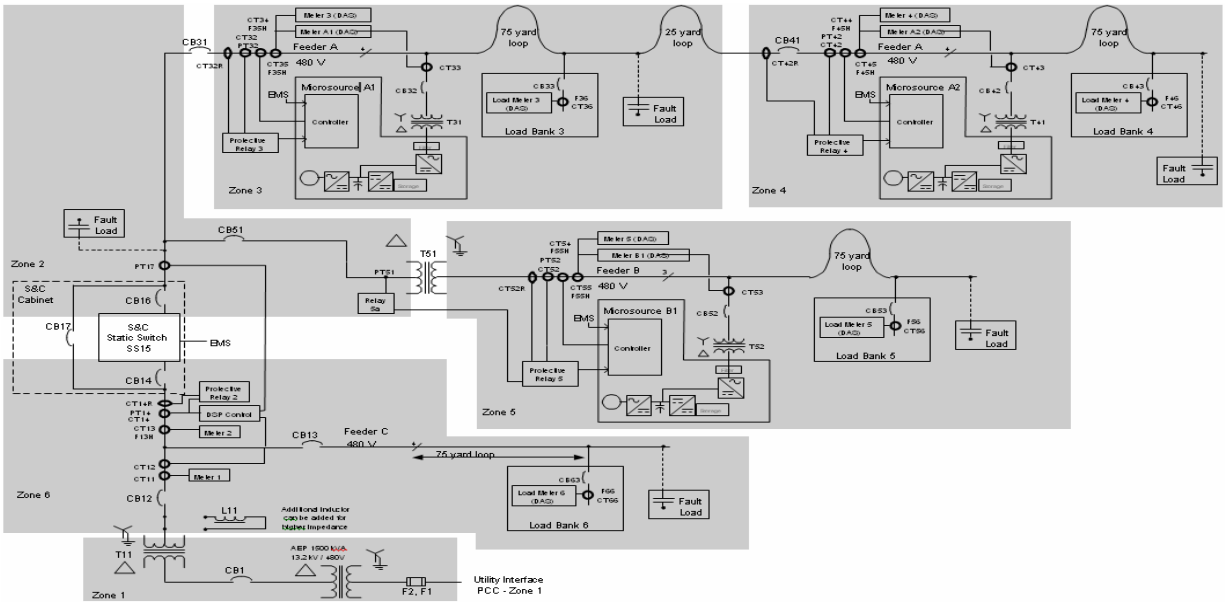

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

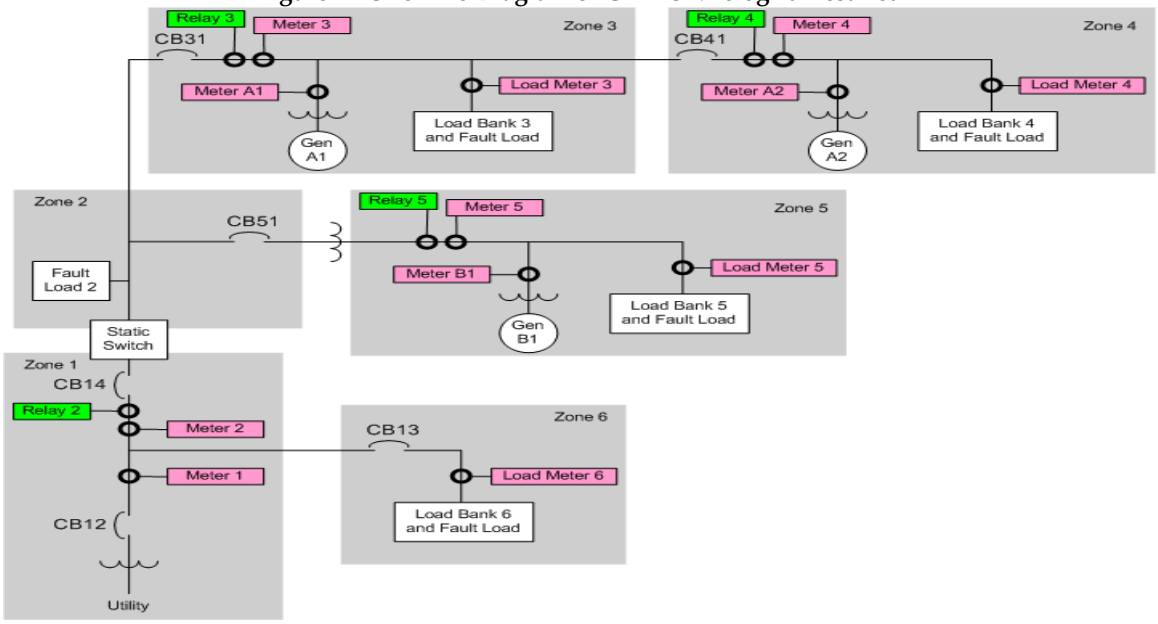

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

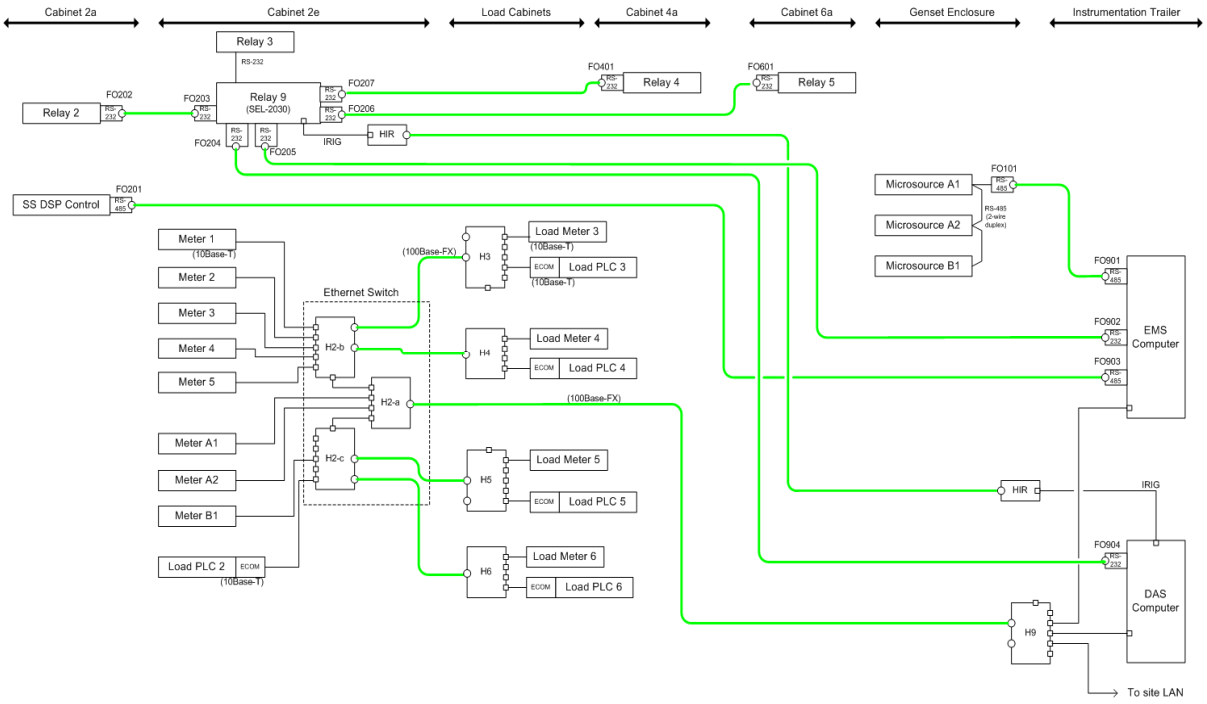

Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – "Purpose, References, and Definitions" describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – "Responsibilities" informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.

- Section 3 – "Training - Team Members" lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.

- Section 4 – "Procedure – CERTS Microgrid Test Bed Lockout/Tagout" entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.

- Section 5 – "Procedure – General" is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.

- Section 6 – "Procedure – Microgrid Test Bed System Checkout" was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.

- Section 7 – "Validate Protection Settings & Initial Fault Testing" is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.

- Section 8 – "Procedure – Reduced System Tests" is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.

- Section 9 – "Procedure – Demonstration Tests of Control Power Flow" demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – "Procedure – Test Difficult Loads" determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.

- Section 11 - "Hazards & Mitigation" informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.

- Section 12 – "Quality Assurance" ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 8.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a "Red" plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

To maintain a common understanding of Gen-set control modes during tests described in the following paragraphs, it is important to know the difference between unit power control mode and zone control mode. Unit power control mode involves the amount of power (i.e., kW) injected into the Zone from the Gen-set being controlled. Zone power control mode involves the amount of power (i.e., kW) entering/exiting the Zone which controls the output of the Gen-set in that zone.

Section 8 consists of 13 tests designed to validate the inverter controls tested by TECONGEN/The Switch in a laboratory setting with field demonstration. In each test waveforms were captured and recorded in the DAS, as described below.

Test 8.1 was designed to verify smooth transitions in Gen-set A1 when different step conditions of load are applied in Load Bank 3 with voltage set points ranging from +5% to -5%. The same test was repeated for Gen-set A2 and Load Bank 4 and Gen-set B1 and Load Bank 5.

Test 8.2 was designed to verify smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A1 to a lower limit of zero kW.

Test 8.3 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions which drive Gen-set A2 to an upper limit of 60kW.

Test 8.4 verified smooth transitions of Gen-sets A1 and A2 response to different step conditions with an un-balanced load in Zone 3.

Test 8.5 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode. During a load step change in Load Bank 3, Gen-set A1 was driven to an upper limit of 60kW.

Test 8.6 verified smooth transitions of Gen-sets, A1 in zone operation mode and Gen-set A2 in Unit operation mode. During a load step change in Load Bank 4, Gen-set A1 is driven to its maximum which causes an automatic reset of the zone set points.

Test 8.7 verified smooth transitions of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a change of zone power in Feeder A.

Test 8.8 verified smooth transition of Gen-sets, A1 in zone operation mode and A2 in unit operation mode, with a static switch operation and a change of zone power in Feeder A when islanded.

Test 8.9 verified smooth transition of Gen-sets, A1 in Zone operation mode and A2 in Unit operation mode, with a static switch operation and a change of zone power in Feeder A when islanded. Gen-sets A1 and A2 were driven to their maximum which caused an automatic reset of their set-points.

Test 8.10 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Feeder A and Feeder B when islanded.

Test 8.11 verified smooth transitions of Gen-sets, A1 and B1 in Zone operation mode, with a static switch operation and a change of zone power in Feeder A and Feeder B when islanded. When islanded, Gen-set A1 and B1 set-points were reset based on the remaining load in the islanded system.

Test 8.12 tested the manual procedure used to black-start the CERTS Micro-grid Test Bed in the event of a lengthy utility outage occurs with the Gen-sets off-line.

Test 8.13 was designed to determine the black-start capacity by increasing the amount of load on the CERTS Microgrid Test Bed from a black-out condition without generation or protection trips.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 8 – REDUCED SYSTEM TESTS

6.1.1 Initial Voltage Regulation Test – Single Zone, Islanded

Performance Goal:

Verify smooth transitions of Gen-sets A1 response to different step conditions of load in Load Bank 3 with voltage set point changes ranging from +5% to -5%. Repeat tests with Gen-set A2 and Load Bank 4, then with Gen-set B1 and Load Bank 5.

During all tests in this voltage regulation test section, the static switch was open isolating the microgrid from the utility grid. All data graphs from each voltage regulation test are available in Appendix A. Table 3 provides a brief summary of test

results obtained during these twenty-seven voltage step changes in Zone 3, Zone 4 and Zone 5 of the microgrid.

Initially, Gen-set A1 in Zone 3 was running for a few minutes to warm-up with the voltage set-point at 277V, with zero load at Load Bank 3. Load Bank 3 was set at 20kW which was measured as approximately 19kW. Real and reactive power output response to this load increase was approximately 21kW and 4kVAr, respectively. The electrical impedance in the 75 yards of distribution conductors between Gen-set A1 and Load Bank 3 was the primary cause of the power difference. The voltage at Gen-set A1 was steady at approximately 273V and the frequency was approximately 59.99 Hz. Once all the data was recorded and validated, Load Bank 3 was increased from 20kW to 40kW. A smooth transition occurred when the load increased by ~20kW with the resultant load being 36kW, as measured by Load Meter 3. At the time of this load change, Gen-set A1 increased its output power from approximately 21kW and 4kVAr to 38kW and 4.4kVAr. The voltage remained the same at the Gen-set (i.e., 273V) from the previous reading and the frequency dropped to 59.84Hz. Once all the data was recorded and validated, Load Bank 3 was increased by an additional 20kW to a total of 60kW. Power flow at Load Bank 3 was approximately 52.5kW and the Gen-set responded to this load step with a smooth transition producing an output power of 55kW and 4.8kVAr. The voltage at Gen-set A1 measured the same as the previous load change, at 273V. During this load change, frequency was reduced from approximately 59.84Hz to 59.70Hz. The drop in frequency was caused by the CERTS algorithm for Real Power versus Frequency droop control. Gen-set A1 and the microgrid remained stable through all the load step changes of 20kW at 277V. All data was recorded in DAS and the next test was implemented.

The voltage set-point (i.e., MG Voltage) of Gen-set A1 was increased by 5% to 291V and Load Bank3 was reset to 0kW. Then, Load Bank 3 was brought on-line with a 20kW setting. In response to this load step change, output power at Gen-set A1 was 22.5kW and 6.5kVAr. The voltage was measured at approximately 287V, which remained the same at Gen-set A1. The rise in reactive power from the previous test (i.e., load step of 20kW at 277V) was adjusted by the Gen-set to increase its voltage from 273V to 287V. Frequency at Gen-set A1 was 59.98Hz. Once all data was recorded and validated, Load Bank 3 was increased from 20kW to 40kW. Load Meter 3 measured a power flow of approximately 40kW at Load Bank 3 with voltage at Gen-set A1 of 287V. The voltage held constant, allowing for a smooth transition between the load step changes. Gen-set A1 increased its output power from approximately 22.5kW and 6.5kVAr to 41.5kW and 6.8kVAr, supplying power to Load Bank 3 and the frequency within the microgrid decreased from 59.98Hz to 59.82Hz. Once all data was recorded and validated, Load Bank 3 was increased from 40kW to 60kW. The voltage at Gen-set A1 remained the same at 287V, resulting in a smooth transition. Load Meter 3 measured a power flow of approximately 57kW at Load Bank 3 and the resultant output power of Gen-set A1

increased to 59.5kW and 7.7kVAr. The microgrid frequency during this load step change decreased from 59.82Hz to 59.15Hz. All data was recorded in the DAS and the next test was implemented.

The voltage set-point (i.e., MG Voltage) of Gen-set A1 was decreased from 291V to 263V (i.e., minus 5% of nominal 277V) and Load Bank 3 was reset to 0kW. Load Bank 3 was then brought on-line with a 20kW setting and a resultant measurement of approximately 17kW. The voltage was measured at approximately 260V and remained the same at Gen-set A1. In response to the load step change, the output power at Gen-set A1 was 19kW and 2.55kVAr. A decrease in the reactive power from the previous test (i.e., load step of 20 kW at 277V) was adjusted by the Gen-set to decrease its voltage to approximately 260V. Frequency in the microgrid from Gen-set A1 was 60.00Hz. Once all data was recorded and validated, Load Bank 3 was increased from 20kW to 40kW. Load Meter 3 measured a power flow of approximately 32kW with voltage at Load Bank 3 of 260V. The voltage held constant, allowing for a smooth transition between load step changes. Gen-set A1 increased its output power from approximately 19kW and 2.55kVAr to 34.5kW and 2.9kVAr, supplying power to Load Bank 3, and frequency within the microgrid decreased from 60.00Hz to 59.87Hz. Once all data was recorded and validated, Load Bank 3 was increased from 40kW to 60kW. Voltage at Gen-set A1 remained the same from the 40kW load step test at 260V, resulting in a smooth transition. Load Meter 3 measured a power flow of approximately 47.5kW at Load Bank 3 and the output power of Gen-set A1 increased to 50kW and 3.3kVAr. The microgrid frequency during this load step change decreased from 59.87Hz to 59.74Hz. Once all data was recorded and validated, Gen-set A1 was shut down, manually, and all loads and alarms were reset in preparation for the next set of tests.

The above tests were repeated with adding 3 load steps of 20kW and varying the voltage by +5% and -5% of the nominal 277V for Gen-set A2 with Load Bank 4; and repeated again for Gen-set B1 with Load Bank 5. In each test, the Gen-sets transitioned smoothly through each load step change and voltage change.

	Set-point Values		Test Results				
	Gen-set Voltage	Load Bank kW	Load Bank (kW)	Gen-set Output Real Power (kW)	Gen-set Output Reactive Power (kVAr)	Freq. (Hz)	Voltage
Gen A1	277	20	19	21	4	59.99	273
	277	40	36	38	4.4	59.84	273
	277	60	52.5	55	4.8	59.70	273

	291	20	20	22.5	6.5	59.98	287
	291	40	40	41.5	6.8	59.82	287
	291	60	57	59.5	7.7	59.15	287
	263	20	17	19	2.55	60.00	260
	263	40	32	34.5	2.9	59.87	260
	263	60	47.5	50	3.3	59.74	260
	277	20	18.5	21	4.45	58.89	277
	277	40	37	39	5	59.84	277
	277	60	53.5	56	5.4	59.71	277
Gen A2	291	20	20	23	7.5	59.97	291
	291	40	39.5	42.5	8	59.82	291
	291	60	57.5	60.5	8	59.59	291
	263	20	16.5	18.5	2.9	60.02	263
	263	40	33	35	3.2	59.89	263
	263	60	48.5	51	3.6	59.75	263
	277	20	20	22.5	4.9	59.99	277
	277	40	37.5	40	5.2	59.85	277
	277	60	54.5	57	5.5	59.71	277
Gen B1	291	20	21.5	24	8.2	59.97	291
	291	40	40	43.5	8.4	59.82	291
	291	60	57.5	60	7.7	59.68	291
	263	20	16.5	19	3	60.02	263
	263	40	33.5	36	3.3	59.88	263
	263	60	49.5	51.5	3.6	59.75	263

Table 1 – Voltage regulation test results of Gen-set A1, A2 and B1 in Zone 3, 4 and 5, respectively.

6.1.2 Open Static Switch Test, Gen-set A1

Performance Goal:

Verify smooth transitions in Unit power control mode of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN" / "CLOSE") when the lower power control limit, 0kW, of Gen-set A1 is reached.

Table 4 shows the values of Gen-sets, loads, power flows and frequency with the static switch closed and the final values after the static switch was opened, islanding the microgrid. The static switch was also allowed to reclose in this test and resultant values were expected to return to the initial values before the static switch was opened. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition, Load Banks 3, 4 and 6 were connected with approximately 18.2kW, 18.1kW and 28.7kW, respectively. Gen-set A1 output power was approximately 5kW and Gen-set A2 output power was approximately 55kW. Power flow through the static switch, before it was open, was approximately -21.5kW. Power flow from the utility grid was approximately 7kW which combined with the power flowing from the microgrid supplying power for Load Bank 6.

As soon as the manual open was asserted to the static switch, Load Bank 6 was no longer powered by the Gen-sets but by the utility grid and was approximately 29.35kW. Load Banks 3 and 4 were picked up by Gen-set A2, because of the CERTS power versus frequency droop control, and Gen-set A1 output power was reduced to 0kW. Gen-set A2 output power was approximately 37kW and Load Banks 3 and 4 were 17.5kW and 17.3kW, respectively. The frequency increased when the microgrid islanded from 60.00Hz to 60.14Hz, because the load demand decreased within the microgrid and because of the CERTS algorithm. Power flow at the static switch was 0kW and approximately 29.5kW at Meter 1 on the utility side of the switch. The islanded microgrid operated this way for a few minutes before the static switch manual open was removed.

After the manual open was removed, the static switch reconnected the microgrid to the utility grid in a smooth transition and Load Bank 6 was supplied power by the microgrid and utility grid. Gen-set A1 increased its output power to approximately 6kW and Gen-set A2 increased output power to approximately 56.5kW. Load Banks 3, 4 and 6 measured approximately 18.2kW, 18.1kW and 28.7kW, respectively. Power flow at the static switch was approximately -22.5kW with 7kW at the utility side. Frequency within the microgrid decreased from 60.15Hz to approximately 60.00Hz. The resultant

values, after the static switch reconnected the microgrid to the utility grid, were very similar to the values at the beginning of the test.

Gen-sets A1 and A2 were shut down manually and all loads and alarms were reset and equipment was prepared for the next test.

Test Results							
Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Set-point	Expected Result	Start	End	Start	End
A1	Unit	5kW	0.0kW	5kW	0.0kW	0.0kW	6.0kW
A2	Unit	55kW	40kW	56kW	37kW	37.5kW	56.5kW
B1		Off	Off	Off	Off	Off	Off
Freq		~60Hz	~60.12Hz	60Hz	60.14Hz	60.15Hz	60Hz
L3		20kW	20kW	18.2kW	17.5kW	17.5kW	18.2kW
L4		20kW	20kW	18.1kW	17.3kW	17.3kW	18.1kW
L5		0.0kW	0.0kW	0.0kW	0.0kW	0.0kW	0.0kW
L6		30kW	30kW	28.7kW	29.35kW	29.4kW	28.7kW
SS		-20kW	0.0kW	-21.5kW	0.0kW	0.0kW	-22.5kW
Grid		0.0kW	20kW	7kW	29.5kW	30kW	7kW
Let SS re-close Expect the system to return to Start values							

Table 4 – Open Static Switch (SS) Test Results, Gen-set A1

6.1.3 Open Static Switch Test, Gen-set A2

Performance Goal:

Verify smooth transitions in Unit power control mode of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN" / "CLOSE") when the upper power control limit, 60kW, of Gen-set A2 is reached.

Table 5 shows the values of Gen-sets, loads, power flows and frequency with the static switch closed and the final values after the static switch was opened, islanding the microgrid. The static switch was also allowed to reclose in this test and resultant values were expected to return to the initial values before the static switch opened. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition, Load Banks 3 and 4 were connected with approximately 53.9kW and 35.6kW, respectively. Gen-set A1 output power was approximately 5kW and Gen-set A2 output power was approximately 55kW. Power flow from the utility grid through the static switch was approximately 32kW, indicating that part of the loads within the microgrid were being supported by the utility grid.

As soon as the static switch opened, the utility grid was no longer providing the additional power needed to satisfy loads in the microgrid. Therefore, Gen-set A1 and A2 had to increase their output power, accordingly. Gen-set A1 output power increased from approximately 5kW to 29kW and Gen-set A2 increased from 55kW to 60kW. The frequency decreased when the microgrid islanded from 59.94Hz to 59.80Hz, because load demand increased within the microgrid and because of the CERTS algorithm. Likewise, voltage in the system dropped from approximately 280V to 277V, decreasing load demands in Load Banks 3 and 4 to approximately 51.75kW and 34.2kW, respectively. Power flow from the utility and through the static switch was 0kW. The islanded microgrid operated for a few minutes before the static switch manual open was removed.

The static switch reconnected the microgrid to the utility in a smooth transition with Load Banks 3 and 4 being supplied by the microgrid and utility grid. Gen-set A1 decreased its output power to approximately 2kW and Gen-set A2 had an output power of approximately 53kW. Load Banks 3 and 4 measured approximately 53.7kW and 35.5kW, respectively. The power flow at the static switch was approximately 37kW at the utility side. Voltage within the microgrid increased from approximately 277V to 280V and the frequency increased from 59.80Hz to approximately 60.02Hz. The values after the static switch reconnected the microgrid to the utility grid are very similar to the values at the beginning of the test which was expected.

Gen-sets A1 and A2 were shut down manually and all loads and alarms were reset, and equipment was prepared for the next test.

Test Results							
Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Set-point	Expected Results	Start	End	Start	End
A1	Unit	5kW	40kW	5kW	29kW	29kW	2kW
A2	Unit	55kW	60kW	55kW	60kW	60kW	53kW
B1		Off	Off	Off	Off	Off	Off
Fq		~60Hz	~59.72Hz	59.94Hz	59.8Hz	59.80Hz	60.02Hz
L3		60kW	60kW	53.9kW	51.75kW	51.7kW	53.7kW
L4		40kW	40kW	35.6kW	34.2kW	34.25kW	35.5kW
L5		0kW	0kW	0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW	0kW	0kW
SS		40kW	0kW	32kW	0kW	0kW	37kW
Grid		40kW	0kW	32kW	0kW	0kW	37kW
Let SS re-close Expect the system to return to Start values							

Table 5 – Open Static Switch (SS) Test Results, Gen-set A2

6.1.4 Test Island Operation, Unbalanced Load

Performance Goal:

Verify smooth transitions in Unit power control mode of Gen-sets A1 and A2 response to different step conditions (i.e., static switch "OPEN" / "CLOSE") with an un-balanced load in Zone 3.

Table 6 shows the values of Gen-sets, loads, power flows and frequency before and after the load on A-phase of Load Bank 3 was reduced. During this test, the static switch remained open.

After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition, Load Bank 3 was connected with approximately 54kW. Gen-set A1 output power was approximately 13kW and Gen-set A2 output power was approximately 43kW.

As soon as A-phase load in Load Bank 3 was reduced, as verified by 0A flowing at Load Meter 3 on A-phase, Gen-sets A1 and A2 output power decreased to meet the new load demand. Gen-set A1 output power decreased from approximately 13kW to 4kW and Gen-set A2 decreased from approximately 43kW to 34kW. The frequency increased when the microgrid was islanded from approximately 60.00Hz to 60.09Hz, because load demand decreased within the microgrid and because of the CERTS algorithm. Likewise, voltage in the system increased from approximately 275V to 277V on phases A and B and decreased on C-phase from approximately 275V to 270V. After reducing A-phase load to zero, Load Bank 3 decreased to approximately 35kW. Gen-sets A1 and A2 were shut down manually and all loads and alarms were reset, and equipment was prepared for the next test.

Test Results					
Event Open Phase-A of Load Bank 3				Event Results	
	Mode	Set-point	Expected Results	Start	End
A1	Unit	15kW	~2.5kW	13kW	4kW
A2	Unit	45kW	~37.5kW	43kW	34kW
B1		Off	Off	Off	Off
Freq		~60Hz	~60.09Hz	60Hz	60.09Hz
L3		60kW	40kW	54kW	35kW
L4		0kW	0kW	0kW	0kW
L5		0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW
SS	Open	0kW	0kW	0kW	0kW

Grid		0kW	0kW	0kW	0kW
Should be no current in Phase A					
Note: SS Open					

Table 6 - Test Results, Island Operation, Unbalanced Load

6.1.5 Mixed Mode Operation Test – Feeder A, Gen-set A1 Upper Limit, 60kW

Performance Goal:

Verify smooth transitions of Gen-set, A1 in Zone power control mode with a 60kW upper limit and Gen-set A2 in Unit power control mode, during a load step change in Load Bank 3.

Table 7 shows the values of Gen-sets, loads, power flows and frequency before load in Zone 3 was expected to increase by 50kW and the final values after load in Zone 3 was increased. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for zone power control mode and Gen-set A2 was set for unit power control mode. After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition with the static switch closed, Load Banks 3 and 4 were connected and measured approximately 35kW and 33.5kW, respectively. Gen-set A1 output power was approximately 10kW and Gen-set A2 output power was approximately 5.5kW. Power flow through the static switch before additional load was added to Zone 3 was approximately 55kW. Likewise, power flow from the utility grid was approximately 55kW. Frequency in the microgrid before Zone 3 load was increased was approximately 60.005Hz and voltage was approximately 277V.

As soon as load was added in Zone 3 by Load Bank 3, increasing its load from approximately 35kW to 80kW, Gen-set A1 increased its output power from approximately 10kW to 55kW due to its Zone control set-point, which satisfied the increased load demand. Because frequency remained at approximately 60.005Hz no additional power was supplied from Gen-set A2. The resultant voltage in the system dropped from approximately 277V to 276V, decreasing load power demand in Load Bank 4 to approximately 33.25kW. Power flow from the utility through the static switch was 57kW. Although it was desired to put Gen-set A1 at its upper power control limit, differences in actual power delivered by the load banks prevented it from being reached. Gen-set A1 did correctly meet its zone control set point of 54kW; however, it only needed to provide 55kW instead of the anticipated 60kW. The electrical system was

allowed to operate for a couple of minutes to see if an event would occur, which did not happen.

Gen-sets A1 and A2 were shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results					
Event Load Step in Zone 3				Event Results	
	Mode	Set-point	Expected Results	Start	End
A1	Zone	54kW	54kW	52kW	54kW
A1	Injected P	10kW	60kW	10kW	55kW
A2	Unit	6kW	6kW	5.5kW	5.5kW
B1		Off	Off	Off	Off
Freq		~60Hz	~60Hz	60.005Hz	60.005Hz
L3		35kW	85kW	35kW	80kW
L4		35kW	35kW	33.45kW	33.25kW
L5		0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW
SS	Closed	54kW	54kW	55kW	57kW
Grid		54kW	54kW	55kW	57kW

Table 7 - Mixed Mode Operation Test Results, Feeder A, Gen-set A1 Upper Limit, 60kW

6.1.6 Mixed Mode Operation Test – Feeder A, Automatic Reset of Zone Level Set-Point

Performance Goal:

Verify smooth transitions of Gen-set A1 in Zone power control mode with an automatic reset of the set-point and Gen-set A2 in Unit power control mode, during a load step change in Load Bank 4.

Table 8 shows the values of Gen-sets, loads, power flows and frequency before load in Zone 4 was increased by 20kW and the resultant values after load in Zone 4 was

increased. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for zone power control mode and Gen-set A2 was set for unit power control mode. After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition with the static switch closed, Load Banks 3 and 4 were connected and measured approximately 68.95kW and 33.5kW, respectively. Gen-set A1 output power was approximately 44kW and Gen-set A2 output power was approximately 6.5kW. Power flow through the static switch before additional load was added to Zone 4 was approximately 55kW. Likewise, power flow from the utility grid was approximately 55kW which means that about half of the load in Load Banks 3 and 4 was supplied power by the utility grid. Frequency in the microgrid, before Zone 4 load was increased, was approximately 59.95Hz and voltage was approximately 277V.

As soon as load was added in Zone 4 by Load Bank 4, increasing its load from approximately 33.5kW to 52.5kW, Gen-set A1 increased its output power from approximately 44kW to 58kW due to its Zone control set-point, which satisfied the increased load demand. No additional power was supplied from Gen-set A2, which remained the same at approximately 6.5kW, and load demand in Load Bank 3 stayed the same at approximately 68.95kW. The resultant voltage in the system dropped from approximately 277V to 276V and frequency increased from approximately59.95Hz to 59.98Hz. Power flow from the utility through the static switch was 61kW. Gen-set A1 did correctly meet its zone control set-point of 55kW; however, differences in actual power delivered by the load banks prevented it from reaching the anticipated 60kW. The electrical system was allowed to operate for a couple of minutes to see if an event would occur, which did not happen.

Gen-sets A1 and A2 were shut down manually, all loads and alarms were reset and equipment was prepared for the next test.

Test Results					
Event Load step in Zone 4				Event Results	
	Mode	Set-point	Expected Results	Start	End
A1	Zone	55kW	65kW	52kW	58kW
A1	Injected P	50kW	60kW at Max	44kW	58kW

A2	Unit	5kW	5kW	6.5kW	6.5kW
B1		Off	Off	Off	Off
Freq		~60Hz	~60Hz	59.95Hz	59.98Hz
L3		75kW	75kW	68.95kW	68.95kW
L4		35kW	55kW	33.5kW	52.5kW
L5		0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW
SS	Closed	55kW	65kW	55kW	61kW
Grid		55kW	65kW	55kW	61kW
Starting and ending frequency are ~60Hz					

Table 8 – Mixed Mode Operation Test Results, Feeder A, Automatic Reset of Zone Level Set-point.

6.1.7 Mixed Mode Operation Test – Feeder A, Zone Power Change

Performance Goal:

Verify smooth transitions of Gen-set A1 in Zone power control mode and Gen-set A2 in Unit power control mode, with a change of zone power in Feeder A. Table 9 shows the values of Gen-sets, loads, power flows and frequency before the EMS requested Zone 3 power be increased by 56kW and the resultant values after Zone 3 power was increased. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for zone power control mode and Gen-set A2 was set for unit power control mode. After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition with the static switch closed, Load Banks 3 and 4 were connected and measured approximately 75.7kW and 33.3kW, respectively. Gen-set A1 output power was approximately 50.5kW and Gen-set A2 output power was approximately 5.25kW. Power flow through the static switch was approximately 57kW before the EMS increased power in Zone 3 and was approximately 54kW in Zone 3. Frequency in the microgrid before the EMS changed the power in Zone 3 was approximately 60.008Hz and voltage was approximately 277V.

As soon as the EMS increased the power set-point setting of Gen-set A1 in Zone 3, Gen-set A1 decreased its output power from approximately 50.5kW to 0kW, due to its zone control set-point which increased load demand to Zone 3. Gen-set A2 output power increased slightly from 5.25kW to approximately 5.6kW. The resultant voltage in the

system dropped from approximately 277V to 276V and frequency decreased slightly (i.e., from 60.008Hz to 60.003Hz), reducing load at Load Banks 3 and 4 to approximately 75.55kW and 33.24kW, respectively. Power flow at the static switch increased from 57kW to 107.5kW. This 50.5kW increase by the utility grid was required to meet the increased set-point setting in Zone 3, and Gen-set A1 reduced to 0kW. The electrical system was allowed to operate for a couple of minutes to see if an event would occur, which did not happen.

Gen-sets A1 and A2 was shut down manually, all loads and alarms were reset and equipment was prepared for the next test.

Test Results					
Event Increase Zone 3 set-point				Event Results	
	Mode	Set-point	Expected Results	Start	End
A1	Zone	54kW	110kW	54kW	104kW
A1	Injected P	60kW at Max	4kW	50.5kW	0kW
A2	Unit	6kW	6kW	5.25kW	5.6kW
B1		Off	Off	Off	Off
Freq		~60Hz	~60Hz	60.008Hz	60.003Hz
L3		85kW	85kW	75.7kW	75.55kW
L4		35kW	35kW	33.3kW	33.24kW
L5		0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW
SS	Closed	54kW	110kW	57kW	107.5kW
Grid		54kW	110kW	57kW	107.5kW
Reset Zone Power for Gen-set A1 to ~110kW					

Table 9 - Mixed Mode Operation Test Results, Feeder A Zone Power Change

6.1.8 Mixed Mode Operation Test – Feeder A, Zone Power Change When Islanded

Performance Goal:

Verify smooth transition of Gen-sets, A1 in Zone power control mode and A2 in Unit power control mode, with a static switch operation to island the microgrid and a change of zone power control in Feeder A.

Table 10 shows the values of Gen-sets, loads, power flows and frequency before the static switch was opened and the resultant values after the static switch islanded the microgrid. The static switch was also allowed to reclose in this test to compare values indicated in the table before the static switch was opened. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for zone power control mode and Gen-set A2 was set for unit power control mode. After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition with the static switch closed, Load Banks 3 and 4 were connected and measured approximately 33.75kW and 33.4kW, respectively. Gen-set A1 output power was approximately 14kW and Gen-set A2 output power was approximately 5kW. Power flow through the static switch, from the utility grid, was approximately 52.5kW with approximately 75% of the loads within the microgrid being supplied by the utility grid.

As soon as the static switch was manually opened, the utility grid was no longer providing power to the microgrid with Gen-sets A1 and A2 adjusting their output power, accordingly. Gen-set A1 output power decreased from approximately 14kW to 9kW because Zone 3 power set-point was decreased from 50kW; and Gen-set A2 output power increased from 5kW to 59kW. Gen-set A1 continued producing power in Zone 3, because Gen-set A2 was at its maximum power limit and could not satisfy load demand from Load Banks 3 and 4. The resultant frequency decreased when the microgrid islanded from 60.02Hz to 59.58Hz, because the load increased within the microgrid and because of the CERTS algorithm. In addition, voltage in the microgrid dropped from approximately 280V to 277V, and decreased load power demands in Load Banks 3 and 4 to approximately 32.8kW and 32.6kW, respectively. Power flow at the static switch decreased from 52.5kWto 0kW. The islanded microgrid operated this way for a few minutes before the static switch manual open was removed.

The static switch reconnected the microgrid to the utility grid in a smooth transition with Load Banks 3 and 4 supplied power by the microgrid and utility grid. Gen-set A1 increased its output power to approximately 14kW and Gen-set A2 decreased its output power to approximately 5kW. Load Banks 3 and 4 were measured at approximately 33.65kW and 33.4kW, respectively. Power flow through the static switch was

approximately 52.5kW from the utility. Voltage within the microgrid increased from approximately 277V to 280V and frequency increased from approximately 59.55Hz to 60.00Hz. The resultant values after the static switch reconnected the microgrid to the utility grid were very similar to the values at the beginning of the test.

Gen-sets A1 and A2 were shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results							
Test Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Start	End	Start	End	Start	End
A1	Zone	50kW	0kW	50kW	0kW	0kW	50kW
A1	Injected P	14kW	~18kW	14kW	9kW	9kW	14kW
A2	Unit	6kW	~52kW	5kW	59kW	59kW	5kW
B1		Off	Off	Off	Off	Off	Off
Freq		~60Hz	~59.6Hz	60.02Hz	59.58Hz	59.55Hz	60Hz
L3		35kW	35kW	33.75kW	32.8kW	32.7kW	33.65kW
L4		35kW	35kW	33.4kW	32.6kW	32.6kW	33.4kW
L5		0kW	0kW	0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW	0kW	0kW
SS	Closed	50kW	0kW	52.5kW	0kW	0kW	52.5kW
Grid		50kW	0kW	52.5kW	0kW	0kW	52.5kW
Allow SS to re-close Expect the system to return to Start values.							

Table 10 - Mixed Mode Operation Test Results, Feeder A, Zone Power Change When Islanded

6.1.9 Mixed Mode Operation Test – Feeder A, When Islanded Automatic Reset of Zone Level Set-point

Performance Goal:

Verify smooth transitions of Gen-sets A1 in Zone power control mode with automatic reset of set point and Gen-set A2 in Unit power control mode, with a static switch operation and a change of zone power control set-point in Feeder A, when islanded.

Table 11 shows the values of Gen-sets, loads, power flows and frequency before the static switch opened and the resultant values after the static switch islanded the microgrid. The static switch was also allowed to reclose in this test to compare values indicated in the table before the static switch was opened. During this test, the series inductor L11 is connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for zone power control mode and Gen-set A2 was set for unit power control mode. After Gen-sets A1 and A2 were running for a few minutes and in a steady state condition, Load Banks 3 and 4 were connected and measured approximately 54kW and 54kW, respectively. Gen-set A1 output power was approximately 50kW and Gen-set A2 output power was approximately 10kW. Power flow from the utility through the static switch, before it was opened, was approximately 53kW, indicating that about half of the load within the microgrid was being supplied by the utility grid.

As soon as the static switch was manually opened, the utility grid was no longer providing additional power needed to satisfy the loads in the microgrid; therefore, Gen-set A1 and A2 had to increase or decrease their output powers, accordingly. Gen-set A1 output power decreased from approximately 50kW to 47kW and Gen-set A2 increased from 10kW to 60kW. Gen-set A1 continued producing power because Gen-set A2 was at its maximum power point and could not satisfy load demand from Load Banks 3 and 4. The frequency decreased when the microgrid islanded from 59.965Hz to 59.78Hz, because the load demand increased within the microgrid and because of the CERTS algorithm. The resultant voltage in the system dropped from approximately 280V to 275V, decreasing load power demands in Load Banks 3 and 4 to approximately 52kW and 52.25kW, respectively. Power flow from the utility through the static switch was 0kW. The islanded microgrid operated this way for a few minutes before the static switch manual open was removed.

The static switch reconnected the microgrid to the utility grid in a smooth transition with Load Banks 3 and 4 supplied power from the microgrid and utility grid. Gen-set A1 increased its output power to approximately 49kW and Gen-set A2 decreased its output power to approximately 4kW. Load Banks 3 and 4 measured approximately

53.5kW and 52.8kW, respectively. Power flow at the static switch was approximately 57.5kW from the utility side. Voltage within the microgrid increased from approximately 275V to 280V and frequency increased approximately to 60.02Hz. The values after the static switch reconnected the microgrid to the utility grid were very similar to the values at the beginning of the test, which was expected.

Gen-sets A1 and A2 were shut down manually, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results							
Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Set-point	Expected Results	Start	End	Start	End
A1	Zone	54kW	0kW	50kW	0kW	0kW	55kW
A1	Injected P	60kW	60kW at Max	50kW	47kW	45kW	49kW
A2	Unit	6kW	60kW	10kW	60kW	60kW	4kW
B1		Off	Off	Off	Off	Off	Off
Freq		~60Hz	~59.5Hz	59.965Hz	59.54Hz	59.79Hz	60.02Hz
L3		60kW	60kW	54kW	52kW	51.7kW	53.5kW
L4		60kW	60kW	54kW	52.25kW	51.3kW	52.8kW
L5		0kW	0kW	0kW	0kW	0kW	0kW
L6		0kW	0kW	0kW	0kW	0kW	0kW
SS	Closed	54kW	0kW	53kW	0kW	0kW	57.5kW
Grid		54kW	0kW	53kW	0kW	0kW	57.5kW
Allow SS to Re-close Expect the system to return to Start values.							

Table 11 - Mixed Mode Operation Test Results, Feeder A When Islanded Automatic Reset of Zone Level Set-point

6.1.10 Two Sources in Zone Control – Separate Feeders, When Islanded Automatic Reset of Zone Set Points, Zones Sum Equal 0kW

Performance Goal:

Verify smooth transitions of Gen-sets, A1 and B1 in Zone power control mode, with a static switch operation and a change of zone power control settings in Feeder A and Feeder B, when islanded.

Table 12 shows the values of Gen-sets, loads, power flows and frequency before the static switch opened and resultant values after the static switch opened, islanding the microgrid. The static switch was also allowed to reclose in this test to compare values with initial values of the test before the static switch was opened. During this test, the series inductor L11 was connected to the utility grid to simulate weak grid conditions at the PCC to the microgrid.

Gen-sets A1 and B1 are both set for zone power control mode. After Gen-sets A1 and B1 were running for a few minutes and in a steady state condition, Load Banks 3 and 5 were connected, measuring approximately 35.5kW and 46.4kW, respectively. Gen-set A1 output power was approximately 0kW and Gen-set B1 output power was approximately 34kW. Power flow from the utility through the static switch, before it opened, was approximately 50kW, with a little more than half of the load within the microgrid being supplied by the utility grid.

As soon as the static switch was manually opened, the utility grid was no longer providing additional power needed to satisfy the loads in the microgrid; therefore, Gen-set A1 and B1 increased their output power, accordingly. Gen-set A1 output power increased from approximately 0kW to 22kW and Gen-set B1 increased from 34kW to 61kW. Zone 3 received 15kW from Zone 5 to cover the load demand of Load Bank 3. Frequency decreased when the microgrid islanded from 60.03Hz to 59.78Hz, because load demand increased within the microgrid and because of the CERTS algorithm. The resultant voltage in the system dropped from approximately 277V to 272V, decreasing load power demands in Load Banks 3 and 5 to approximately 34.2kW and 45.4kW, respectively. Power flow from the utility through the static switch was 0kW. The islanded microgrid operated this way for a few minutes before the static switch manual open was removed.

The static switch reconnected the microgrid to the utility grid in a smooth transition with Load Banks 3 and 5 being supplied power by the microgrid and utility grid. Gen-set A1 decreased its output power to approximately 0kW and Gen-set B1 decreased its output power to approximately 34kW. Load Banks 3 and 5 measured approximately 35.7kW and 46.3kW, respectively. Power flow at the static switch was approximately

50kW from the utility grid. Voltage within the microgrid increased from approximately 272V to 277V and frequency increased to approximately 60.015Hz. The resultant values after the static switch reconnected the microgrid to the utility grid were very similar to the values at the beginning of the test, which were expected.

Gen-sets A1 and B1 were manually shut down, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results							
Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Start	End	Start	End	Start	End
A1	Zone	40kW	10kW	35kW	13kW	13kW	36kW
A1	Injected P	0kW	30kW	0kW	22kW	21.5kW	0kW
A2		Off	Off	Off	Off	Off	Off
B1	Zone	10kW	-10kW	13kW	-15kW	-15.5kW	12kW
B1	Injected P	40kW	60kW	34kW	61kW	61kW	34kW
Fq		~60Hz	~59.76Hz	60.03Hz	59.78Hz	59.87Hz	60.015Hz
L3		40kW	40kW	35.5kW	34.2kW	34.4kW	35.7kW
L4		0kW	0kW	0kW	0kW	0kW	0kW
L5		50kW	50kW	46.4kW	45.4kW	45.3kW	46.3kW
L6		0kW	0kW	0kW	0kW	0kW	0kW
SS	Closed	50kW	0kW	50kW	0kW	0kW	50kW
Grid		50kW	0kW	50kW	0kW	0kW	50kW
Allow SS to re-close Expect the system to return to Start values							

Table 12 - Two Sources in Zone Control Test Results, Separate Feeders When Islanded, Automatic Reset of Zone Set-points, Zone Sums Equal Zero kW

6.1.11 Two Sources in Zone Control – Separate Feeders, When Islanded Automatic Reset of Zone Set Point

Performance Goal:

Verify smooth transitions of Gen-sets A1 and B1 in Zone power control mode, both having automatic reset of set points, with a static switch operation and a change of zone control power in Feeder A and Feeder B, when islanded.

Table 13 shows the values of Gen-sets, loads, power flows and frequency before the static switch opened and resultant final values after the static switch opened, islanding the microgrid. The static switch was also allowed to reclose in this test to compare values indicated in the table with initial values of the test before the static switch opened. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-sets A1 and B1 were both set for zone power control mode. After Gen-sets A1 and B1 were running for a few minutes and in a steady state condition, Load Banks 3, 5 and 6 were connected, measuring approximately 18.1kW, 35.8kW, and 18.15kW respectively. Gen-set A1 output power was approximately 43.6kW and Gen-set B1 output power was approximately 14kW. Power flow through the static switch before it opened was approximately -0.5kW, meaning that power was flowing beyond the static switch. Power flow from the utility grid was approximately 17.7kW which means that Load Bank 6 was being supported mainly by the utility grid. Gen-set A1 was supporting Load Bank 3 and sending approximately 25.1kW to Zone 5 and Load Bank 6.

As soon as the static switch was manually opened, the utility grid was no longer providing additional power needed to satisfy loads in the microgrid, therefore, Gen-set A1 and B1 had to increase and decrease their output powers, accordingly. Because nearly 0kW was being exported from the microgrid very little changed once the static switch opened. The frequency increased from 60.014Hz to 60.024Hz because load demand decreased within the microgrid and because of the CERTS algorithm. The resultant voltage in the system dropped from approximately 280V to 272V decreasing the load power demands in Load Banks 3 and 5 to approximately 17.45kW and 34.2kW, respectively. Power flow at the static switch was 0kW with approximately 18.6kW from the utility feeding Load Bank 6. The islanded microgrid operated this way for a few minutes before the static switch manual open was removed.

The static switch reconnected the microgrid to the utility grid in a smooth transition with Load Banks 3, 5 and 6 now being supplied power by the microgrid and utility grid. Gen-set A1 increased its output power to approximately 45kW and Gen-set B1 increased its output power to approximately 15.25kW. Load Banks 3, 5 and 6 measured

approximately 18.15kW, 35.7kW and 18.1kW, respectively. Power flow at the static switch was approximately -3.5kW and 14.75kW from the utility side. Gen-set A1 increased its power output which was distributed to Zone 5 and Load Bank 6. Voltage within the microgrid increased from approximately 272V to 280V and frequency decreased to approximately 60.005Hz. The resultant values after the static switch reconnected the microgrid to the utility grid were very similar to the values at the beginning of the test, which was expected.

Gen-sets A1 and B1 were manually shut down, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results							
Event Open SS				Event Results Open SS		Event Results Close SS	
	Mode	Set-point	Expected Results	Start	End	Start	End
A1	Zone	-30kW	-25kW	-25.1kW	-25.4kW	-25.5kW	-26.75kW
A1	Injected P	50kW	45kW	43.6kW	42.9kW	43kW	45kW
A2		Off	Off	Off	Off	Off	Off
B1	Zone	20kW	25kW	21.7kW	22.7kW	22.5kW	20.5kW
B1	Injected P	20kW	15kW	14kW	12kW	12.25kW	15.25kW
Freq		~60Hz	~60.04Hz	60.014Hz	60.024Hz	60.01Hz	60.005Hz
L3		20kW	20kW	18.1kW	17.45kW	17.55kW	18.15kW
L4		0kW	0kW	0kW	0kW	0kW	0kW
L5		40kW	40kW	35.8kW	34.2kW	34.4kW	35.7kW
L6		20kW	20kW	18.15kW	18.475kW	18.425kW	18.1kW
SS	Closed	-10kW	0kW	-0.5kW	0.1kW	0kW	-3.5kW
Grid		10kW	20kW	17.7kW	18.6kW	18.5kW	14.75kW
Allow SS to re-close Expect the system to return to Start values							

Table 13 - Two Sources in Zone Control Test Results, Separate Feeders When Islanded, Automatic Reset of Zone Set-point

6.1.12 Test Generator Black-Start Procedure

Performance Goal:

Bring up the Micro-grid Test Bed from a black-out condition without generation or protection trips. During this test, the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1, A2 and B1 were set for injection power control, but were left off-line. Breaker CB1 was then opened where the microgrid was isolated from the utility with Load Bank 6 still part of the microgrid loads. A manual open was sent to the static switch to isolate the microgrid, islanding it from the utility grid. Gen-sets A1, A2 and B1 were started and allowed to run for a few minutes until steady state conditions were established. At this time Load Banks 3, 4, and 5 were applied to the microgrid at approximately 22.55kW + j10.35kVAr, 22.3kW + j9.95kVAr and 22.625kW + j10.45kVAr, respectively. Gen-set A1, A2 and B1 output powers were approximately 23kW, 23kW and 24kW, respectively. Frequency on the microgrid was 59.978Hz at a voltage level of approximately 271V. The grid supplied approximately 6kW to Load bank 6 which measured approximately 5.9kW + j10.95kVAr.

The manual "Open" was removed from the static switch and CB1 was closed. The static switch waited 300 seconds before closing into the utility grid, because of IEEE Standard 1547 requirements. A smooth transition occurred when the static switch closed into the utility grid.

The voltage and frequency increased in the microgrid to approximately 277V and 60.006Hz which in turn increased the load demands in Load Banks 3, 4 and 5 to approximately 23.35kW + j10.75kVAr, 23.075kW + j10.34kVAr and 23.275kW + j10.775kVAr, respectively. Load Bank 6 reduced to approximately 5.715kW + j10.61kVAr. Gen-sets A1, A2 and B1 decreased their output power to approximately 18.5kW, 19.5kW and 19.5kW, respectively. The additional power needed to support all loads in the microgrid and Load Bank 6 was supplied by the utility grid, which increased from approximately 6kW to 21kW. Zones 3, 4 and 5 increased to approximately 9kW, 4kW and 3.75kW. The microgrid was operated like this for a couple of minutes to monitor performance and fault events, which did not occur.

Gen-sets A1, A2 and B1 were manually shut down, all loads and alarms were reset, and equipment was prepared for the next test.

Test Results			
Event Close SS			
	Mode	Event Results Start	Event Results End
A1	Unit	23kW	18.5kW
A2	Zone	23kW	19.5kW
B1	Zone	24kW	19.5kW
Freq		59.978Hz	60.006Hz
L3		22.55kW	23.35kW
L4		22.3kW	23.075kW
L5		22.625kW	23.275kW
L6		5.9kW	5.715kW
SS	Open	0kW	15.5kW
Grid		6kW	21kW

Table 14 - Generator Black Start Procedure Test Results

6.1.13 Test/Establish Generator Black-Start Capacity

Performance Goal:

Determine the Black-start capacity of the microgrid by increasing the amount of load on the Micro-grid Test Bed from a black-out condition without generation or protection trips. During this test the series inductor L11 was connected to the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Gen-set A1 was set for unit power control mode, but was left off-line. CB1 was opened isolating the microgrid with Load Bank 6 still part of the microgrid loads. A manual open was sent to the static switch to isolate the microgrid, islanding it from the utility grid. At this time Load Bank 3 was connected to the microgrid at approximately 18kW + j17.5kVAr. Gen-set A1 was started and closed into the load in Load Bank 3. Gen-set A1 output power was approximately 20kW + j20.5kVAr. Zone 3 was approximately -2.3kW + j2.75kVAr supporting transformer T51 and the load of the static switch controls. Frequency on the microgrid was 60.00Hz at a voltage level of approximately 270V. Gen-set A1 was shut down manually after if ran for a few minutes. Load Bank 3 was then increased to approximately 31kW + j17.5kVAr and then Gen-set A1 was restarted.

The process above continued for three more load increases in Load Bank 3 (i.e., 47kW + j17.8kVAr, 50kW + j26.5kVAr and 59kW + j26.5kVAr). The results for all the Black-start load step tests are shown in Tables 15a – 15e. Gen-sets A1 was manually shut down, all loads and alarms were reset, and equipment was prepared for the next test.

		Event Results	
	Mode	Open SS and Gen-set A1 Start	
Load		**LOAD 20kW+j20kVar**	
		Start	End
A1	Unit	20kW	-2.3kW-j2.75kVar
A1	Injected P	0kW	20kW+j20.5kVar
A2		Off	Off
B1		Off	Off
Freq		0Hz	60Hz
L3		0kW	18kW+j17.5kVar
L4		Off	Off
L5		Off	Off
L6		Off	Off
SS		0kW+j0kVar	0kW+j0kVar
Grid		0kW+j0kVar	0kW+j0kVar

Table 15a - Black Start Test Results, 20kW + j20kVAr

		Event Results	
	Mode	Open SS and Gen-set A1 Start	
Load		**LOAD 35kW+j20kVar**	
		Start	End
A1	Unit	0kW	-2.3kW-j2.75kVar
A1	Injected P	0kW	32.5kW+j20kVar

A2	Off	Off
B1	Off	Off
Fq	0Hz	59.9Hz
L3	0kW	31kW+j17.5kVar
L4	Off	Off
L5	Off	Off
L6	Off	Off
SS	0kW+j0kVar	0kW+j0kVar
Grid	0kW+j0kVar	0kW+j0kVar

Table 15b - Black Start Test Results, 35kW + j20kVAr

		Event Results	
	Mode	Open SS and Gen-set A1 Start	
Load		**LOAD 55kW+j20kVar**	
		Start	End
A1	Zone	0kW	-2.35-j2.75kVar
A1	Injected P	0kW	50kW+j20.5kVar
A2		Off	Off
B1		Off	Off
Fq		0Hz	59.9Hz
L3		0kW	47kW+j17.8kVar
L4		Off	Off
L5		Off	Off
L6		Off	Off
SS		0kW+j0kVar	0kW+j0kVar
Grid		0kW+j0kVar	0kW+j0kVar

Table 15c - Black Start Test Results, 55kW + j20kVAr

	Event Results
Mode	Open SS and Gen-set A1 Start

Load		LOAD 60kW+j30kVar	
		Start	End
A1	Zone	0kW	-2.25kW-j2.5kVar
A1	Injected P	0kW	52.5kW+j29kVar
A2		Off	Off
B1		Off	Off
Fq		0Hz	59.75Hz
L3		0kW	50kW+j26.5kVar
L4		Off	Off
L5		Off	Off
L6		Off	Off
SS		0kW+j0kVar	0kW+j0kVar
Grid		0kW+j0kVar	0kW+j0kVar

Table 15d - Black Start Test Results, 60kW + j30kVAr

		Event Results	
	Mode	Open SS and Gen-set A1 Start	
Load		LOAD 70kW+j30kVar	
		Start	End
A1	Zone	0kW	-2.19kW-j2.35kVar
A1	Injected P	0kW	61kW+j29kVar
A2		Off	Off
B1		Off	Off
Fq		0Hz	59.8Hz
L3		0kW	59kW+j26.5kVar
L4		Off	Off
L5		Off	Off
L6		Off	Off
SS		0kW+j0kVar	0kW+j0kVar

Grid	0kW+j0kVar	0kW+j0kVar

Table 15e - Black Start Test Results, 70kW + j30kVAr

7.0 CONCLUSION

The tests performed in section 8.0 "Reduced System Tests" were successfully performed which provided confidence that the Gen-set inverter controls were working properly and prepared for the power control test in section 9.0.

The tests proved to be more robust than previously predicted in the Black Start Tests in section 6.1.13 when the load was increased to a demand greater than the rating of the Gen-sets and all components remained online.

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 9.0
Power Flow Control Tests

APPENDIX L

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CERTS
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CERTS MICROGRID TEST REPORT

SECTION 9.0

"Power Flow Control Tests"

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as "islanded" from it. This paper describes the tests that were performed in Section 9.0 "Power Flow Control Tests" of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility's distribution system, isolating the microgrid's load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility's electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating

adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to a 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

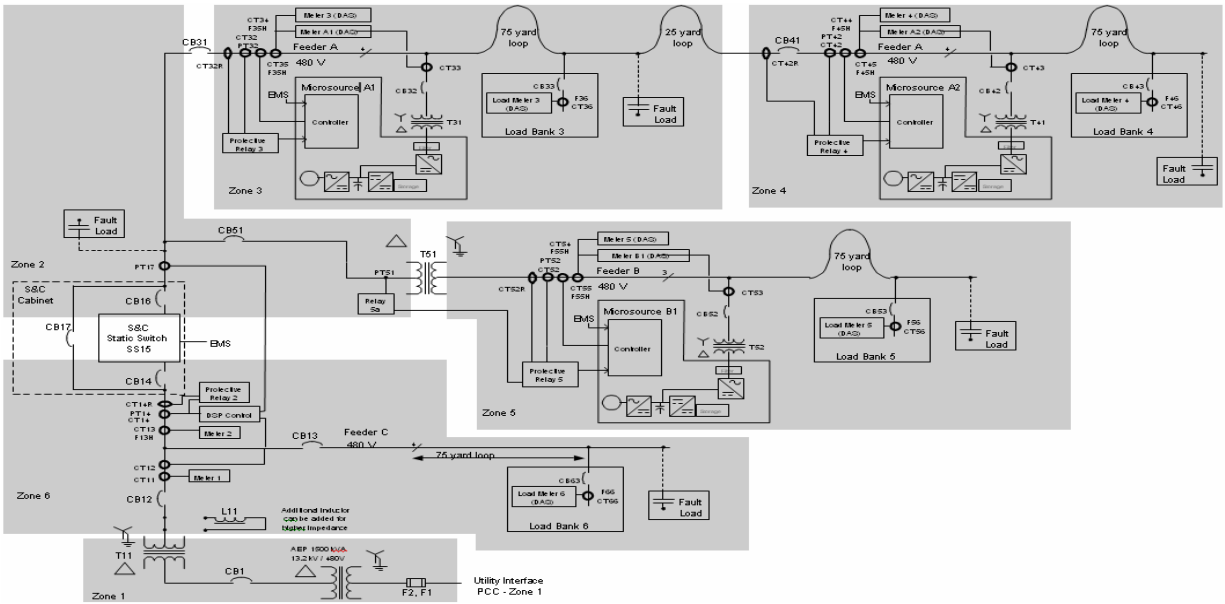

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

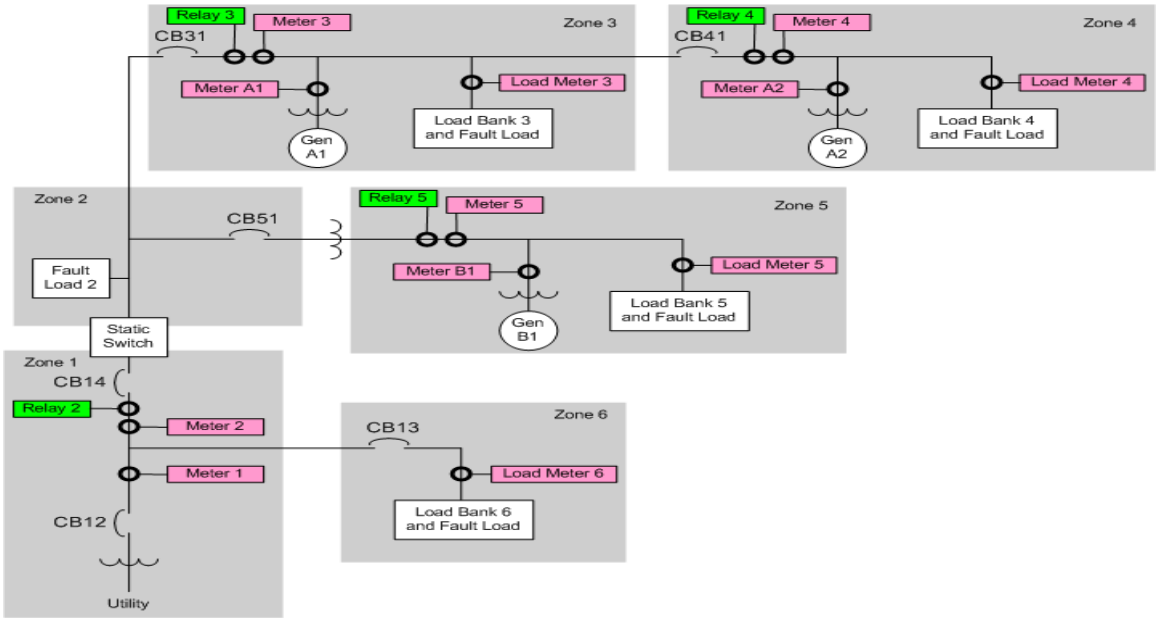

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

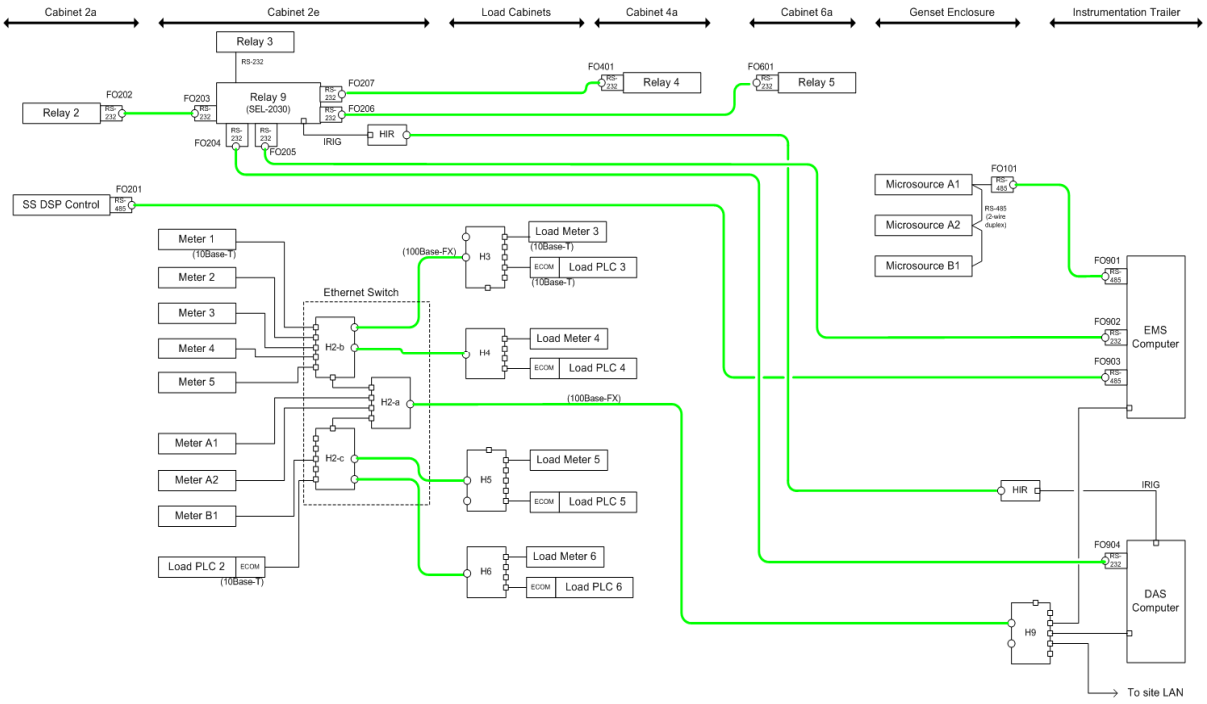

Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – "Purpose, References, and Definitions" describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – "Responsibilities" informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.

- Section 3 – "Training - Team Members" lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.

- Section 4 – "Procedure – CERTS Microgrid Test Bed Lockout/Tagout" entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.

- Section 5 – "Procedure – General" is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.

- Section 6 – "Procedure – Microgrid Test Bed System Checkout" was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.

- Section 7 – "Validate Protection Settings & Initial Fault Testing" is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.

- Section 8 – "Procedure – Reduced System Tests" is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.

- Section 9 – "Procedure – Demonstration Tests of Control Power Flow" demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – "Procedure – Test Difficult Loads" determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.

- Section 11 - "Hazards & Mitigation" informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.

- Section 12 – "Quality Assurance" ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 9.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a "Red" plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

Section 9 tests were designed to demonstrate the flexibility of the CERTS Microgrid connected to the utility grid and islanded. Various loads are applied to the microgrid while in unit control and zone control mode along with different power settings of the Gen-sets.

Tests performed in this section included inductor L11 in the circuit, reflecting weak utility grid conditions. Load on Feeder A and Feeder B were less than 170kW and Feeder C was such that there was no power going into the utility grid. All the loads included an approximate 0.9 power factor (pf) when possible and the motor load was connected and included as part of Zone 3.

Weak grid conditions were tested in the beginning of the test plan to minimize any damage to equipment. Time constraints forced a decision by the Team to postpone strong grid testing to a later date with concentration on weak grid testing. Therefore, strong grid tests were postponed from Tests 9.1, 9.2, 9.3 and 9.4. Tests 9.1 – 9.3 were required to verify and document power flow and Microgrid frequency changes when transitioning from utility connected to an islanded mode of operation. In each test, 9.1 – 9.3, a series of tests were performed that vary in the amount of load that is applied to the microgrid in a weak grid scenario along with the power settings of each Gen-set. The difference between each test is the type of control mode that the Gen-sets are in. In Test 9.1, all the Gen-sets are set for unit control mode and then the next test, 9.2, all the Gen-sets are set for zone control mode. Test 9.3 mixes the unit and zone control modes of the Gen-sets during each test.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 9 – POWER FLOW CONTROL TESTS

6.1.1 Unit Control Mode, Weak Grid

Performance Goal:

Verify and document power flow and micro-grid frequency changes when transitioning from utility connected mode to an islanded mode of operation.

Four tests were completed in this section with each test event and settings listed in Table 16a. During each test Gen-sets A1, A2, and B1 were set for unit power control mode of operation. Each of the four tests varied the output power command set-point in each Gen-set, along with varying the load settings in load banks LB3, LB4, LB5 and LB6. During each test, inductor L11 was in series with the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Test Event	**Gen-set A1**	**Gen –set A2**	**Gen -set B1**	**Meter 2**	**Meter 3**	**Meter 4**	**Meter 5**	**LB 3**	**LB 4**	**LB 5**	**LB 6**
9.1.7	Unit, 30 kW	Unit, 30 kW	Unit, 30 kW	+30 kW	+20 kW	+10 kW	+10 kW	40 kW 20 kVAr	40 kW 20 kVAr	40 kW 20 kVAr	20 kW 10 kVAr
9.1.8	Unit, 40 kW	Unit, 30 kW	Unit, 25 kW	+15 kW	-10 kW	-15 kW	+25 kW	20 kW 10 kVAr	40 kW 20 kVAr	50 kW 20 kVAr	20 kW 10 kVAr
9.1.9	Unit, 40 kW	Unit, 30 kW	Unit, 30 kW	-10 kW	-30 kW	+10 kW	+20 kW	25 kW 10 kVAr	15 kW 10 kVAr	50 kW 20 kVAr	30 kW 10 kVAr
9.1.10	Unit, 30 kW	Unit, 20 kW	Unit, 45 kW	+20 kW	+40 kW	20 kW	-20 kW	50 kW 20 kVAr	40 kW 20 kVAr	25 kW 10 kVAr	30 kW 10 kVAr

Table 16a - Unit Control Mode, Weak Grid Settings for Load Banks and Gen-sets

The procedure for each test event began with setting the kW and kVAr load (i.e., balanced load) conditions, as indicated in Table 16a, using the EMS at each Load Bank to achieve an approximate 0.9 power factor. Before loads were brought on-line, Gen-sets A1, A2 and B1 were started to allow them to warm up. After the Gen-sets ran for a few minutes and steady-state conditions established, the loads were brought on-line, the static switch was allowed to close, and measurements were taken from Meters 2, 3, 4 and

5. The measurements were then compared with the expected values in Table 16a. When the measured values coincided with the expected values from the table, then a manual open of the static switch was initiated to isolate/island the microgrid from the utility grid. Gen-sets were observed at this time to make sure they increased or decreased their output power as planned to satisfy the loads at load banks (i.e., LB3, LB4, LB5 and LB6) and that a smooth transition occurred. When all the measurements were verified and recorded in the DAS Database, the manual open signal to the static switch was released, allowing it to synchronize and close back into the utility grid. As soon as the static switch synchronized and re-closed, all data (i.e., from the manual open event and the reconnection event) was verified and recorded in the DAS Database. Loads and Unit Power Control set-points were then changed to the settings for the next test. Test results are explained in the following paragraphs.

For Test 9.1.7 the measured values, after the Gen-sets were warmed up and load banks brought on-line, were approximately 40kW at Meter 1, 22kW at Meter 2, 12.5 kW at Meter 3, 3.5kW at Meter 4, 7kW at Meter 5, shown in Table 16b. From the microgrid, 26.5kW was produced by Gen-set A1, 31.5 kW produced by Gen-set A2, and 28kW produced by Gen-set B1. The load banks were slightly less than planned with 35.5kW at LB3, 34.7kW at LB4, 34.8kW at LB5, and 18.32kW at LB6. These measurements were relatively close to the expected values in Table 16a, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW setting for LB3, LB4 and LB5; and 20kW setting for LB6 were also below the selected set values. The deviation of selected values versus actual values was consistent for the other three tests in this section. At the time of these measurements, the voltage and frequency was 276V and 59.99Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 276V and 59.99Hz at Meter 3. The power factor at each load was approximately 0.87 which is a 3% difference from the desired 0.9 power factor.

9.1.7												
	GENSET A1	**GENSET A2**	**GENSET B1**	**METER 1**	**METER 2**	**METER 3**	**METER 4**	**METER 5**	**LB 3**	**LB 4**	**LB 5**	**LB 6**
INITIAL SETUP	UNIT +30kW	UNIT +30kW	UNIT +30kW		+30kW	+20kW		+10kW	40kW	40kW	40kW	20kW
GRID-TO-ISLAND												
Start												
Voltage (V)					276	276						
Current (A)	32	40	39	80	56	41	15	11				
Real Power (kW)	26.5	31.5	28	40	22	12.5	3.5	7	35.15	34.7	34.8	18.32

Reactive Power (kVAr)	0	8	14.5	51	41	31.5	11	5	19.7	19.7	19.7	10.675
Power Factor (pf)	1.00	0.97	0.89						0.87	0.87	0.87	0.86
Frequency (Hz)					59.99	59.99						
End												
Voltage (V)					281	268						
Current (A)	42	54	52.5	26	0	5	6.5	9				
Real Power (kW)	32	37	33.6	19	0	-2.5	-4	-0.25	33.3	32.85	33.3	19
Reactive Power (kVAr)	13	21	25	12	0	3	-3	-6	18.7	18.7	18.9	11.25
Power Factor (pf)	0.93	0.87	0.80						0.87	0.87	0.87	0.86
Frequency (Hz)					59.988	59.944						
ISLAND-TO-GRID												
Start												
Voltage (V)					280	268						
Current (A)	42	52	52	26	0	5	6	8				
Real Power (kW)	32	36.5	33.5	19	0	-2	-4	-0.25	33.35	32.7	33.1	18.75
Reactive Power (kVAr)	13	22	25	12	0	4	-3	-6	18.7	18.75	18.95	11.24
Power Factor (pf)	0.93	0.86	0.80						0.87	0.87	0.87	0.86
Frequency (Hz)					60.009	59.942						
End												
Voltage (V)					276	272						
Current (I)	30	30	35	85	60	45	16	13				
Real Power (kW)	23.5	28.5	25	47	30	17	6	9.5	35.1	34.45	34.55	17.9
Reactive Power (kVAr)	0	9	15.5	50	39	31	10	4	19.7	19.75	19.75	10.7
Power Factor (pf)	1.00	0.95	0.85						0.87	0.87	0.87	0.86
Frequency (Hz)					60.01	60.01						

Table 16b – Test 9.1.7 results with dark squares in the table meaning that measurements were not needed.

According to the measurements in Table 16b when connected to the utility grid, each Gen-set in the microgrid was set at 30kW which was not enough to satisfy the loads in LB3, LB4 and LB5 and needed approximately 22kW from the utility grid, as measured by Meter 2. Total power from the utility grid was measured at approximately 40kW from Meter 1, because it was meeting the demands of not only the microgrid loads, but the load at LB6. Once all data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually open.

When the static switch opened, Meter 1 decreased to approximately 19kW satisfying the load demand in LB6 which was approximately 19kW and not supplying any power beyond the static switch to the microgrid loads. 0kW was recorded at Meter 2, showing that power was not flowing through the static switch. LB3, LB4 and LB5 loads reduced slightly to 33.3kW, 32.85kW and 33.3kW, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 29a, from approximately 276V (i.e., 276V on A-phase and 273V on B- & C-phases) when connected to the utility grid to 268V at Meter 3 (i.e., on A-, B-, and C-phases) when islanded.

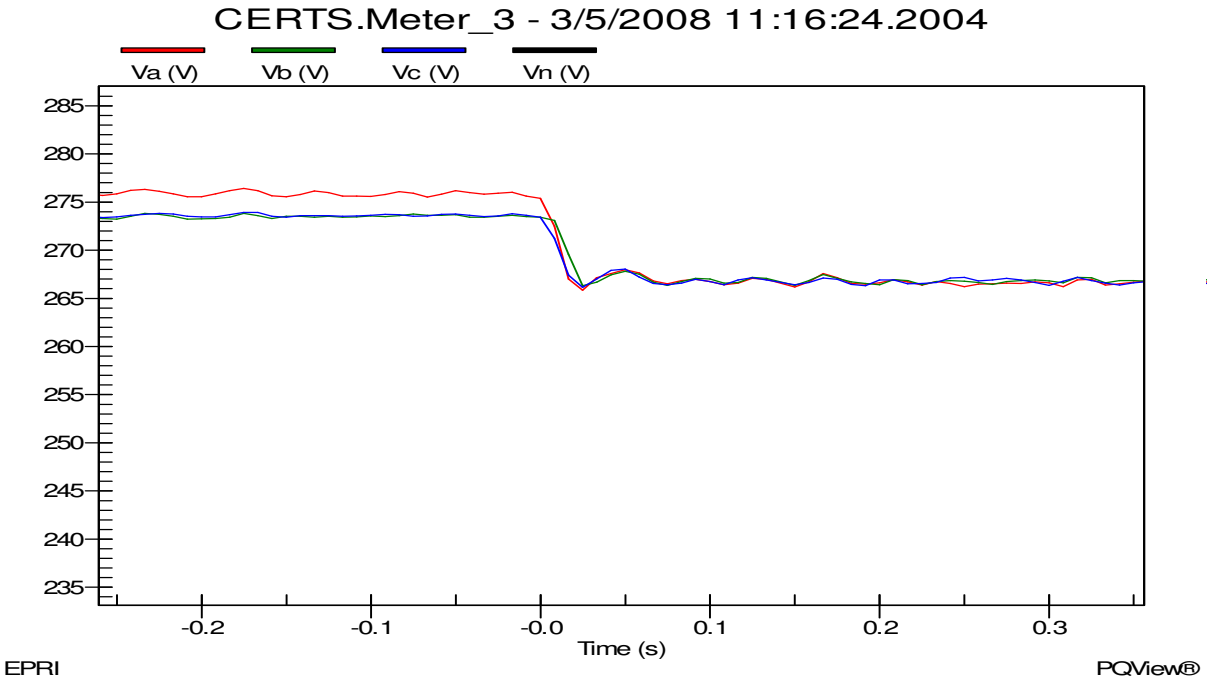

Figure 29a - Meter 3 voltage before/after the static switch opened, islanding the microgrid from the utility grid

Frequency change in the microgrid, shown in Figure 29b, dropped from 59.99Hz when connected to the utility grid to approximately 59.94 Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to increase their output power to satisfy the load demands. Gen-set A1, A2, and B1 increased their output power to approximately 32kW, 37kW and 33.6kW, respectively. Meters 3, 4 and

5 were negative values (-2.5kW, -4kW and -0.25kW, respectively), indicating the Gen-sets were satisfying the loads in the microgrid and the power losses in the line. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize to the utility grid.

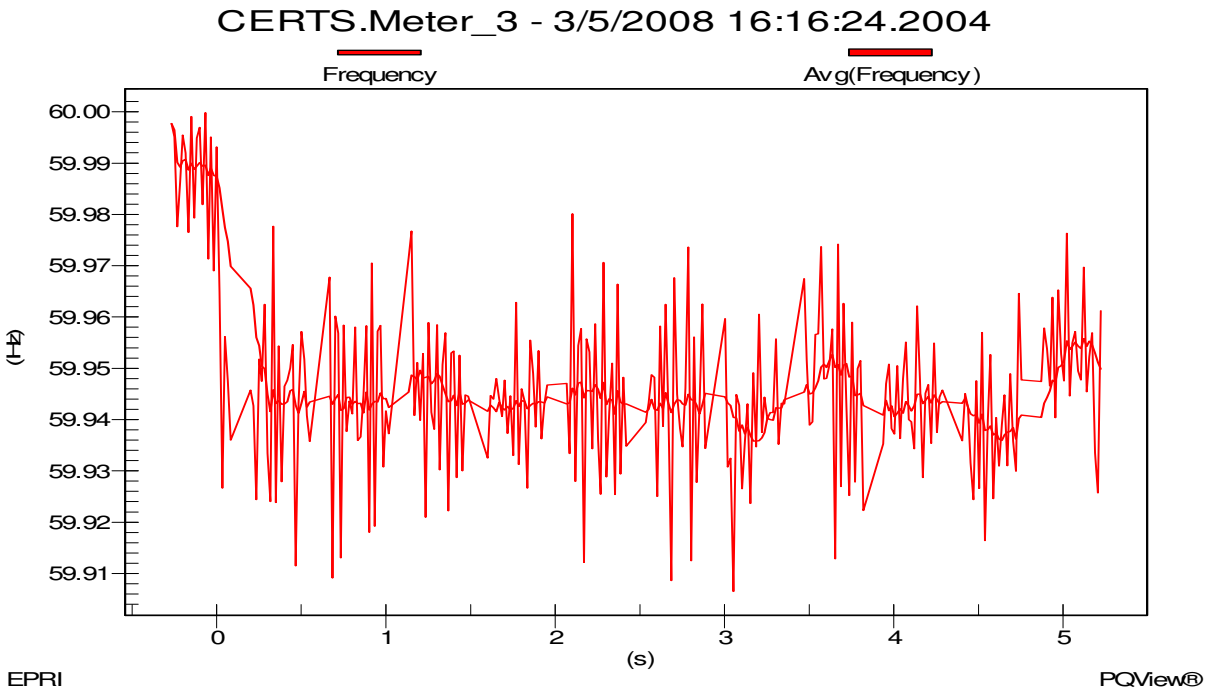

Figure 29b – Meter 3 frequency before/after the static switch opened, islanding the microgrid from the utility grid.

As soon as the static switch closed and steady-state conditions established, the measurements at the Gen-sets, Meters and Load Banks were compared to the initial conditions at the beginning of the test. The measured values when synchronized to the utility grid were very similar to the initial conditions. Voltage and frequency in the microgrid increased from 268V to 276V and 59.944Hz to 60.01Hz. The power factor of approximately 0.87 remained the same throughout the test. After all the data was verified and recorded into the DAS Database the Gen-sets and Load Banks set-points were changed according to the next test (9.1.8) in Table 16a.

For Test 9.1.8 the measured values, after the Gen-sets were warmed up and load banks brought on-line, were approximately 35kW at Meter 1, 17kW at Meter 2, -10 kW at Meter 3, 6kW at Meter 4, and 24kW at Meter 5, shown in Table 16c. From the microgrid, 33.75kW was produced by Gen-set A1, 29 kW produced by Gen-set A2, and 20.5kW produced by Gen-set B1. The load banks were slightly less than planned with 18.05kW at LB3, 34.6kW at LB4, 44.5 kW at LB5, and 18.1kW at LB6. These measurements were

relatively close to the expected values in Table 16a but not exact, due to temperature, phase voltages and electrical losses in the conductors. In addition, the desired kW settings for LB3, LB4, LB5 and LB6 were also below the set values. This deviation of set values verses actual values was consistent for the other tests in this section. At the time of these measurements, the voltage and frequency when connected to the utility grid was 277V and 60.008Hz at the static switch (i.e., Meter 2); and 277V and 60.008Hz at Meter 3. The power factor at LB3, LB4 and LB6 was approximately 0.87 and 0.91 at LB5 which is close to the desired 0.9 power factor.

9.1.8												
	GENSET A1	**GENSET A2**	**GENSET B1**	**METER 1**	**METER 2**	**METER 3**	**METER 4**	**METER 5**	**LB 3**	**LB 4**	**LB 5**	**LB 6**
INITIAL SETUP	UNIT +40kW	UNIT +30kW	UNIT +25kW		+15kW	-10kW		+25kW	20kW	40kW	50kW	20kW
GRID-TO-ISLAND												
Start												
Voltage (V)					277	277						
Current (A)	41	37	30	71	50	35	18	30				
Real Power (kW)	33.75	29	20.5	35	17	-10	6	24	18.05	34.6	44.5	18.1
Reactive Power (kVAr)	-3	6	15	47	37	28	0	4.8	10.65	19.95	19.8	10.8
Power Factor (pf)	1.00	0.98	0.81						0.86	0.87	0.91	0.86
Frequency (Hz)					60.008	60.008						
End												
Voltage (V)					280	269						
Current (A)	47	46	44	26	0	26	3	24				
Real Power (kW)	37.5	33.25	25	19	0	-21	0	18	17.15	33	42.8	18.85
Reactive Power (kVAr)	9	18	24.5	12	0	2	1.5	-5.5	10.1	19	19	11.3
Power Factor (pf)	0.97	0.88	0.71						0.86	0.87	0.91	0.86
Frequency (Hz)					60.008	59.974						
ISLAND-TO-GRID												
Start												
Voltage (V)					281	269						

Current (A)	47	46	44	26	0	26	3	24				
Real Power (kW)	38	33.5	25	19	0	-21	0	18	17.25	33.1	42.9	18.9
Reactive Power (kVAr)	9	18	24.5	12	0	2.5	1	-6	10.1	19	19.05	11.35
Power Factor (pf)	0.97	0.88	0.71						0.86	0.87	0.91	0.86
Frequency (Hz)					59.985	59.975						
End												
Voltage (V)					276	276						
Current (I)	42	39	32	70	50	38	19	28				
Real Power (kW)	35.5	31	22.5	30	13	-12.5	4.5	22.5	18.2	34.9	44.7	18.1
Reactive Power (kVAr)	-4	5	14	50	39	29.5	15	5	10.7	20	19.8	10.8
Power Factor (pf)	0.99	0.99	0.85						0.86	0.87	0.91	0.86
Frequency (Hz)					59.995	59.995						

Table 16c – Test 9.1.8 results with dark squares in the table meaning that measurements were not needed.

According to the measurements in Figure 16c when connected to the utility grid, each Gen-set in the microgrid was set at 40kW for Gen-set A1, 30kW for Gen-set A2 and 25kW for Gen-set B1, which was not enough to satisfy the loads in LB4 and LB5, and needed approximately 17kW from the utility grid, measured by Meter 2. Total power from the utility grid was measured at approximately 35kW in Meter 1, because it was meeting the demands of not only the microgrid loads, but the load at LB6. In addition, Meter 3 recorded approximately -10kW, meaning Gen-set A1 was supplying power for all of LB3, 6kW to LB4, measured by Meter 4, and approximately 10kW to LB5. Once all data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually open.

When the static switch opened, Meter 1 decreased to approximately 19kW satisfying the load demand in LB6 which was approximately 18.85kW and not supplying any power beyond the static switch to the microgrid loads. 0kW was measured at Meter 2, showing that power was not flowing through the static switch. LB3, LB4 and LB5 loads reduced slightly to17.15kW, 33kW and 42.8kW, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 29c, from approximately 277V (i.e., 277V on A-phase, 275V on B- and C-phases) when connected to the utility grid to 269V on all three phases when islanded.

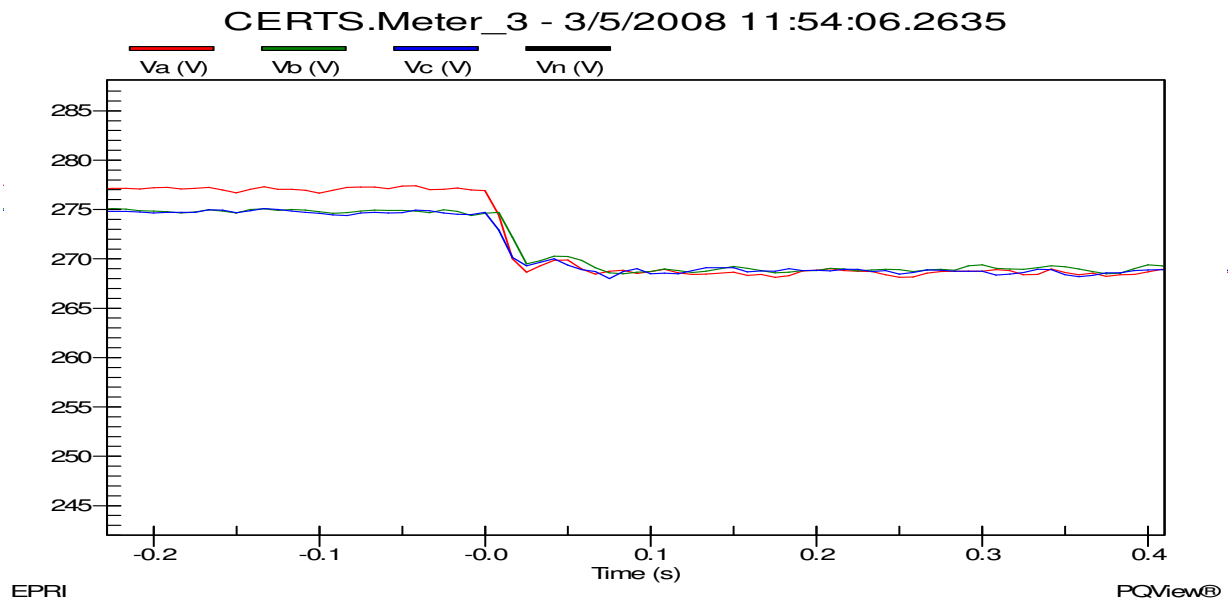

Figure 29c – Meter 3 voltage before/after the static switch opened, islanding the microgrid from the utility grid.

Frequency changed in the microgrid, shown in Figure 29d, from 60.008Hz to 59.974 Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to increase their output power to satisfy the load demands. Gen-set A1, A2 and B1 increased their output power to 37.5kW, 33.25kW and 25kW, respectively. Meter 3 indicated a negative value of -21kW, meaning it supplied all of LB3 load and 18kW of LB5 at Meter 5. Meter 4 indicated 0kW showing that Gen-set A2 supplied all of LB4 load. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize to the utility grid.

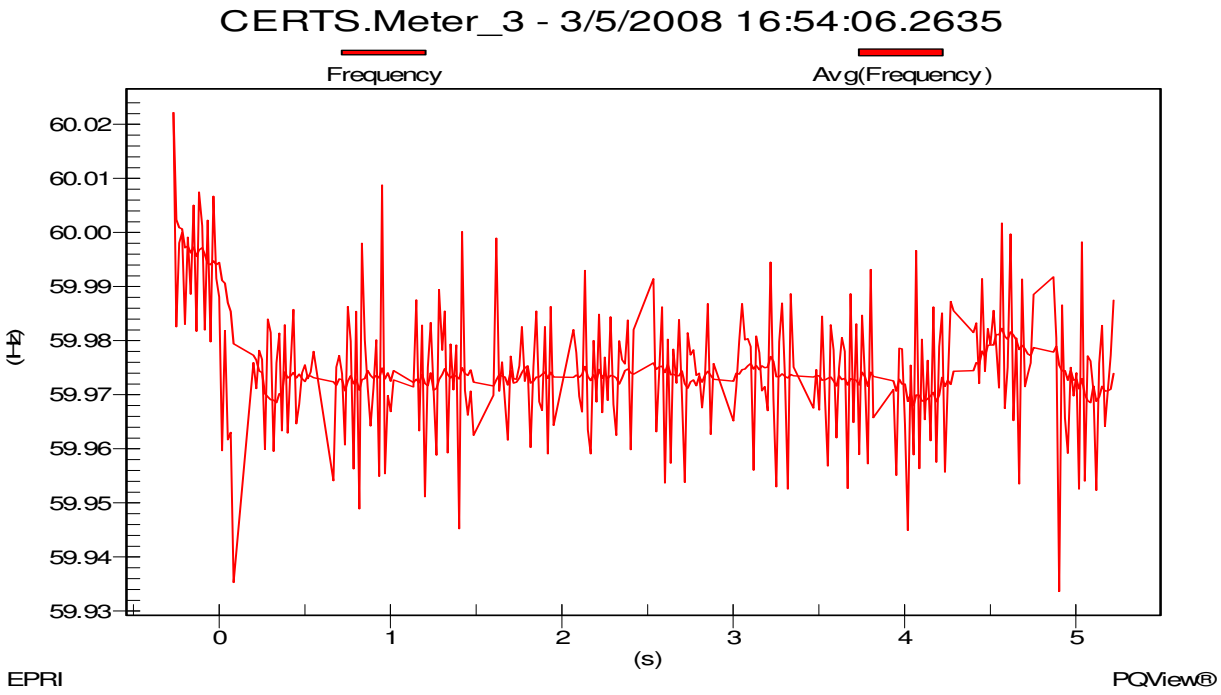

Figure 29d – Meter 3 frequency before/after the static switch opened, islanding the microgrid from the utility grid.

As soon as the static switch closed and steady-state conditions established, the measurements at the Gen-sets, Meters and Load Banks were compared to the initial conditions at the beginning of the test. The measured values were very similar to the initial test conditions which were approximately 30kW at Meter 1, 13kW at Meter 2, -12.5kW at Meter 3, 4.5kW at Meter 4, and 22.5kW at Meter 5 with 35.5kW produced by Gen-set A1, 31kW produced by Gen-set A2, and 22.5kW produced by Gen-set B1. Likewise, 18.2kW was at LB3, 34.9kW at LB4, 44.7kW at LB5 and 18.1kW at LB6. The microgrid voltage increased from 269V to 276V and frequency increased from 59.974Hz to 59.995Hz. The power factor of approximately 0.87 remained the same throughout the test for LB3, LB4 and LB6 and 0.91 for LB5. After all data was verified and recorded into the DAS Database, Gen-sets A1, A2 and B1 were shut down manually and all load banks/alarms were reset and prepared for the next test (9.1.9) in Table 16a.

For Test 9.1.9 the measured values, after the Gen-sets were warmed up and load banks brought on-line, were approximately 15kW at Meter 1, -13.5kW at Meter 2, -33 kW at Meter 3, -15kW at Meter 4, and 16.5kW at Meter 5. From the microgrid 40.5kW was produced by Gen-set A1, 32 kW produced by Gen-set A2, 28.5kW produced by Gen-set B1. The load banks were slightly less than planned with 23.25kW at LB3, 16kW at LB4, 45kW at LB5, and 28.6kW at LB6. These measurements were relatively close to the expected values in Table 16a but not exact, due to temperature, phase voltages and electrical losses in conductors. In addition, the desired kW settings for LB3, LB4, LB5 and LB6 were below the set values. This deviation of set values verses actual values was

consistent for the other tests in this section. At the time of these measurements the voltage and frequency was 277V and 59.99Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 277V and 59.99Hz at Meter 3. The power factor at LB4 was approximately 0.85, 0.91 at LB3 and LB5, and 0.94 at LB6 which was close to the desired 0.9 power factor.

9.1.9												
	GENSET A1	**GENSET A2**	**GENSET B1**	**METER 1**	**METER 2**	**METER 3**	**METER 4**	**METER 5**	**LB 3**	**LB 4**	**LB 5**	**LB 6**
INITIAL SETUP	UNIT +40kW	UNIT +30kW	UNIT +30kW		-10kW	-30kW		+20kW	25kW	15kW	50kW	30kW
GRID-TO-ISLAND												
Start												
Voltage (V)					277	277						
Current (A)	47	39	38	60	45	50	22	22				
Real Power (kW)	40.5	32	28.5	15	-13.5	-33	-15	16.5	23.25	16	45	28.6
Reactive Power (kVAr)	-5	3	12.5	45	35	23	7	7	10.8	10	19.9	10.8
Power Factor (pf)	0.99	1.00	0.92						0.91	0.85	0.91	0.94
Frequency (Hz)					59.99	59.99						
End												
Voltage (V)					280	270						
Current (A)	44	37	39	39	30	0	15	26				
Real Power (kW)	35	26	23	30	0	-23	-11	21	22.25	15.3	43.4	29.65
Reactive Power (kVAr)	6	15	22	12	0	-1	-5	-3	10.3	9.55	19.2	11.2
Power Factor (pf)	0.99	0.87	0.72						0.91	0.85	0.91	0.94
Frequency (Hz)					59.986	60.03						
ISLAND-TO-GRID												
Start												
Voltage (V)					280	270						
Current (A)	44	37	39	39	0	30	15	26				
Real Power (kW)	35	26	23	30	0	-23	-10.5	21	22.3	15.35	43.4	29.6

Reactive Power (kVAr)	6	15	22	12	0	0	-5	-3	10.3	9.55	19.2	11.25
Power Factor (pf)	0.99	0.87	0.72						0.91	0.85	0.91	0.93
Frequency (Hz)					59.997	60.06						
End												
Voltage (V)					276	276						
Current (I)	50	40	38	60	47	50	21	22				
Real Power (kW)	40.5	32	29	13	-15	-34	-16	16	23.25	16.05	45	28.55
Reactive Power (kVAr)	-5	3	12.5	46	45	23	7	7	10.8	10	19.95	10.8
Power Factor (pf)	0.99	1.00	0.92						0.91	0.85	0.91	0.94
Frequency (Hz)					59.98	59.98						

Table 16d - Test 9.1.9 results with dark squares in the table meaning that measurements were not needed.

According to the measurements in Table 16d when connected to the utility grid, each Gen-set in the microgrid was set at 40kW for Gen-set A1, 30kW for Gen-set A2 and 30kW for Gen-set B1 which was enough to satisfy the loads in LB3, LB4 and LB5 and provided 13.5kW measured at Meter 2. The utility supplied approximately 15kW, measured in Meter 1, because it supplied the remaining portion of load at LB6. In addition, Meter 4 measured -15kW meaning that Gen-set A2 was supplying all the power to LB4, plus an additional 15kW. Meter 3 measured 33kW, meaning Gen-set A1 was supplying all the power to LB3 plus producing an additional 18kW. The excess of approximately 33kW, flowing out of Zone 3, was supplied to LB5 and LB6, measured by Meter 5 at 16.5kW and Meter 1 at 15kW. Once all data was verified and recorded into the DAS Database, the static switch was manually opened by the EMS.

When the static switch opened, Meter 1 increased to approximately 30kW satisfying the load demand in LB6, which was 29.65kW and not supplying any power beyond the static switch to microgrid loads. 0kW was measured at Meter 2, showing that power was not flowing through the static switch. LB3, LB4 and LB5 loads reduced slightly to 22.25kW, 15.3kW and 43.4kW, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 29e, from approximately 277V (i.e., 277.5V on A-phase and 275.5V on B- and C-phases) when connected to the utility grid, to 270V on all three phases when islanded.

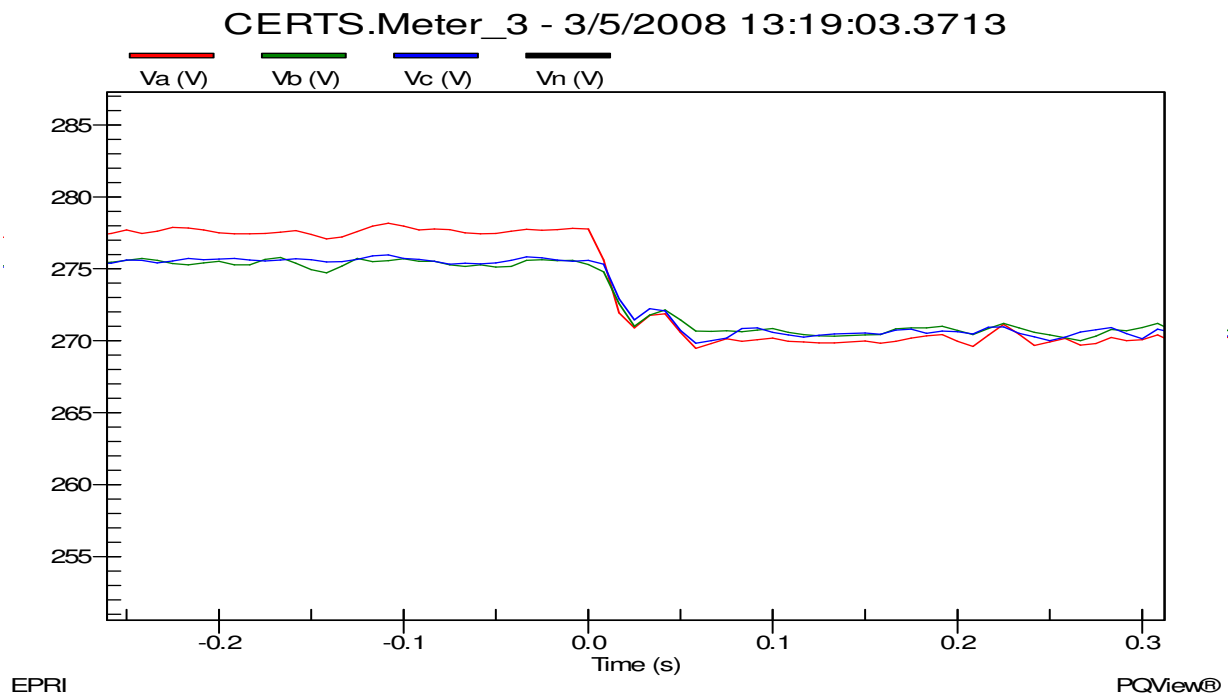

Figure 29e – Meter 3 voltage before/after the static switch opened, islanding the microgrid from the utility grid.

Frequency changed in the microgrid, shown in Figure 29f, and increased to approximately 60.03 Hz which was part of the CERTS algorithm which allowed the Gen-sets to decrease their output power to satisfy the load demands. Gen-set A1, A2 and B1 decreased their output power to approximately 35kW, 26kW and 23kW, respectively. Meter 4 measured approximately -11kW and Meter 3 measured -23kW. Gen-sets A1 and A2 supplied all the power to LB3 and LB4 plus supplied approximately 21kW of LB5 indicated on Meter5. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize to the utility grid.

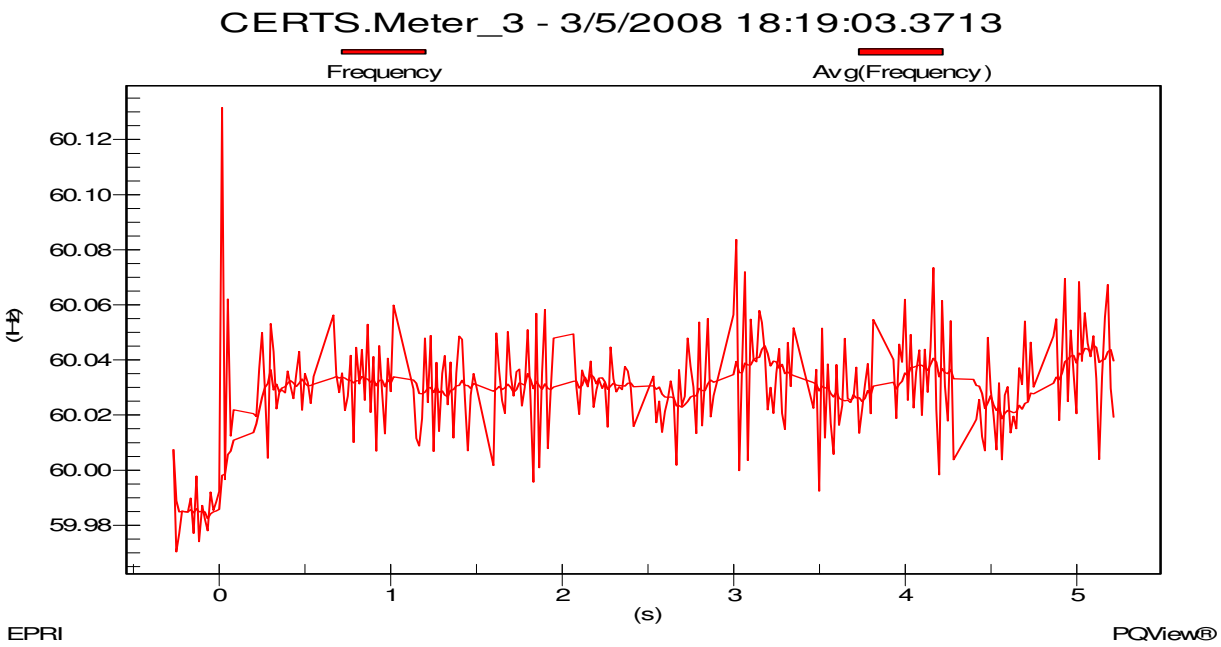

Figure 29f – Meter 3 frequency before/after the static switch opened, islanding the microgrid from the utility grid.

As soon as the static switch closed and steady-state conditions established, the measurements at the Gen-sets, Meters and Load Banks were compared to the initial conditions at the beginning of the test. The measured values were very similar to the initial test conditions which were 13kW at Meter 1, -15kW at Meter 2, -34kW at Meter 3, -16kW at Meter 4, and 16kW at Meter 5 with 40.5kW produced by Gen-set A1, 32kW produced by Gen-set A2, and 29kW produced by Gen-set B1. Likewise, 23.25kW was at LB3, 16.05kW at LB4, 45kW at LB5 and 28.55kW at LB6. The microgrid voltage increased from 270V to 276V and frequency decreased from 60.03Hz to 59.98Hz. The power factor of approximately 0.85 remained the same throughout the test for LB4, 0.91 for LB3 and LB5, and 0.94 for LB6. After all data was verified and recorded into the DAS Database, Gen-sets A1, A2 and B1 were shut down manually and all load banks/alarms were reset and prepared for the next test (9.1.10) in Table 16a.

For Test 9.1.10 the measured values, after the Gen-sets were warmed up and the load banks brought on-line, were approximately 36kW at Meter 1, 7.5kW at Meter 2, 26 kW at Meter 3, 12kW at Meter 4, and -21.5kW at Meter 5. From the microgrid 31.3kW was produced by Gen-set A1, 22.6kW produced by Gen-set A2, and 44.5kW produced by Gen-set B1. The load banks were slightly less than planned with 45.5kW at LB3, 34.55kW at LB4, 22.95 kW at LB5, and 28.35kW at LB6. These measurements were relatively close to the expected values in Table 16a but not exact, due to temperature, phase voltages, and electrical losses in conductors. In addition, the desired kW setting for LB3, LB4, LB5 and LB6 were below the set values. This deviation of set values verses

actual values was consistent with other tests in this section. At the time of these measurements the voltage and frequency was 276V and 59.9785Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 276V and 59.977Hz at Meter 3. The power factor at LB4 was approximately 0.87, 0.91 at LB5, 0.92 at LB3, and 0.94 at LB6 which is close to the desired 0.9 power factor.

9.1.10												
	GENSET A1	GENSET A2	GENSET B1	METER 1	METER 2	METER 3	METER 4	METER 5	LB 3	LB 4	LB 5	LB 6
INITIAL SETUP	UNIT +30kW	UNIT +20kW	UNIT +45kW		+20kW	+40kW		-20kW	50kW	40kW	25kW	30kW
GRID-TO-ISLAND												
Start												
Voltage (V)					276	276						
Current (A)	37	31	55	75	46	54	21.5	26.5				
Real Power (kW)	31.3	22.6	44.5	36	7.5	26	12	-21.5	45.5	34.55	22.95	28.35
Reactive Power (kVAr)	-2	9	9.5	50	39	33	11	1	19.725	19.75	10.74	10.7
Power Factor (pf)	1.00	0.93	0.98						0.92	0.87	0.91	0.94
Frequency (Hz)					59.978	59.977						
End												
Voltage (V)					279	268						
Current (A)	41	40	61	37	0	27	13	31				
Real Power (kW)	32	23.3	45.4	29.6	0	21	9.5	-23	43.2	32.85	22	29.55
Reactive Power (kVAr)	10.9	21.5	19.5	2	0	5	-2.5	-9	18.75	18.75	10.25	11.2
Power Factor (pf)	0.95	0.73	0.92						0.92	0.87	0.91	0.94
Frequency (Hz)					59.9775	59.97						
ISLAND-TO-GRID												
Start												
Voltage (V)					281	270						
Current (A)	42	40	61	39	0	29	12	31				
Real Power (kW)	32.5	23.5	45.5	30	0	21	9	-23.2	43.3	32.9	22.1	29.7

Reactive Power (kVAr)	32.5	21	20	12	0	6	-2.5	-9.5	18.8	18.85	10.25	11.3
Power Factor (pf)	0.71	0.75	0.92						0.92	0.87	0.91	0.93
Frequency (Hz)					59.995	59.98						
End												
Voltage (V)					275	277						
Current (I)	37	27	54	80	52	59	22.5	25				
Real Power (kW)	30	21.25	43	40	12	29.5	13.75	-20	45.6	34.7	23.5	28.4
Reactive Power (kVAr)	30	8	9	51	40	35	11	1.9	19.8	19.85	10.75	10.75
Power Factor (pf)	0.71	0.94	0.98						0.92	0.87	0.91	0.94
Frequency (Hz)					59.99	59.99						

Table 16e - Test 9.1.9 results with dark squares in the table meaning that measurements were not needed.

According to the measurements in Table 16e, Gen-sets in the microgrid were set at 30kW for Gen-set A1, 20kW for Gen-set A2 and 45kW for Gen-set B1, which was not enough to satisfy the loads in LB3 and LB4 and needed approximately 7.5kW from the utility grid, measured by Meter 2. The utility grid supplied a total power of approximately 36kW, measured in Meter 1, because it met the demands of not only the microgrid loads, but the load at LB6l. Meter 5 measured approximately -21.5kW, meaning Gen-set B1 supplied all the power to LB5 and exported some power to LB3 and LB4. The power exported from the utility grid and Gen-set B1 was approximately 26kW into LB3 and LB4, measured by Meter 3. Meter 4 measured 12kW meaning that LB3 needed an additional 14kW on top of the power produced by Gen-set A1 and LB4 needed an additional 12kW on top of the power produced by Gen-set A2. Once all data was verified and recorded into the DAS Database, the static switch was manually opened by the EMS.

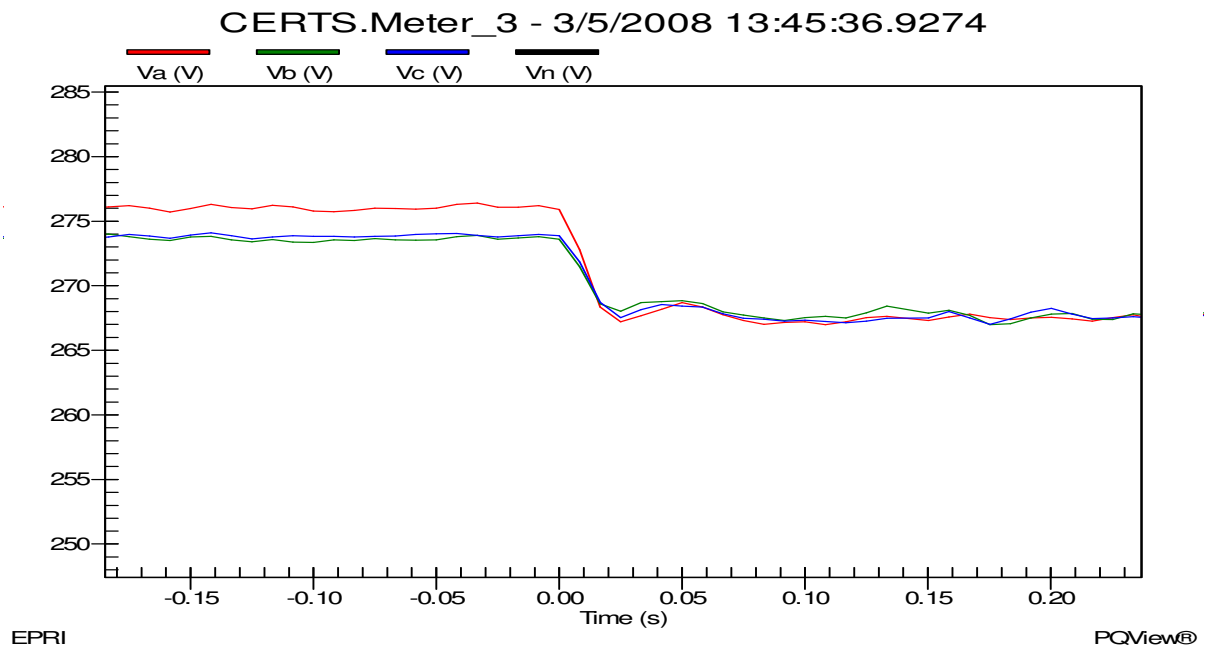

Figure 29g – Meter 3 voltage before/after the static switch opened, islanding the microgrid from the utility grid.

When the static switch opened, Meter 1 decreased to approximately 29.6kW satisfying the load demand in LB6, which was approximately 29.55kW and not supplying any power beyond the static switch to microgrid loads. 0kW was measured at Meter 2, showing that power was not flowing through the static switch. LB3, LB4 and LB5 loads reduced slightly to 43.2kW, 32.85kW and 22kW, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 29g, from approximately 276V (i.e., 276V on A-phase and 274V on B- and C-phases), when connected to the grid, to 268V on all three phases when islanded.

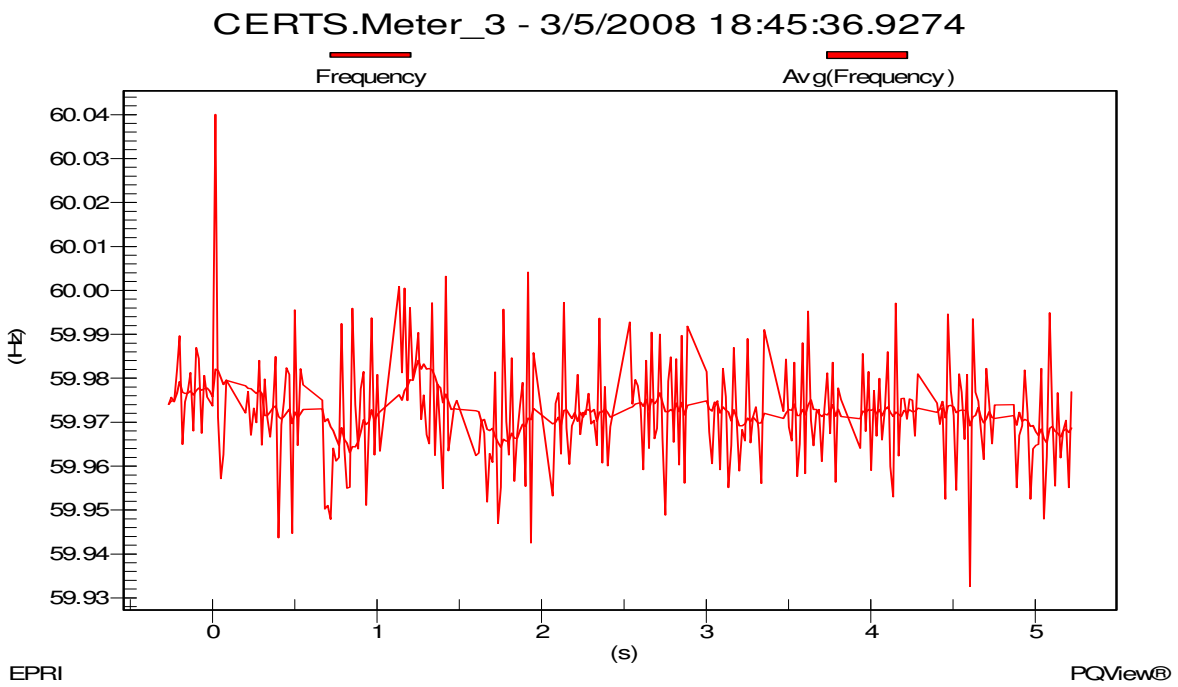

Figure 29h – Meter 3 frequency before/after the static switch opened, islanding the microgrid from the utility grid.

Frequency in the microgrid changed slightly, as shown in Figure 29h to approximately 59.97 Hz which was part of the CERTS algorithm which allowed the Gen-sets to increase their output power to satisfy the load demands. Gen-set A1, A2 and B1 increased output power to approximately 32kW, 23.3kW and 45.5kW, respectively. Meter 5 measured approximately -23kW meaning that Gen-set B1 supplied all the power to LB5 and exported some of its power to LB3 and LB4. The power exported from Gen-set B1 was approximately 21kW into LB3 and LB4, measured by Meter 3. Meter 4 measured approximately 9.5kW, meaning LB3 needed an additional 11.5kW on top of the power produced by Gen-set A1 and LB4 needed and additional 9.5kW on top of the power produced by Gen-set A2. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before manual open signal was released and allowed the static switch to synchronize to the utility grid.

As soon as the static switch closed and steady-state conditions established, the measurement values in Table 16e were compared to the initial conditions at the beginning of the test. The measured values were very similar to initial test conditions which were approximately 40kW at Meter 1, 12kW at Meter 2, 29.5kW at Meter 3, 13.75kW at Meter 4, and -20kW at Meter 5 with 30kW produced by Gen-set A1, 21.25kW produced by Gen-set A2, and 43kW produced by Gen-set B1. Likewise, 45.6kW was at LB3, 34.7kW at LB4, 23.5kW at LB5 and 28.4kW at LB6. The microgrid voltage increased from 270V to 277V and frequency increased from 59.98Hz to 59.99Hz. The power factor remained the same throughout the test with 0.87 for LB4, 0.91 for LB5, 0.92 for LB3 and

0.94 for LB6. After all data was verified and recorded into the DAS Database the Gen-sets A1, A2 and B1 were shut down manually by the EMS, and all the loads/alarms were reset and prepared for the next planned tests.

7.0 CONCLUSION

The tests in section 9.0 "Demonstration Tests of Control Power Flow" were all successfully performed to as predicted. These successful tests provide confidence that the CERTS algorithms real power versus frequency and reactive power versus voltage work for the Gen-sets in unit and zone power control modes while utility connected and islanded.

Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 10.0
Difficult Loads

APPENDIX M

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CERTS MICROGRID TEST REPORT

SECTION 10.0

"Difficult Load Tests"

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as "islanded" from it. This paper describes the tests that were performed in Section 10.0 "Difficult Load Tests" of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility's distribution system, isolating the microgrid's load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility's electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to a 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

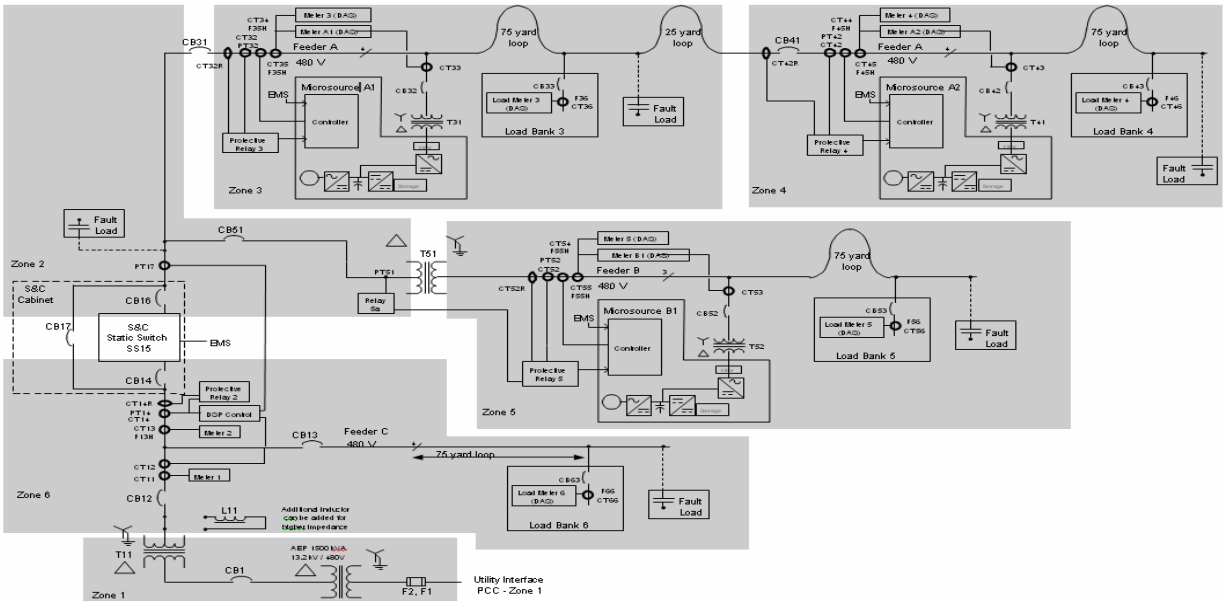

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

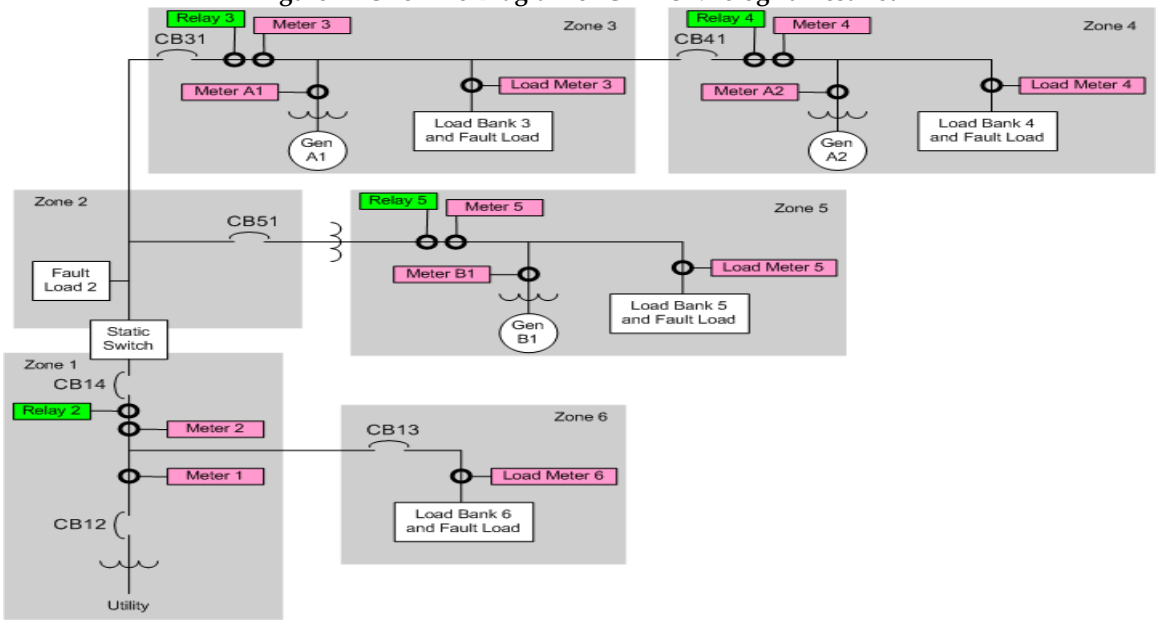

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

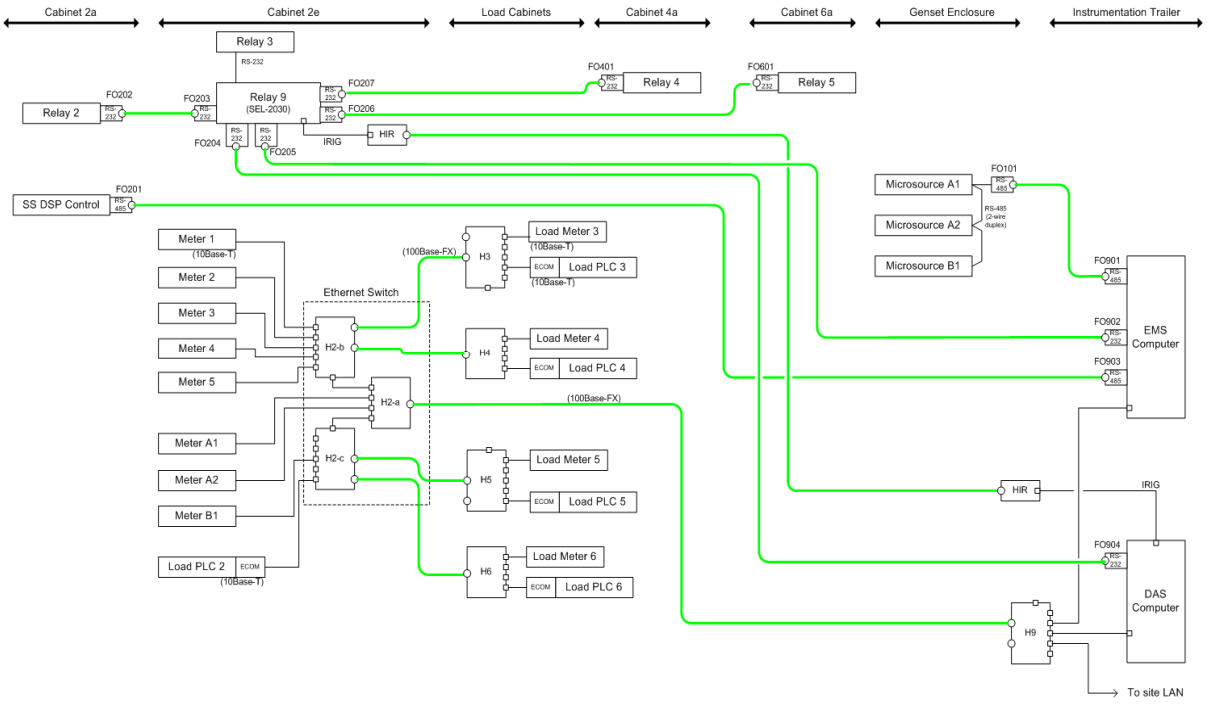

Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – "Purpose, References, and Definitions" describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – "Responsibilities" informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.

- Section 3 – "Training - Team Members" lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.

- Section 4 – "Procedure – CERTS Microgrid Test Bed Lockout/Tagout" entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.

- Section 5 – "Procedure – General" is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.

- Section 6 – "Procedure – Microgrid Test Bed System Checkout" was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.

- Section 7 – "Validate Protection Settings & Initial Fault Testing" is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.

- Section 8 – "Procedure – Reduced System Tests" is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.

- Section 9 – "Procedure – Demonstration Tests of Control Power Flow" demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – "Procedure – Test Difficult Loads" determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.

- Section 11 - "Hazards & Mitigation" informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.

- Section 12 – "Quality Assurance" ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 10.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate "Closed", not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a "Red" plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

Section 10 tests were developed to determine operation limits of the Microgrid (i.e., power quality, protection and inverter limits) with low power factor (pf) loads, motor loads, harmonic load and unbalance loads.

For Section 10, weak grid conditions were planned in the beginning of the test plan to minimize any damage to equipment. However, time constraints forced a decision by the Team to postpone strong grid testing to a later date with concentration on weak grid testing. Motor start tests done in Test 10.2 had balanced loads at 0.9 in power factor in a weak grid scenario, while connected to the utility grid and islanded. These tests were to verify and document power flow, Microgrid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and then repeat motor start test during an islanded mode of operation. Test 10.3 is similar to Test 10.2, except that the loads are now unbalanced with a 0.9 power factor.

In Test 10.4 tests were created to verify and document power flow, Microgrid frequency changes and protection design with different Gen-set settings during changes of unbalanced load in Load Banks. Test 10.5 is similar to Test 10.4, except that the loads are balanced. Power factor tests with unbalanced loads were tested in Test 10.6 which was designed to verify and document power flow, Microgrid frequency changes and protection design with different Gen-set settings during changes of power factor of unbalanced load in Load Banks.

Tests 10.7 – 10.15 are similar tests that verify and document power flow, Microgrid frequency changes and protection design with different Gen-set settings. Changes of harmonic loads in different Zones with a motor start and balanced load in Load Banks were planned.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 10 – DIFFICULT LOAD TESTS

To maintain a common understanding of Gen-set control modes and power flows during tests described in the following sections, it is important to know the difference

between unit power control mode and zone control mode and positive versus negative power flow.

Unit power control mode involves the amount of power (i.e., kW) injected into the Zone from the Gen-set being controlled. Zone power control mode involves the amount of power (i.e., kW) entering/exiting the Zone which controls the output of the Gen-set in that zone.

Positive power flow recorded by Meter 1, Meter 2, Meter 3, Meter 4 and Meter 5 are in the direction from the utility going downstream into the microgrid. Negative power flow through these meters means that the power is flowing from the Gen-sets out towards the utility. For example, if Meter 2 (i.e., static switch) recorded a power flow of -20kW + j35kVAr then real power is flowing from the Gen-sets through the static switch out into Zone 6 and reactive power is flowing in the opposite direction from Zone 6 into the critical loads of the microgrid (Zones 2, 3, 4 and 5). Positive power flow recorded by Meters A1, A2 and B1 are what the Gen-sets are producing and negative power flow is what the Gen-sets are absorbing. This is vice versa for Meters LB3, LB4, LB5 and LB6 meaning that a positive power flow is what the Load Bank is absorbing. Load Bank meters will never have a negative power flow.

6.1.1 Motor Start Tests, Weak Grid, Balanced Load with 0.9 Power Factor

Performance Goal:

Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and then repeat motor start test during an islanded mode of operation.

Six tests were completed in this section with each test event and settings listed in Table 1. During each test Gen-sets A1 and A2 were both set for either unit or zone power control mode of operation. Each of the six tests varied the output power command set-point in each Gen-set, along with varying the load settings in load banks LB3, LB4 and LB6. During each test, inductor L11 was in series with the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Test Event	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
10.2.12	Unit	Unit	+20kW	-20kW	-20kW	+10kW	10kW	40kW	40kW

	+40kW	+30kW							
10.2.14	Unit +40kW	0kW	+10kW	-30kW	-30kW	0kW	10kW	0kW	40kW
10.2.15	Unit +40kW	Unit +30kW	+70kW	+30kW	+30kW	+20kW	50kW	50kW	40kW
10.2.17	Unit +40kW	0kW	+20kW	-20kW	-20kW	0kW	20kW	0kW	40kW
10.2.18	Zone -10kW	Zone +10kW	+30kW	-10kW	-10kW	+10kW	20kW	40kW	40kW
10.2.20	Zone -20kW	0kW	+20kW	-20kW	-20kW	0kW	20kW	0kW	40kW

Table 1 -Balance Load, Weak Grid, Before Motor Start settings of Gen-sets and Load Banks

The procedure for each test event began with setting the kW and kVAr load (i.e., balanced load) conditions, as indicated in Table 1. Before loads were brought on-line, Gen-sets A1 and A2 or just Gen-set A1 depending on the test setup, were started to allow them to warm up. After the Gen-sets ran for a few minutes and steady-state conditions established, the loads were brought on-line, the static switch was allowed to close, and measurements were taken from Meters 1, 2, 3 and 4. The measurements were then compared with the expected values in Table 1. When the measured values coincided with the expected values from the table, then a 10Hp motor was started in Zone 3 with the dynamometer set in ft-lbs at 100% motor rating. When all measurements were verified and recorded in the DAS Database for before and after the motor start, the motor was turned off and the manual open signal to the static switch was initiated. This allowed the static switch to open and separate the microgrid from the utility grid. Gen-sets were observed at this time to make sure they increased or decreased their output power as planned to satisfy the loads at load banks (i.e., LB3, LB4 and LB6) and that a smooth transition occurred. When all the measurements were verified and recorded in the DAS Database, the 10Hp motor was started again with the dynamometer set in ft-lbs for 100% motor rating. Once all measurements were verified and recorded in the DAS Database for before and after the motor start, the manual open signal to the static switch was released. Releasing the manual open signal allowed the static switch to synchronize and reclose. All data (i.e., from the manual open event and the reconnection event) was verified and recorded in the DAS Database. Loads, power control set-points and operation modes were then changed to the settings for the next test. Test results are explained in the following paragraphs.

For Test 10.2.12 the measured values, after the Gen-sets were warmed up and load banks brought on-line, were approximately 12kW + j24kVAr at Meter 1, -24kW + j22kVAr at Meter 2, -27kW + j16kVAr at Meter 3 and 3.5kW + j5kVAr at Meter 4. From the microgrid, 41kW – j12kVAr was produced by Gen-set A1 and 33kW – j3kVAr was produced by Gen-set A2. The load banks were 11kW + j0kVAr at LB3, 35.9kW + j0.645kVAr at LB4 and 35.9kW + j0.6975kVAr at LB6. These measurements were relatively close to the expected values in Table 1, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB4 and LB6 were also below selected set values. The deviation of selected values versus actual values was consistent for the other five tests in this section. At the time of these measurements, the voltage and frequency was 281.5V on A-phase, 279V on B-phase and 279V on C-phase and 59.98Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282V on A-phase, 280V on B-phase and 280V on C-phase and 59.98Hz at Meter 3.

The Gen-sets in this test were set up to produce more power than Load Banks 3 and 4 needed which approximately 24kW of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 35.9kW + j0.6975kVAr, the utility had to supply approximately 12kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 22kVAr because Gen-sets A1 and A2 needed approximately 15kVAr between the two and the reactive power of Load Banks 3 and 4. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

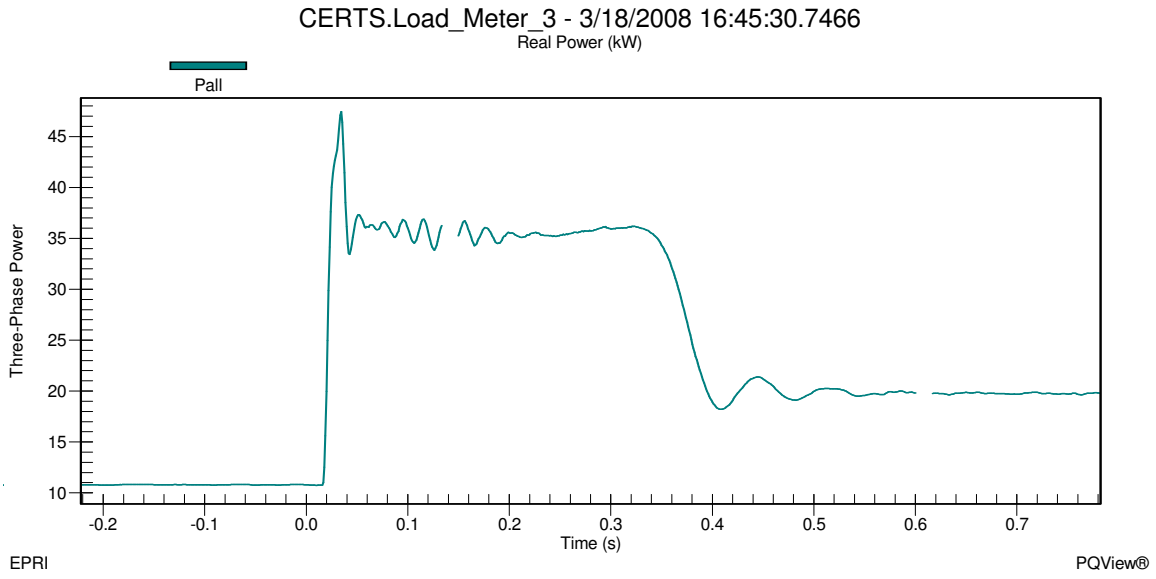

Figure 5a - Load Bank 3 Real Power Motor Start and Utility Connected for Test 10.2.12

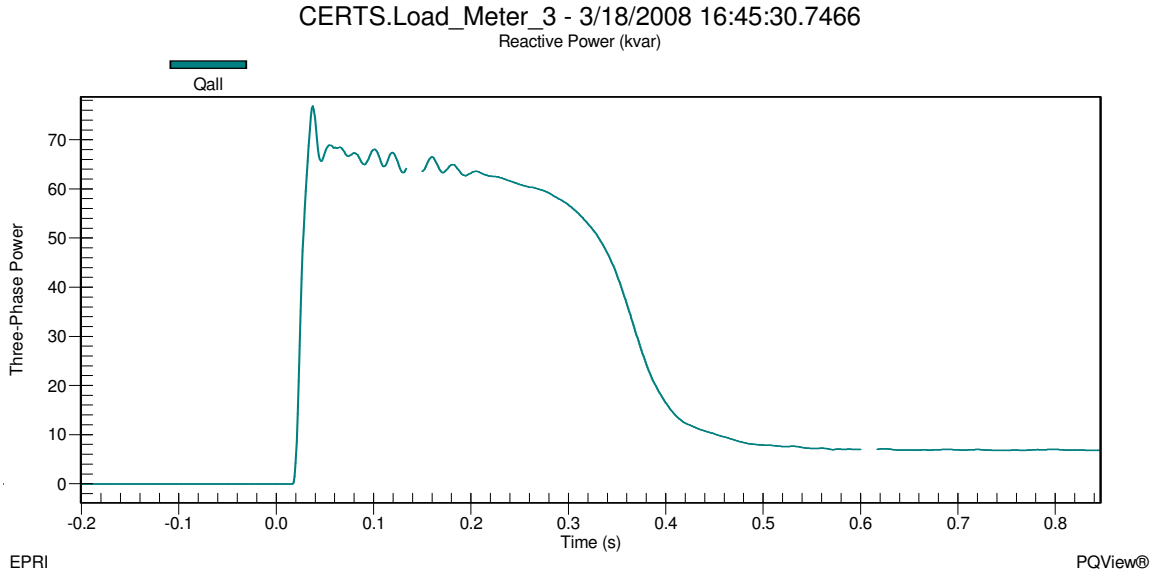

Figure 5b - Load Bank 3 Reactive Power during Motor Start and Utility Connected for Test 10.2.12

In Figures 5a and 5b it can be seen that the load in Zone 3 was approximately 10.9kW + j0kVAr before the start of the induction motor and increased to approximately 47.4kW + j77kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 35.6kW + j64kVAr during the warm up phase which

lasted about 24 cycles (0.40 seconds). When the motor reached steady state, the load in Zone 3 was approximately 19.9kW + j6.9kVAr.

The voltage and frequency at the static switch before the motor start was approximately 281.2V on A-phase, 278.7V on B-phase and 279V on C-phase shown in Figure 5c and approximately 59.97Hz shown in Figure 5d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.3V on A-phase, 271.4V on B-phase and 272.4V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.90Hz and quickly increased back to the starting frequency of approximately 59.97Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 280.6V on A-phase, 278.4V on B-phase and 278V on C-phase at an approximate frequency of 59.97Hz.

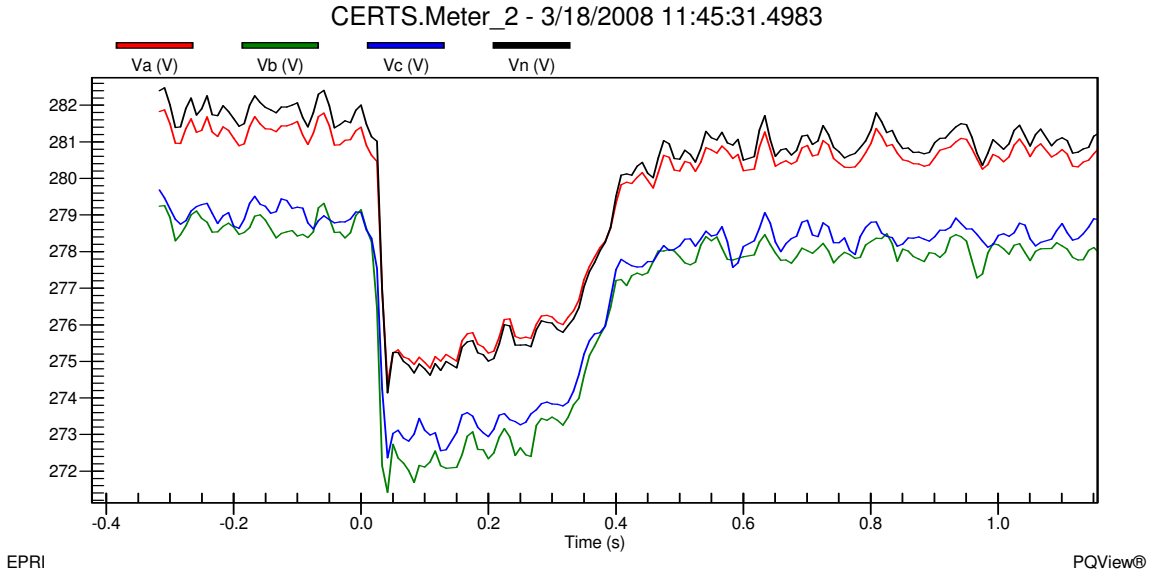

Figure 5c – Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.2.12

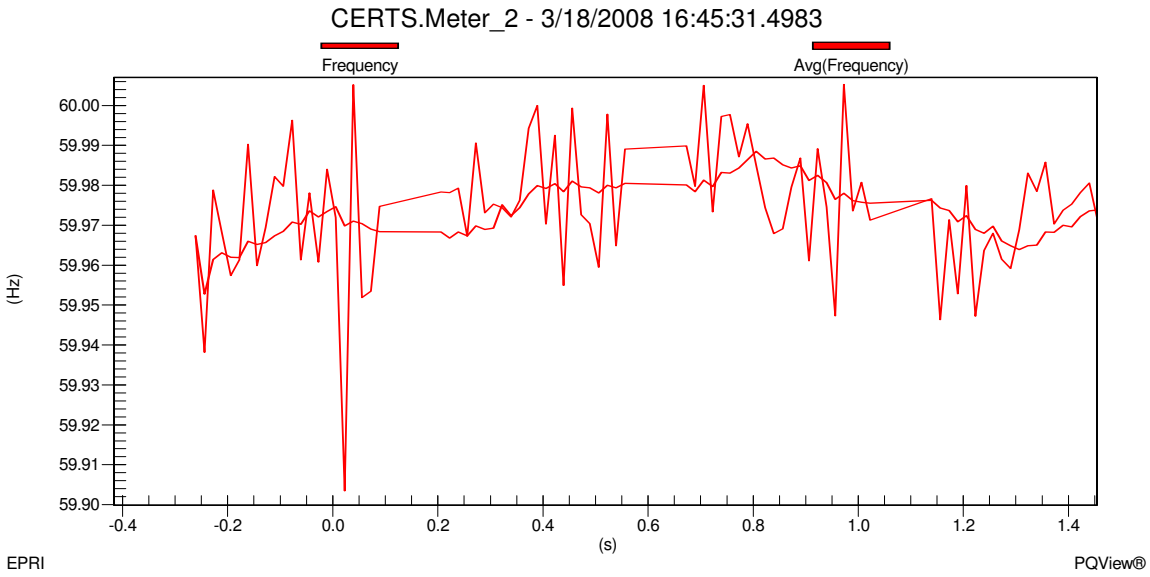

Figure 5d – Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.12

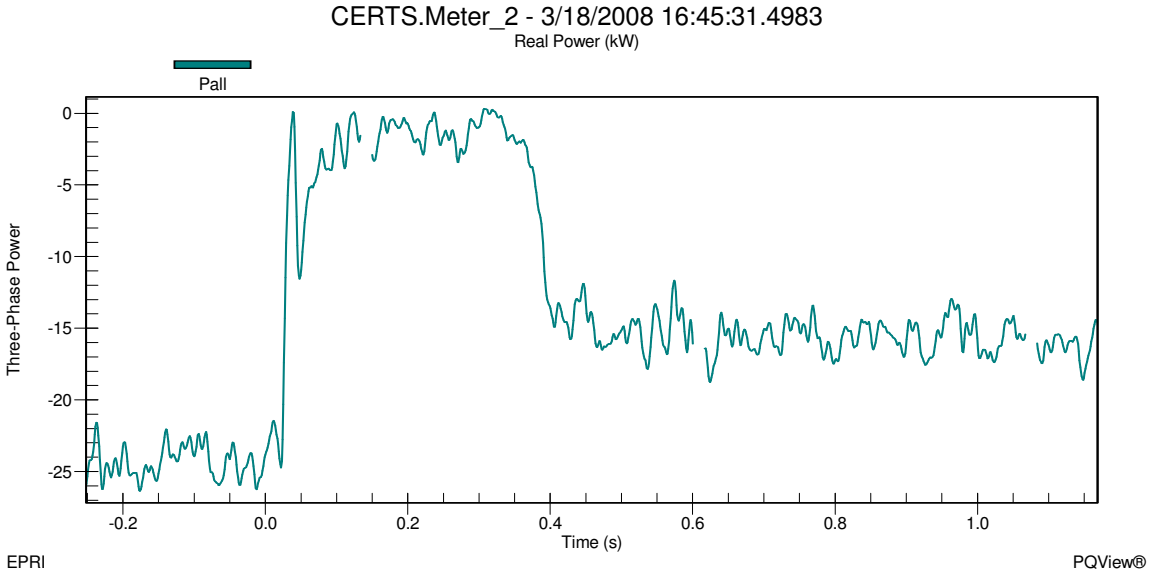

Figure 5e - Static Switch Real Power during Motor Start and Utility Connected for Test 10.2.12

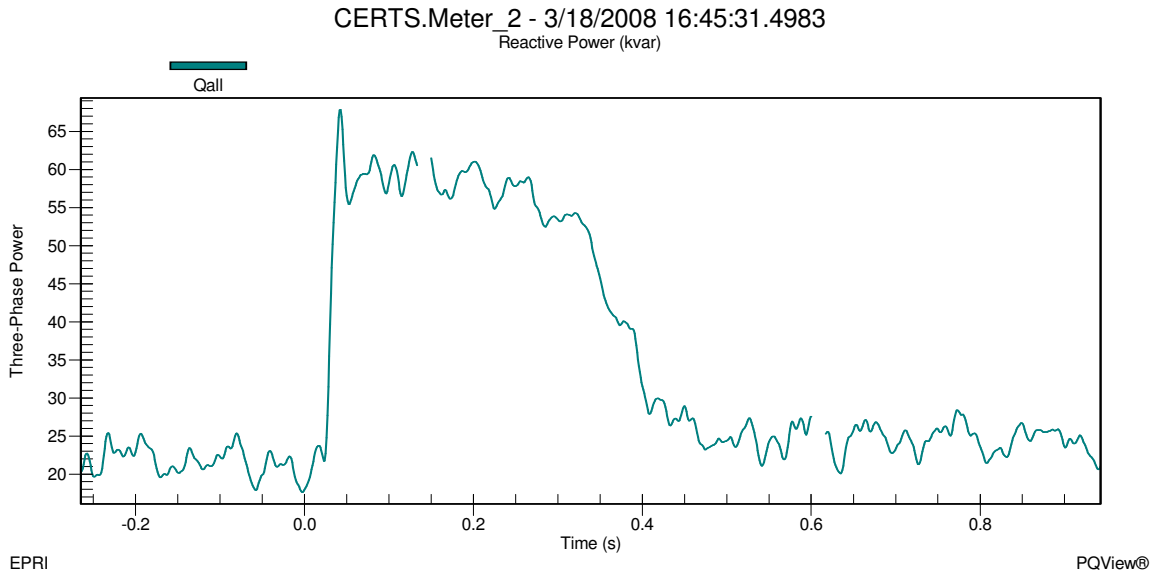

Figure 5f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.12

Before the motor started Gen-sets A1 and A2 were producing approximately 41.1kW – j12kVAr and 32.6kW – j3.8kVAr, respectively. This was enough for the load demands of Zones 3 and 4 with real power being exported to Zone 6 of approximately 24kW shown in Figure 5e. The grid was supporting the reactive power of the microgrid with approximately 22kVAr shown in Figure 5f. When the motor started the inrush caused the utility to supply approximately 68kVAr and to pick up the load demand of Load Bank 6. The power that was being supplied by Gen-sets A1 and A2 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 5e as the real power through the static switch becomes 0kW. Gen-sets A1 and A2 increased their real and reactive power output levels to approximately 45.9kW + j1.5kVAr and 40.4kW + j15.9kVAr, respectively. Notice the signs of the VAr output changed from negative to positive for both Gen-sets in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -15.8kW + j24.2kVAr which meant that Gen-sets A1 and A2 were supplying the power for the induction motor and approximately 15.8kW of Load Bank 6. Gen-sets A1 and A2 real power returned to the values before the motor started of approximately 41.1kW and 32.6kW, respectively, and the reactive power increased to approximately -10.5kVAr in Gen-set A1 and -1.9 in Gen-set A2. Once all data was

verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 37kW and reactive power decreased to 0kVAr satisfying the load demand in Load Bank 6 which was approximately 36.6kW + j0kVAr and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Banks 3 and 4 loads reduced slightly to 10.5kW – j0.039kVAr and 34.5kW + j0.685kVAr, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 5g, from approximately 282V on A-phase, 280V on B-phase and 280V on C-phase when connected to the utility grid to 275V on A-phase, 275V on B-phase and 276V on C-phase at Meter 3 when islanded.

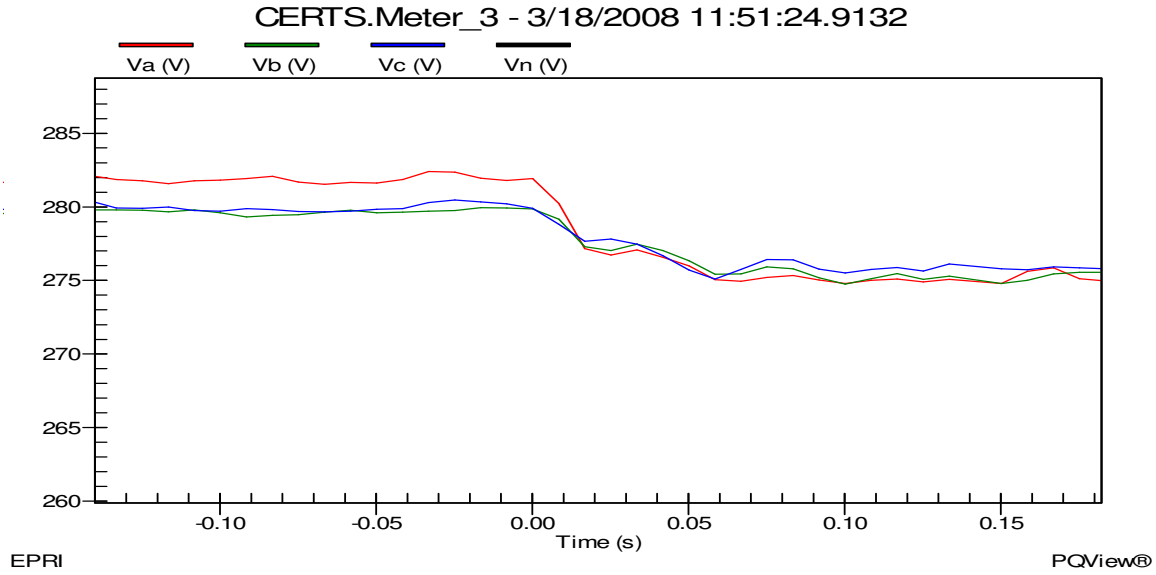

Figure 5g – Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.12

Frequency change in the microgrid, shown in Figure 5h, increased from approximately 60.02Hz when connected to the utility grid to approximately 60.08Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to decrease their output power to satisfy the load demands. Gen-set A1 and A2 decreased their output real power to approximately 28.5kW and 19.5kW, respectively and increased their output reactive power to approximately 2.5kVAr and 2.5kVAr,

respectively. Meter 3 was approximately -3.8kW + j0.4kVAr indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

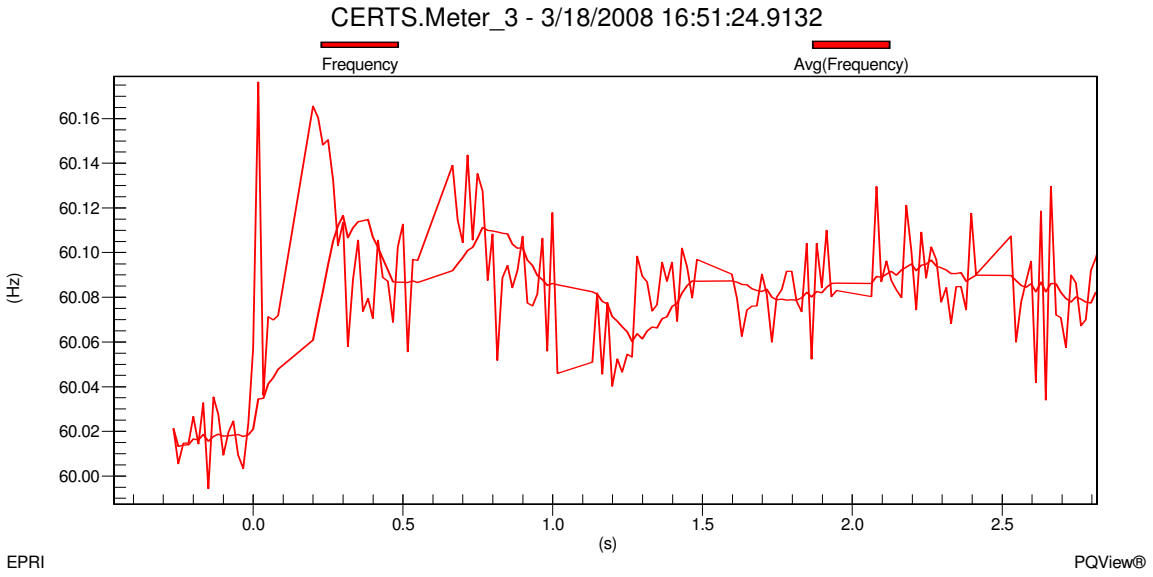

Figure 5h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.12

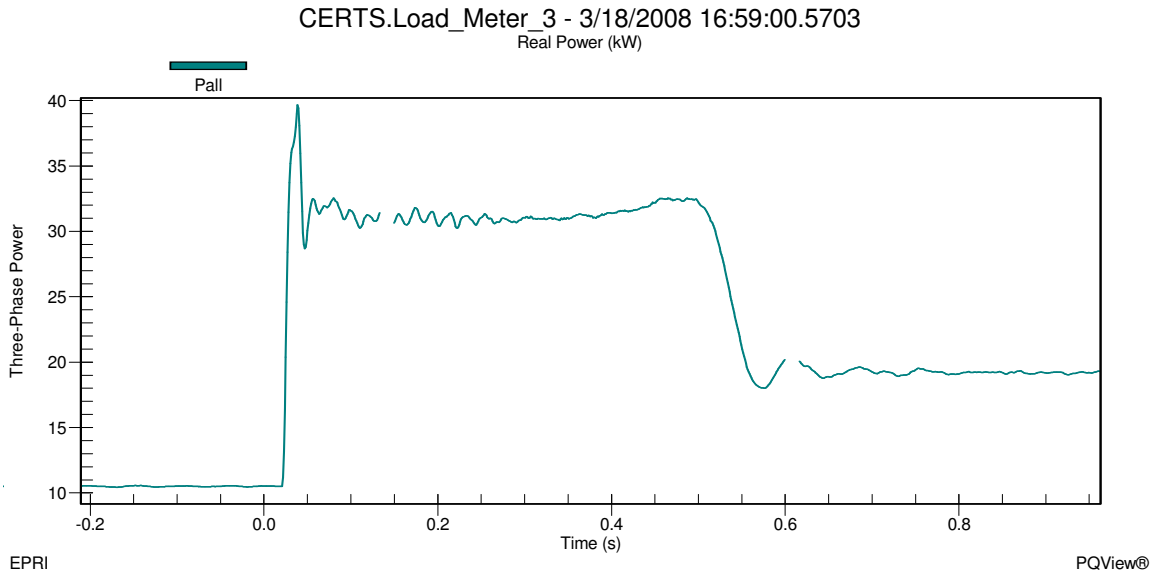

Figure 5i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.12

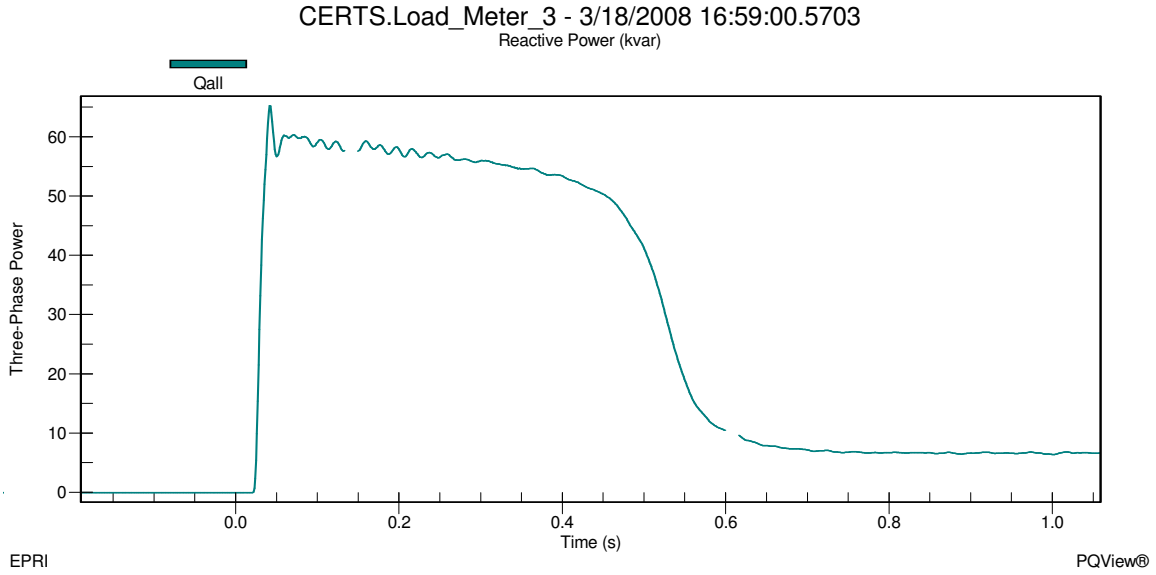

Figure 5j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.12

In Figures 5i and 5j it can be seen that the load in Zone 3 was approximately 10.5kW + j0kVAr before the start of the induction motor and increased to approximately 39.7kW + j65kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 31kW + j56kVAr during the warm up phase which lasted

about 39 cycles (0.65 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 19.2kW + j6kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 275V (i.e., 275V on A-Phase, 275V on B-Phase and 275V on C-phase) shown in Figure 5k and approximately 60.09Hz shown in Figure 5l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 256V (i.e., 256V on A-Phase, 256V on B-Phase and 256V on C-Phase) for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.99Hz and quickly increased to approximately 60.01Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 273V (i.e., 273V on A-Phase, 273V on B-Phase and 273V on C-Phase) at an approximate frequency of 60.05Hz.

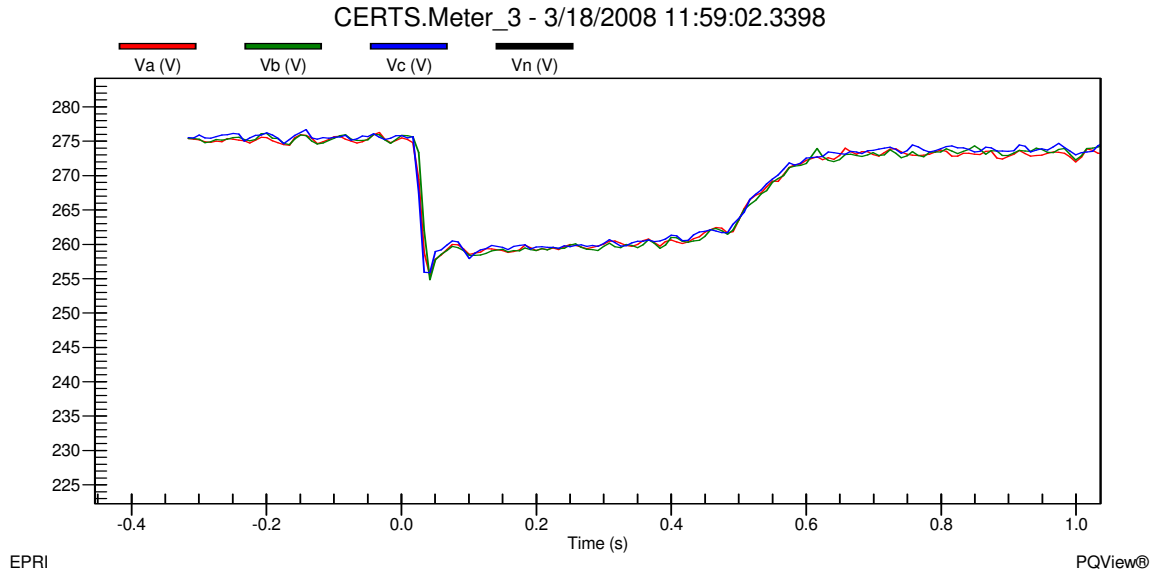

Figure 5k – Meter 3 Line-to-Ground Voltage during Motor Start and Islanded for Test 10.2.12

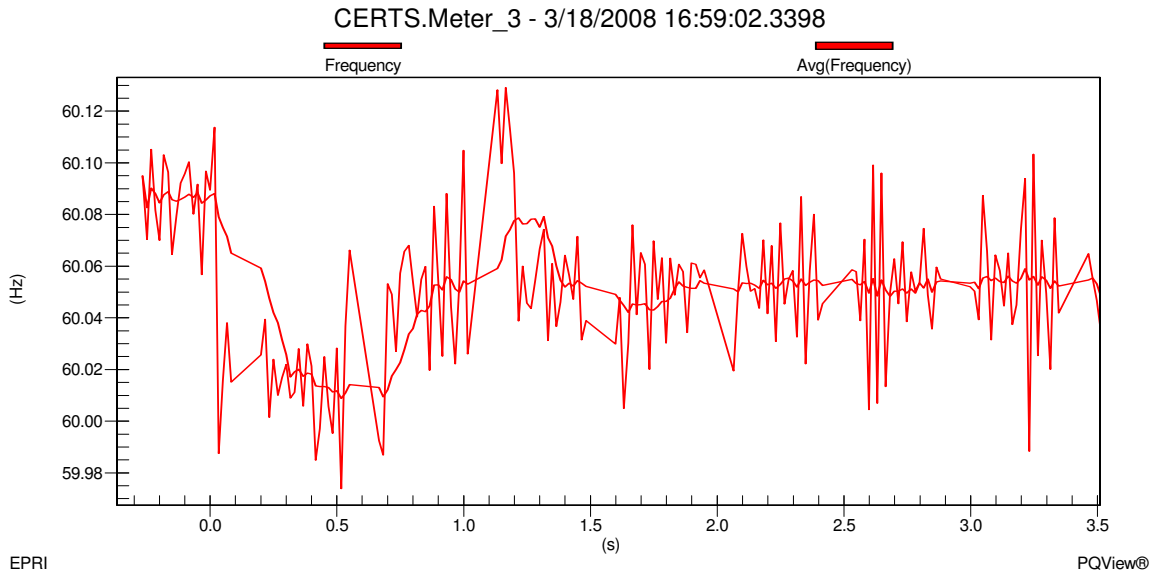

Figure 5l – Meter 3 Frequency during Motor Start and Islanded for Test 10.2.12

Before the motor started Gen-sets A1 and A2 were producing approximately 28.1kW - j2.8kVAr and 19.4kW + j7kVAr, respectively shown in Figures 5m – 5p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output levels to 38.9kW + j30.5kVAr for Gen-set A1 and 32.5kW + j37.7kVAr for Gen-set A2. The Gen-sets decreased their output levels while the motor was warming up and eventually dropped to 32kW + j0.2kVAr for Gen-set A1 and 23.6kW + j10kVAr for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

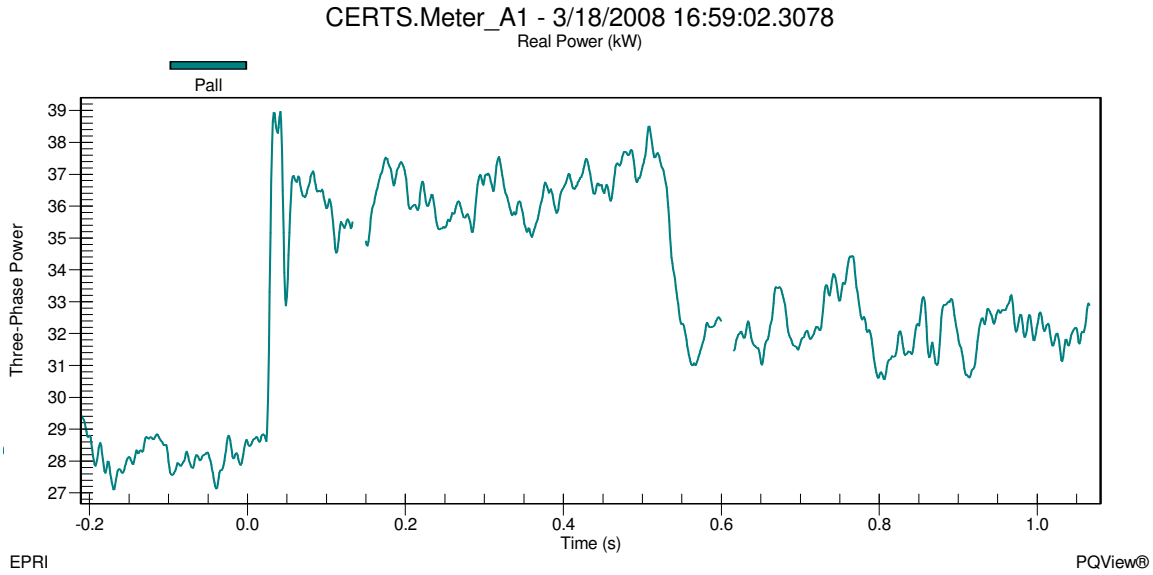

Figure 5m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.12

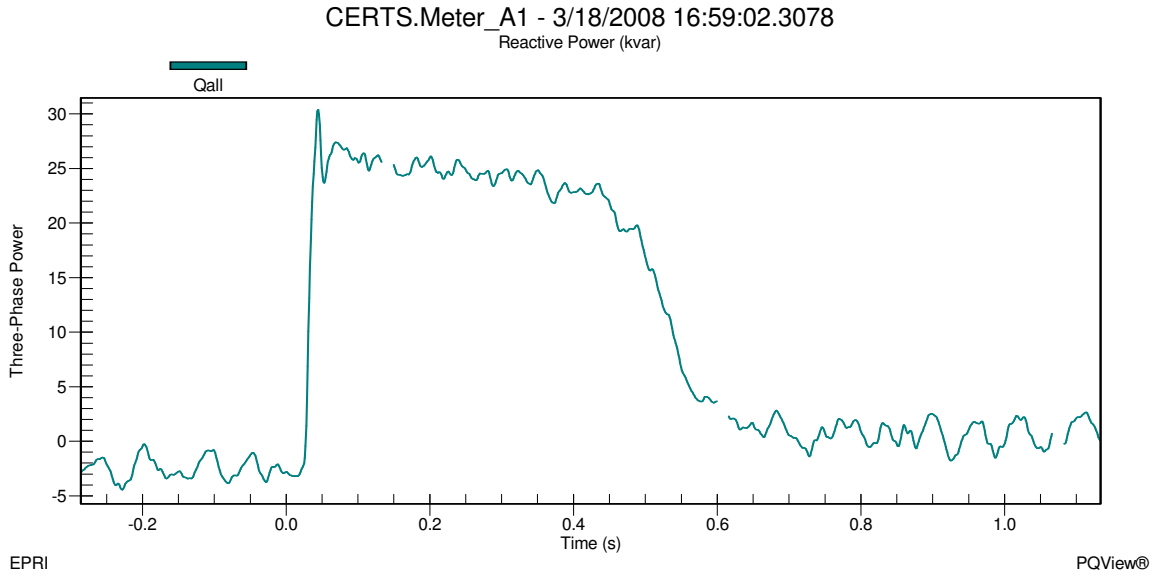

Figure 5n - Gen-Set A1 Reactive Power during Motor Start and Islanded for Test 10.2.12

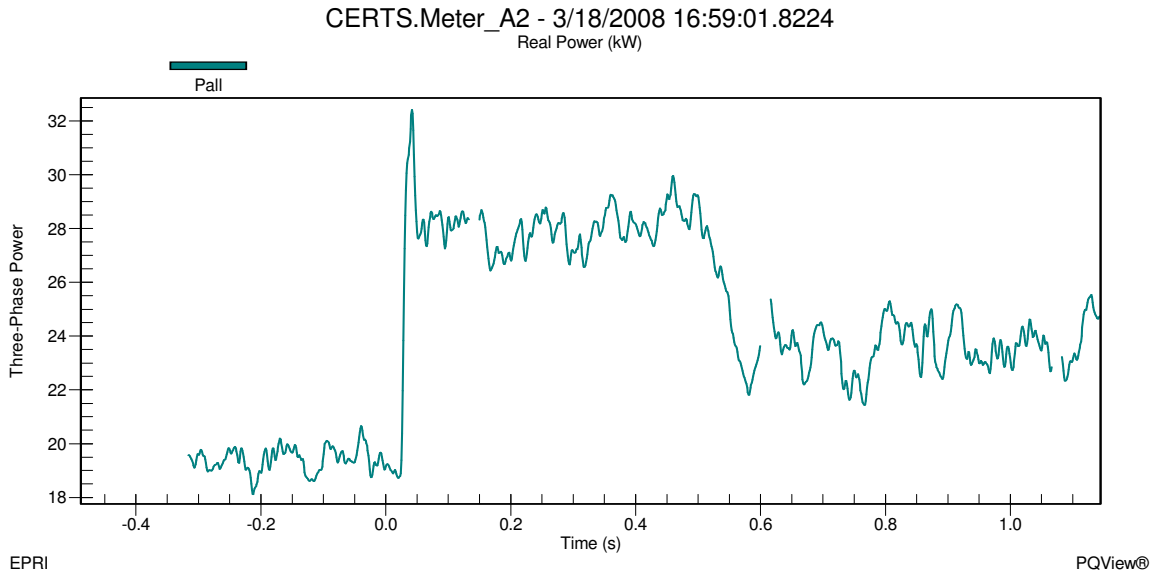

Figure 5o - Gen-set A2 Real Power during Motor Start and Islanded for Test 10.2.12

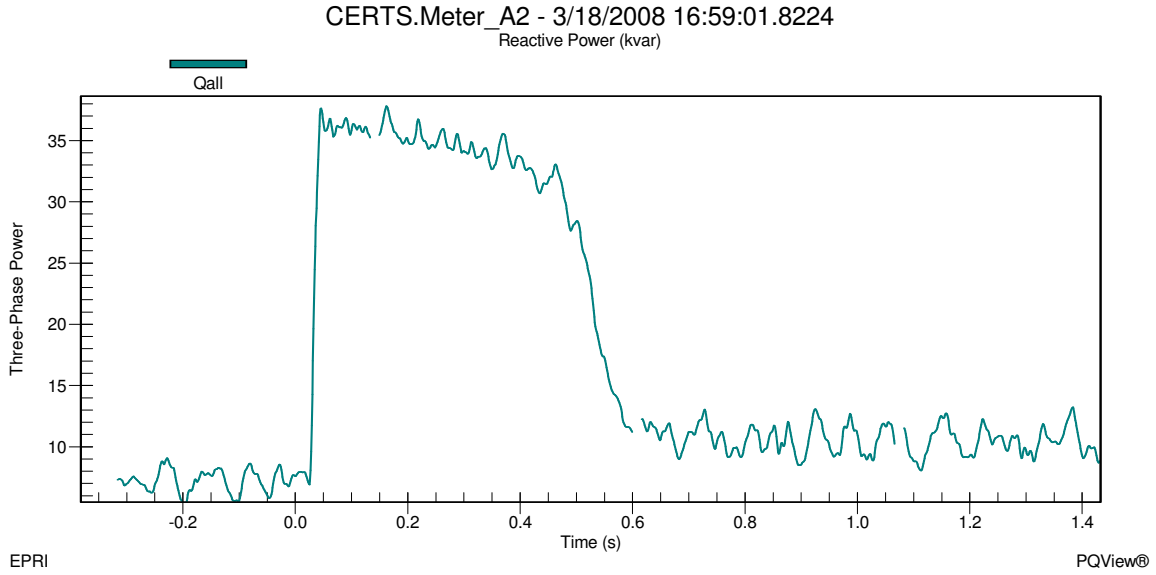

Figure 5p - Gen-set A2 Reactive Power during Motor Start and Islanded for Test 10.2.12

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 37kW to 24kW and reactive power increased from approximately 0kVAr to 28kVAr which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 5q and 5r show the static switch decreasing from approximately 0kW to -11.5kW and increasing from approximately 0kVAr to 27kVAr. At the beginning of the test, the initial power flow through the static switch was -24kW + j22kVAr which is not the same recorded at this

point in the test because the 10Hp motor load is on in Zone 3. The Gen-sets have picked up the motor load and supporting Load Bank6 with approximately 11.5kW.

Load Banks 3 and 4 loads increased slightly to 35.7kW + j0.71kVAr and 17.95kW + j6.15kVAr, respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 5s, from approximately 273.8V (i.e., 273.8V on A-phase, 273.8V on B-phase and 273.8V on C-phase) when islanded to 281.8V on A-phase, 279.2V on B-phase and 279.2V on C-phase at Meter 3 when connected to the utility grid.

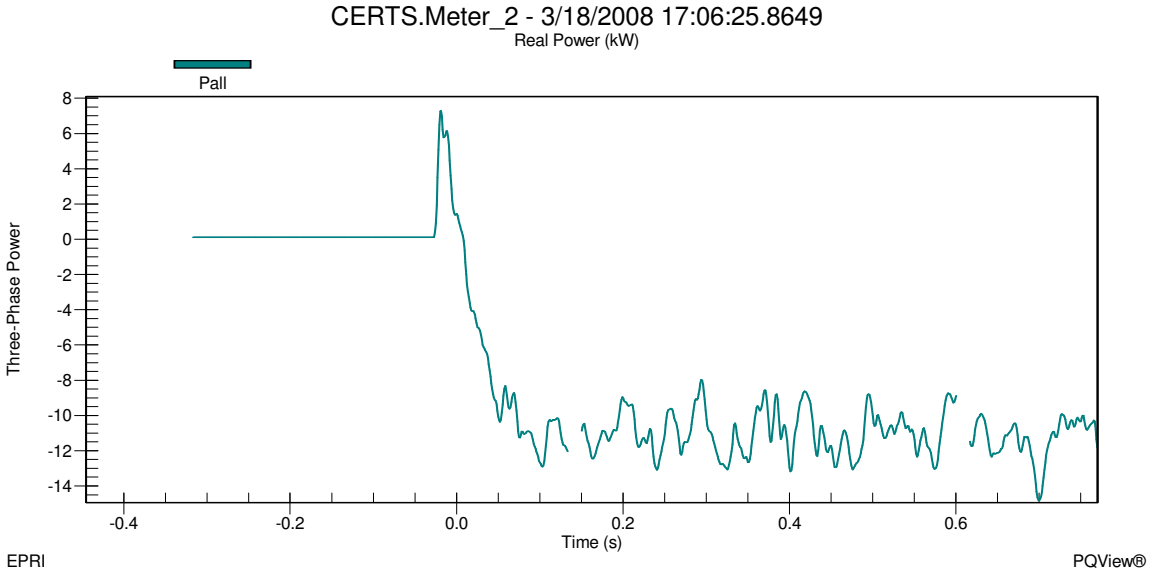

Figure 5q – Static Switch Real Power during Island to Utility Connected mode for Test 10.2.12

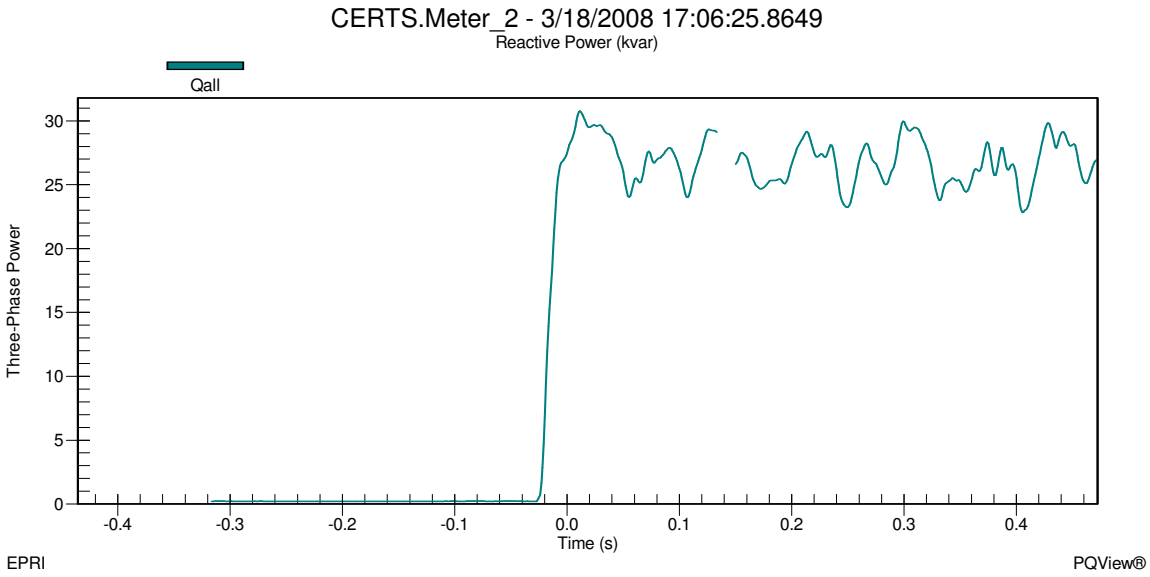

Figure 5r – Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.12

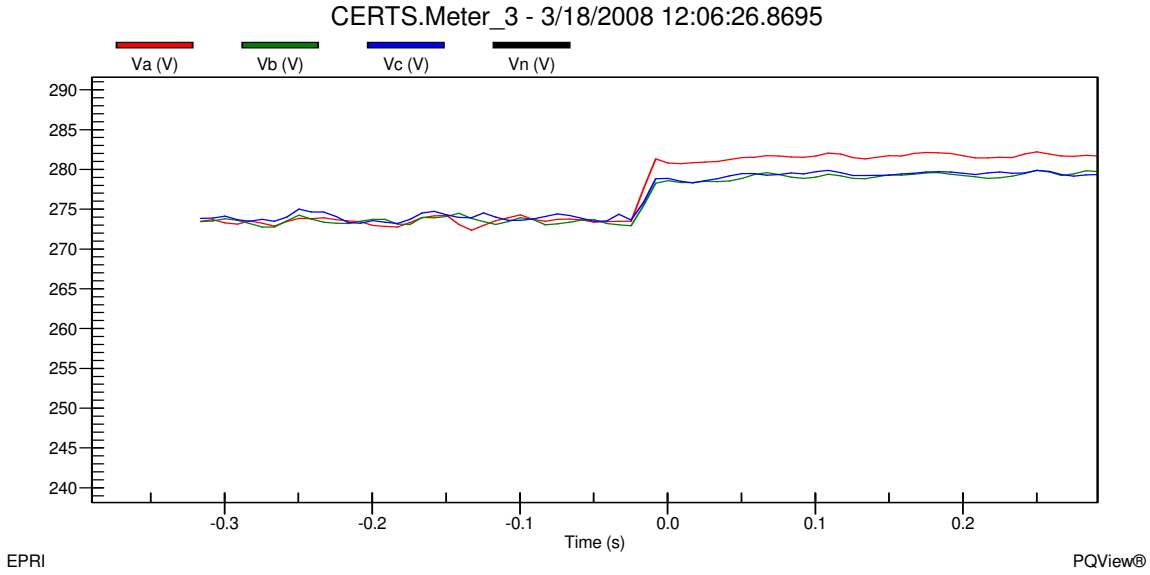

Figure 5s - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.12

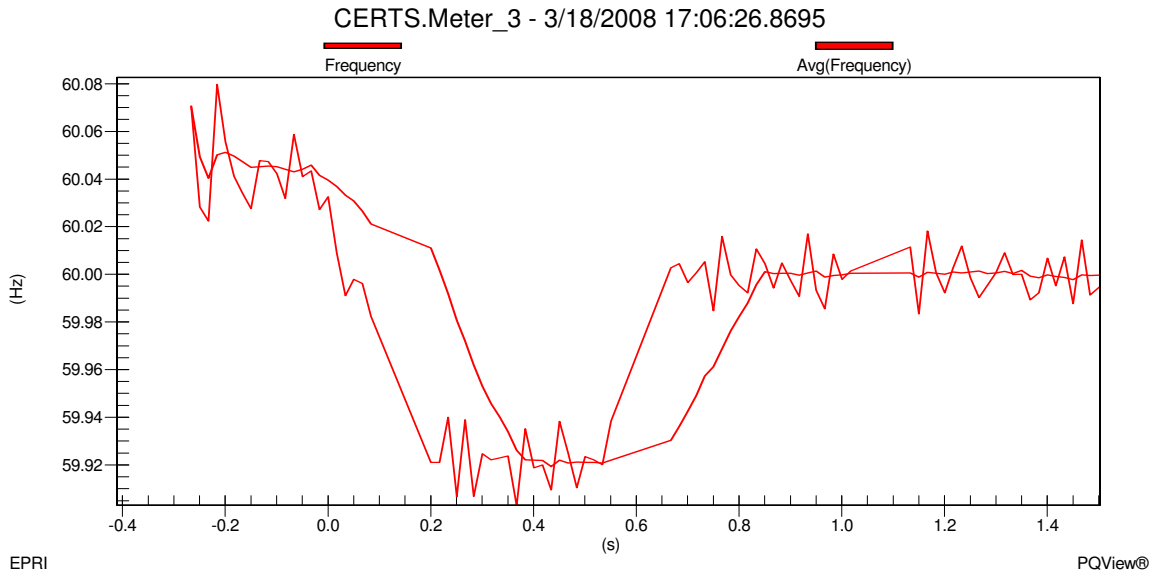

Figure 5t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.12

Frequency change in the microgrid, shown in Figure 5t, decreased from approximately 60.05Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in unit power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on their set-points initialized at the beginning of the test. The output power for both Gen-sets were relatively close to the values at the beginning of the test with Gen-set A1 producing approximately 38kW – j12kVAr and Gen-set A2 producing approximately 30kW – j3kVAr. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.2.14) in Table 1.

For Test 10.2.14 the measured values, after Gen-set A1 was warmed up and load banks brought on-line, were approximately 10kW + j20kVAR at Meter 1, -26kW + j20kVAr at Meter 2 and -29kW + j15kVAR at Meter 3. From the microgrid, 40kW – j14kVAr was produced by Gen-set A1. The Load Banks were 11kW + j0kVAr at LB3 and 36.1kW + j0.745kVAr at LB6. At the time of these measurements, the voltage and frequency was 282.8 on A-phase, 279.6V on B-phase and 279.8V on C-phase and 59.986Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 283V on A-phase, 280V on B-phase and 280V on C-phase at Meter 3.

Gen-set A1 was setup in this test to produce more power than Load Bank 3 needed which approximately 26kW of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 36.1kW + j0.0745kVAr, the utility

had to supply approximately 10kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 20kVAr because Gen-set A1 needed approximately 14kVAr and the reactive power absorbed in the electrical lines. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

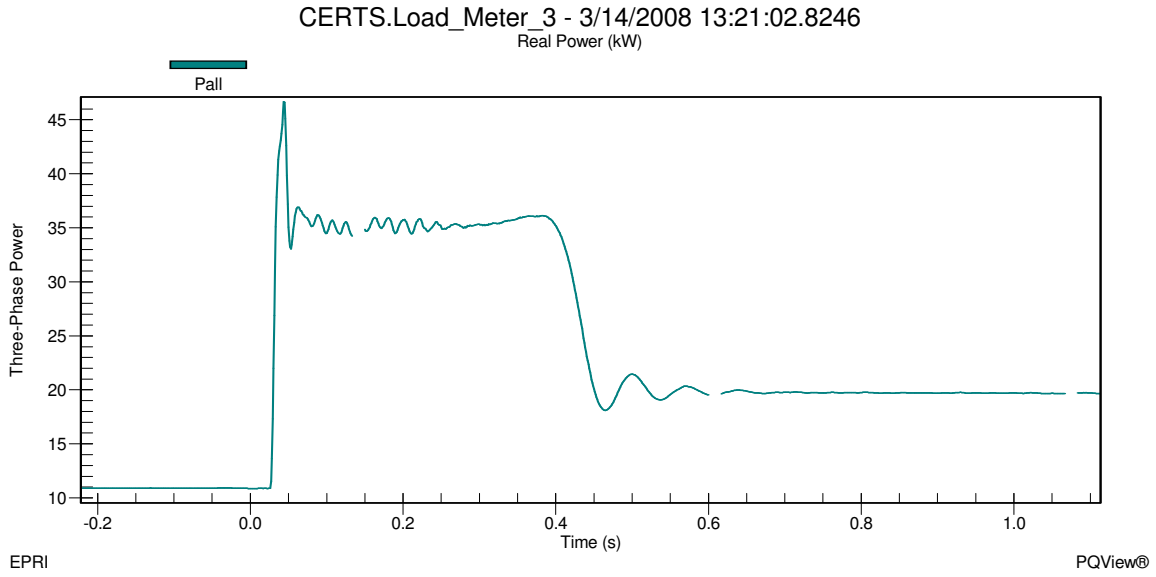

Figure 6a - Load Bank 3 Real Power during Motor Start and Utility Connected for Test 10.2.14

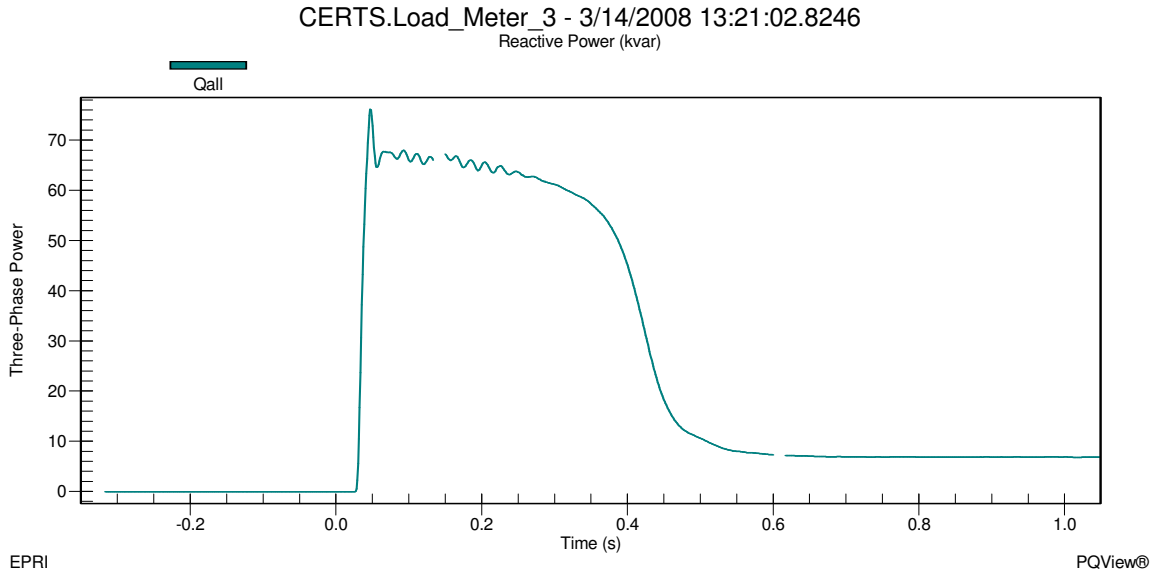

Figure 6b - Load Bank 3 Reactive Power during Motor Start and Utility Connected for Test 10.2.14

In Figures 6a and 6b it can be seen that the load in Zone 3 was approximately 11kW + j0kVAr before the start of the induction motor and increased to approximately 46.8kW + j76kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 35kW + j63kVAr during the warm up phase which lasted about 33 cycles (0.55 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 19.8kW + j7kVAr.

The voltage and frequency at the static switch before the motor start was approximately 282.8V on A-phase, 279.6V on B-phase and 279.8V on C-phase shown in Figure 6c and approximately 59.99Hz shown in Figure 6d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.6V on A-phase, 271.7V on B-phase and 271V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.92Hz and quickly increased back to the starting frequency of approximately 59.99Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 282V on A-phase, 278.8V on B-phase and 279V on C-phase at an approximate frequency of 59.98Hz.

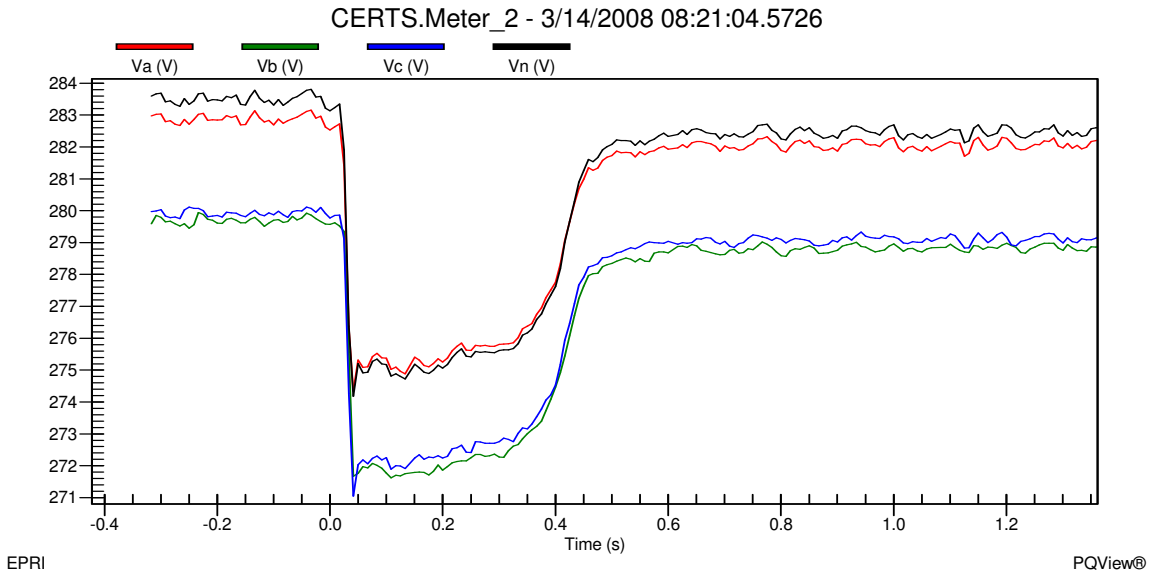

Figure 6c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.2.14

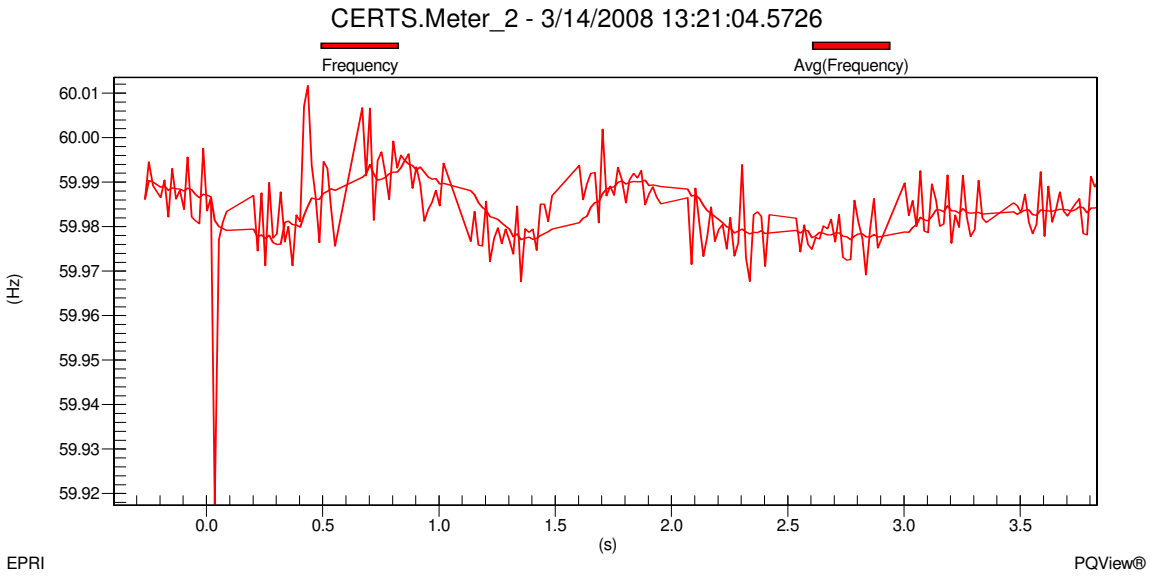

Figure 6d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.14

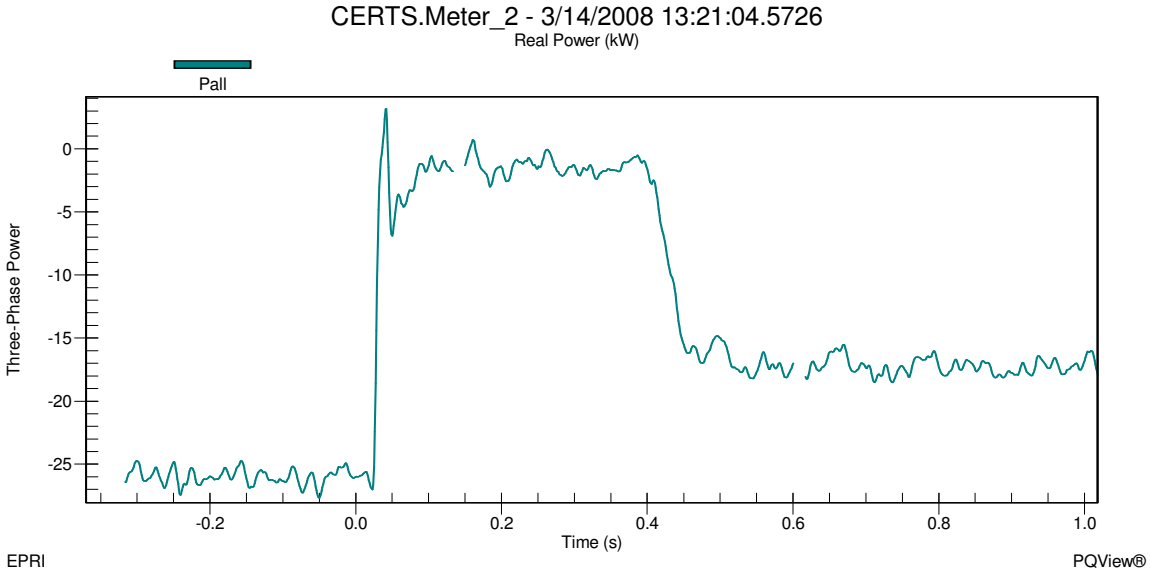

Figure 6e - Static Switch Real Power during Motor Start and Utility Connected for Test 10.2.14

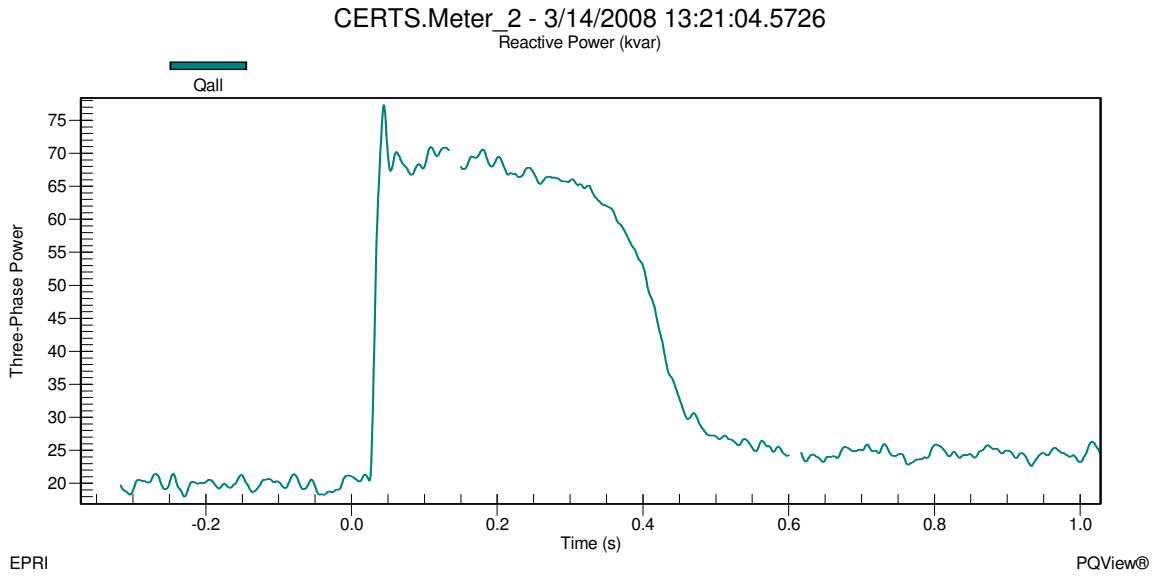

Figure 6f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.14

Before the motor started Gen-set A1 was producing approximately 40kW – j14kVAr. This was enough for the load demands of Zone 3 with real power being exported to Zone 6 of approximately 26kW shown in Figure 6e. The grid was supporting the reactive power of the microgrid with approximately 20kVAr shown in Figure 6f. When the motor started the inrush caused the utility to supply approximately 77.1kVAr and to pick up the load demand in Load Bank 6 along with approximately 3kW of the load in Zone 3. The power being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 6e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output level to approximately 46.9kW + j5kVAr. Notice the sign of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -17.2kW + j24kVAr which meant that Gen-set A1 was supplying the power for the induction motor and approximately 17.2kW of Load Bank 6. Gen-set A1 real power returned to the value before the motor started of approximately 40kW and the reactive power increased to approximately -12kVAr. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 37kW and reactive power decreased to 0kVAr satisfying the load demand in Load Bank 6 which was approximately 36.6kW + j0kVAr and not supplying

any power beyond the static switch to Load Bank 3. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads was slightly reduced to 10.3kW – j0.041kVAr. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 6g, from approximately 283V on A-phase, 280V on B-phase and 280V on C-phase when connected to the utility grid to 273V on A-phase, 271.5V on B-phase and 273V on C-phase at Meter 3 when islanded.

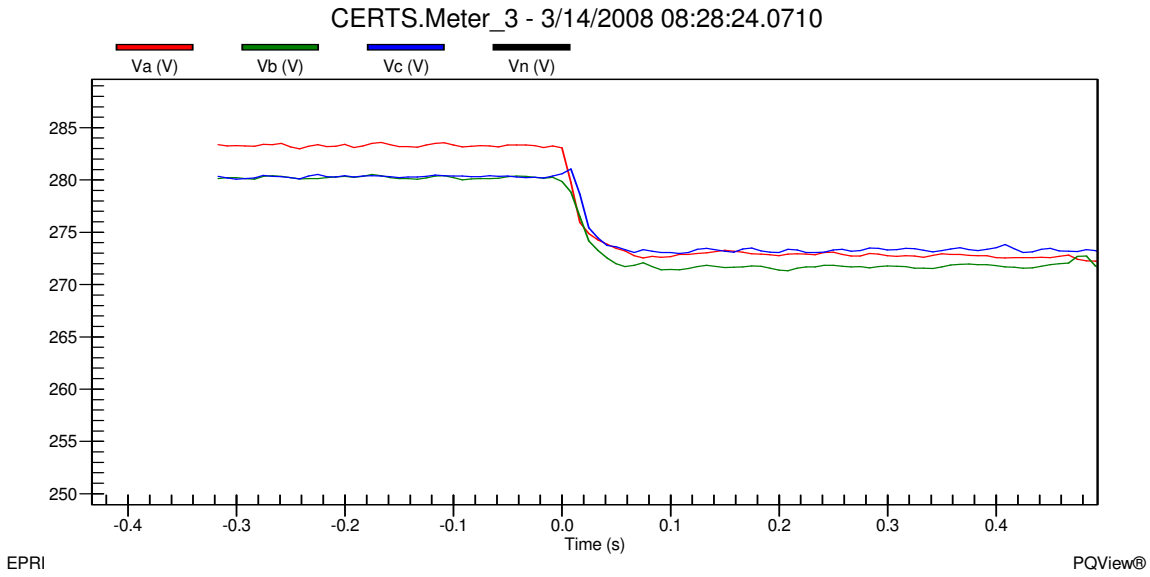

Figure 6g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.14

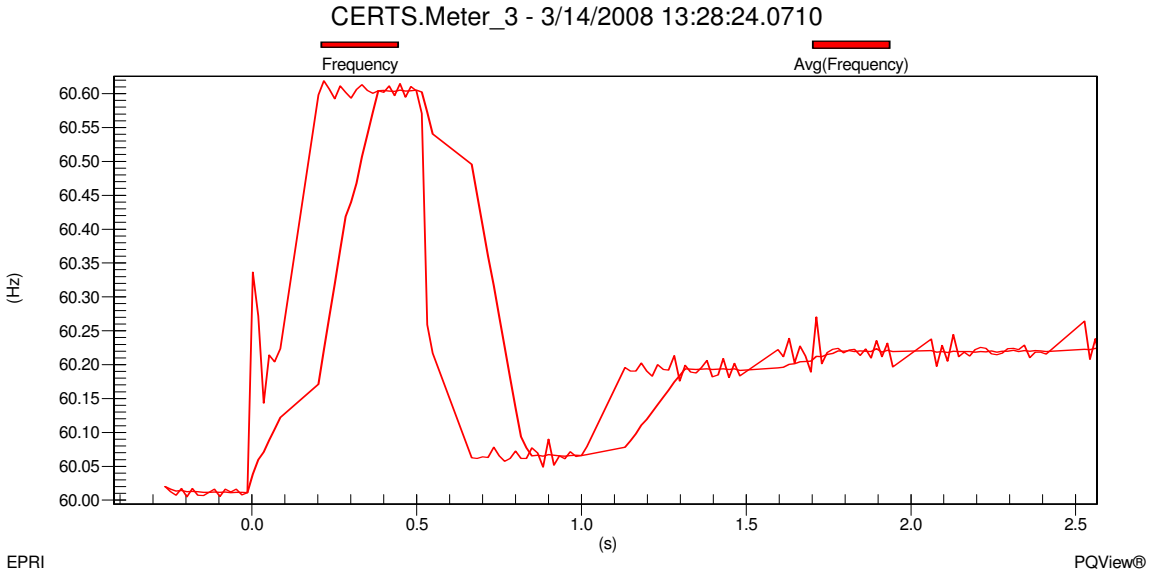

Figure 6h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.14

Frequency change in the microgrid, shown in Figure 6h, increased from approximately 60.01Hz when connected to the utility grid to approximately 60.22Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the load demands. Gen-set A1 decreased its output real power to approximately 13kW and increased its output reactive power to approximately 3.5kVAr. Meter 3 was approximately -3.5kW - j3.9kVAr indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

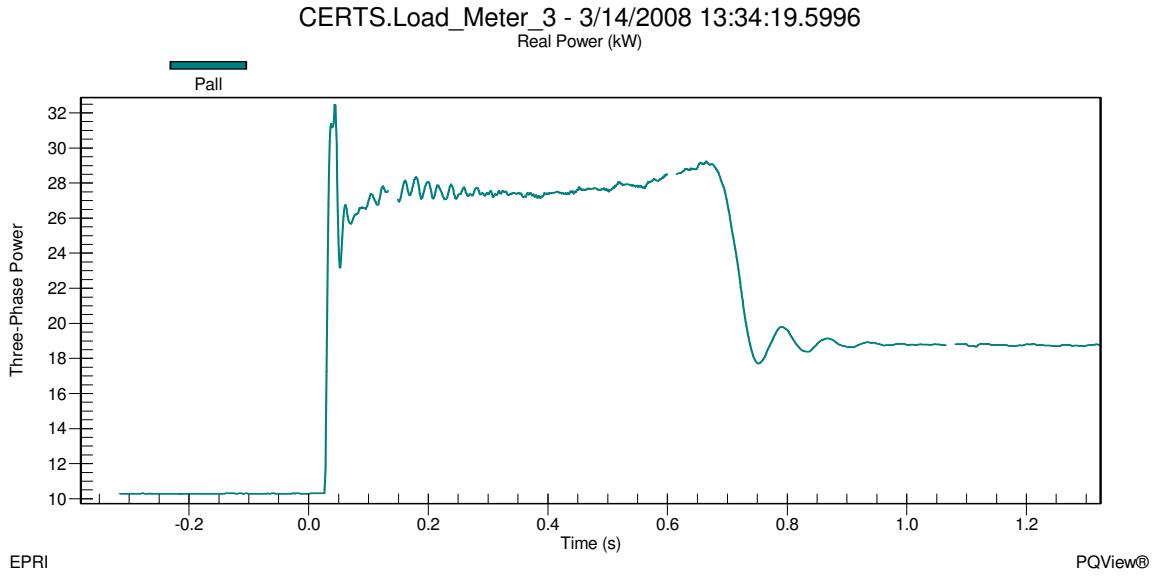

Figure 6i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.14

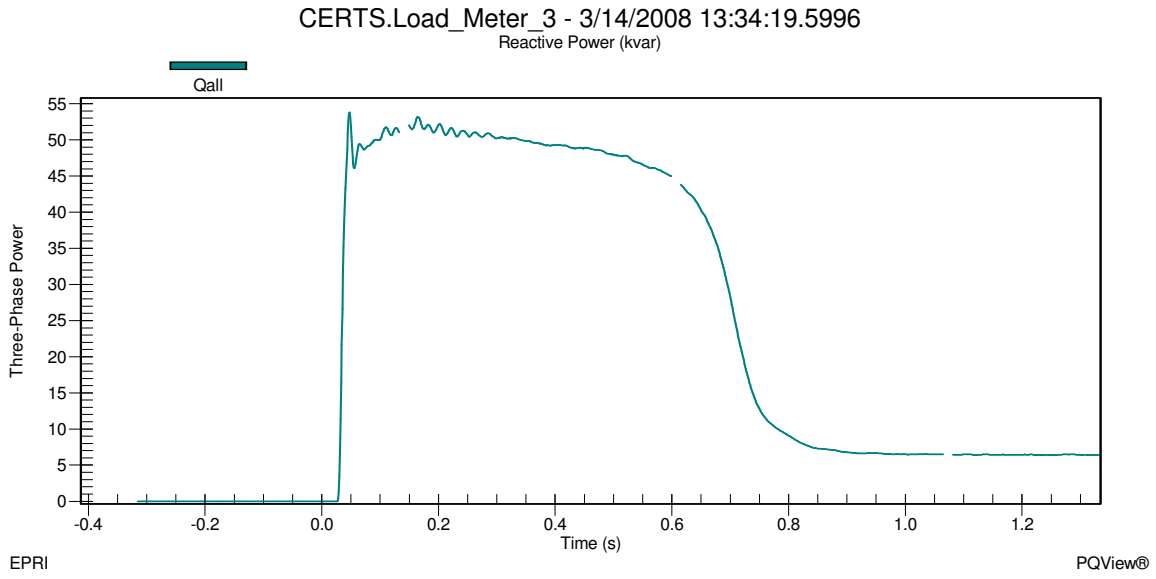

Figure 6j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.14

In Figures 6i and 6j it can be seen that the load in Zone 3 was approximately 10.4kW + j0kVAr before the start of the induction motor and increased to approximately 32.5kW + j54kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 28kW + j50kVAr during the warm up phase which lasted about 51 cycles (0.85 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 18.8kW + j6.8kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 272.5V on A-phase, 272.5V on B-phase and 272.5V on C-phase shown in Figure 6k and approximately 60.22Hz shown in Figure 6l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 235V on A-phase, 235V on B-phase and 235V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.88Hz and quickly increased to approximately 60.15Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 268.8V on A-phase, 268.8V on B-phase and 268.8V on C-phase at an approximate frequency of 60.15Hz.

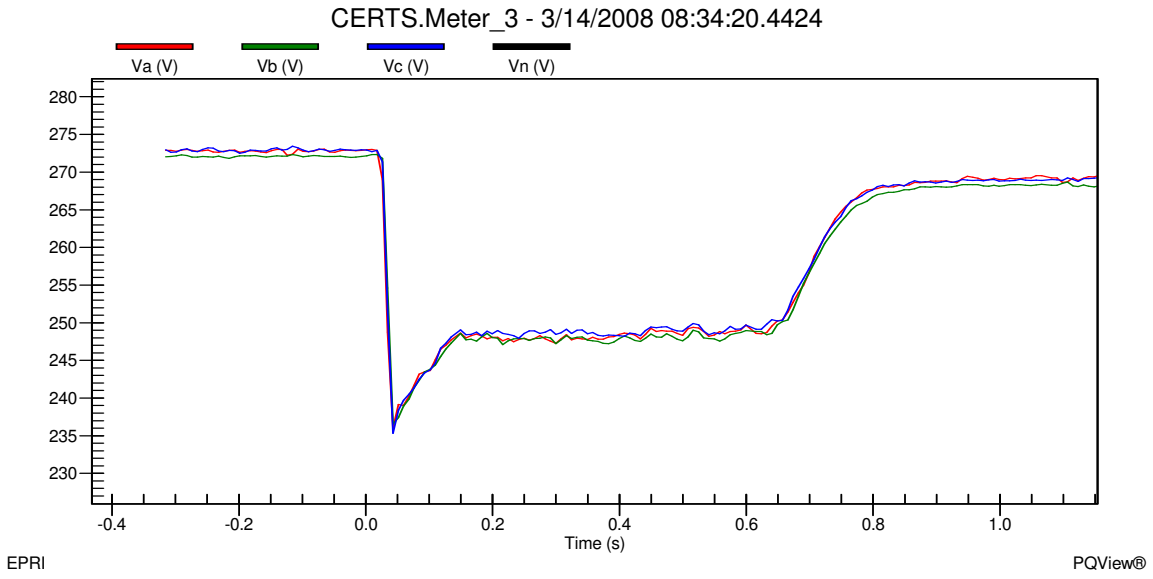

Figure 6k – Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.2.14

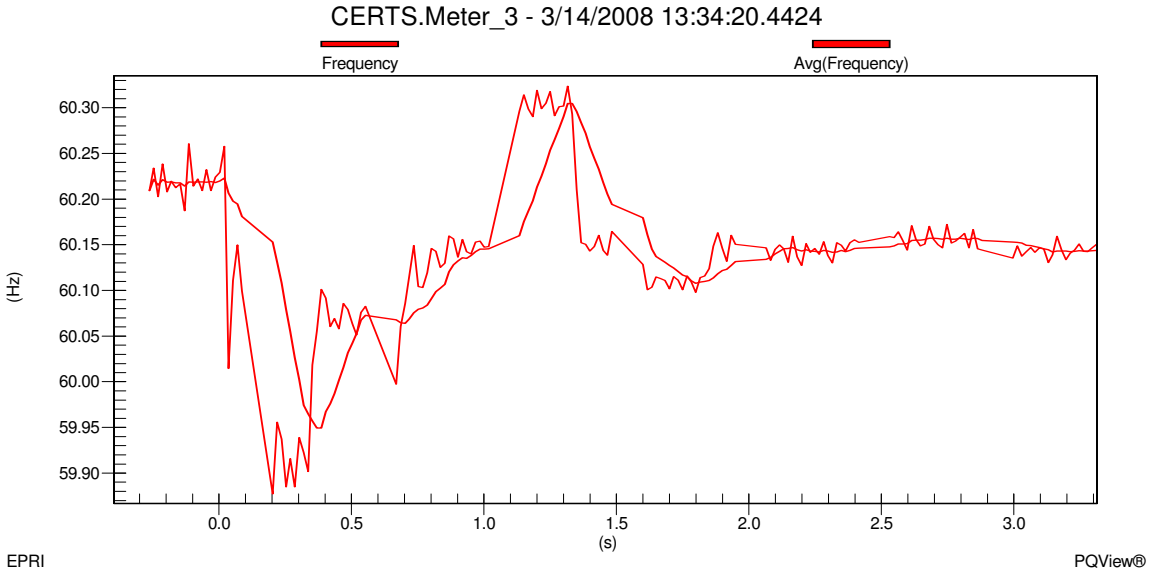

Figure 6l – Meter 3 Frequency during Motor Start and Islanded for Test 10.2.14

Before the motor started, Gen-set A1 was producing approximately 12.5kW + j3.5kVAr shown in Figures 6m and 6n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-set to increase its output level to 34.3kW + j55kVAr. Gen-set A1 decreased its output level while the motor was warming up and eventually dropped to 21kW +j9.8kVAr when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

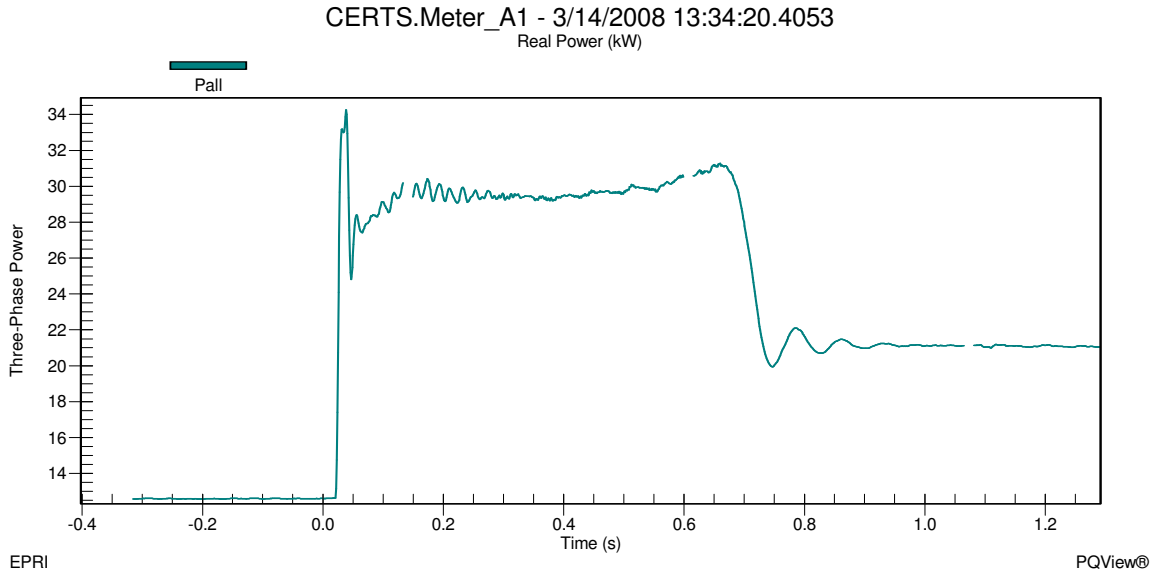

Figure 6m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.14

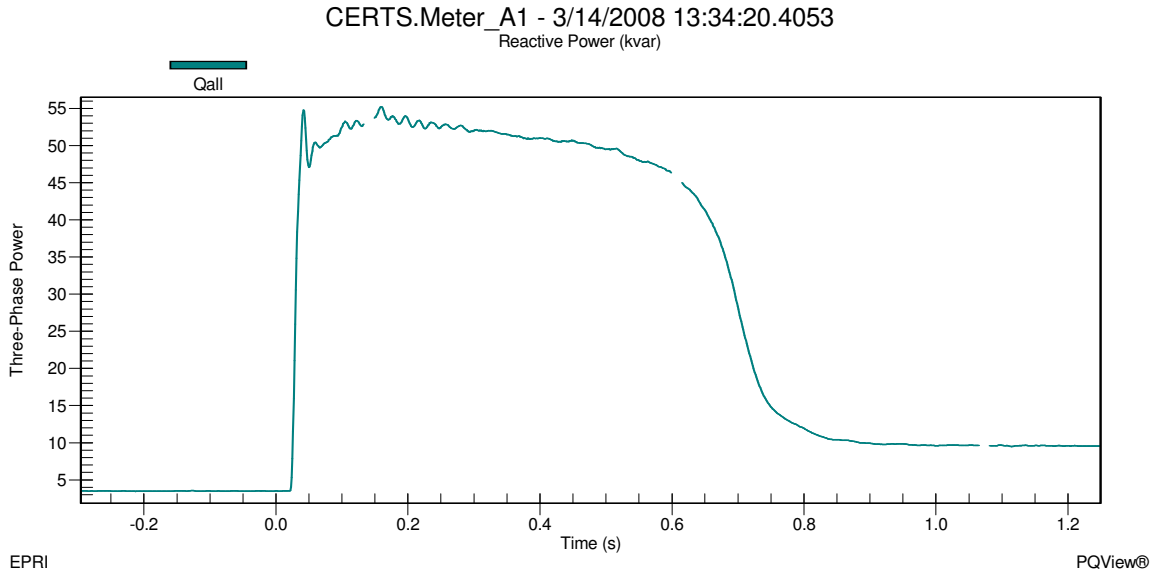

Figure 6n - Gen-set A1 Reactive Power during Motor Start and Islanded for Test 10.2.14

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 37kW to 18kW and reactive power increased from approximately 0kVAr to 25kVAr which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 6o and 6p show the static switch decreasing from approximately 0kW to -17.7kW and increasing from approximately 0kVAr to 24kVAr. At the beginning of the test, the initial power flow through the static switch was -26kW + j20kVAr which was not the same recorded at this

point in the test because the 10Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and is supporting Load Bank 6 with approximately 17.7kW.

Load Bank 3 loads increased slightly to 17.65kW + j6.1kVAr. This slight increase is a result from a voltage rise in the microgrid, shown in Figure 6q, from approximately 269V on A-phase, 269V on B-phase and 269V on C-phase when islanded to 282V on A-phase, 280V on B-phase and 280V on C-phase at Meter 3 when connected to the utility grid.

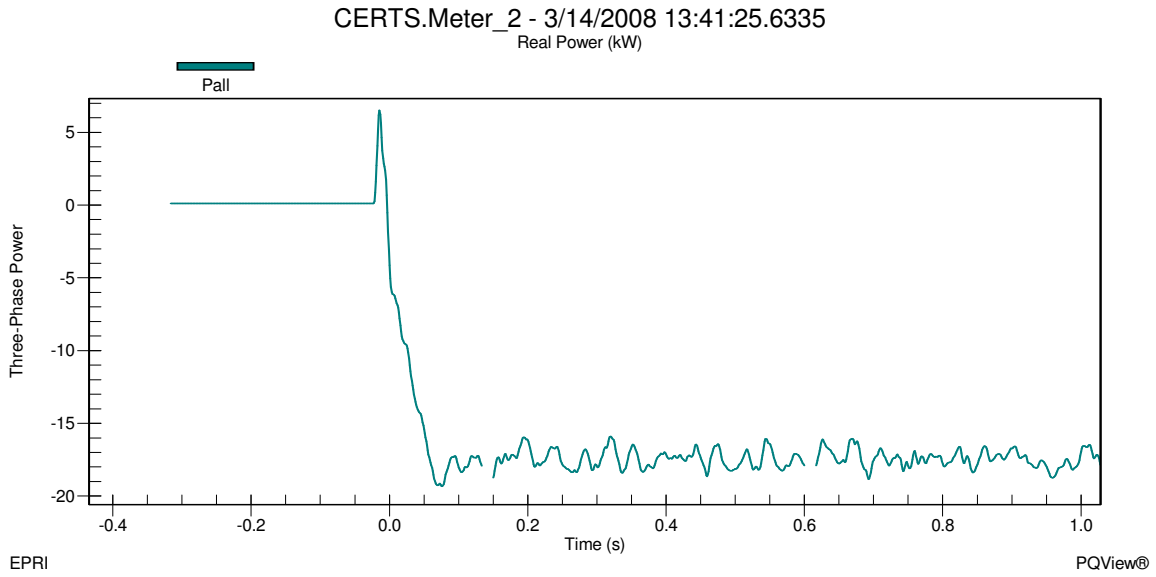

Figure 6o – Static Switch Real Power during Island to Utility Connected mode for Test 10.2.14

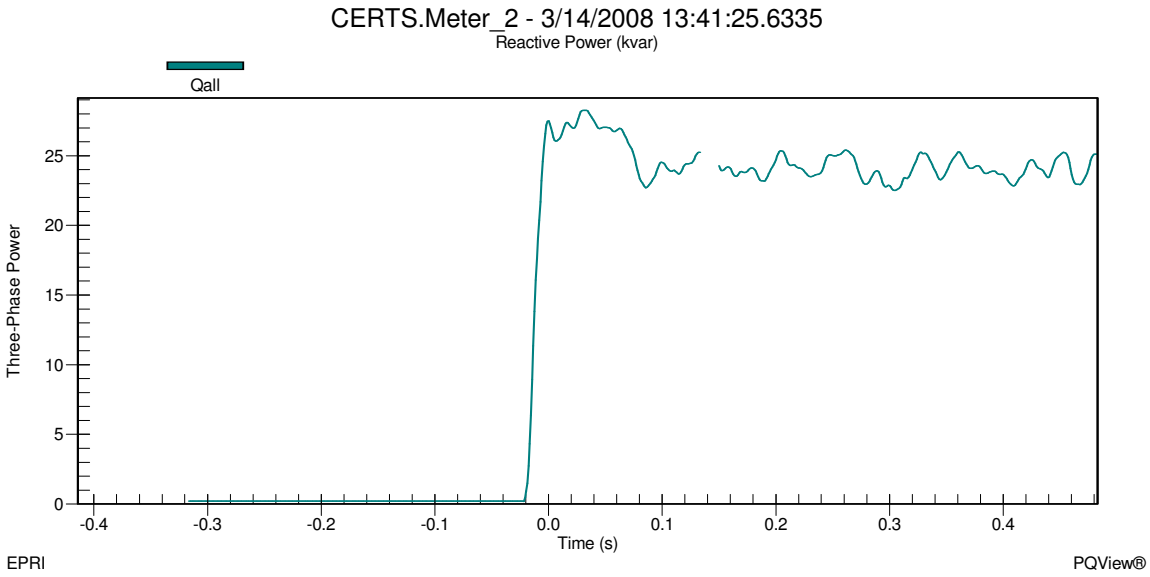

Figure 6p – Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.14

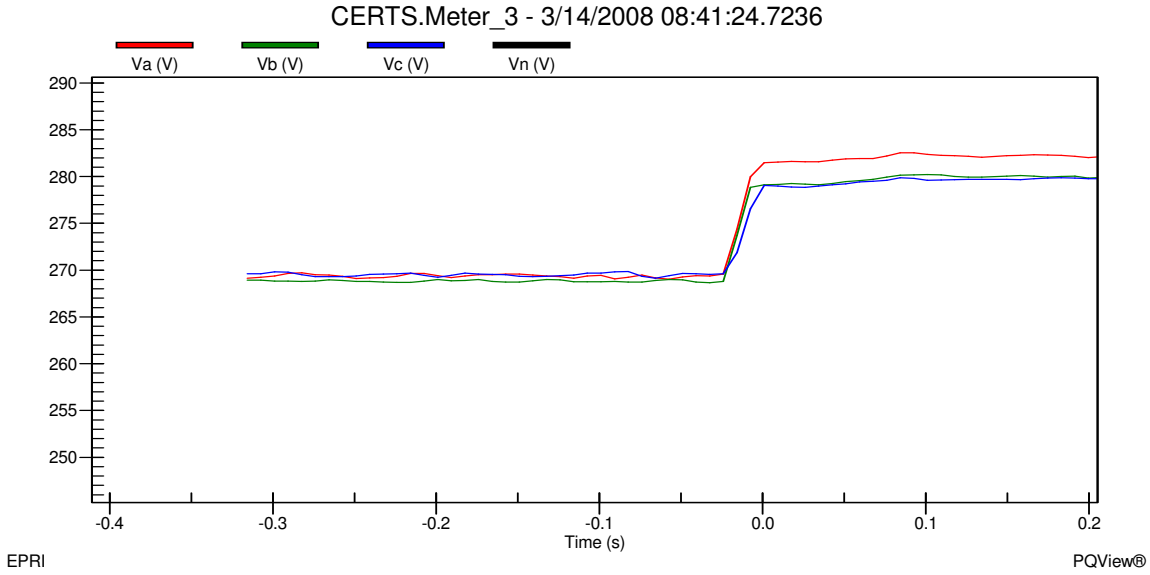

Figure 6q - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.14

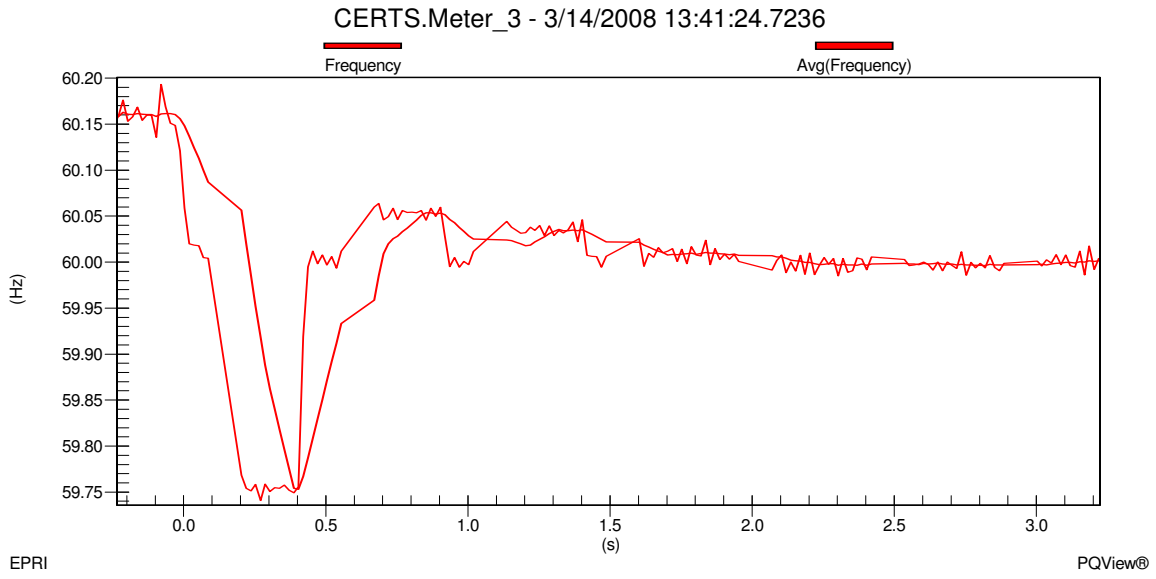

Figure 6r - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.14

Frequency change in the microgrid, shown in Figure 6r, decreased from approximately 60.16Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by Gen-set A1 using the CERTS algorithm but by the utility. Gen-set A1 is in unit power control mode therefore when the static switch closed back into the utility the Gen-set produced real power based on the set-point initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the values at the beginning of the test with Gen-set A1 producing approximately 38kW – j12kVAr. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.2.15) in Table 1.

For Test 10.2.15 the measured values, after the Gen-sets were warmed up and load bank brought on-line, were approximately 64kW + 17kVAr at Meter 1, 28kW + j16kVAr at Meter 2, 25kW + j10kVAr at Meter 3 and 16kW + j1kVAr. From the microgrid, 38.4kW – j10kVAr was produced by Gen-set A1 and 30kW + j0kVAr was produced by Gen-set A2. The load banks were 47kW + j0kVAr at LB3, 46.9kW + j0.715kVAr at LB4 and 35.8kW + j0.766kVAr at LB6. These measurements were relatively close to the expected values in Table 1, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 50kW settings for LB3 and LB4 and the 40kW setting for LB6 were also below selected set values. At the time of these measurements, the voltage and frequency was 281.6V on A-phase, 279.1V on B-phase and 279.1V on C-phase and 60.02Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 281.6V on A-phase, 279.1V on B-phase and 279.1V on C-phase and 60.02Hz at Meter 3.

The Gen-sets in this test were set up to produce less power than the microgrid loads needed which approximately 28kW of power was imported from the utility through the static switch to support Load Banks 3 and 4. Since Load Bank 6 was approximately 35.8kW + j0.766kVAr, the utility had to supply approximately 64kW to satisfy the load demand of Load Bank 6 and the microgrid loads. Reactive power had to be imported in from the utility of approximately 16kVAr because Gen-set A1 and A2 needed approximately 10kVAr between the two and the reactive power of Load Banks 3 and 4 and electrical wires. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

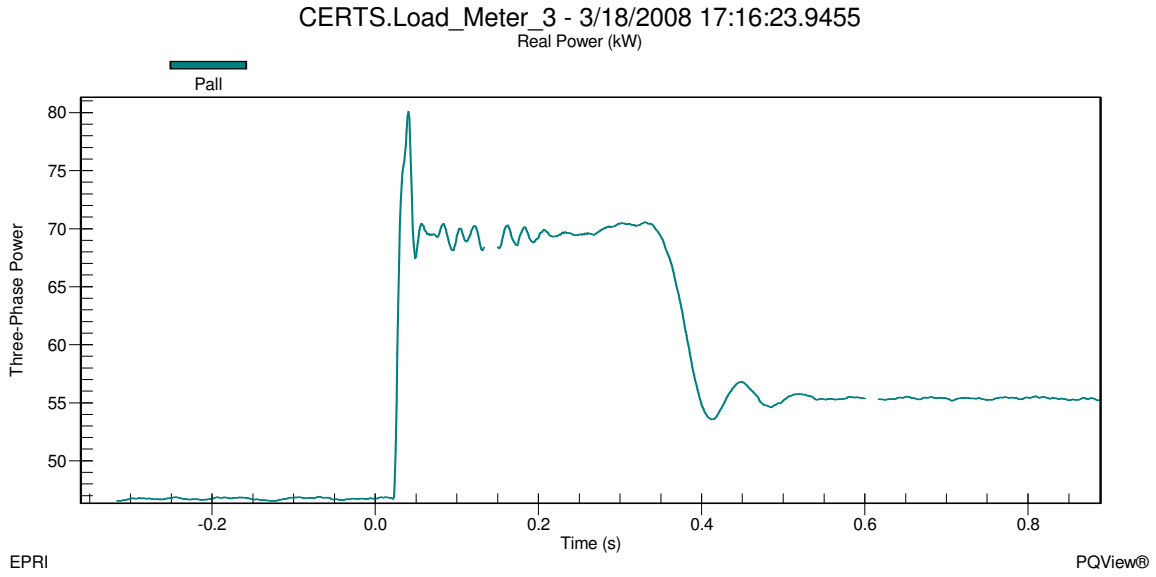

Figure 7a - Load Bank 3 Real Power during Motor Start Utility Connected for Test 10.2.15

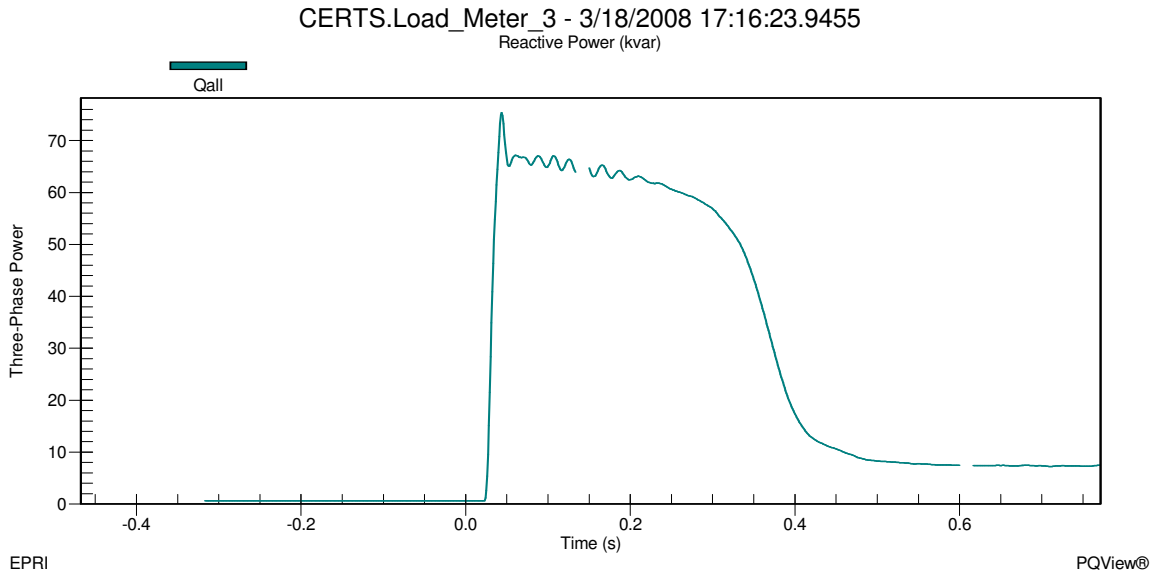

Figure 7b - Load Bank 3 Reactive Power during Motor Start Utility Connected for Test 10.2.15

In Figures 7a and 7b it can be seen that the load in Zone 3 was approximately 46.9kW + j0.715kVAr before the start of the induction motor and increased to approximately 80kW + j75kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 69.5kW + j64kVAr during the warm up phase which lasted about 33 cycles (0.55 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 55.5kW + j7kVAr.

The voltage and frequency at the static switch before the motor start was approximately 281.6V on A-phase, 279.1V on B-phase and 279.1V on C-phase shown in Figure 7c and approximately 60.02Hz shown in Figure 7d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.6V on A-phase, 271.6V on B-phase and 272.1V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.95Hz and quickly increased back to approximately 60.00Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 280.8V on A-phase, 278.2V on B-phase and 278.4V on C-phase at an approximate frequency of 60.00Hz.

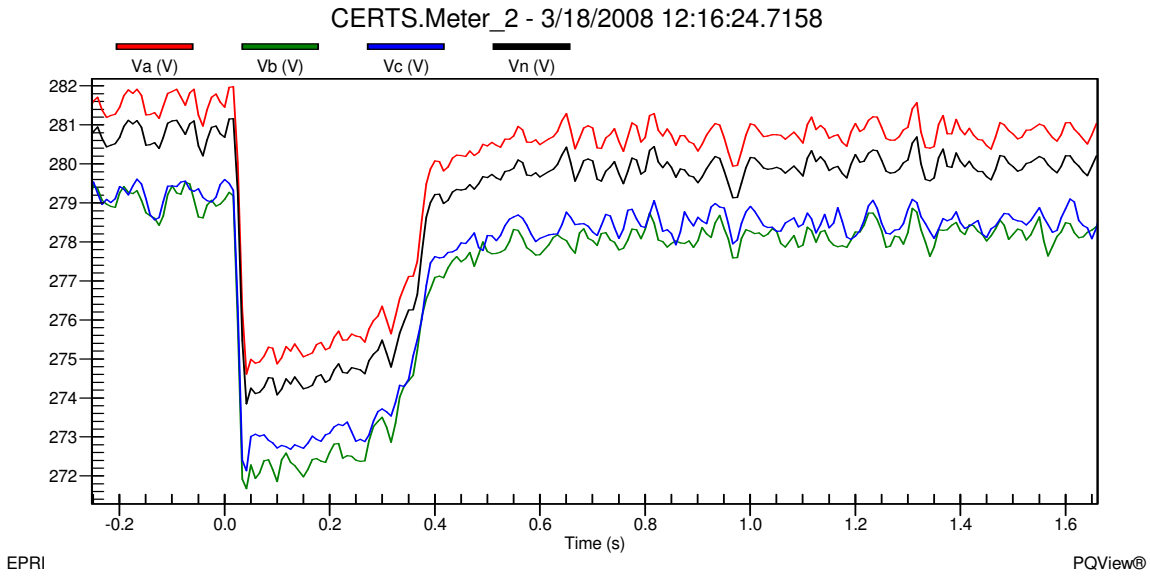

Figure 7c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.2.15

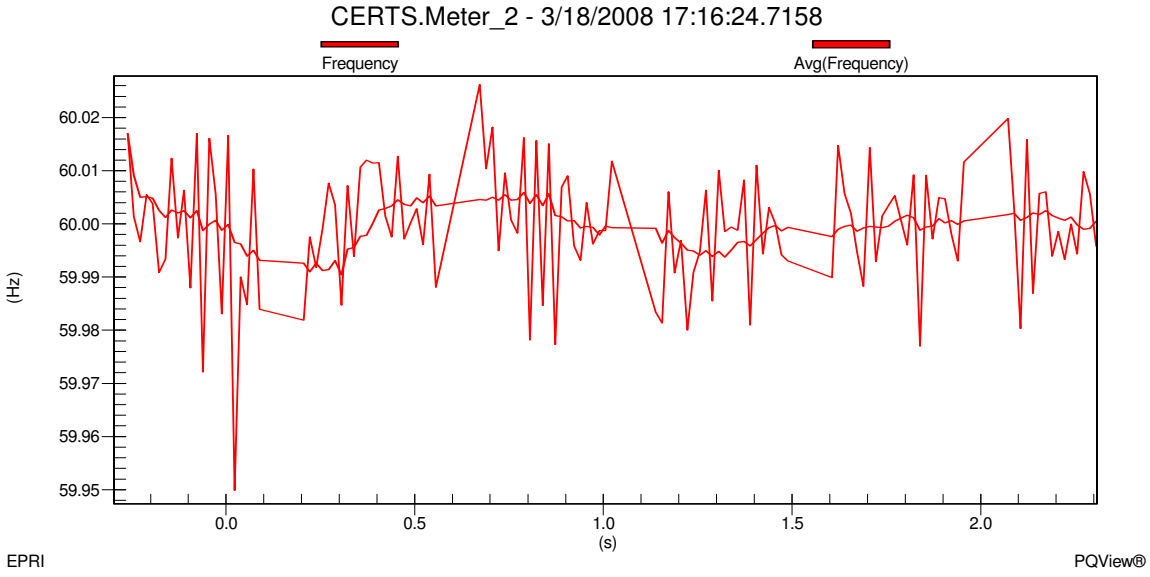

Figure 7d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.15

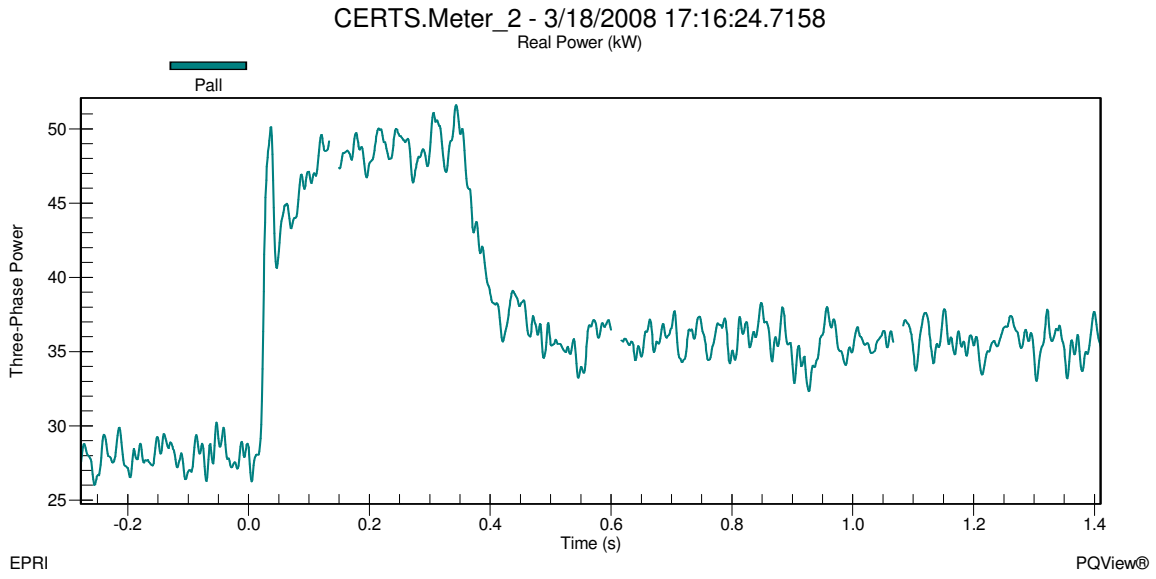

Figure 7e - Static Switch Real power during Motor Start and Utility Connected for Test 10.2.15

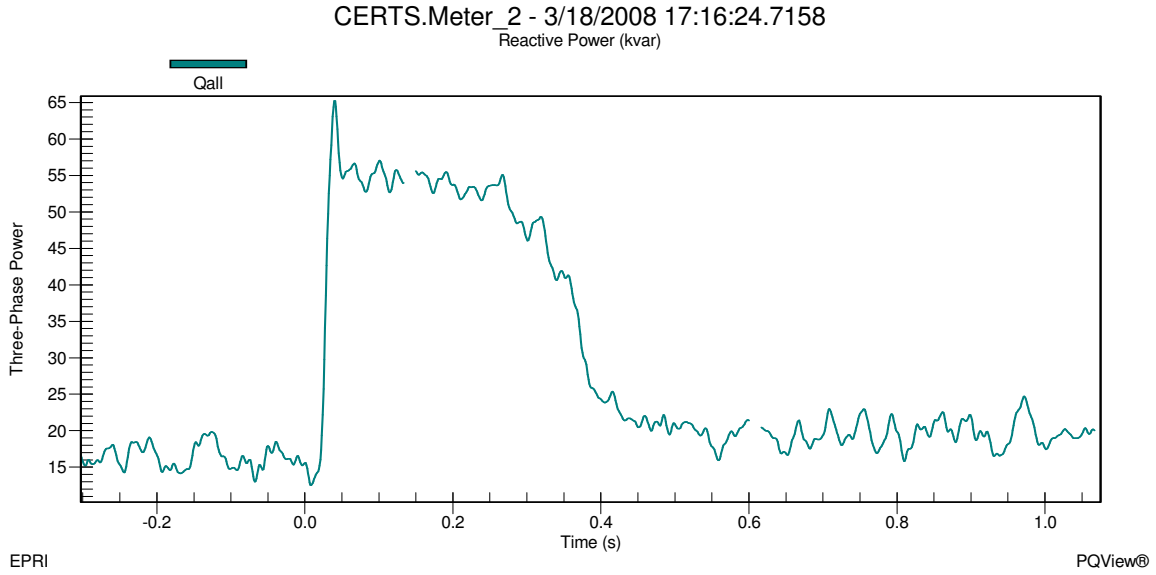

Figure 7f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.15

Before the motor started Gen-sets A1 and A2 were producing approximately 38.4kW – j10kVAr and 30kW + j0kVAr, respectively. The load demands of Load Banks 3 and 4 were greater than the power being produced by both Gen-sets therefore the utility had to supply approximately 28kW shown in Figure 7e. The utility was supporting the reactive power of the microgrid with approximately 16kVAr shown in Figure 7f. When the motor started the inrush caused the utility to supply approximately 50kW + j65kVAr to the microgrid loads, shown in Figures 7e and 7f, and Gen-sets A1 and A2 increased their output power levels to 41.8kW + j5kVAr and 35.5kW + j14.5kVAr, respectively.

Notice the sign of the VAr output changed from negative to positive for Gen-set A1 and 0kVAr to 14.5kVAr for Gen-set A2 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately 35.5kW + j19kVAr which meant that the utility was supplying the power for the induction motor. Gen-sets A1 and A2 real power returned to the values before the motor started of approximately 38.4kW and 30kW, respectively, and the reactive power slightly increased to approximately -9kVAr in Gen-set A1 and 2kVAr in Gen-set A2. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real and reactive power decreased to approximately 37kW + j1.4kVAr satisfying the load demand in Load Bank 6 which was approximately 36.6kW + j0.78kVAr and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Banks 3 and 4 loads reduced slightly to 44.9kW + j0.645kVAr and 44.4kW + j0.688kVAr, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 7g, from approximately 280.8V on A-phase, 278.2V on B-phase and 278.2V on C-phase when connected to the utility grid to 274.1V on A-phase, 274.1V on B-phase and 274.1V on C-phase at Meter 3 when islanded.

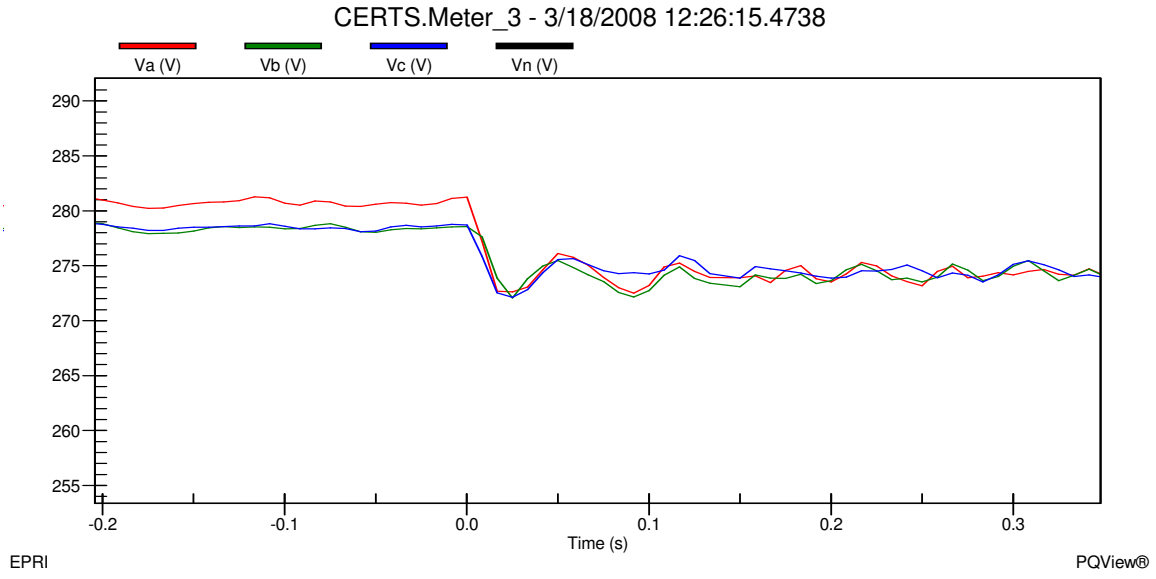

Figure 7g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.15

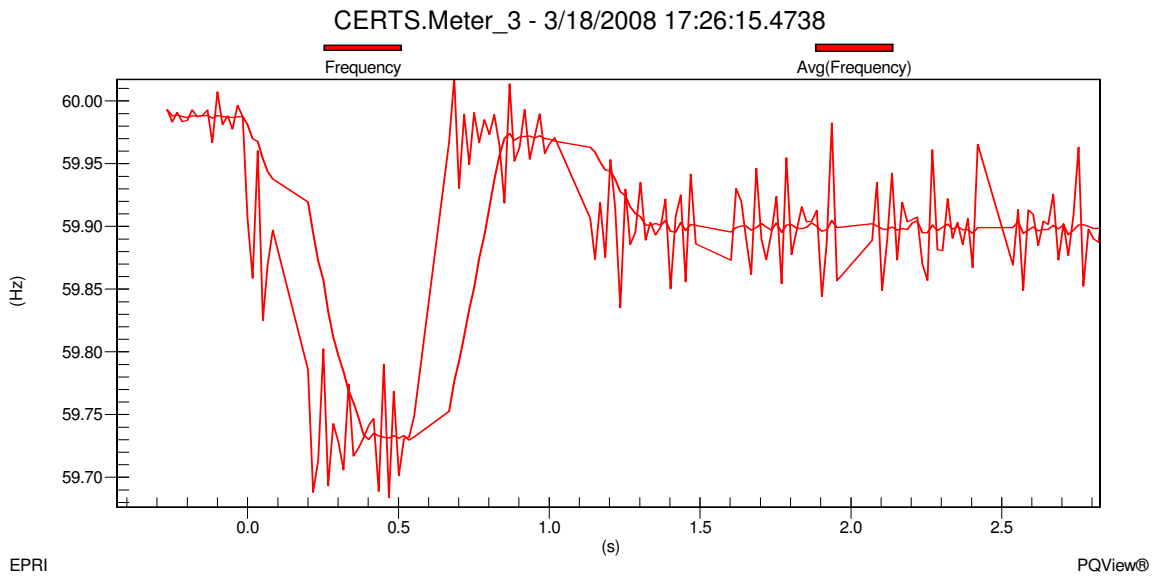

Figure 7h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.15

Frequency change in the microgrid, shown in Figure 7h, decreased from approximately 59.99Hz when connected to the utility grid to approximately 59.90Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to increase their output power to satisfy the load demands. Gen-set A1 and A2 increased their output real and reactive powers approximately 49.6kW – j2kVAr and 41.9kW + j7kVAr, respectively. Meter 3 was approximately -2kW – j3kVAr indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

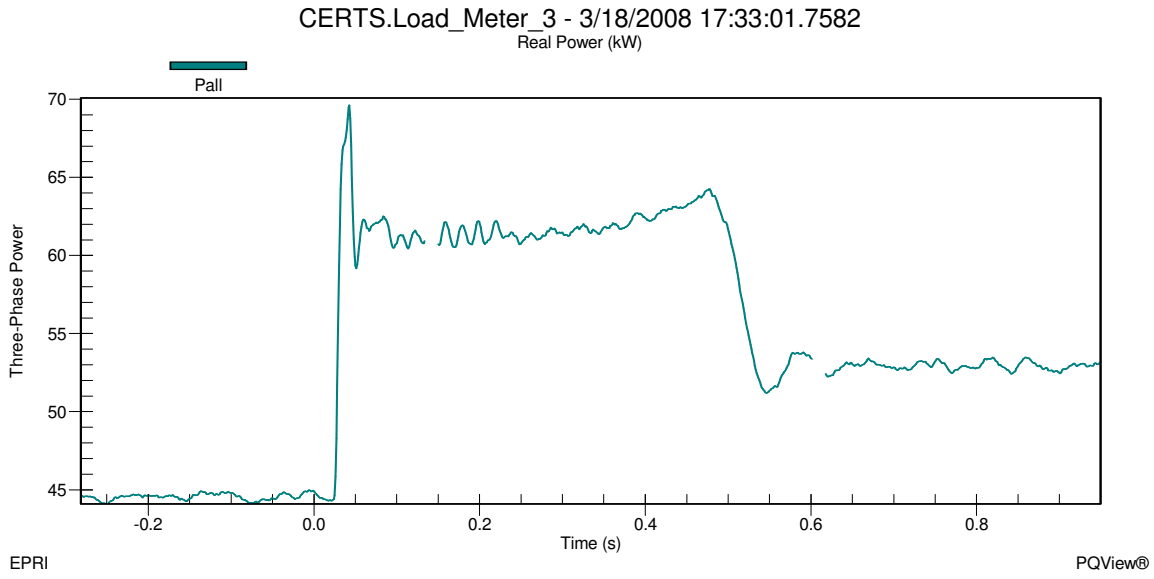

Figure 7i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.15

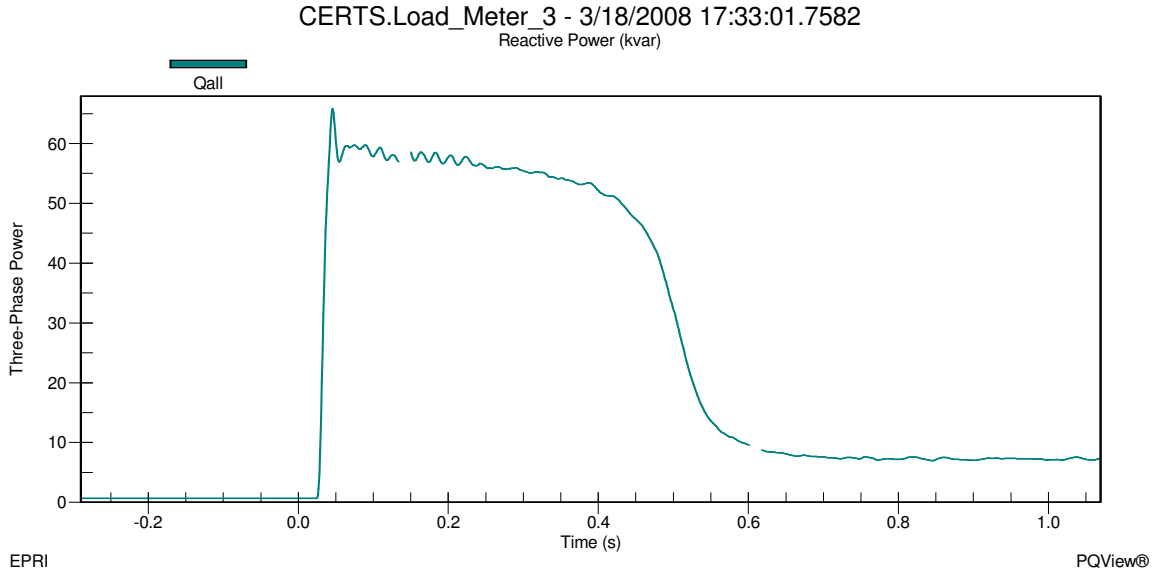

Figure 7j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.15

In Figures 7i and 7j it can be seen that the load in Zone 3 was approximately 44.5kW + j1kVAr before the start of the induction motor and increased to approximately 69.6kW + j66kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 61.8kW + j56kVAr during the warm up phase which lasted about 39 cycles (0.65 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 53kW + j7.5kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 274V on A-Phase, 274V on B-Phase and 274V on C-phase shown in Figure 7k and approximately 59.90Hz shown in Figure 7l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 254.8V on A-Phase, 254.8V on B-Phase and 254.8V on C-Phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.81Hz and quickly increased to approximately 59.84Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 272V on A-Phase, 272V on B-Phase and 272V on C-Phase at an approximate frequency of 59.87Hz.

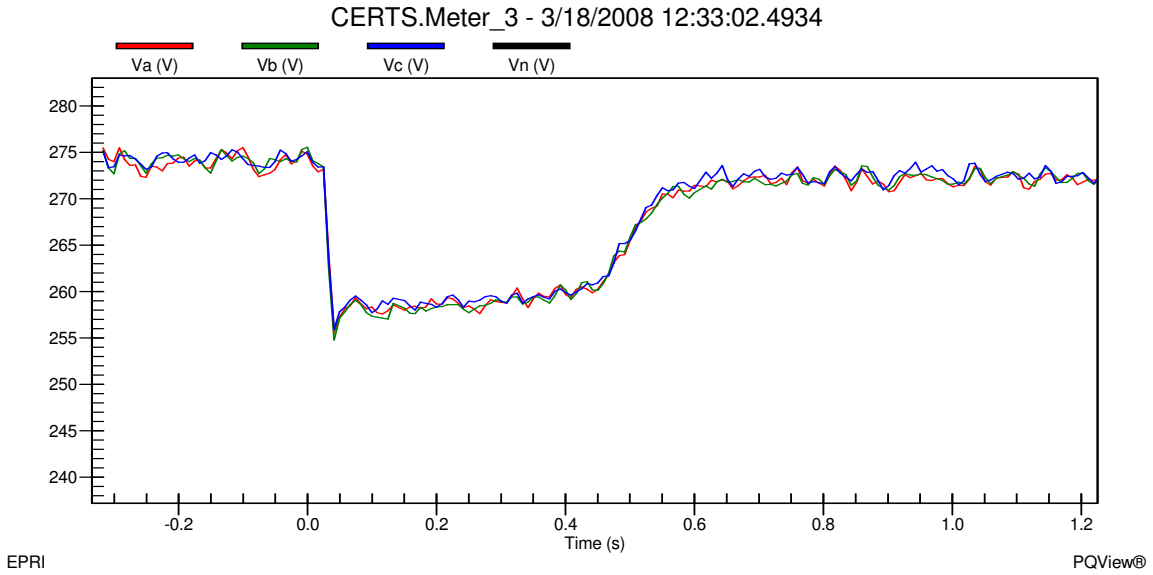

Figure 7k – Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.2.15

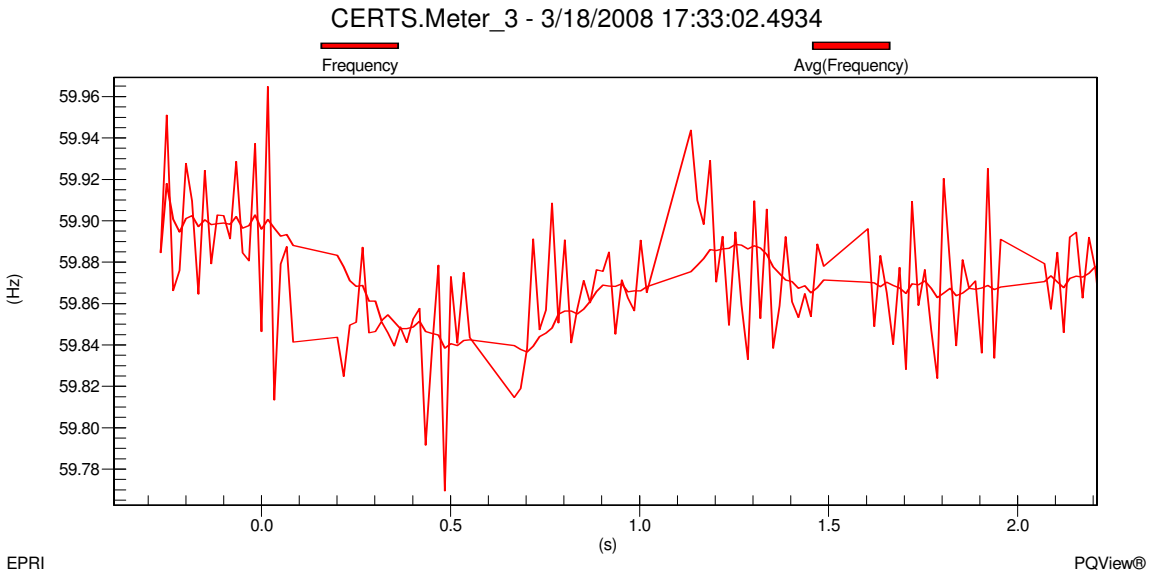

Figure 7l – Meter 3 Frequency during Motor Start and Islanded for Test 10.2.15

Before the motor started Gen-sets A1 and A2 were producing approximately 49.6kW – j2kVAr and 41.9kW + j7kVAr, respectively shown in Figures 7m – 7p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output levels to 59kW + j30.7kVAr for Gen-set A1 and 52kW + j38kVAr for Gen-set A2. The Gen-sets decreased their output levels while the motor was warming up and eventually dropped to 53.4kW + j1kVAr for Gen-set A1 and 45.5kW + j10.5 for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

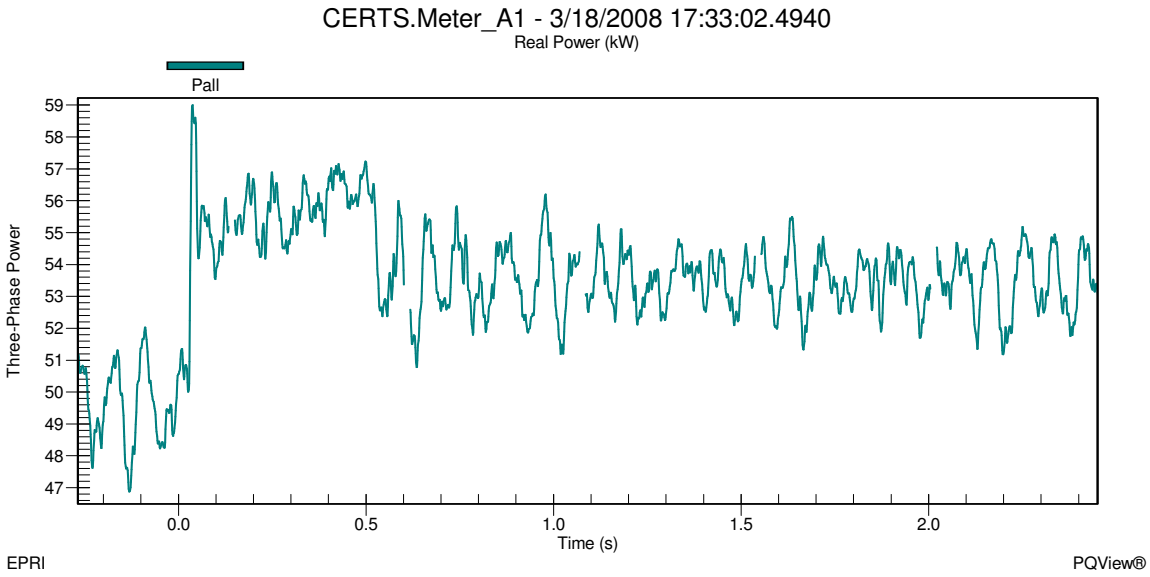

Figure 7m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.15

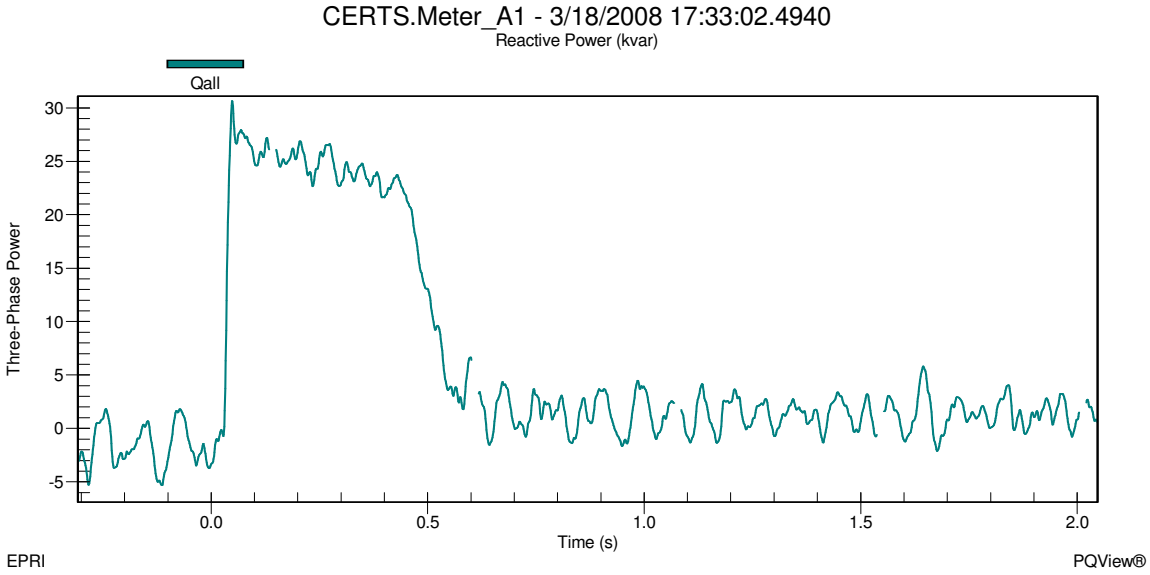

Figure 7n - Gen-set A1 Reactive Power during Motor Start and Islanded for Test 10.2.15

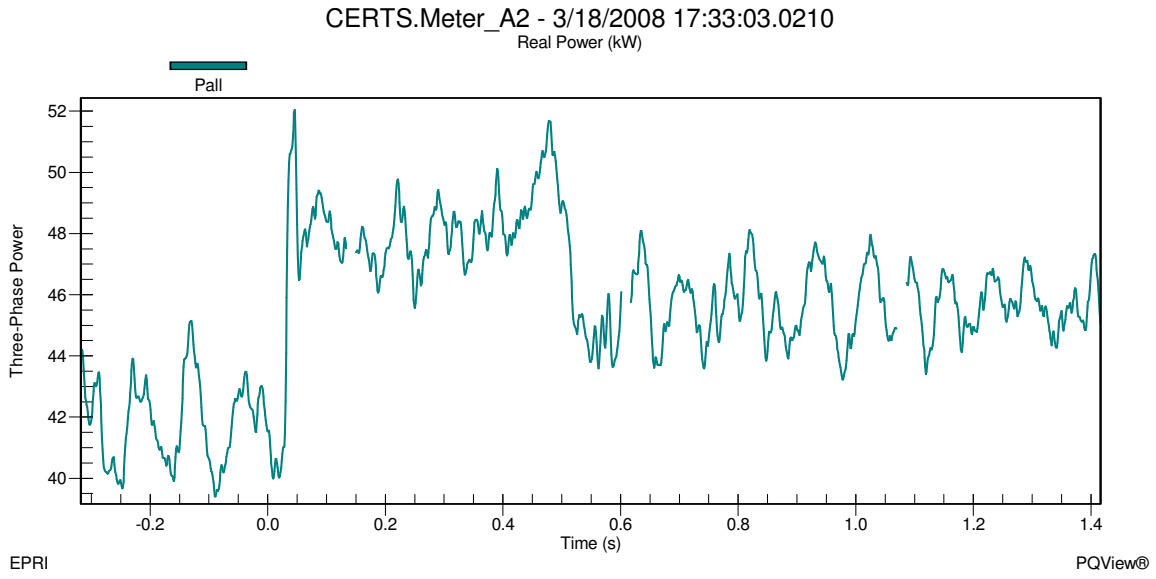

Figure 7o - Gen-set A2 Real Power during Motor Start and Islanded for Test 10.2.15

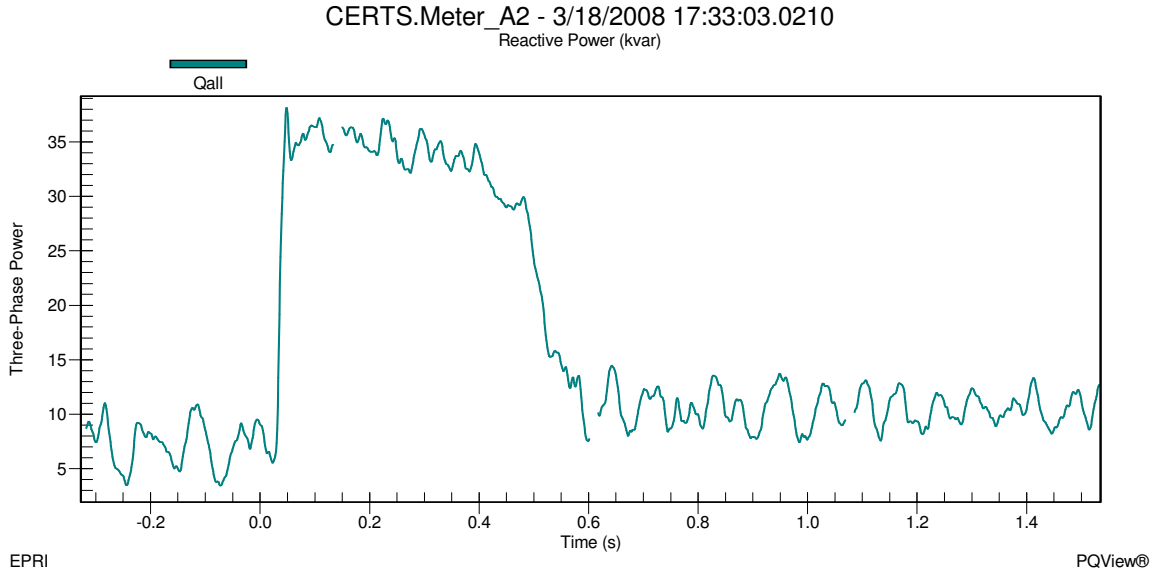

Figure 7p - Gen-set A2 Reactive Power during Motor Start and Islanded for Test 10.2.15

As soon as the static switch closed, Meter 1 recorded real and reactive powers increased from approximately 37kW + j1.1kVArto 70kW + j23kAVr which means that the utility was satisfying not only the load demand of Load Bank 6 but also all the reactive power and a portion of the real power for the microgrid loads. Figures 7q and 7r show the static switch increasing from approximately 0kW + j0kVAr to 34.5kW + j21kVAr. At the beginning of the test, the initial power flow through the static switch was 28kW + j16kVAr which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. The Gen-sets A1 and A2 output power levels reduced to

approximately 37.2kW – j9.5kVAr and 30kW + j1.5kVAr, respectively, which are relatively close to the initial values at the beginning of the test. Since the motor is on in Zone 3 and the Gen-sets returned to their initial values at the beginning of the test before the motor was turned on means that the induction motor is completely being powered by the utility.

Load Banks 3 and 4 loads increased slightly to 53kW + j6.7kVAr and 45.7kW + j0.707kVAr, respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 7s, from approximately 272.5V on A-phase, 272.5V on B-phase and 272.5V on C-phase when islanded to 280V on A-phase, 278V on B-phase and 278V on C-phase at Meter 3 when connected to the utility grid.

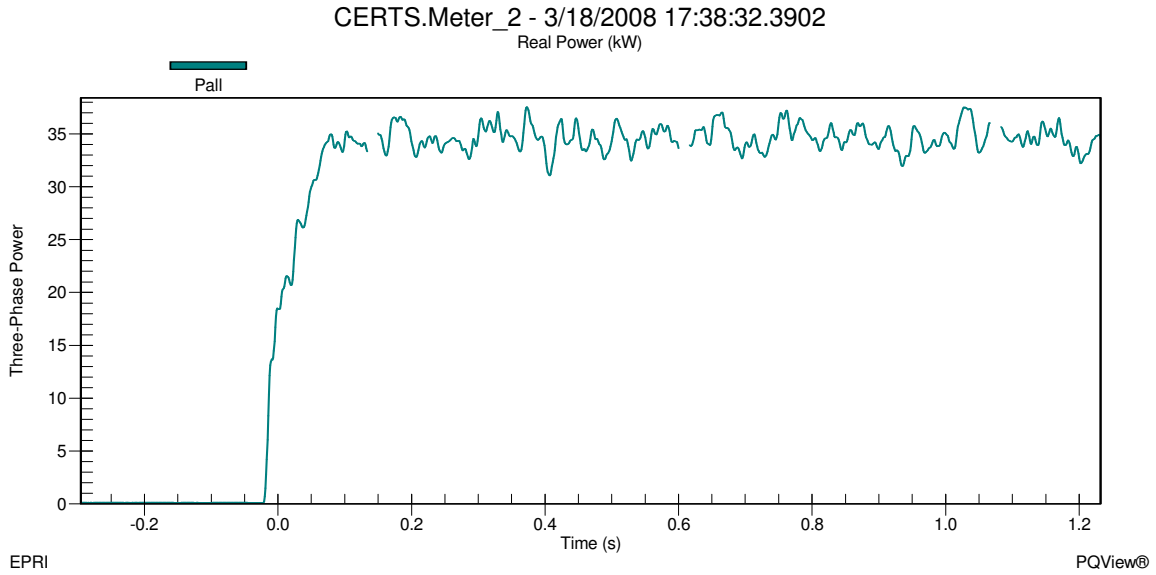

Figure 7q – Static Switch Real Power during Island to Utility Connected mode for Test 10.2.15

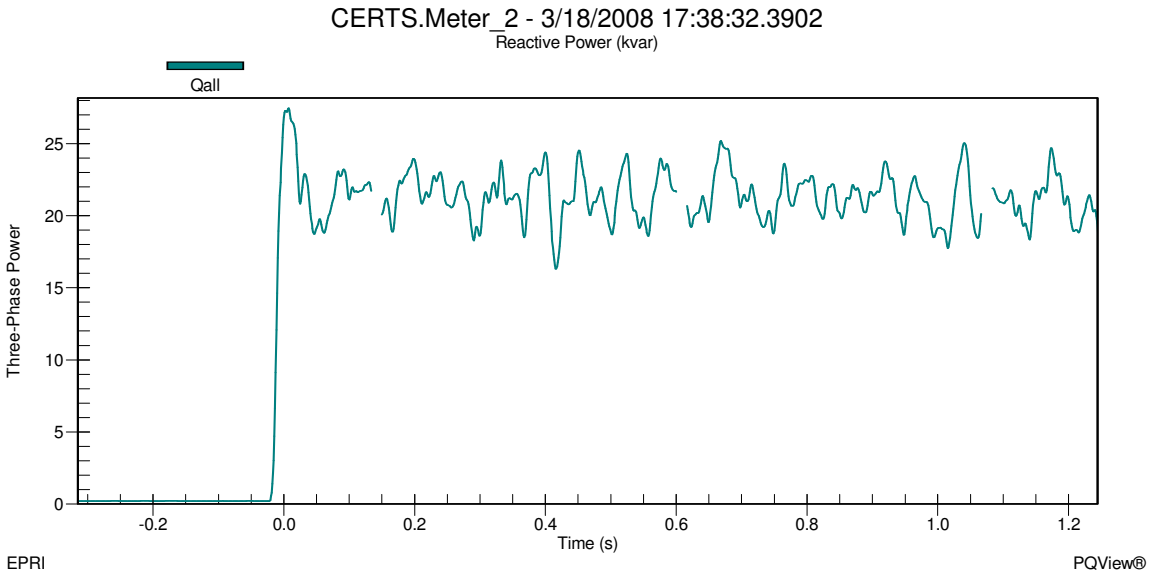

Figure 7r – Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.15

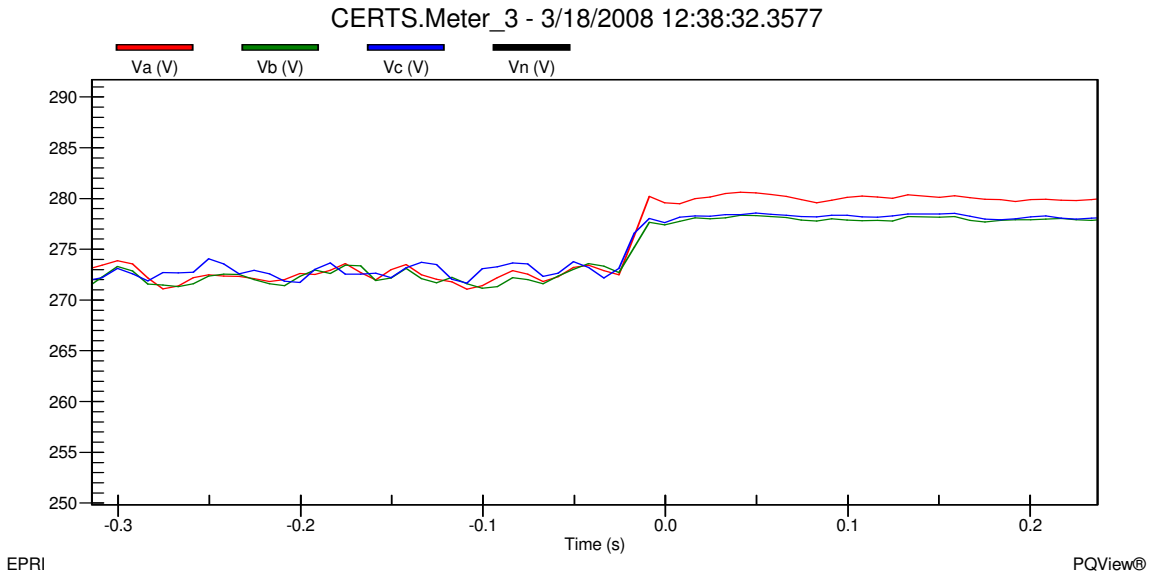

Figure 7s - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.15

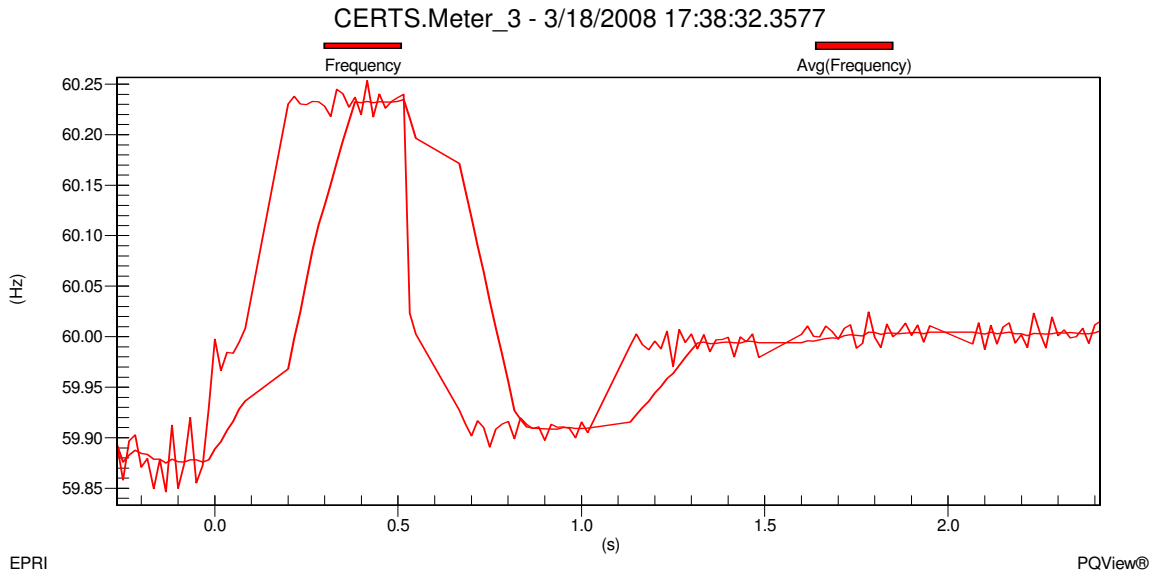

Figure 7t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.15

Frequency change in the microgrid, shown in Figure 7t, increased from approximately 59.88Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in unit power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on their set-points initialized at the beginning of the test. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.2.17) in Table 1.

For Test 10.2.17 the measured values, after Gen-set A1 was warmed up and load banks brought on-line, were approximately 19kW + j20kVAr at Meter 1, -17kW + j19.8kVAr at Meter 2 and -20kW + j 14kVAr at Meter 3. From the microgrid, 38.5kW – j13kVAr was produced by Gen-set A1. The Load Banks were 18.2kW + j0kVAr at LB3 and 35.92kW + j0.78kVAr at LB6. At the time of these measurements, the voltage and frequency was 282.6V on A-phase, 279.2V on B-phase and 279.4V on C-phase and 60.00Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282.6V on A-phase, 280V on B-phase and 280V on C-phase at Meter 3.

Gen-set A1 was setup in this test to produce more power than Load Bank 3 needed which approximately 17kW of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 35.92kW + j0.78kVAr, the utility had to supply approximately 19kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 19.8kVAr because Gen-set A1 needed

approximately 13kVAr and the reactive power absorbed in the electrical lines. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

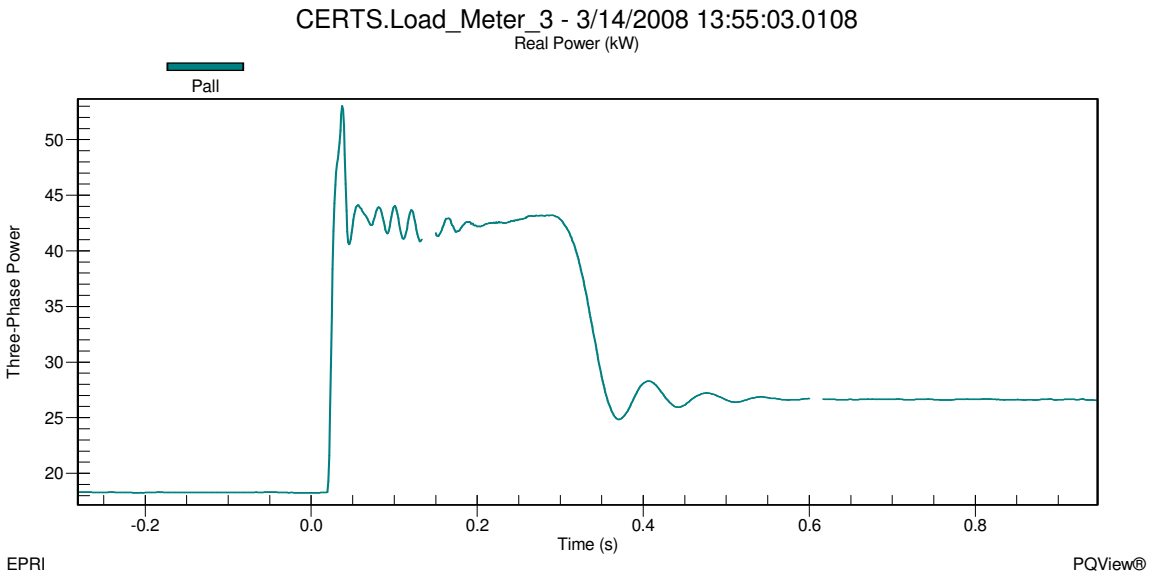

Figure 8a - Load Bank 3 Real Power during Motor Start and Utility Connected for Test 10.2.17

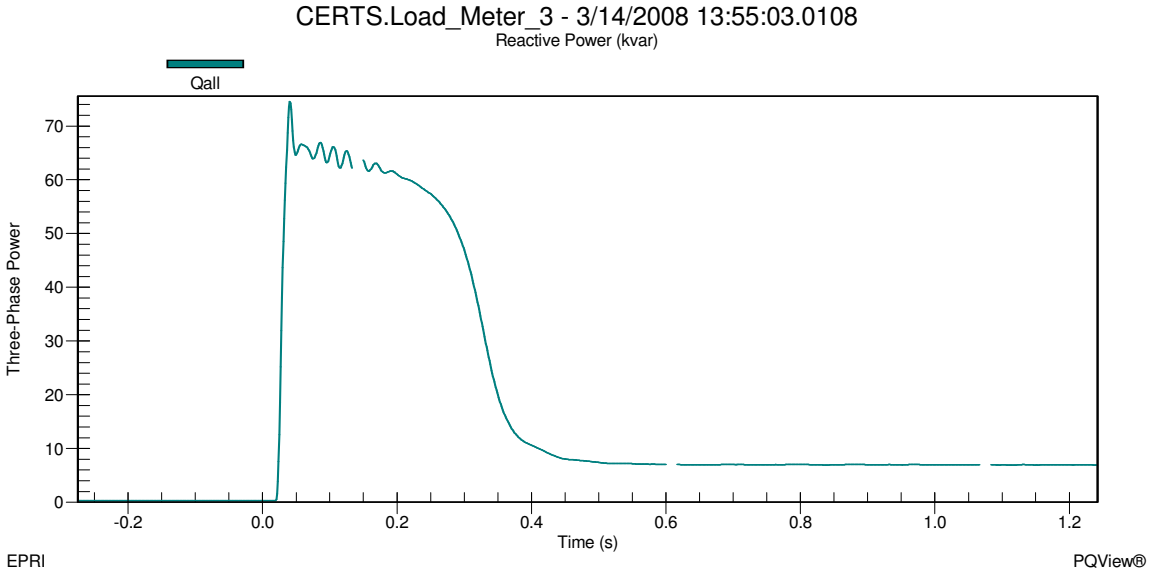

Figure 8b - Load Bank 3 Reactive Power during Motor Start and Utility Connected for Test 10.2.17

In Figures 8a and 8b it can be seen that the load in Zone 3 was approximately 18.2kW + j0kVAr before the start of the induction motor and increased to approximately 53kW + j75kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor

settled down to approximately 42.8kW + j62kVAr during the warm up phase which lasted about 27 cycles (0.45 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.7kW + j7kVAr.

The voltage and frequency at the static switch before the motor start was approximately 282.6V on A-phase, 279.2V on B-phase and 279.4V on C-phase shown in Figure 8c and approximately 60.00Hz shown in Figure 8d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.4V on A-phase, 270.9V on B-phase and 271.2V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.90Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 281.6V on A-phase, 278.2V on B-phase and 278.8V on C-phase at an approximate frequency of 60.00Hz.

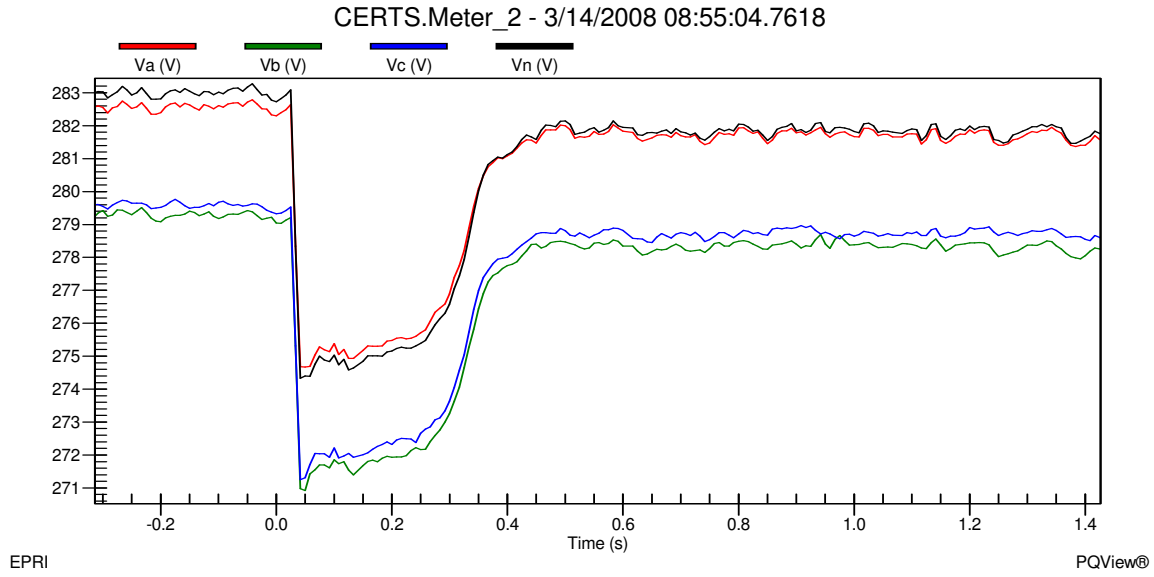

Figure 8c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.2.17

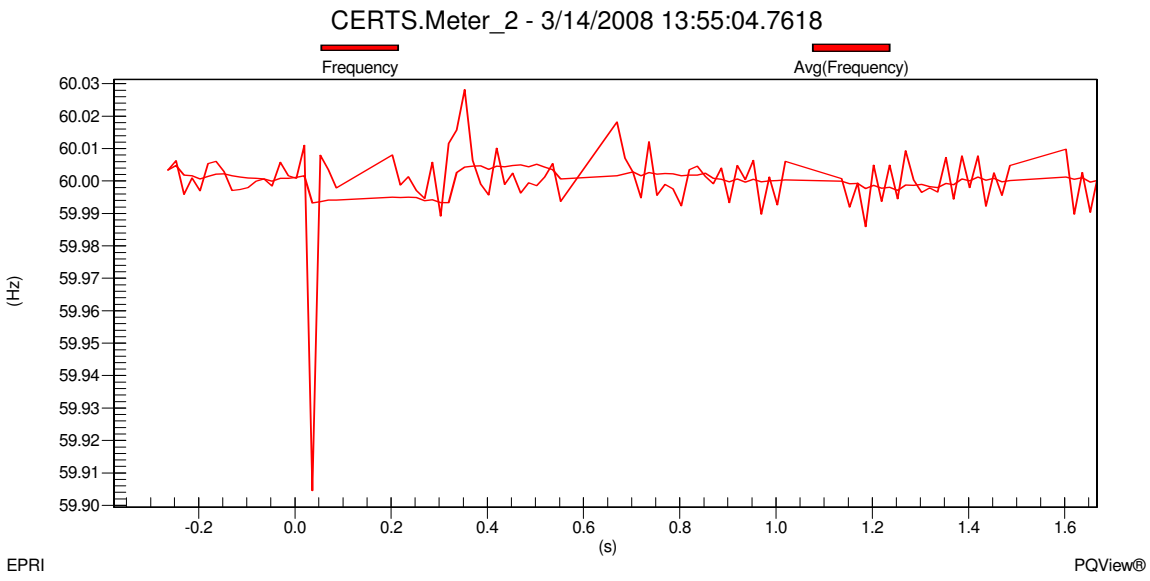

Figure 8d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.17

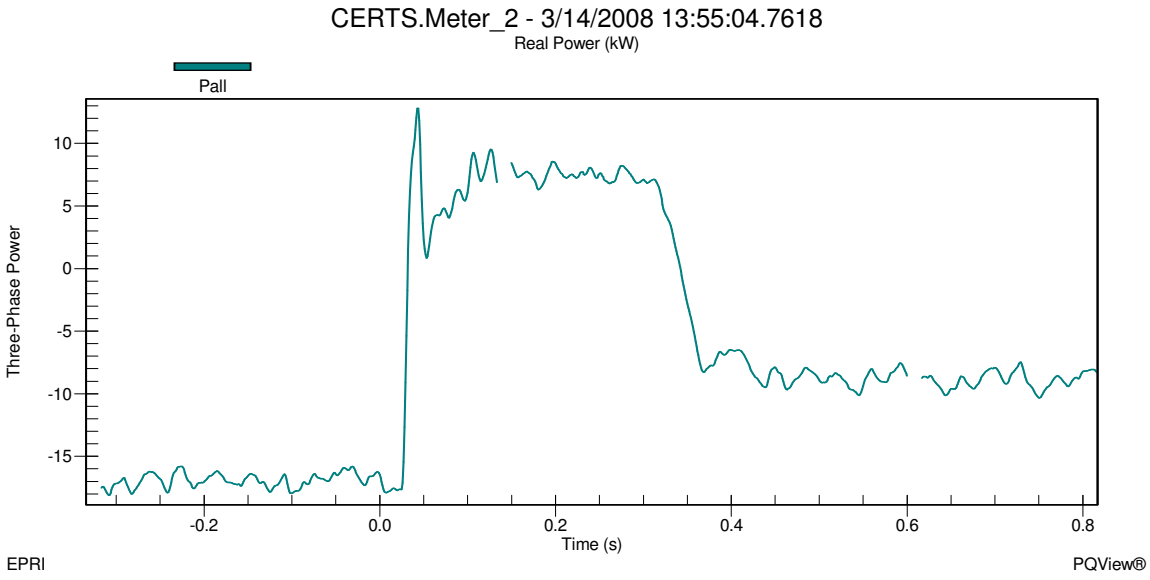

Figure 8e - Static Switch Real Power during Motor Start and Utility Connected for Test 10.2.17

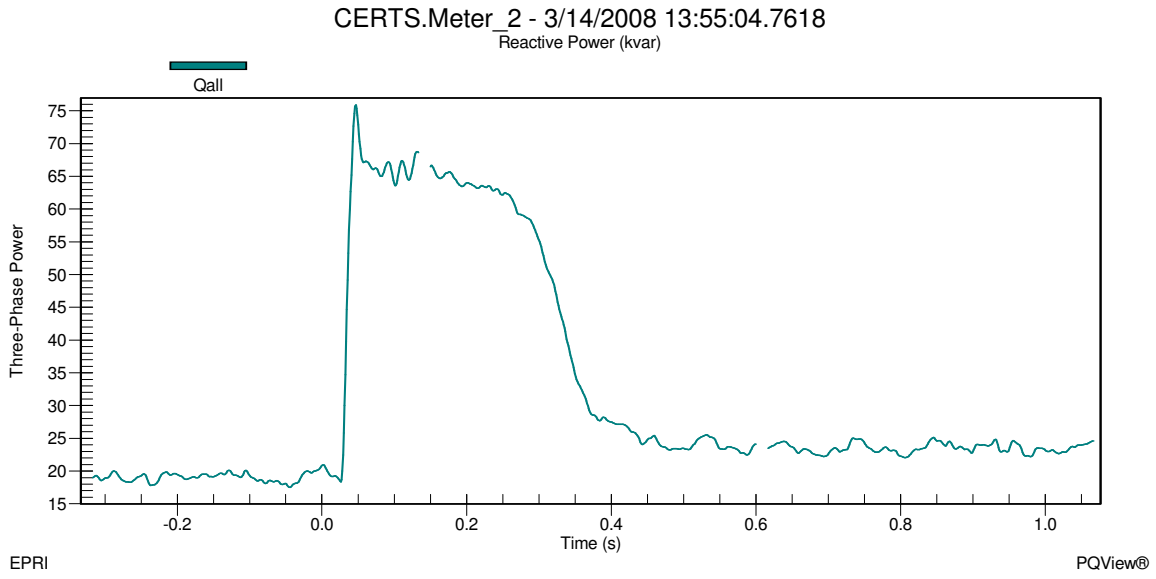

Figure 8f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.17

Before the motor start Gen-set A1 was producing approximately 38.5kW – j13kVAr. This was enough for the load demands of Zone 3 with real power being exported to Zone 6 of approximately 17kW shown in Figure 8e. The grid was supporting the reactive power of the microgrid with approximately 19.8 shown in Figure 8f. When the motor started the inrush caused the utility to supply approximately 76kVAr and to pick up the load demand in Load Bank 6 along with approximately 13kW of the load in Zone 3. The power being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 8e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output level to approximately 44kW + j4.6kVAr. Notice the sign of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -9kW + j23kVAr which meant that Gen-set A1 was supplying the power for the induction motor and approximately 9kW of Load Bank 6. Gen-set A1 real power returned to the value before the motor started of approximately 38.5kW and the reactive power increased to approximately -11.4kVAr. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 36.9kW and reactive power decreased to 1kVAr satisfying the load demand in Load Bank6 which was approximately 36.82kW + j0.787kVAr and not

supplying any power beyond the static switch to Load Bank 3. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads was slightly reduced to 23.3kW + j5.9kVAr. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 8g, from approximately 282V on A-phase, 279V on B-phase and 279V on C-phase when connected to the utility grid to 269V on A-phase, 268V on B-phase, and 269V on C-phase at Meter 3 when islanded.

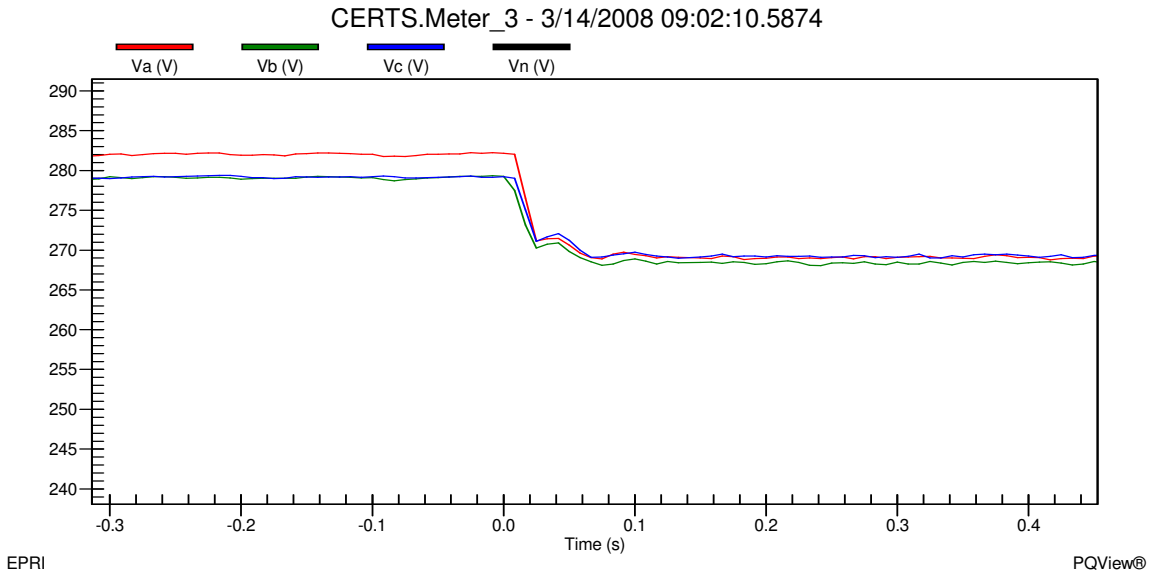

Figure 8g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.17

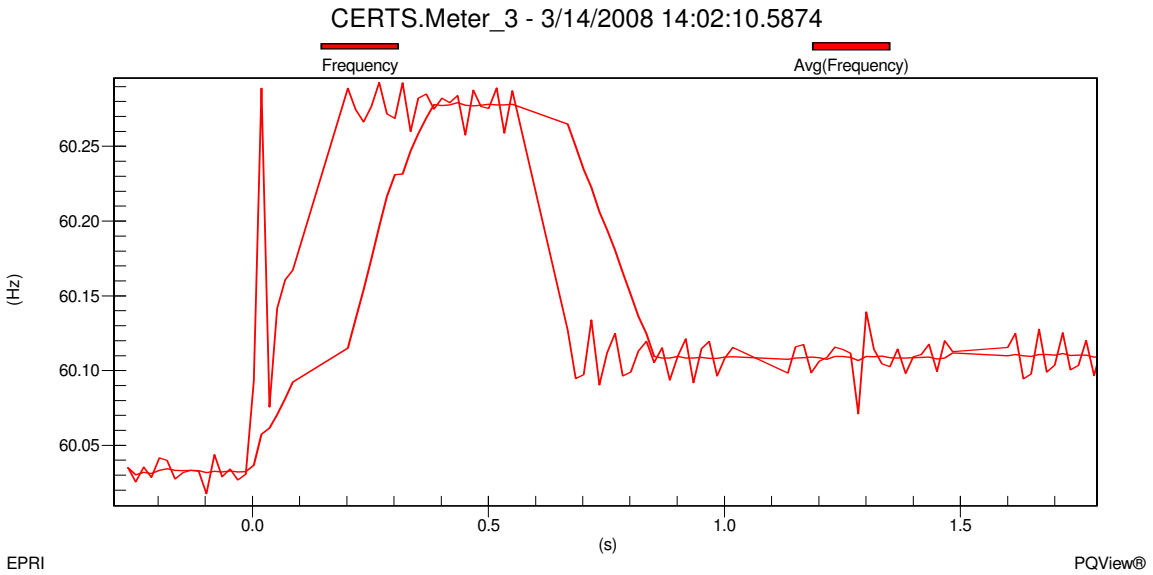

Figure 8h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.17

Frequency change in the microgrid, shown in Figure 8h, increased from approximately 60.03Hz when connected to the utility grid to approximately 60.11Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the load demands. Gen-set A1 decreased its output power to approximately 25.5kW and increased its output reactive power to approximately 9kVAr. Meter 3 was approximately -2.3kW – j3.0kVAr indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

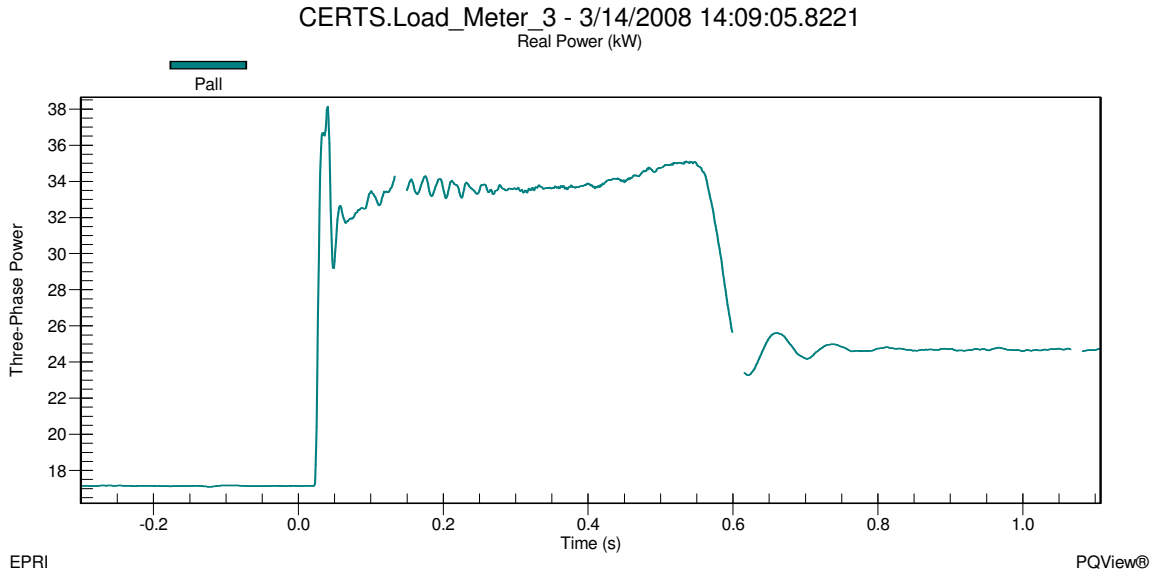

Figure 8i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.17

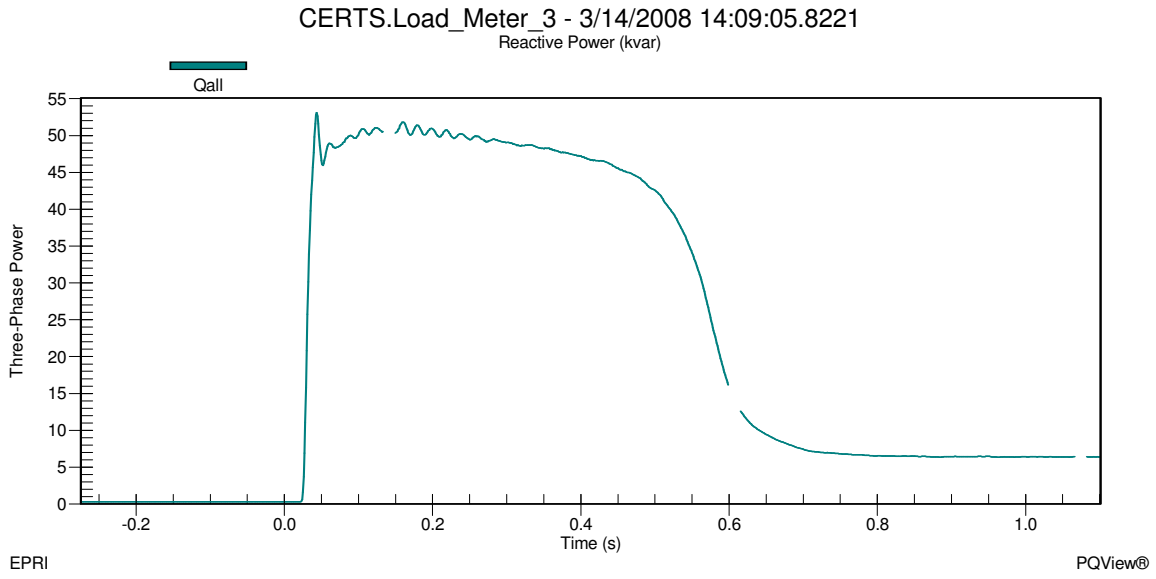

Figure 8j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.17

In Figures 8i and 8j it can be seen that the load in Zone 3 was approximately 16.4kW + j0.2kVAr before the start of the induction motor and increased to approximately 38kW + j53kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 33.5kW + j49kVAr during the warm up phase which lasted about 43.8 cycles (0.73 Seconds). When the motor reached steady state the load in Zone 3 was approximately 24.6kW + j6.5kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 272V on A-phase, 272V on B-phase and 272V on C-phase shown in Figure 8k and approximately 60.18Hz shown in Figure 8l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 238.5V on A-phase, 237.5V on B-phase and 238.5V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.75Hz and quickly increased to approximately 60.03Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 269V on A-phase, 268V on B-phase and 269V on C-phase at an approximate frequency of 60.10Hz.

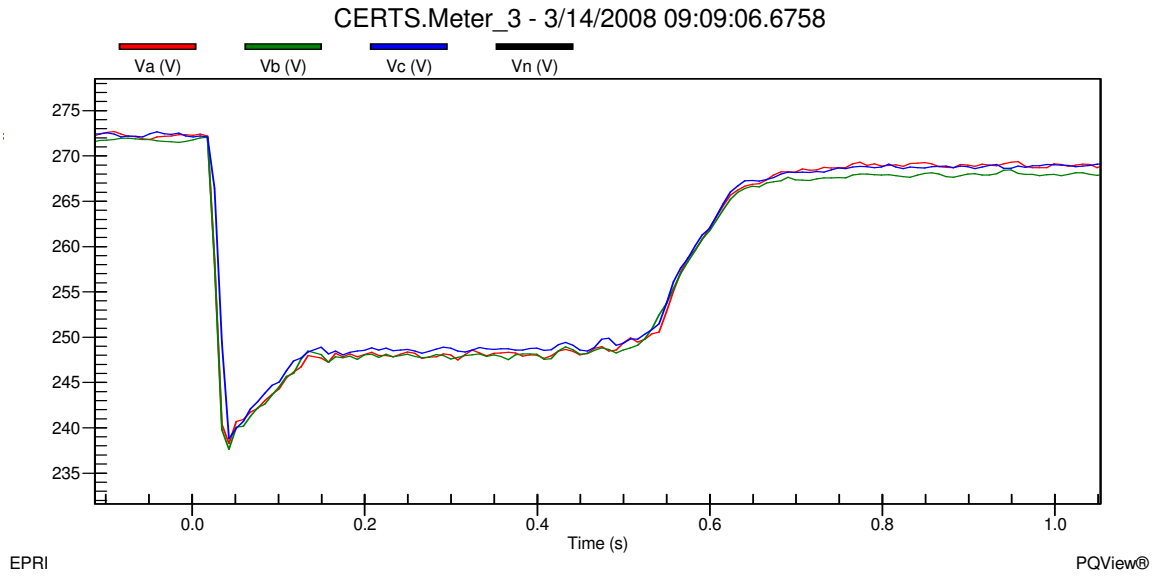

Figure 8k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.2.17

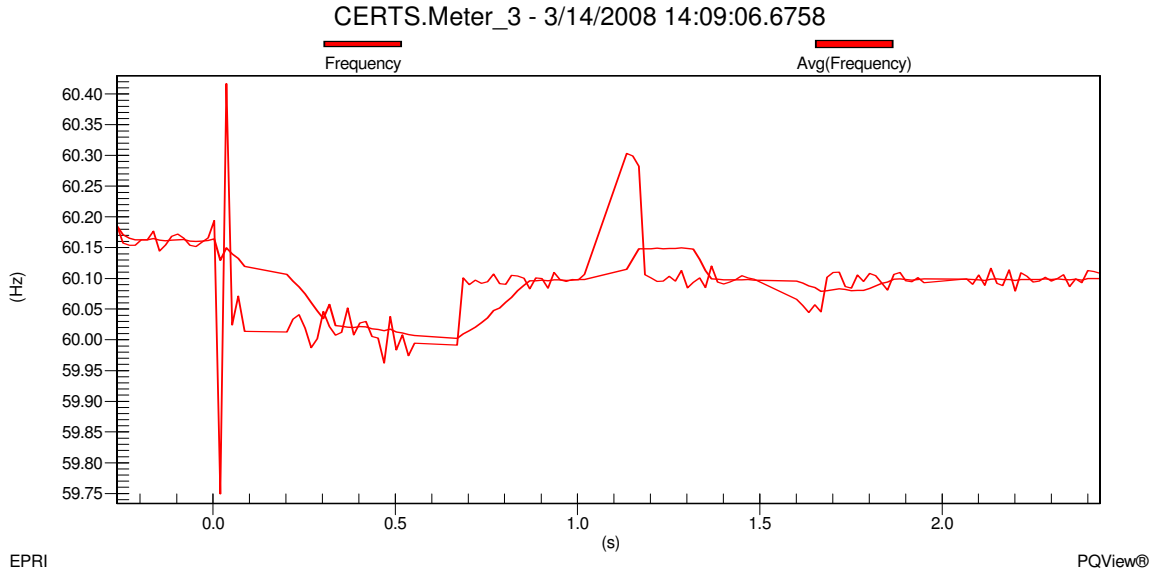

Figure 8l - Meter 3 Frequency during Motor Start and Islanded for Test 10.2.17

Before the motor started, Gen-set A1 was producing approximately 18.9kW + j4kvAr shown in Figures 8m and 8n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-set to increase its output level to 40kW + j54kVAr. Gen-set A1 decreased its output level when the motor was warming up and eventually dropped to 27kW + j9.8kVAr when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

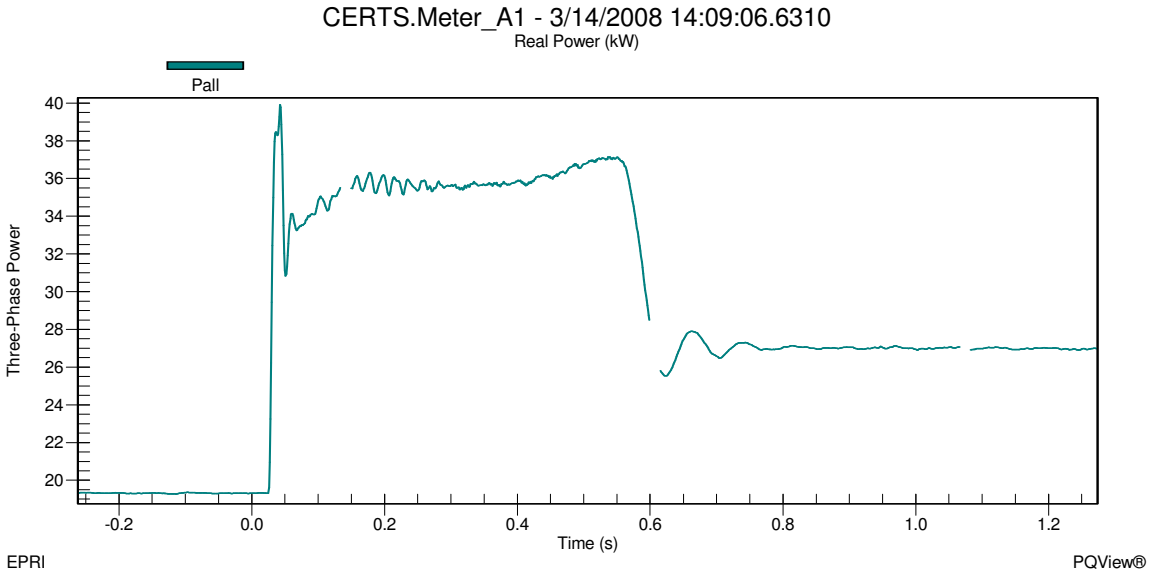

Figure 8m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.17

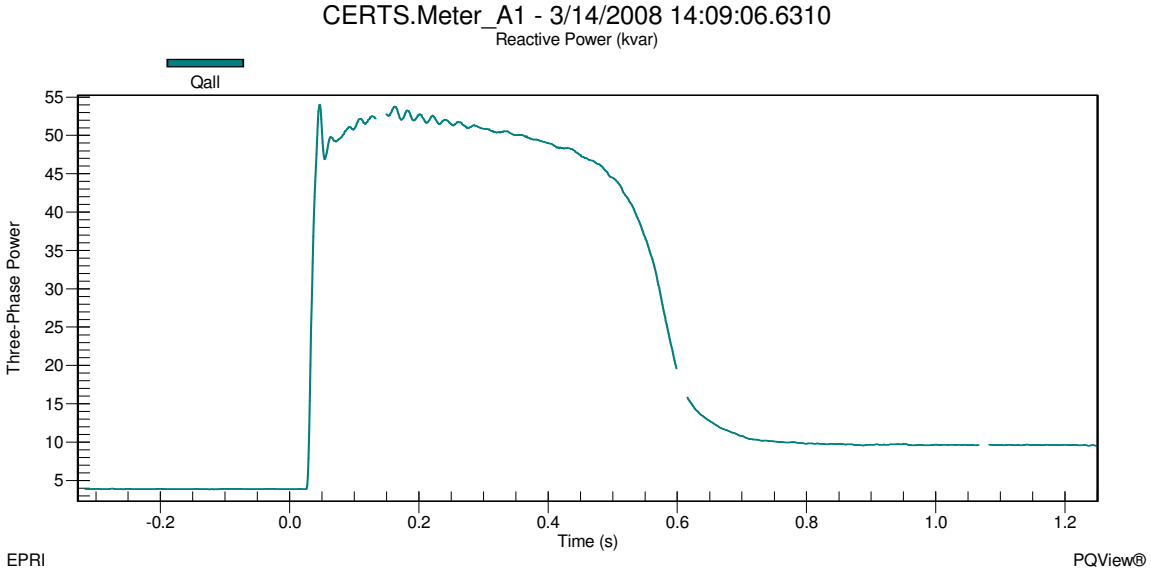

Figure 8n - Gen-set A1 Reactive Power during Motor Start and Islanded for Test 10.2.17

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 36.8kW to 25kW and reactive power increased from approximately 1kVAr to 23.7kVAr which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 8o and 8p show the static switch real power decreasing from approximately 0kW to -11kW and reactive power increasing from approximately 0kVAr to 22.2kVAr. At the beginning of the test, the initial power flow through the static switch was -17kW + j19.8kVAr which is

not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and is supporting Load Bank6 with approximately 11kW.

Load Bank 3 loads increased slightly to 25kW + j6.4kVAr. This slight increase is a result from a voltage rise in the microgrid, shown in Figure 8q, from approximately 269V on A-phase, 268V on B-phase and 269V on C-phase when islanded to 281.5V on A-phase, 279V on B-phase and 279V on C-phase at Meter 3 when connected to the utility grid.

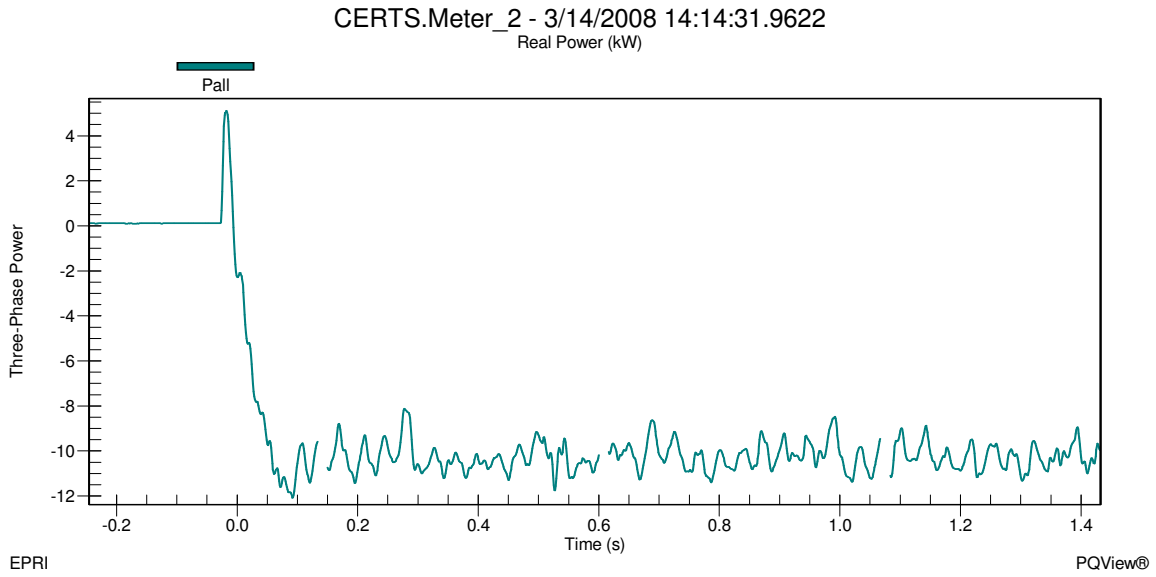

Figure 8o - Static Switch Real Power during Island to Utility Connected mode for Test 10.2.17

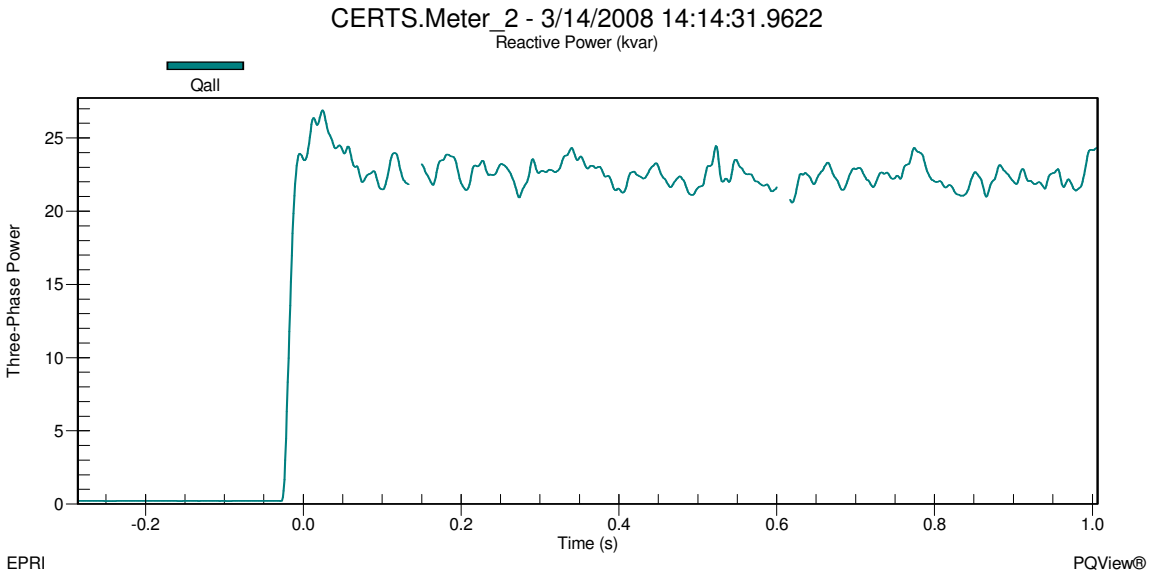

Figure 8p - Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.17

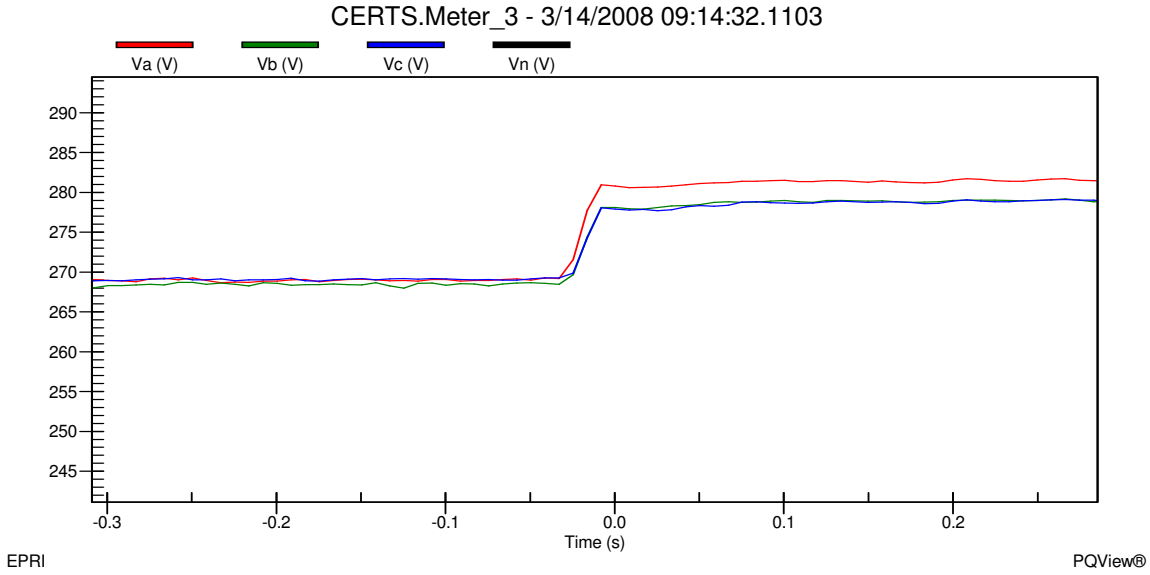

Figure 8q - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.17

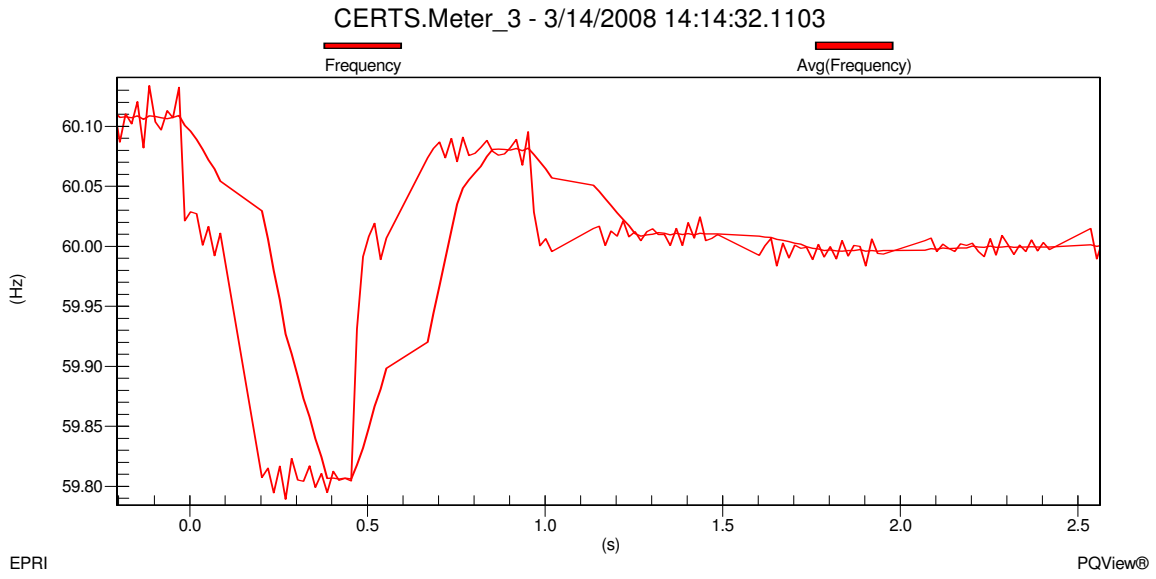

Figure 8r - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.17

Frequency change in the microgrid, shown in Figure 8r, decreased from approximately 60.11Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by Gen-set A1 using the CERTS algorithm but by the utility. Gen-set A1 is in unit power control mode therefore when the static switch closed back into the utility the Gen-set produced real power based on the set-point initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the value at the beginning of the test with Gen-set A1 producing approximately 38kW – j11.5kVAr. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.2.18) in Table 1.

For Test 10.2.18 the measured values, after the Gen-sets were warmed up and load banks brought on-line, were approximately 33kW + j22kVAr at Meter 1, -2.5kW + j20kVAr at Meter 2, -6kW + j15kVAr at Meter 3 and 12.5kW + j3kVAr at Meter 4. From the microgrid, 36kW – j12kVAr was produced by Gen-set A1 and 23.5kW – j2kVAr was produced by Gen-set A2. The load banks were 18kW + j0kVAr at LB3, 35.78kW + j0.714kVAr at LB4 and 35.9kW + j0.77kVAr at LB6. These measurements were relatively close to the expected values in Table 1, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB4 and LB6 and 20kW setting for LB3 were also below selected set values. At the time of these measurements, the voltage and frequency was 281.8V on A-phase, 279.7V on B-phase and 279.7V on C-phase and 60.02Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 281.9V on A-phase, 279.7V on B-phase and 279.2V on C-phase and 60.00Hz at Meter 3.

The Gen-sets in this test were set up to produce -10kW going through Zone 3 (i.e., Meter 3) which means they produced 10kW more power than Load Banks 3 and 4 needed. Approximately 6kW of excess power was exported out of Zone 3 and 2.5kW of that power went through the static switch to Load Bank 6 and the remaining 3.5kW was due to power losses in the conductors. Since Load Bank 6 was approximately 35.9kW + j0.77kVAr, the utility had to supply approximately 33kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 22kVAr because Gen-sets A1 and A2 needed approximately 14lkVAr between the two and the reactive power of Load Bank 4. Once all the data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

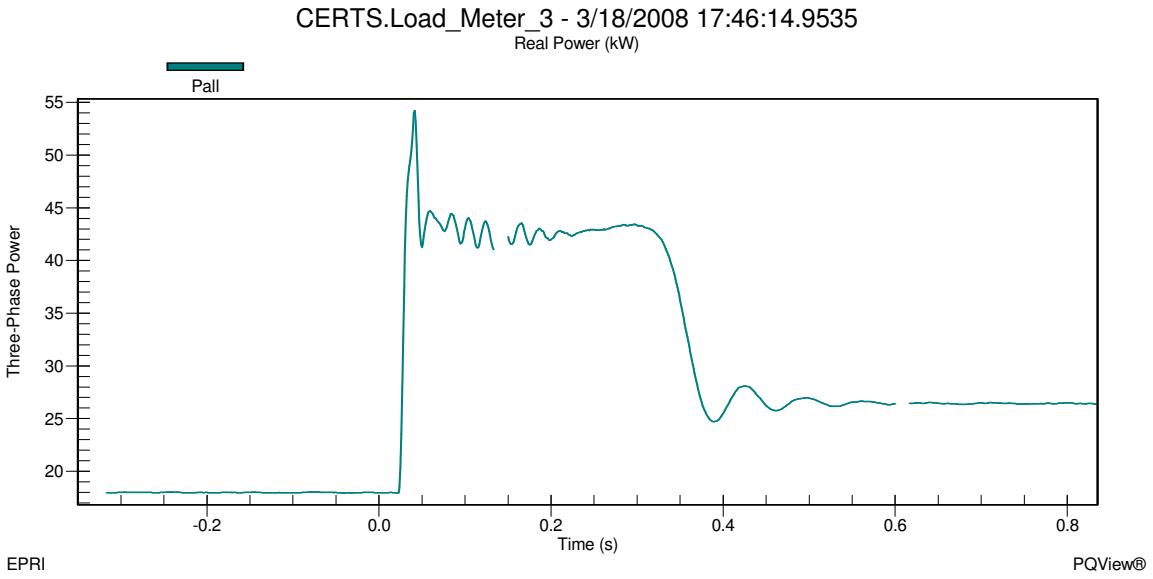

Figure 9a - Load Bank 3 Real Power during Motor Start and Utility Connected for Test 10.2.18

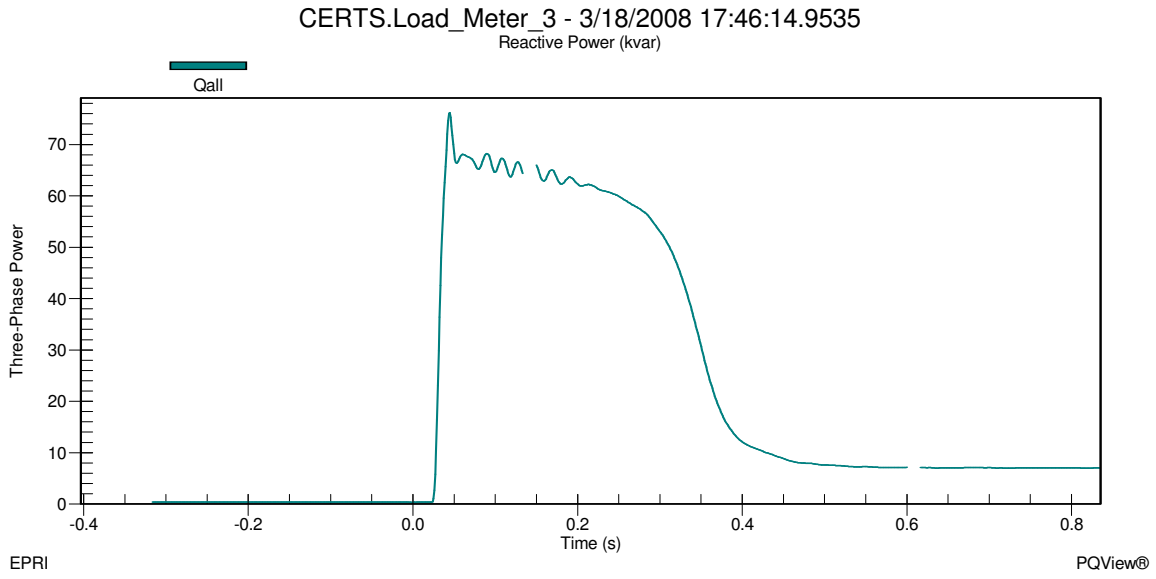

Figure 9b - Load Bank 3 Reactive Power during Motor Start and Utility Connected for Test 10.2.18

In Figures 9a and 9b it can be seen that the load in Zone 3 was approximately 18kW + j0kVAr before the start of the induction motor and increased to approximately 54.2kW + j76kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 42.8kW + j63kVAr during the warm up phase which lasted about 28.2 cycles (0.47 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.5kW + j7kVar.

The voltage and frequency at the static switch before the motor start was approximately 281.8V on A-phase, 279.7V on B-phase and 279.7V on C-phase shown in Figure 9c and approximately 60.02Hz shown in Figure 9d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.5V on A-phase, 271.5V on B-phase and 271.5V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.94Hz and quickly increased to approximately 60.02Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 280.8V on A-phase, 278.8V on B-phase and 278.8V on C-phase at an approximate frequency 60.02Hz.

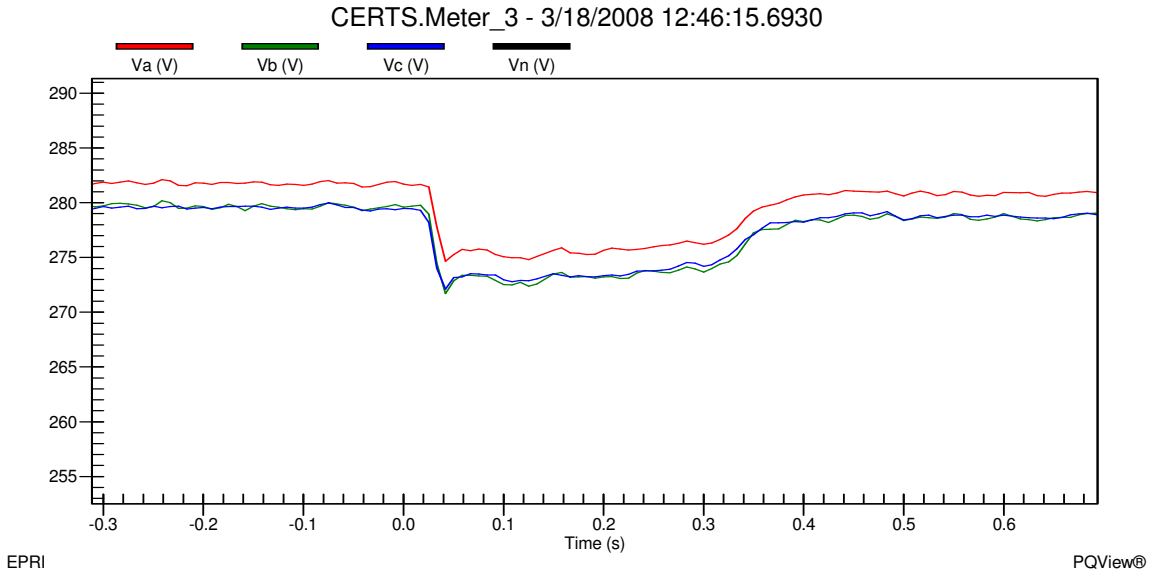

Figure 9c - Static Switch Line-to-Ground Voltage during Motor Start and Utility Connected for Test 10.2.18

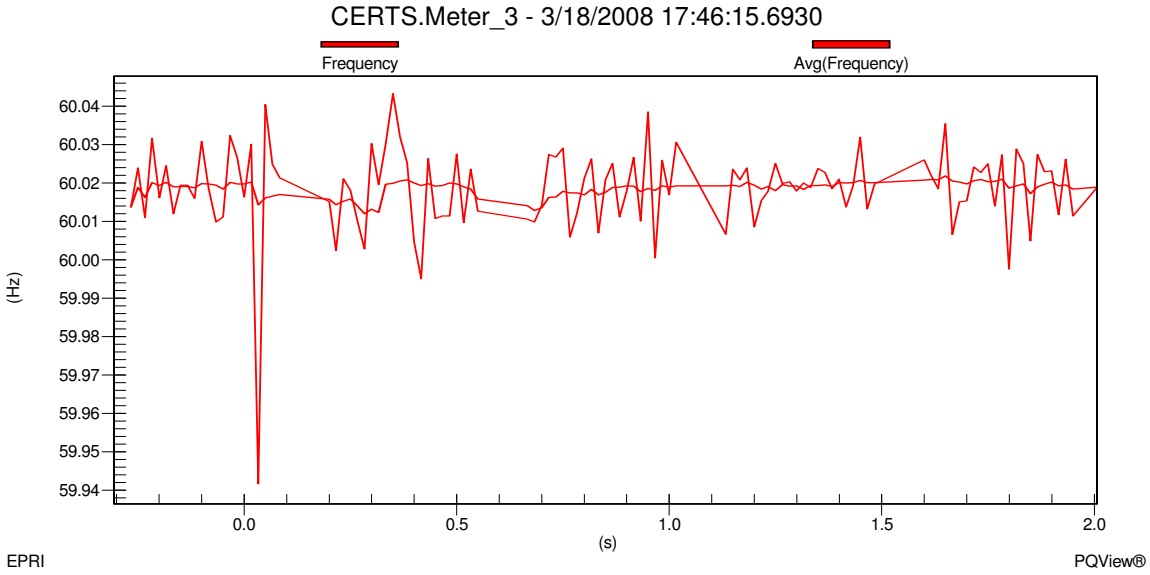

Figure 9d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.18

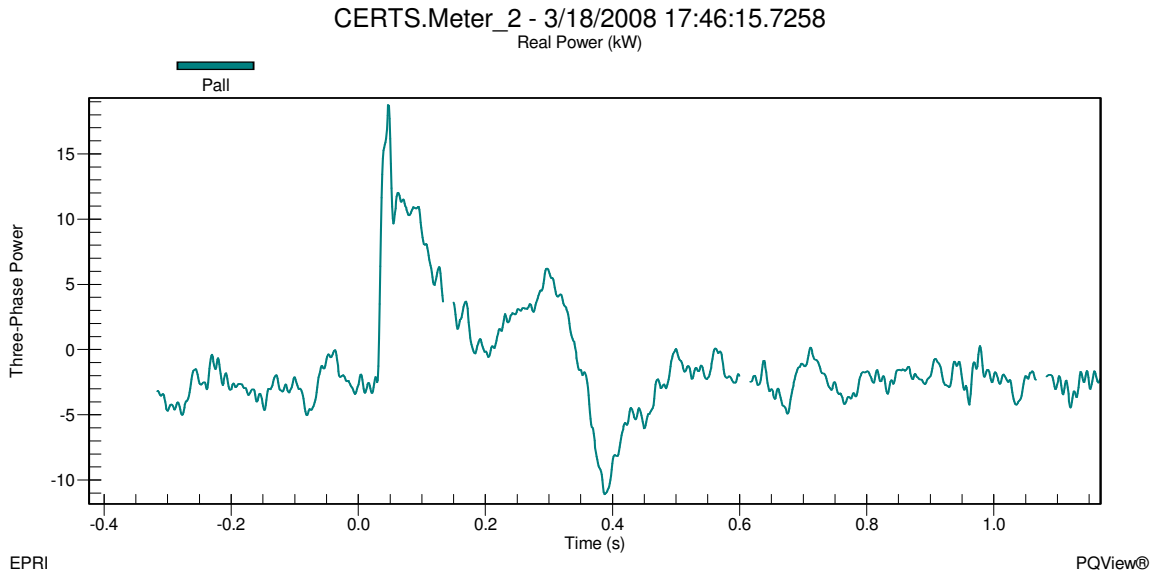

Figure 9e - Static Switch Real Power during Motor Start and Utility Connected for Test 10.2.18

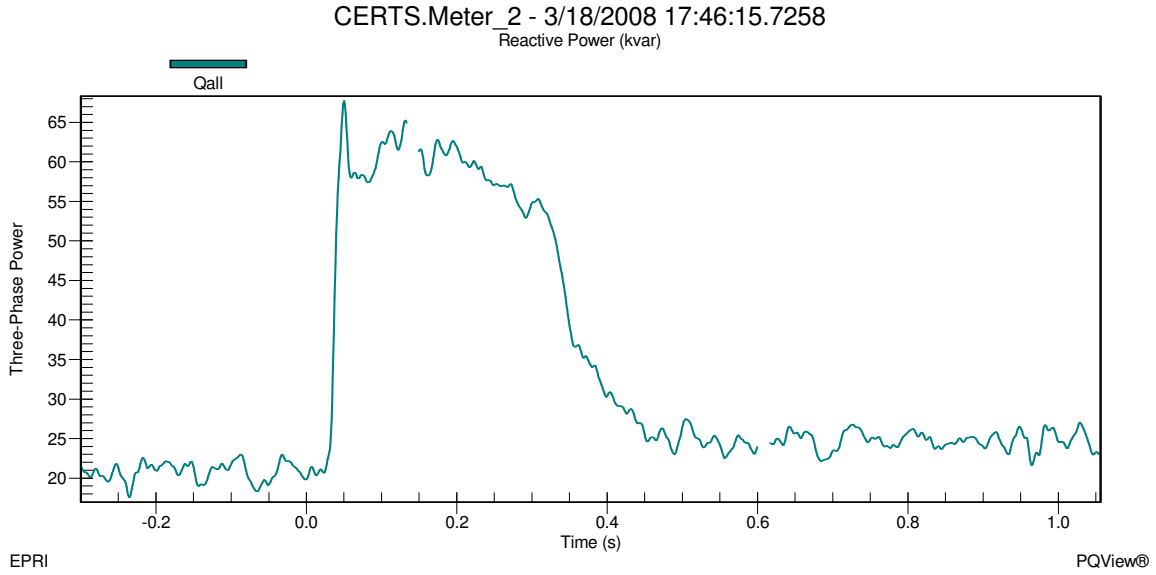

Figure 9f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.18

Before the motor started Gen-sets A1 and A2 were producing approximately 36kW – j12kVAr and 23.5kW – j2kVAr, respectively. This was enough power for the load demands of Load Banks 3 and 4 with real power being exported to Zone 6 of approximately 2.5kW shown in Figure 9e. The grid was supporting the reactive power of the microgrid with approximately 20kVAr shown in Figure 9f. When the motor started the inrush caused the utility to supply approximately 68kVAr and to pick up the load demand of Load Bank 6 and approximately 18.8kW of the microgrid loads. The power that was being supplied by Gen-set A1 to Load Bank 6 was now supplying the

motor inrush which can be seen in Figure 9e as the real power through the static switch becomes positive. Gen-sets A1 and A2 increased their real and reactive power output levels to approximately 59kW – j0.6kVAr and 31.8kW + j18kVAr, respectively. Notice the signs of the VAr output changed from negative to positive for both Gen-sets in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -2.5kW + j24kVAr which meant that Gen-sets A1 and A2 were supplying the power for the induction motor and approximately 2.5kW of Load Bank 6. The real power in Gen-set A1 increased from its initial value at the beginning of the test to approximately 44kW and the real power for Gen-set A2 returned to the value before the motor started which was approximately 23.5kW. Reactive power in Gen-set A1 and A2 increased from its initial value at the beginning of the test to approximately -9kVAr and -0.5kVAr, respectively. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 37kW and reactive power decreased to 1.2kVAr satisfying the load demand in Load Bank 6 which was approximately 36.78kW + j0.785kVAr and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Banks 3 and 4 loads reduced slightly to 17.4kW + j0.3285kVAr and 34.45kW + j0.686kVAr, respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 9g, from approximately 281.9V on A-phase, 279.8V on B-phase and 279.8V on C-phase when connected to the utility grid to 275V on A-phase, 275V on B-phase and 275V on C-phase at Meter 3 when islanded.

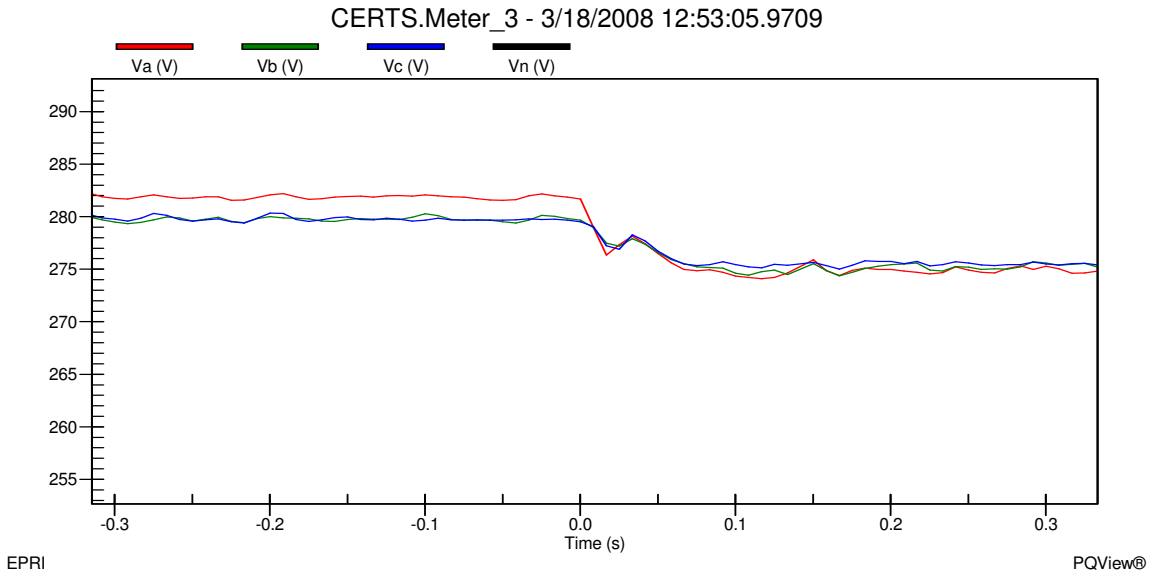

Figure 9g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.18

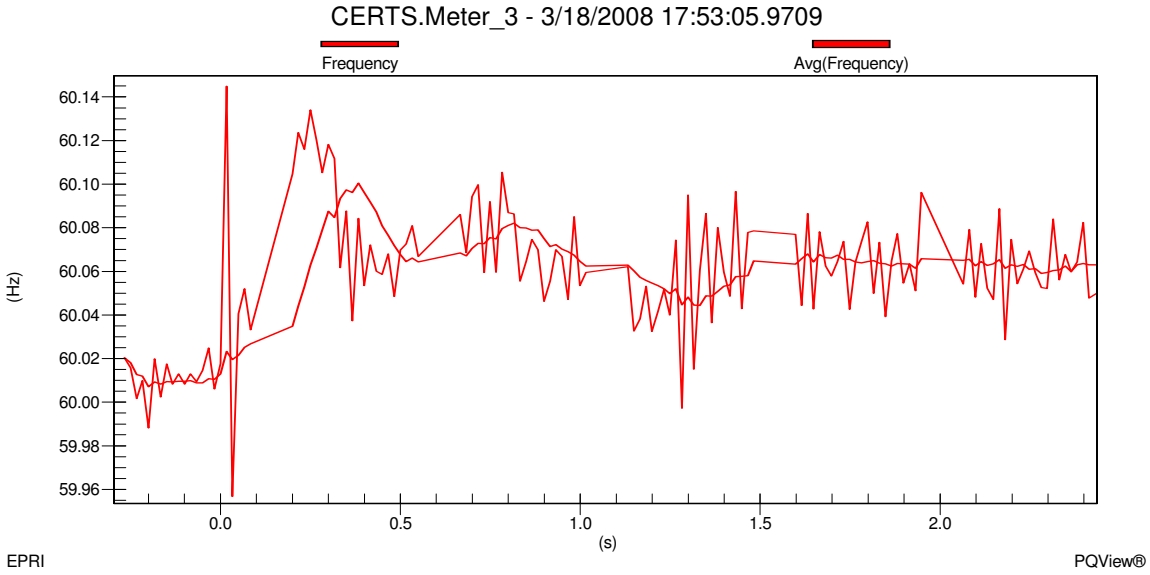

Figure 9h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.18

Frequency change in the microgrid, shown in Figure 9h, increased from approximately 60.01Hz when connected to the utility grid to approximately 60.06Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A2 to decrease its output real power to approximately 17.5kW. Gen-set A1 remained relatively at the same level which was approximately 37kW. Reactive power in Gen-sets A1 and A2 increased to approximately -3kVAr and 8kVAr, respectively. Meter 3 was approximately -2.03kW -j2.05kAr indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

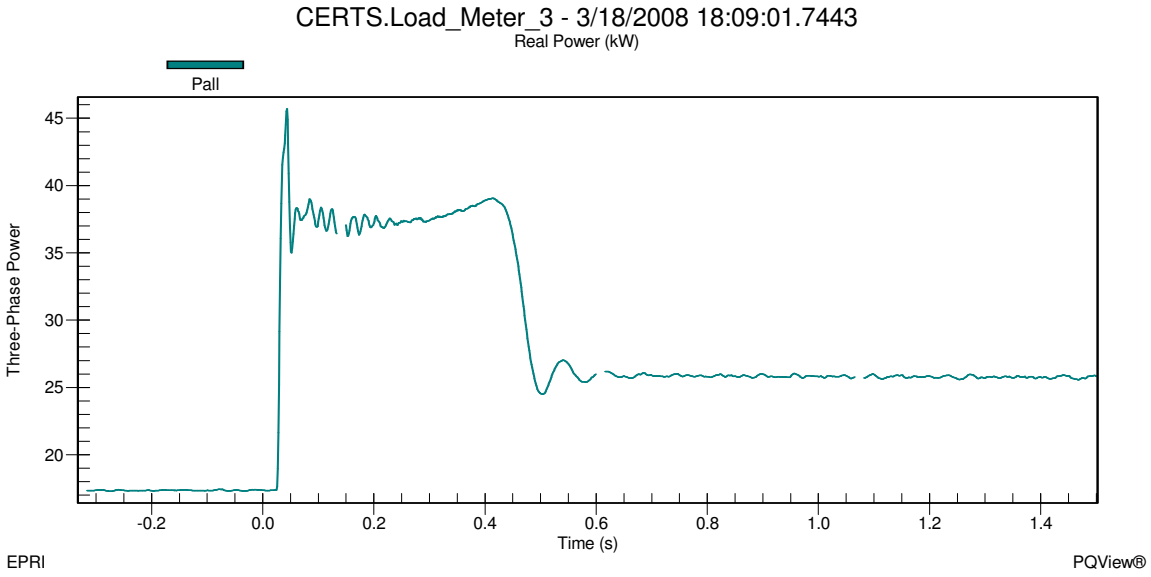

Figure 9i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.18

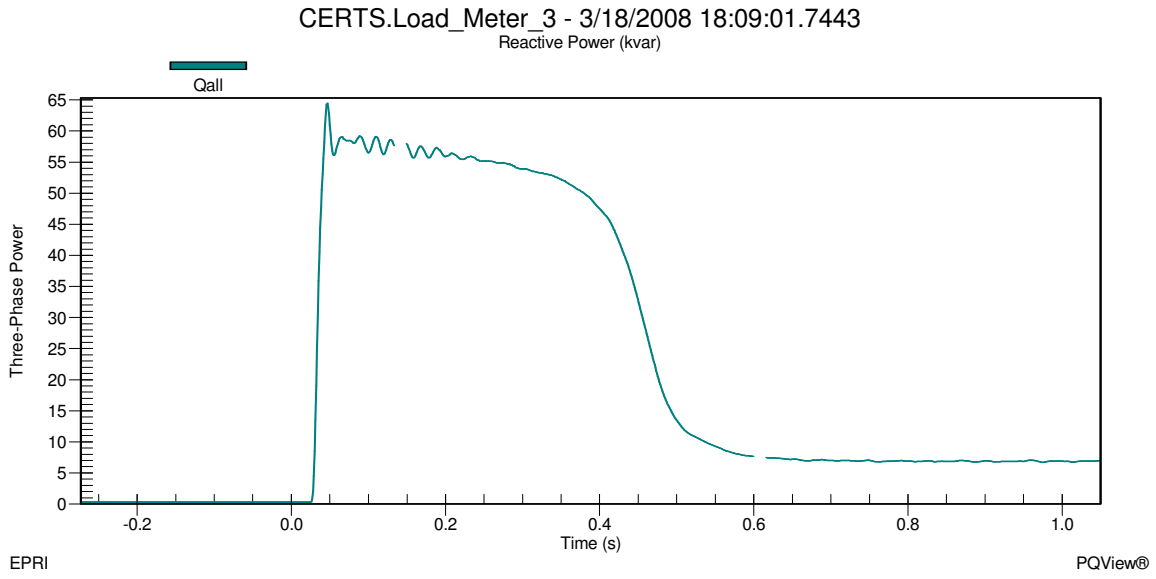

Figure 9j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.18

In Figures 9i and 9j it can be seen that the load in Zone 3 was approximately 17.5kW + j0kVAr before the start of the induction motor and increased to approximately 46kW + j65kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 37.8kW + j55kVAr during the warm up phase which lasted about 37.8 cycles (0.63 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 25.8kW + j7kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 275V on A-phase, 275V on B-phase and 275V on C-phase shown in Figure 9k and approximately 60.07Hz shown in Figure 9l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 254.5V on A-phase, 255.9V on B-phase and 255.9V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.97Hz and quickly increased to approximately 60.03Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 273V on A-phase, 273V on B-phase and 273V on C-phase at an approximate frequency of 60.06Hz.

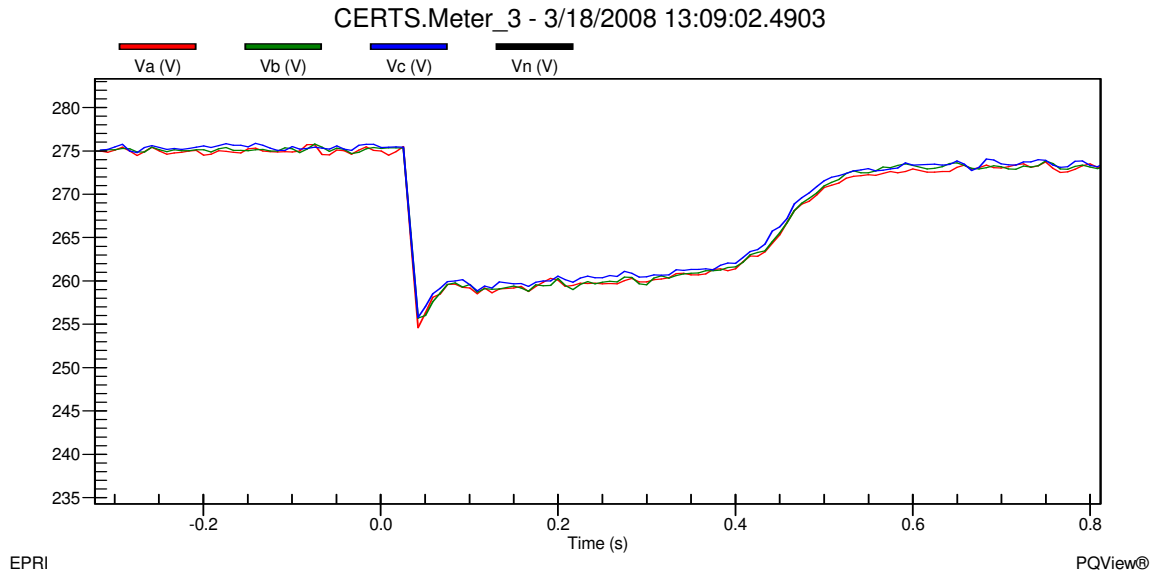

Figure 9k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.2.18

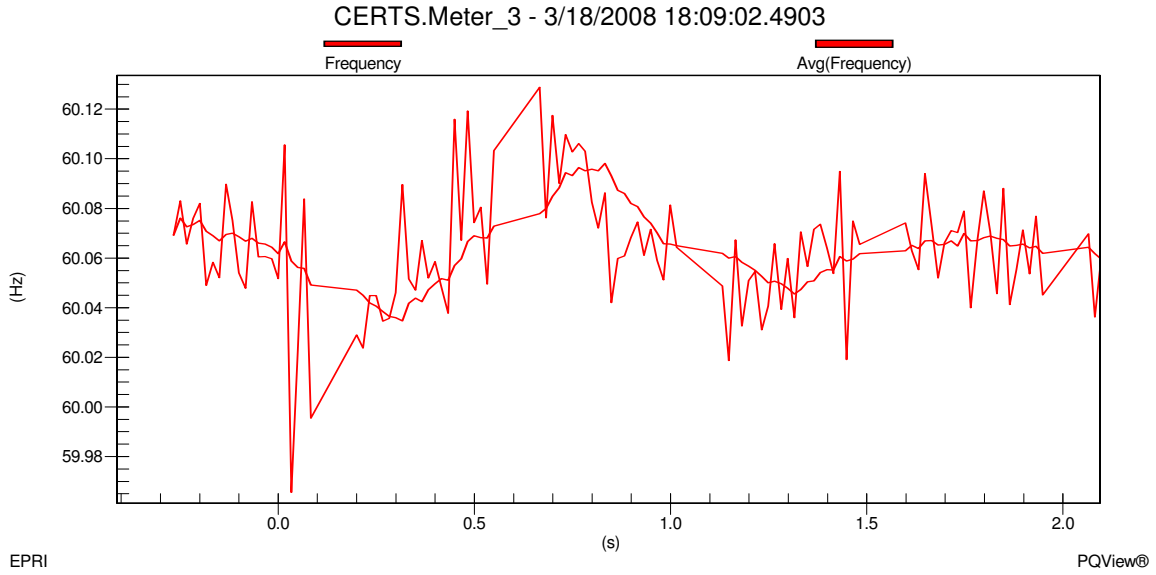

Figure 9l - Meter 3 Frequency during Motor Start and Islanded for Test 10.2.18

Before the motor started Gen-sets A1 and A2 were producing approximately 37kW – j3kVAr and 17.5kW + j8kVAr, respectively shown in Figures 9m – 9p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output power levels to 47.5kW + j30kVAr for Gen-set A1 and 30kW + j37kVAr for Gen-set A2. The increase in real and reactive power due to the motor start inrush was shared by both Gen-sets and Gen-set A2 picked up most of the real power. Gen-set A1 increased its output real power during the warm up phase to approximately 57kW and decreased its reactive power. Gen-set A2 decreased real and reactive power output during the warm up phase. The Gen-sets eventually dropped

their output levels to 45.4kW – j0.2kVAr for Gen-set A1 and 16.5kW + 11.1kVAr for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

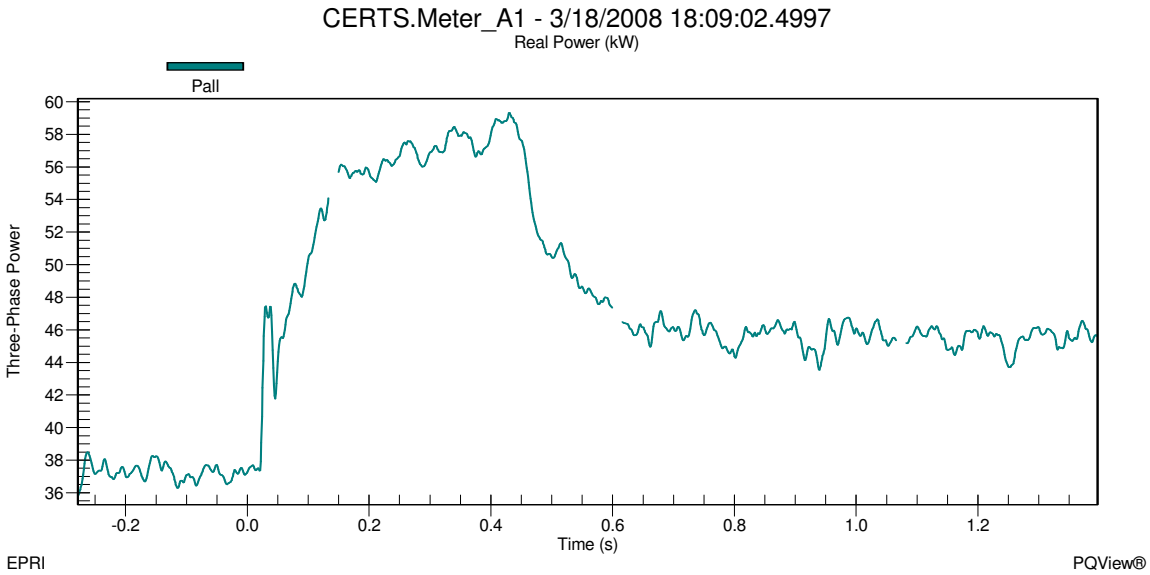

Figure 9m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.18

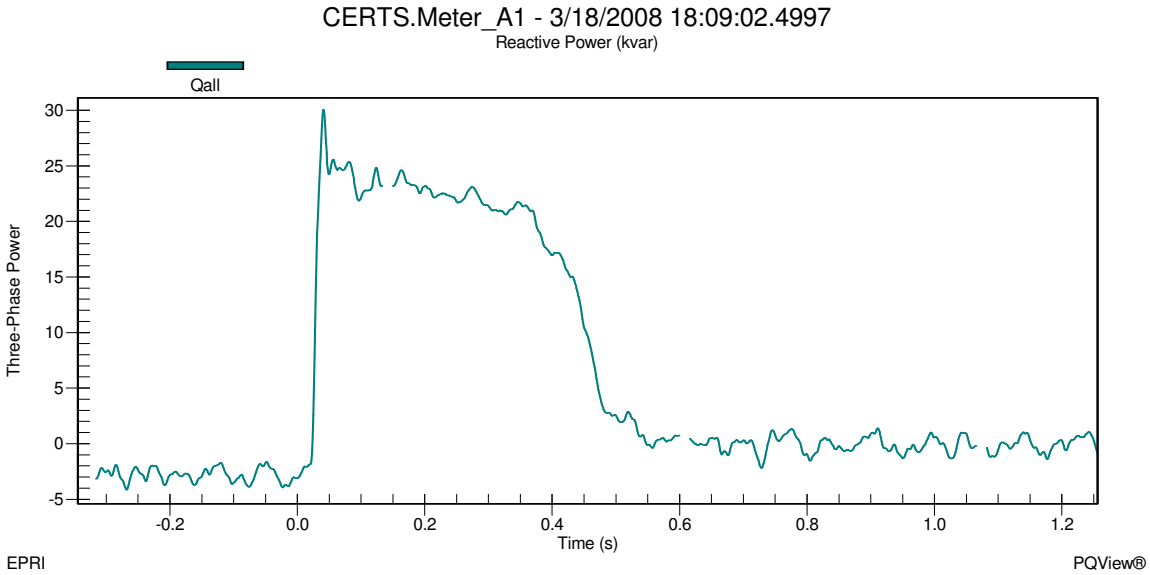

Figure 9n - Gen-set A1 Reactive Power during Motor Start and Islanded for Test 10.2.18

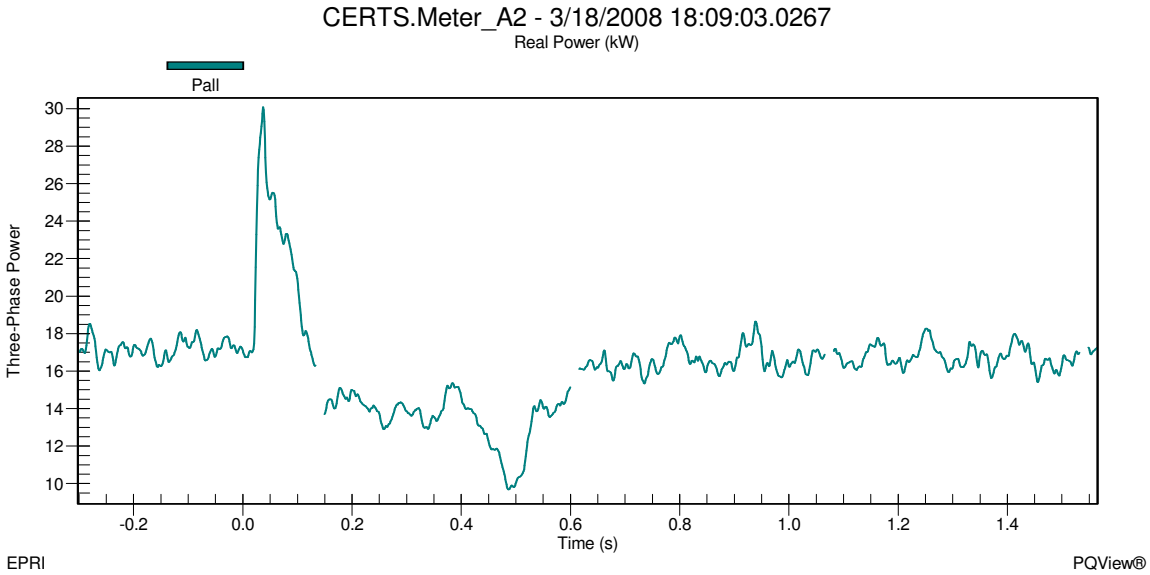

Figure 9o - Gen-set A2 Real Power during Motor Start and Islanded for Test 10.2.18

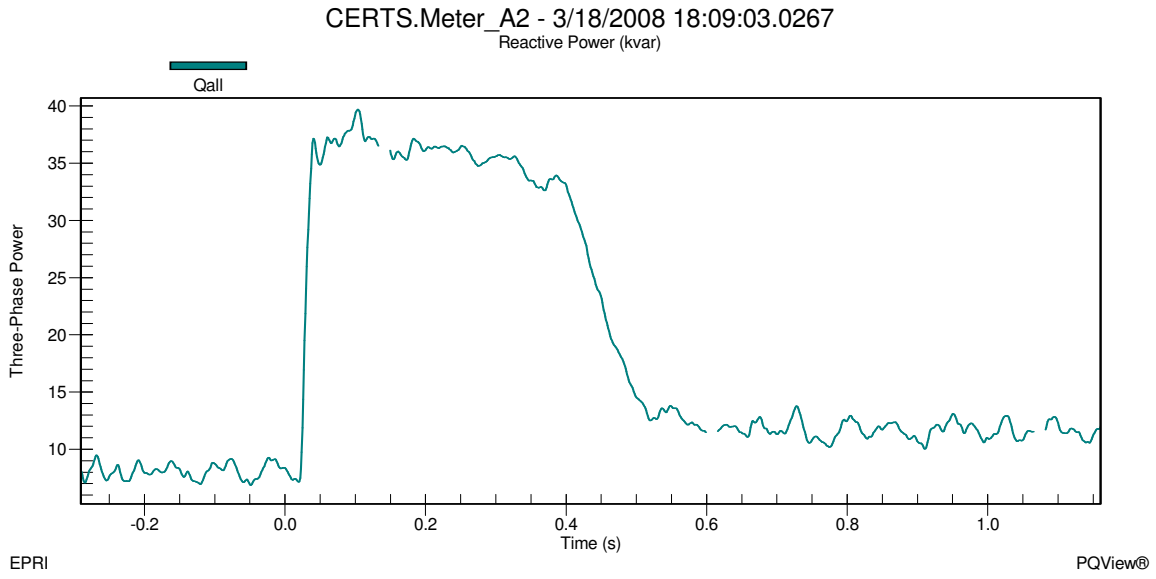

Figure 9p - Gen-set A2 Reactive Power during Motor Start and Islanded for Test 10.2.18

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 37kW to 30kW and reactive power increased from approximately 1.5kVAr to 29kVAr which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 9q and 9r show the static switch real power decreasing from approximately 0kW to -5kW and reactive power increasing from approximately 0kVAr to 27.2kVAr. At the beginning of the test, the initial power flow through the static switch was -2.5kW + j20kVAr which is not the same recorded at this point in the test because the 10 Hp motor load is on in Zone 3. The Gen-sets have picked up the motor load and supporting Load Bank 6 with approximately 5kW.

Load Banks 3 and 4 loads increased slightly to 25.1kW + j6.49kVAr and 35.8kW + j0.714kVAr, respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 9s, from approximately 273.2V on A-phase, 273.2V on B-phase and 273.2V on C-phase when islanded to 282V on A-phase, 279.5V on B-phase and 279.5V on C-phase at Meter 3 when connected to the utility grid.

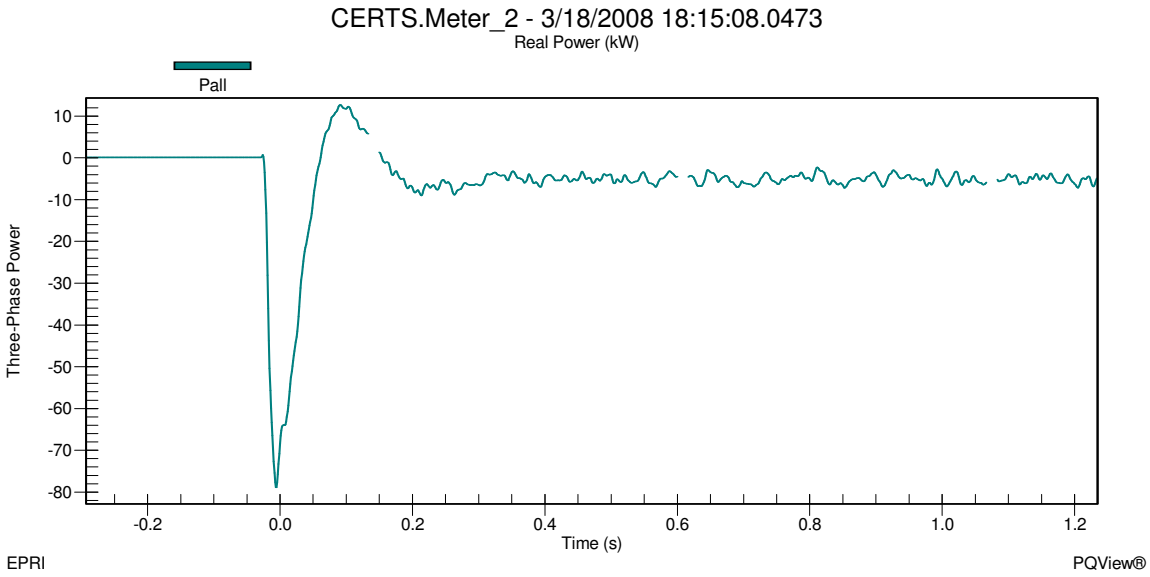

Figure 9q - Static Switch Real Power during Island to Utility Connected mode for Test 10.2.18

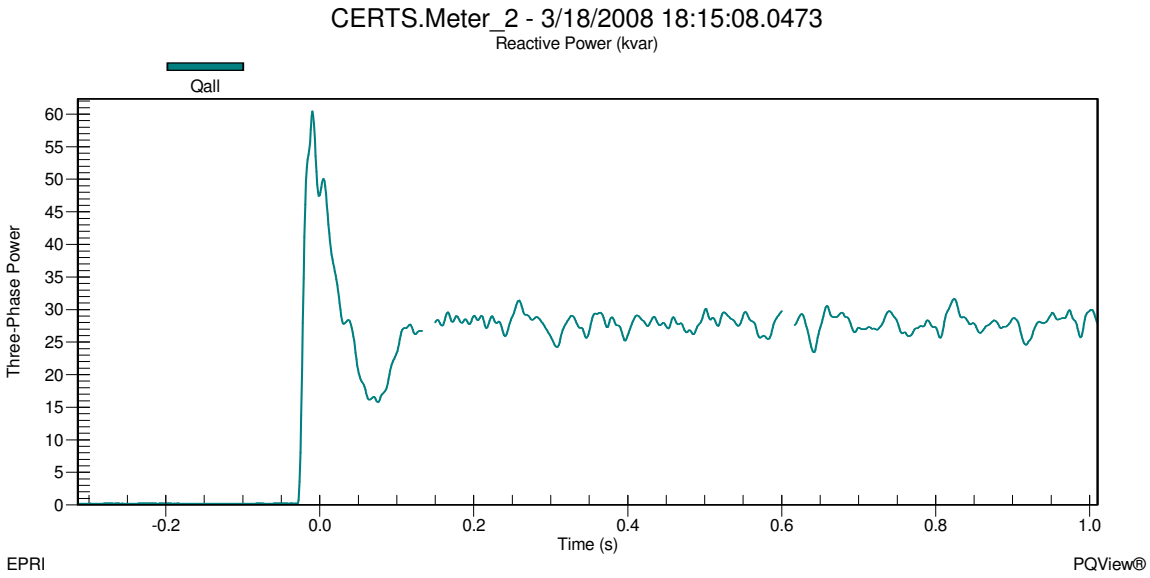

Figure 9r - Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.18

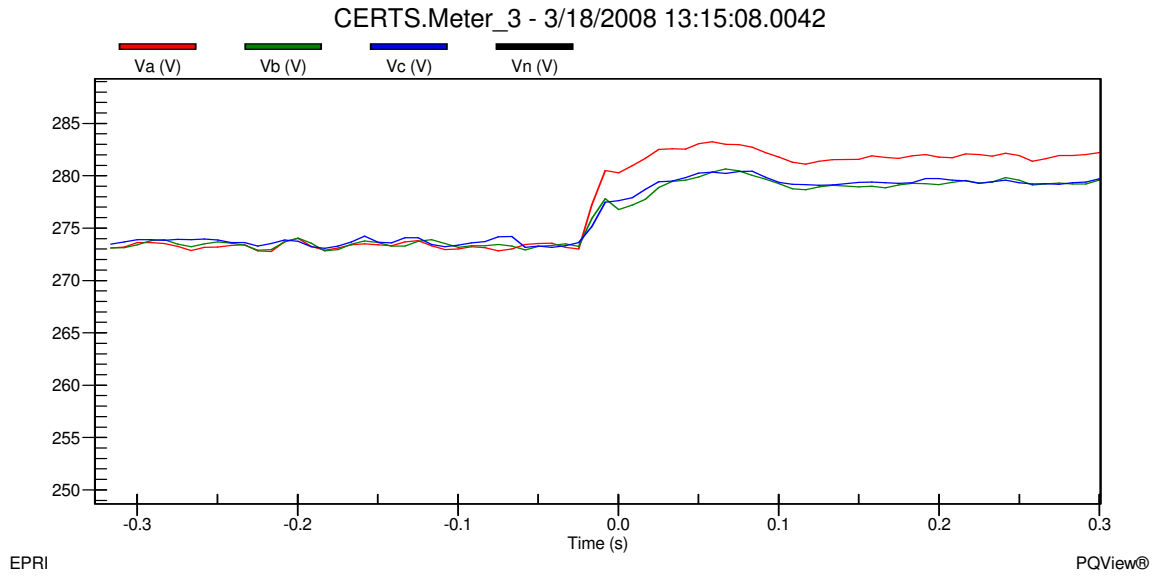

Figure 9s - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.18

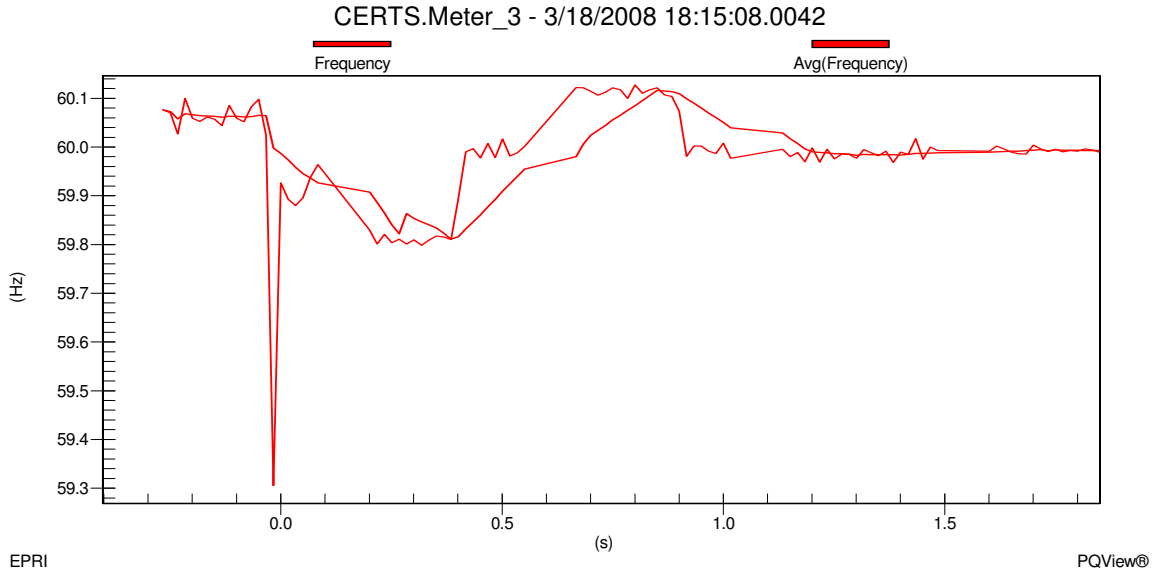

Figure 9t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.18

Frequency change in the microgrid, shown in Figure 9t, decreased from approximately 60.06Hz when islanded to approximately 59.99Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in zone power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on set-points for the power flow through Zones 3 and 4 initialized at the beginning of the test. The real power in both Gen-sets increased from their initial values at the beginning of the test to approximately 42kW for Gen-set

A1 and 26kW for Gen-set A2. This increase is because the Gen-sets have picked up the real power of the induction motor in Zone 3. Reactive powers for both Gen-sets were relatively close to the values at the beginning of the test with approximately -12.5kVAr for Gen-set A1 and -3kVAr for Gen-set A2. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.2.20) in Table 1.

For Test 10.2.20 the measured values, after Gen-set A1 was warmed up and load banks brought on-line, were approximately 22kW + j19kVAr at Meter 1, -15kW + j18kVAr at Meter 2 and -17kW + j8kVAr at Meter 3. From the microgrid, 35.8kW – j12kVAr was produced by Gen-set A1. The load banks were 18kW + j0kVAr at LB3 and 35.8kW + j0.775kVAr at LB6. These measurements were relatively close to the expected values in Table 1, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW setting for LB6 and 20kW setting for LB3 were also below selected set values. At the time of these measurements, the voltage and frequency was 282.2V on A-phase, 278.8V on B-phase and 278.8V on C-phase and 60.00Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282.5V on A-phase, 279.5V on B-phase and 279.5V on C-phase and 60.00Hz at Meter 3.

Gen-set A1 in this test was set up to produce -20kW going through Zone 3 (i.e., Meter 3) which means it produced 20kW more power than Load Bank 3 needed. Approximately 17kW of excess power was exported out of Zone 3 and 15kW of that power went through the static switch to Load Bank 6 and the remaining 2kW was due to power losses in the conductors. Since Load Bank 6 was approximately 35.8kW + j0.775kVAr, the utility had to supply approximately 22kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 19kVAr because Gen-set A1 needed approximately 12kVAr and losses in the conductors.

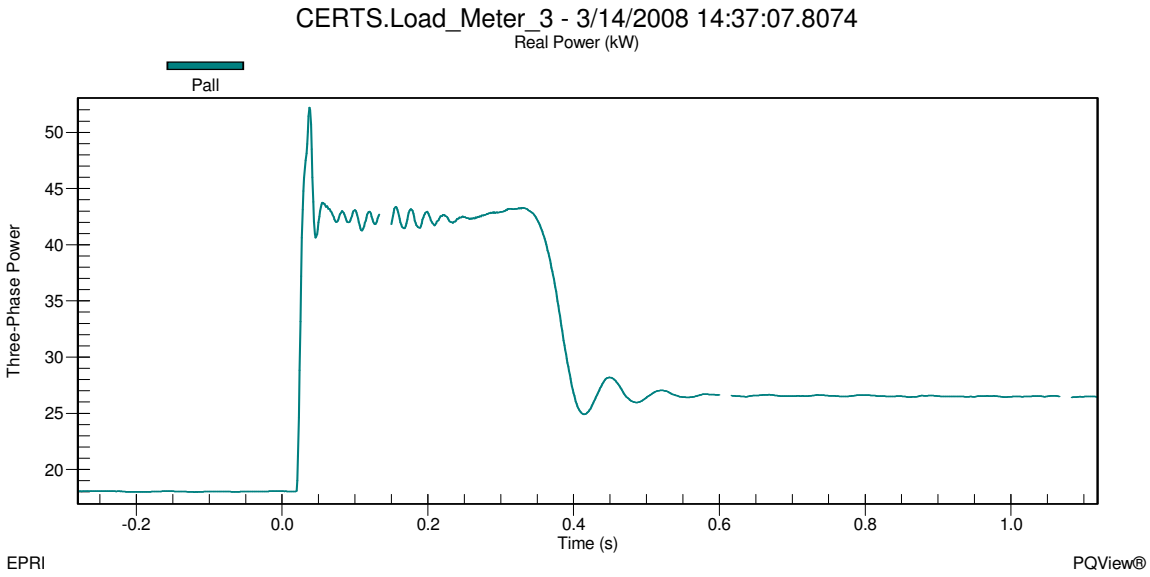

Figure 10a - Load Bank 3 Real Power during Motor Start and Utility Connected for Test 10.2.20

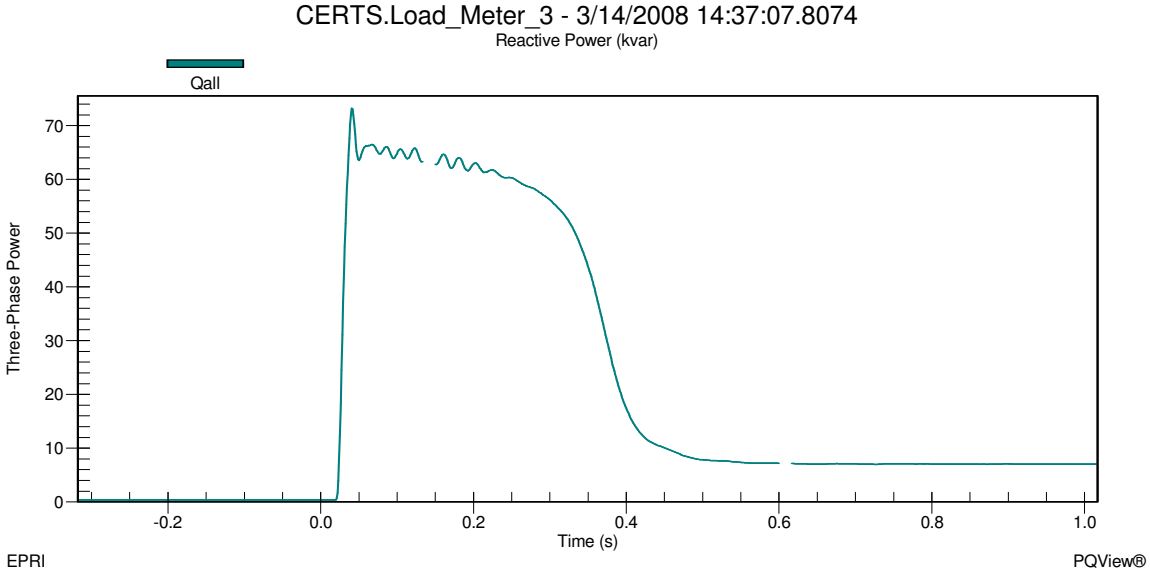

Figure 10b - Load Bank 3 Reactive Power during Motor Start and Utility Connected for Test 10.2.20

In Figures 10a and 10b it can be seen that the load in Zone 3 was approximately 18kW + j0kVAr before the start of the induction motor and increased to approximately 52.2kW + j73.1kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 42.5kW + j62kVAr during the warm up phase which lasted about 33 cycles (0.55 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.5kW + j7kVAr.

The voltage and frequency at the static switch before the motor start was approximately 282.2V on A-phase, 278.8V on B-phase and 278.8V on C-phase shown in Figure 10c and approximately 60.00Hz shown in Figure 10d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.3V on A-phase, 270.6V on B-phase and 270.8V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.90Hz and quickly increased to approximately 60.00Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 281.6V on A-phase, 278.2V on B-phase and 278.2V on C-phase at an approximate frequency 60.00Hz.

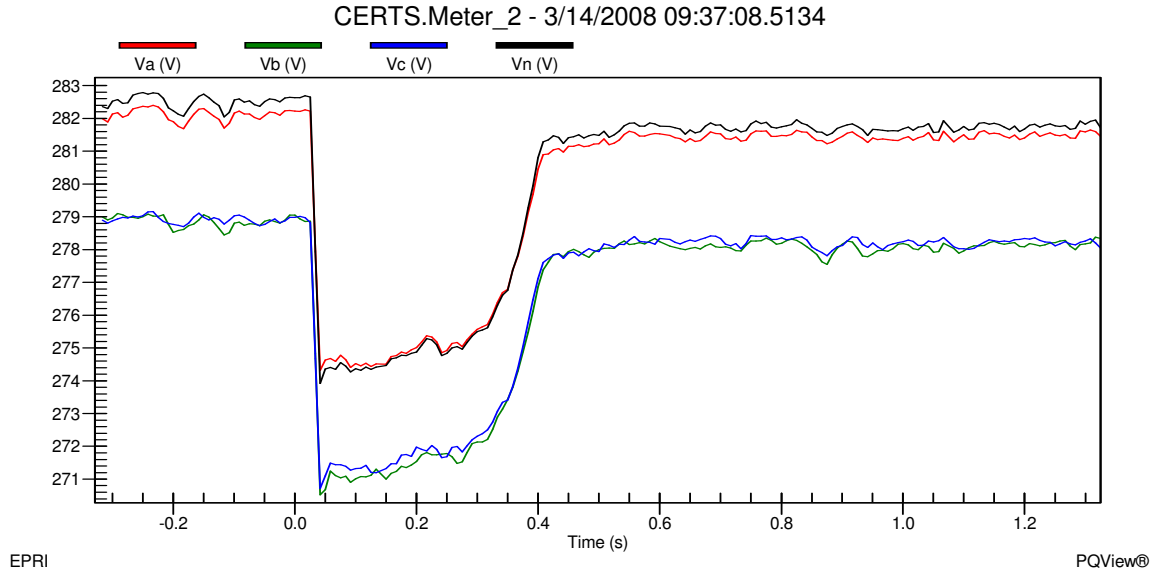

Figure 10c - Static Switch Line-to-Ground Voltage during Motor Start and Utility Connected for Test 10.2.20

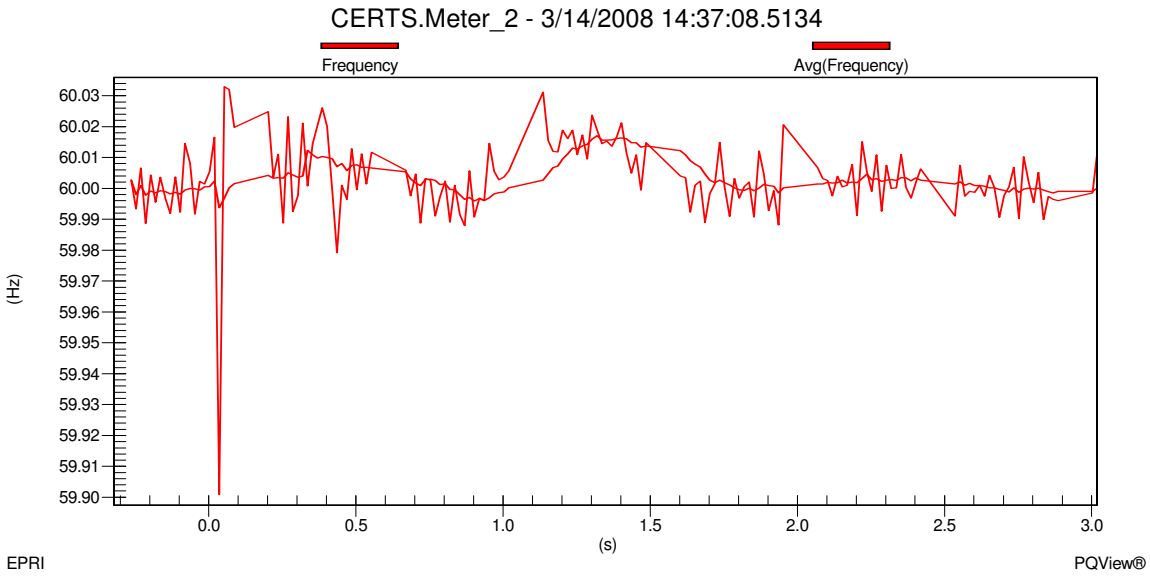

Figure 10d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.2.20

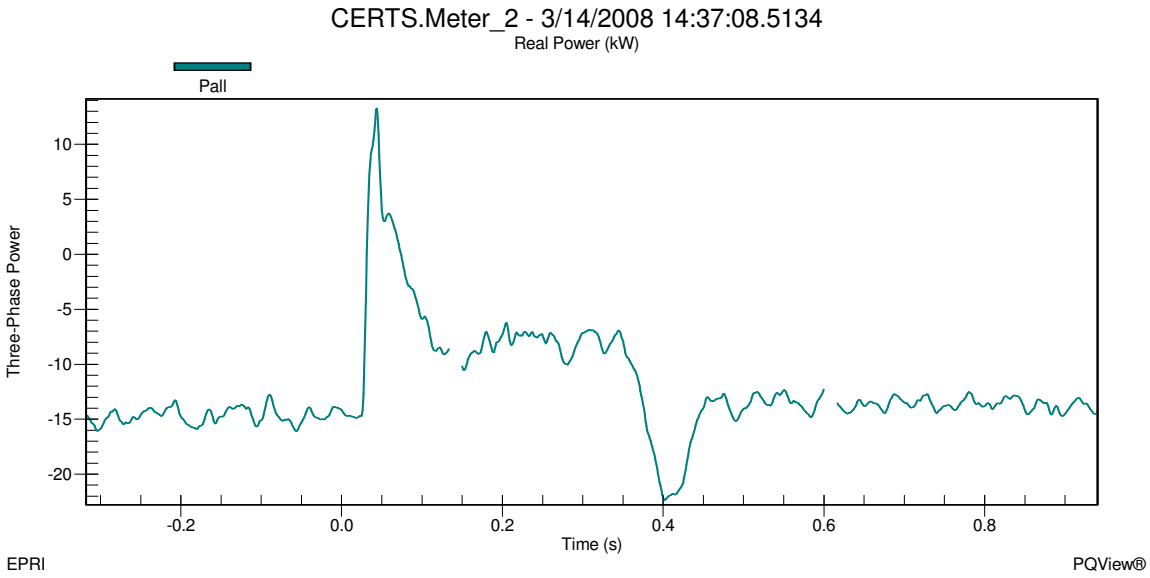

Figure 10e - Static Switch Real Power during Motor Start and Utility Connected for Test 10.2.20

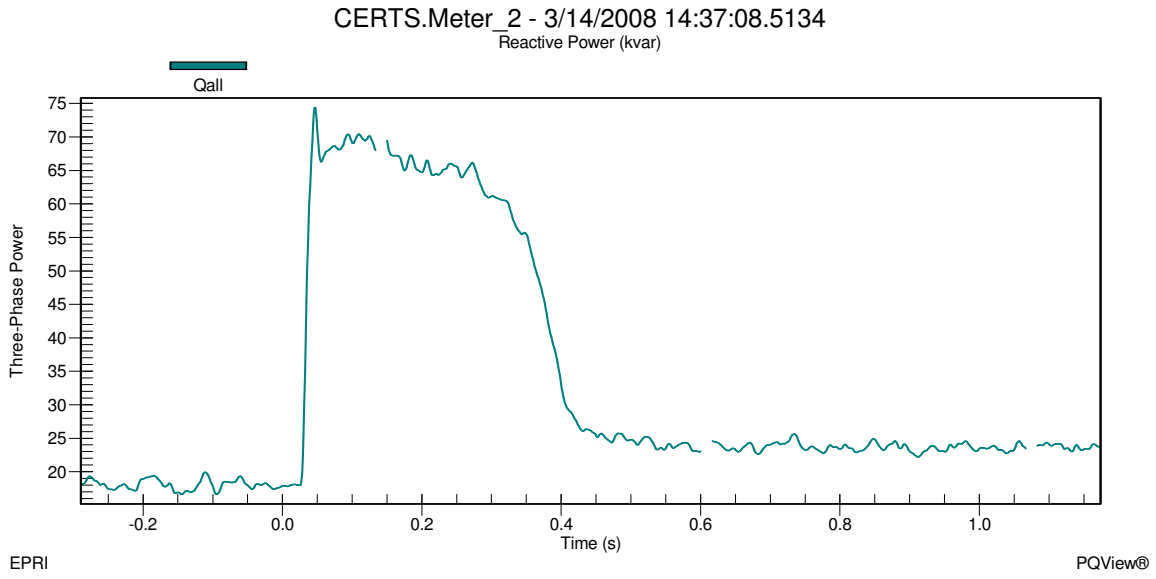

Figure 10f - Static Switch Reactive Power during Motor Start and Utility Connected for Test 10.2.20

Before the motor started Gen-set A1 was producing approximately 35.8kW – j12kVAr. This was enough power for the load demands of Load Bank 3 with real power being exported to Zone 6 of approximately 15kW shown in Figure 10e. The grid was supporting the reactive power of the microgrid with approximately 19kVAr shown in Figure 10f. When the motor started the inrush caused the utility to supply approximately 74.5kVAr and to pick up the load demand of Load Bank 6 and approximately 13.3kW of the load demand in Zone 3. The power that was being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 9e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output levels to approximately 55.1kW + j2.9kVAr. Notice the signs of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -14kW + j23.5kVAr which meant that Gen-set A1 was supplying the power for the induction motor and approximately 14kW of Load Bank 6. The real power in Gen-set A1 increased from its initial value at the beginning of the test to approximately 43.2kW and the reactive power went relatively back to the initial value before the motor started of approximately -11kVAr. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 36.9kW and reactive power decreased to 1kVAr satisfying the load

demand in Load Bank 6 which was approximately 36.5kW + j0.781kVAr and not supplying any power beyond the static switch to Load Bank 3. 0kW + j0kVAr was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads reduced slightly to 17.05kW + j0kVAr. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 10g, from approximately 282.5V on A-phase, 279.5V on B-phase and 279.5V on C-phase when connected to the utility to 272V on A-phase, 272V on B-phase and 272V on C-phase at Meter 3 when islanded.

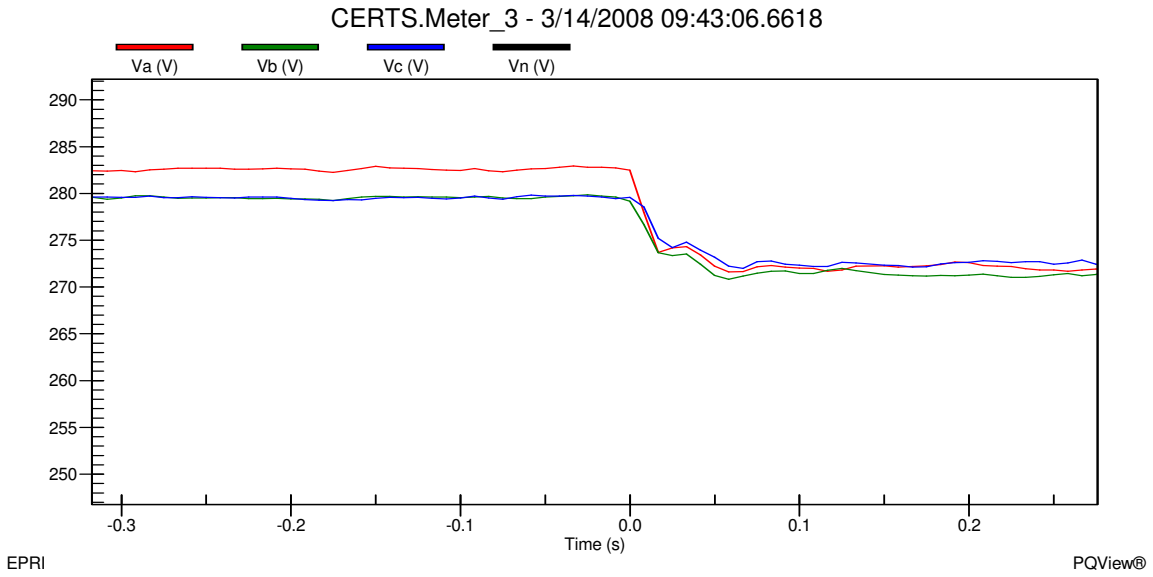

Figure 10g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.2.20

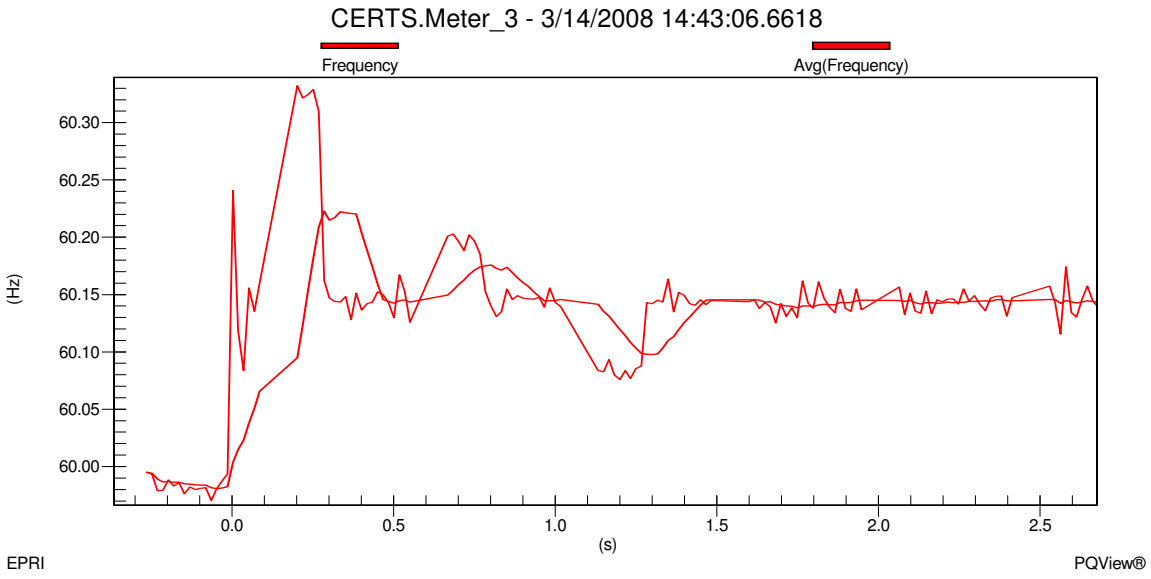

Figure 10h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.2.20

Frequency change in the microgrid, shown in Figure 10h, increased from approximately 59.99Hz when connected to the utility grid to approximately 60.15Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output real power to approximately 18.8kW. Reactive power in Gen-set A1 increased to approximately 4kVAr. Meter 3 was approximately -2.5kW – 3.2kVAr indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

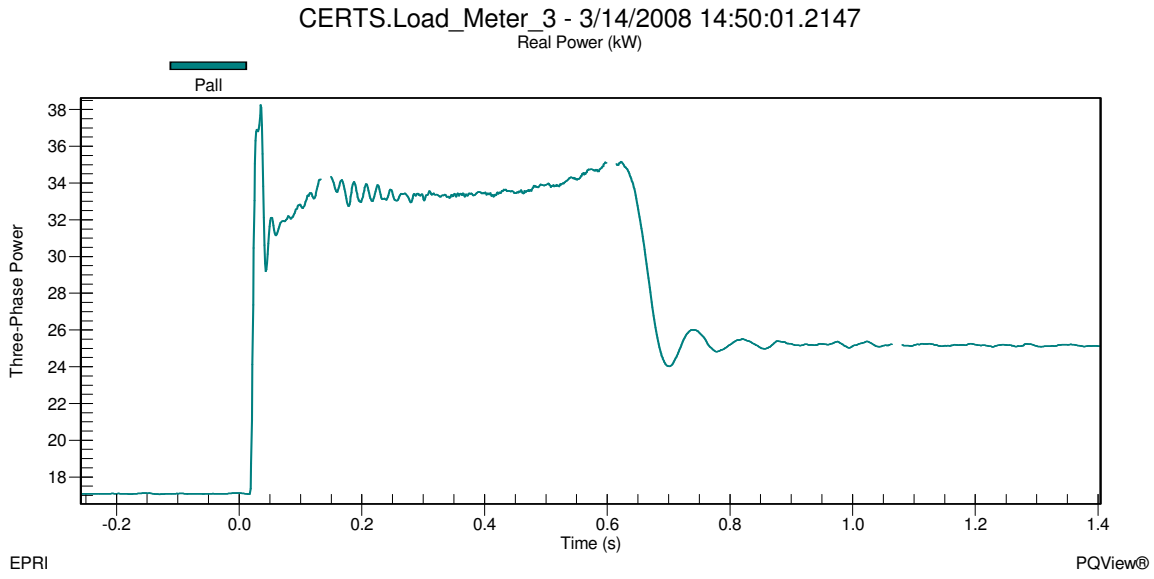

Figure 10i - Load Bank 3 Real Power during Motor Start and Islanded for Test 10.2.20

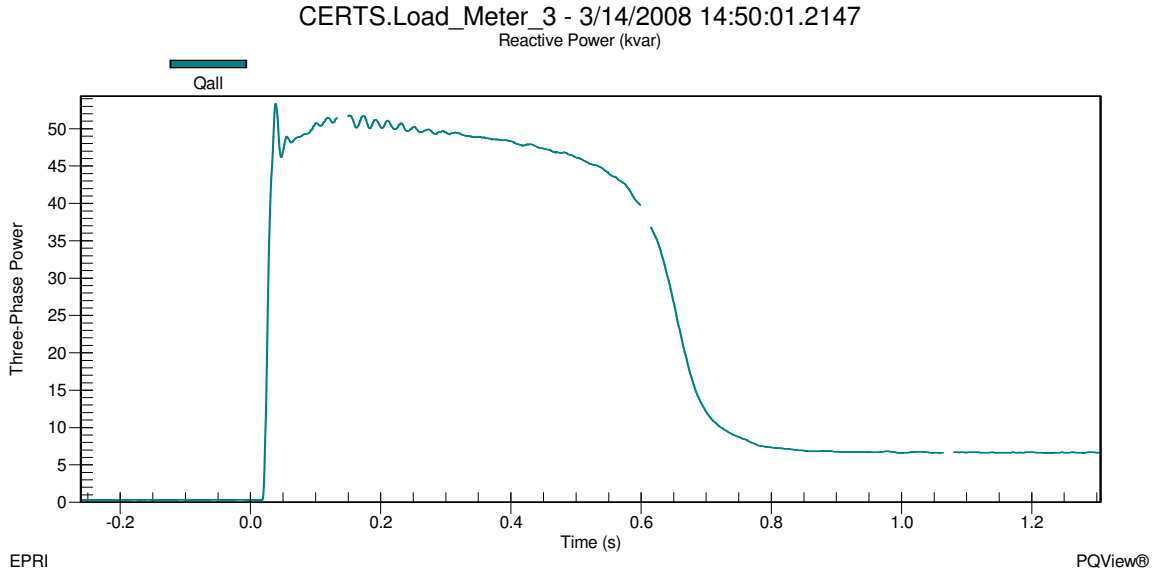

Figure 10j - Load Bank 3 Reactive Power during Motor Start and Islanded for Test 10.2.20

In Figures 10i and 10j it can be seen that the load in Zone 3 was approximately 16kW + j0.3kVAr before the start of the induction motor and increased to approximately 38.3kW + j53.2kVAr during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 34kW + j48.3kVAr during the warm up phase which lasted about 49.2 cycles (0.82 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 25.2kW + j7kVAr.

The voltage and frequency at Meter 3 before the motor start was approximately 272V on A-phase, 272V on B-phase and 272V on C-phase shown in Figure 10k and approximately 60.17HZ shown in Figure 10l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 235.5V on A-phase, 235.5V on B-phase and 235.5V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.99Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 269V on A-phase, 269V on B-phase and 269V on C-phase at an approximate frequency of 60.15Hz.

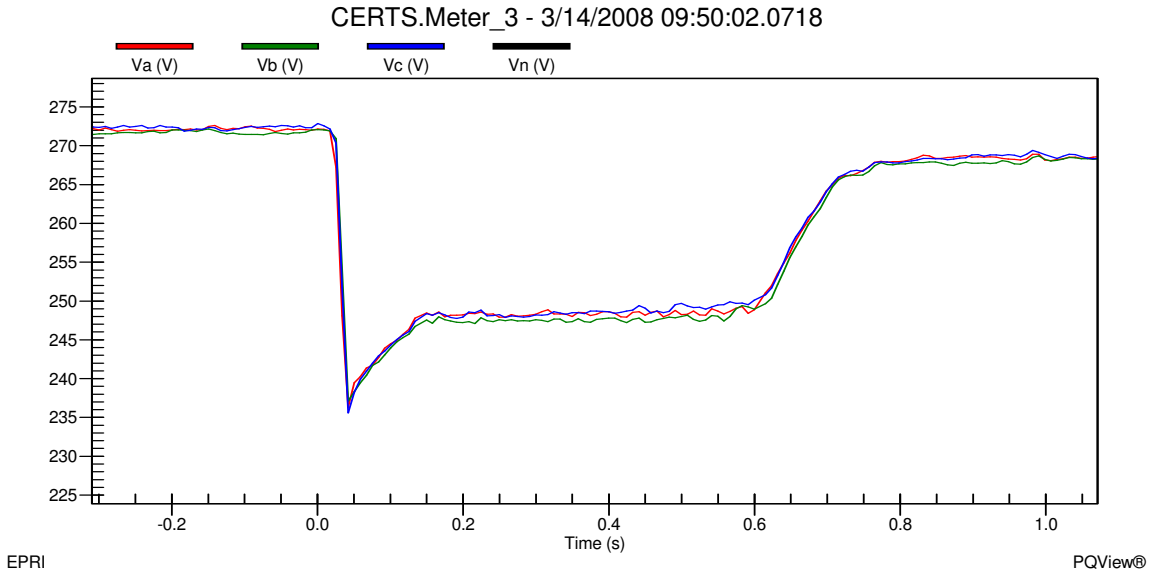

Figure 10k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.2.20

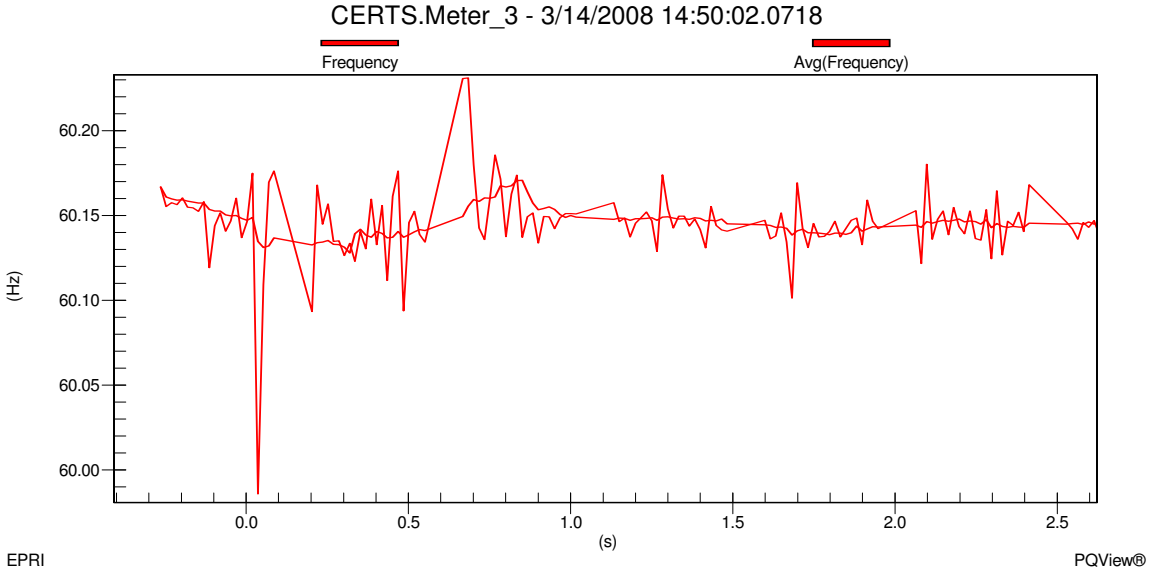

Figure 10l - Meter 3 Frequency during Motor Start and Islanded for Test 10.2.20

Before the motor started, Gen-set A1 was producing approximately 18.8kW + j4kVAr shown in Figures 10m and 10n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused Gen-set A1 to increase its output power level to 40kW + j54.5kVAr. Gen-set A1 decreased its output level while the motor was warming up and eventually dropped to 27.5kW + j10kVAr when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

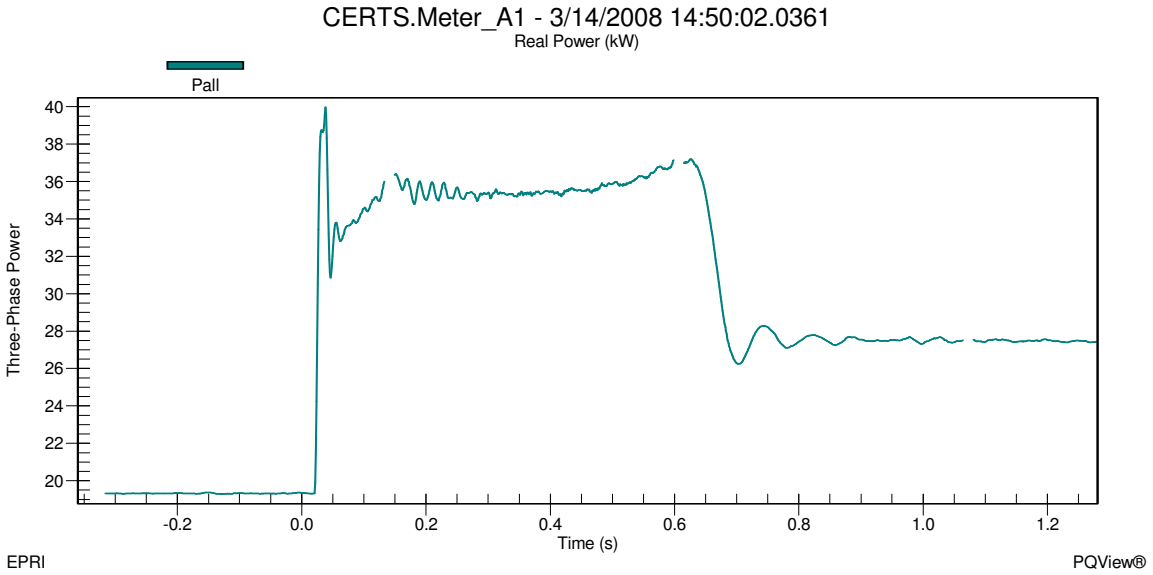

Figure 10m - Gen-set A1 Real Power during Motor Start and Islanded for Test 10.2.20

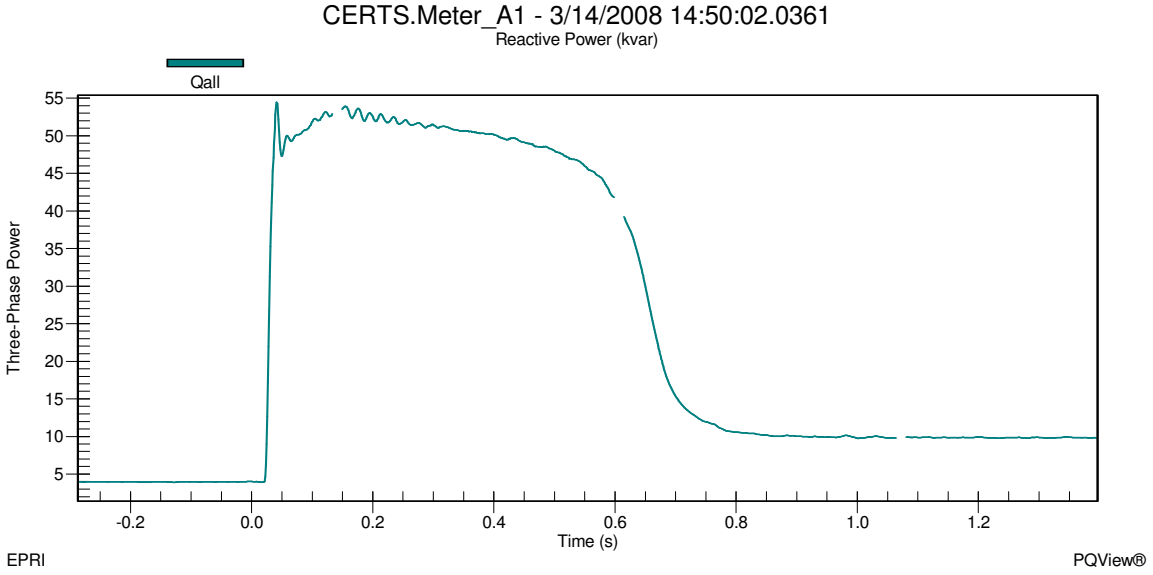

Figure 10n - Gen-set A1 Reactive Power during Motor Start and Islanded for Test 10.2.20

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 36.8kW to 26.7kW and reactive power increased from approximately 1kVAr to 25kVAr which means that the utility was satisfying a portion of the load demand in Load Bank6 and all the reactive power in the microgrid. Figures 10o and 10p show the static switch real power decreasing from approximately 0kW to -10.6kW and reactive power increasing from approximately 0kVAr to 24kVAr. At the beginning of the test, the initial power flow through the static switch was -15kW + j18kVAr which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and supporting Load Bank 6 with approximately 10.6kW.

Load Bank 3 increased slightly to 24.9kW + j6.4kAVr. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 10q, from approximately 269V on A-phase, 269V on B-phase and 269V on C-phase when islanded to 282V on A-phase, 279.3V on B-phase and 279.3V on C-phase at Meter 3 when connected to the utility grid.

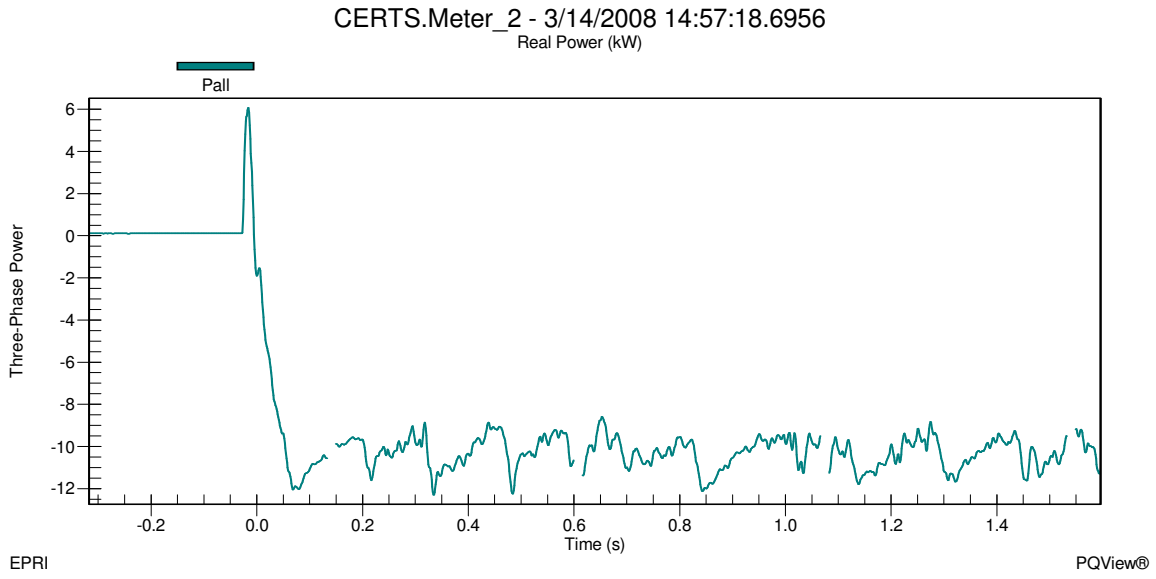

Figure 10o - Static Switch Real Power during Island to Utility Connected mode for Test 10.2.20

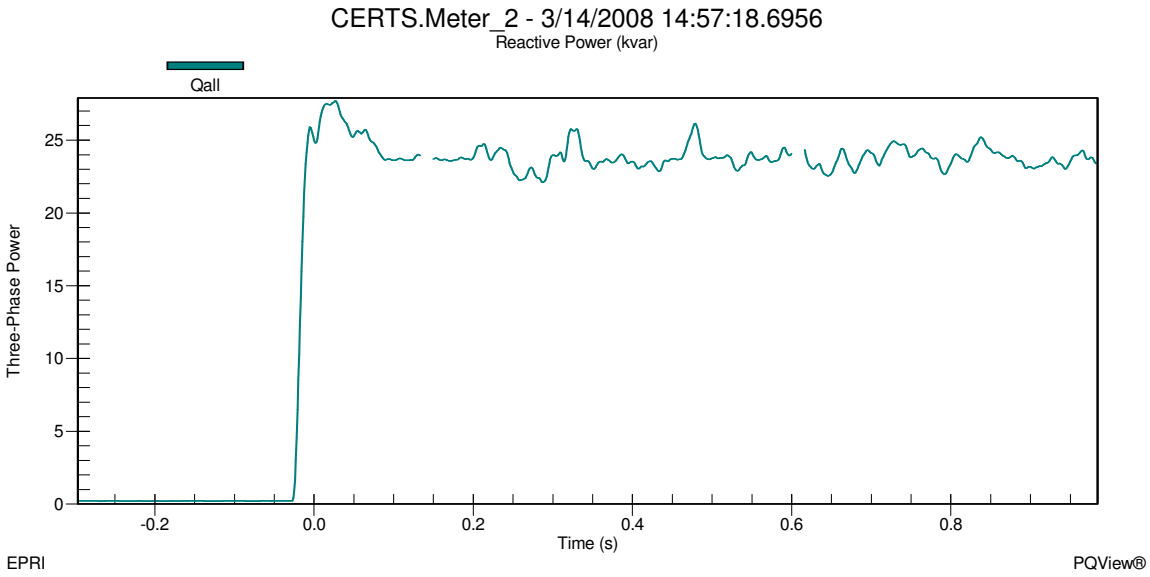

Figure 10p - Static Switch Reactive Power during Island to Utility Connected mode for Test 10.2.20

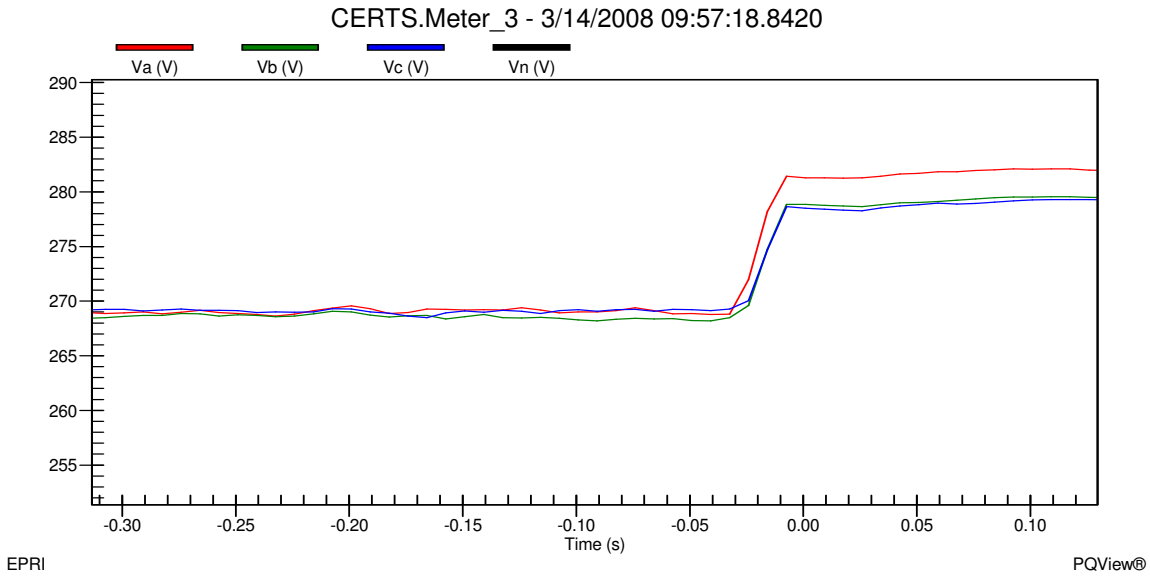

Figure 10q - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.2.20

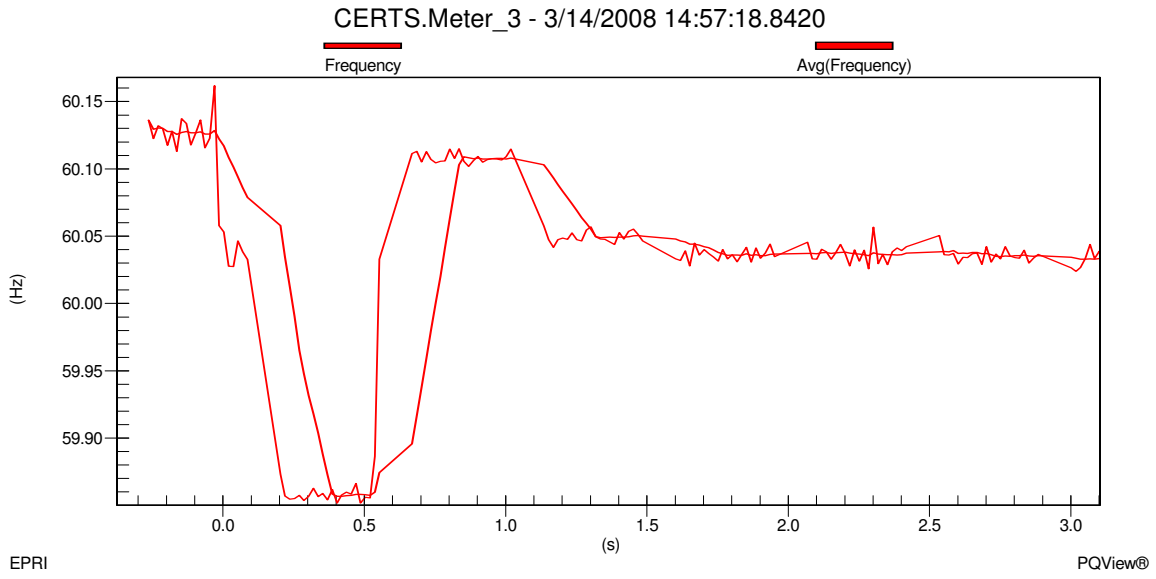

Figure 10r - Meter 3 Frequency during Island to Utility Connected mode for Test 10.2.20

Frequency change in the microgrid, shown in Figure 10r, decreased from approximately 60.13Hz when islanded to approximately 60.03Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-set using the CERTS algorithm but by the utility. Gen-set A1 is in zone power control mode therefore when the static switch closed back into the utility Gen-set A1 produced real power based on set-points for the power flow through Zone 3 initialized at the beginning of the test. The real power increased from its initial value at the beginning o f the test to approximately 38.4kW for Gen-set A1. This increase is because Gen-set A1 has picked up the real power of the induction motor in Zone 3. Reactive power for Gen-set A1 was relatively close to the value at the beginning of the test with approximately -11.2kVAr. After all the data was verified and recorded into the DAS Database, the motor, Gen-set A1, and Load Banks 3 and 6 were turned off.

6.1.2 Motor Start Tests, Weak Grid, Unbalanced Load with 0.9 Power Factor

Performance Goal:

Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during motor starts when utility connected and then repeat motor start test during an islanded mode of operation.

Six tests were completed in this section with each test event and settings listed in Table 1. During each test Gen-sets A1 and A2 were both set for either unit or zone power

control mode of operation. Each of the six tests varied the output power command set-point in each Gen-set, along with varying the load settings in load banks LB3, LB4 and LB6. During each test, inductor L11 was in series with the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Test Event	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
10.3.12	Unit +40kW	Unit +30kW	+30kW	-10kW	-10kW	+10kW	20kW	A=10kW B=15kW C=15kW	A=10kW B=20kW C=10kW
10.3.14	Unit +40kW	0kW	+10kW	-30kW	-30kW	0kW	10kW	0kW	A=10kW B=20kW C=10kW
10.3.15	Unit +40kW	Unit +30kW	+70kW	+30kW	+30kW	+20kW	50kW	A=10kW B=20kW C=20kW	A=10kW B=20kW C=10kW
10.3.17	Unit +40kW	0kW	+20kW	-20kW	-20kW	0kW	20kW	0kW	A=10kW B=20kW C=10kW
10.3.18	Zone -10kW	Zone +10kW	+30kW	-10kW	-10kW	+10kW	20kW	A=10kW B=15kW C=15kW	A=10kW B=20kW C=10kW
10.3.20	Zone -20kW	0kW	+20kW	-20kW	-20kW	0kW	20kW	0kW	A=10kW B=20kW C=10kW

Table 2 -Unbalance Load, Weak Grid, Before Motor Start settings of Gen-sets and Load Banks

The test procedures for these six tests were exactly the same as in the tests performed in Section 6.1.1 (Tests 10.2.12 – 10.2.20).

For Test 10.3.12 the measured values, after the Gen-sets were warmed up and load banks brought on-line are provided in Table 3.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	37.5	28.5	30	-7.8	-10.5	8.5	18.2	36.7	36.9
1 Phase kW	A=11 B=15.5 C=10.5	A=8 B=12 C=8.5	A=8 B=11 C=11	A=-2 B=-7 C=1.2	A=-3 B=-8 C=0.05	A=2 B=1.5 C=5	A=6 B=6.2 C=6	A=9.7 B=13.5 C=13.5	A=9.7 B=17.6 C=9.6
3 Phase kVAr	-12	-4	24.5	22.4	17.9	5	0.3	0.615	0.638
1 Phase kVAr	A=-4.5 B=-4 C=-3.5	A=-2 B=-1 C=-1	A=9 B=8 C=7.5	A=8.7 B=7 C=6.7	A=7.5 B=5.2 C=5.2	A=2.4 B=1.2 C=1.4	A=0.1 B=0.1 C=0.1	A=0.13 B=0.28 C=0.205	A=0.122 B=0.394 C=0.122

Table 3 - Measured Values after Start Up for Test 10.3.12

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB3 and LB4 and the 20kW setting for LB3 were also below selected set values. At the time of the measurements, the voltage and frequency was 282.7V on A-phase, 279V on B-phase and 279.6V on C-phase and 60.02Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282.7V on A-phase, 279.5V on B-phase and 279.5V on C-phase and 60.02Hz at Meter 3.

The Gen-sets in this test were set up to produce more power than Load Banks 3 and 4 needed which approximately 7.8kW of excess power was exported through the static with to Load Bank 6. Since Load Bank 6 was approximately 36.9kW (A= 9.7kW B=17.6kW C=9.6kW) + j0.638kVAr (A=0.122kVAr B=0.394kVAr C=0.122kVAr), the utility had to supply approximately 30kW (A=8kW B=11kW C=11kW) to satisfy the load. Reactive power had to be imported in from the utility of approximately 24.5kVAr (A=9kVAr B=8kVAr C=7.5kVAr) because of Gen-set A1 and A2 needed approximately 16kVAr between both and the reactive power absorbed in the electrical lines. Once all the data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

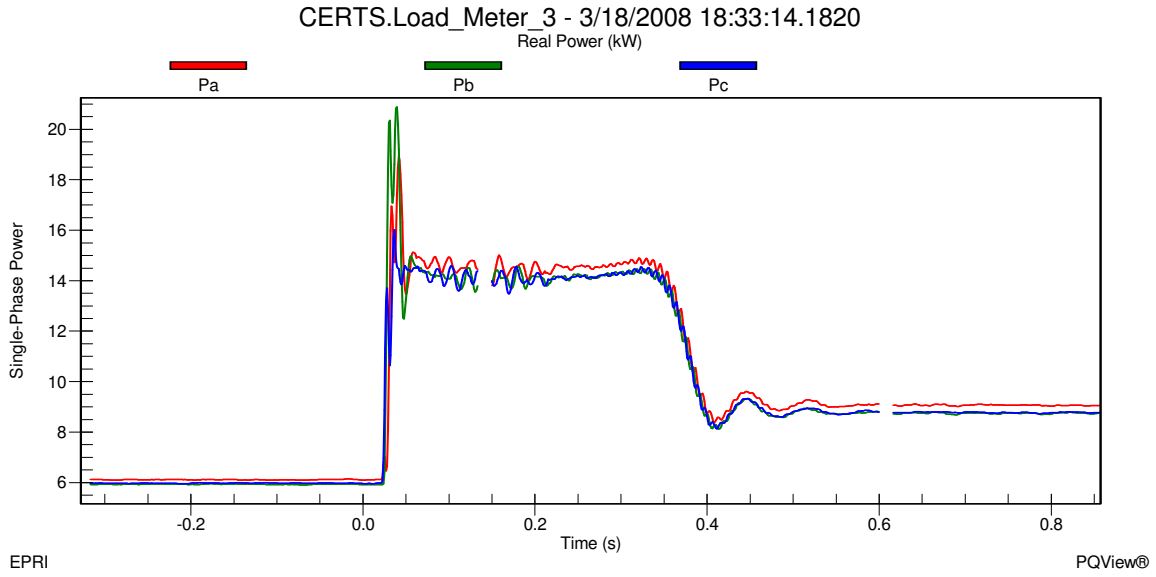

Figure 11a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.12

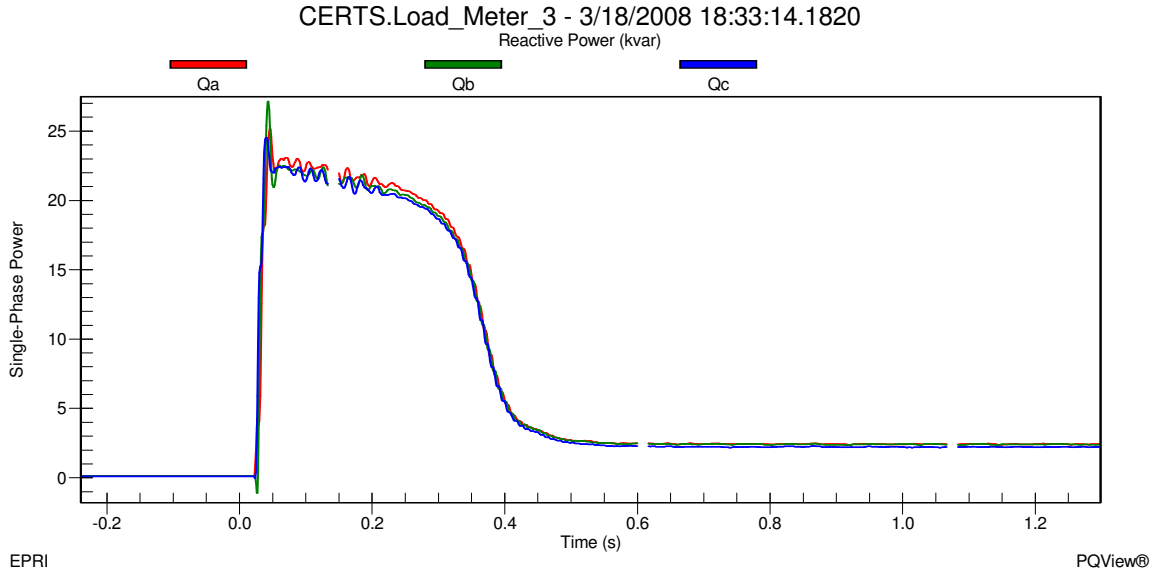

Figure 11b - Load Bank 3 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.12

In Figures 11a and 11b it can be seen that the load in Zone 3 was approximately 18.2kW (A=6kW B=6.2kW C=6kW) + j0.3kVAr (A=0.1kVAr B=0.1kVAr C=0.1kVAr) before the start of the induction motor and increased to approximately 55.6kW (A=19kW B=20.9kW C=15.7kW) + j76.1kVAr (A=24.5kVAr B=27.1kVAr C=24.5kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately

43.1kW (A=14.7kW B=14.2kW C=14.2kW) + j63.5kVAr (A=21.5kVAr B=21kVAr C=21kAVr) during the warm up phase which lasted about 33 cycles (0.55 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.5kW (A=9.1kW B=8.7kW C=8.7kW) + j6.6kVAr (A=2.2kVAr B=2.2kVAr C=2.2kVAr).

The voltage and frequency at the static switch before the motor start was approximately 282.7V on A-phase 279V, on B-phase and 279.6V on C-phase shown in Figure 11c and approximately 60.02Hz shown in Figure 11d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 276.3V on A-phase, 272.4V on B-phase and 273V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.96Hz and quickly increased to approximately 60.00Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 282.1V on A-phase, 278.2V on B-phase and 278.9V on C-phase at an approximate frequency of 60.01Hz.

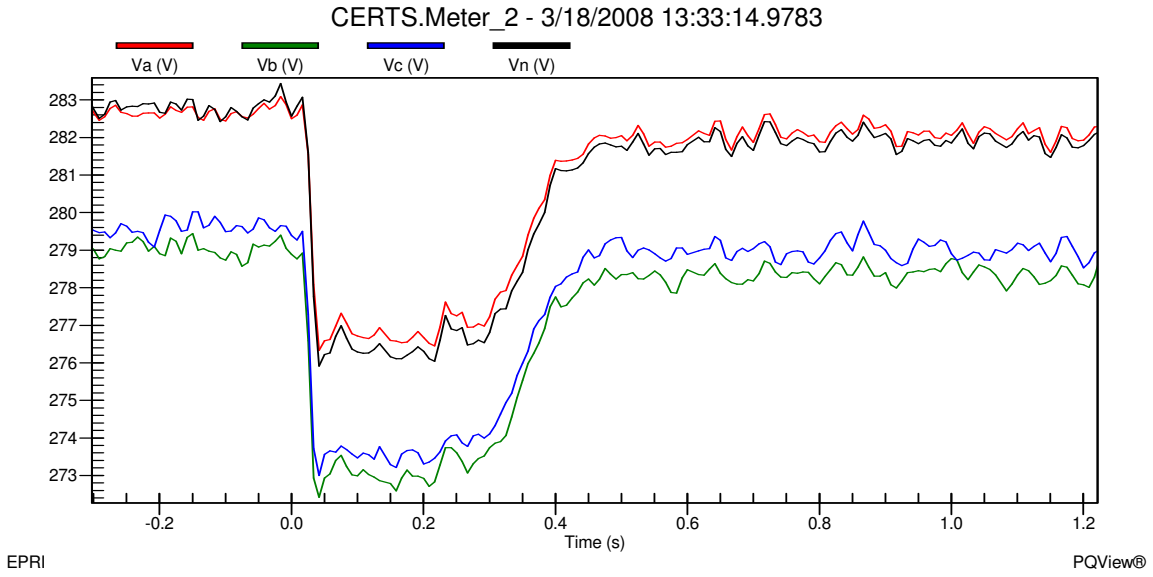

Figure 11c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.3.12

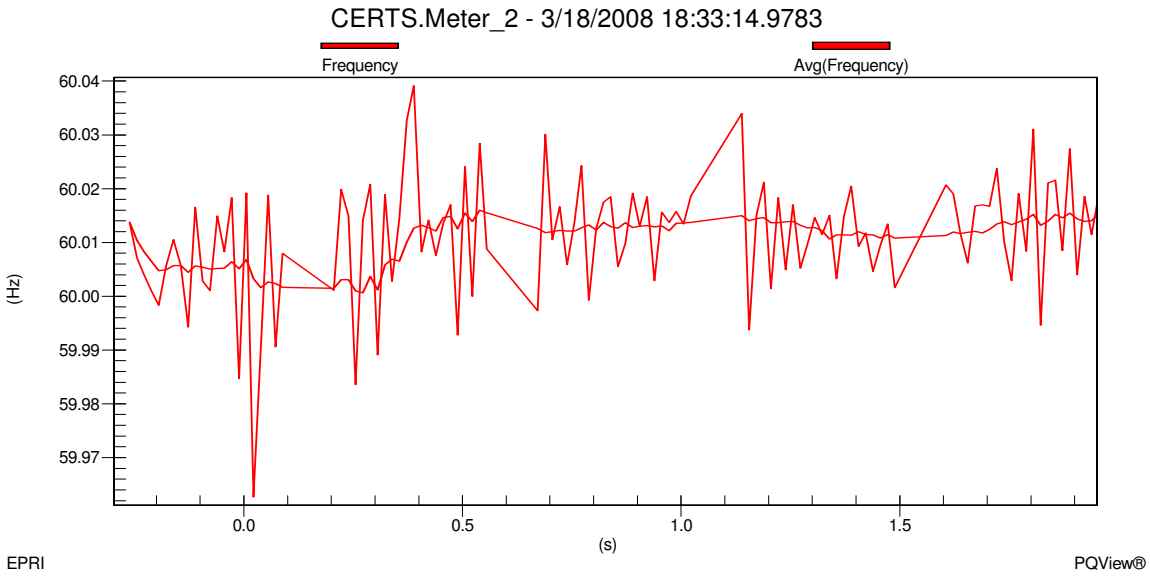

Figure 11d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.12

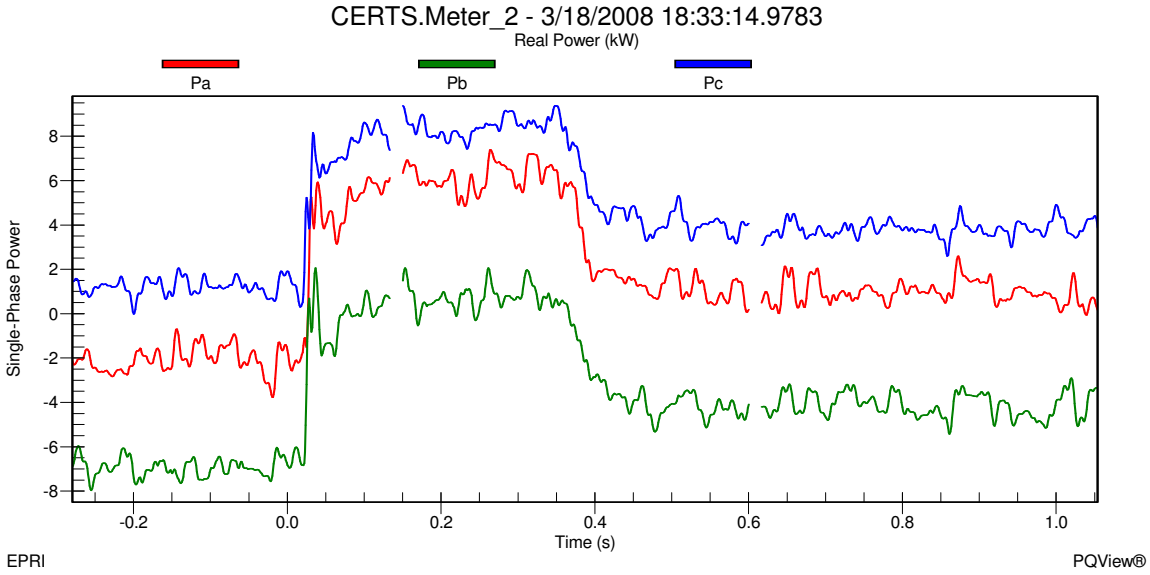

Figure 11e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.12

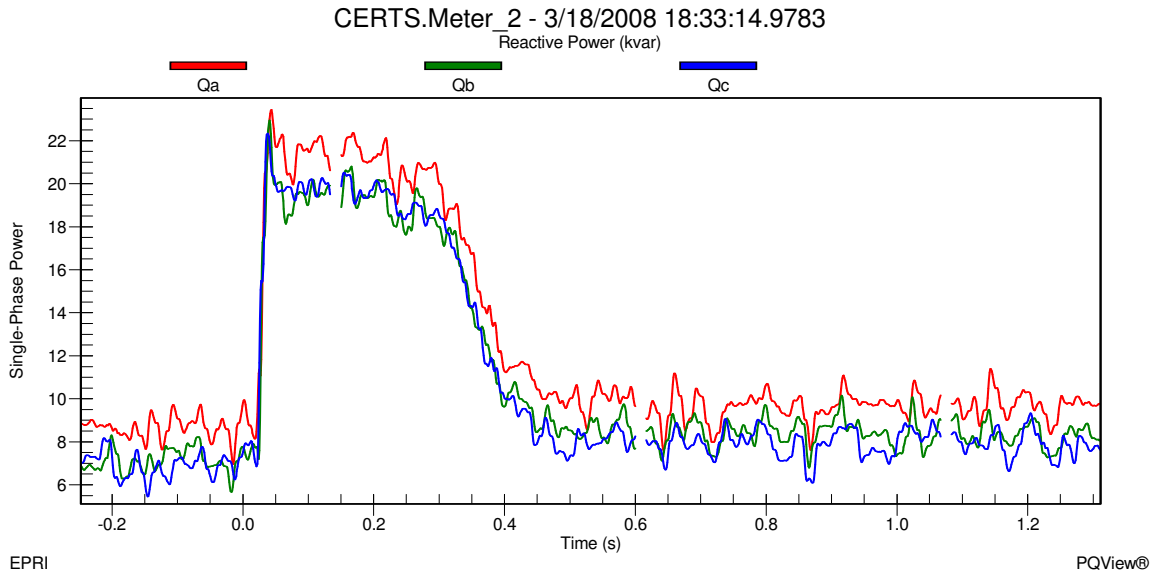

Figure 11f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.12

Before the motor started Gen-sets A1 and A2 were producing approximately 37.5kW (A=11kW B=15.5kW C=10.5kW) – j12kVAr (A=-4.5kVAr B=-4kVAr C=-3.5kVAr) and 28.5kW (A=8kW B=12kW C=8.5kW) – j4kVAr (A=-2kVAr B=-1kVAr C=-1kVAr), respectively. This was enough power for the load demands of Zones 3 and 4 with real power being exported to Zone 6 of approximately 7.8kW shown in Figure 11e. The grid was supporting the reactive power of the microgrid with approximately 22.4kVAr (A=8.7kVAr B=7kVAr C=6.7kVAr) shown in Figure 11f. When the motor started the inrush caused the utility to supply approximately 68.4kVAr (A=23.5kVAr B=22.6kVAr C=22.3kVAr) and to pick up the load demands of Load Bank 6 along with approximately 15.3kW (A=5.3kW B=1.8kW C=8.2kW) of the microgrid critical loads. The power being supplied by Gen-sets A1 and A2 to Load Bank 6 was now supplying a portion of the motor inrush which can be seen in Figure 11e as the real power becomes positive. Gen-sets A1 and A2 increased their real and reactive power output levels to approximately 43kW (A=13kW B=18kW C=12kW) + j0.3kVAr (A=-1kVAr B=0.9kVAr C=0.4kVAr) and 36.5kW (A=10.1kW B=15.8kW C=10.6kW) + j12kVAr (A=3.7kVAr B=4.6kVAr C=3.7kVAr), respectively. Notice the signs of the VAr output changed from negative to positive for both Gen-sets in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately 0.4kW (A=0.9kW B=-4.3kW C=3.8kW) + j25.8kVAr (A=9.7kVAr B=8.4kVAr C=7.7kVAr) which meant that Gen-sets A1 and A2 were supplying enough power for the induction motor and Load Banks 3 and 4 but needed approximately 0.4kW (A=0.9kW B=4.3kW C=3.8kW) from the utility grid for the power losses in the conductors. Gen-sets A1 and A2 real power returned to the values before

the motor started of approximately 37.5kW (A=11kW B=15.5kW C=10.5kW) and 28.5kW (A=8kW B=12kW C=8.5kW), respectively, and the reactive power increased to approximately -10.8kVAr (A=-4kVAr B=-3.3kVAr C=-3.5kVAr) in Gen-set A1 and -1kVAr (A=-1.4kVAr B=0.2kVAr C=0.2kVAr) in Gen-set A2. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 38.1kW (A=10.1kW B=18.1kW C=9.9kW) and reactive power decreased to -0.5kVAr (A=-0.3kVAr B=0.1kVAr C=-0.3kVAr) satisfying the load demand in Load Bank 6 which was approximately 37.9kW (A=10.1kW B=9.8kW C=18kW) + j0.655kVAr (A=0.123kVAr B=0.405kVAr C=0.127kVAr) and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch indicating that power was not flowing through the static switch. Load banks 3 and 4 loads reduced slightly to 17.35kW (A=5.76kW B=5.84kW C=5.75kW) + j0.321kVAr (A=0.105kVAr B=0.123kVAr C=0.093kVAr) and 35.4kW (A=9.3kW B=13.1kW C=13kW) + j0.59kVAr (A=0.115kVAr B=0.275kVAr C=0.2kVAr), respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 11g, from approximately 283V on A-phase, 280V on B-phase and 280V on C-phase when connected to the utility grid to 275V on A-phase, 276V on B-phase and 274V on C-phase at Meter 3 when islanded.

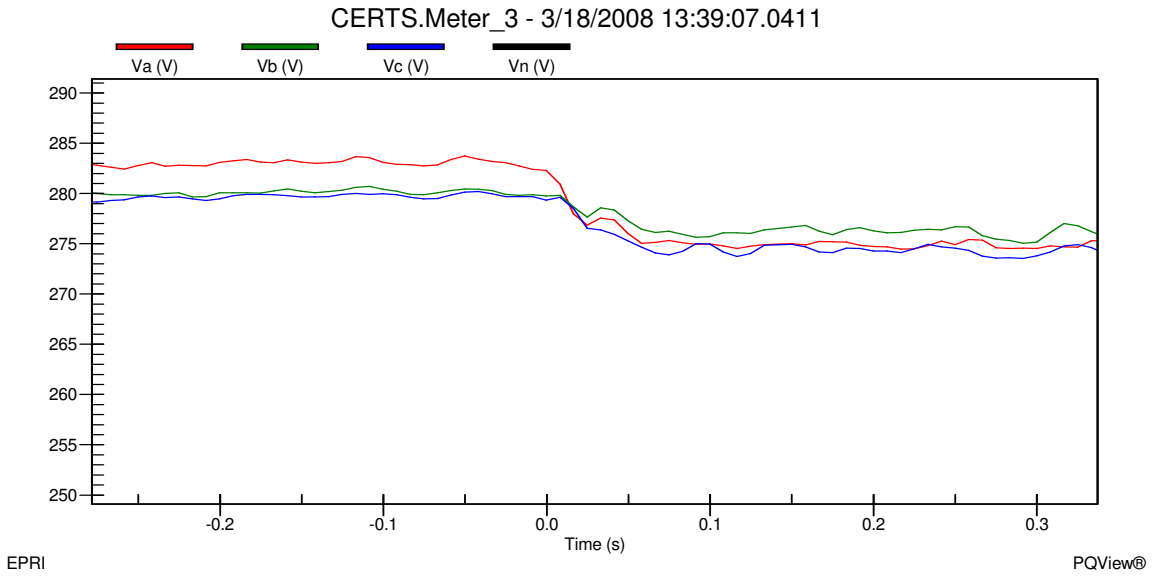

Figure 11g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.12

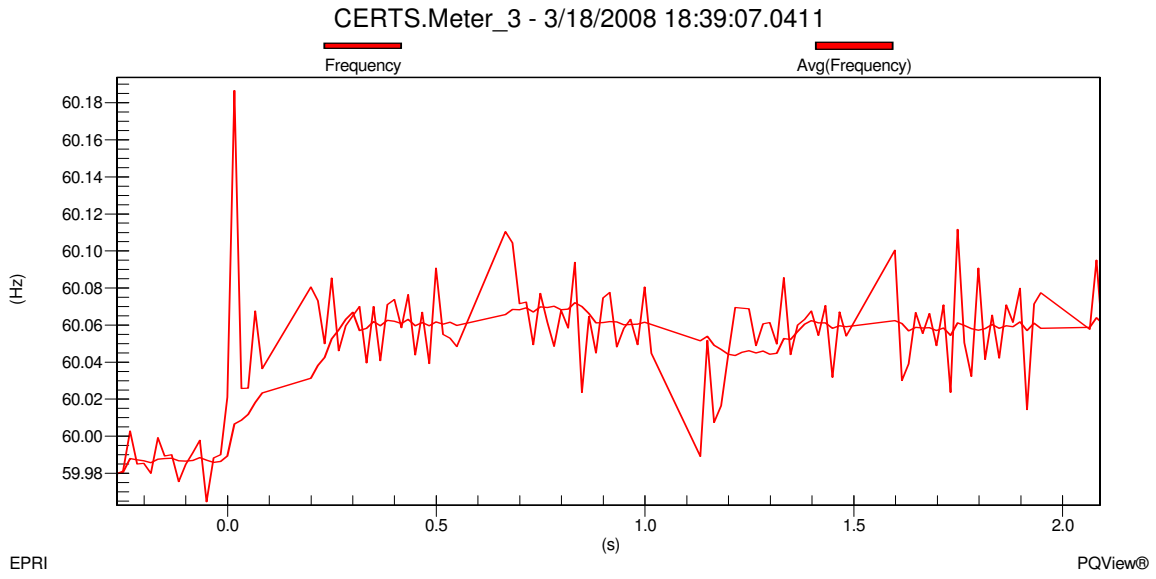

Figure 11h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.12

Frequency change in the microgrid, shown in Figure 11h, increased from approximately 59.99Hz when connected to the utility grid to approximately 60.06Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to decrease their output power to satisfy the load demands. Gen-set A1 and A2 decreased their output real power to approximately 31.4kW (A=9kW B=11.4kW C=11kW) and 22.7kW (A=6.8kW B=2kW C=8.5kW), respectively and increased their output reactive power to approximately -2.2kVAr (A=-0.8kVAr B=-1kVAr C=-0.4kVAr) and 7.5kVAr (A=2.5kVAr B=2.5kVAr C=2.5kVAr), respectively. Meter 3 was approximately –1.1kW (A=-0.1kW B=-0.5kW C=-0.5kW) - j4.2kVAr (A=-1.5kVAr B=-1.1kVAr C=-1.6kVAr) indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All the data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

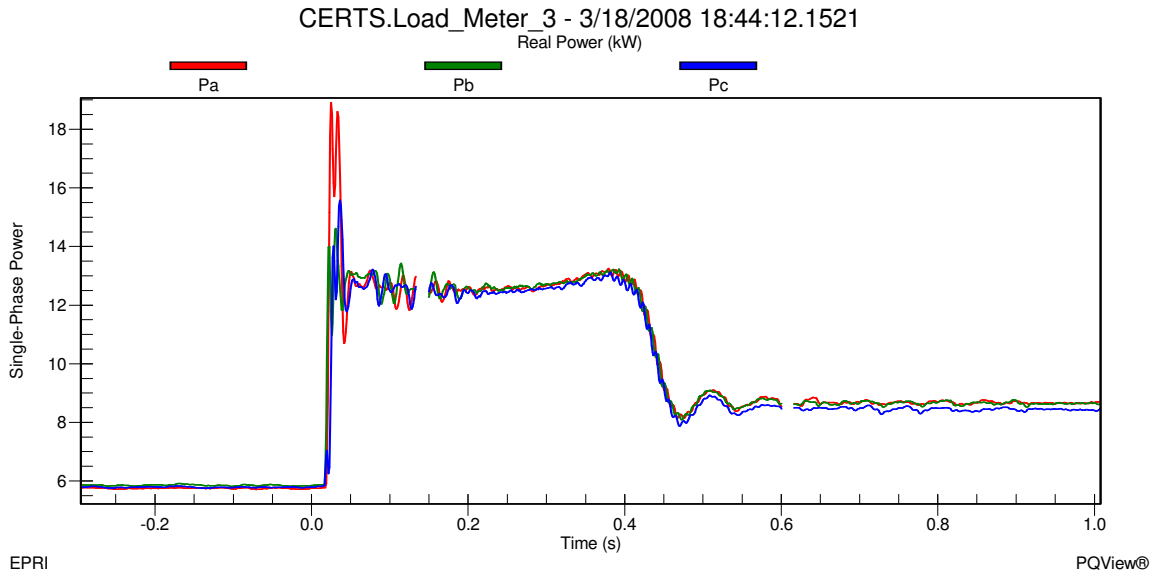

Figure 11i - Load Bank3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.12

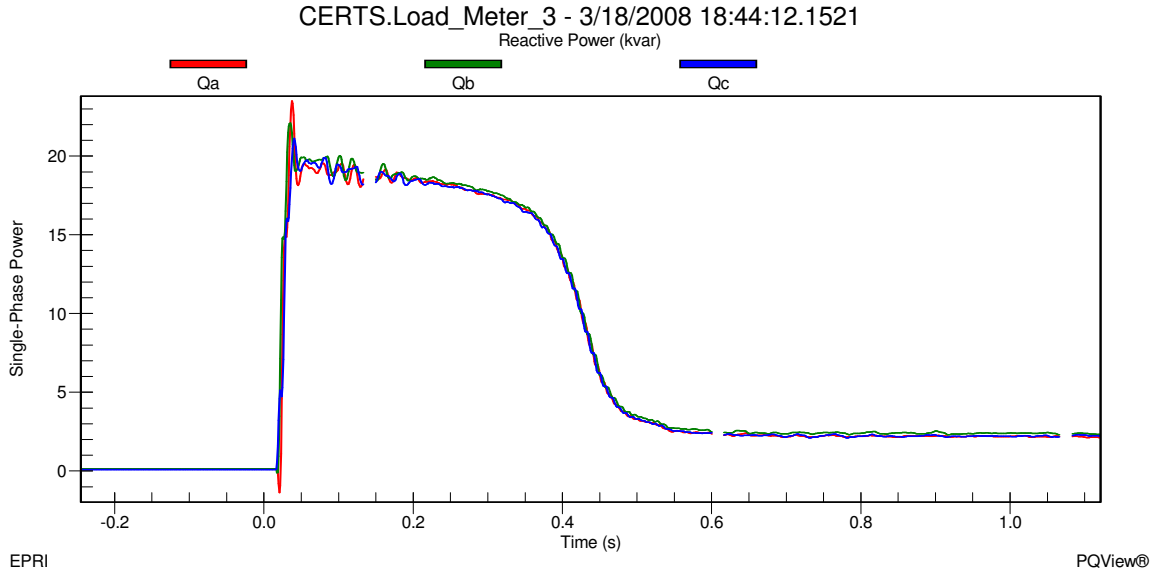

Figure 11j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.12

In Figures 11i and 11j it can be seen that the load in Zone 3 was approximately 17.4kW (A=5.8kW B=5.8kW C=5.8kW) + j0.15kVAr (A=0.05kVAr B=0.05kVAr C=0.05kVAr) before the start of the induction motor and increased to approximately 47kW (A=19kW B=14kW C=14kW) + j66.8kVAr (A=23.7kVAr B=22kVAr C=21.1kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 37.8kW (A=12.6kW B=12.6kW C=12.6kW) + j56.1kVAr (A=18.7kVAr B=18.7kVAr C=18.7kVAr) during the warm up phase which lasted about 36 cycles (0.6 Seconds). When the motor

reached steady state, the load in Zone 3 was approximately 25.8kW (A=8.7kW B=8.4kW C=8.7kW) + j6.9kVAr (A=2.3kVAr B=2.3kVAr C=2.3kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 275V on A-phase, 275.5V on B-phase and 274V on C-phase shown in Figure 11k and approximately 60.05Hz shown in Figure 11l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 255V on A-phase, 254.3V on B-phase and 254.3V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.81Hz and quickly increased to approximately 60.00Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 273.2V on A-phase, 273.2V on B-phase and 272.7V on C-phase at an approximate frequency of 60.02Hz.

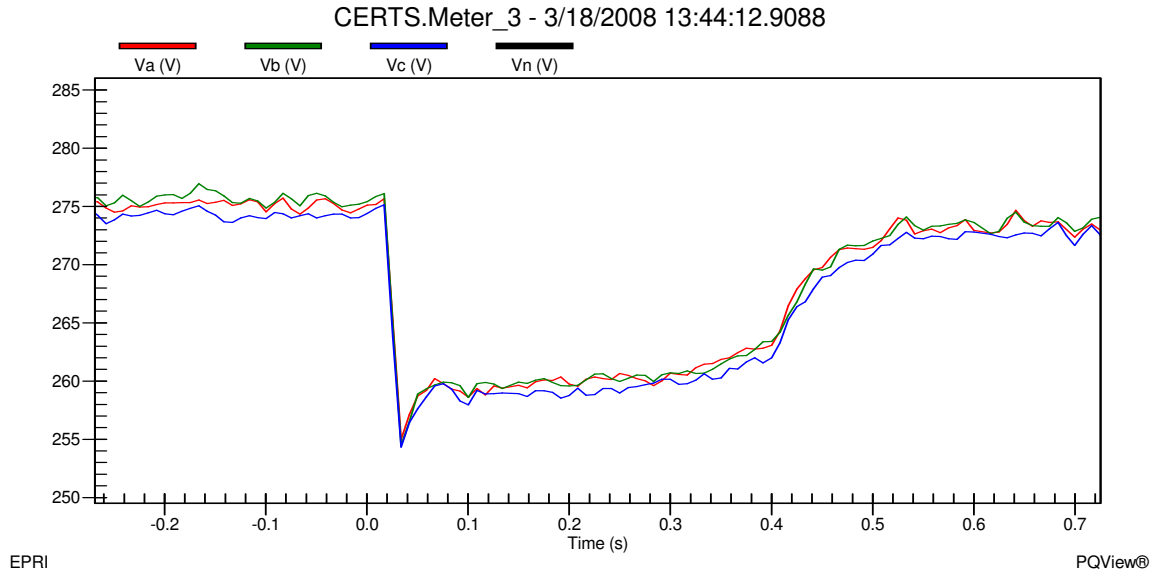

Figure 11k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.3.12

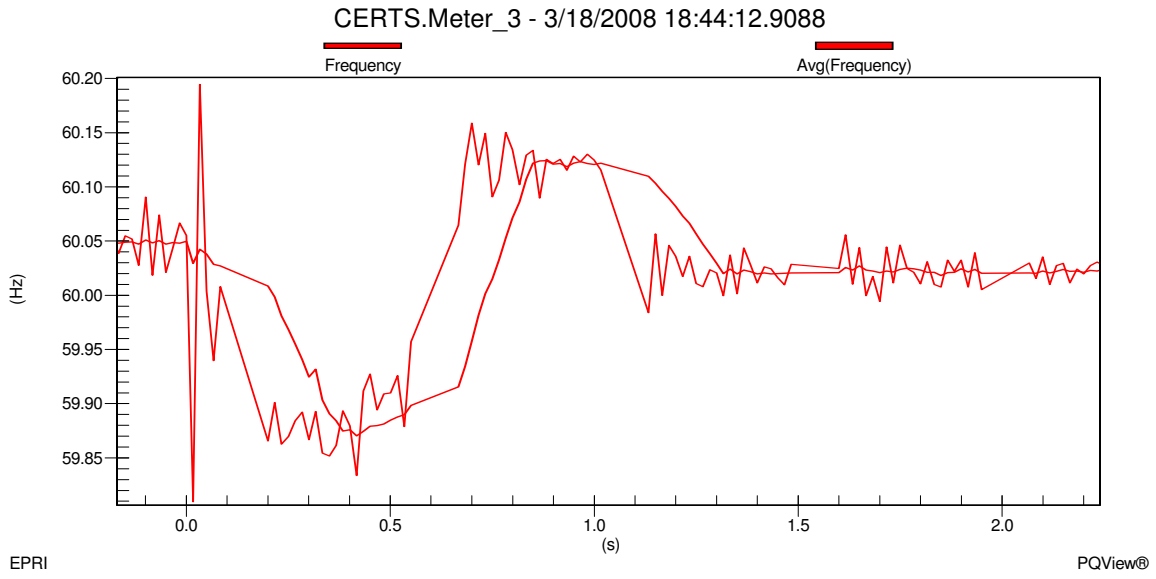

Figure 111 - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.12

Before the motor started Gen-sets A1 and A2 were producing approximately 32kW (A=9.5kW B=11.7kW C=10.8kW) – j2kVAr (A=-1kVAr B=-0.8kVAr C=-0.2kVAr) and 23.5kW (A=6.5kW B=8.5kW C=8.5kW) + j7.1kVAr (A=2.3kVAr B=2.5kVAr C=2.3kVAr), respectively shown in Figures 11m – 11p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output levels to 46.1kW (A=16.2kW B=15.8kW C=14.1kW) + j27.6kVAr (A=7.5kVAr B=11kVAr C=9.1kVAr) for Gen-set A1 and 35.4kW (A=10.7kW B=11.5kW C=13.2kW) + j37.8kVAr (A=13.5kVAr B=11.3kVAr C=13kVAr) for Gen-set A2. The Gen-sets decreased their output levels while the motor was warming up and eventually dropped to 35.5kW (A=11kW B=12.6kW C=11.9kW) + j1.3kVAr (A=0kVAr B=0.5kVAr C=0.8kVAr) for Gen-set A1 and 27.5kW (A=7.7kW B=9.9kW C=9.9kW) + j10.3kVAr (A=3.4kVAr B=3.5kVAr C=3.4kVAr) for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

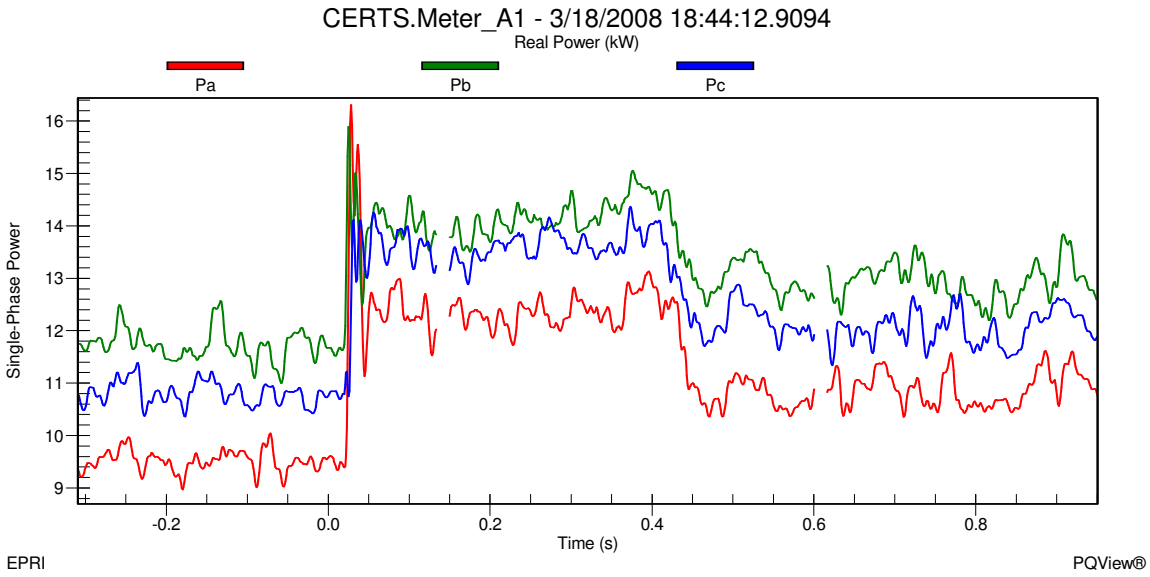

Figure 11m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.12

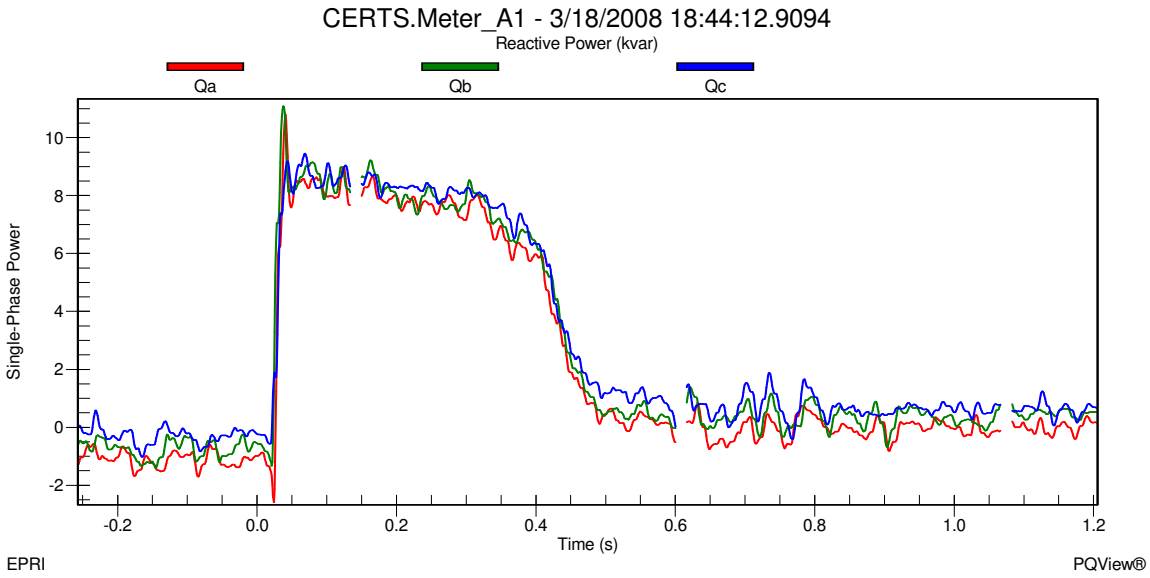

Figure 11n - Gen-set A1 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.12

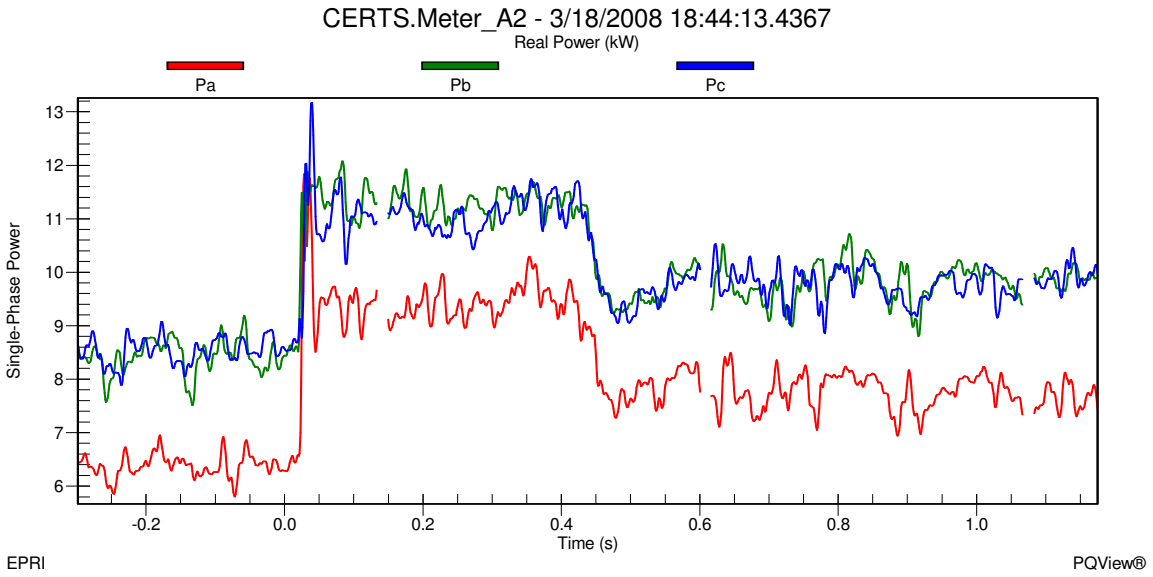

Figure 11o - Gen-set A2 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.12

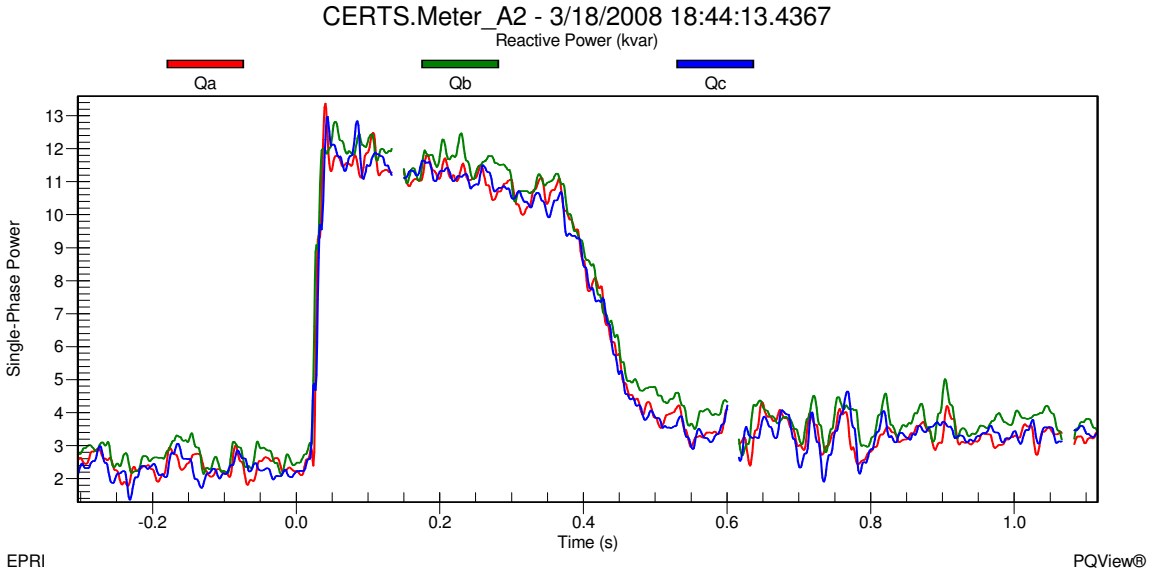

Figure 11p - Gen-set A2 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.12

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 37.7kW (A=10kW B=18kW C=9.7kW) to 33.2kW (A=9.2kW B=12kW C=12kW) and reactive power increased from approximately 0.9kVAr (A=0.2kVAr B=0.5kVAr C=0.2kVAr) to 24kVAr (A=8.7kVAr B=8kVAr C=7.3kVAr) which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 11q and 11r show the static switch decreasing in real power from approximately 0kW (A=0kW B=0kW C=0kW) to -3.7kW (A=-0.5kW B=-5.6kW C=2.4kW) and increasing in reactive power from approximately 0kVAr

(A=0kVAr B=0kVAr C=0kVAr) to 23.3kVAr (A=8.6kVAr B=7.6kVAr C=7.3kVAr). At the beginning of the test, the initial power flow through the static switch was -7.8kW (A=-2kW B=-7kW C=1.2kW) + j22.4kVAr (A=8.7kVAr B=7kVAr C=6.7kVAr) which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. The Gen-sets have picked up the motor load and supporting Load Bank 6 with approximately 3.7kW.

Load Banks 3 and 4 loads increased slightly to 24.8kW (A=8.45kW B=8.2kW C=8.15kW) + j6.34kVAr (A=2.17kVAr B=2.17kVAr C=2kVAr) and 36.4kW (A=9.7kW B=13.4kW C=13.3kW) + j0.61kVAr (A=0.12kVAr B=0.28kVAr C=0.21kVAr), respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 11s, from approximately 273.6V on A-phase, 273.6V on B-phase and 272.5V on C-phase when islanded to 281V on A-phase, 278.1V on B-phase and 277.9V on C-phase at Meter 3 when connected to the utility grid.

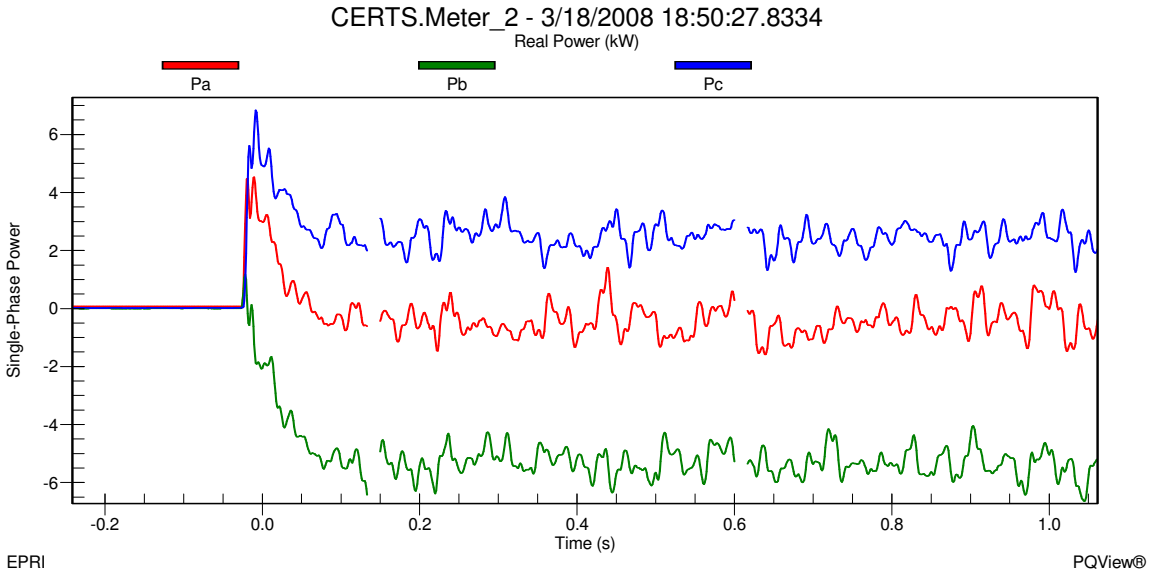

Figure 11q - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.12

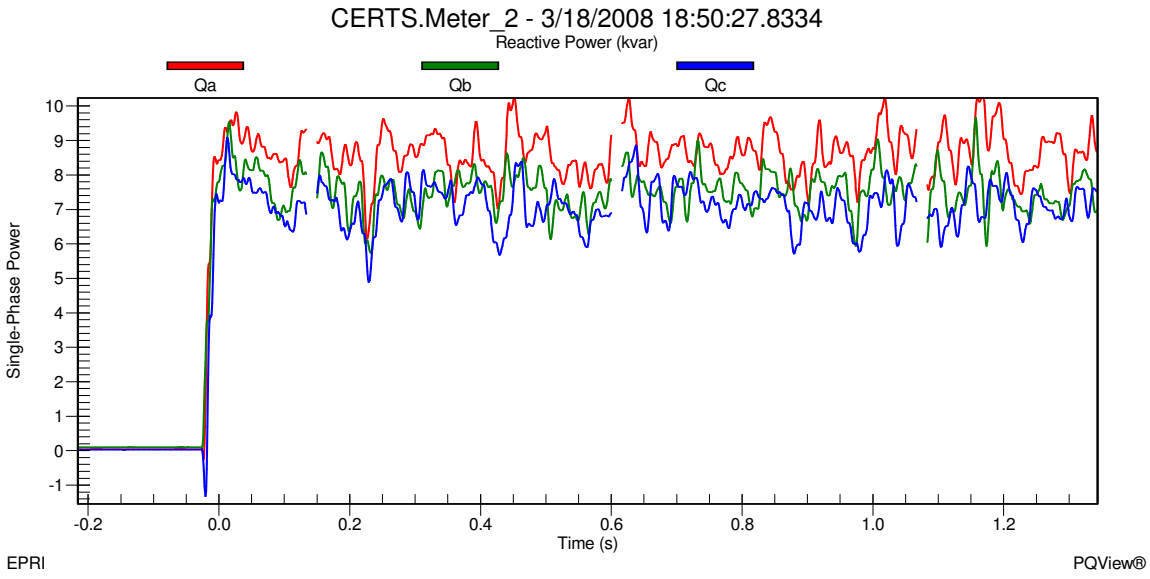

Figure 11r - Static Switch Reactive Single-Phase Power during Island to Utility Connected mode for Test 10.3.12

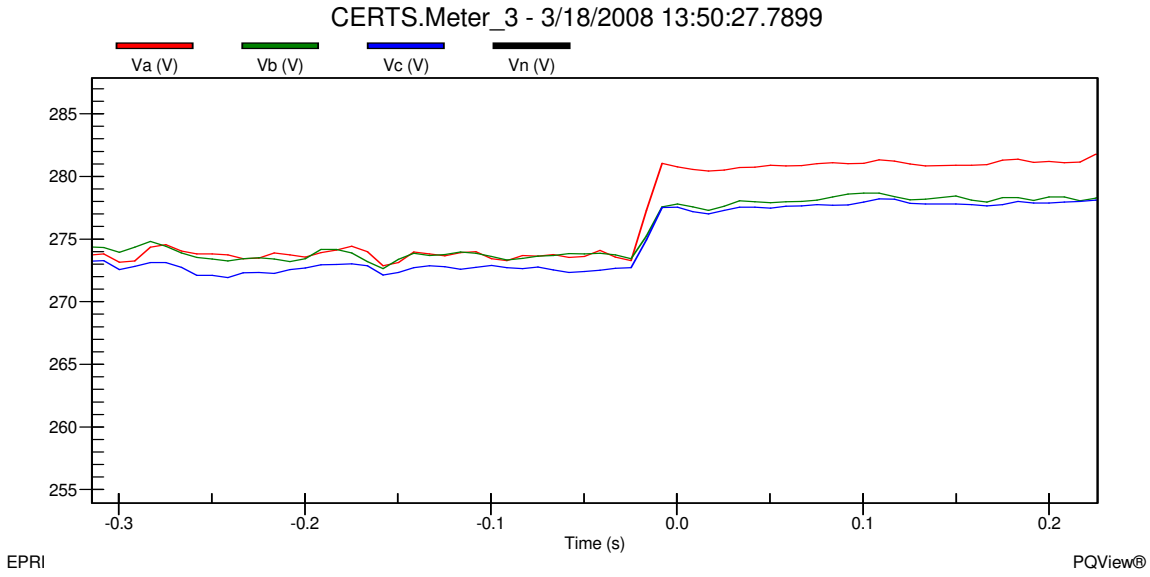

Figure 11s - Meter 3 Line-to-Ground Voltage during Island to Utility Connected mode for Test 10.3.12

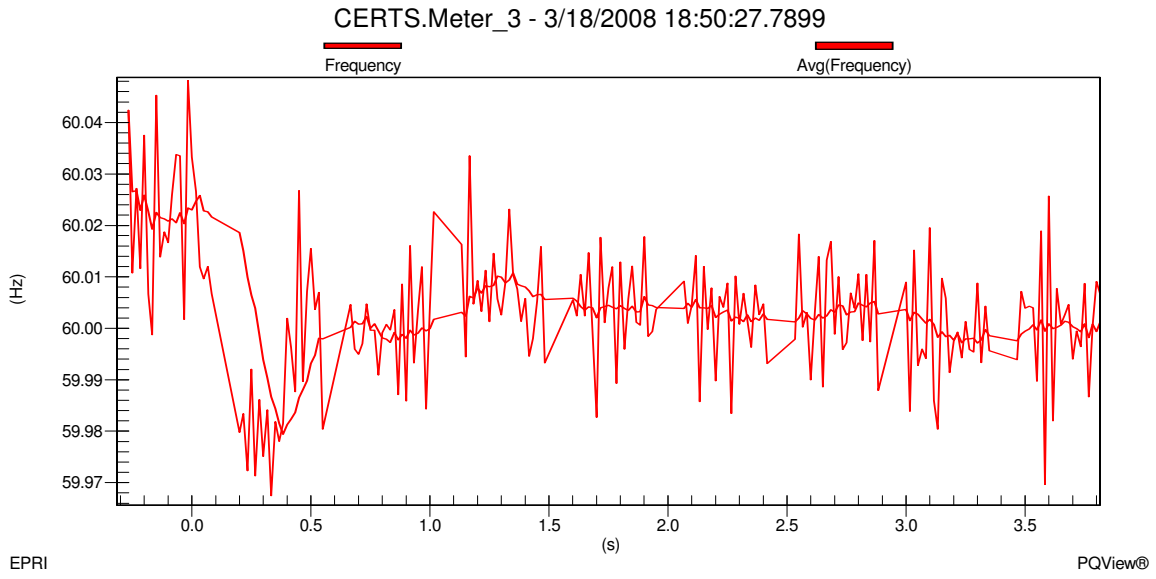

Figure 11t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.3.12

Frequency change in the microgrid, shown in Figure 11t, decreased from approximately 60.02Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in unit power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on their set-points initialized at the beginning of the test. The output power for both Gen-sets were relatively close to the values at the beginning of the test with Gen-set A1 producing approximately 38.5kW (A=11.5kW B=16kW C=11kW) – j10kVAr (A=-3.6kVAr B=-3.5kVAr C=-2.9kVAr) and Gen-set A2 producing approximately 29.4kW (A=8.4kW B=12.2kW C=8.8kW) – j1kVAr (A=-1kVAr B=0kVAr C=0kVAr). After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.3.14) in Table 2.

For Test 10.3.14 the measured values, after Gen-set A1 was warmed up and load banks brought on-line are provided in Table 4.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	37.3	0	14.1	-23.4	-26.5	0	10.95	0	37.1
1 Phase	A=11.3	A=0	A=3.1	A=-6.6	A=-7.6	A=0	A=3.75	A=0	A=9.8

kW	B=16.1 C=9.9	B=0 C=0	B=6.5 C=4.5	B=-11.2 C=-5.6	B=-12.8 C=-6.1	B=0 C=0	B=3.6 C=3.6	B=0 C=0	B=17.8 C=9.5
3 Phase kVAr	-13.1	0	19.5	18.9	13.4	0	0	0	0.645
1 Phase kVAr	A=-4.7 B=-4.6 C=-3.8	A=0 B=0 C=0	A=6.5 B=7 C=6	A=6.5 B=6.5 C=5.9	A=4.9 B=4.6 C=3.9	A=0 B=0 C=0	A=0 B=0 C=0	A=0 B=0 C=0	A=0.125 B=0.39 C=0.13

Table 4 - Measured Values after Start Up for Test 10.3.14

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW setting for LB6 was below the selected set value. At the time of the measurements, the voltage and frequency was 283.1V on A-phase, 278.9V on B-phase and 279.2V on C-phase and 60.00Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 283.8V on A-phase, 279.8V on B-phase and 279.9V on C-phase and 60.02Hz at Meter 3.

Gen-set A1 was setup in this test to produce more power than Load Bank 3 needed which approximately 23.4kW of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 37.1kW (A=9.8kW B=17.8kW C=9.5kW) + j0.645kVAr (A=0.125kVAr B=0.39kVAr C=0.13kVAr), the utility had to supply approximately 14.1kW to satisfy the load. Reactive power had to be imported in from the utility of approximately 18.9kVAr because Gen-sets A1 needed approximately j13.1kVAr (A=-4.7kVAr B=-4.6kVAr C=-3.8kVAr) and the reactive power absorbed in the electrical lines. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

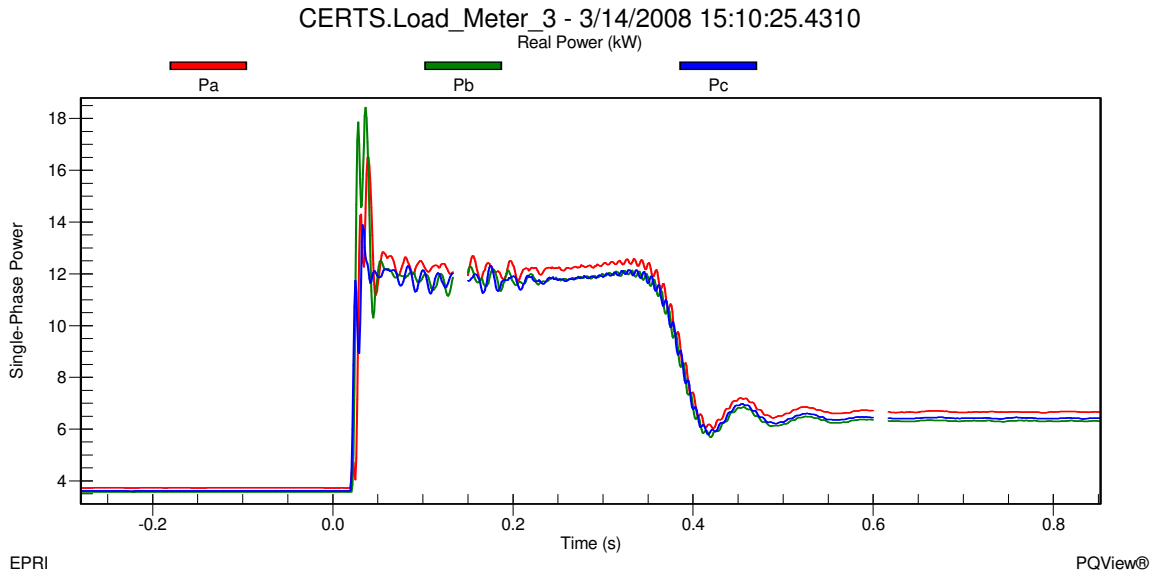

Figure 12a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.14

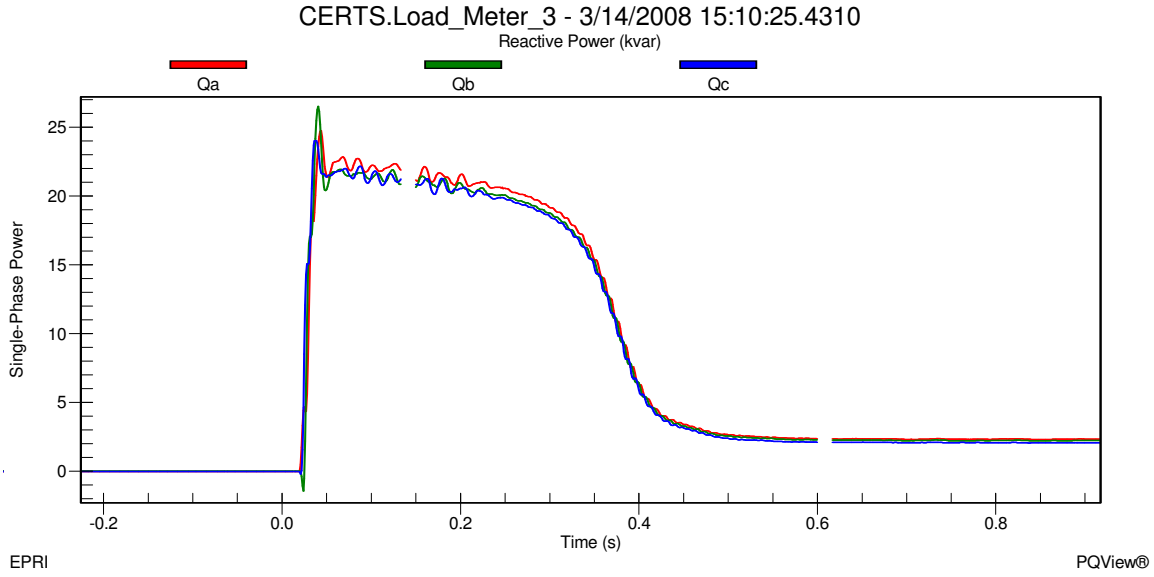

Figure 12b - Load Bank 3 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.14

In Figures 12a and 12b it can be seen that the load in Zone 3 was approximately 10.95kW (A=3.75kW B=3.6kW C=3.6kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) before the start of the induction motor and increased to approximately 48.45kW (A=16.25kW B=18.5kW C=13.7kW) + j75.1kVAr (A=24.6kVAr B=26.5kVAr C=24kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 35.8kW (A=12.2kW B=11.8kW C=11.8kW) + j62kVAr (A=21kVAr B=20.5kVAr C=20.5kVAr) during the warm up phase which lasted about 30 cycles (0.5 Seconds). When the motor

reached steady state, the load in Zone 3 was approximately 19.4kW (A=6.7kW B=6.3kW C=6.4kW) + j6.7kVAr (A=2.4kVAr B=2.2kVAr C=2.1kVAr).

The voltage and frequency at the static switch before the motor start was approximately 283.1V on A-phase, 278.9V on B-phase and 279.2V on C-phase shown in Figure 12c and approximately 60.00Hz shown in Figure 12d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.8V on A-phase, 271.6V on B-phase and 271.6V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.91Hz and quickly increased to approximately 59.99Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 282.8V on A-phase, 278V on B-phase and 278.3V on C-phase at an approximate frequency of 60.01Hz.

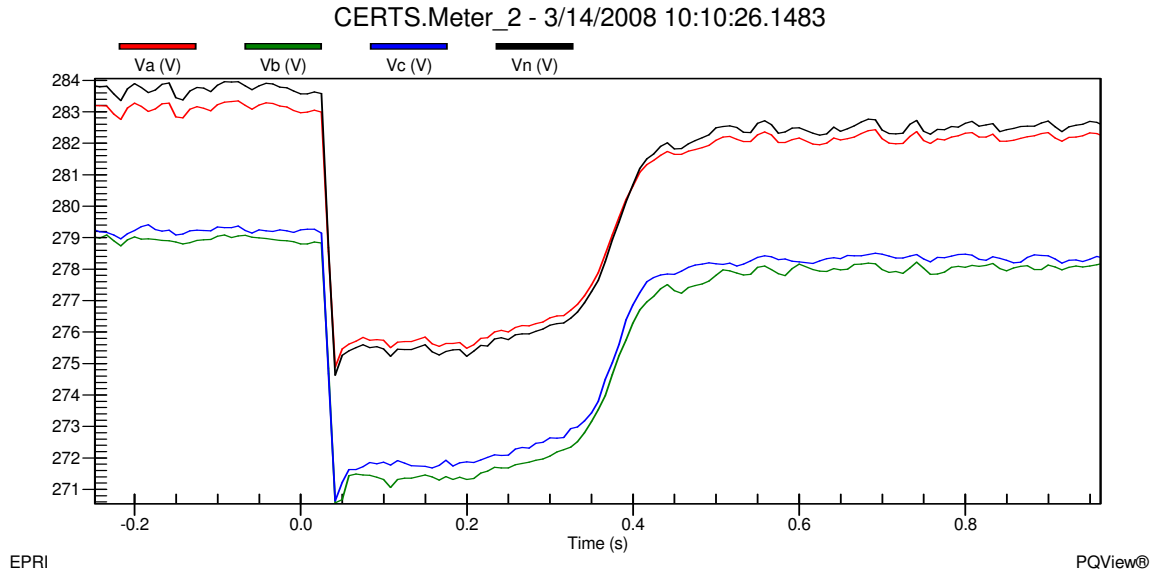

Figure 12c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.3.14

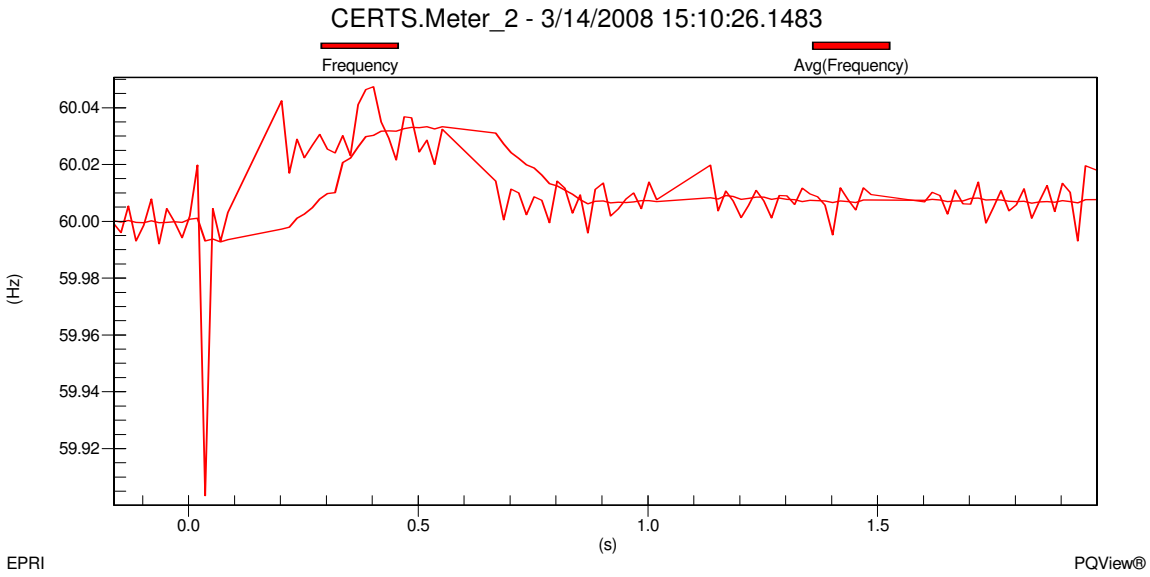

Figure 12d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.14

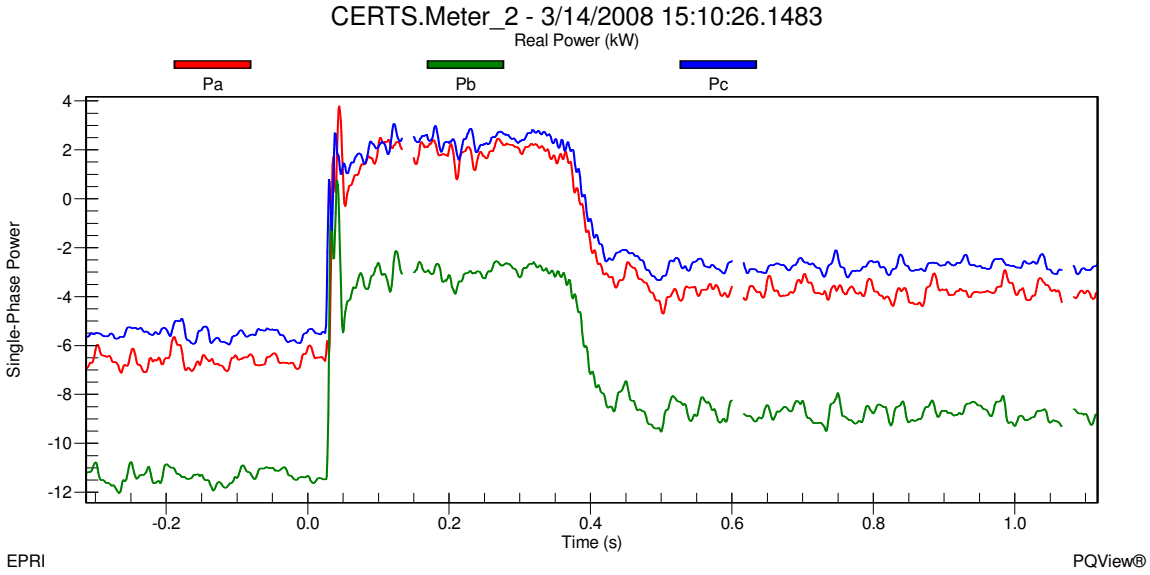

Figure 12e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.14

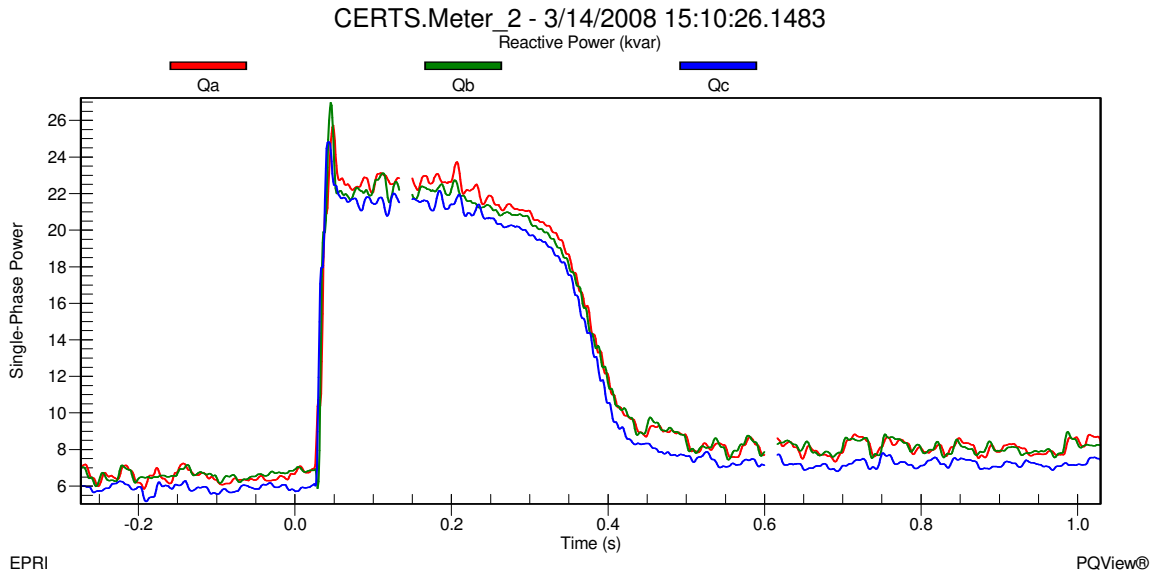

Figure 12f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.14

Before the motor started Gen-set A1 was producing approximately 37.3kW (A=11.3kW B=16.1kW C=9.9kW) – j13.1kVAr (A=-4.7kVAr B=-4.6kVAr C=-3.8kVAr). This was enough for the load demands of Zone 3 with real power being exported to Zone 6 of approximately 23.4kW (A=6.6kW B=11.2kW C=5.6kW) shown in Figure 12e. The grid was supporting the reactive power of the microgrid with approximately 18.9kVAr (A=6.5kVAr B=6.5kVAr C=5.9kVAr) shown in Figure 12f. When the motor started the inrush caused the utility to supply approximately 77.3kVAr (A=25.7kVAr B=26.8kVAr C=24.8kVAr) and to pick up the load demand in Load Bank 6 along with approximately 6.35kW (A=3.8kW B=0.75kW C=1.8kW) of the load in Zone 3. The power being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 12e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output level to approximately 44.5kW (A=13.6kW B=19.3kW C=11.6kW) + j5.7kVAr (A=1.5kVAr B=2.1kVAr C=2.1kVAr). Notice the sign of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -15.3kW (A=-3.8kW B=-8.75kW C=-2.75kW) + j23.45kVAr (A=8.1kVAr B=8.1kVAr C=7.25kVAr) which meant that Gen-set A1 was supplying the power for the induction motor and approximately 15.3kW (A=3.8kW B=8.75kW C=2.75kW) of Load Bank 6. Gen-set A1 real power returned relative close to the value before the motor started of approximately 37.6kW (A=11.4kW B=16.3kW C=9.9kW) and the reactive power increased to approximately -j11.6kVAr (A=-4.25kVAr B=-4.1kVAr C=-

3.25kVAr). Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 38.1kW (A=10.1kW B=18.1kW C=9.9kW) and reactive power decreased to j1.1kVAr (A=0.25kVAr B=0.6kVAr C=0.25kVAr) satisfying the load demand in Load Bank 6 which was approximately 37.7kW (A=10kW B=18kW C=9.7kW) + j0.657kVAr (A=0.129kVAr B=0.399kVAr C=0.129kVAr) and not supplying any power beyond the static switch to Load Bank 3. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads was slightly reduced to 10.3kW (A=3.44kW B=3.43kW C=3.43kW) – j0.041kVAr (A=-0.016kVAr B=-0.002kVAr C=-0.023kVAr). This load reduction resulted from a voltage drop in the microgrid, shown in Figure 12g, from approximately 284V on A-phase, 279.5V on B-phase and 279.5V on C-phase when connected to the utility grid to 272.8V on A-phase, 271.6V on B-phase and 272.8V on C-phase at Meter 3 when islanded.

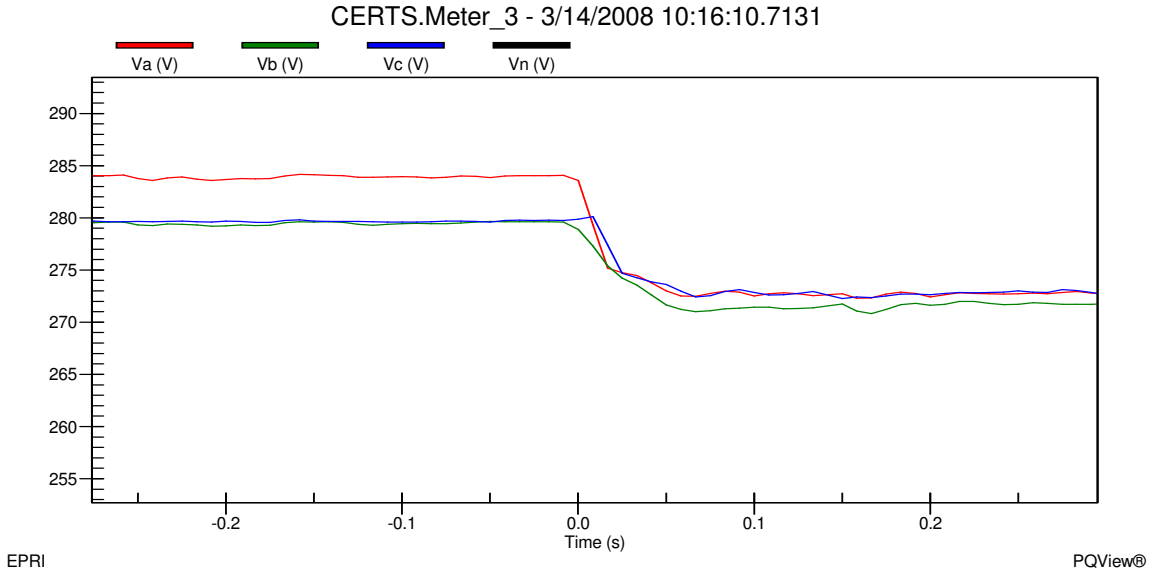

Figure 12g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.14

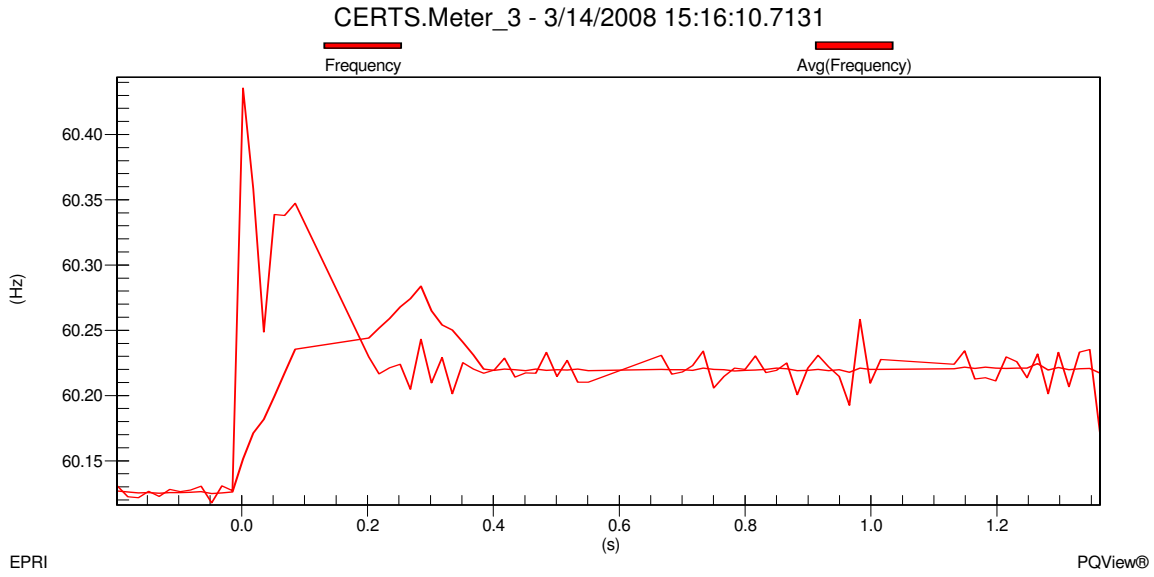

Figure 12h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.14

Frequency change in the microgrid, shown in Figure 12h, increased from approximately 60.13Hz when connected to the utility grid to approximately 60.22Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the load demands. Gen-set A1 decreased its output real power to approximately 12.8kW (A=4.2kW B=4.6kW C=4kW) and increased its output reactive power to approximately j3.6kVAr (A=0.8kVAr B=1.4kVAr C=1.4kVAr). Meter 3 was approximately -2.2kW (A=-0.7kW B=-1kW C=-0.5kW) – j3.6kVAr (A=-0.8kVAr B=-1.4kVAr C=-1.4kVAr) indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

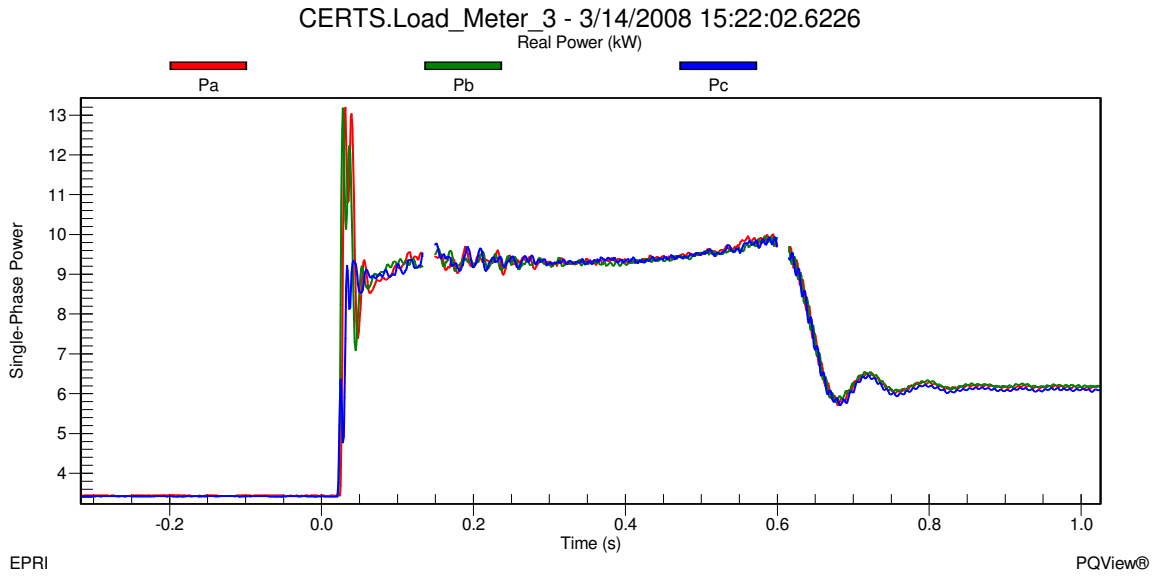

Figure 12i - Load Bank 3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.14

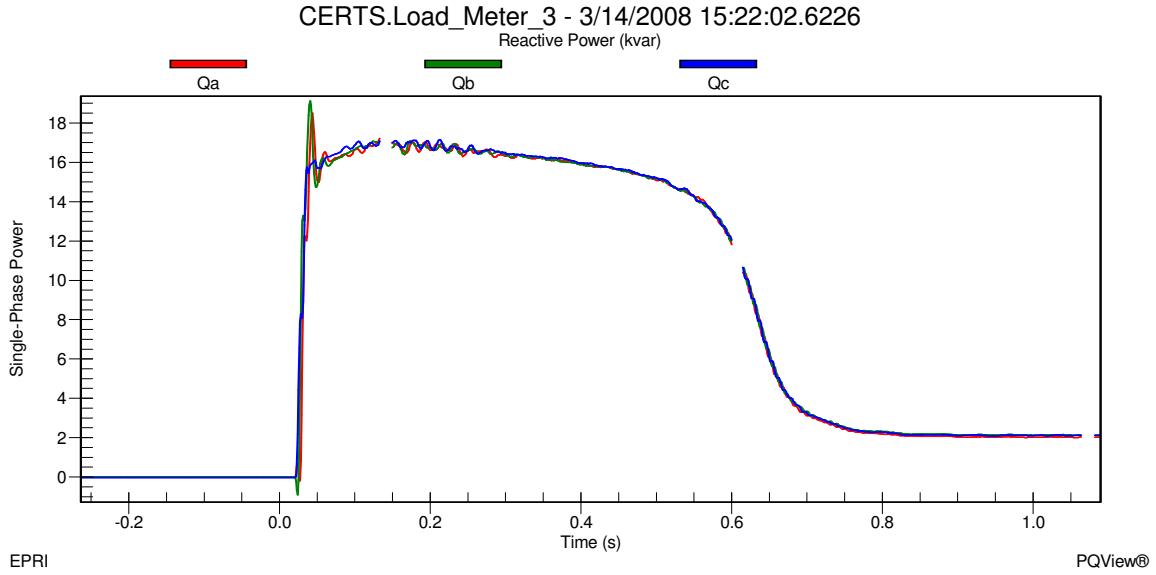

Figure 12j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.14

In Figures 12i and 12j it can be seen that the load in Zone 3 was approximately 10.2kW (A=3.4kW B=3.4kW C=3.4kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) before the start of the induction motor and increased to approximately 34.5kW (A=13.2kW B=12.1kW C=9.2kW) + j53.3kVAr (A=19.2kVAr B=18.1kVAr C=16kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 28.5kW (A=9.5kW B=9.5kW C=9.5kW) + j48.3kVAr (A=16.1kVAr B=16.1kVAr C=16.1kVAr) during the warm up phase which lasted about 48 cycles (0.8 Seconds). When the motor

reached steady state, the load in Zone 3 was approximately 18.6kW (A=6.2kW B=6.2kW C=6.2kW) + j6kVAr (A=2kVAr B=2kVAr C=2kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 272.8V on A-phase, 272V on B-phase and 272.7V on C-phase shown in Figure 12k and approximately 60.22Hz shown in Figure 12l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 238.1V on A-phase, 237.6V on B-phase and 236V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.8Hz and quickly increased to approximately 60.38Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 269V on A-phase, 269V on B-phase and 269.1V on C-phase at an approximate frequency of 60.15Hz.

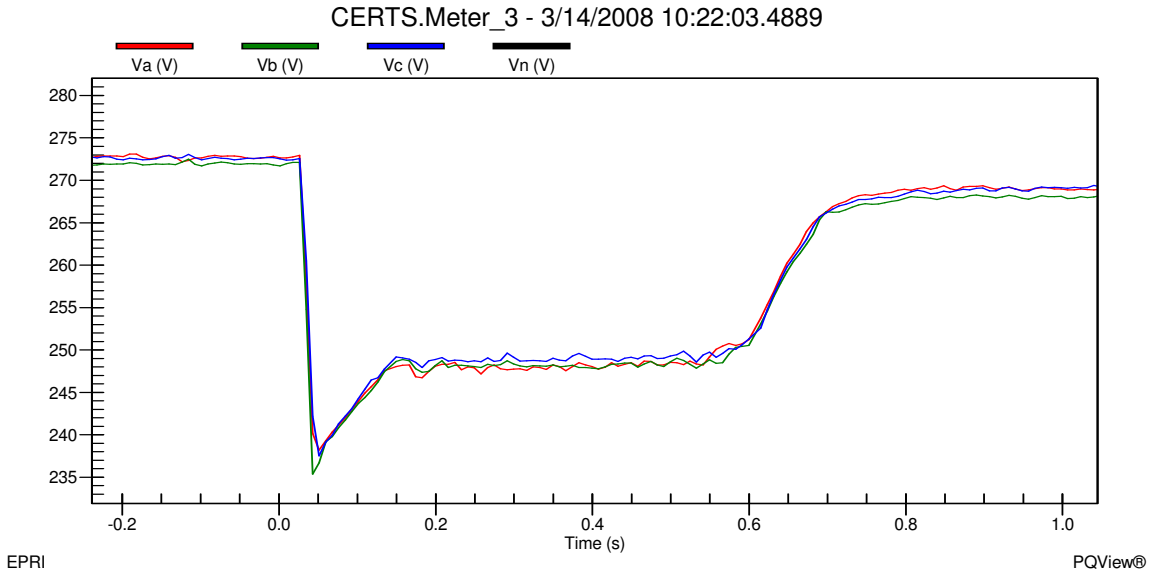

Figure 12k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.3.14

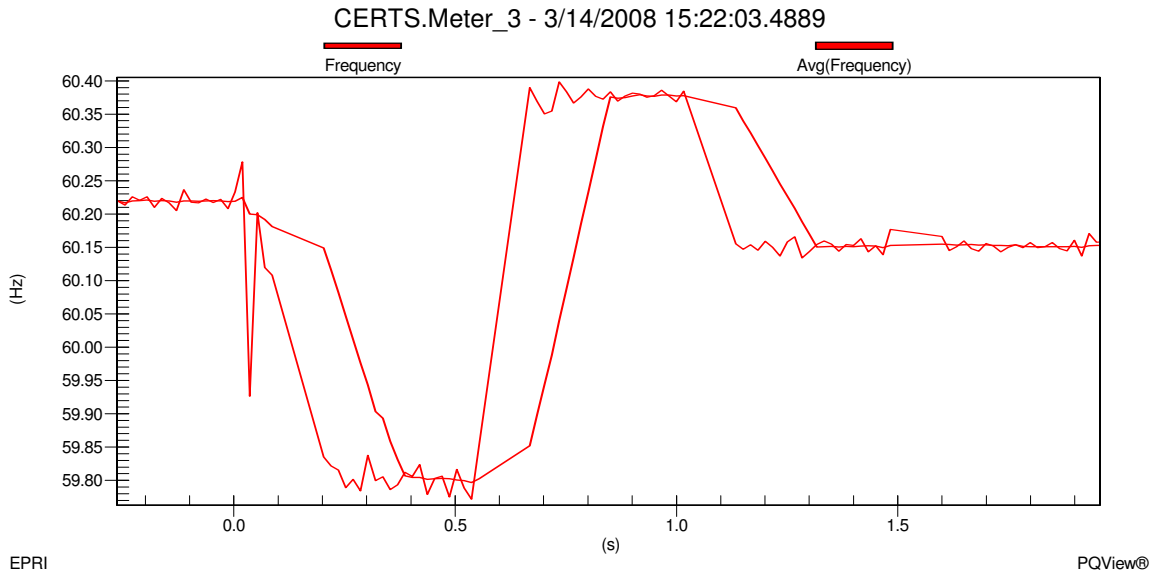

Figure 121 - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.14

Before the motor started Gen-set A1 was producing approximately 12.6kW (A=4.2kW B=4.5kW C=3.9kW) + j3.6kVAr (A=0.8kVAr B=1.4kVAr C=1.4kVAr) shown in Figure 12m and 12n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-set to increase its output level to 36.5kW (A=13.9kW B=13.9kW C=8.7kW) + j54.2kVAr (A=18.2kVAr B=19.6kVAr C=16.4kVAr). Gen-set A1 decreased its output level while the motor was warming up and eventually dropped to 20.8kW (A=6.9kW B=7.3kW C=6.6kW) + j9.5kVAr (A=2.75kVAr B=3.4kVAr C=3.4kVAr) when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

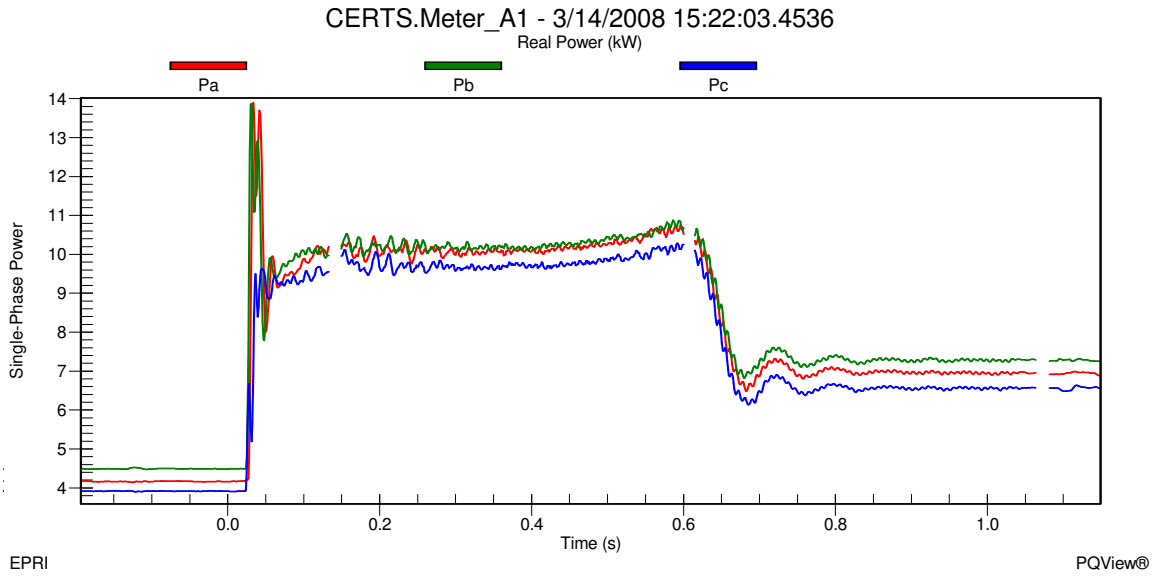

Figure 12m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.14

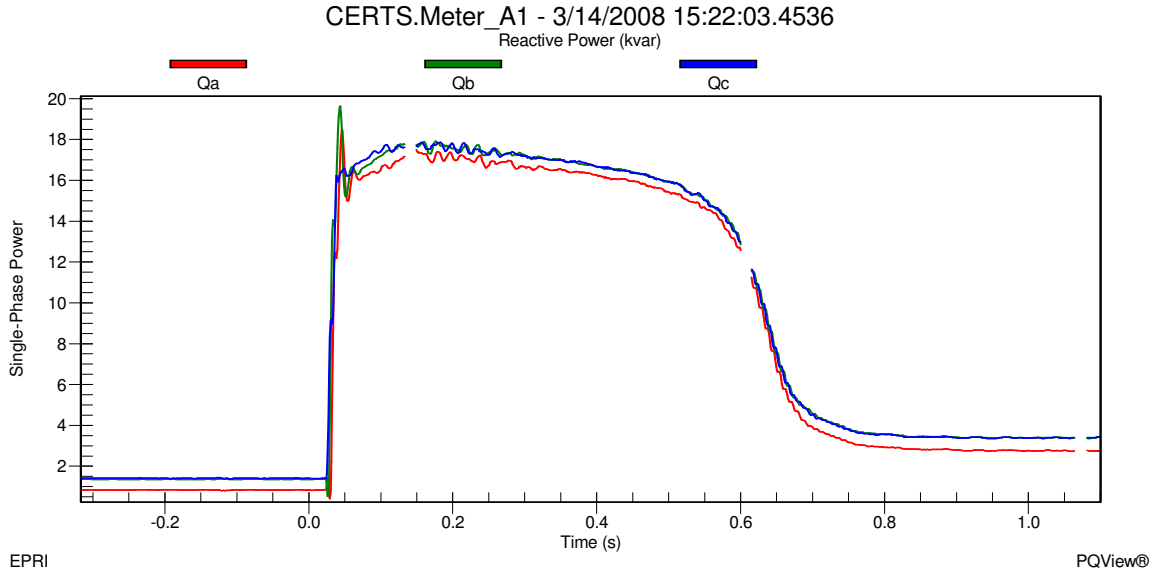

Figure 12n - Gen-set A1 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.14

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 38.2kW (A=10.2kW B=18.1kW C=9.9kW) to 20.9kW (A=5.7kW B=8.6kW C=6.6kW) and reactive power increased from approximately j1kVAr (A=0.2kVAr B=0.6kVAr C=0.2kVAr) to j25kVAr (A=8.5kVAr B=8.7kVAr C=7.8kVAr) which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 12o and 12p show the static switch decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -16.45kW (A=-4.25kW B=-9.2kW C=-3kW) and increasing from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to

j24.1kVAr (A=8.3kVAr B=8.1kVAr C=7.7kVAr). At the beginning of the test, the initial power flow through the static switch was -23.4kW (A=-6.6kW B=-11.2kW C=-5.6kW) + j18.9kVAr (A=6.5kVAr B=6.5kVAr C=5.9kVAr) which is not the same recorded at this point in the test because the 10 Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and is supporting Load Bank 6 with approximately 16.45kW (A=4.25kW B=9.2kW C=3kW).

Load Bank 3 loads increased slightly to 17.65kW (A=6.06kW B=5.74kW C=5.85kW) + j6kVAr (A=2.12kVAr B=2.01kVAr C=1.87kVAr). This slight increase is a result from a voltage rise in the microgrid, shown in Figure 12q, from approximately 269.3V on A-phase, 269V on B-phase and 269.1V on C-phase when islanded to 283V on A-phase, 279.4V on B-phase and 279.4V on C-phase at Meter 3 when connected to the utility grid.

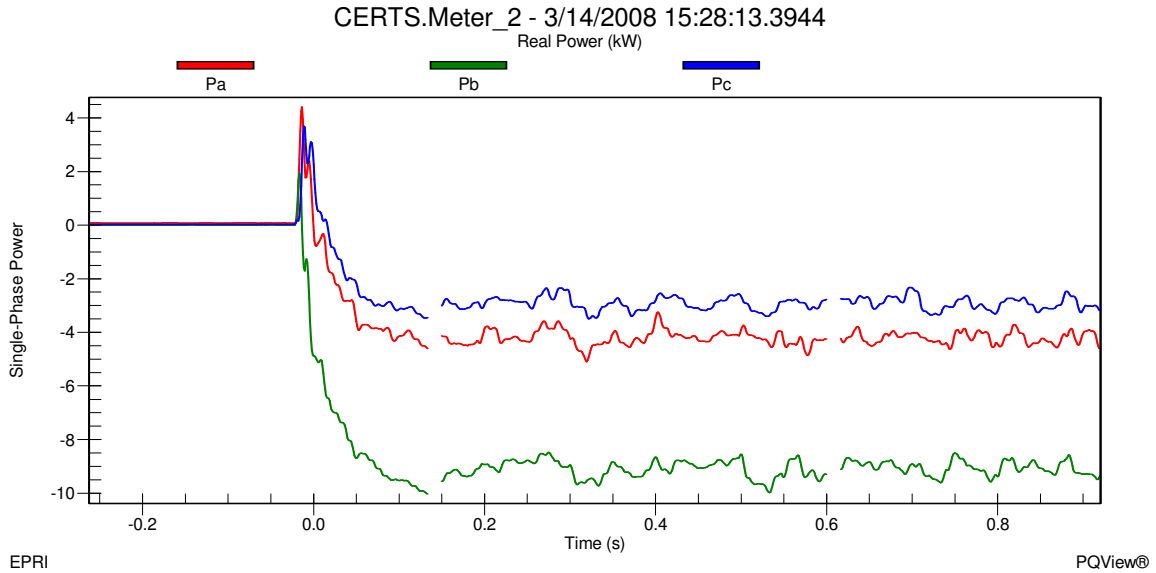

Figure 12o - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.14

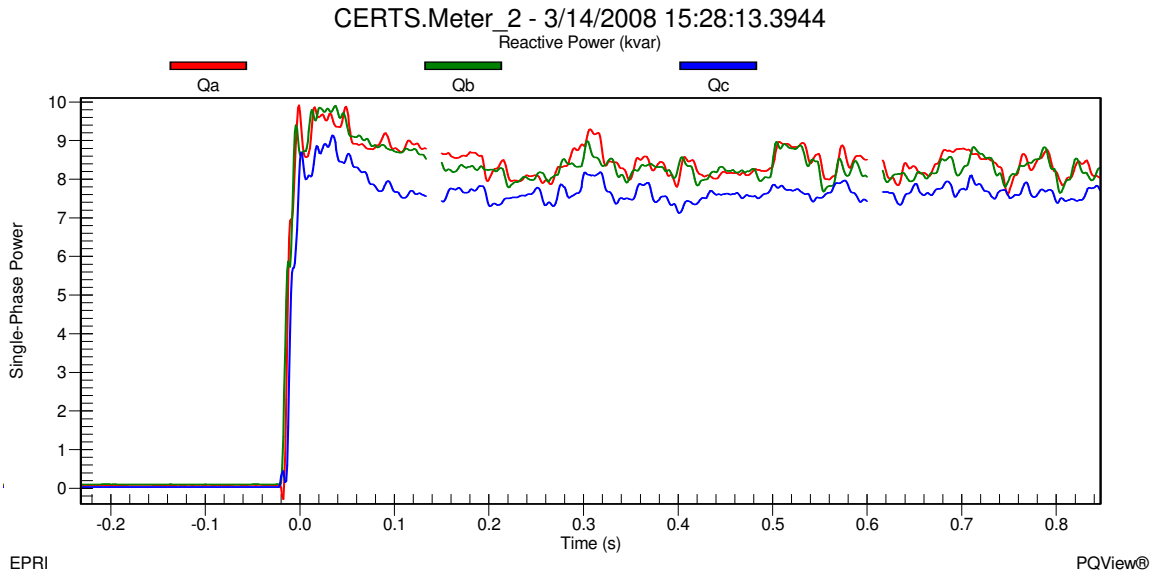

Figure 12p - Static Switch Reactive Single-Phase Power during Island to Utility Connected mode for Test 10.3.14

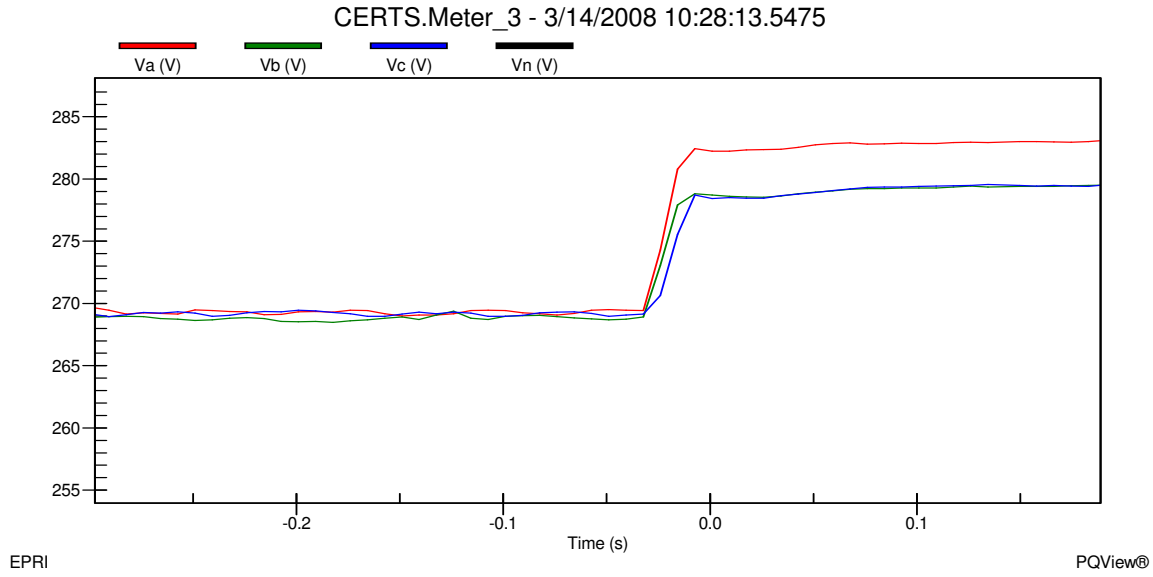

Figure 12q - Meter 3 Line-to-Ground Voltages during Island to Utility Connected for Test 10.3.14

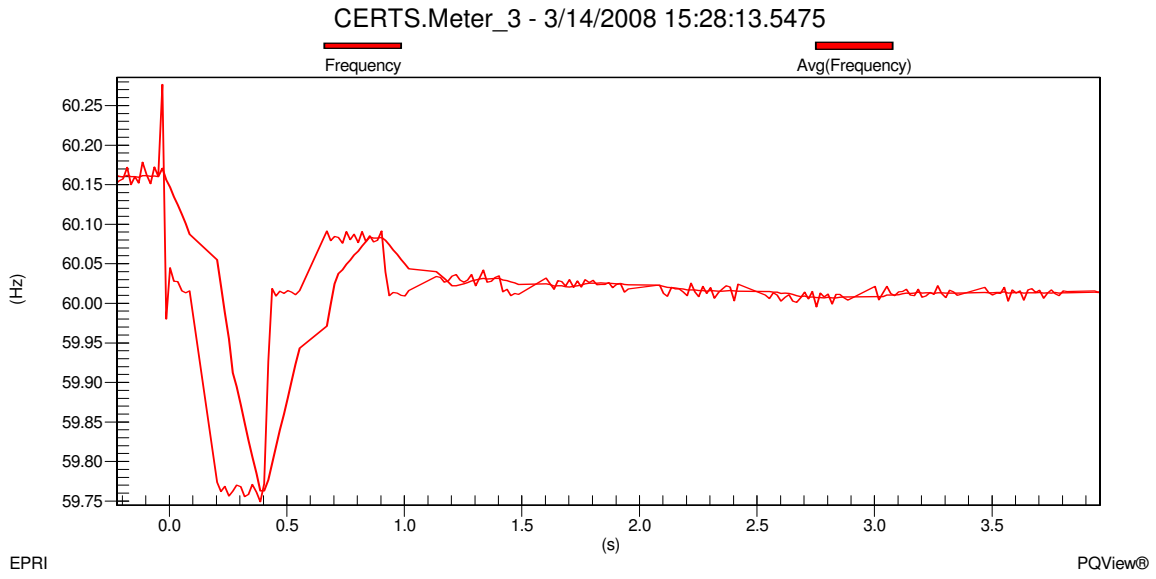

Figure 12r - Meter 3 Frequency during Island to Utility Connected mode for Test 10.3.14

Frequency change in the microgrid, shown in Figure 12r, decreased from approximately 60.16Hz when islanded to approximately 60.01Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by Gen-set A1 using the CRETS algorithm but by the utility. Gen-set A1 is in unit power control mode therefore when the static switch closed back into the utility the Gen-set produced real power based on the set-point initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the value at the beginning of the test with Gen-set A1 producing approximately 36.6kW (A=11.1kW B=16kW C=9.5kW) – j12.7kVAr (A=-4.6kVAr B=-4.4kVAr C=-3.7kVAr). After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.3.15) in Table 2.

For Test 10.3.15 the measured values, after the Gen-sets were warmed up and load banks brought on-line are provided in Table 5.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	38.3	29.8	62.8	25.95	23.2	14.9	46.2	44.65	36.8
1 Phase kW	A=10.5 B=16.6	A=7.1 B=13.1	A=18.4 B=22.2	A=8.75 B=4.6	A=7.9 B=3.2	A=2.6 B=4.4	A=15.6 B=15.3	A=9.75 B=17.5	A=9.7 B=17.6

	C=11.2	C=9.6	C=22.2	C=12.6	C=12.1	C=7.9	C=15.3	C=17.4	C=9.5
3 Phase kVAr	-9	0.1	16.8	15.05	10.5	0.5	0.6	0.803	0.641
1 Phase kVAr	A=-3.4 B=-2.8 C=-2.8	A=-0.9 B=0.1 C=0.9	A=6.5 B=4.8 C=5.5	A=5.8 B=4 C=5.25	A=4.8 B=2.2 C=3.5	A=1 B=-0.7 C=0.2	A=0.2 B=0.2 C=0.2	A=0.119 B=0.38 C=0.304	A=0.12 B=0.4 C=0.121

Table 5 - Measured Values after Start Up for Test 10.3.15

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 50kW settings for LB3 and LB4 and the 40kW setting for LB6 were also below selected set values. At the time of the measurements, the voltage and frequency was 281.7V on A-phase, 278.5V on B-phase and 278V on C-phase and 60.00Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 281V on A-phase, 278V on B-phase and 277V on C-phase and 60.00Hz at Meter 3.

The Gen-sets in this test were set up to produce less power than the microgrid loads needed which approximately 25.95kW (A=8.75kW B=4.6kW C=12.6kW) of power was imported from the utility through the static switch to support Load Banks 3 and 4. Since Load Bank 6 was approximately 36.8kW (A=9.7kW B=17.6kW C=9.5kW) + j0.641kVAr (A=0.12kVAr B=0.4kVAr C=0.121kVAr), the utility had to supply approximately 62.8kW (A=18.4kW B=22.2kW C=22.2kW) to satisfy the load demand of Load Bank 6 and the microgrid loads. Reactive power had to be imported in from the utility of approximately 16.8kVAr (A=6.5kVAr B=4.8kVAr C=5.5kVAr) because Gen-sets A1 and A2 needed approximately 8.9kVAr between the two and the reactive power of Load Banks 3 and 4 and electrical wires. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

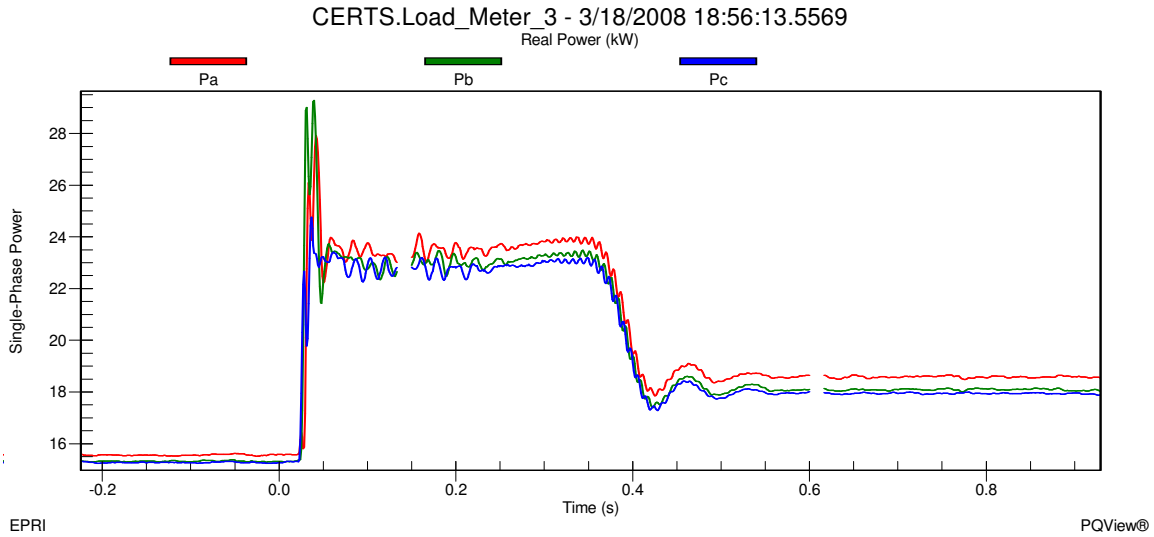

Figure 13a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.15

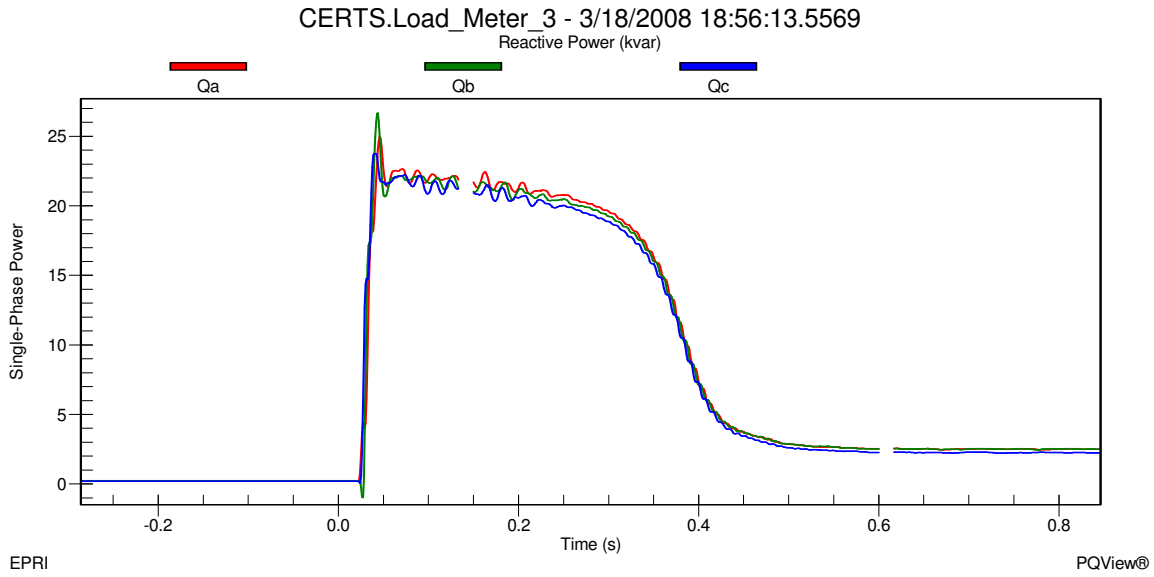

Figure 13b - Load Bank 2 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.15

In Figures 13a and 13b it can be seen that the load in Zone 3 was approximately 46.2kW (A=15.6kW B=15.3kW C=15.3kW) + j0.6kVAr (A=0.2kVAr B=0.2kVAr C=0.2kVAr) before the start of the induction motor and increased to approximately 79.45kW (A=25.5kW B=29.2kW C=24.75kW) + j75.6kVAr (A=24.9kVAr B=26.8kVAr C=23.9kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 69.7kW (A=23.6kW B=23.2kW C=22.9kW) + j63.3kVAr (A=21.3kVAr B=21kVAr C=21kVAr) during the warm up phase which lasted about 33 cycles (0.55 Seconds). When the motor reached steady state, the load in Zone 3 was approximately

54.6kW (A=18.6kW B=18.1kW C=17.9kW) + j7.2kVAr (A=2.5kVAr B=2.5kVAr C=2.2kVAr).

The voltage and frequency at the static switch before the motor start was approximately 281.7V on A-phase, 278.5V on B-phase and 278V on C-phase shown in Figure 13c and approximately 60.00Hz shown in Figure 13d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 274.9V on A-phase, 271.8V on B-phase and 271V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.96Hz and quickly increased back to approximately 59.99Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 281.1V on A-phase, 277.7V on B-phase and 277.4V on C-phase at an approximate frequency of 60.00 Hz.

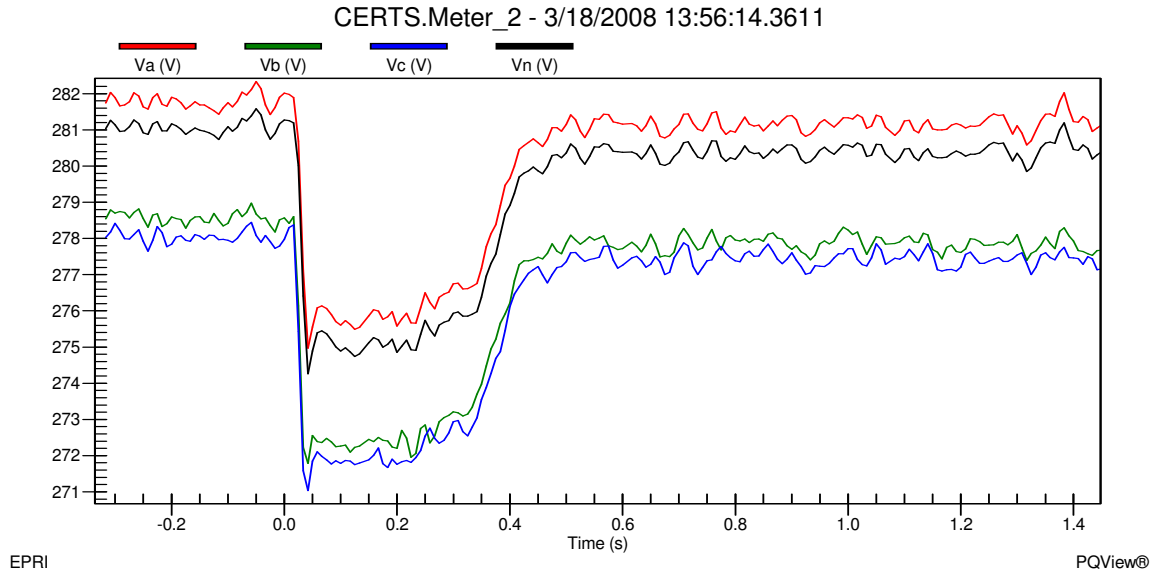

Figure 13c - Static Switch Line-to-Ground Voltage during Motor Start and Utility Connected for Test 10.3.15

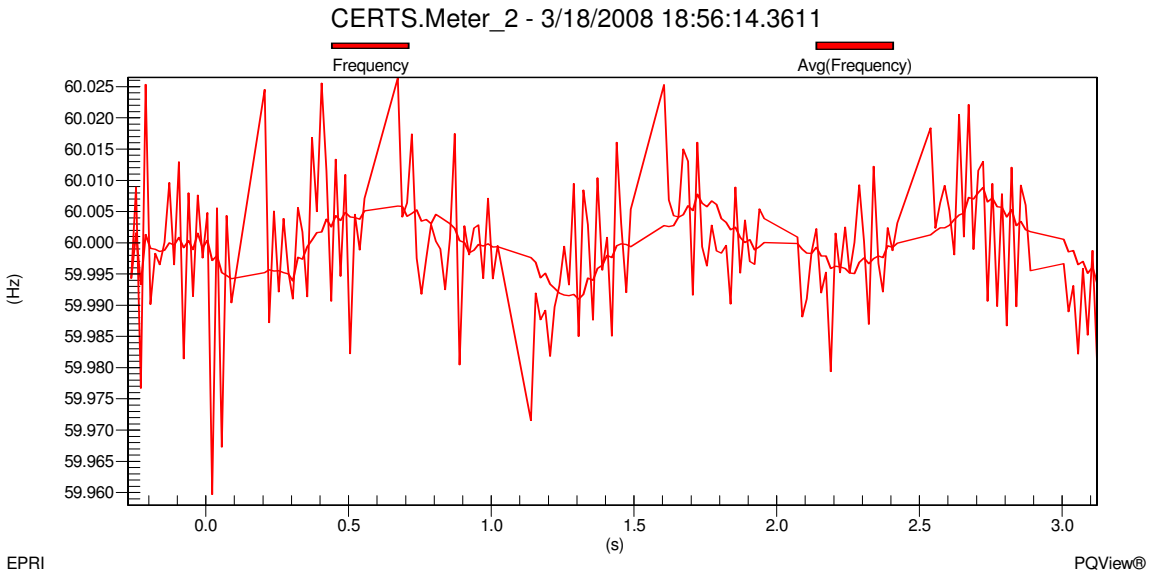

Figure 13d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.15

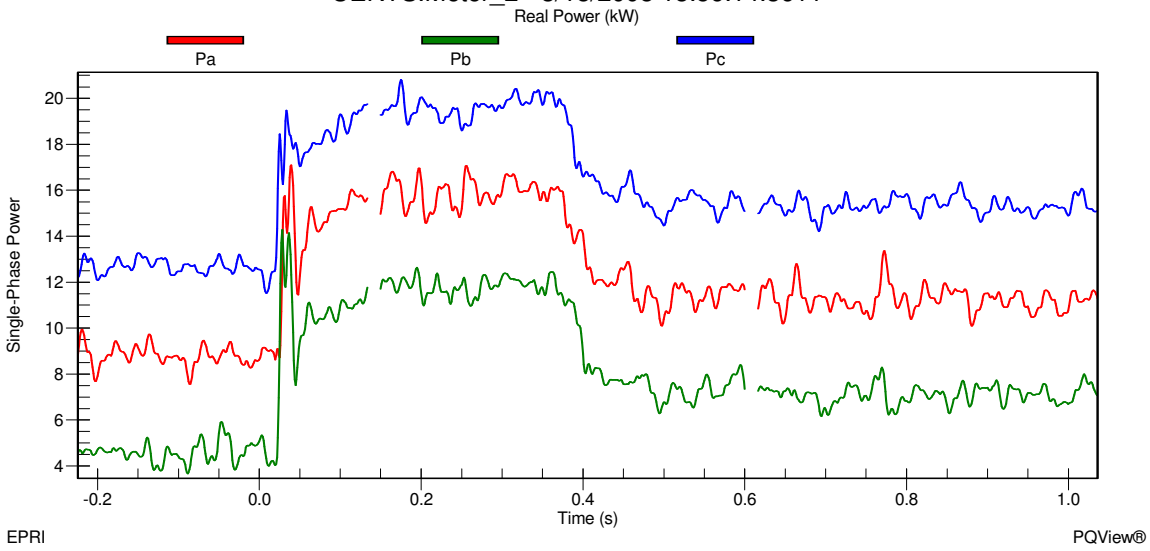

Figure 13e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.15

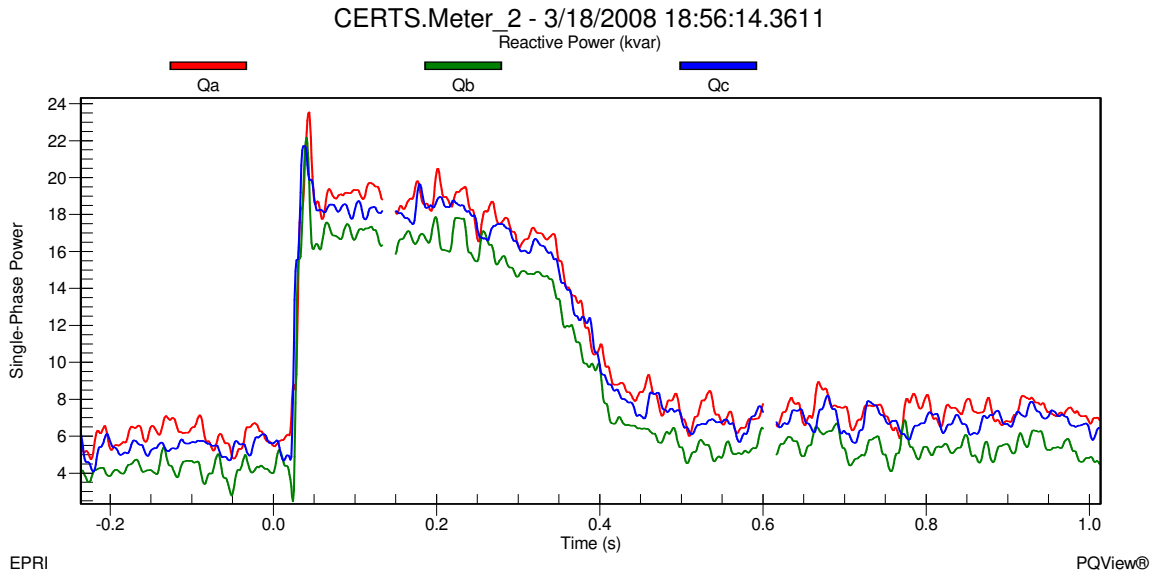

Figure 13f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.15

Before the motor started Gen-sets A1 and A2 were producing approximately 38.3kW (A=10.5kW B=16.6kW C=11.2kW) - j9kVAr (A=-3.4kVAr B=-2.8kVAr C=-2.8kVAr) and 29.8kW (A=7.1kW B=13.1kW C=9.6kW) + j0.1kVAr (A=-0.9kVAr B=0.1kVAr C=0.9kVAr), respectively. The load demands of Load Banks 3 and 4 were greater than the power being produced by both Gen-sets therefore the utility had to supply approximately 25.95 (A=8.75kW B=4.6kW C=12.6kW) shown in Figure 13e. The utility was supporting the reactive power of the microgrid with approximately 15.05kVAr (A=5.8kVAr B=4kVAr C=5.25kVAr) shown in Figure 13f. When the motor started the inrush caused the utility to supply approximately 50.25kW (A=16.75kW B=14.2kW C=19.3kW) + j67.2kVAr (A=23.5kVAr B=22.2kVAr C=21.5kVAr) to the microgrid loads, shown in Figure 13e and 13f, and Gen-sets A1 and A2 increased their output power levels to 42.4kW (A=12.6kW B=17.2kW C=12.6kW) + j3.4kVAr (A=1kVAr B=1.6kVAr C=0.8kVAr) and 35.1kW (A=9.6kW B=14.4kW C=11.1kW) + j16.9kVAr (A=4.9kVAr B=6.75kVAr C=5.25kVAr), respectively. Notice the sign of the VAr output changed from negative to positive for Gen-set A1 and 0.1 kVAr (A=-0.9kVAr B=0.1kVAr C=0.9kVAr) to 16.9kVAr (A=4.9kVAr B=6.75kVAr C=5.25kVAr) in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately 33.6kW (A=11.25kW B=7.1kW C=15.25kW) + j18.85kVAr (A=7kVAr B=5.25kVAr C=6.6kVAr) which meant the utility was supplying the power for the induction motor. Gen-set A1 and A2 real power returned relatively close to the values before the motor started of approximately 38.5kW (A=10.7kW B=16.6kW C=11.2kW) and 29.95kW (A=7.1kW B=13.1kW C=9.75kW), respectively, and the reactive power slightly increased to approximately -j7.6kVAr (A=-2.8kVAr B=-2.3kVAr C=-

2.5kVAr) in Gen-set A1 and j1.75kVAr (A=-0.25kVAr B=1.5kVAr C=0.5kVAr) in Gen-set A2. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real and reactive power decreased to approximately 37.9kW (A=10kW B=18.1kW C=9.8kW) + j1.1kVAr (A=0.25kVAr B=0.6kVAr C=0.25kVAr) satisfying the load demand in Load Bank 6 which was approximately 37.65kW (A=10kW B=17.9kW C=9.75kW) + j0.651kVAr (A=0.121kVAr B=0.409kVAr C=0.121kVAr) and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch, indicating that power was not flowing through the static switch. Load Banks 3 and 4 loads reduced slightly to 51.35kW (A=17.3kW B=17.3kW C=16.75kW) + j6.55kVAr (A=2.14kVAr B=2.35kVAr C=206kVAr) and 42.5kW (A=9.2kW B=16.8kW C=16.5kW) + j0.775kVAr (A=0.11kVAr B=0.375kVAr C=0.29kVAr), respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 13g, from approximately 280.5V on A-phase, 277.4V on B-phase and 276.9V on C-phase when connected to the utility grid to 273.2V on A-phase, 273.2V on B-phase and 270.4V on C-phase at Meter 3 when islanded.

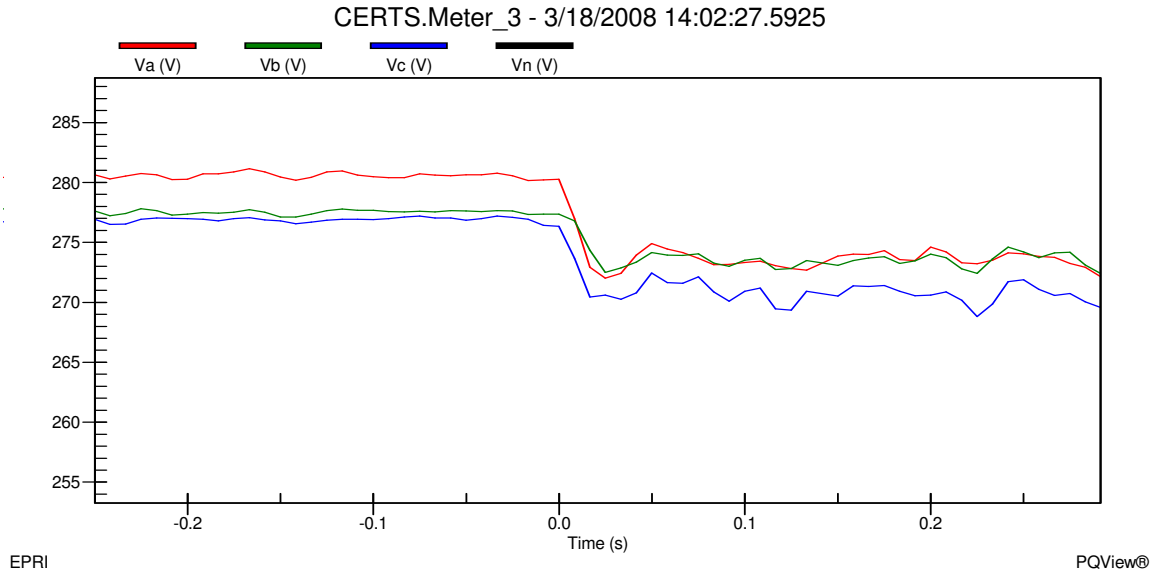

Figure 13g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.15

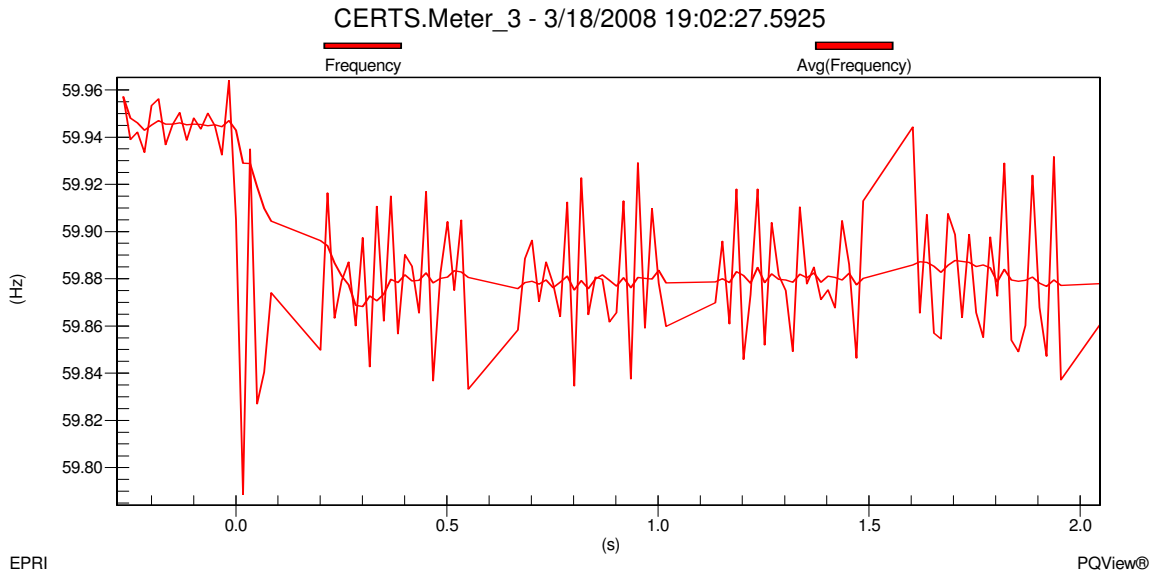

Figure 13h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.15

Frequency change in the microgrid, shown in Figure 13h, decreased from approximately 59.95Hz when connected to the utility grid to approximately 59.88Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets to increase their output power to satisfy the load demands. Gen-set A1 and A2 increased their output real and reactive powers to approximately 52.1kW (A=15.25kW B=19.1kW C=17.75kW) + j1.2kVAr (A=0.1kVAr B=0.2kVAr C=0.9kVAr) and 44.2kW (A=12kW B=16.2kW C=16kW) + j10kVAr (A=3.1kVAr B=3.8kVAr C=3.1kVAr), respectively. Meter 3 was approximately -1.25kW (A=-0.4kW B=-0.6kW C=-0.25kW) + j-4kVAr (A=-1kVAr B=-1.5kVAr C=-1.5kVAr) indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

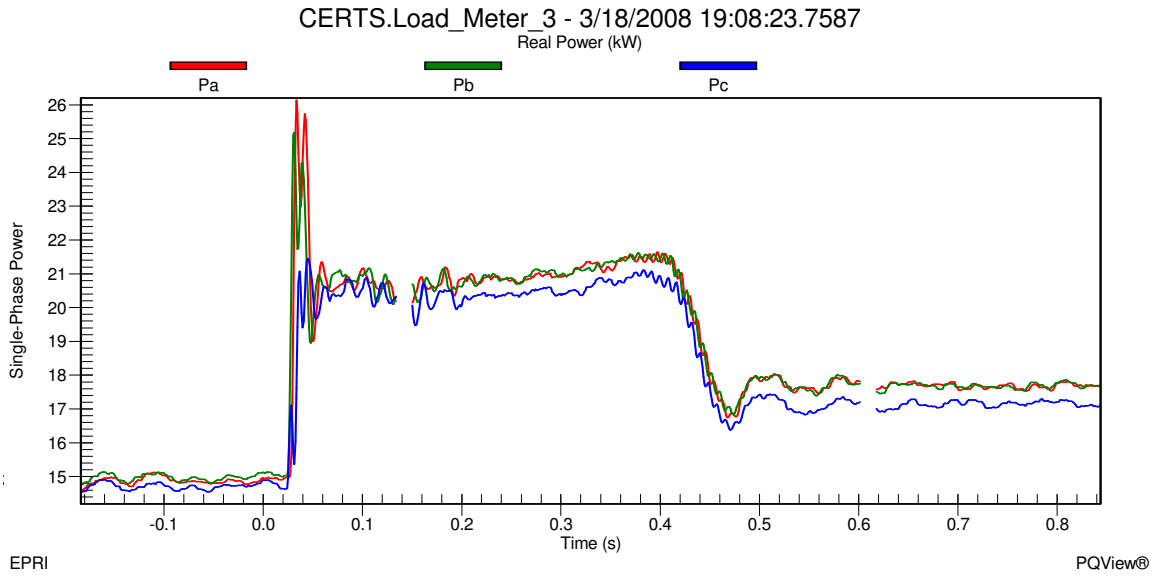

Figure 13i - Load Bank 3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.15

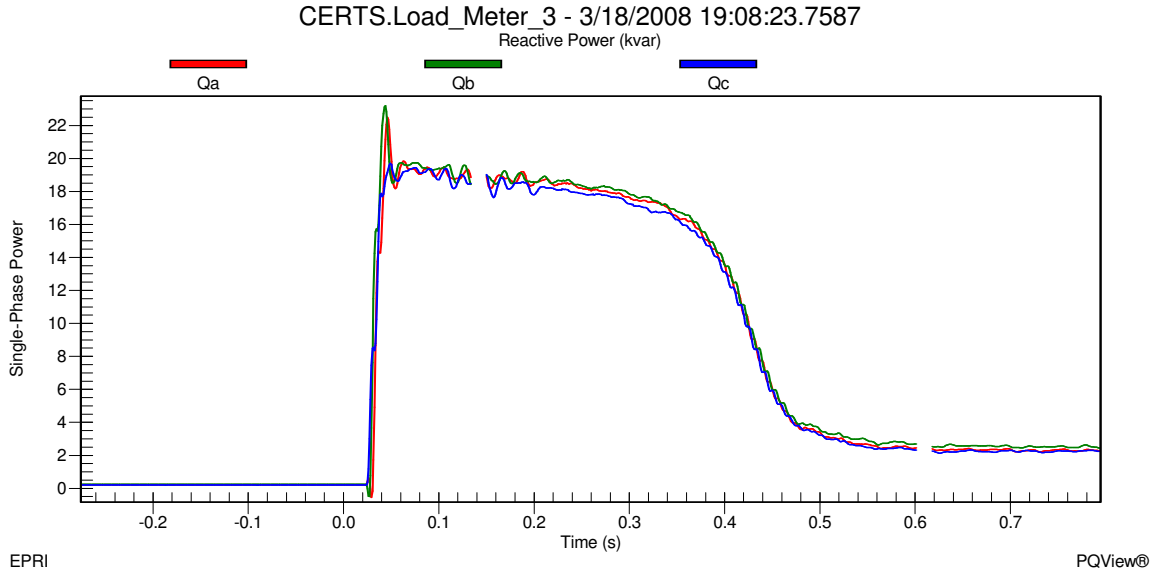

Figure 13j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.15

In Figures 13i and 13j it can be seen that the load in Zone 3 was approximately 44.5kW (A=14.8kW B=15kW C=14.7kW) + j0.75kVAr (A=0.25kVAr B=0.25kVAr C=0.25kVAr) before the start of the induction motor and increased to approximately 71.4kW (A=26.2kW B=24.4kW C=20.8kW) + j64.75kVAr (A=22.5kVAr B=23.25kVAr C=19kVAr) during the inrush phase of the motor start. After about 1.2 cycles, the motor settled down to approximately 62.5kW (A=21kW B=21kW C=20.5kW) + j55.1kVAr (A=18.5kVAr B=18.5kVAr C=18.1kVAr) during the warm up phase which lasted about 32 cycles (0.53 Seconds). When the motor reached steady state, the load in Zone 3 was approximately

52.6kW (A=17.7kW B=17.7kW C=17.2kW) + j7.1kVAr (A=2.3kVAr B=2.5kVAr C=2.3kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 275V on A-phase, 275V on B-phase and 272.8V on C-phase shown in Figure 13k and approximately 59.91Hz shown in Figure 13l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 255V on A-phase, 255V on B-phase and 253.2V on C-phase for about 1.2 cycles. Frequency dropped during the inrush to approximately 59.74Hz and quickly increased to approximately 59.82Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 273V on A-phase, 273V on B-phase and 270.9V on C-phase at an approximate frequency of 59.87Hz.

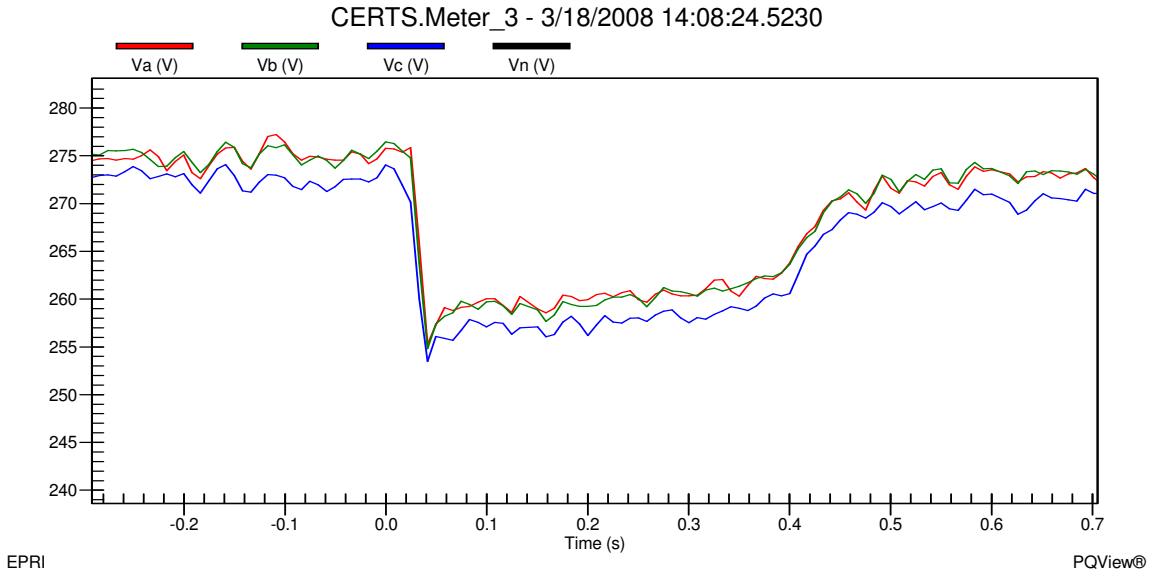

Figure 13k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.3.15

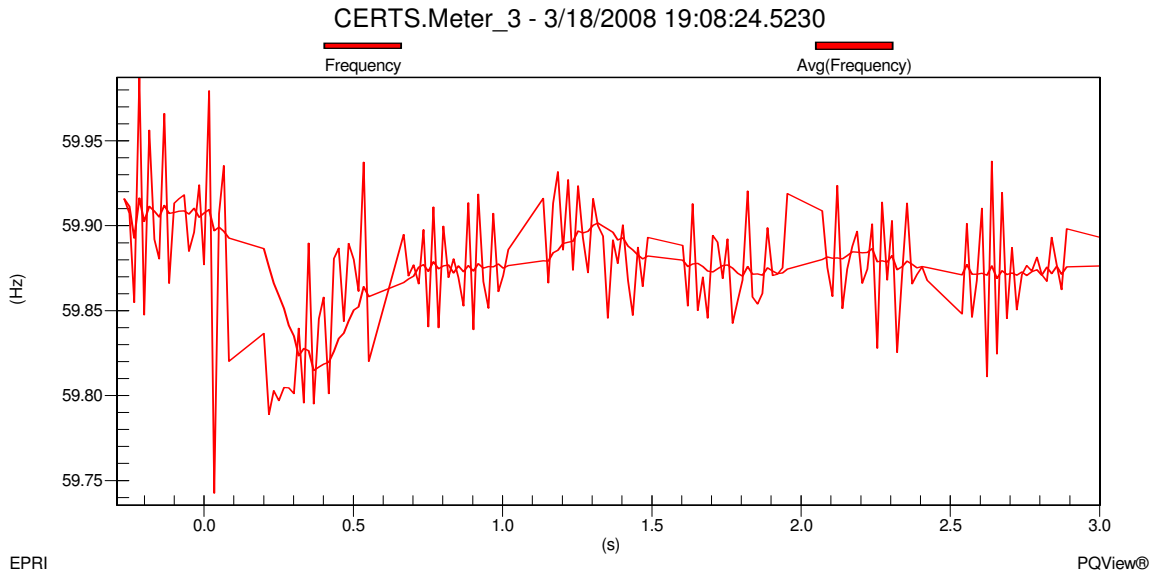

Figure 13l - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.15

Before the motor started Gen-sets A1 and A2 were producing approximately 49.1kW (A=14.1kW B=18.1kW C=16.9kW) – j3.7kVAr (A=-1.5kVAr B=-1.5kVAr C=-0.7kVAr) and 41kW (A=10.7kW B=15.2kW C=15.1kW) + j7.2kVAr (A=2.2kVAr B=2.6kVAr C=2.4kVAr), respectively shown in Figures 13m – 13p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output levels to 58.3kW (A=18.3kW B=22.6kW C=17.4kW) + j28.5kVAr (A=8.9kVAr B=10.9kVAr C=8.7kVAr) for Gen-set A1 and 50.4kW (A=15.6kW B=19kW C=15.8kW) + j37kVAr (A=12.1kVAr B=13.6kVAr C=11.3kVAr) for Gen-set A2. The Gen-sets decreased their output levels while the motor was warming up and eventually dropped to 52.7kW (A=15.4kW B=19.4kW C=17.9kW) + j1.3kVAr (A=0kVAr B=0.5kVAr C=0.8kVAr) for Gen-set A1 and 44.8kW (A=12.2kW B=16.4kW C=16.2kW) + j10.1kVAr (A=3.2kVAr B=4.1kVAr C=3.2kVAr) for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

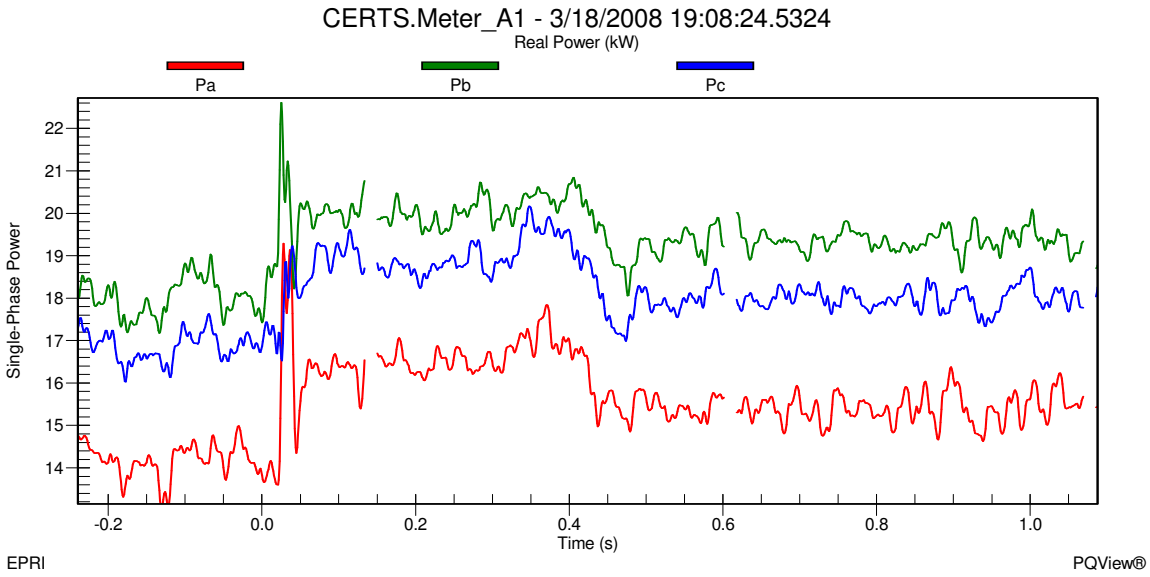

Figure 13m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.15

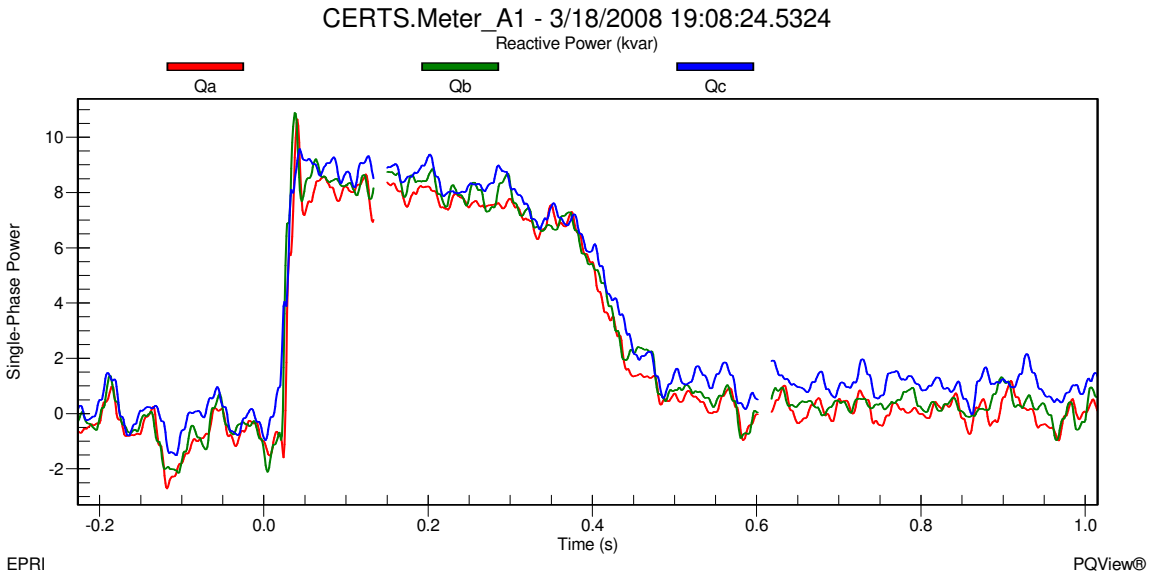

Figure 13n - Gen-set A1 Reactive Single-Phase Reactive Power during Motor Start and Islanded for Test 10.3.15

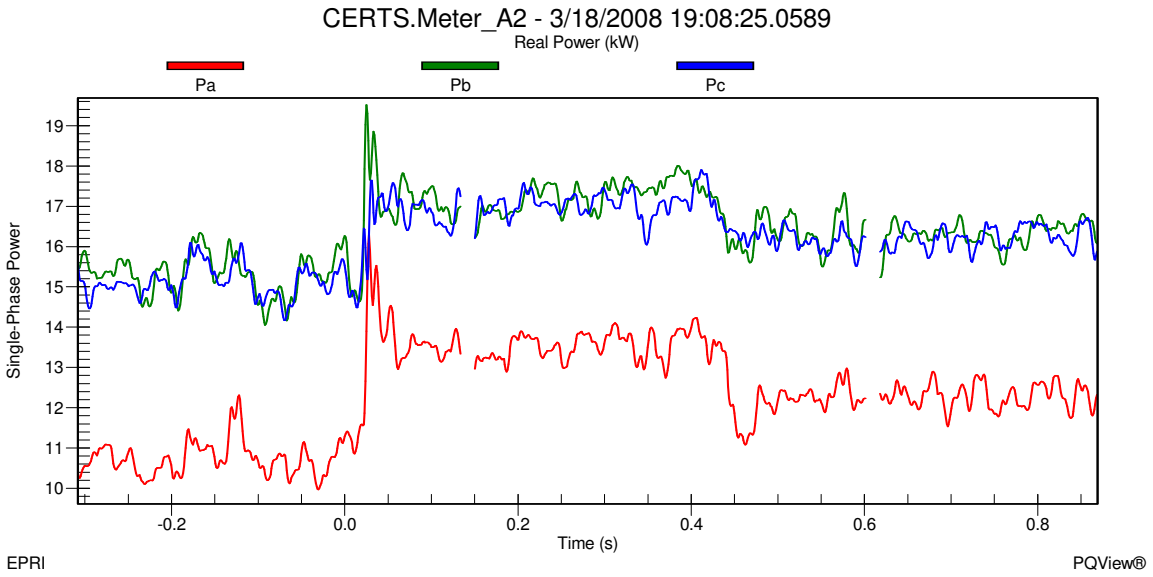

Figure 13o - Gen-set A2 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.15

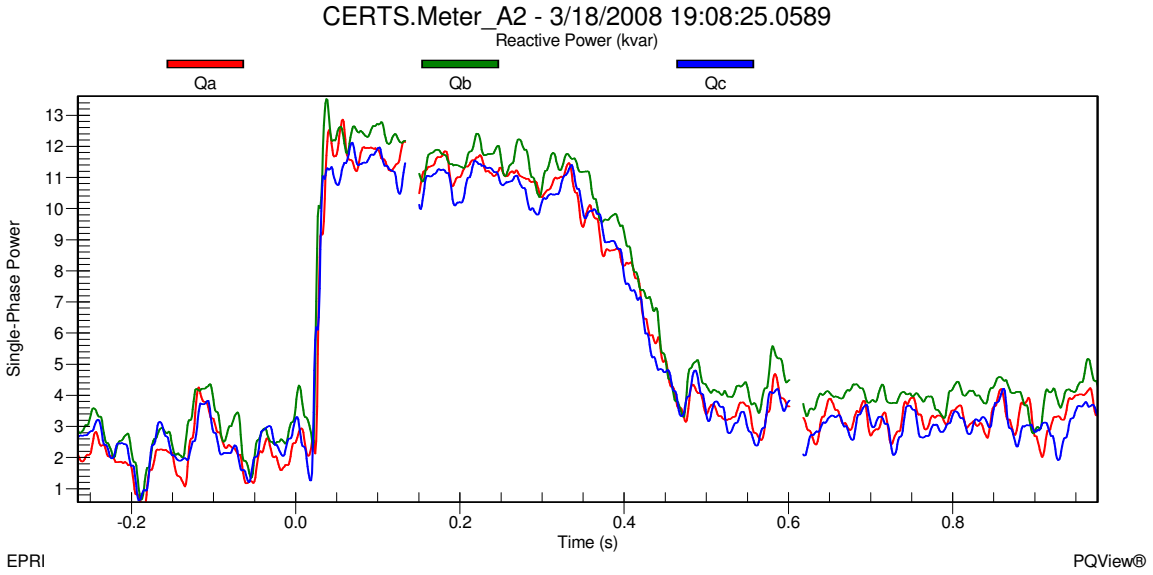

Figure 13p - Gen-set A2 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.15

As soon as the static switch closed, Meter 1 recorded real and reactive powers increased from approximately 38kW (A=10kW B=18.1kW C=9.9kW) + j1.1kVAr (A=0.25kVAr B=0.6kVAr C=0.25kVAr) to 65.5kW (A=19.4kW B=23kW C=23.1kW) + j22.65kVAr (A=8.2kVAr B=6.75kVAr C=7.7kVAr) which means that the utility was satisfying not only the load demand of Load Bank 6 but also all the reactive power except 0.7kVAr from Gen-set A2 and a portion of the real power for the microgrid loads.

Figures 13q and 13r show the static switch increasing from approximately 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to 28.6kW (A=9.6kW B=5.25kW

C=13.75kW) + j21.8kVAr (A=8kVAr B=6.4kVAr C=7.4kVAr). At the beginning of the test, the initial power flow through the static switch was 25.95kW (A=8.75kW B=4.6kW C=12.6kW) + j15.05kVAr (A=5.8kVAr B=4kVAr C=5.25kVAr) which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. The Gens-sets A1 and A2 output power levels reduced to approximately 40kW (A=11.3kW B=17.2kW C=11.5kW) – j9.3kVAr (A=-3.4kVAr B=-3kVAr C=-2.9kVAr) and 31.5kW (A=7.8kW B=13.6kW C=10.1kW) + j0.7kVAr (A=-0.5kVAr B=1.2kVAr C=0kVAr), respectively. These power levels are relatively close to the initial values at the beginning of the test. Since the motor is on in Zone 3 and the Gen-sets returned to their initial values at the beginning of the test before the motor was turned on means that the induction motor is completely being powered by the utility.

Load Banks 3 and 4 loads increased slightly to 53.12kW (A=18.08kW B=17.6kW C=17.44kW) + j6.77kVAr (A=2.34kVAr B=2.34kVAr C=2.09kVAr) and 44.3kW (A=9.75kW B=17.3kW C=17.25kW) + j0.83kVAr (A=0.119kVAr B=0.391kVAr C=0.32kVAr), respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 13s, from approximately 273.1V on A-phase, 273.1V on B-phase and 270.9V on C-phase when islanded to 280.7V on A-phase, 278V on B-phase and 277.3V on C-phase at Meter 3 when connected to the utility grid.

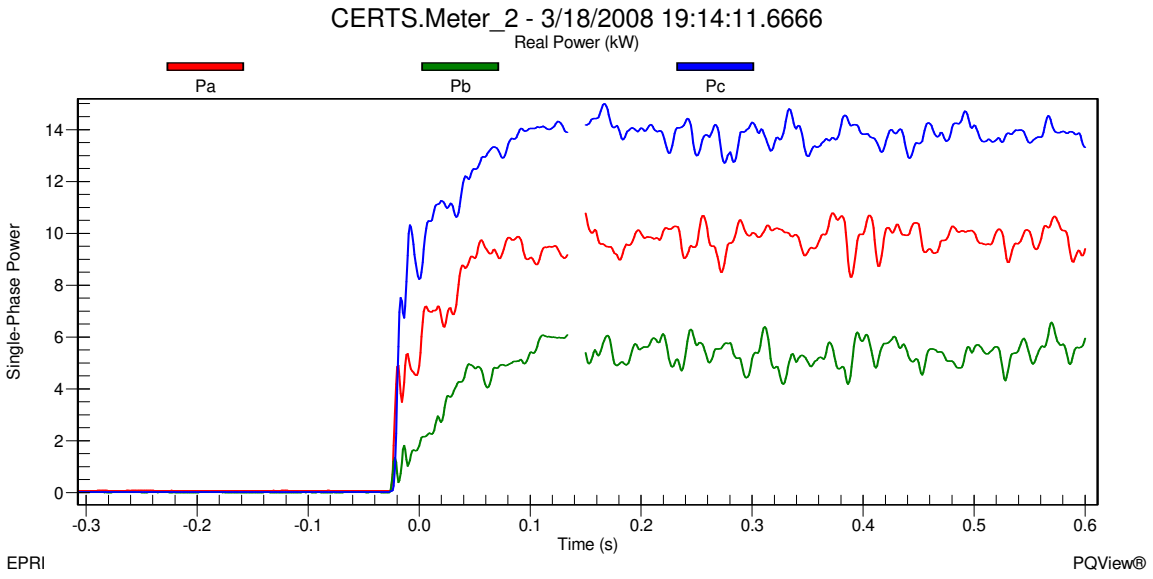

Figure 13q - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.15

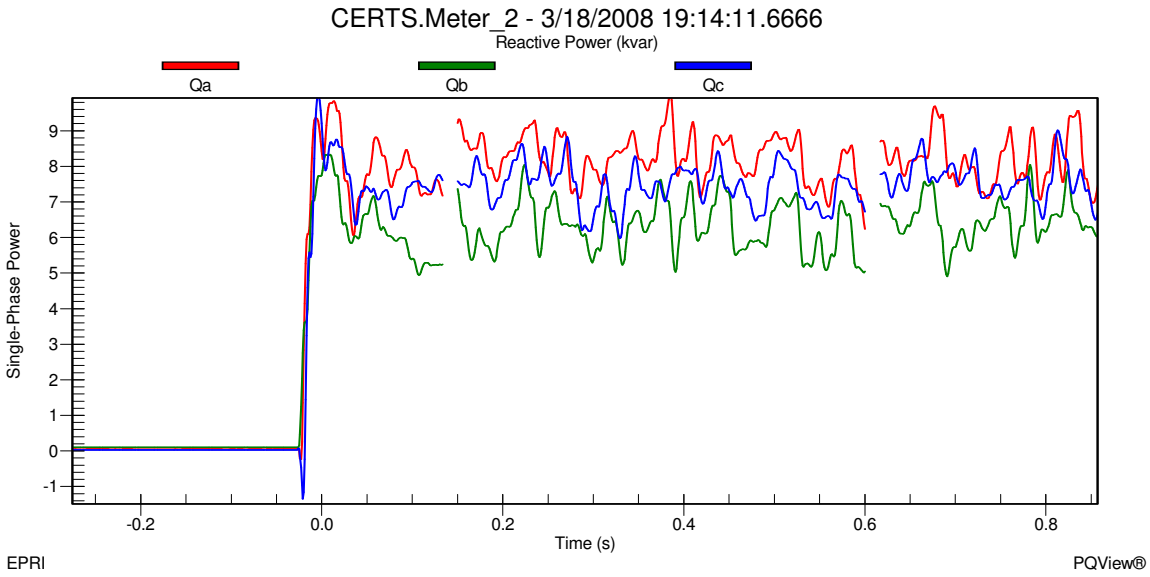

Figure 13r - Static Switch Reactive Single-Phase Power during Island to Utility Connected mode for Test 10.3.15

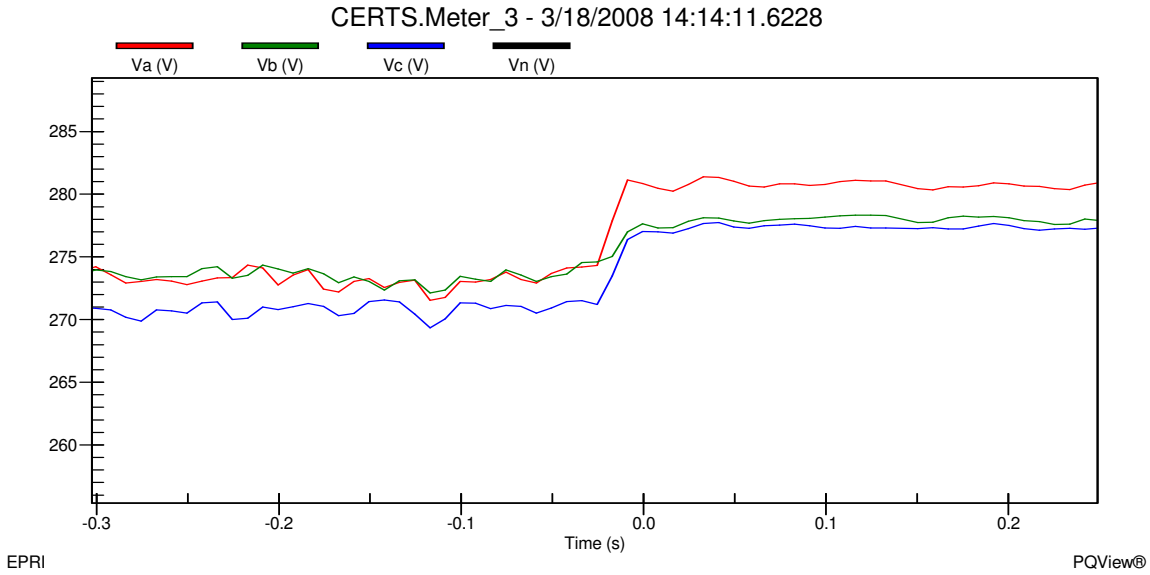

Figure 13s - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.3.15

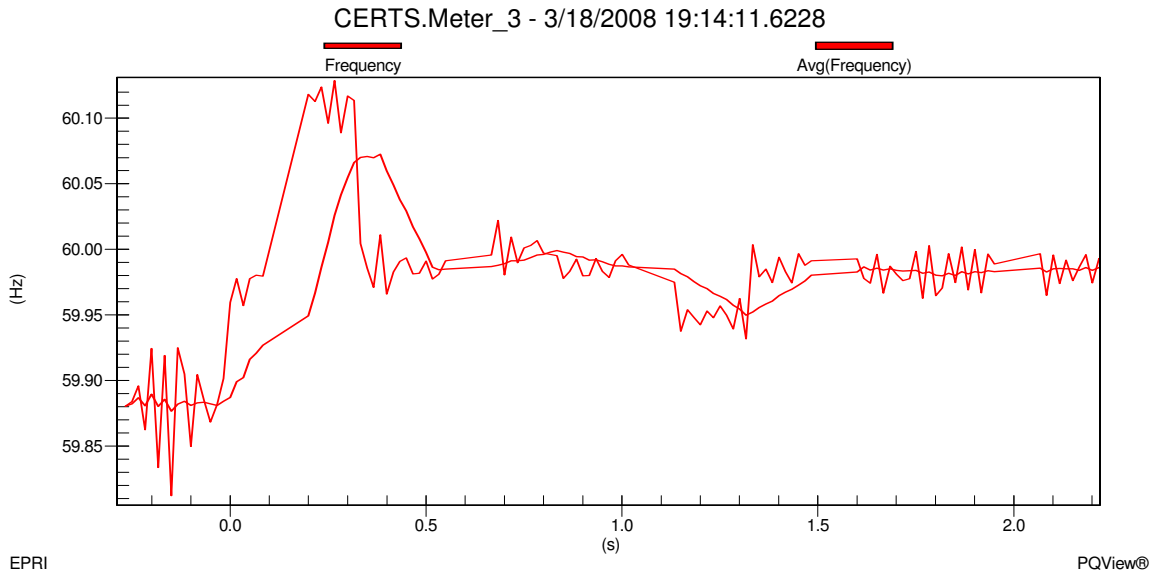

Figure 13t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.3.15

Frequency change in the microgrid, shown in Figure 13t, increased from approximately 59.88Hz when islanded to approximately 59.98Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in unit power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on their set-points initialized at the beginning of the test. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.3.17) in Table 2.

For Test 10.3.17 the measured values, after Gen-set A1 was warmed up and load banks brought on-line are provided in Table 6.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	35.4	0	23.6	-14.25	-17.2	0	18.45	0	37.4
1 Phase kW	A=10.7 B=15.6 C=9.1	A=0 B=0 C=0	A=6.5 B=9.8 C=7.3	A=-3.5 B=-8.25 C=-2.5	A=-4.5 B=-9.6 C=-3.1	A=0 B=0 C=0	A=6.25 B=6.1 C=6.1	A=0 B=0 C=0	A=9.9 B=17.8 C=9.7

3 Phase kVAr	-13.6	0	20.3	19.7	14.3	0	0.3	0	0.574
1 Phase kVAr	A=-4.9 B=-4.8 C=-3.9	A=0 B=0 C=0	A=6.9 B=7.1 C=6.3	A=6.8 B=6.9 C=6	A=5.2 B=5 C=4.1	A=0 B=0 C=0	A=0.1 B=0.1 C=0.1	A=0 B=0 C=0	A=0.104 B=0.359 C=0.111

Table 6 - Measured Values after Start Up for Test 10.3.17

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB6 and the 20kW setting for LB3 were also below selected set values. At the time of the measurements, the voltage and frequency was 283.6V on A-phase, 279.3V on B-phase and 279.9V on C-phase and 60.02Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 284V on A-phase, 280V on B-phase and 280.1V on C-phase and 60.02Hz at Meter 3.

Gen-set A1 was setup in this test to produce more power than Load Bank 3 needed which approximately 14.25kW (A=3.5kW B=8.25kW C=2.5kW) of excess power was exported through the static switch to load Bank 6. Since Load Bank 6 was approximately 37.4kW (A=9.9kW B=17.8kW C=9.7kW) + j0.574kVAr (A=0.104kVAr B=0.359kVAr C=0.111kVAr), the utility had to supply approximately 23.6kW (A=6.5kW B=9.8kW C=7.3kW) to satisfy the load. Reactive power had to be imported in from the utility of approximately j19.7kVAr (A=6.8kVAr B=6.9kVAr C=6kVAr) because Gen-set A1 needed approximately j13.6kVAr (A=4.9kVAr B=4.8kVAr C=3.9kVAr) and the reactive power absorbed in the electrical lines. Once all data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

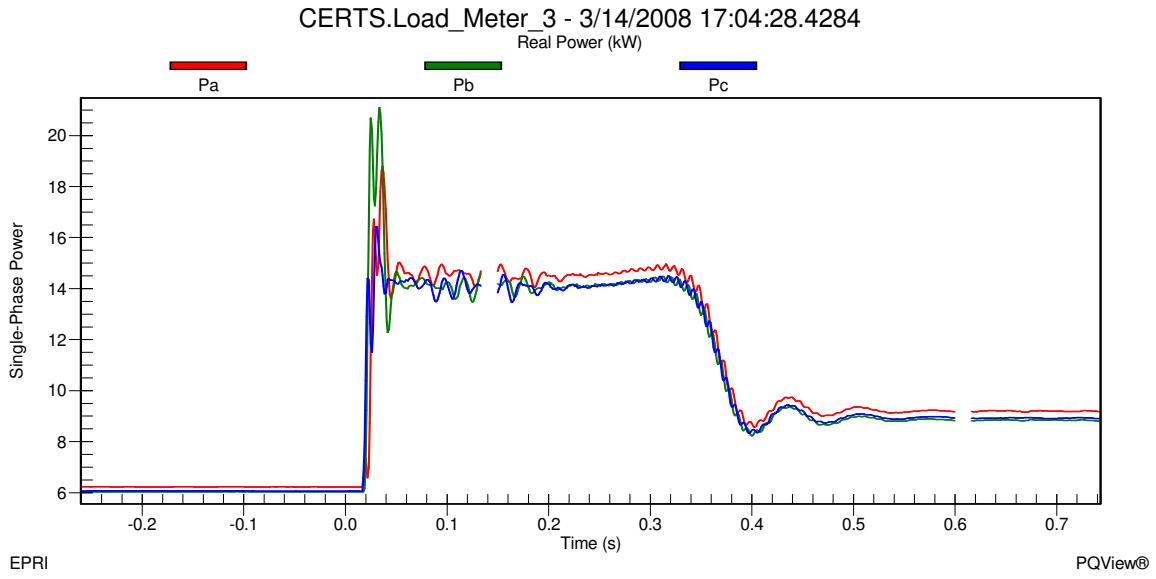

Figure 14a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.17

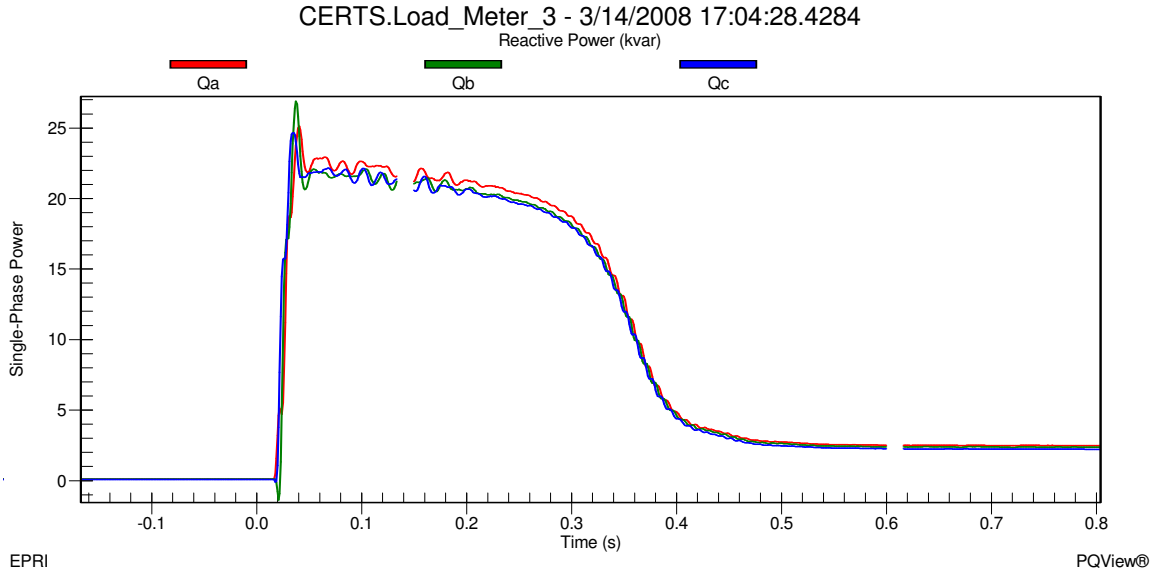

Figure 14b - Load Bank 3 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.17

In Figures 14a and 14b it can be seen that the load in Zone 3 was approximately 18.45kW (A=6.25kW B=6.1kW C=6.1kW) + j0.3kVAr (A=0.1kVAr B=0.1kVAr C=0.1kVAr) before the start of the induction motor and increased to approximately 54.7kW (A=17.1kW B=21.2kW C=16.4kW) + j75.8kVAr (A=24.5kVAr B=26.8kVAr C=24.5kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 43.1kW (A=14.6kW B=14.25kW C=14.25kW) + j63.5kVAr (A=21.5kVAr B=21kVAr C=21kVAr) during the warm up phase which lasted about 30 cycles (0.5

Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.95kW (A=9.25kW B=8.9kW C=8.8kW) + j7.1kVAr (A=2.5kVAr B=2.4kVAr C=2.2kVAr).

The voltage and frequency at the static switch before the motor start was approximately 283.6V on A-phase, 279.3V on B-phase and 279.9V on C-phase shown in Figure 14c and approximately 60.02Hz shown in Figure 14d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 275.6V on A-phase, 271.2V on B-phase and 271.4V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.92Hz and quickly increased to 60.01Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 282.8V on A-phase, 278.4V on B-phase and 279.2V on C-phase at an approximate frequency of 60.03 Hz.

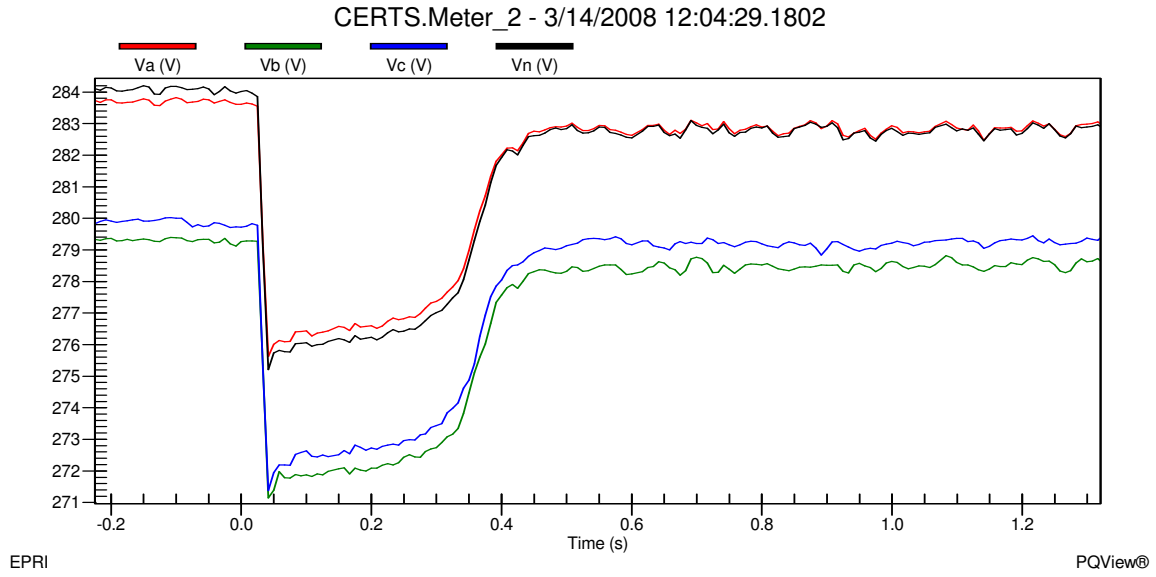

Figure 14c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.3.17

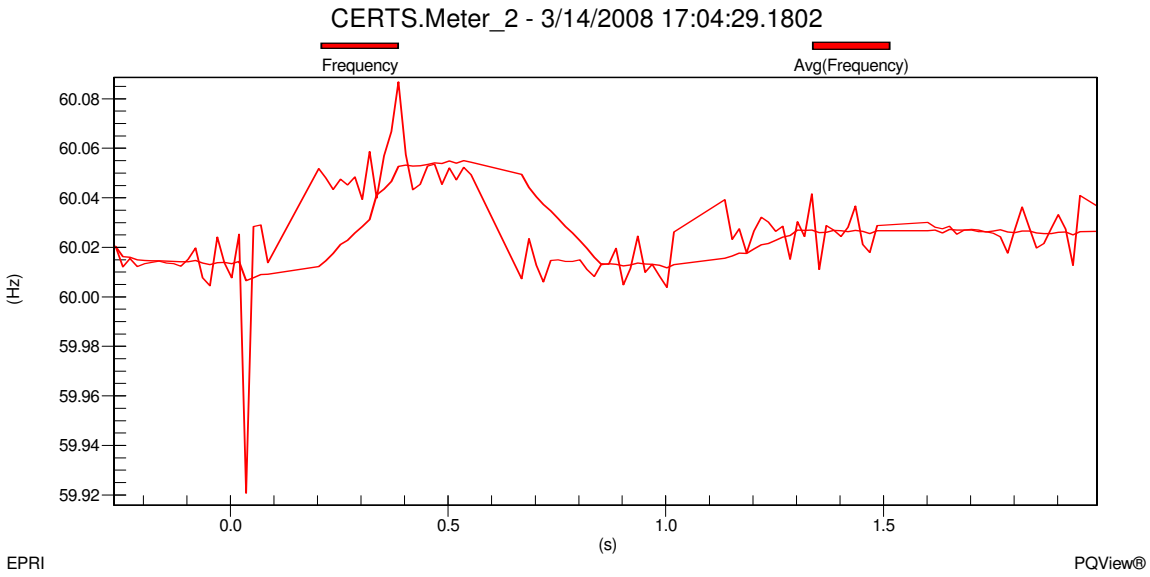

Figure 14d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.17

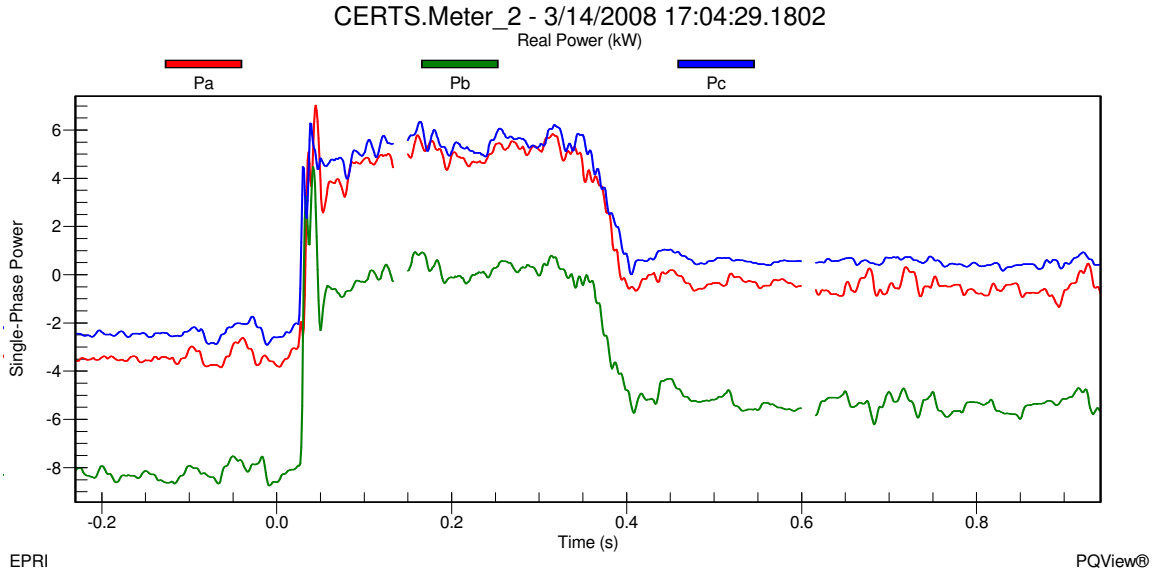

Figure 14e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.17

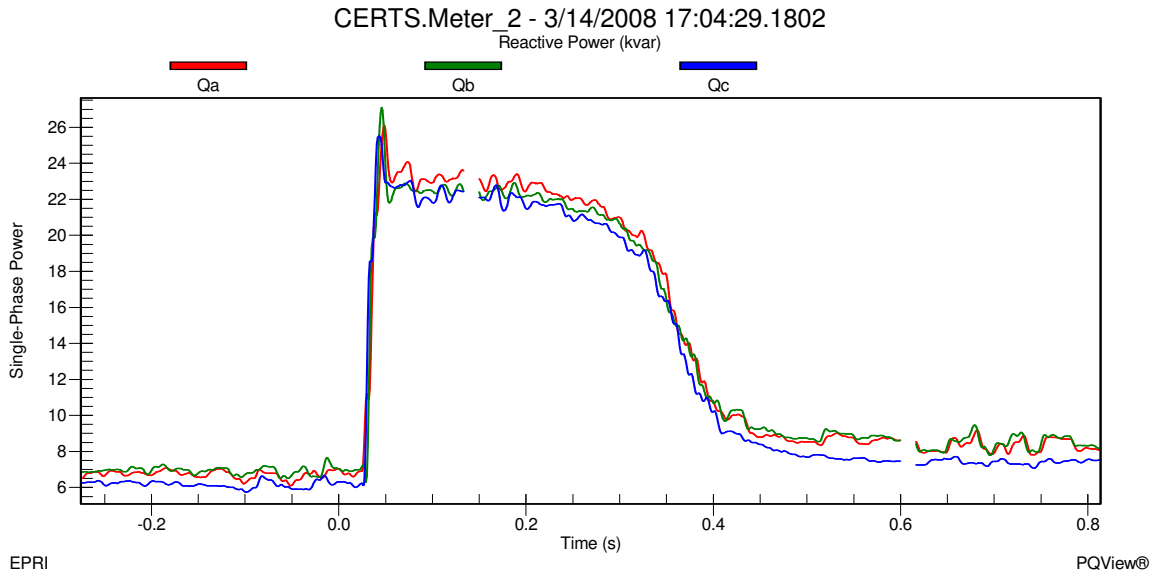

Figure 14f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.17

Before the motor start Gen-set A1 was producing approximately 35.4kW (A=10.7kW B=15.6kW C=9.1kW) – j13.6kVAr (A=-4.9kVAr B=-4.8kVAr C=-3.9kVAr). This was enough for the load demands of Zone 3 with real power being exported to Zone 6 of approximately 14.25kW (A=3.5kW B=8.25kW C=2.5kW) shown in Figure 14e. The grid was supporting the reactive power of the microgrid with approximately j19.7kVAr (A=6.8kVAr B=6.9kVAr C=6kVAr) shown in Figure 14f. When the motor started the inrush caused the utility to pick up the load demand in Load Bank 6 along with approximately 16.8kW (A=7.1kW B=4.5kW C=5.2kW) + j78kVAr (A=25.4kVAr B=27.2kVAr C=25.4kVAr) of the microgrid critical loads. The power being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 14e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output levels to approximately 41.7kW (A=17.9kW B=12.9kW C=10.9kW) + j3.5kVAr (A=0.75kVAr B=1kVAr C=1.75kVAr). Notice the sign of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -7kW (A=-0.6kW B=-5.5kW C=-0.9kW) + j24.2kVAr (A=8.4kVAr B=8.4kVAr C=7.4kVAr) which meant that Gen-set A1 was supplying the power for the induction motor and approximately 7kW (A=0.6kW B=5.5kW C=0.9kW) of Load Bank 6. Gen-set A1 real power returned to the value before the motor started of approximately 35.1kW (A=10.7kW B=15.3kW C=9.1kW) and the reactive power increased to approximately –j11.9kVAr (A=-4.4kVAr B=-4.2kVAr C=-3.3kVAr). Once all

the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 38.4kW (A=10.2kW B=18.3kW C=9.9kW) and reactive power decreased to j1.1kVAr (A=0.25kVAr B=0.6kVAr C=0.25kVAr) satisfying the load demand in Load Bank 6 which was approximately 38.1kW (A=10.1kW B=18.2kW C=9.8kW) + j0.617kVAr (A=0.117kVAr B=0.381kVAr C=0.119kVAr) and not supplying any power beyond the static switch to Load Bank 3. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads was slightly reduced to 17.065kW (A=5.675kW B=5.71kW C=5.68kW) + j0.294kVAr (A=0.095kVAr B=0.112kVAr C=0.087kVAr). This load reduction resulted from a voltage drop in the microgrid, shown in Figure 14g, from approximately 284.3V on A-phase, 280.1V on B-phase and 280.5V on C-phase when connected to the utility grid to 272.2V on A-phase, 271.9V on B-phase and 271.7V on C-phase at Meter 3 when islanded.

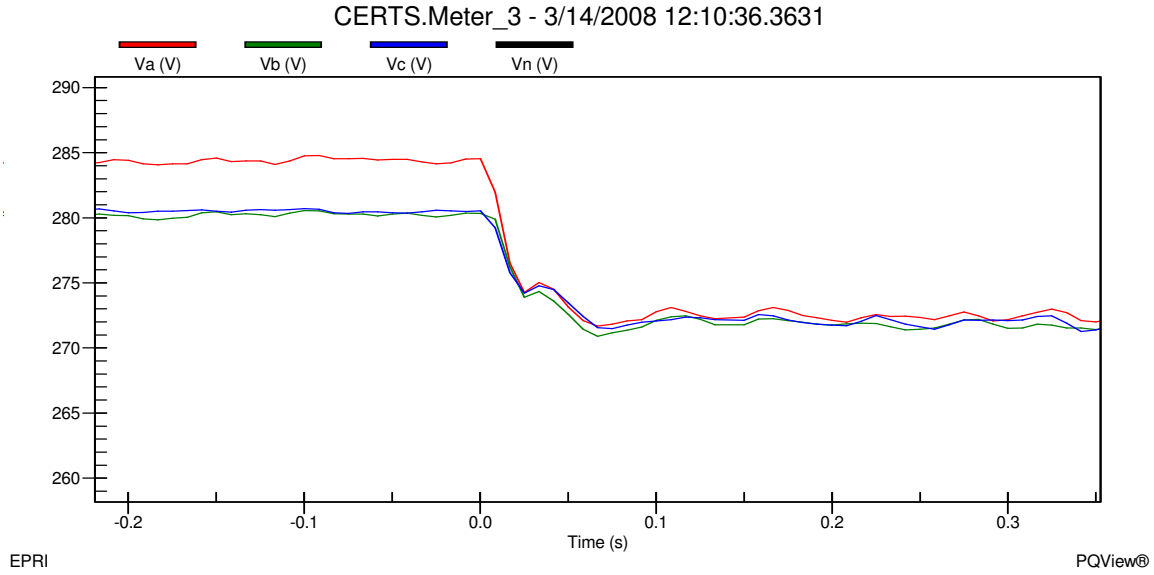

Figure 14g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.17

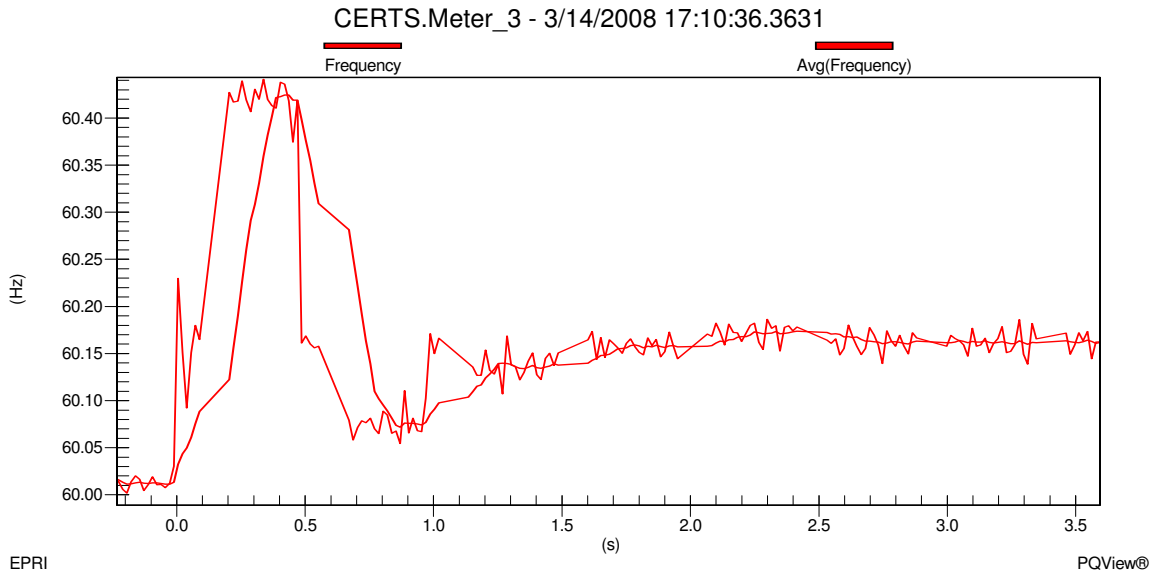

Figure 14h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.17

Frequency change in the microgrid, shown in Figure 14h, increased from approximately 60.01Hz when connected to the utility grid to approximately 60.16Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the load demands. Gen-set A1 decreased its output power to approximately 19.4kW (A=6.4kW B=6.8kW C=6.2kW) and increased its output reactive power to approximately j4kVAr (A=1kVAr B=1.5kVAr C=1.5kVAr). Meter 3 was approximately -2.45kW (A=-0.75kW B=-1.2kW C=-0.5kW) – j3.4kVAr (A=-0.8kVAr B=-1.3kVAr C=-1.3kVAr) indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

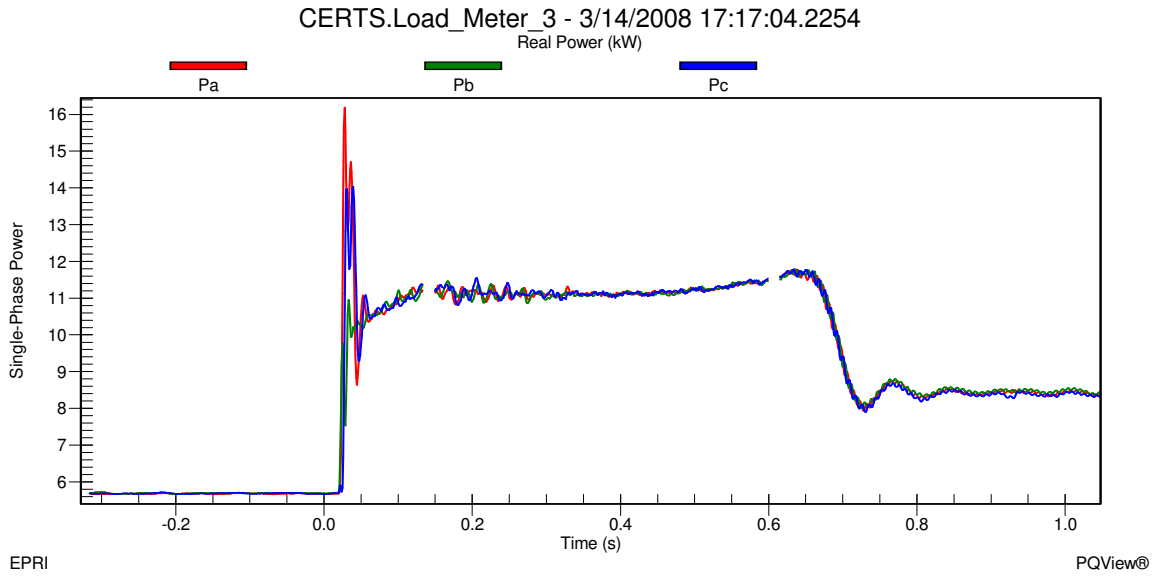

Figure 14i - Load Bank3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.17

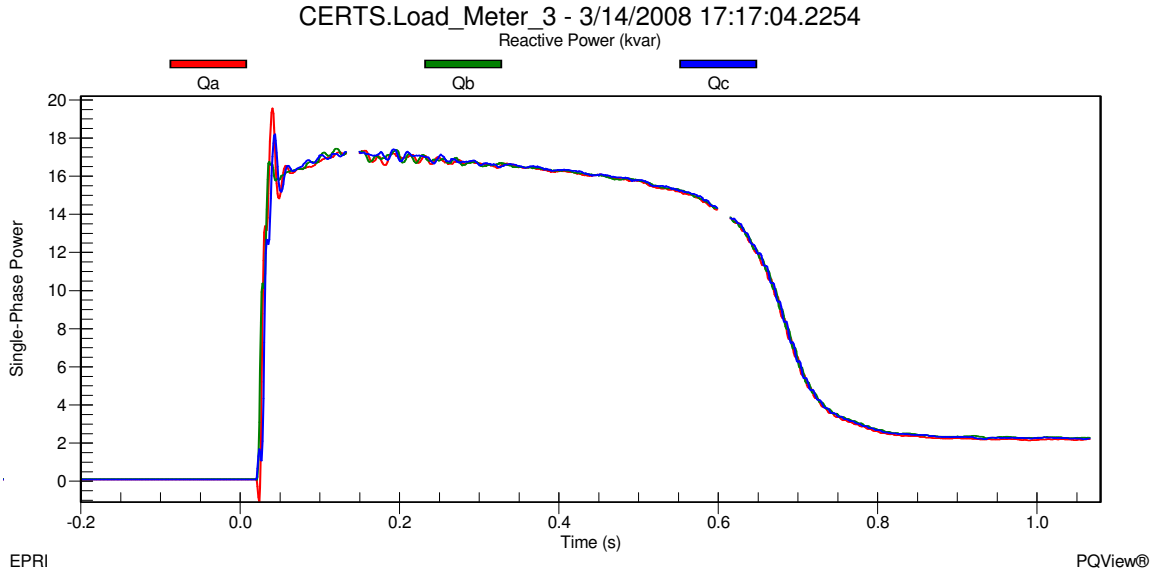

Figure 14j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.17

If Figures 14i and 14j it can be seen that the load in Zone 3 was approximately 17.1kW (A=5.7kW B=5.7kW C=5.7kW) + j0.6kVAr (A=0.2kVAr B=0.2kVAr C=0.2kVAr) before the start of the induction motor and increased to approximately 40.7kW (A=16.2kW B=10.5kW C=14kW) + j53.95kVAr (A=19.6kVAr B=16.6kVAr C=17.75kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 33.9kW (A=11.3kW B=11.3kW C=11.3kW) + j49.5kVAr (A=16.5kVAr B=16.5kVAr C=16.5kVAr) during the warm up phase which lasted about 49.2 cycles (0.82 Seconds). When the motor reached steady state the load in Zone 3 was approximately

25.2kW (A=8.4kW B=8.4kW C=8.4kW) + j6.75kVAr (A=2.25kVAr B=2.25kVAr C=2.25kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 272V on A-phase, 271.4V on B-phase and 272V on C-phase shown in Figure 14k and approximately 60.16Hz shown in Figure 14l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 235.7V on A-phase, 235.7V on B-phase and 237.1V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.76Hz and quickly increased to approximately 60.02Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 269.2V on A-phase, 268.5V on B-phase and 268.9V on C-phase at an approximate frequency of 60.10Hz.

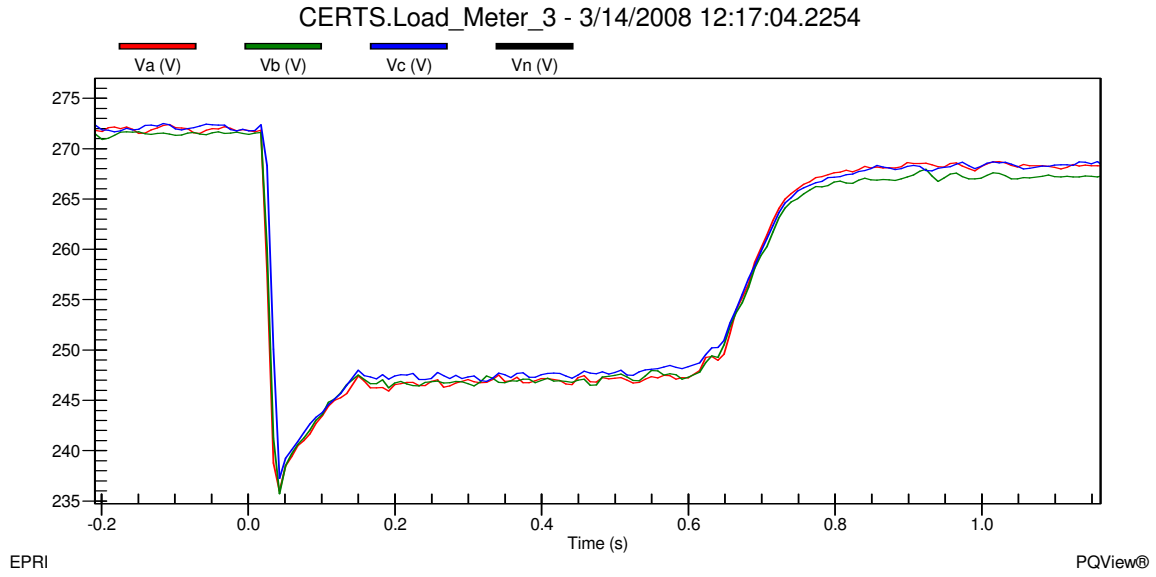

Figure 14k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.3.17

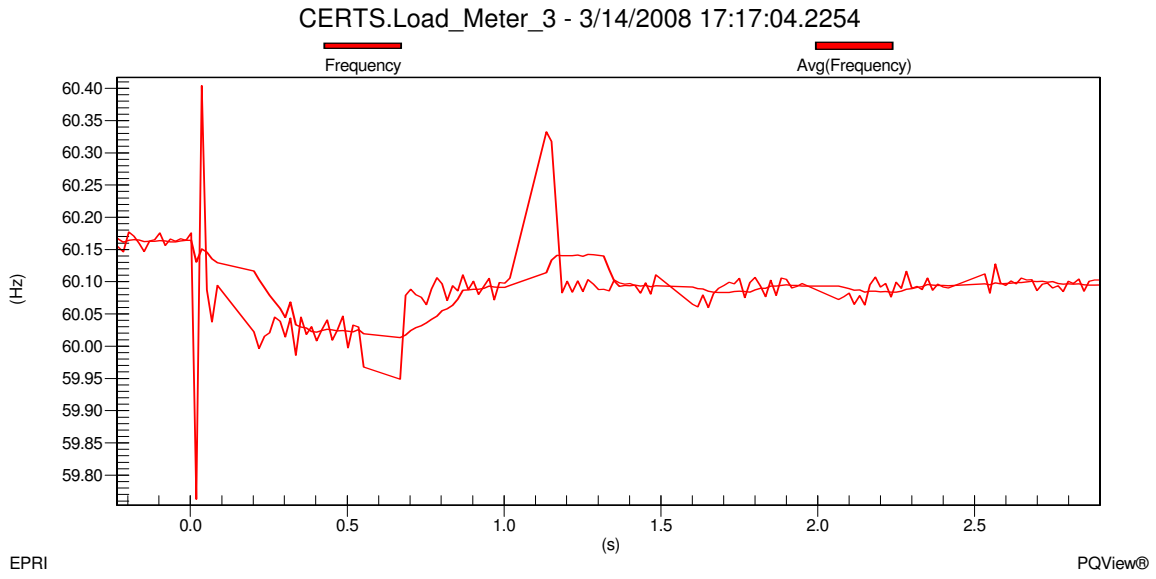

Figure 14l - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.17

Before the motor started, Gen-set A1 was producing approximately 19.3kW (A=6.4kW B=6.8kW C=6.1kW) + j4kVAr (A=1kVAr B=1.5kVAr C=1.5kVAr) shown in Figures 14m and 14n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-set to increase its output level to 41.6kW (A=16.7kW B=10.6kW C=14.3kW) + j55.05kVAr (A=19.75kVAr B=17.3kVAr C=18kVAr). Gen-set A1 decreased its output level when the motor was warming up and eventually dropped to 27.5kW (A=9.2kW B=9.5kW C=8.8kW) + j9.9kVAr (A=2.9kVAr B=3.5kVAr C=3.5kVAr) when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

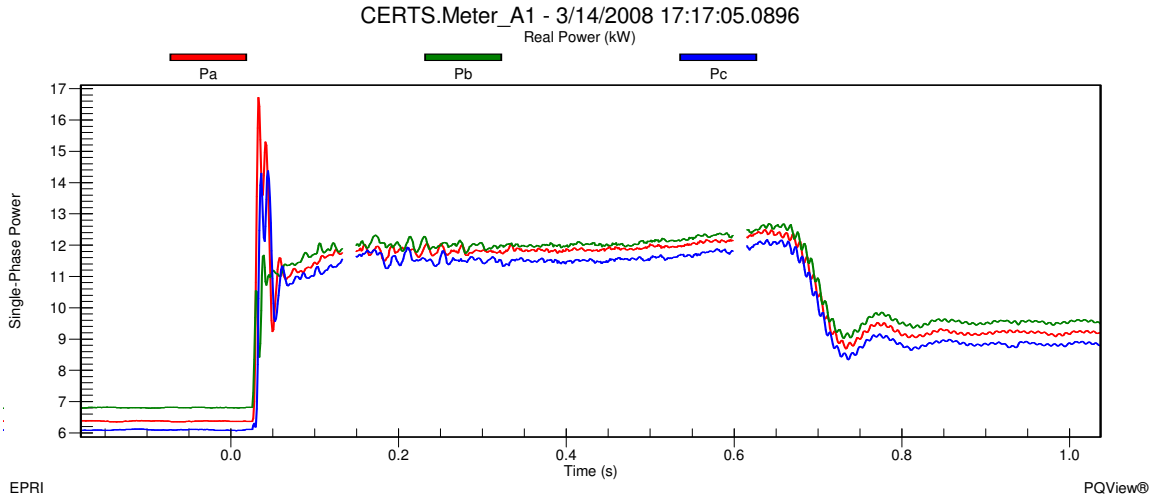

Figure 14m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.17

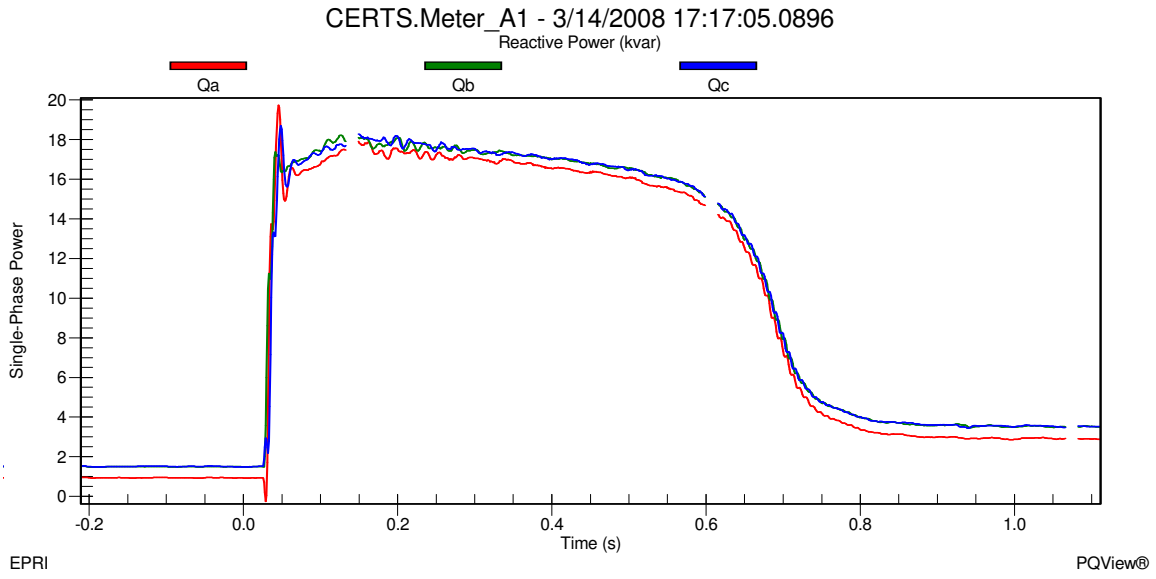

Figure 14n - Gen-set A1 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.17

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 38.1kW (A=10.2kW B=18.1kW C=9.8kW) to 28.65kW (A=8.4kW B=11.25kW C=9kW) and reactive power increased from approximately j1.1kVAr (A=0.25kVAr B=0.6kVAr C=0.25kVAr) to j24.3kVAr (A=8.25kVAr B=8.75kVAr C=7.3kVAr) which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 14o and 14p show the static switch real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -8.1kW (A=-1.5kW B=-6.2kW C=-0.4kW) and reactive power increasing from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to j23.4kVAr (A=8.1kVAr B=8.2kVAr C=7.1kVAr). At the beginning of the test, the initial power flow through the static switch was -14.25kW (A=-3.5kW B=-8.25kW C=-2.5kW) + j19.7kVAr (A=6.8kVAr B=6.9kVAr C=6kVAr) which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and is supporting Load Bank 6 with approximately 8.1kW (A=1.5kW B=6.2kW C=0.4kW).

Load Bank 3 loads increased slightly to 25.1kW (A=8.58kW B=8.22kW C=8.3kW) + 6.485kVAr (A=2.275kVAr B=2.18kVAr C=2.03kVAr). This slight increase is a result from a voltage rise in the microgrid, shown in Figure 14q, from approximately 268.9V on A-phase, 268.5V on B-phase and 268.9V on C-phase 3 when islanded to 282.5V on A-phase, 279.1V on B-phase and 278.8V on C-phase at Meter 3 when connected to the utility grid.

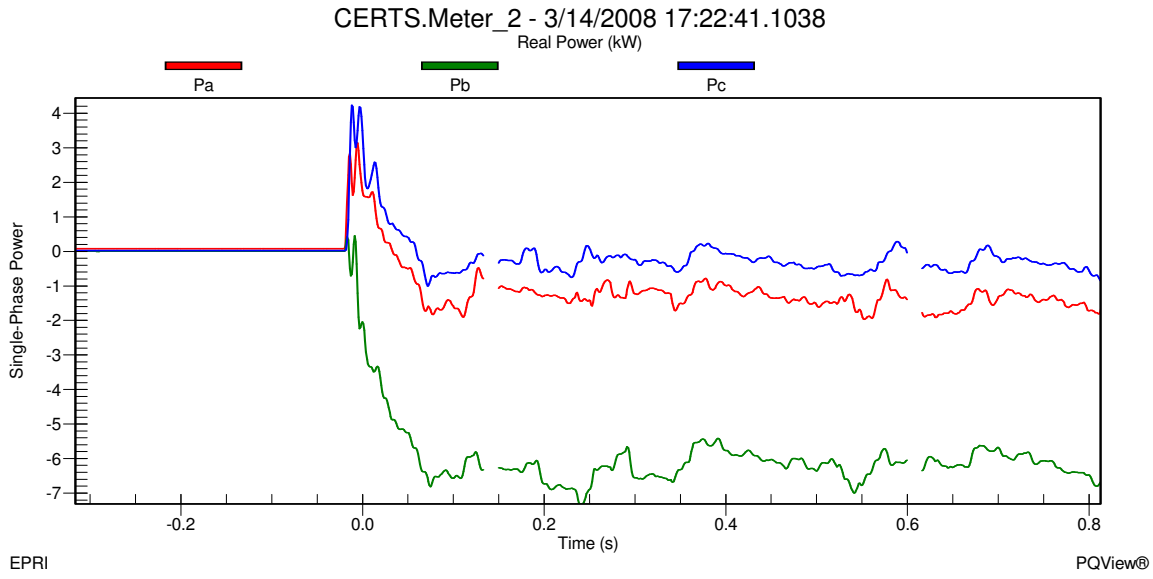

Figure 14o - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.17

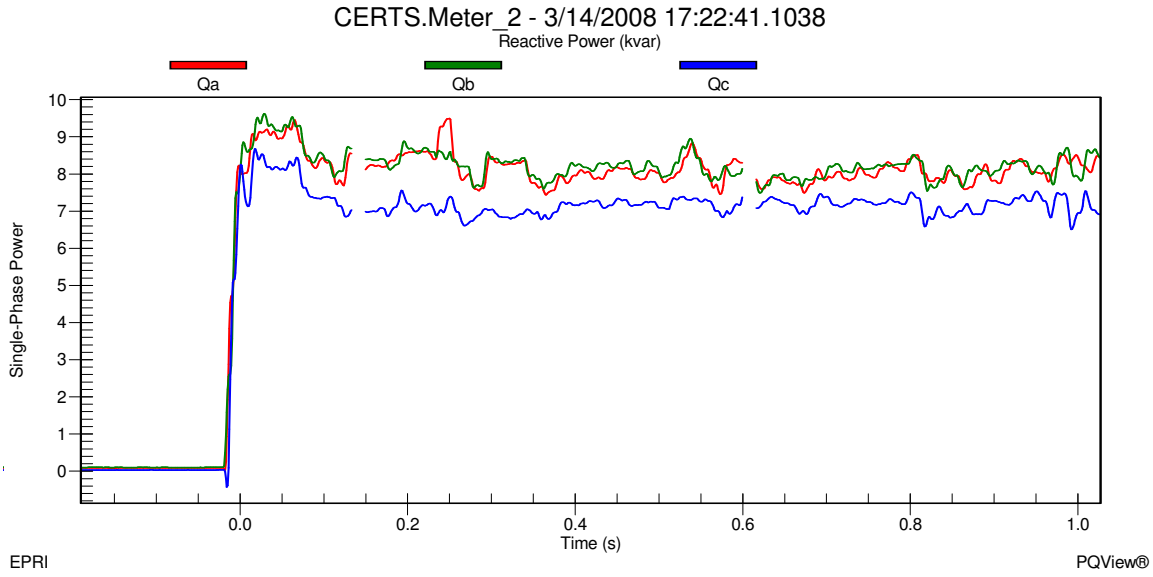

Figure 14p - Static Switch Reactive Single-Phase Power during Islanded to Utility Connected mode for Test 10.3.17

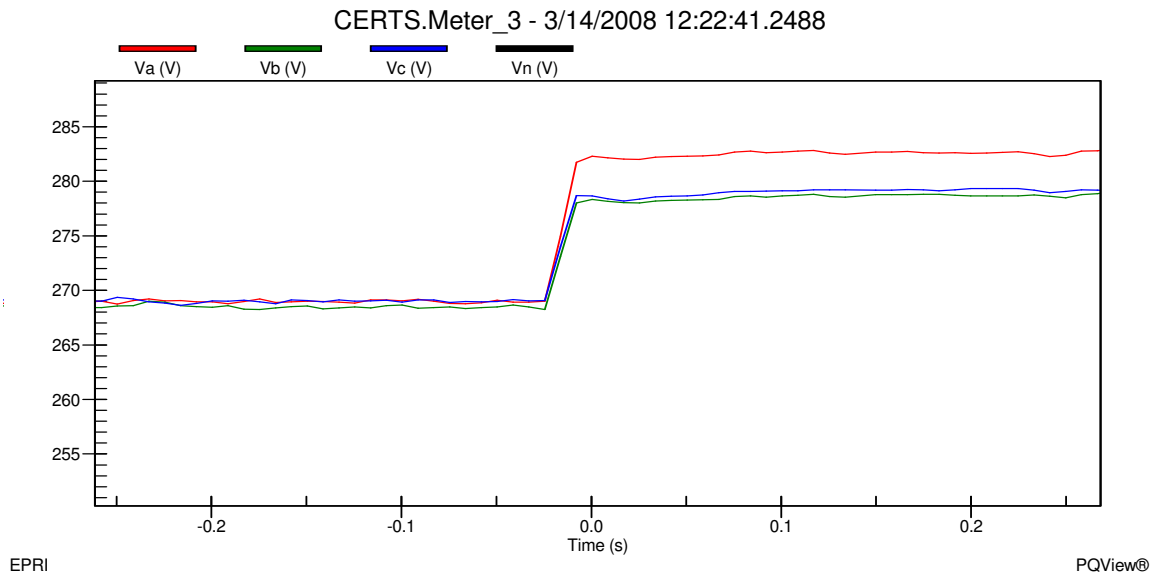

Figure 14q - Meter 3 Line-to-Ground Voltages during Islanded to Utility Connected mode for Test 10.3.17

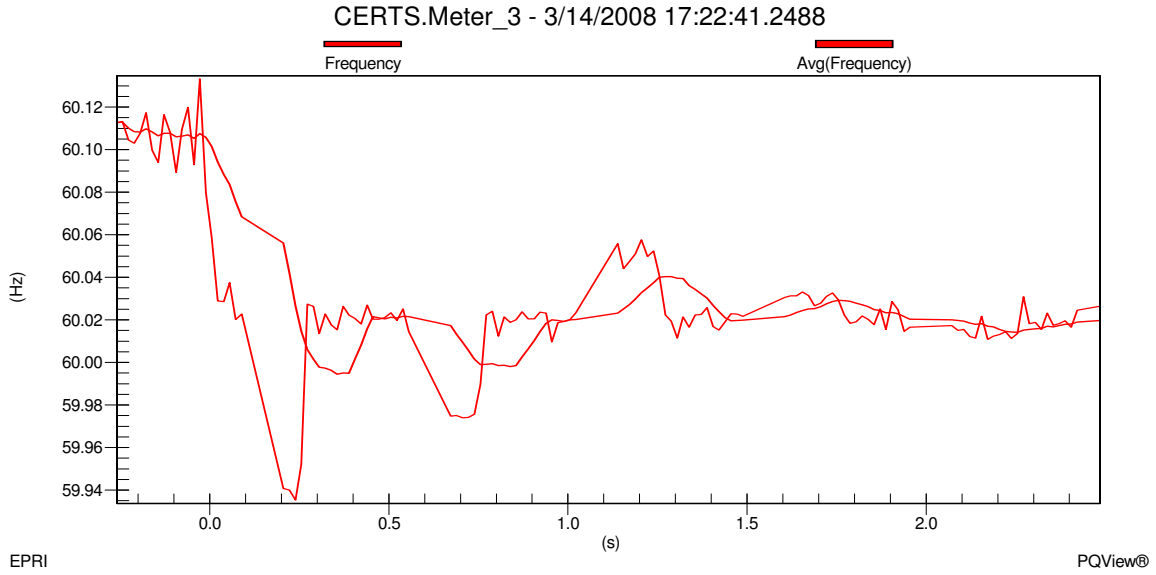

Figure 14r - Meter 3 Frequency during Islanded to Utility Connected mode for Test 10.3.17

Frequency change in the microgrid, shown in Figure 14r, decreased from approximately 60.11Hz when islanded to approximately 60.02Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by Gen-set A1 using the CERTS algorithm by the utility. Gen-set A1 is in unit power control mode therefore when the static switch closed back into the utility the Gen-set produced real power based on the set-point initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the value at the beginning of the test with Gen-set A1 producing approximately 36kW (A=10.9kW B=15.7kW C=9.4kW) – j11.8kVAr (A=-

4.4kVAr B=-4.2kVAr C=-3.2kVAr). After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.3.18) in Table 2.

For Test 10.3.18 the measured values, after Gen-set A1 was warmed up and load banks brought on-line are provided in Table 7.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	36.2	27	31.3	-6.05	-8.5	9.3	17.9	36.6	36.95
1 Phase kW	A=10.6 B=15.4 C=10.2	A=7.4 B=11.6 C=8	A=8.5 B=11.4 C=11.4	A=-1.4 B=-6.25 C=1.6	A=-2 B=-7.5 C=-1	A=2.3 B=1.8 C=5.2	A=6.1 B=5.9 C=5.9	A=9.75 B=13.45 C=13.4	A=9.75 B=17.6 C=9.6
3 Phase kVAr	-11.5	-2.5	22	20.1	15	3	0	0.615	0.641
1 Phase kVAr	A=-4.2 B=-3.9 C=-3.4	A=-1.5 B=-0.5 C=-0.5	A=8.3 B=7.2 C=6.5	A=7.5 B=6.9 C=6	A=6 B=4.8 C=4.2	A=1.6 B=0.7 C=0.7	A=0 B=0 C=0	A=0.12 B=0.28 C=0.215	A=0.12 B=0.4 C=0.121

Table 7 - Measured Values after Start Up for Test 10.3.18

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB4 and LB6 and the 20kW setting for LB3 were also below selected set values. At the time of the measurements, the voltage and frequency was 282.2V on A-phase, 278.6V on B-phase and 279.2V on C-phase and 60.01Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282V on A-phase, 279.3V on B-phase and 279V on C-phase and 60.01Hz at Meter 3.

The Gen-sets in this test were set up to produce -10kW through Zone 3 (i.e., Meter 3) which means they produced 10kW more power than Load Banks 3 and 4 needed. Approximately 8.5kW (A=2kW B=7.5kW C=-1kW) of excess power was exported out of Zone 3 and 6.05kW (A=1.4kW B=6.25kW C=-1.6kW) of that power went through the static switch to Load Bank 6 and the remaining 2.45kW (A=0.6kW B=1.25kW C=0.6kW) was loss to the electrical characteristics of the conductors. Since Load Bank 6 was

approximately 36.95kW (A=9.75kW B=17.6kW C=9.6kW) + j0.641kVAr (A=0.12kVAr B=0.4kVAr C=0.121kVAr), the utility had to supply approximately 31.3kW (A=8.5kW B=11.4kW C=11.4kW) real power to satisfy the load. Reactive power had to be imported in from the utility of approximately j20.1kVAr (A=7.5kVAr B=6.6kVAr C=6kVAr) because Gen-sets A1 and A2 needed approximately –j14kVAr (A=-5.7kVAr B=-4.4kVAr C=-3.9kVAr) between the two and the reactive power of Load Bank 4. Once all the data was verified and recorded into the DAS Database, the 10Hp induction motor was started in Zone 3.

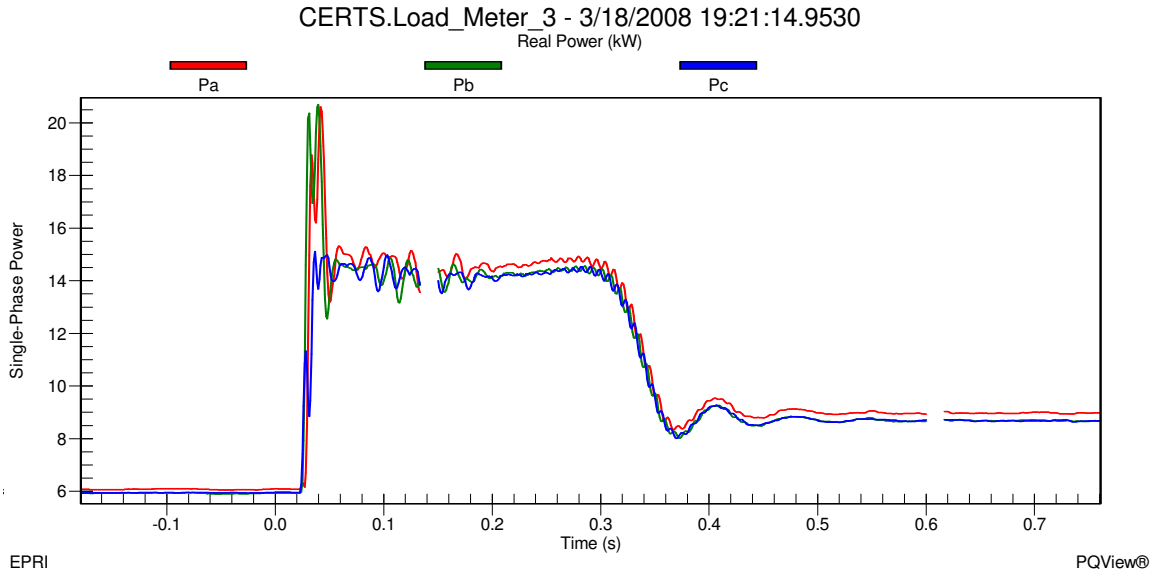

Figure 15a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.18

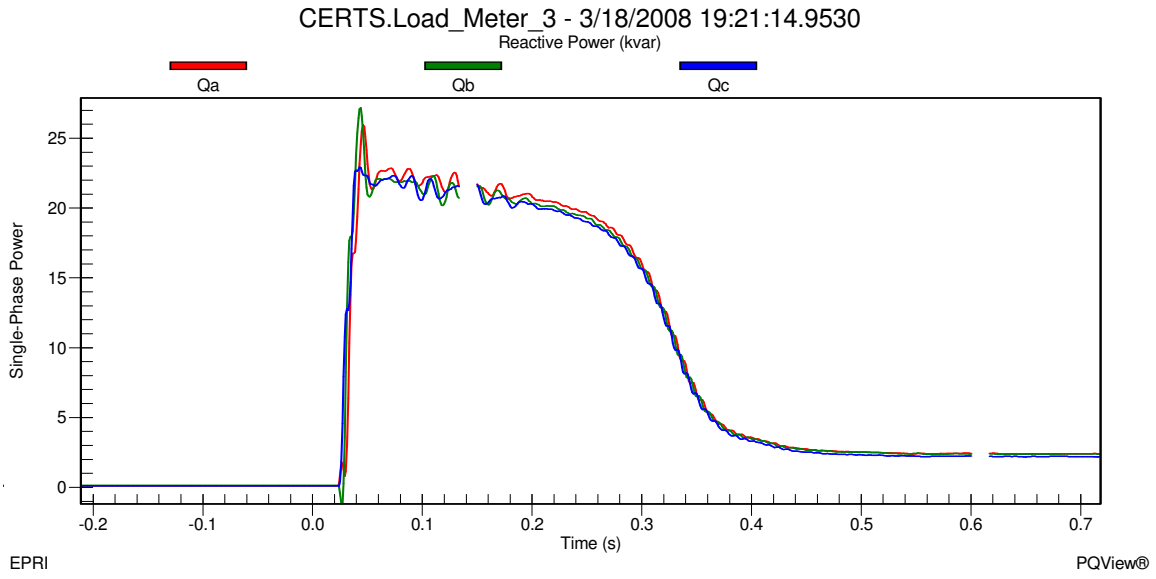

Figure 15b - Load Bank 3 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.18

In Figures 15a and 15b it can be seen that the load in Zone 3 was approximately 17.9kW (A=6.1kW B=5.9kW C=5.9kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) before the start of the induction motor and increased to approximately 56.1kW (A=20.6kW B=21.4kW C=14.1kW) + j74.7kVAr (A=24.5kVAr B=27.2kVAr C=23kVAr) during the inrush phase of the motor start. After about 1.32 cycles, the motor settled down to approximately 43.1kW (A=14.6kW B=14.25kW C=14.25kW) + j61.2kVAr (A=20.8kVAr B=20.2kVAr C=20.2kVAr) during the warm up phase which lasted about 30 cycles (0.5 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 26.4kW (A=9kW B=8.7kW C=8.7kW) + j7kVAr (A=2.4kVAr B=2.4kVAr C=2.2kVAr).

The voltage and frequency at the static switch before the motor start was approximately 282.2V on A-phase, 278.6V on B-phase and 279.2V on C-phase shown in Figure 15c and approximately 60.01Hz shown in Figure 15d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 276V on A-phase, 271.8V on B-phase and 272.8V on C-phase for about 1.32 cycles. Frequency dropped during the inrush to approximately 59.91Hz and quickly increased to approximately 59.99Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 281.6V on A-phase, 277.9V on B-phase and 278.4V on C-phase at an approximate frequency 60.00Hz.

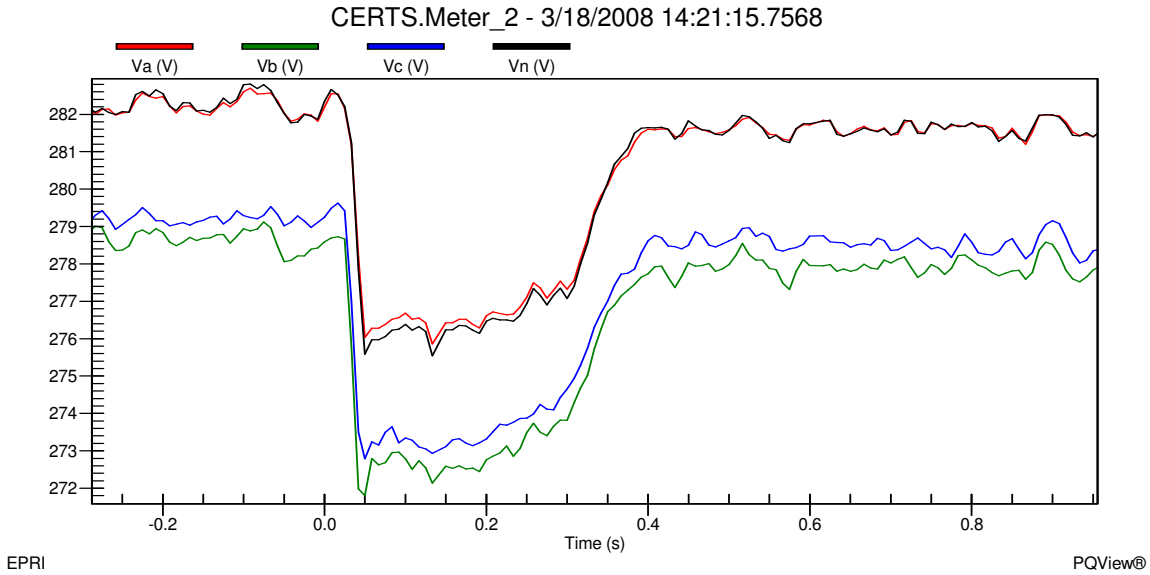

Figure 15c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.3.18

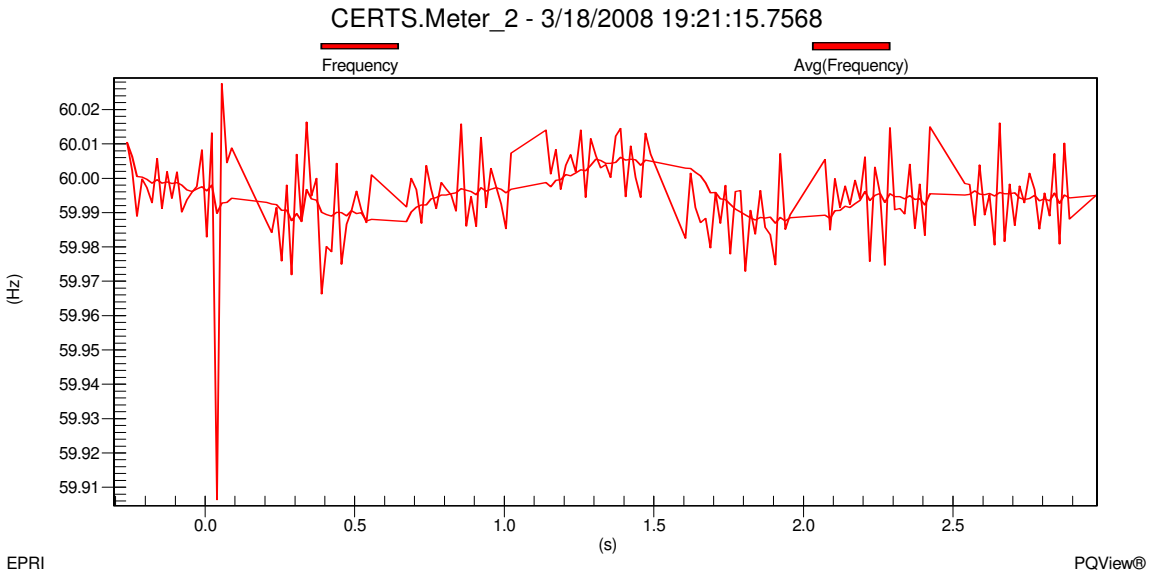

Figure 15d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.18

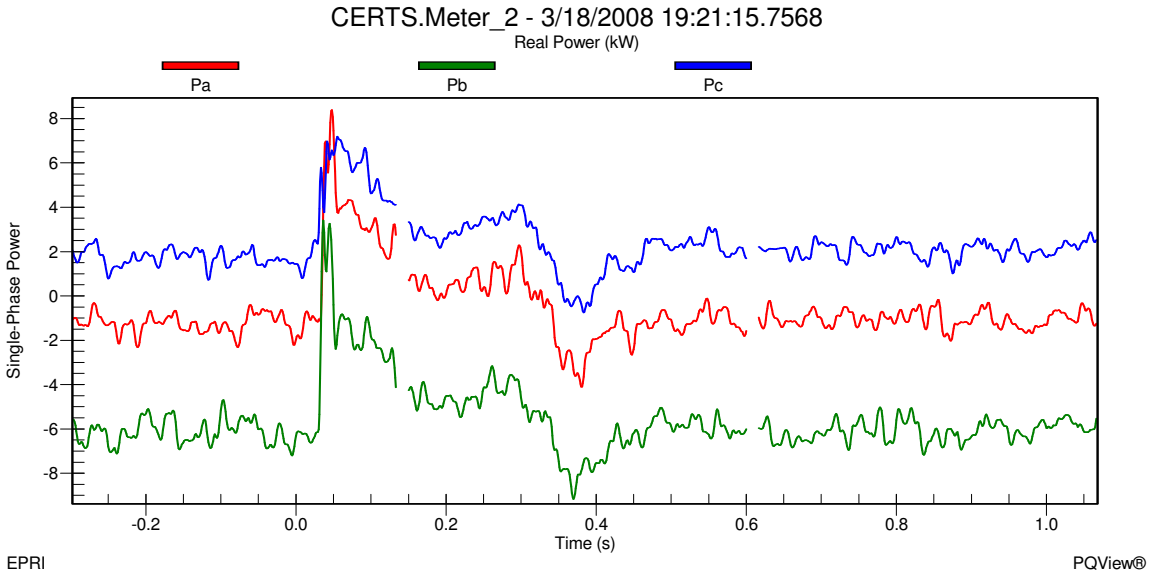

Figure 15e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.18

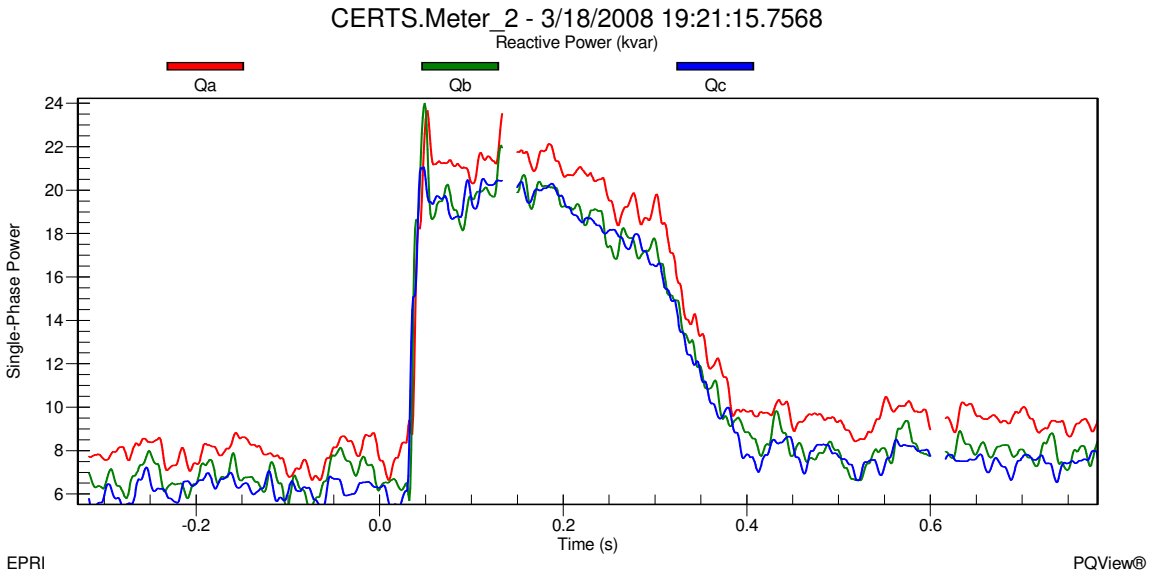

Figure 15f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.18

Before the motor started Gen-sets A1 and A2 were producing approximately 36.2kW (A=10.6kW B=15.4kW C=10.2kW) – j11.5kVAr (A=-4.2kVAr B=-3.9kVAr C=-3.4kVAr) and 27kW (A=7.4kW B=11.6kW C=8kW) – j2.5kVAr (A=-1.5kVAr B=-0.5kVAr C=-0.5kVAr), respectively. This was enough power for the load demands of Load Banks 3 and 4 with

real power being exported to Zone 6 of approximately 6.05kW (A=1.4kW B=6.25kW C=-1.6kW) shown in Figure 15e. The grid was supporting the reactive power of the microgrid with approximately j20.1kVAr (A=7.5kVAr B=6.6kVAr C=6kVAr) shown in Figure 15f. When the motor started the inrush caused the utility to pick up the load demand of Load Bank 6 and supply approximately 18.05kW (A=8.3kW B=3.25kW C=6.5kW) + j68.7kVAr (A=23.6kVAr B=24kVAr C=21.1kVAr) to the microgrid critical load banks (i.e., Load Banks 3 and 4). The power that was being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 15e as the real power through the static switch becomes positive. Gen-sets A1 and A2 increased their real and reactive power output levels to approximately 59kW (A=18.4kW B=22.9kW C=17.7kW) + j0.5kVAr (A=-0.55kVAr B=1.25kVAr C=-0.2kVAr) and 33.4kW (A=8.9kW B=14.25kW C=10.25kW) + j17.7kVAr (A=4.7kVAr B=7kVAr C=6kVAr), respectively. Notice the signs of the VAr output changed from negative to positive for both Gen-sets in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -5.65kW (A=-1.2kW B=-6.25kW C=1.8kW) + j24.35kVAr (A=9.3kVAr B=7.8kVAr C=7.25kVAr) which meant that Gen-sets A1 and A2 were supplying the real power for the induction motor and approximately 5.65kW (A=1.2kW B=6.25kW C=-1.8kW) of Load Bank 6. The real power in Gen-set A1 increased from it initial value at the beginning of the test to approximately 43.2kW (A=13.1kW B=17.7kW C=12.4kW) and the real power for Gen-set A2 returned relatively close to the value before the motor started which was approximately 27.2kW (A=7.5kW B=11.5kW C=8.2kW). Reactive power in Gen-set A1 and A2 slightly increased from its initial value at the beginning of the test to approximately –j11.05kVAr (A=-4.2kVAr B=-3.75kVAr C=-3.1kVAr) and –j1.2kVAr (A=-1.2kVAr B=0kVAr C=0kVAr), respectively. Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 38.1kW (A=10.1kW B=18.1kW C=9.9kW) and reactive power decreased to j1kVAr (A=0.2kVAr B=0.6kVAr C=0.2kVAr) satisfying the load demand in Load bank6 which was approximately 37.8kW (A=10kW B=18kW C=9.8kW) + j0.655kVAr (A=0.12kVAr B=0.41kVAr C=0.125kVAr) and not supplying any power beyond the static switch to Load Banks 3 and 4. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch, indicating that power was not flowing through the static switch. Load Banks 3 and 4 loads reduced slightly to 17.39kW (A=5.78kW B=5.84kW C=5.77kW) + j0.3284kVAr (A=0.107kVAr B=0.1225kVAr C=0.989kVAr) and 35.35kW (A=9.3kW B=13.1kW C=12.95kW) + j0.603kVAr (A=0.114kVAr B=0.275kVAr C=0.214kVAr), respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 15g, from approximately 282.2V

on A-phase, 279.4V on B-phase and 278.9V on C-phase when connected to the utility grid to 275.1V on A-phase, 275.8V on B-phase and 274.7V on C-phase at Meter 3 when islanded.

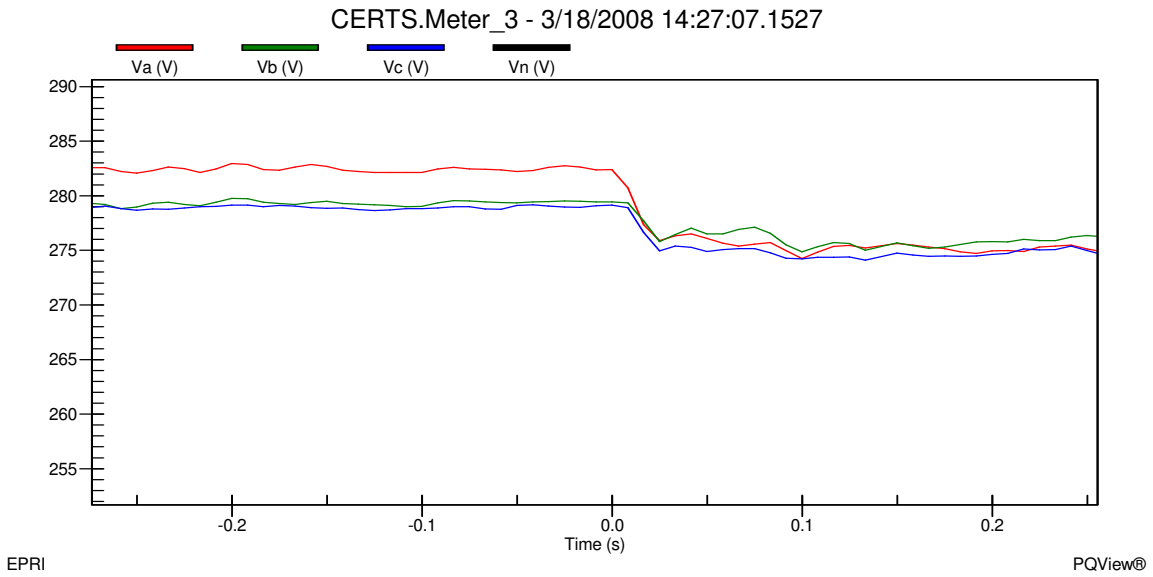

Figure 15g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.18

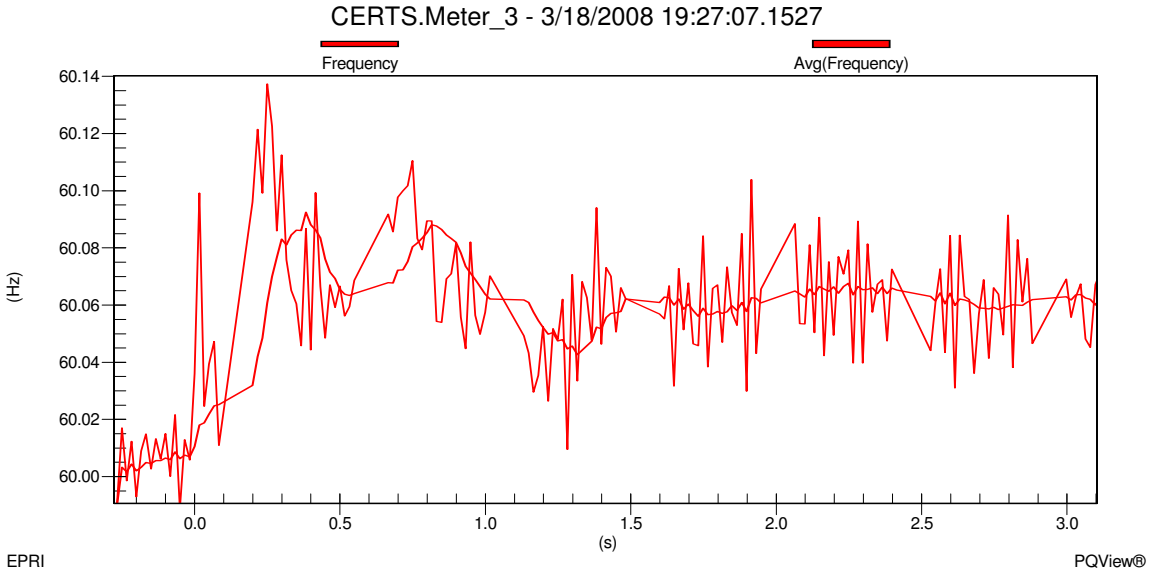

Figure 15h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.18

Frequency change in the microgrid, shown in Figure 15h, increased from approximately 60.00Hz when connected to the utility grid to approximately 60.06Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A2 to

decrease its output real power to approximately 18.1kW (A=4.6kW B=6.75kW C=6.75kW). Gen-set A1 remained relatively at the same level which was approximately 37.2kW (A=11.3kW B=13.4kW C=12.5kW). Reactive power in Gen-sets A1 and A2 increased to approximately –j2.8kVAr (A=-1.3kVAr B=-1kVAr C=-0.5kVAr) and j8kVAr (A=2.5kVAr B=3kVAr C=2.5kVAr), respectively. Meter 3 was approximately -2.5kW (A=-0.8kW B=-1.2kW C=-0.5kW) – j4.2kVAr (A=-1kVAr B=-1.6kVAr C=-1.6kVAr) indicating that the Gen-sets were satisfying the loads in the microgrid and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran fro a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

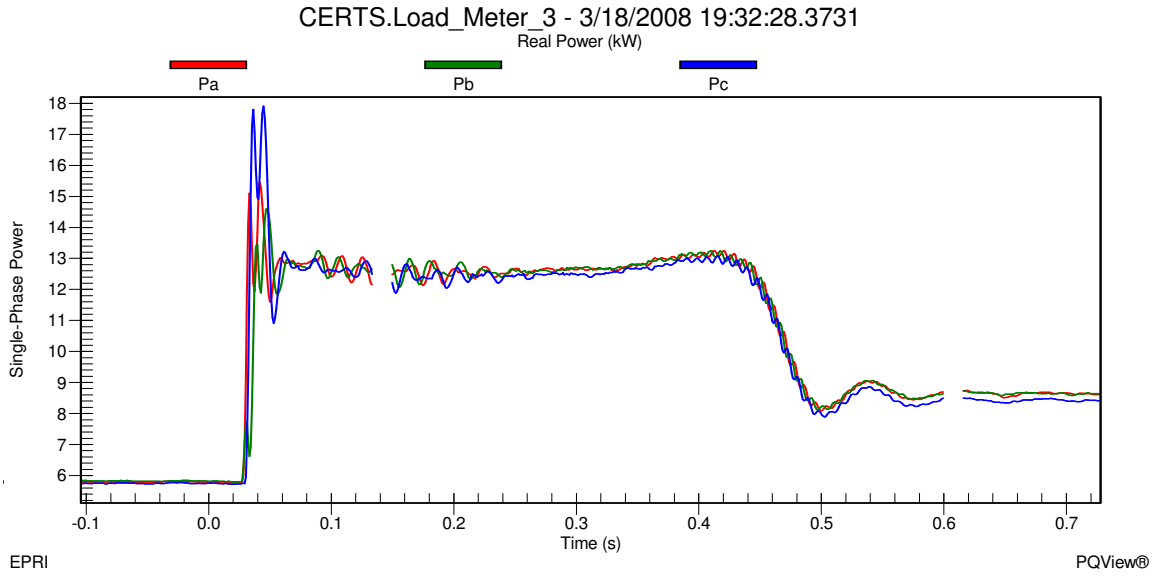

Figure 15i - Load Bank 3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.18

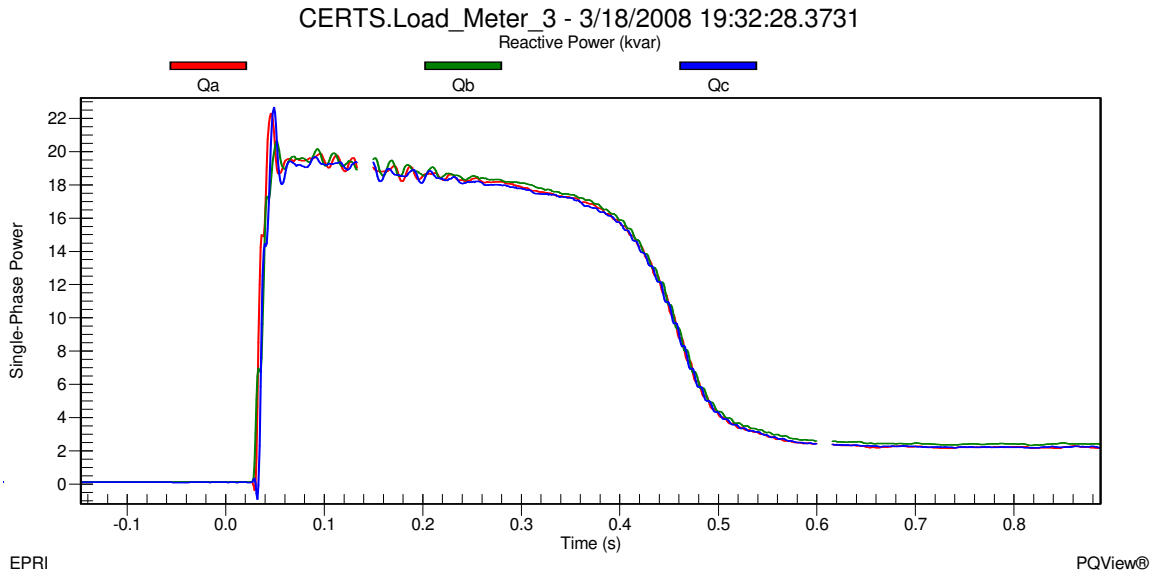

Figure 15j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.18

In Figures 15i and 15j it can be seen that the load in Zone 3 was approximately 17.3kW (A=5.8kW B=5.8kW C=5.7kW) + j0.3kVAr (A=0.1kVAr B=0.1kVAr C=0.1kVAr) before the start of the induction motor and increased to approximately 47kW (A=14.8kW B=14.3kW C=17.9kW) + j64.95kVAr (A=21.75kVAr B=20.5kVAr C=22.7kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 37.8kW (A=12.6kW B=12.6kW C=12.6kW) + j55.2kVAr (A=18.4kVAr B=18.4kVAr C=18.4kVAr) during the warm up phase which lasted about 36cycles (0.6 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 25.6kW (A=8.6kW B=8.6kW C=8.4kW) + j6.9kVAr (A=2.25kVAr B=2.4kVAr C=2.25kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 275.4V on A-phase, 275.7V on B-phase and 274V on C-phase shown in Figure 15k and approximately 60.06Hz shown in Figure 15l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 256V on A-phase, 255.5V on B-phase and 255.3V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.96Hz and quickly increased to approximately 60.03Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 273.6V on A-phase, 273.6V on B-phase and 272.5V on C-phase at an approximate frequency of 60.07Hz.

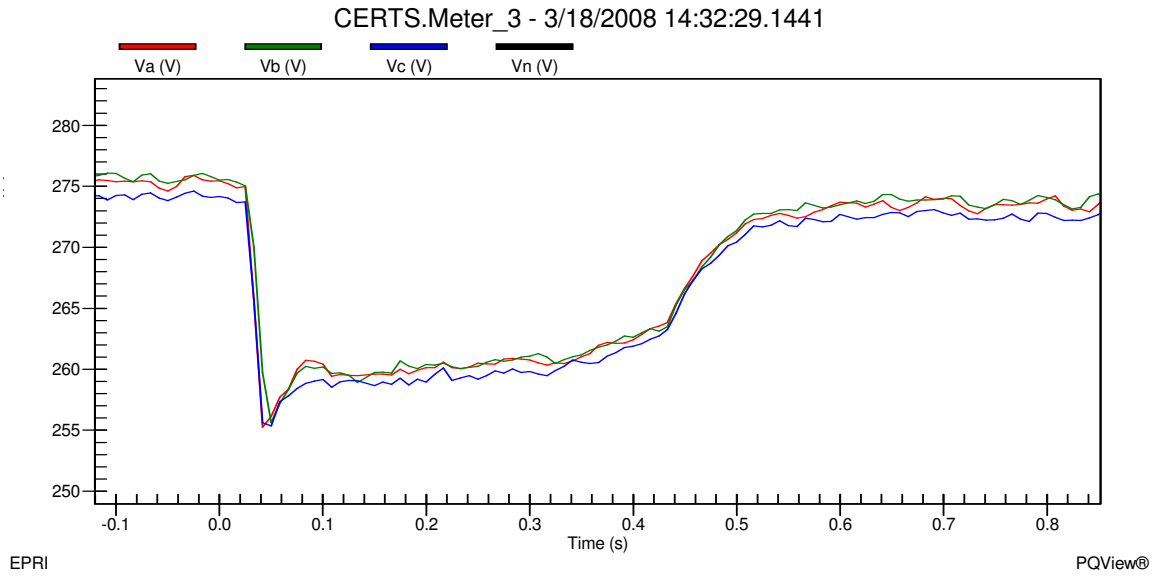

Figure 15k - Meter 3 Line-to-Ground Voltages during Motor Start and Islanded for Test 10.3.18

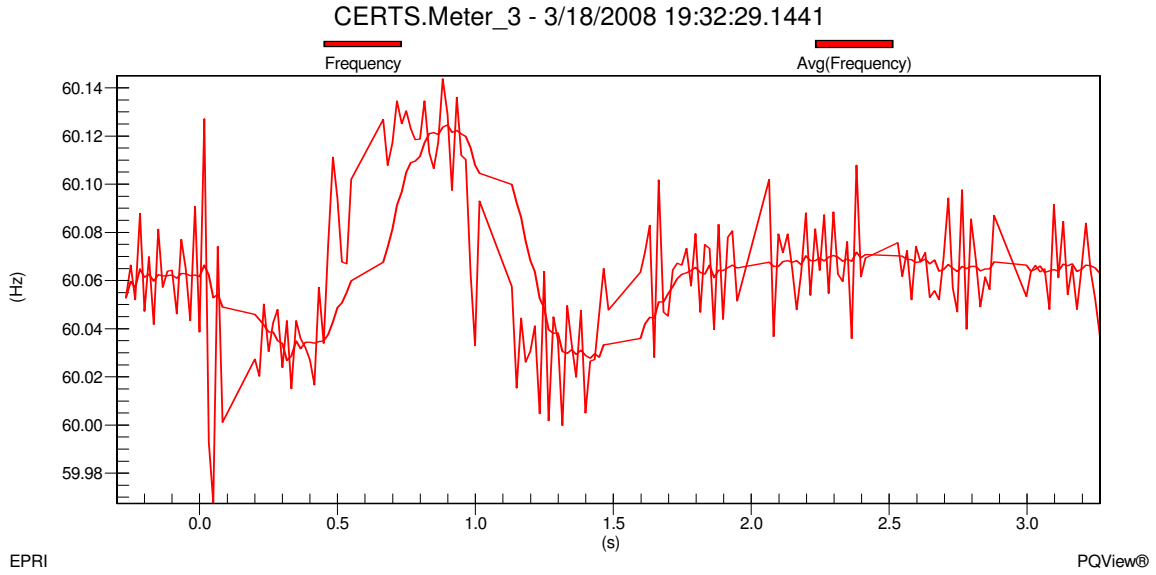

Figure 15l - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.18

Before the motor started Gen-sets A1 and A2 were producing approximately 37.1kW (A=11.2kW B=13.5kW C=12.4kW) – j2.9kVAr (A=-1.4kVAr B=-1kVAr C=-0.5kVAr) and 18kW (A=4.7kW B=6.5kW C=6.8kW) + j7.6kVAr (A=2.4kVAr B=2.8kVAr C=2.4kVAr), respectively shown in Figures 15m – 15p. The power generated by both Gen-sets was satisfying the loads in Load Banks 3 and 4 and all the electrical losses in the microgrid system. When the motor started the inrush caused the Gen-sets to increase their output power levels to 47kW (A=13.4kW B=15.9kW C=17.7kW) + j29kVAr (A=9.5kVAr B=9.1kVAr C=10.4kVAr) for Gen-set A1 and 32.1kW (A=9.6kW B=9.9kW C=12.6kW) +

j38.7kVAr (A=13.2kVAr B=12.2kVAr C=13.3kVAr) for Gen-set A2. The increase in real and reactive power due to the motor start inrush was shared by Gen-sets A1 and A2. Gen-sets A1 increased its output real power during the warm up phase to approximately 57.4kW (A=18.2kW B=20.1kW C=19.1kW) and decreased its reactive power. Gen-set A2 decreased real and reactive power output during the warm up phase. The Gen-sets eventually dropped their output levels to 45.3kW (A=14.1kW B=16.2kW C=15kW) – j0.1kVAr (A=-0.4kVAr B=0kVAr C=0.3kVAr) for Gen-set A1 and 17.4kW (A=4.4kW B=6.4kW C=6.6kW) + j11.1kVAr (A=3.6kVAr B=3.9kVAr C=3.6kVAr) for Gen-set A2 when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

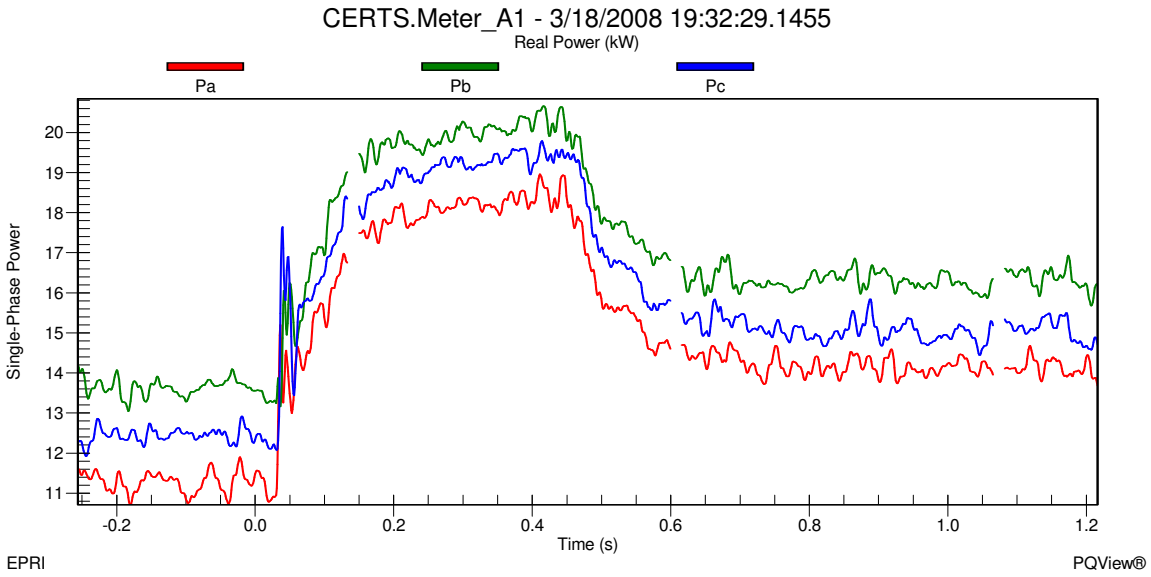

Figure 15m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.18

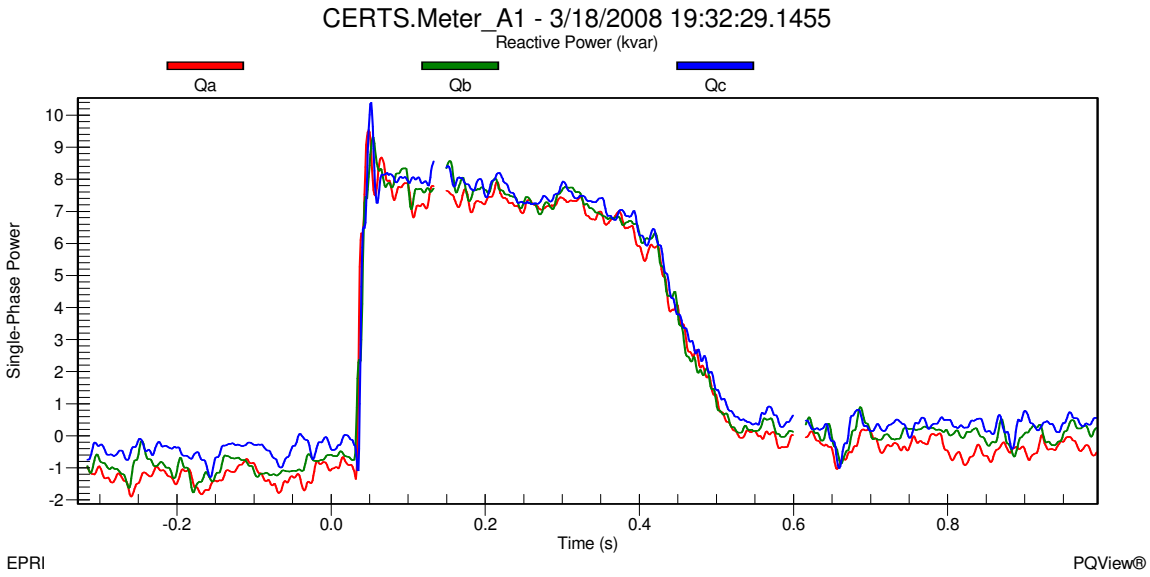

Figure 15n - Gen-set A1 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.18

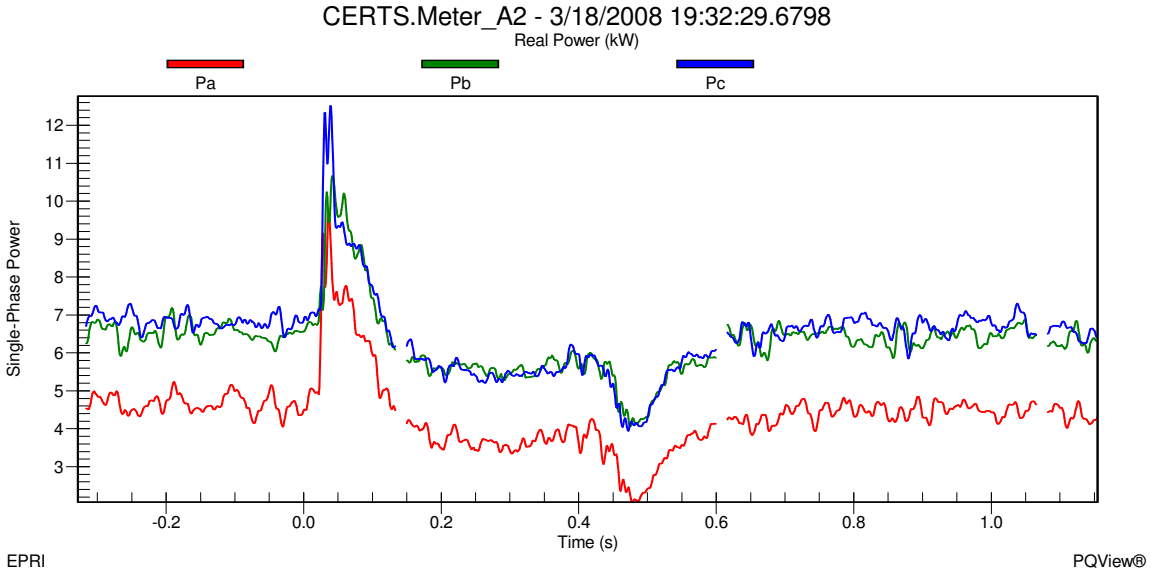

Figure 15o - Gen-set A2 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.18

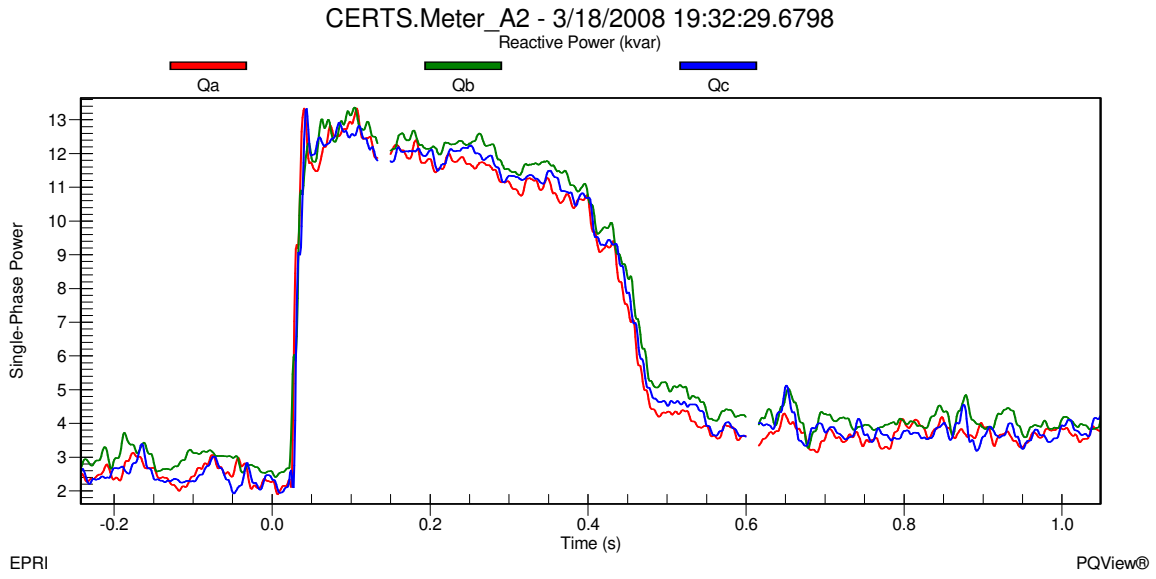

Figure 15p - Gen-set A2 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.18

As soon as the static switch closed, Meter 1 recorded real power decreased from 38kW (A=10.1kW B=18.1kW C=9.8kW) to 32.5kW (A=8.9kW B=11.8kW C=11.8kW) and reactive power increased from approximately j1kVAr (A=0.2kVAr B=0.6kVAr C=0.2kVAr) to j27.4kVAr (A=10kVAr B=9.2kVAr C=8.2kVAr) which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 15q and 15r show the static switch real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -4.75kW (A=-1kW B=-6kW C=2.25kW) and reactive power increasing from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to j26.1kVAr (A=9.6kVAr B=8.5kVAr C=8kVAr). At the beginning of the test, the initial power flow through the static switch was -6.05kW (A=-1.4kW B=-6.25kW C=1.6kW) + j20.1kVAr (A=7.5kVAr B=6.6kVAr C=6kVAr) which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. The Gen-sets have picked up the motor load and supporting Load Bank 6 with approximately 4.75kW (A=1kW B=6kW C=-2.25kW).

Load Banks 3 and 4 loads increased slightly to 24.9kW (A=8.5kW B=8.2kW C=8.2kW) + j6.43kVAr (A=2.205kVAr B=2.205kVAr C=2.02kVAr) and 36.62kW (A=9.8kW B=13.47kW C=13.35kW) + j0.613kVAr (A=0.12kVAr B=0.28kVAr C=0.213kVAr), respectively. This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 15s, from approximately 273.9V on A-phase, 273.9V on B-phase and 272.6V on C-phase when islanded to 282.4V on A-phase, 279V on B-phase and 279V on C-phase at Meter 3 when connected to the utility grid.

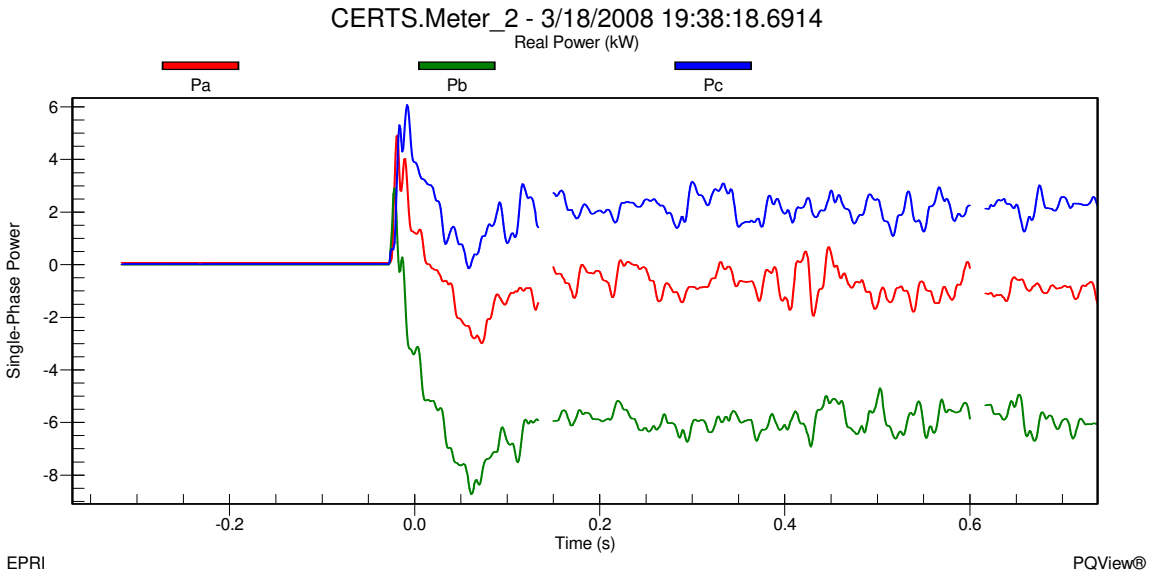

Figure 15q - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.18

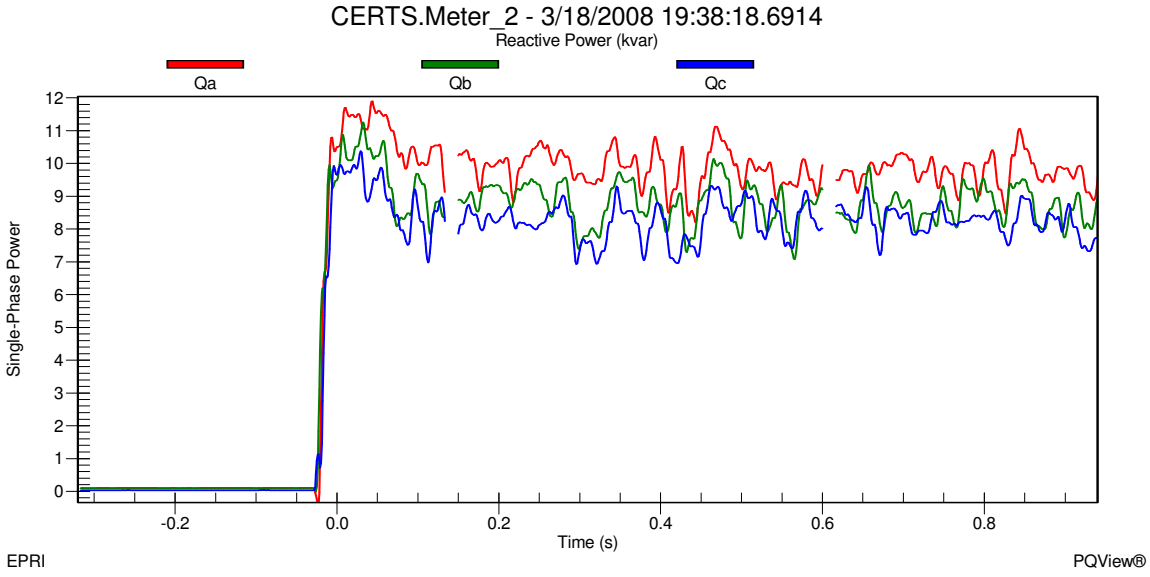

Figure 15r - Static Switch Reactive Single-Phase Power during Island to Utility Connected mode for Test 10.3.18

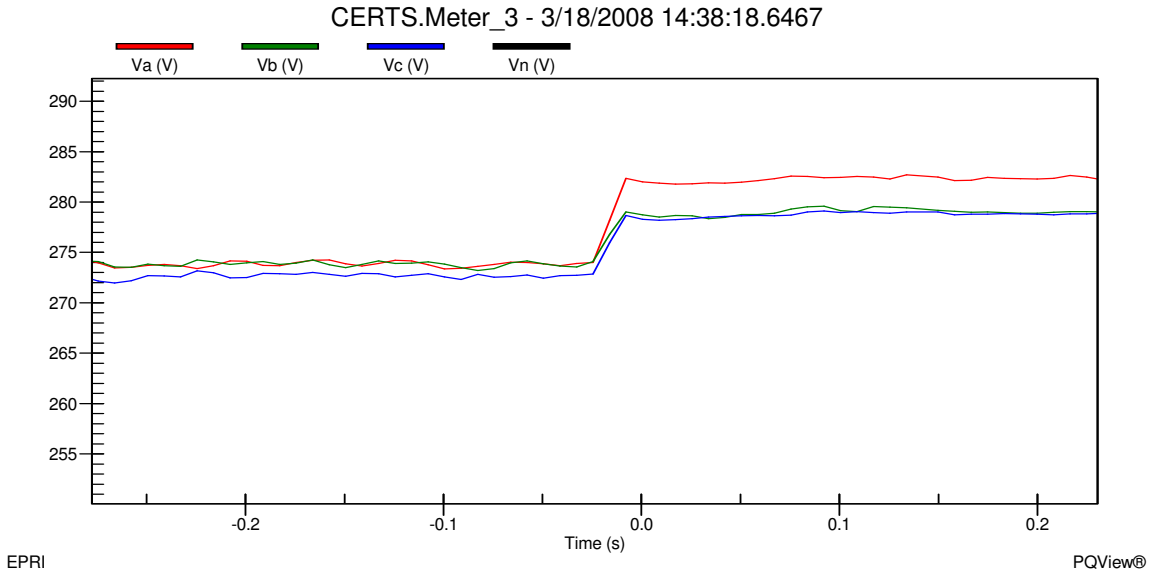

Figure 15s - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.3.18

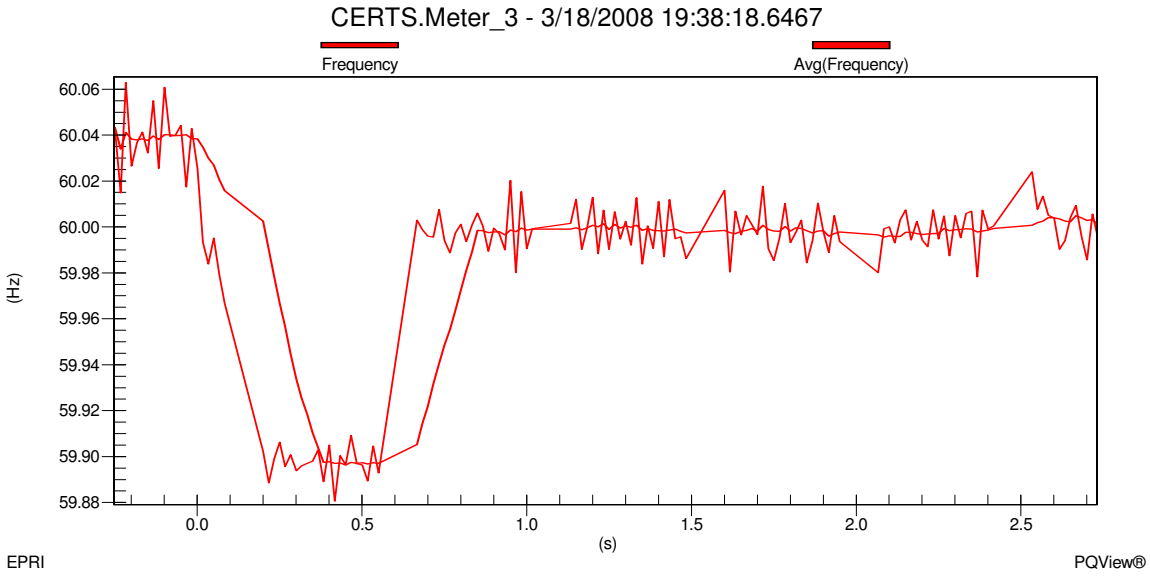

Figure 15t - Meter 3 Frequency during Island to Utility Connected mode for Test 10.3.18

Frequency change in microgrid, shown in Figure 15t, decreased from approximately 60.04Hz when islanded to approximately 60.00Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-sets using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in zone power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on set-points for the power flow through Zones 3 and 4 initialized at the beginning of the test. The real power in Gen-set A1 increased

from its initial value at the beginning of the test to approximately 42.25kW (A=12.75kW B=17.5kW C=12kW). Gen-set A2 real power was relatively close to its initial value at the beginning of the test which was approximately 26.4kW (A=7.25kW B=11.25kW C=7.9kW). Reactive powers for both Gen-sets were relatively close to the values at the beginning of the test with approximately –j11.85kVAr (A=-4.25kVAr B=-4kVAr C=-3.6kVAr) for Gen-set A1 and –j2kVAr (A=-1.6kVAr B=-0.2kVAr C=-0.2kVAr) for Gen-set A2. After all the data was verified and recorded into the DAS Database, the motor was turned off and the Gen-sets and Load Banks set-points were changed according to the next test (10.3.20) in Table 2.

For Test 10.3.20 the measured values, after Gen-set A1 was warmed up and load banks brought on-line are provided in Table 7.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	33.1	0	25.5	-12.4	-14.9	0	17.9	18.2	37.25
1 Phase kW	A=10 B=14.7 C=8.4	A=0 B=0 C=0	A=7 B=10.5 C=8	A=-3 B=-7.5 C=-1.9	A=-3.9 B=-8.8 C=-2.2	A=0 B=0 C=0	A=6.1 B=5.9 C=5.9	A=6.2 B=6 C=6	A=9.9 B=17.75 C=9.6
3 Phase kVAr	-13.8	0	21	20	14.45	0	0	0.3	0.656
1 Phase kVAr	A=-5 B=-4.8 C=-4	A=0 B=0 C=0	A=7 B=7.5 C=6.5	A=6.75 B=7 C=6.25	A=5.2 B=5 C=4.25	A=0 B=0 C=0	A=0 B=0 C=0	A=0.1 B=0.1 C=0.1	A=0.12 B=0.411 C=0.125

Table 8 - Measured Values after Start Up for Test 10.3.20

These measurements were relatively close to the expected values in Table 2, but not exact due to temperature, phase voltages and electrical losses in conductors. In addition, the 40kW settings for LB6 and the 20kW setting for LB3 were also below selected set values. At the time of the measurements, the voltage and frequency was 284V on A-phase, 279.6V on B-phase and 280V on C-phase and 60.03Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 284.3V on A-phase, 280.1V on B-phase and 280.1V on C-phase and 60.03Hz at Meter 3.

Gen-set A1 in this test was set up to produce -20kW going through Zone 3 (i.e., Meter 3) which means it produced 20kW more power than Load Bank 3 needed. Approximately 14.9kW (A=3.9kW B=8.8kW C=2.2kW) of excess power was exported out of Zone 3 and 12.4kW (A=3kW B=7.5kW C=1.9kW) of that power went through the static switch to Load Bank 6 and the remaining 2.5kW (A=0.9kW B=1.3kW C=0.3kW) was due to power losses in the conductors. Since Load Bank 6 was approximately 37.25kW (A=9.9kW B=17.75kW C=9.6kW) + j0.656kVAr (A=0.12kVAr B=0.411kVAr C=0.125kVAr), the utility had to supply approximately 25.5kW (A=7kW B=10.5kW C=8kW) to satisfy the load. Reactive power had to be imported in from the utility of approximately j20kVAr (A=6.75kVAr B=7kVAr C=6.25kVAr) because Gen-set A1 needed approximately j13.8kVAr (A=5kVAr B=4.8kVAr C=4kVAr) and losses in the conductors.

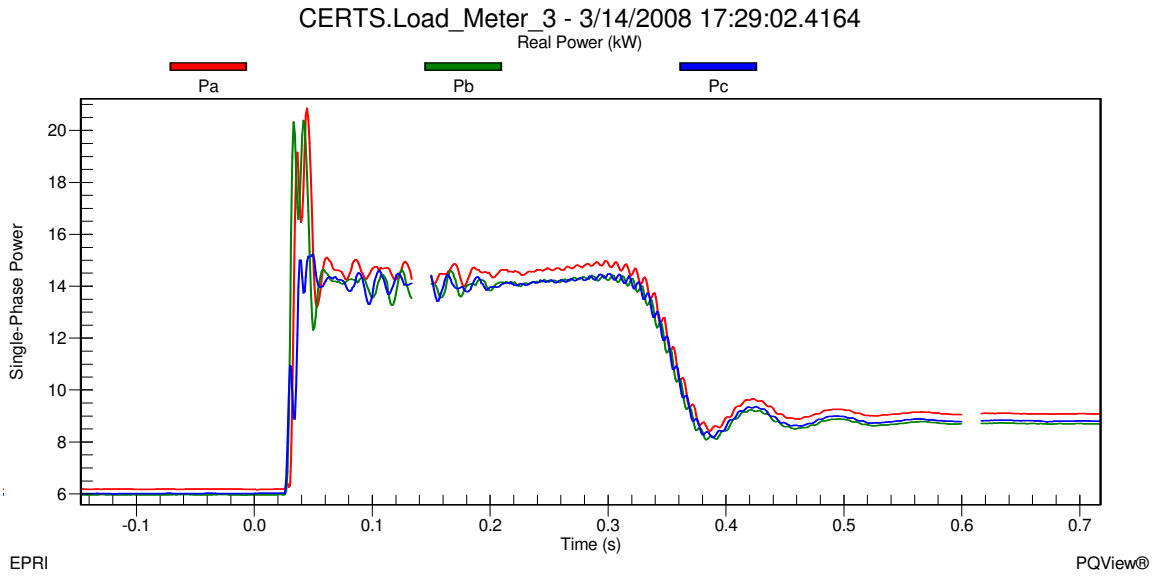

Figure 16a - Load Bank 3 Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.20

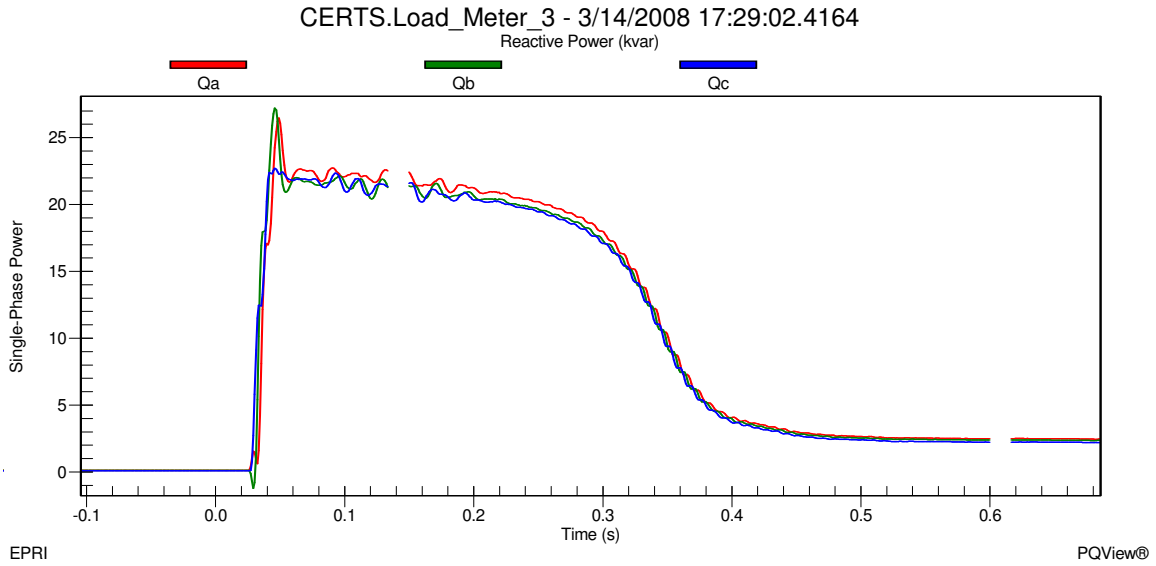

Figure 16b - Load Bank 3 Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.20

In Figures 16a and 16b it can be seen that the load in Zone 3 was approximately 18.2kW (A=6.2kW B=6kW C=6kW) + j0.3kVAr (A=0.1kVAr B=0.1kVAr C=0.1kVAr) before the start of the induction motor and increased to approximately 55.8kW (A=21kW B=19.6kW C=15.2kW) + j75.8kVAr (A=25.9kVAr B=27.2kVAr C=22.7kVAr) during the inrush phase of the motor start. After about 1.555 cycles, the motor settled down to approximately 42.9kW (A=14.5kW B=14.2kW C=14.2kW) + j61.4kVAr (A=20.8kVAr B=20.3kVAr C=20.3kVAr) during the warm up phase which lasted about 36.6 cycles (0.61 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 27.15kW (A=9.6kW B=8.75kW C=8.8kW) + j7kVAr (A=2.5kVAr B=2.3kVAr C=2.2kVAr).

The voltage and frequency at the static switch before the motor start was approximately 284V on A-phase, 279.6V on B-phase and 280V on C-phase shown in Figure 16c and approximately 60.03Hz shown in Figure 16d. When the motor started, the voltage at the static switch during the inrush decreased to approximately 275.8V on A-phase, 270.9V on B-phase and 272.25V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.93Hz and quickly increased to approximately 60.03Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 283V on A-phase, 278.8V on B-phase and 279.25V on C-phase at an approximate frequency 60.02Hz.

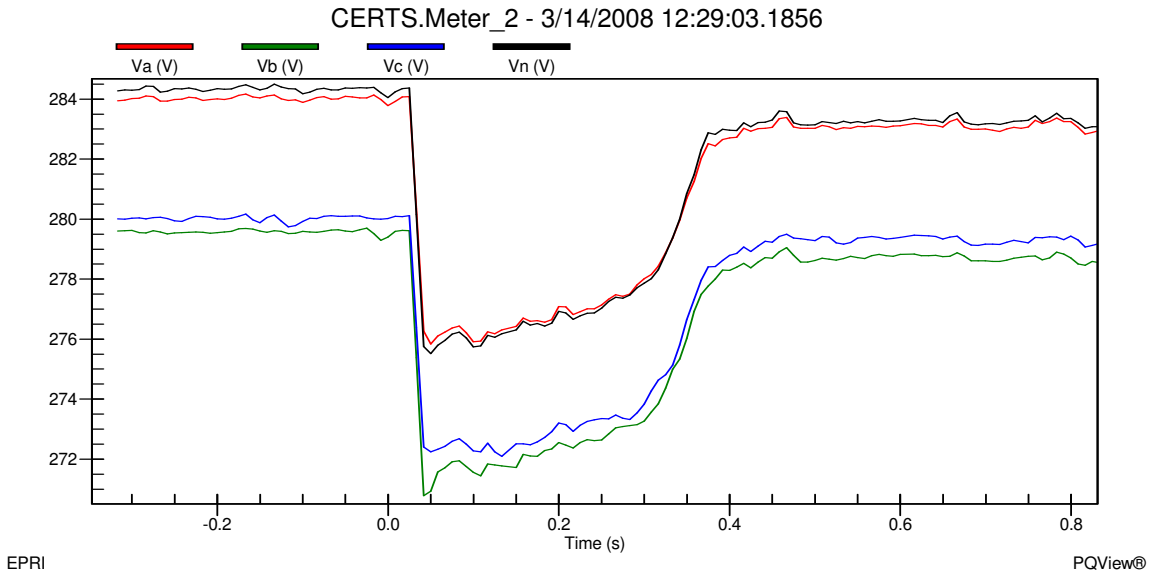

Figure 16c - Static Switch Line-to-Ground Voltages during Motor Start and Utility Connected for Test 10.3.20

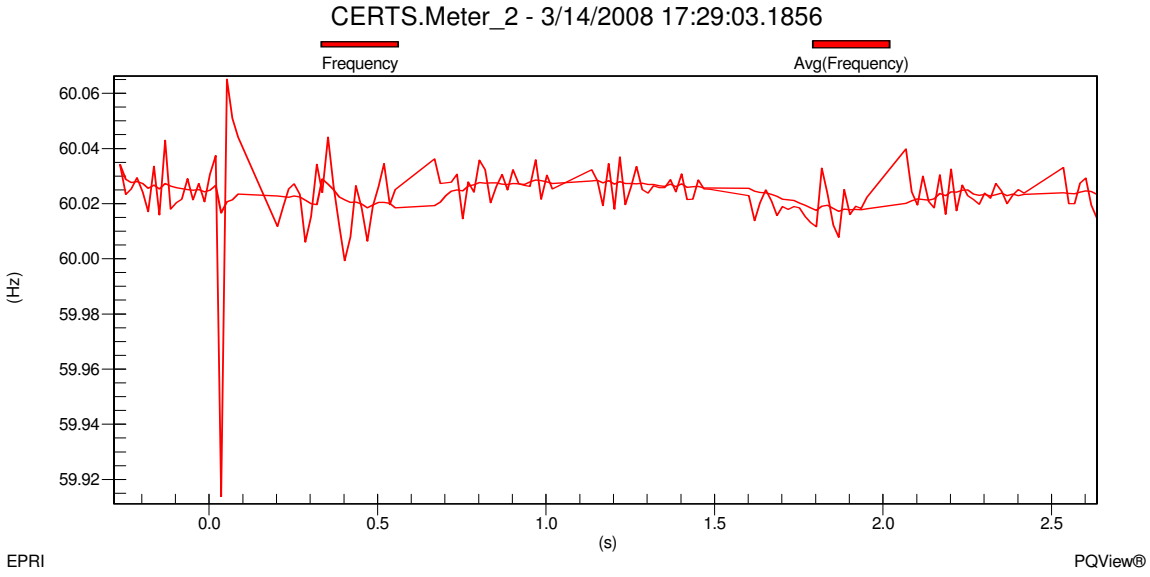

Figure 16d - Static Switch Frequency during Motor Start and Utility Connected for Test 10.3.20

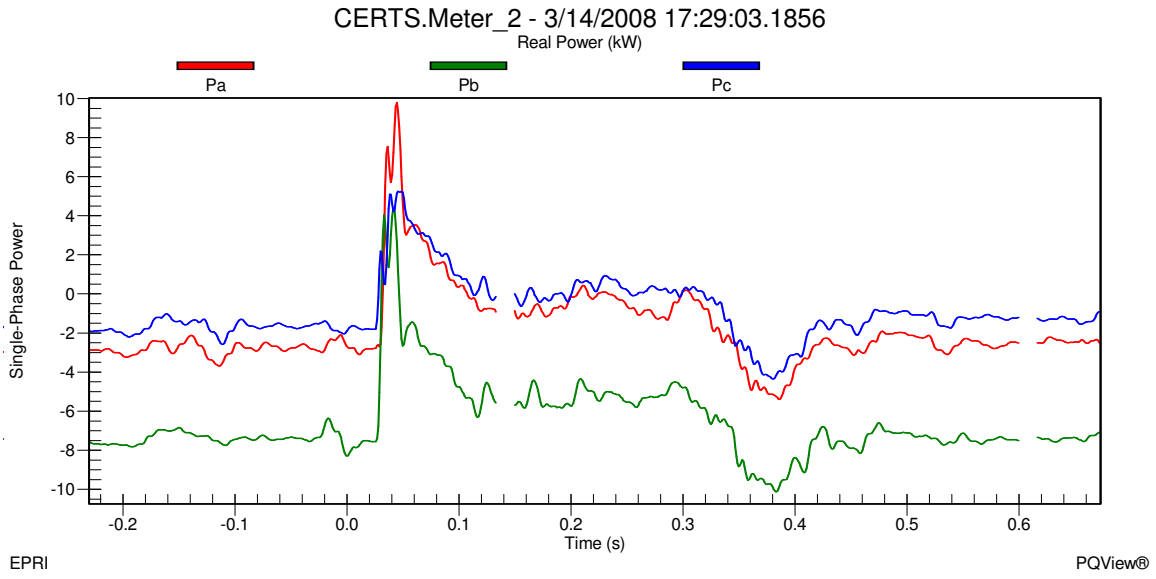

Figure 16e - Static Switch Real Single-Phase Power during Motor Start and Utility Connected for Test 10.3.20

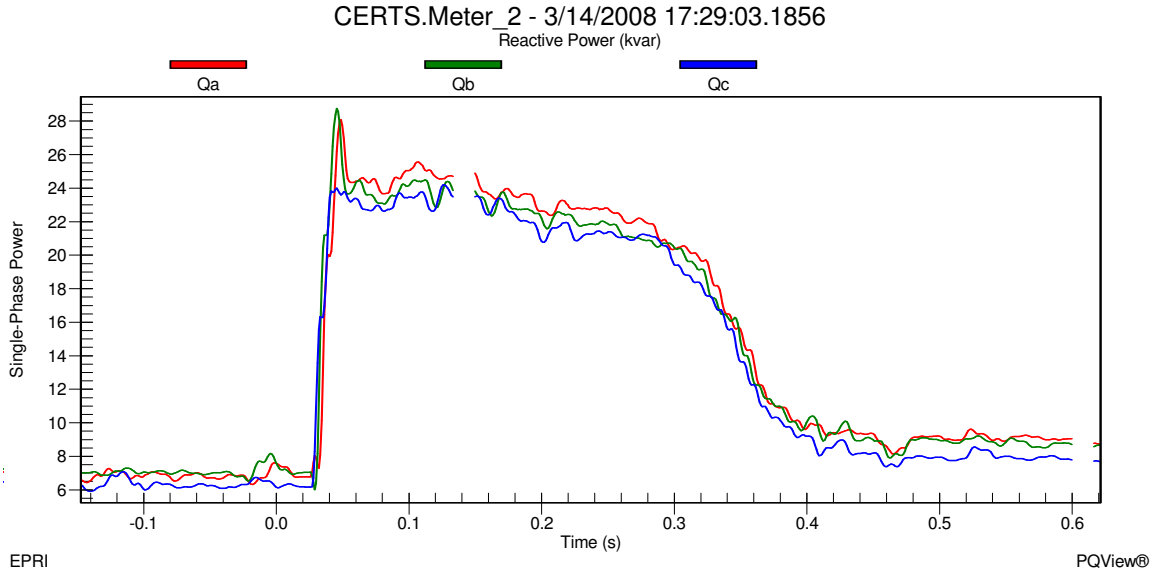

Figure 16f - Static Switch Reactive Single-Phase Power during Motor Start and Utility Connected for Test 10.3.20

Before the motor started Gen-set A1 was producing approximately 33.1kW (A=10kW B=14.7kW C=8.4kW) – j13.8kVAr (A=-5kVAr B=-4.8kVAr C=-4kVAr). This was enough power for the load demands of Load Bank 3 with real power being exported to Zone 6 of approximately -12.4kW (A=-3kW B=-7.5kW C=-1.9kW) shown in Figure 16e. The grid was supporting the reactive power of the microgrid with approximately j20kVAr (A=6.75kVAr B=7kVAr C=6.25kVAr) shown in Figure 16f. When the motor started the inrush caused the utility to supply approximately j81.5kVAr (A=28.3kVAr B=29.2kVAr C=24kVAr) and to pick up the load demand of Load Bank 6 and approximately 18.6kW

(A=9.9kW B=3.4kW C=5.3kW) of the load demand in Zone 3. The power that was being supplied by Gen-set A1 to Load Bank 6 was now supplying the motor inrush which can be seen in Figure 16e as the real power through the static switch becomes positive. Gen-set A1 increased its real and reactive power output levels to approximately 54.15kW (A=17.1kW B=21.8kW C=15.25kW) + j1.8kVAr (A=-0.3kVAr B=0.3kVAr C=1.8kVAr). Notice the signs of the VAr output changed from negative to positive for Gen-set A1 in order to support the induction motor load in Zone 3.

When the motor reached steady state, the real and reactive power through the static switch was approximately -11.3kW (A=-2.6kW B=-7.4kW C=-1.3kW) + j25.8kVAr (A=9kVAr B=8.8kVAr C=8kVAr) which meant that Gen-set A1 was supplying the power for the induction motor and approximately 11.3kW (A=2.6kW B=7.4kW C=1.3kW) of Load Bank 6. The real power in Gen-set A1 increased from its initial value at the beginning of the test to approximately 40.5kW (A=12.4kW B=17.1kW C=11kW) and the reactive power went relatively back to the initial value before the motor started of approximately –j12.5kVAr (A=-4.6kVAr B=-4.4kVAr C=-3.5kVAr). Once all the data was verified and recorded into the DAS Database, the motor was shut down and the static switch was directed by the EMS to manually open.

As soon as the static switch opened, Meter 1 recorded real power increased to approximately 38.1kW (A=10.1kW B=18.2kW C=9.8kW) and reactive power decreased to j1kVAr (A=0.2kVAr B=0.6kVAr C=0.2kVAr) satisfying the load demand in Load Bank 6 which was approximately 37.85kW (A=10.05kW B=18kW C=9.8kW) + j0.659kVAr (A=0.124kVAr B=0.41kVAr C=0.125kVAr) and not supplying any power beyond the static switch to Load Bank 3. 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at the static switch, indicating that power was not flowing through the static switch. Load Bank 3 loads reduced slightly to 16.97kW (A=5.645kW B=5.66kW C=5.665kW) + j0.3205kVAr (A=0.103kVAr B=0.12kVAr C=0.0975kVAr). This load reduction resulted from a voltage drop in the microgrid, shown in Figure 16g, from approximately 284.1V on A-phase, 279.9V on B-phase and 280V on C-phase when connected to the utility to 272.2V on A-phase, 271.2V on B-phase and 281.9V on C-phase at Meter 3 when Islanded.

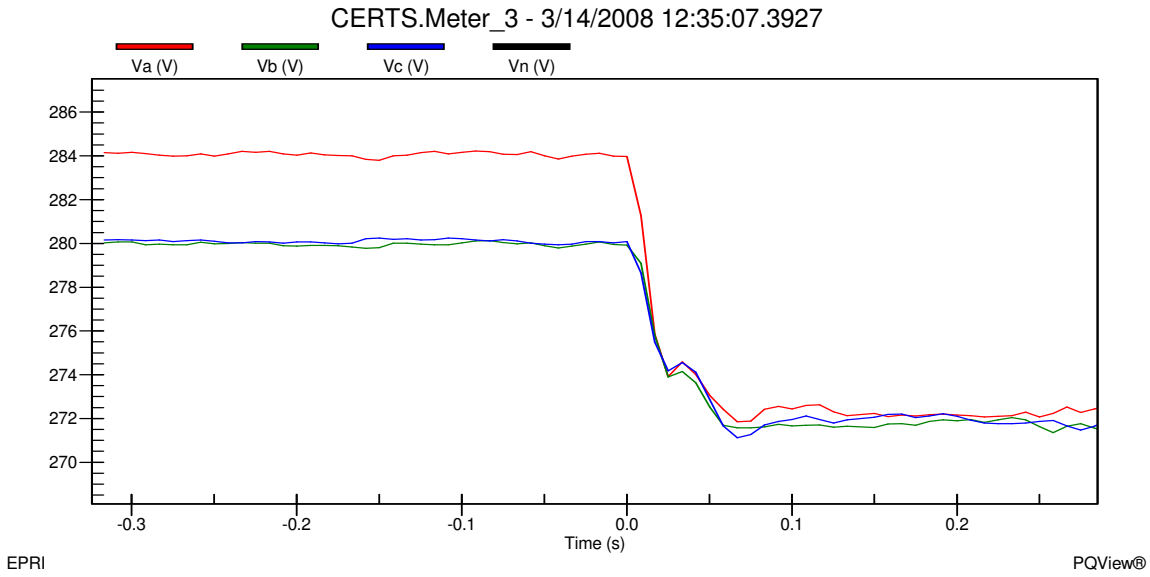

Figure 16g - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.3.20

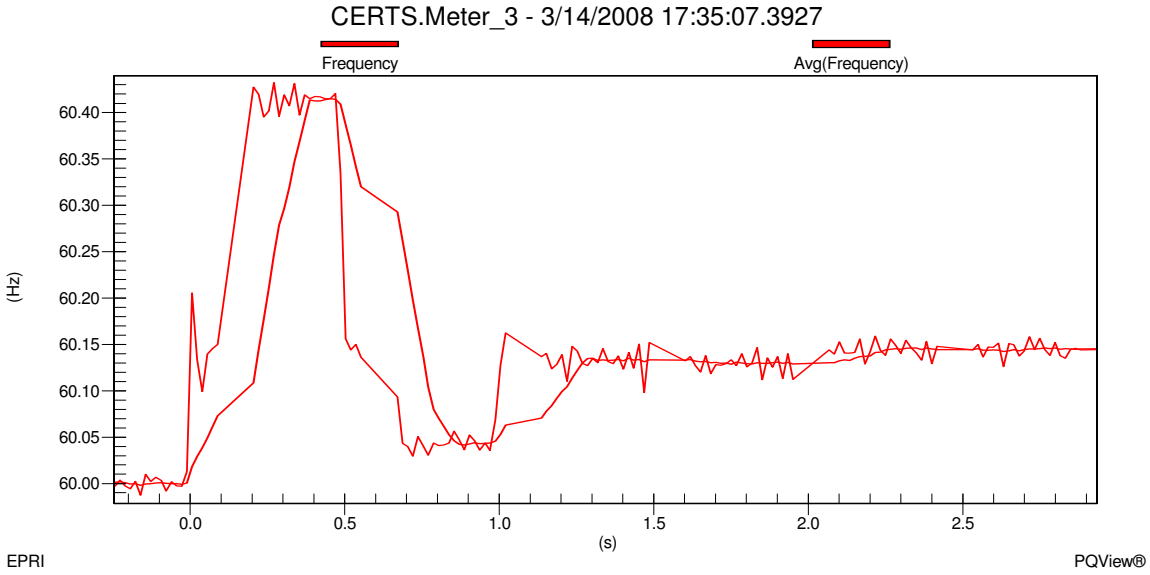

Figure 16h - Meter 3 Frequency during Utility Connected to Island mode for Test 10.3.20

Frequency change in the microgrid, shown in Figure 16h, increased from approximately 60.00Hz when connected to the utility grid to approximately 60.14Hz when islanded.

This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output real power to approximately 19.4kW (A=6.4kW B=6.8kW C=6.2kW). Reactive power in Gen-set A1 increased to approximately j4kVAr (A=1kVAr B=1.5kVAr C=1.5kVAr). Meter 3 was approximately -2.4kW (A=-0.8kW B=-1.1kW C=-0.5kW) – j3.69kVAr (A=-0.85kVAr B=-1.4kVAr C=-1.44kVAr) indicating that Gen-set A1 was satisfying the load in Load Bank 3 and the power losses in the electrical lines. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the 10Hp induction motor was started in Zone 3.

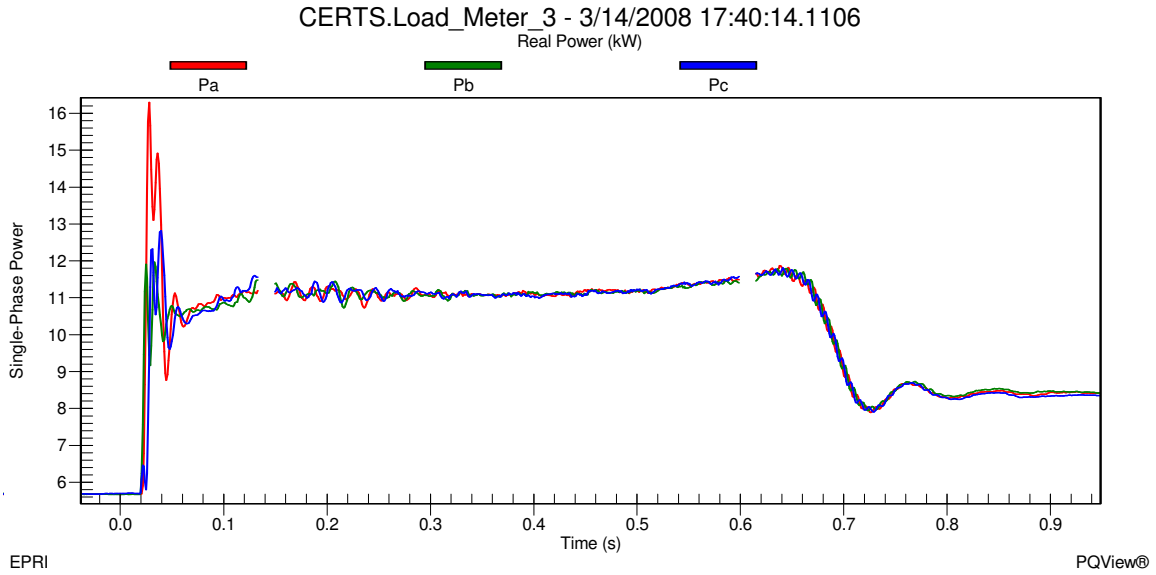

Figure 16i - Load Bank 3 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.20

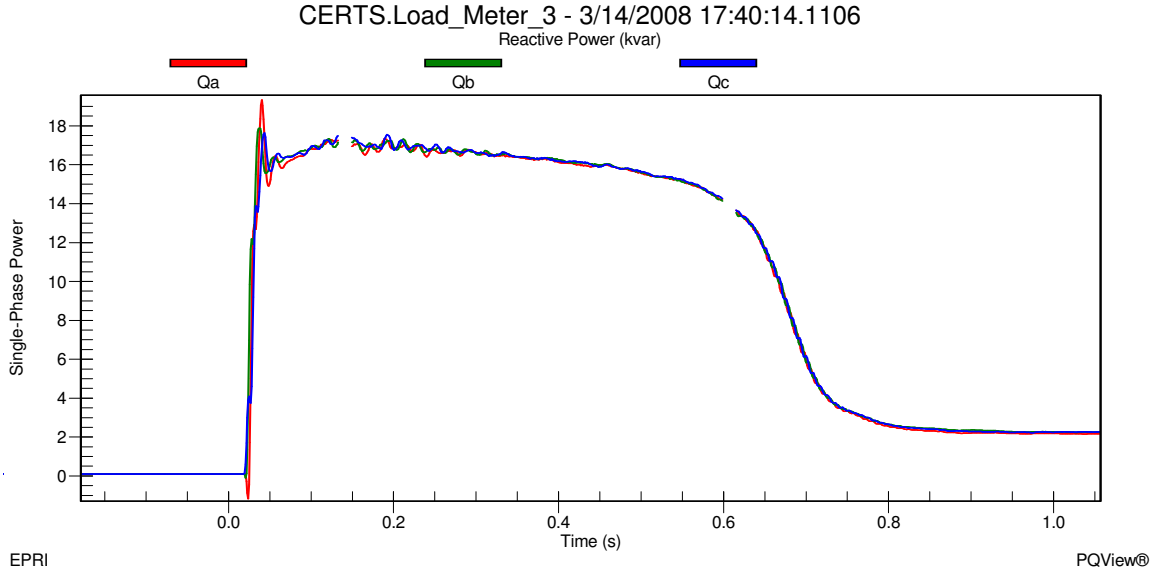

Figure 16j - Load Bank 3 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.20

In Figures 16i and 16j it can be seen that the load in Zone 3 was approximately 17.1kW (A=5.7kW B=5.7kW C=5.7kW) + j0.6kVAr (A=0.2kVAr B=0.2kVAr C=0.2kVAr) before the start of the induction motor and increased to approximately 38.6kW (A=16.4kW B=10.2kW C=12kW) + j54.75kVAr (A=19.4kVAr B=17.75kVAr C=17.6kVAr) during the inrush phase of the motor start. After about 1.5 cycles, the motor settled down to approximately 33.6kW (A=11.2kW B=11.2kW C=11.2kW) + j48.6kVAr (A=16.2kVAr B=16.2kVAr C=16.2kVAr) during the warm up phase which lasted about 48 cycles (0.8 Seconds). When the motor reached steady state, the load in Zone 3 was approximately 25.2kW (A=8.4kW B=8.4kW C=8.4kW) + j6.75kVAr (A=2.25kVAr B=2.25kVAr C=2.25kVAr).

The voltage and frequency at Meter 3 before the motor start was approximately 272.1V on A-phase, 271.8V on B-phase and 272.1V on C-phase shown in Figure 16k and approximately 60.13Hz shown in Figure 16l. When the motor started, the voltage at Meter 3 during the inrush decreased to approximately 236.4V on A-phase, 235.8V on B-phase and 237.6V on C-phase for about 1.5 cycles. Frequency dropped during the inrush to approximately 59.76Hz. Voltage increased as the motor was warming up and eventually settled at a steady state voltage at approximately 268.5V on A-phase, 268V on B-phase and 268.9V on C-phase at an approximate frequency of 60.15Hz.

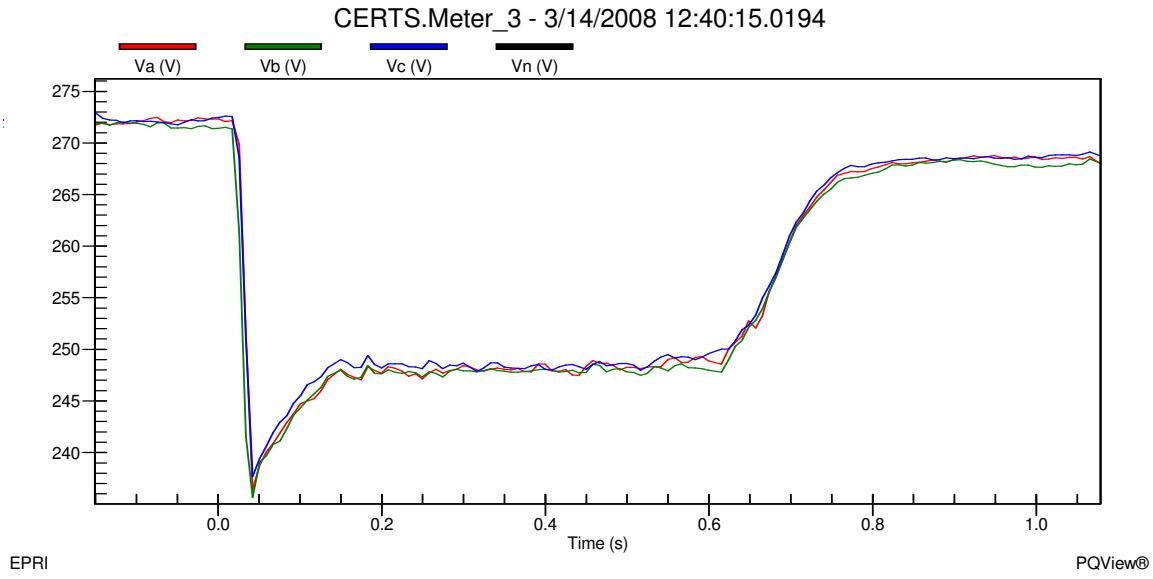

Figure 16k - Meter 3 Line-to-Ground Voltage during Motor Start and Islanded for Test 10.3.20

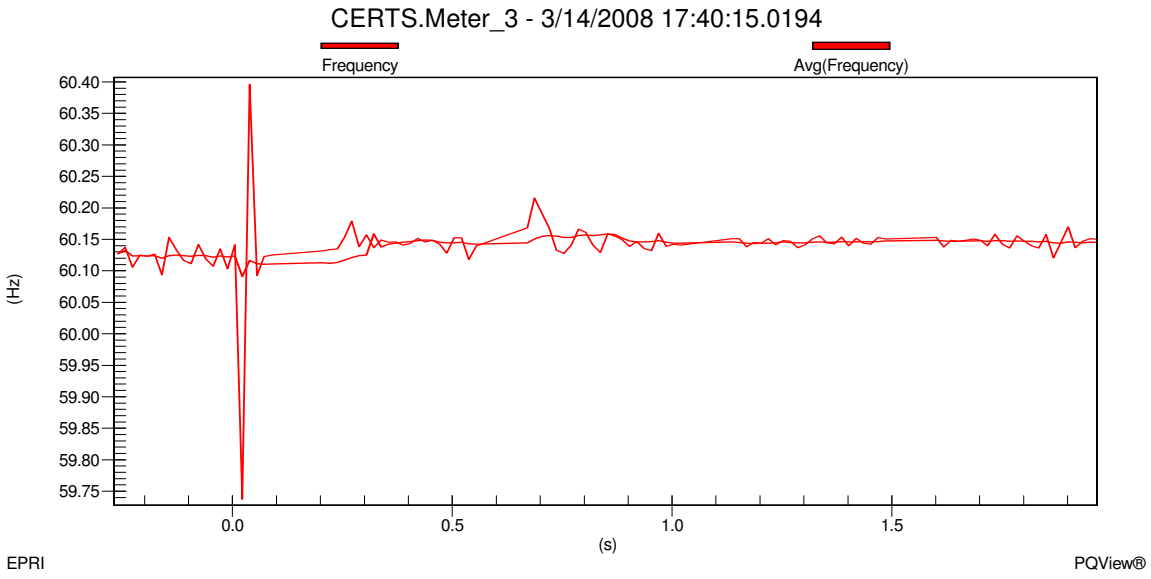

Figure 16l - Meter 3 Frequency during Motor Start and Islanded for Test 10.3.20

Before the motor started, Gen-set A1 was producing approximately 19.28kW (A=6.4kW B=6.78kW C=6.1kW) + j4kVAr (A=1kVAr B=1.5kVAr C=1.5kVAr) shown in Figures 16m and 16n. The power generated by Gen-set A1 was satisfying the loads in Load Bank 3 and all the electrical losses in the microgrid system. When the motor started the inrush caused Gen-set A1 to increase its output power level to 41.4kW (A=16.8kW B=12.3kW C=12.3kW) + j55.6kVAr (A=19.4kVAr B=18.3kVAr C=17.9kVAr). Gen-set A1 decreased its output level while the motor was warming up and eventually dropped to 27.5kW (A=9.2kW B=9.5kW C=8.8kW) + j9.9kVAr (A=2.9kVAr B=3.5kVAr C=3.5kVAr) when the motor reached steady state. Once all the data was verified and recorded into the DAS Database, the static switch was directed by the EMS to manually close.

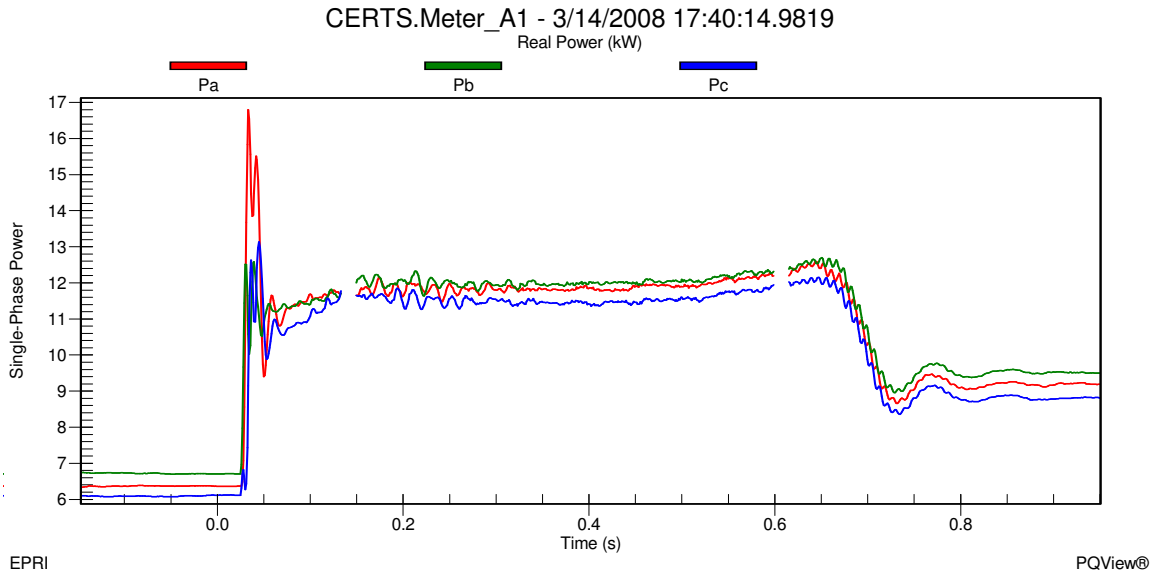

Figure 16m - Gen-set A1 Real Single-Phase Power during Motor Start and Islanded for Test 10.3.20

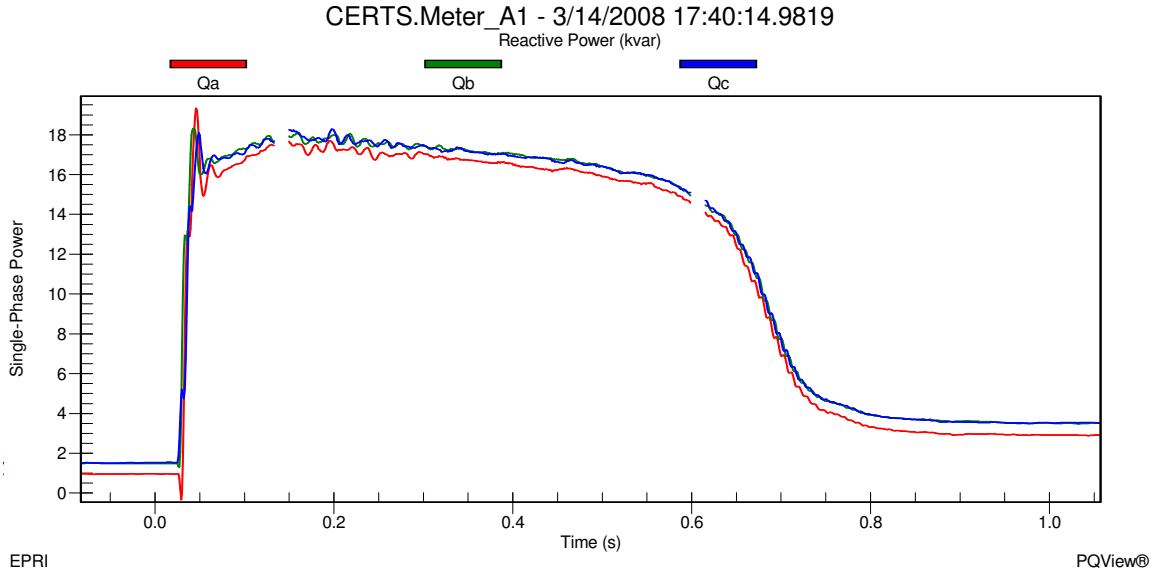

Figure 16n - Gen-set A1 Reactive Single-Phase Power during Motor Start and Islanded for Test 10.3.20

As soon as the static switch closed, Meter 1 recorded real power decreased from approximately 38.09kW (A=10.1kW B=18.17kW C=9.82kW) to 24.1kW (A=6.7kW B=9.7kW C=7.7kW) and reactive power increased from approximately j1kVAr (A=0.2kVAr B=0.6kVAr C=0.2kVAr) to j25.9kVAr (A=8.7kVAr B=9kVAr C=8.2kVAr) which means that the utility was satisfying a portion of the load demand in Load Bank 6 and all the reactive power in the microgrid. Figures 16o and 16p show the static switch real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -13.5kW (A=-3.4kW B=-8kW C=-2.1kW) and reactive power increasing from j0kVAr (A=0kVAr

B=0kVAr C=0kVAr) to j24.8kVAr (A=8.5kVAr B=8.5kVAr C=7.8kVAr). At the beginning of the test, the initial power flow through the static switch was -12.4kW (A=-3kW B=-7.5kW C=-1.9kW) + j20kVAr (A=6.75kVAr B=7kVAr C=6.25kVAr) which is not the same recorded at this point in the test because the 10Hp motor load is on in Zone 3. Gen-set A1 has picked up the motor load and supporting Load Bank 6 with approximately 13.5kW (A=3.4kW B=8kW C=2.1kW).

Load Bank 3 increased slightly to 25.25kW (A=8.62kW B=8.27kW C=8.36kW) + j6.53kVAr (A=2..27kVAr B=2.2kVAr C=2.06kVAr). This slight load increase is a result from a voltage rise in the microgrid, shown in Figure 16q, from approximately 268.5V on A-phase, 268.5V on B-phase and 268.5V on C-phase when islanded to 283V on A-phase, 279V on B-phase and 279.5V on C-phase at Meter 3 when connected to the utility grid.

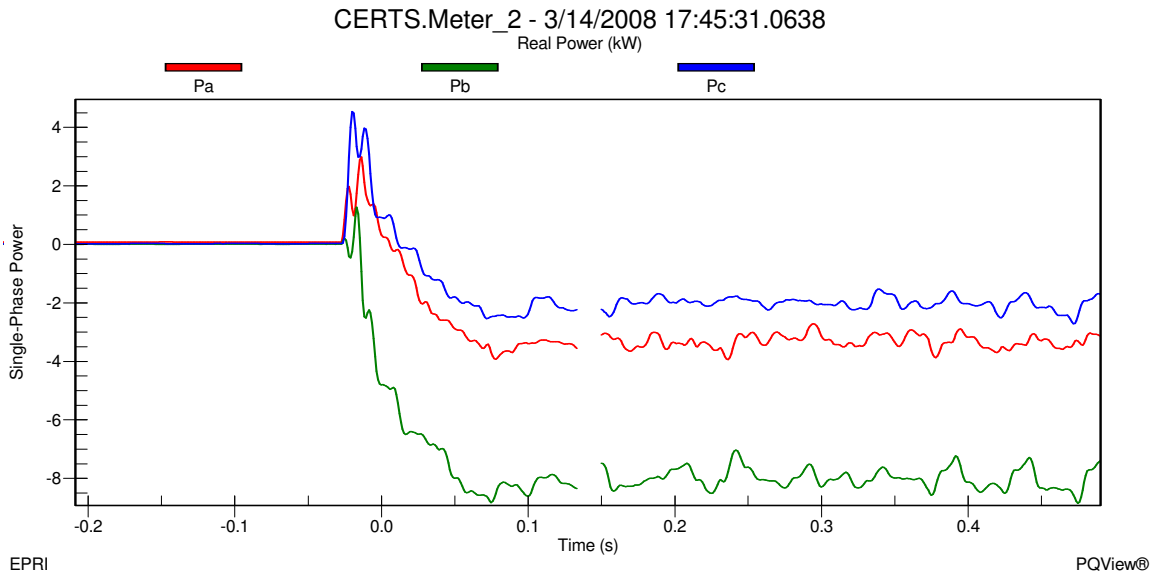

Figure 16o - Static Switch Real Single-Phase Power during Island to Utility Connected mode for Test 10.3.20

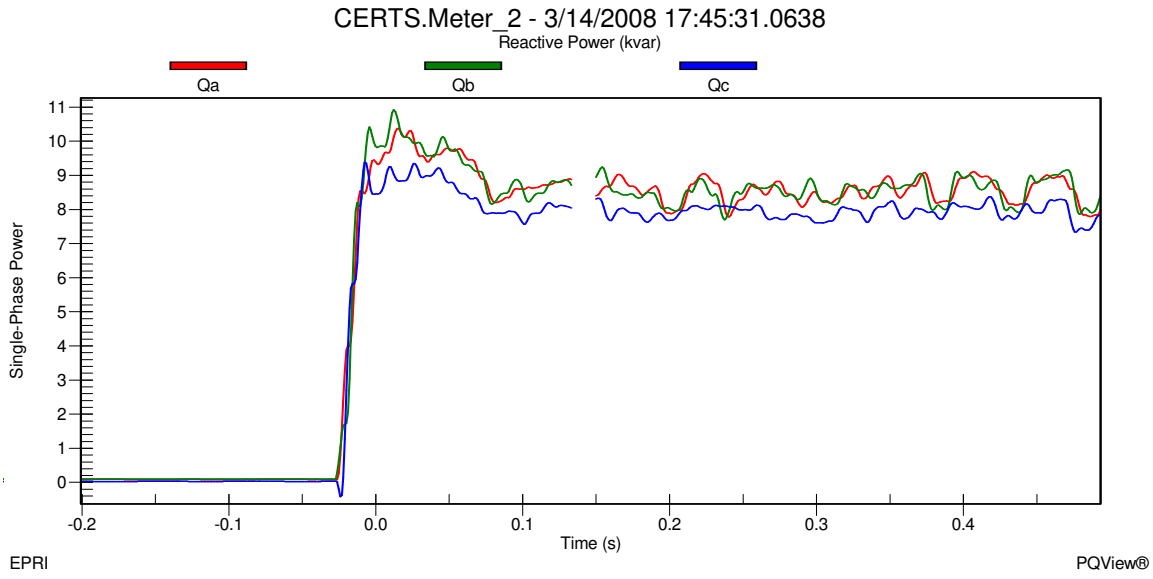

Figure 16p - Static Switch Reactive Single-Phase Power during Island to Utility Connected mode for Test 10.3.20

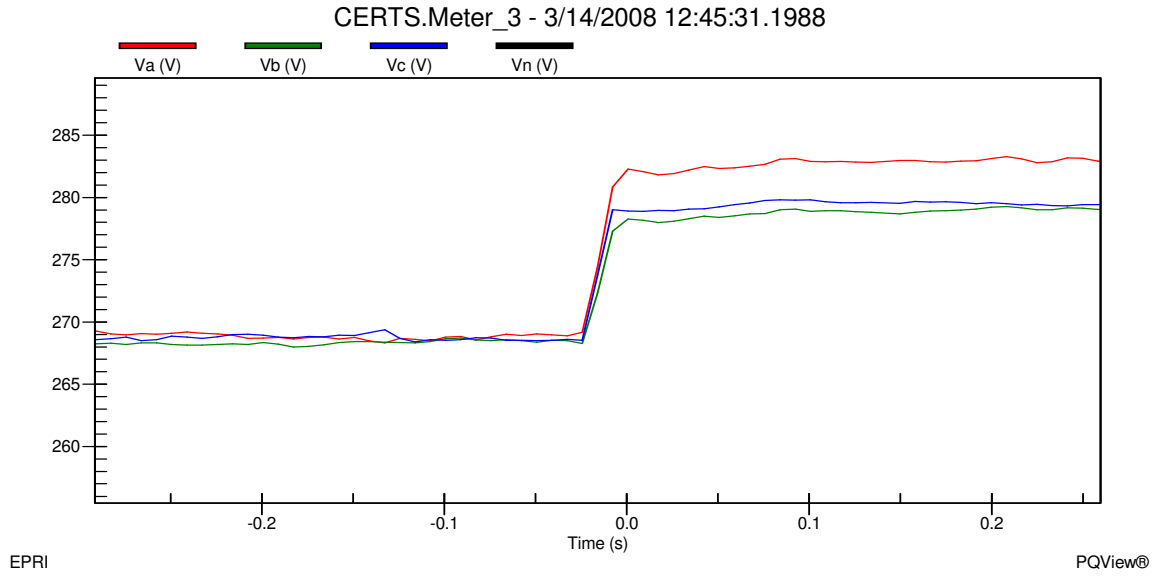

Figure 16q - Meter 3 Line-to-Ground Voltages during Island to Utility Connected mode for Test 10.3.20

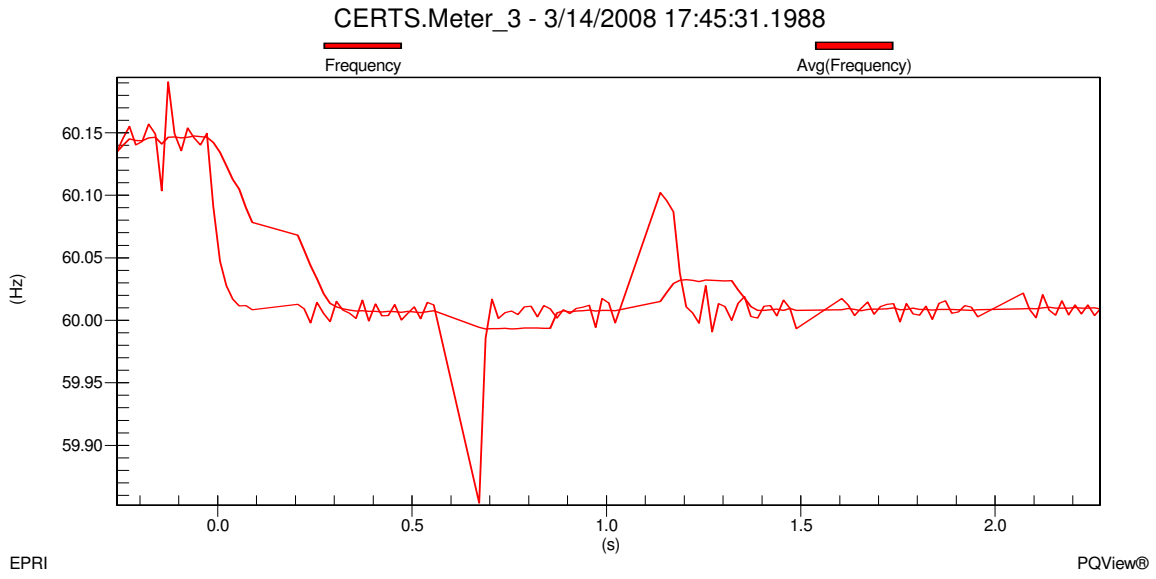

Figure 16r - Static Switch Frequency during Island to Utility Connected mode for Test 10.3.20

Frequency change in the microgrid, shown in Figure 16r, decreased from approximately 60.14Hz when islanded to approximately 60.01Hz when connected to the utility grid. This change in frequency is due to the frequency no longer being established by the Gen-set using the CERTS algorithm but by the utility. Gen-set A1 is in zone power control mode therefore when the static switch closed back into the utility Gen-set A1 produced real power based on set-points for the power flow through Zone 3 initialized at the beginning of the test. The real power increased from its initial value at the beginning of the test to approximately 41.3kW (A=12.8kW B=17.5kW C=11kW) for Gen-set A1. This increase is because Gen-set A1 has picked up the real power of the induction motor in Zone 3. Reactive power for Gen-set A1 was relatively close to the value at the beginning of the test with approximately –j12.6kVAr (A=-4.6kVAr B=-4.2kVAr C=-3.8kVAr). After all the data was verified and recorded into the DAS Database, the motor, Gen-set A1, and Load Banks 3 and 6 were turned off.

6.1.3 Unbalanced Load Tests, Weak Grid, 0.9 Power Factor

Performance Goal:

Verify and document power flow, Micro-grid frequency changes and protection design with different Gen-set settings during changes of unbalanced load in Load Banks. Continue tests with additional reduction of unbalanced load during an islanded mode of operation.

Three tests were completed in this section with each test event and settings listed in Table 9. During each test Gen-sets A1 and A2 were both set for either unit or zone

power control mode of operation. Each of the three tests varied the output power command set-point in each Gen-set, along with varying the load settings in load banks LB3, LB4 and LB6. During each test, inductor L11 was in series with the utility grid to simulate a weak grid condition at the PCC to the microgrid.

Test Event	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
10.4.12	Unit +40kW	Unit +30kW	+20kW	-20kW	-20kW	+10kW	10kW	40kW	40kW
10.4.14	Unit +40kW	0kW	+10kW	-30kW	-30kW	0kW	10kW	0kW	40kW
10.3.17	Zone - 20kW	0kW	+20kW	-20kW	-20kW	0kW	20kW	0kW	40kW

Table 9 -Unbalance Load Test, Weak Grid, settings of Gen-sets and Load Banks

The procedure for each test event began with setting the kW and kVAr (i.e., balanced load) conditions, as indicated in Table 9. Before loads were brought on-line, Gen-sets A1 and A2 or just Gen-set A1 depending on the test setup, were started to allow them to warm up. After the Gen-sets ran for a few minutes and steady-state conditions established, the loads were brought on-line, the static switch was allowed to close, and measurements were taken from Meters 1, 2, 3 and 4. The measurements were then compared with the expected values in Table 9. When the measured values coincided with the expected values from the table, then the A-phase load was reduced by 50% in Load Banks 3, 4 and 6. When all measurements were verified and recorded in the DAS Database for before and after the A-phase reduction, the manual open signal to the static switch was initiated. Gen-sets were observed at this time to make sure they increased or decreased their output power as planned to satisfy the loads at load banks (i.e., LB3, LB4 and LB6) and that a smooth transition occurred. Frequency on the microgrid is also observed for an increase or decrease depending on the Gen-set and load settings. When all measurement were verified and recorded in the DAS Database, the A-phase load was reduced by another 50% (i.e., 75% from balanced load value) in Load Banks 3, 4 and 6. The measurement were verified and recorded into the DAS Database and then the A-phase load was reduced by 100% (i.e., zero load in A-phase) in Load Banks 3, 4 and 6. After all the measurements were verified and recorded into the DAS Database, the manual static switch "Open" condition was released and allowed to self synchronize and reclose into the utility with the unbalanced load. All data (i.e., from the manual open event and the reconnection event) was verified and recorded into the DAS Database. Loads, power control set-points and operation modes were then changed to the settings for the next test. Test results are explained in the following paragraphs.

For Test 10.4.12 the measured values, after the Gen-sets were warmed up and load banks brought on-line with the A-phase in Load Banks 3 and 6 reduced by 50% are provided in Table 10.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	40.35	31.8	4.8	-25.2	-28	2.7	9	35.945	29.9
1 Phase kW	A=11.8 B=15.75 C=12.8	A=9.5 B=12.1 C=10.1	A=-0.4 B=0.5 C=4.7	A=-6.6 B=-11.4 C=-7.2	A=-7.5 B=-12.8 C=-7.7	A=2.4 B=-1 C=1.3	A=1.8 B=3.61 C=3.59	A=12.15 B=11.92 C=11.875	A=6.1 B=11.9 C=11.9
3 Phase kVAr	-12.55	-4	21.7	21.45	15.9	4.2	-0.028	0.635	0.569
1 Phase kVAr	A=-5.3 B=-3.25 C=-4	A=-2 B=-1 C=-1	A=8.6 B=6.2 C=6.9	A=8.75 B=6 C=6.7	A=7.2 B=4 C=4.7	A=2 B=1.1 C=1.1	A=0.0028 B=-0.003 C=-0.027	A=0.244 B=0.236 C=0.175	A=0.108 B=0.234 C=0.227

Table 10 - Measured Values after Start Up for Test 10.4.12 and Load Banks 3 and 6 A-phase Reduced by 50%

These measurements were relatively close to the expected values, but not exact due to temperature, phase voltages and electrical losses in conductors. At the time of the measurements, the voltage and frequency was 281.6V on A-phase, 279.1V on B-phase and 278.6V on C-phase and 59.98Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 282V on A-phase, 280V on B-phase and 279.4V on C-phase and 59.98Hz at Meter 3.

The Gen-sets in this test were set up to produce more power than Load Banks 3 and 4 needed which approximately 25.2kW (A=6.6kW B=11.4kW C=7.2kW) of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 29.9kW (A=6.1kW B=11.9kW C=11.9kW) + j0.569kVAr (A=0.108kVAr B=0.234kVAr C=0.227kVAr), the utility had to supply approximately 4.8kW (A=-0.4kW B=0.5kW C=4.7kW) to satisfy the load in Load Bank 6. Reactive power had to be imported in from the utility of approximately j21.45kVAr (A=8.75kVAr B=6kVAr C=6.7kVAr) because of Gen-set A1 and A2 needed approximately j16.55kVAr

(A=7.3kVAr B=4.25kVAr C=5kVAr) between both and the reactive power absorbed in the electrical lines.

Very soon after the A-phase in Load Banks 3 and 6 were reduced by 50%, the static switch tripped on a reverse power condition shown in Figure 17a isolating the CERTS microgrid from the utility grid. The static switch was reset and started with a manual open and all data was verified and recorded into the DAS Database. Table 11 shows the measured values after the static switch was open.

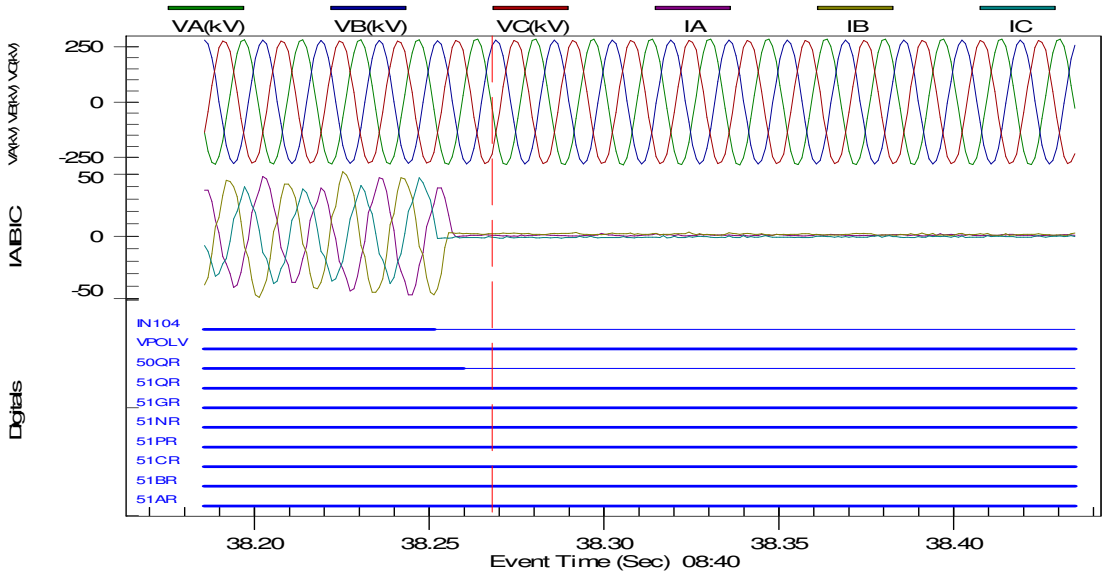

Figure 17a - Relay 2 (Static Switch) Tripping on a Reverse Power Condition

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	27	18.6	30.7	0	-2.4	15.8	8.7	35.645	30.55
1 Phase kW	A=8.4 B=9.6 C=9	A=5.6 B=6.5 C=6.5	A=6.3 B=12.2 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1.2 C=-0.4	A=5.8 B=5 C=5	A=1.7 B=3.51 C=3.49	A=11.575 B=11.55 C=11.52	A=6.25 B=12.1 C=12.2
3 Phase kVAr	-2.75	7.5	0.8	0	-4	-6.9	-0.03	0.6205	0.575
1 Phase kVAr	A=-1.25	A=2.5	A=0.2	A=0	A=-1	A=-2.3	A=0.001	A=0.216	A=0.108

	B=-0.75 C=-0.75	B=2.5 C=2.5	B=0.3 C=0.3	B=0 C=0	B=-1.5 C=-1.5	B=-2.3 C=-2.3	B=-0.004 C=-0.027	B=0.2325 C=0.172	B=0.236 C=0.231

Table 11 - Measured Values after Static Switch Opened for Test 10.4.12

In Table 11, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from 4.8kW (A=-0.4kW B=0.5kW C=4.7kW) to 30.7kW (A=6.3kW B=12.2kW C=12.2kW) and reactive power decreased from j21.7kVAr (A=8.6kVAr B=6.2kVAr C=6.9kVAr) to j0.8kVAr (A=0.2kVAr B=0.3kVAr C=0.3kVAr). The change in power is because the microgrid is no longer supplying power for Load Bank 6 which was approximately 30.55kW (A=6.25kW B=12.1kW C=12.2kW) + j0.575kVAr (A=0.108kVAr B=0.236kVAr C=0.231kVAr). Load Banks 3 and 4 reduced slightly to 8.7kW (A=1.7kW B=3.51kW C=3.41kW) – j0.03kVAr (A=0.001kVAr B=-0.004kVAr C=-0.027kVAr) and 35.645kW (A=11.575kW B=11.55kW C=11.52kW) + j0.6205kVAr (A=0.216kVAr B=0.2325kVAr C=0.172kVAr), respectively. This load reduction resulted from a voltage drop in the microgrid, shown in Figure 17b, from approximately 282V on A-phase, 280V on B-phase and 279.4V on C-phase when connected to the utility grid to 275V on A-phase, 276V on B-phase and 275.2V on C-phase when islanded at Meter 3.

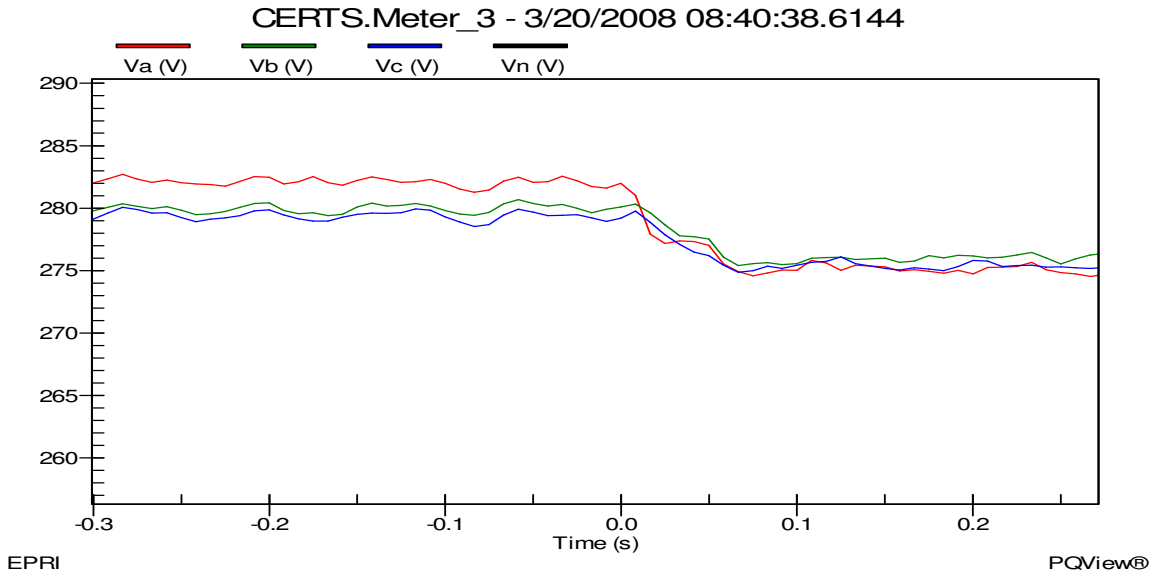

Figure 17b - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.4.12

Frequency change in the microgrid, shown in Figure 17c, increased from approximately 59.98Hz when connected to the utility grid to approximately 60.09Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed the Gen-sets

to decrease their output power to satisfy the critical load demands. Gen-sets A1 and A2 decreased their output power to approximately 27kW (A=8.4kW B=9.6kW C=9kW) – j2.75kVAr (A=-1.25kVAr B=-0.75kVAr C=-0.75kVAr) and 18.6kW (A=5.6kW B=6.5kW C=6.5kW) + j7.5kVAr (A=2.5kVAr B=2.5kVAr C=2.5kVAr), respectively. Meters 3 and 4 were approximately -2.4kW (A=-0.8kW B=-1.2kW C=-1.4kW) – j4kVAr (A=-1kVAr B=-1.5kVAr C=-1.5kVAr) and 15.8kW (A=5.8kW B=5kW C=5kW) – j6.9kVAr (A=-2.3kVAr B=-2.3kVAr C=-2.3kVAr), respectively. Negative power recorded at Meter 3 indicates that all the critical loads in the microgrid were being satisfied by Gen-sets A1 and A2. Meter 4 indicates that Gen-set A2 was not supplying enough real power for Load Bank 4 load demand and needed approximately 15.8kW (A=5.8kW B=5kW C=5kW) from Gen-set A1. All the reactive power in the critical loads was supplied by Gen-set A2 of approximately j7.5kVAr (A=2.5kVAr B=2.5kVAr C=2.5kVAr). All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 3 by 100% and A-phase in Load Bank 6 by an additional 50% (i.e., 75% from balanced load value). The measured values for the A-phase load reduction in Load Banks 3 and 6 are in Table 12.

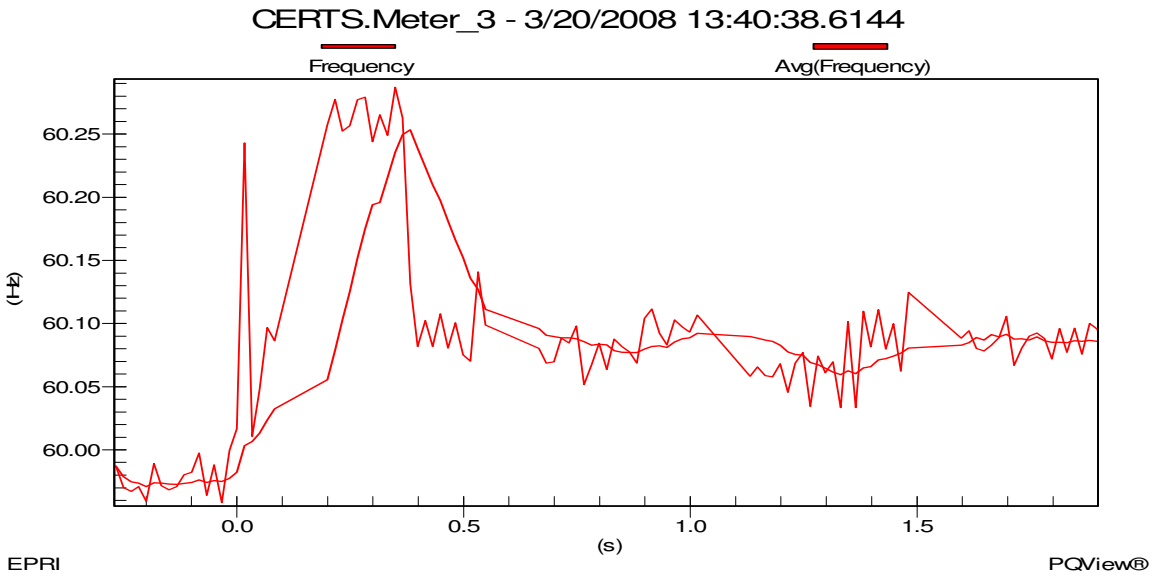

Figure 17c - Meter 3 Frequency before/after the static switch opened for Test 10.4.12

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	26.45	17.6	28.25	0	-2.475	16.75	6.99	39.2	28.1
1 Phase kW	A=7.6	A=4.8	A=3.8	A=0	A=-0.82	A=6.75	A=0	A=13.1	A=3.8

	B=9.75 C=9.1	B=6.4 C=6.4	B=12.2 C=12.25	B=0 C=0	B=-1.175 C=-0.48	B=5 C=5	B=3.5 C=3.49	B=13.1 C=13	B=12.1 C=12.2
3 Phase kVAr	-2.5	7.1	0.738	0	-4.06	-6.87	-0.0305	0.68	0.506
1 Phase kVAr	A=-1.2 B=-0.7 C=-0.6	A=2.4 B=2.4 C=2.3	A=0.07 B=0.345 C=0.323	A=0 B=0 C=0	A=-0.9 B=-1.58 C=-1.58	A=-2.25 B=-2.4 C=-2.22	A=-0.002 B=-.0025 C=-0.026	A=0.24 B=0.25 C=0.19	A=0.01 B=0.25 C=0.246

Table 12 - Measured Values with Static Switch Open and A-Phase Reduced in Load Bank 3 by 100%and Load Bank 6 by 75% for Test 10.4.12

In Table 12, Meter 1 real power decreased from approximately 30.7kW (A=6.3kW B=12.2kW C=12.2kW) to 28.25kW (A=3.8kW B=12.2kW C=12.25kW) because of the A-phase reduction in Load Bank 6 which was approximately 28.1kW (A=3.8kW B=12.1kW C=12.2kW) + j0.506kVAr (A=0.01kVAr B=0.25kVAr C=0.246kVAr). The reduction in Load Bank 3 from approximately 8.7kW (A=1.7kW B=3.51kW C=3.49kW) – j0.03kVAr (A=0.001kVAr B=-0.004kVAr C=-0.027kVAr) to 6.99kW (A=0kW B=3.5kW C=3.49kW) – j0.0305kVAr (A=-0.002kVAr B=-0.0025kVAr C=-0.026kVAr) caused the frequency to increase within the microgrid from approximately 60.09Hz to 60.13Hz. The increase in frequency is part of the CERTS algorithm which caused the Gen-sets to decrease their power level outputs due to the decrease in the A-phase load demand of Load Bank 3. Gen-set A1 decreased from approximately 27kW (A=8.4kW B=9.6kW C=9kW) – j2.75kVAr (A=-1.25kVAr B=-0.75kVAr C=-0.75kVAr) to 26.45kW (A=7.6kW B=9.75kW C=9.1kW) – j2.5kVAr (A=-1.2kVAr B=-0.7kVAr C=-0.6kVAr) and Gen-set A2 decreased from approximately 18.6kW (A=5.6kW B=6.5kW C=6.5kW) + j7.5kVAr (A=2.5kVAr B=2.5kVAr C=2.5kVAr) to 17.6kW (A=4.8kW B=6.4kW C=6.4kW) + j7.1kVAr (A=2.4kVAr B=2.4kVAr C=2.3kVAr). Since both Gen-sets decreased their real power outputs, power being supplied by Gen-set A1 to Load Bank 4 load demand increased from approximately 15.8kW (A=5.8kW B=5kW C=5kW) to 16.75kW (A=6.75kW B=5kW C=5kW) measured by Meter 4. The voltage within the microgrid during these measurements was approximately 275.7V on A-phase, 276.2V on B-phase and 274.9V on C-phase.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 4 by 75%. The measured values for the A-phase load reduction for Load Bank 4 are in Table 13.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	22.6	13.45	28.25	0	-2.52	12.75	7	29.2	28.1
1 Phase kW	A=4.2 B=9.7 C=8.7	A=0.25 B=6.6 C=6.6	A=3.8 B=12.2 C=12.25	A=0 B=0 C=0	A=-0.875 B=-1.17 C=-0.475	A=3.25 B=4.8 C=4.7	A=0 B=3.6 C=3.4	A=3.5 B=13.1 C=12.6	A=3.8 B=12.1 C=12.2
3 Phase kVAr	-3	7.4	0.738	0	-3.92	-7.08	-0.0293	0.43	0.506
1 Phase kVAr	A=-1.4 B=-1.3 C=-0.3	A=2.25 B=3.1 C=2.05	A=0.07 B=0.345 C=0.323	A=0 B=0 C=0	A=-0.8 B=-1.62 C=-1.5	A=-2.3 B=-2.82 C=-1.96	A=-.0019 B=-.0019 C=-.0255	A=0 B=0.25 C=0.18	A=0.01 B=0.25 C=0.246

Table 13 - Measured Values with Static Switch Open and A-Phase Reduced in Load Bank 4 by 75% for Test 10.4.12

In Table 13, Meter 4 real power decreased from approximately 16.75kW (A=6.75kW B=5kW C=5kW) to 12.75kW (A=3.25kW B=4.8kW C=4.7kW) because of the A-phase reduction in Load Bank 4 which was approximately 29.2kW (A=3.5kW B=13.1kW C=12.6kW) + j0.43kVAr (A=0kVAr B=0.25kVAr C=0.18kVAr). The reduction in Load Bank 4 caused the frequency to increase within the microgrid from approximately 60.13Hz to 60.14Hz. The increase in frequency is part of the CERTS algorithm which caused the Gen-sets to decrease their power level output due to the decrease in the A-phase load demand of Load Bank 4. Gen-set A1 decreased from approximately 26.45kW (A=7.6kW B=9.75kW C=9.1kW) – j2.5kVAr (A=-1.2kVAr B=-0.7kVAr C=-0.6kVAr) to 22.6kW (A=4.2kW B=9.7kW C=8.7kW) – j3kVAr (A=-1.4kVAr B=-1.3kVAr C=-0.3kVAr) and Gen-set A2 decreased from approximately 17.6kW (A=4.8kW B=6.4kW C=6.4kW) + j7.1kVAr (A=2.4kVAr B=2.4kVAr C=2.3kVAr) to 13.45kW (A=0.25kW B=6.6kW C=6.6kW) + j7.4kVAr (A=2.25kVAr B=3.1kVAr C=2.05kVAr). The voltage within the microgrid during these measurements was approximately 276.7V on A-phase, 277.6V on B-phase and 272.8V on C-phase. Load Bank 6 load demands was not changed at this time, therefore, all the measured values for Load Bank 6, Meter 1 and Meter 2 did not change from the previous load reduction in Load Banks 3 and 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6 by 100%. The measured values for the A-phase load reduction for Load Bank 6 are in Table 14.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	22.45	13.5	24.31	0	-2.515	12.65	7	26.35	24.1
1 Phase kW	A=4.25 B=9.5 C=8.7	A=0.25 B=6.5 C=6.75	A=0.1 B=12.1 C=12.11	A=0 B=0 C=0	A=-0.86 B=-1.18 C=-0.475	A=3.3 B=4.75 C=4.6	A=0 B=3.6 C=3.4	A=3.5 B=11.5 C=11.25	A=0 B=12.1 C=12.2
3 Phase kVAr	-2.65	7	0.79	0	-3.92	-6.7	-0.0273	0.45	0.509
1 Phase kVAr	A=-1.3 B=-1.05 C=-0.3	A=2.4 B=2.7 C=1.9	A=0.09 B=0.35 C=0.35	A=0 B=0 C=0	A=-0.8 B=-1.62 C=-1.5	A=-2.2 B=-2.75 C=-1.75	A=-.0015 B=-.0013 C=-.0245	A=0 B=0.26 C=0.19	A=0 B=0.255 C=0.254

Table 14 - Measured Values with Static Switch Open and A-Phase Reduced in Load Bank 6 by 100% for Test 10.4.12

In Table 14, Meter 1 real power decreased from approximately 28.25kW (A=3.8kW B=12.2kW C=12.25kW) to 24.31kW (A=0.1kW B=12.1kW C=12.11kW) because of the A-phase reduction in Load Bank 6 which was approximately 24.1kW (A=0kW B=12kW C=12.1kW) + j0.509kVAr (A=0kVAr B=0.255kVAr C=0.254kVAr). Voltages and frequencies remained the same in both the utility and microgrid when Load Bank 6 A-phase was reduced to 0kW because nothing changed in the CERTS microgrid downstream of the static switch and the utility is a stiff system.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 4 by 100%. The measured values for the A-phase load reduction for Load Bank 4 are in Table 15.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	20.8	11.65	24.31	0	-2.54	11	7.1	22.6	24.1
1 Phase	A=2.6	A=-1.75	A=0.1	A=0	A=-0.91	A=1.6	A=0	A=0	A=0

kW	B=9.5 C=8.7	B=6.7 C=6.7	B=12.1 C=12.11	B=0 C=0	B=-1.17 C=-0.46	B=4.8 C=4.6	B=3.7 C=3.4	B=11.5 C=11.1	B=12 C=12.1
3 Phase kVAr	-2.95	7.07	0.79	0	-4.125	-7.28	-0.0303	0.43	0.509
1 Phase kVAr	A=-1.4 B=-1.45 C=-0.1	A=2.39 B=3 C=1.68	A=0.09 B=0.35 C=0.35	A=0 B=0 C=0	A=-0.975 B=-1.64 C=-1.51	A=-2.41 B=-3.22 C=-1.65	A=-.0013 B=-0.004 C=-0.025	A=0 B=0.25 C=0.18	A=0 B=0.255 C=0.254

Table 15 - Measured Values with Static Switch Open and A-Phase Reduced in Load Bank 4 by 100% for Test 10.4.12

In Table 15, Meter 4 real power decreased from approximately 12.65kW (A=3.3kW B=4.75kW C=4.6kW) to 11kW (A=1.6kW B=4.8kW C=4.6kW) because of the A-phase reduction in Load Bank 4 which was approximately 22.6kW (A=0kW B=11.5kW C=11.1kW) + j0.43kVAr (A=0kVAr B=0.25kVAr C=0.18kVAr). The reduction in Load Bank 4 caused the frequency to increase within the microgrid from approximately 60.14Hz to 60.15Hz. The increase in frequency is part of the CERTS algorithm which caused the Gen-sets to decrease their power level output due to the decrease in the A-phase load demand of Load Bank 4. Gen-set A1 decreased from approximately 22.45kW (A=4.25kW B=9.5kW C=8.7kW) – j2.65kVAr (A=-1.3kVAr B=-1.05kVAr C=-0.3kVAr) to 20.8kW (A=2.6kW B=9.5kW C=8.7kW) – j2.95kVAr (A=-1.4kVAr B=-1.45kVAr C=-0.1kVAr) and Gen-set A2 decreased from approximately 13.5kW (A=0.25kW B=6.5kW C=6.75kW) + j7kVAr (A=2.4kVAr B=2.7kVAr C=1.9kVAr) to 11.65kW (A=-1.75kW B=6.7kW C=6.7kW) + j7.07kVAr (A=2.39kVAr B=3.kVAr C=1.68kVAr). The voltage within the microgrid during these measurements was approximately 276.9V on A-phase, 278.4V on B-phase and 271.1V on C-phase. Load Bank 6 load demands was not changed at this time, therefore, all the measured values for Load Bank 6, Meter 1 and Meter 2 did not change from the previous load reduction in Load Banks 3 and 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize and close back into the utility grid. Shortly after the static switch closed back into the utility it tripped on a reverse power due to the A-phase on Load Banks 3, 4 and 6 equaling 0kW shown in Figure 17d. The measured values are provided in Table 16.

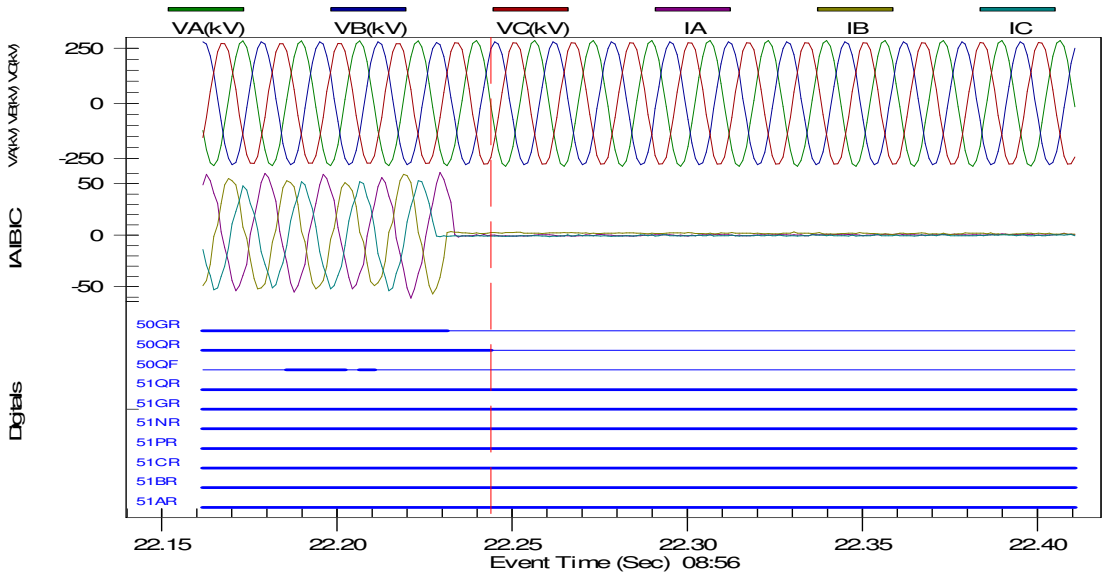

Figure 17d - Relay 2 (Static Switch) Reverse Power Condition Trip for Test 10.4.12

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
Before Static Switch Synchronization and Close									
3 Phase kW	20.6	11.5	24	0	-2.5	11.1	7	22.7	24
1 Phase kW	A=2.6 B=9.5 C=8.5	A=-1.6 B=6.6 C=6.5	A=0 B=12 C=12	A=0 B=0 C=0	A=-1 B=-1.2 C=-0.3	A=1.7 B=4.9 C=4.5	A=0 B=3.6 C=3.4	A=0 B=11.6 C=11.1	A=0 B=12 C=12
3 Phase kVAr	-2.8	7.15	0.9	0	-4.25	-7.2	-0.028	0.454	0.519
1 Phase kVAr	A=-1.3 B=-1.3 C=-0.2	A=2.25 B=3.2 C=1.7	A=0.1 B=0.4 C=0.4	A=0 B=0 C=0	A=-1 B=-1.75 C=-1.5	A=-2.4 B=-3.2 C=-1.6	A=-0.002 B=-0.001 C=-0.025	A=0 B=0.26 C=0.194	A=0 B=0.26 C=0.259
Static Switch Synchronized and Closed									
3 Phase kW	38.9	30.3	-12.5	-36.7	-39.5	-7.3	7.35	23.55	23.5
1 Phase kW	A=8.4 B=17	A=4.7 B=14.1	A=-12.5 B=-5	A=-12.4 B=-14.8	A=-13.3 B=-16.1	A=-4.8 B=-2.5	A=0 B=3.75	A=0 B=11.8	A=0 B=11.8

	C=13.5	C=11.5	C=5	C=-9.5	C=-10.1	C=0	C=3.6	C=11.75	C=11.7
3 Phase kVAr	-13.3	-5.15	23.7	23	17.6	4.2	-0.0306	0.461	0.506
1 Phase kVAr	A=-5.1 B=-3.1 C=-5.1	A=-2.5 B=-2.9 C=0.25	A=8.8 B=4.7 C=10.2	A=8.7 B=4.5 C=9.8	A=7.3 B=2.5 C=7.8	A=2.4 B=-1 C=2.8	A=-0.001 B=-.0033 C=-.0263	A=0 B=0.26 C=0.2	A=0 B=0.256 C=0.25
Static Switch After Reverse Power Condition Trip									
3 Phase kW	20.6	11.5	24	0	-2.5	11.2	7	22.6	24
1 Phase kW	A=2.5 B=9.6 C=8.5	A=-1.6 B=6.6 C=6.5	A=0 B=12 C=12	A=0 B=0 C=0	A=-1 B=-1.2 C=-0.3	A=1.7 B=4.9 C=4.6	A=0 B=3.6 C=3.4	A=0 B=11.5 C=11.1	A=0 B=12 C=12
3 Phase kVAr	-2.8	7.15	0.9	0	-4.25	-7.2	-0.0303	0.45	0.519
1 Phase kVAr	A=-1.3 B=-1.3 C=-0.2	A=2.25 B=3.2 C=1.7	A=0.1 B=0.4 C=0.4	A=0 B=0 C=0	A=-1 B=-1.75 C=-1.5	A=-2.4 B=-3.2 C=-1.6	A=-.0019 B=-.0039 C=-.0245	A=0 B=0.26 C=0.19	A=0 B=0.26 C=0.259

Table 16 - Measured Values before/after Static Switch Synchronized and Closed back into the utility and after Static Switch Tripped on Reverse Power Condition for Test 10.4.12

Voltage and frequency in the microgrid increased from approximately 276.5V on A-phase, 278.4V on B-phase and 271.5V on C-phase and 60.15Hz when islanded to 282.9V on A-phase, 281V on B-phase and 278.1V on C-phase and 59.99Hz when utility connected at Meter 3 shown in Figures 17e and 17f. This change in frequency is due to the frequency no longer being established by the Gen-set using the CERTS algorithm but by the utility. Gen-sets A1 and A2 are in unit power control mode therefore when the static switch closed back into the utility the Gen-sets produced real power based on the set-point initialized at the beginning of the test. The output power for both Gen-sets were relatively close to the value at the beginning of the test with Gen-set A1 producing approximately 38.9kW (A=8.4kW B=17kW C=13.5kW) – j13.3kVAr (A=-5.1kVAr B=-3.1kVAr C=-5.1kVAr) and Gen-set A2 producing approximately 30.3kW (A=4.7kW B=14.1kW C=11.5kW) – j5.15kVAr (A=-2.5kVAr B=-2.9kVAr C=0.25kVAr).

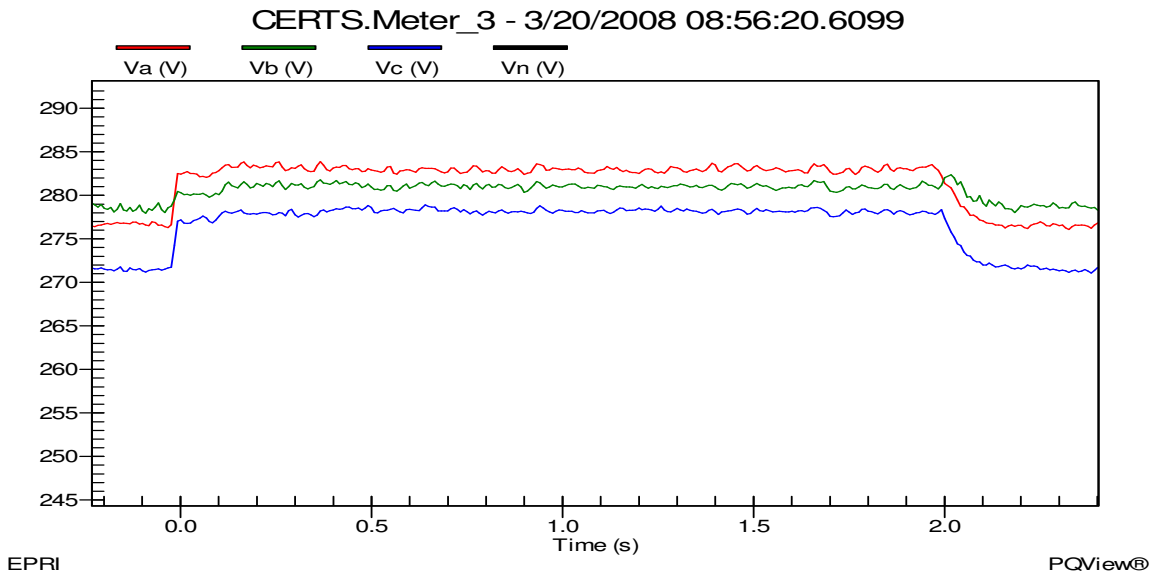

Figure 17e - Meter 3 Line-to-Ground Voltages during Islanded to Utility Connected mode for Test 10.4.12

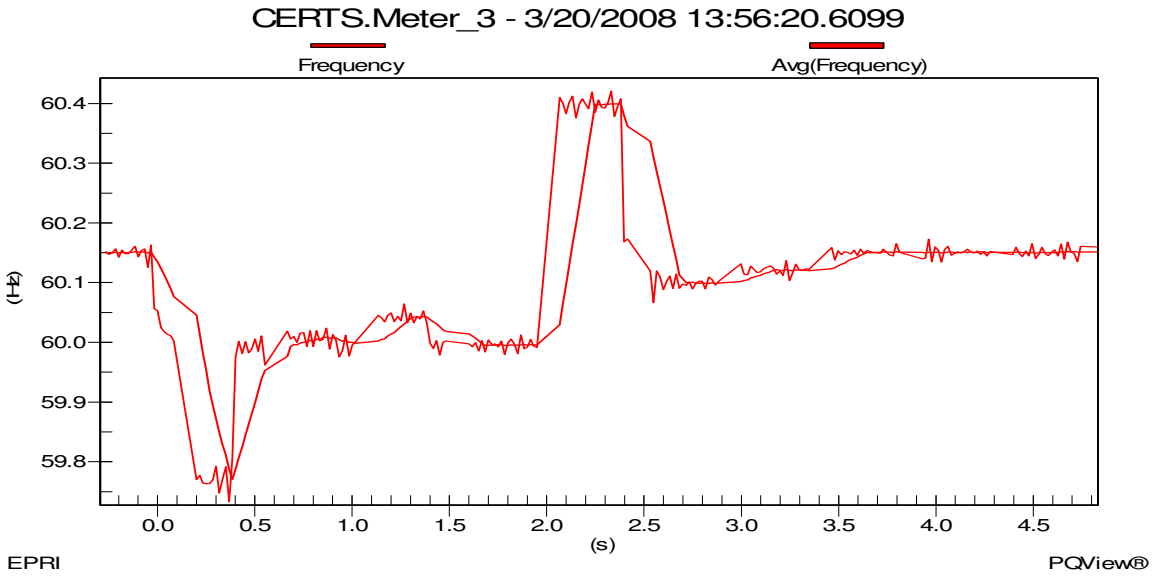

Figure 17f - Meter 3 Frequency during Islanded to Utility Connected mode for Test 10.4.12

Meter 2 recorded real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -36.7kW (A=-12.4kW B=-14.8kW C=-9.5kW) and reactive power increasing

from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to j23kVAr (A=8.7kVAr B=4.5kVAr C=9.8kVAr) after the static switch closed shown in Figure 17g. Gen-sets A1 and A2 were producing power for all the critical loads in the microgrid and approximately 36.7kW (A=12.4kW B=14.8kW C=9.5kW) of Load Bank 6 load demands. Load Bank 6 was approximately 23.5kW (A=0kW B=11.8kW C=11.7kW) + j0.506kVAr (A=0kVAr B=0.256kVAr C=0.25kVAr) which is less than the power supplied by Gen-set A1 and A2 and Meter 1 recorded -12.5kW (A=-12.5kW B=-5kW C=5kW) being exported to the utility. This caused a reverse power condition which opened the static switch in 2.0 seconds islanding the CERTS microgrid from the utility grid shown in Figure 17h.

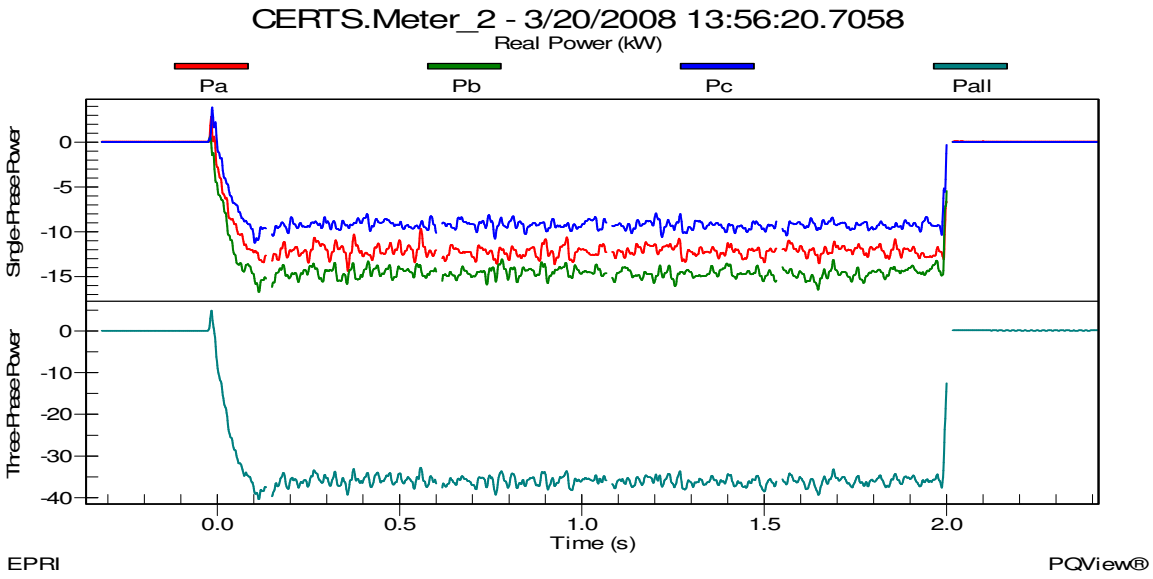

Figure 17g - Static Switch Real Power during Islanded to Utility Connected mode for Test 10.4.12

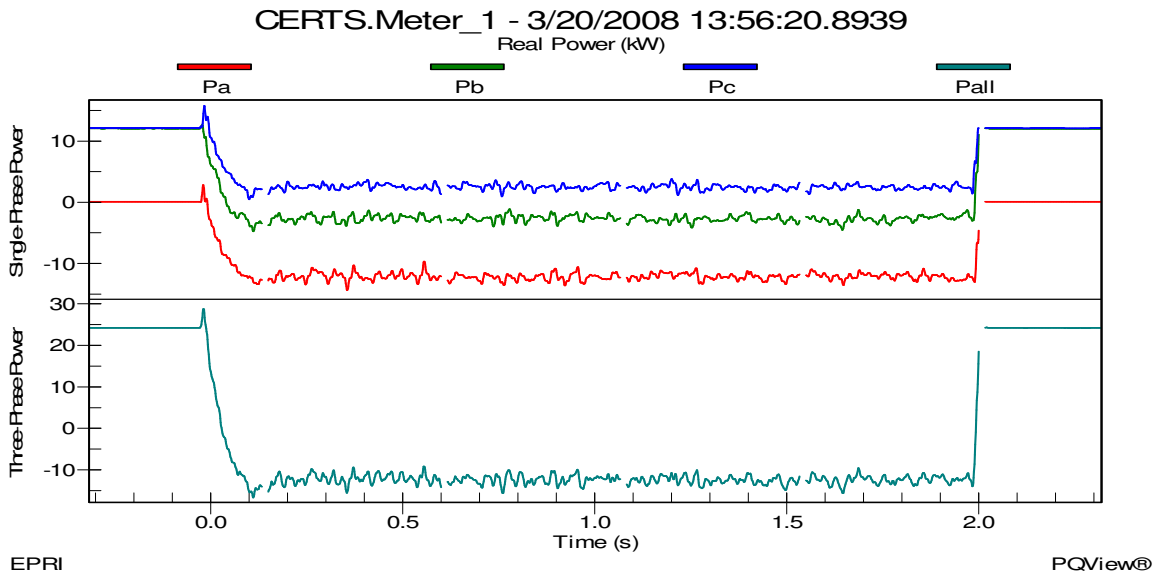

Figure 17h - Meter 1 Real Power during Islanded to Utility Connected mode for Test 10.4.12

In Table 16 after the static switch opened due to the reverse trip condition, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from approximately -12.5kW (A=-12.5kW B=-5kW C=5kW) to 24kW (A=0kW B=12kW C=12kW) and reactive power decreased from approximately j23.7kVAr (A=8.8kVAr B=4.7kVAr C=10.2kVAr) to j0.9kVAr (A=0.1kVAr B=0.4kVAr C=0.4kVAr). The change in power is because the microgrid is no longer supplying power for the load demands of Load Bank 6 which was approximately 24kW (A=0kW B=12kW C=12kW) + j0.519kVAr (A=0kVAr B=0.26kVAr C=0.259kVAr).

The power produced by the Gen-sets were very similar to the measured values before the static switch manual open was released which was approximately 20.6kW (A=2.5kW B=9.6kW C=8.5kW) – j2.8kVAr (A=-1.3kVAr B=-1.3kVAr C=-0.2kVAr) for Gen-set A1 and 11.5kW (A=-1.6kW B=6.6kW C=6.5kW) + j7.15kVAr (A=2.25kVAr B=3.2kVAr C=1.7kVAr) for Gen-set A2. Also, the voltage and frequency returned to measured values before the static switch manual open was released which was 276.5V on A-phase, 278.8V on B-phase and 271.4V on C-phase and 60.15Hz. After all the data was verified and recorded into the DAS Database the Gen-sets and Load Banks set-points were changed according to the next test (10.4.14) in Table 9.

For Test 10.4.14 the measured values after Gen-set A1 was warmed up and load banks brought on-line with the A-phase in Load Banks 3 and 6 reduced by 50% are provided in Table 17.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	38.2	0	3.85	-26	-29.1	0	9.1	0	30.2
1 Phase kW	A=10.3 B=15.8 C=12.1	A=0 B=0 C=0	A=-1.5 B=1.25 C=4.1	A=-7.5 B=-10.7 C=-7.8	A=-8.5 B=-12.1 C=-8.5	A=0 B=0 C=0	A=1.8 B=3.68 C=3.62	A=0 B=0 C=0	A=6.2 B=12 C=12
3 Phase kVAr	-15.75	0	22.65	22.1	15.75	0	-0.024	0	0.82
1 Phase kVAr	A=-6.4 B=-4.25 C=-5.1	A=0 B=0 C=0	A=8.3 B=6.75 C=7.6	A=8.2 B=6.5 C=7.4	A=6.4 B=4.25 C=5.1	A=0 B=0 C=0	A=0.003 B=-0.003 C=-0.024	A=0 B=0 C=0	A=0.15 B=0.35 C=0.32

Table 17 - Measured Values after Start Up for Test 10.4.14 and Load Banks 3 and 6 A-phase Reduced by 50%

These measurements were relatively close to the expected values, but not exact due to temperature, phase voltages and electrical losses in conductors. At the time of the measurements, the voltage and frequency was 284.2V on A-phase, 281V on B-phase and 280.2V on C-phase and 60.00Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 284.8V on A-phase, 281.8V on B-phase and 281V on C-phase and 60.00Hz at Meter 3.

Gen-set A1 in this test was set up to produce more power than Load Bank 3 needed which approximately 26kW (A=7.5kW B=10.7kW C=7.8kW) of excess power was exported through the static switch to Load Bank 6. Since Load Bank 6 was approximately 30.2kW (A=6.2kW B=12kW C=12kW) + j0.82kVAr (A=0.15kVAr B=0.35kVAr C=0.32kVAr), the utility had to supply approximately 3.85kW (A=-1.5kW B=1.25kW C=4.1kW) to satisfy the load demands of Load Bank 6. Reactive power had to be imported in from the utility of approximately j22.1kVAr (A=8.2kVAr B=6.5kVAr C=7.4kVAr) because Gen-set A1 needed approximately j15.75kVAr (A=6.4kVAr B=4.25kVAr C=5.1kVAr) and the reactive power absorbed in the electrical lines.

Very soon after the A-phase in Load Banks 3 and 6 were reduced by 50%, the static switch tripped on a reverse power condition shown in Figure 18a isolating the CERTS microgrid from the utility grid. The static switch was reset and started with a manual

open and all data was verified and recorded into the DAS Database. Table 18 shows the measured values after the static switch was open.

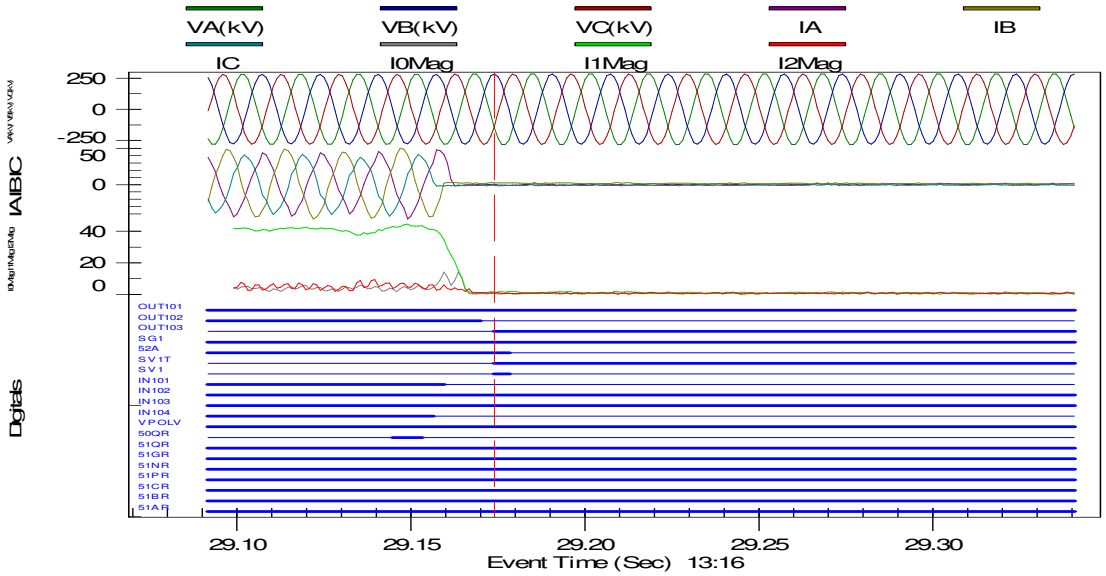

Figure 18a - Relay 2 (Static Switch) Tripping on a Reverse Power Condition for Test 10.4.14

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	11	0	30.9	0	-2.4	0	8.5	0	30.7
1 Phase kW	A=2.5 B=4.6 C=3.9	A=0 B=0 C=0	A=6.5 B=12.2 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1.1 C=-0.5	A=0 B=0 C=0	A=1.65 B=3.45 C=3.4	A=0 B=0 C=0	A=6.3 B=12.2 C=12.2
3 Phase kVAr	3.9	0	0.95	0	-3.6	0	-0.024	0	0.82
1 Phase kVAr	A=0.9 B=1.5 C=1.5	A=0 B=0 C=0	A=0.25 B=0.4 C=0.3	A=0 B=0 C=0	A=-0.8 B=-1.4 C=-1.4	A=0 B=0 C=0	A=0.0015 B=-0.003 C=-.0225	A=0 B=0 C=0	A=0.15 B=0.35 C=0.32

Table 18 - Measured Values after Static Switch Opened for Test 10.4.14

In Table 18, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from 3.85kW (A=-1.5kW B=1.25kW C=4.1kW) to 30.9kW

(A=6.5kW B=12.2kW C=12.2kW) and reactive power decreased from j22.65kVAr (A=8.3kVAr B=6.75kVAr C=7.6kVAr) to j0.95kVAr (A=0.25kVAr B=0.4kVAr C=0.3kVAr). The change in power is because the microgrid is no longer supplying power for Load Bank 6 which was approximately 30.7kW (A=6.3kW B=12.2kW C=12.2kW) + j0.82kVAr (A=0.15kVAr B=0.35kVAr C=0.32kVAr). Load Bank 3 reduced slightly to 8.5kW (A=1.65kW B=3.45kW C=3.4kW) – j0.024kVAr (A=0.0015kVAr B=-0.003kVAr C=-0.0225kVAr). This load reduction resulted from a voltage drop in the microgrid, shown in Figure 18b, from approximately 284.8V on A-phase, 281V on B-phase and 280.2V on C-phase when connected to the utility grid to 273V on A-phase, 272.5V on B-phase and 271.5V on C-phase when islanded at Meter 3.

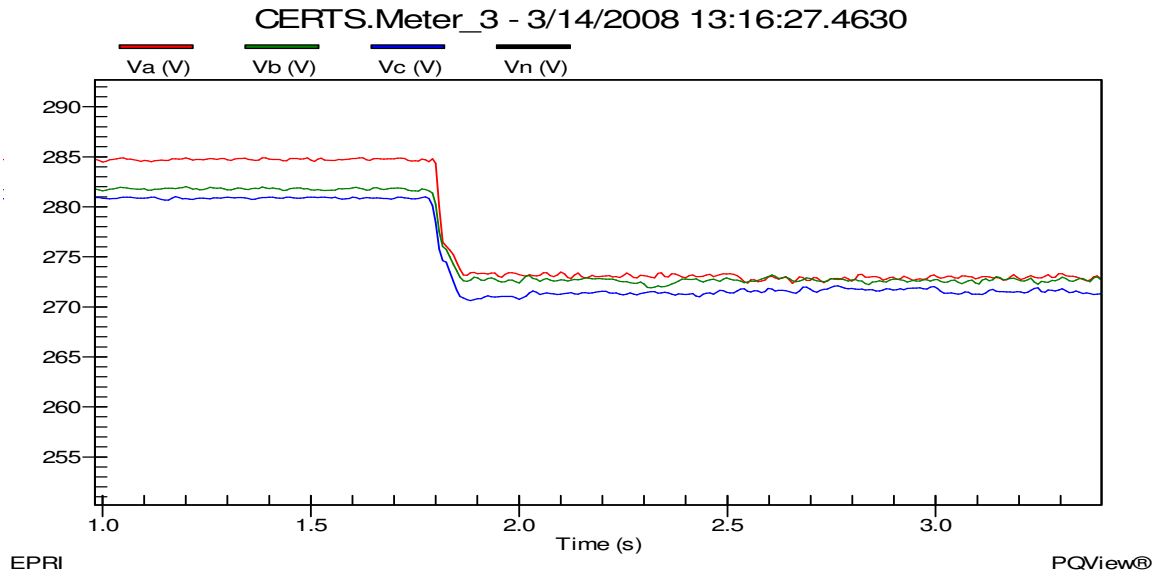

Figure 18b - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.4.14

Frequency change in the microgrid, shown in Figure 18c, increased from approximately 60.00Hz when connected to the utility grid to approximately 60.24Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the critical load demands. Gen-set A1 decreased its real output power to approximately 11kW (A=2.5kW B=4.6kW C=3.9kW) and increased its reactive output power to approximately j3.9kVAr (A=0.9kVAr B=1.5kVAr C=1.5kVAr) to satisfy the critical loads. Note the sign change from negative to positive for Gen-set A1 reactive power when the microgrid is isolated from the utility. This sign change is due to the utility no longer supplying the reactive power for the critical loads but by Gen-set A1. Meter 3 was approximately -2.4kW (A=-0.8kW B=-1.1kW C=-0.5kW) – j3.6kVAr (A=-0.8kVAr B=-1.4kVAr C=-1.4kVAr). Negative power recorded at Meter 3 indicates that all the critical loads in the microgrid were being satisfied by Gen-set A1. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6

by 50% (i.e., 75% from balanced load value). The measured values for the A-phase load reduction in Load Bank 6 are in Table 19.

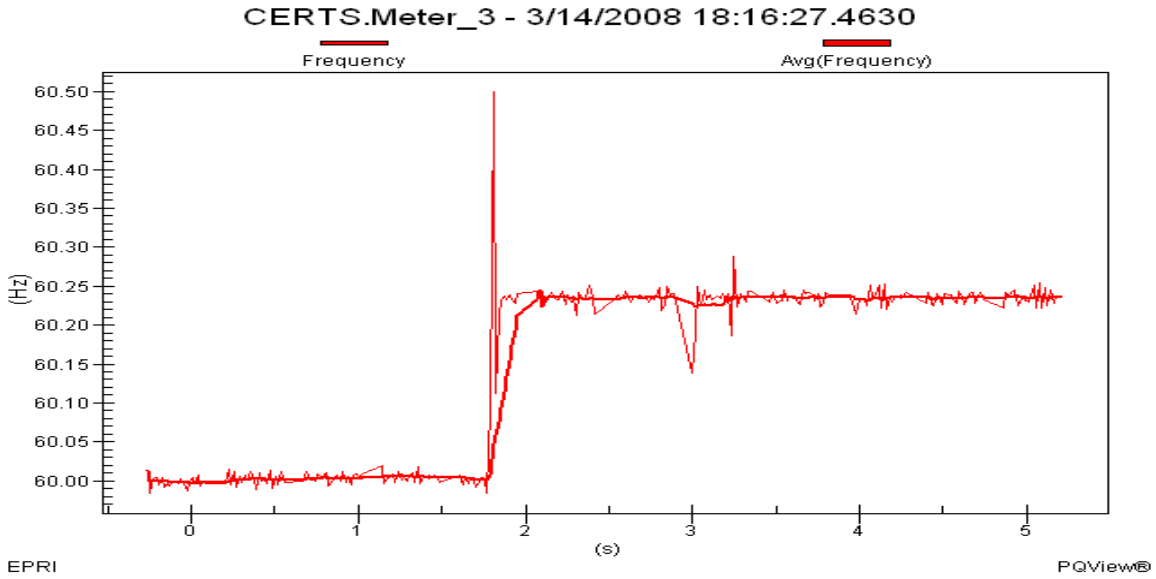

Figure 18c - Meter 3 Frequency Before/After the Static Switch Opened for Test 10.4.14

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	10.9	0	28.18	0	-2.405	0	8.465	0	28
1 Phase kW	A=2.4 B=4.7 C=3.8	A=0 B=0 C=0	A=3.9 B=12.08 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1.13 C=-0.475	A=0 B=0 C=0	A=1.65 B=3.425 C=3.39	A=0 B=0 C=0	A=3.8 B=12 C=12.2
3 Phase kVAr	3.695	0	0.8	0	-3.725	0	-0.02	0	0.52
1 Phase kVAr	A=0.88 B=1.425 C=1.39	A=0 B=0 C=0	A=0.08 B=0.37 C=0.35	A=0 B=0 C=0	A=-0.875 B=-1.43 C=-1.42	A=0 B=0 C=0	A=0.001 B=-0.001 C=-0.02	A=0 B=0 C=0	A=-0.01 B=0.269 C=0.261

Table 19 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 6 by 75% for Test 10.4.14

In Table 19, Meter 1 real power decreased from approximately 30.9kW (A=6.5kW B=12.2kW C=12.2kW) to 28.18kW (A=3.9kW B=12.08kW C=12.2kW) because of the A-

phase reduction in Load Bank 6 which was approximately 28kW (A=3.8kW B=12kW C=12.2kW) + j0.52kVAr (A=-0.01kVAr B=0.269kVAr C=0.261kVAr). Voltages and frequencies remained the same in both the utility and microgrid when Load Bank 6 A-phase was reduced to 3.8kW because nothing changed in the CERTS microgrid downstream of the static switch and the utility is a stiff system.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 3 by 100%. The measured values for the A-phase reduction for Load Bank 3 are in Table 20.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	9.25	0	28.18	0	-2.4	0	6.86	0	28
1 Phase kW	A=0.75 B=4.7 C=3.8	A=0 B=0 C=0	A=3.9 B=12.08 C=12.2	A=0 B=0 C=0	A=-0.82 B=-1.12 C=-0.46	A=0 B=0 C=0	A=0 B=3.48 C=3.38	A=0 B=0 C=0	A=3.8 B=12 C=12.2
3 Phase kVAr	3.63	0	0.8	0	-3.7	0	-0.02	0	0.52
1 Phase kVAr	A=0.87 B=1.39 C=1.37	A=0 B=0 C=0	A=0.08 B=0.37 C=0.35	A=0 B=0 C=0	A=-0.87 B=-1.45 C=-1.38	A=0 B=0 C=0	A=0.001 B=-0.001 C=-0.02	A=0 B=0 C=0	A=-0.01 B=0.269 C=0.261

Table 20 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 3 by 100% for Test 10.4.14

In Table 20, Load Bank 3 was approximately 6.86kW (A=0kW B=3.48kW C=3.48kW) – j0.02kVAr (A=0.001kVAr B=-0.001kVAr C=-0.02kVAr) after the A-phase was reduced by 100%. The reduction in Load Bank 3 caused the frequency to increase within the microgrid from approximately 60.24Hz to 60.25Hz. The increase in frequency is part of the CERTS algorithm which caused Gen-set A1 to decrease its power level output due to the decrease in the A-phase load demand of Load Bank 3. Gen-set A1 decreased from approximately 10.9kW (A=2.4kW B=4.7kW C=3.8kW) + j3.695kVAr (A=0.88kVAr B=1.425kVAr C=1.39kVAr) to 9.25kW (A=0.75kW B=4.7kW C=3.8kW) + j3.63kVAr (A=0.87kVAr B=1.39kVAr C=1.37kVAr). The voltage within the microgrid during these measurements was approximately 273.5V on A-phase, 273.5V on B-phase and 270.1V on

C-phase. Load Bank 6 load demands were not changed at this time, therefore, all the measured values for Load Bank 6, Meter 1 and Meter 2 did not change from the previous load reduction in Load Bank 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6 by 100%. The measured values for the A-phase load reduction for Load Bank 6 are in Table 21.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	9.1	0	24.33	0	-2.4	0	6.87	0	24.2
1 Phase kW	A=0.6 B=4.7 C=3.8	A=0 B=0 C=0	A=0 B=12.08 C=12.25	A=0 B=0 C=0	A=-0.82 B=-1.12 C=-0.46	A=0 B=0 C=0	A=0 B=3.49 C=3.38	A=0 B=0 C=0	A=0 B=12 C=12.2
3 Phase kVAr	3.66	0	0.78	0	-3.69	0	-0.0255	0	0.54
1 Phase kVAr	A=0.86 B=1.44 C=1.36	A=0 B=0 C=0	A=0.08 B=0.35 C=0.35	A=0 B=0 C=0	A=-0.87 B=-1.44 C=-1.38	A=0 B=0 C=0	A=-0.002 B=-0.003 C=-.0205	A=0 B=0 C=0	A=-0.01 B=0.26 C=0.27

Table 21 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 6 by 100% for Test 10.4.14

In Table 21, Meter 1 real power decreased from approximately 28.33kW (A=4kW B=12.08kW C=12.25kW) to 24.33kW (A=0kW B=12.08kW C=12.25kW) because of the A-phase reduction in Load Bank 6 which was approximately 24.2kW (A=0kW B=12kW C=12.2kW) + j0.54kVAr (A=0.01kVAr B=0.26kVAr C=0.27kVAr). Voltages and frequencies remained the same in both the utility and microgrid when Load Bank 6 A-phase was reduced to 0kW because nothing changed in the CERTS microgrid downstream of the static switch and the utility is a stiff system.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize and close back into the utility grid. Shortly after

the static switch closed back into the utility it tripped on a reverse power due to the A-phase on Load Banks 3 and 6 equaling 0kW shown in Figure 18d. The measured values are provided in Table 22.

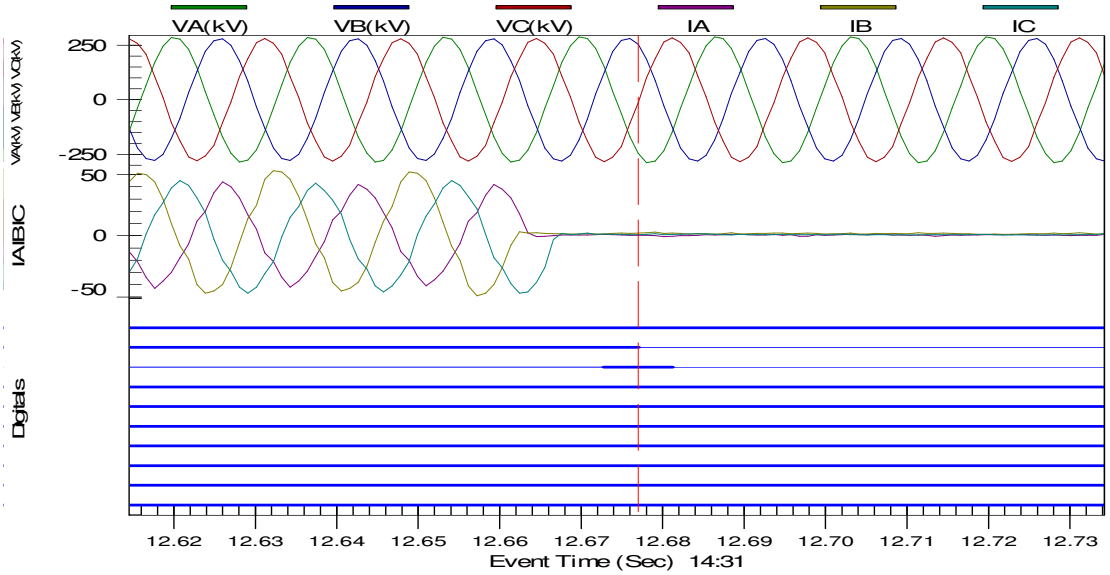

Figure 18d - Relay 2 (Static Switch) Tripping on a Reverse Power Condition during Island to Utility Connected mode for Test 10.4.14

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
Before Static Switch Synchronization and Close									
3 Phase kW	9.4	0	24.4	0	-2.2	0	6.87	0	24.2
1 Phase kW	A=1 B=4.5 C=3.9	A=0 B=0 C=0	A=0 B=12.2 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1 C=-0.4	A=0 B=0 C=0	A=0 B=3.47 C=3.4	A=0 B=0 C=0	A=0 B=12 C=12.2
3 Phase kVAr	3.7	0	1	0	-3.5	0	-0.027	0	0.533
1 Phase kVAr	A=0.8 B=1.5 C=1.4	A=0 B=0 C=0	A=0.1 B=0.5 C=0.4	A=0 B=0 C=0	A=-0.8 B=-1.4 C=-1.3	A=0 B=0 C=0	A=-0.002 B=-0.003 C=-0.022	A=0 B=0 C=0	A=0.001 B=0.269 C=0.263
Static Switch Synchronized and Closed									

3 Phase kW	39.05	0	-4.95	-29	-32	0	7.45	0	23.9
1 Phase kW	A=8.8 B=17.25 C=13	A=0 B=0 C=0	A=-7.9 B=-0.25 C=3.2	A=-7.9 B=-12.4 C=-8.7	A=-8.8 B=-13.8 C=-9.4	A=0 B=0 C=0	A=0 B=3.75 C=3.7	A=0 B=0 C=0	A=0 B=12 C=11.9
3 Phase kVAr	-16.15	0	22.95	22.5	16.35	0	-0.027	0	0.53
1 Phase kVAr	A=-6.2 B=-3.75 C=-6.2	A=0 B=0 C=0	A=7.9 B=6.25 C=8.8	A=8 B=6 C=8.5	A=6.3 B=3.75 C=6.3	A=0 B=0 C=0	A=-0.002 B=-0.003 C=-0.022	A=0 B=0 C=0	A=0.001 B=0.269 C=0.26
Static Switch After Reverse Power Condition Trip									
3 Phase kW	9.4	0	24.4	0	-2.2	0	6.87	0	24.2
1 Phase kW	A=1 B=4.5 C=3.9	A=0 B=0 C=0	A=0 B=12.2 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1 C=-0.34	A=0 B=0 C=0	A=0 B=3.47 C=3.4	A=0 B=0 C=0	A=0 B=12 C=12.2
3 Phase kVAr	3.7	0	1	0	-3.5	0	-0.027	0	0.533
1 Phase kVAr	A=0.8 B=1.5 C=1.4	A=0 B=0 C=0	A=0.1 B=0.5 C=0.4	A=0 B=0 C=0	A=-0.8 B=-1.4 C=-1.3	A=0 B=0 C=0	A=-0.002 B=-0.003 C=-0.022	A=0 B=0 C=0	A=0.001 B=0.269 C=0.263

Table 22 - Measured Values before/after Static Switch Synchronized and Closed back into the utility and after Static Switch Tripped on Reverse Power Condition for Test 10.4.14

Voltage and frequency in the microgrid increased from approximately 273.4V on A-phase, 273.4V on B-phase and 270.1V on C-phase and 60.13Hz when islanded to 285.25V on A-phase, 282V on B-phase and 280.4V on C-phase and 60.00Hz when utility connected at Meter 3 shown in Figures 18e and 18f. This change in frequency is due to the frequency no longer being established by Gen-set A1 using the CERTS algorithm but by the utility. Gen-set A1 is in unit power control mode therefore when the static switch closed back into the utility the Gen-set produced real power based on the set-point initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the value at the beginning of the test with Gen-set A1 producing approximately

39.05kW (A=8.8kW B=17.25kW C=13kW) – j16.15kVAr (A=-6.2kVAr B=-3.75kVAr C=-6.2kVAr).

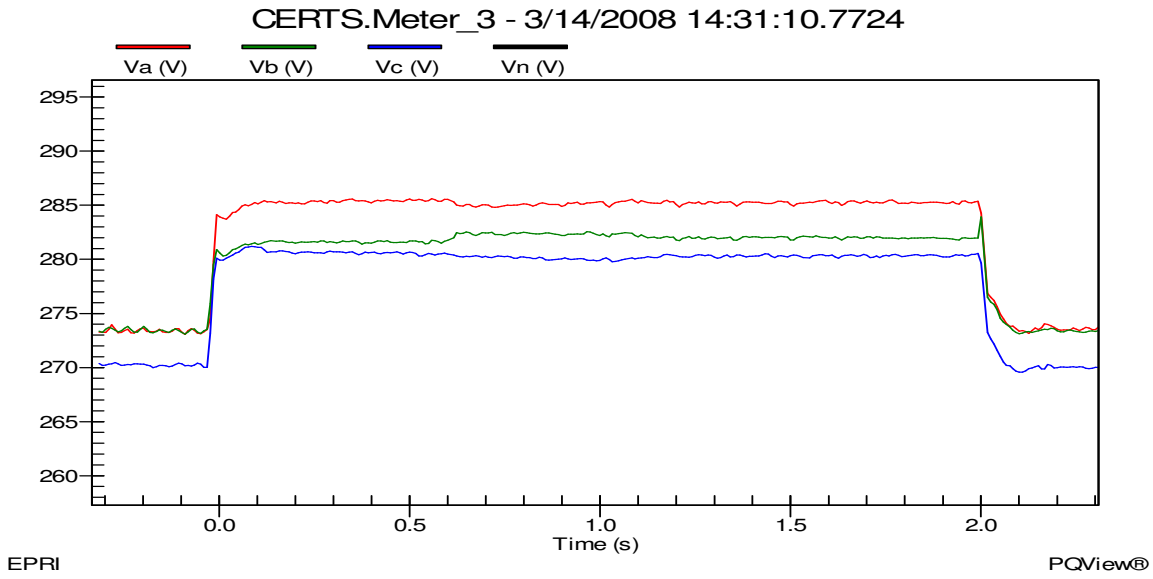

Figure 18e - Meter 3 Line-to-Ground Voltages during Islanded to Utility Connected mode for Test 10.4.14

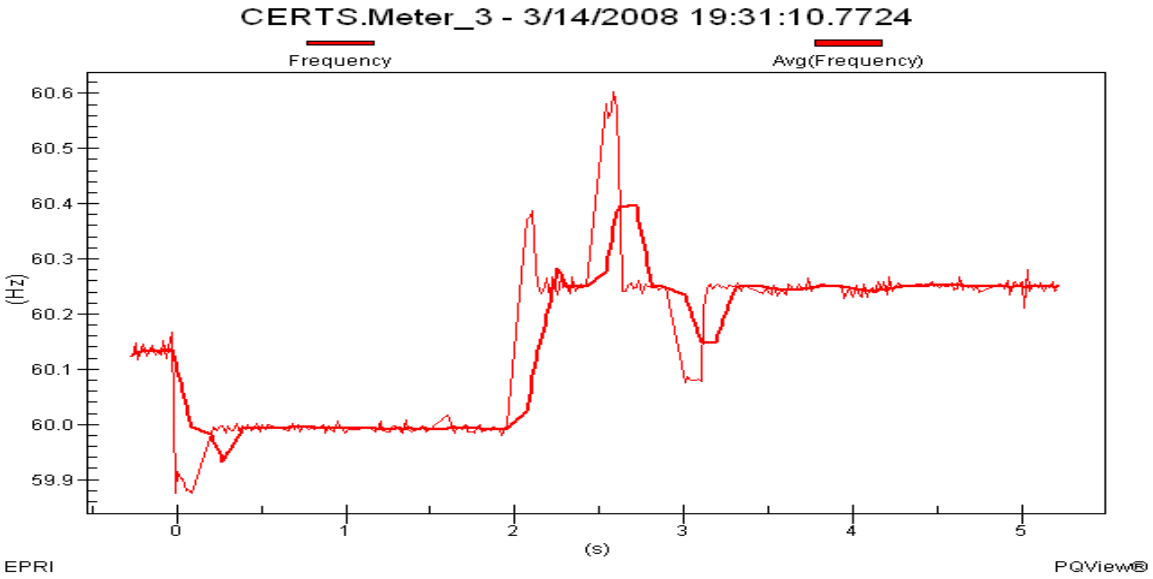

Figure 18f - Meter 3 Frequency during Islanded to Utility Connected mode for Test 10.4.14

Meter 2 recorded real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -29kW (A=-7.9kW B=-12.4kW C=-8.7kW) and reactive power increasing from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to j22.5kVAr (A=8kVAr B=6kVAr C=8.5kVAr) after the static switch closed shown in Figure 18g. Gen-set A1 was

producing power for all the critical loads in the microgrid and approximately 29kW (A=7.9kW B=12.4kW C=8.7kW) of Load Bank 6 load demands. Load Bank 6 was approximately 23.9kW (A=0kW B=12kW C=11.9kW) + j0.53kVAr (A=0.001kVAr B=0.269kVAr C=0.26kVAr) which is less than the power supplied by Gen-set A1 and Meter 1 recorded -4.95kW (A=-7.9kW B=-0.25kW C=3.2kW) being exported to the utility. This caused a reverse power condition which opened the static switch in 2.0 seconds islanding the CERTS microgrid from the utility grid shown in Figure 18h.

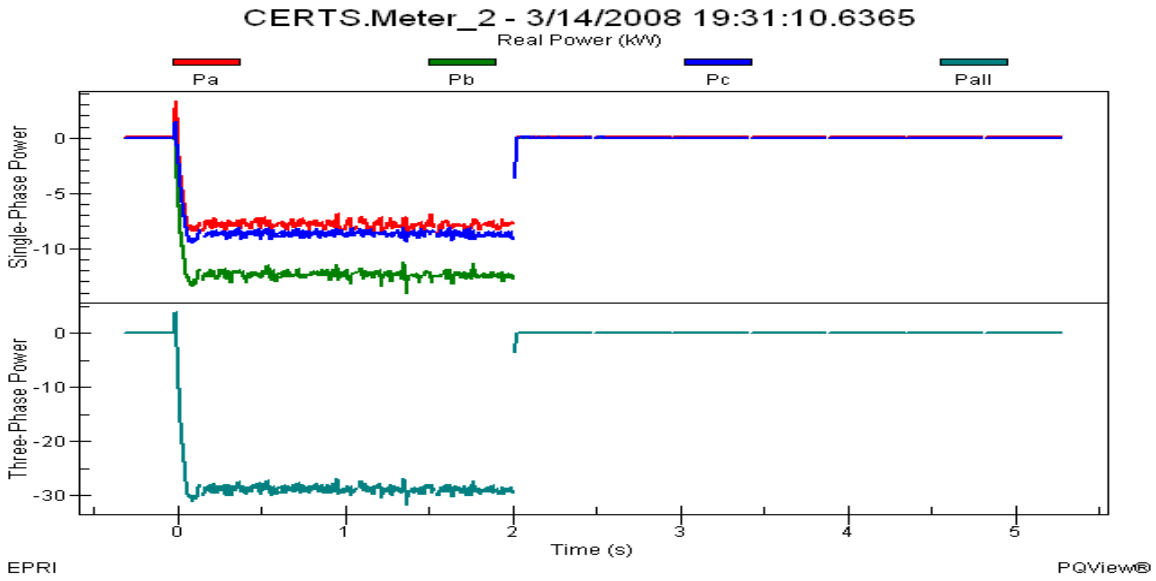

Figure 18g - Static Switch Real Power during Islanded to Utility Connected mode for Test 10.4.14

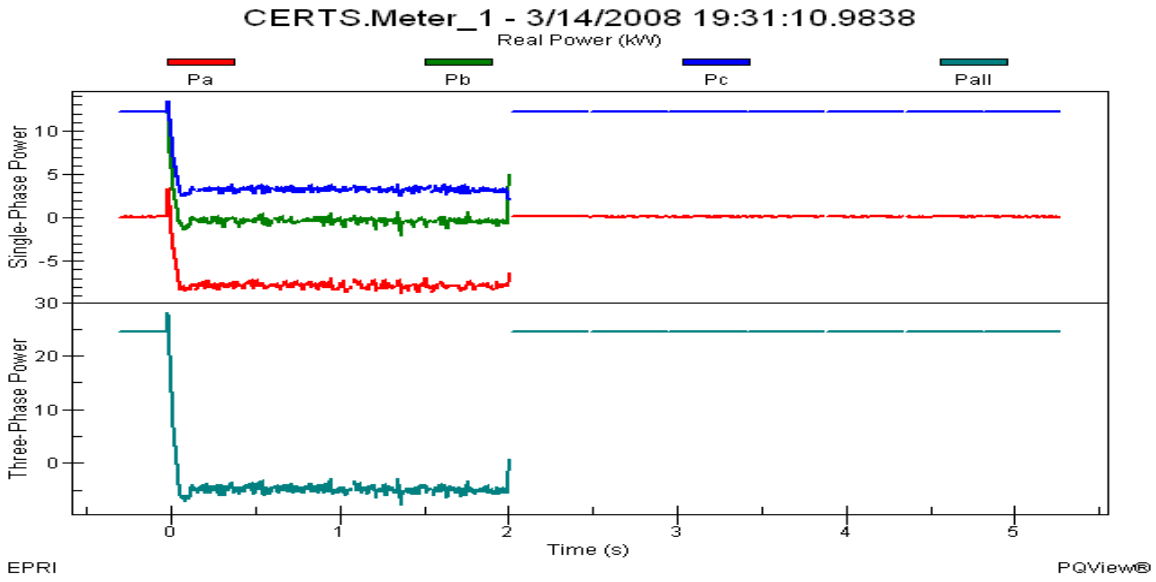

Figure 18h - Meter 1 Real Power during Islanded to Utility Connected mode for Test 10.4.14

In Table 22 after the static switch opened due to the reverse trip condition, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from approximately -4.95kW (A=-7.9kW B=-0.25kW C=3.2kW) to 24.4kW (A=0kW B=12.2kW C=12.2kW) and reactive power decreased from approximately j22.95kVAr (A=7.9kVAr B=6.25kVAr C=8.8kVAr) to j1kVAr (A=0.1kVAr B=0.5kVAr C=0.4kVAr). The change in power is because the microgrid is no longer supplying power for the load demands of Load Bank 6 which was approximately 24.2kW (A=0kW B=12kW C=12.2kW) + j0.533kVAr (A=0.001kVAr B=0.269kVAr C=0.263kVAr).

The power produced by the Gen-set was very similar to the measured value before the static switch manual open was released which was approximately 9.4kW (A=1kW B=4.5kW C=3.9kW) + j3.7kVAr (A=0.8kVAr B=1.5kVAr C=1.4kVAr) for Gen-set A1. Also, the voltage and frequency returned to measured values before the static switch manual open was released which was 273.4V on A-phase, 273.4V on B-phase and 270V on C-phase and 60.25Hz. After all the data was verified and recorded into the DAS Database the Gen-sets and Load Banks set-points were changed according to the next test (10.4.17) in Table 9.

For Test 10.4.17 the measured values, after Gen-set A1 was warmed up and load banks brought on-line with the A-phase in Load Bank 3 reduced by 50% are provided in Table 23.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	32	0	22.8	-13.15	-16.4	0	16.03	0	36.05
1 Phase kW	A=9.5 B=12.7 C=9.8	A=0 B=0 C=0	A=7.1 B=6.7 C=9	A=-4.7 B=-5.25 C=-3.2	A=-6 B=-6.5 C=-3.9	A=0 B=0 C=0	A=3.75 B=6.18 C=6.1	A=0 B=0 C=0	A=12.25 B=11.9 C=11.9
3 Phase kVAr	-14.85	0	22.16	21	14.9	0	0.183	0	0.77
1 Phase kVAr	A=-4.4 B=-4.25 C=-6.2	A=0 B=0 C=0	A=8.15 B=6.6 C=7.4	A=7.75 B=6.5 C=6.75	A=6.1 B=4.4 C=4.4	A=0 B=0 C=0	A=-0.014 B=0.111 C=0.086	A=0 B=0 C=0	A=0.24 B=0.27 C=0.26

Table 23 - Measured Values After Start Up for Test 10.4.17 and Load Bank 3 A-phase Reduced by 50%

These measurements were relatively close to the expected values, but not exact due to temperature, phase voltages and electrical losses in conductors. At the time of the measurements, the voltage and frequency was 283.55V on A-phase, 280.4V on B-phase and 280.5V on C-phase and 60.03Hz at the static switch (i.e., Meter 2) when connected to the utility grid; and 284V on A-phase, 281V on B-phase and 281V on C-phase and 60.03Hz at Meter 3.

Gen-set A1 in this test was set up to produce -20kW going through Zone 3 (i.e., Meter 3) which means it will produce 20kW more power than Load Bank 3 needed. Approximately 16.4kW (A=6kW B=6.5kW C=3.9kW) of excess power was exported out of Zone 3 and 13.15kW (A=4.7kW B=5.25kW C=3.2kW) of that power went through the static switch to Load Bank 6 and the remaining 3.25kW (A=1.3kW B=1.25kW C=0.7kW) was due to power losses in the conductors. Since Load Bank 6 was approximately 36.05kW (A=12.25kW B=11.9kW C=11.9kW) + j0.77kVAr (A=0.24kVAr B=0.27kVAr C=0.26kVAr), the utility had to supply approximately 22.8kW (A=7.1kW B=6.7kW C=9kW) to satisfy the load. Reactive power had to be imported in from the utility of approximately j21kVAr (A=7.75kVAr B=6.5kVAr C=6.75kVAr) because Gen-set A1 needed approximately j14.85kVAr (A=4.4kVAr B=4.25kVAr C=6.2kVAr) and losses in the conductors.

All Data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6 by 50%. The measured values for the A-phase load reduction in Load Bank 6 are in Table 24.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	31.9	0	16.95	-13.1	-16.3	0	16.03	0	30
1 Phase kW	A=8 B=13.7 C=10.2	A=0 B=0 C=0	A=2.7 B=5.75 C=8.5	A=-3.4 B=-6.3 C=-3.4	A=-4.4 B=-7.7 C=-4.2	A=0 B=0 C=0	A=3.75 B=6.18 C=6.1	A=0 B=0 C=0	A=6.2 B=11.9 C=11.9
3 Phase kVAr	-14.5	0	21.86	21.19	15	0	0.183	0	0.655

1 Phase kVAr	A=-5.8 B=-3.8 C=-4.9	A=0 B=0 C=0	A=7.75 B=7.61 C=6.5	A=7.6 B=6.2 C=7.39	A=5.8 B=4 C=5.2	A=0 B=0 C=0	A=-0.014 B=0.111 C=0.086	A=0 B=0 C=0	A=0.125 B=0.27 C=0.26

Table 24 - Measured Values After Start Up for Test 10.4.17 and Load Bank 6 A-phase Reduced by 50%

In Table 24, Meter 1 real power decreased from approximately 22.8kW (A=7.1kW B=6.7kW C=9kW) to 16.95kW (A=2.7kW B=5.75kW C=8.5kW) because of the A-phase reduction in Load Bank 6 which was approximately 30kW (A=6.2kW B=11.9kW C=11.9kW) + j0.655kVAr (A=0.125kVAr B=0.27kVAr C=0.26kVAr). Voltage increased to approximately 283.9V on A-phase and 280.6V on B-phase at the static and 284.2V on A-phase and 281.2V on B-phase at Meter 3. C-phase voltage decreased to approximately 280.1V at the static switch and 280.6V at Meter 3. Frequency decreased from approximately 60.03Hz to 60.01Hz which was caused by the frequency fluctuation in the utility grid. Gen-set A1 did not change its output power level since its primary purpose is to provide 20kW through Zone 3 which is done by producing 20kW more than the load demands of Load Bank 3 which remained constant during the A-phase reduction in Load Bank 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state and then the static switch was directed by the EMS to manually open.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	17.25	0	30.95	0	-2.35	0	14.86	0	30.9
1 Phase kW	A=4.25 B=6.8 C=6.2	A=0 B=0 C=0	A=6.4 B=12.25 C=12.3	A=0 B=0 C=0	A=-0.75 B=-1.2 C=-0.4	A=0 B=0 C=0	A=3.47 B=5.75 C=5.64	A=0 B=0 C=0	A=6.4 B=12.25 C=12.25
3 Phase kVAr	4	0	2.2	0	-3.6	0	0.186	0	0.658
1 Phase kVAr	A=0.9 B=1.6 C=1.5	A=0 B=0 C=0	A=0.5 B=0.9 C=0.8	A=0 B=0 C=0	A=-0.8 B=-1.4 C=-1.4	A=0 B=0 C=0	A=-0.014 B=0.113 C=0.087	A=0 B=0 C=0	A=0.122 B=0.271 C=0.265

Table 25 - Measured Values after Static Switch Opened for Test 10.4.17

In Table 25, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from 16.6kW (A=2.6kW B=5.6kW C=8.4kW) to 30.95kW (A=6.4kW B=12.25kW C=12.3kW) and reactive power decreased from j22.55kVAr (A=7.9kVAr B=6.75kVAr C=7.9kVAr) to j2.2kVAr (A=0.5kVAr B=0.9kVAr C=0.8kVAr). The change in power is because the microgrid is no longer supplying power for Load Bank 6 which was approximately 30.9kW (A=6.4kW B=12.25kW C=12.25kW) + j0.658kVAr (A=0.122kVAr B=0.271kVAr C=0.265kVAr). Load Bank 3 reduced slightly to 14.86kW (A=3.47kW B=5.75kW C=5.64kW) + j0.186kVAr (A=-0.014kVAr B=0.113kVAr C=0.087kVAr). This load reduction resulted from a voltage drop in the microgrid, shown in Figure 19a, from approximately 284.5V on A-phase, 281.6V on B-phase and 281V on C-phase when connected to the utility grid to 273V on A-phase, 272.4V on B-phase and 270.5V on C-phase when islanded at Meter 3.

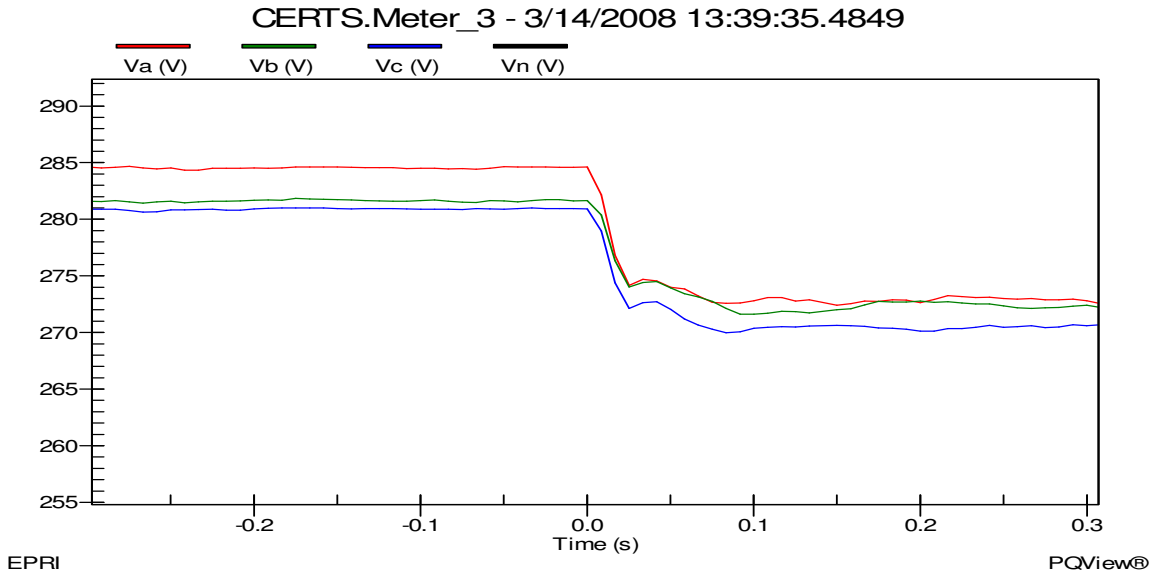

Figure 19a - Meter 3 Line-to-Ground Voltages during Utility Connected to Island mode for Test 10.4.17

Frequency change in the microgrid, shown in Figure 19b, increased from approximately 60.01Hz when connected to the utility grid to approximately 60.14Hz when islanded. This change in frequency was part of the CERTS algorithm which allowed Gen-set A1 to decrease its output power to satisfy the critical load demands. Gen-set A1 decreased its real output power to approximately 17.25kW (A=4.25kW B=6.8kW C=6.2kW) and increased its reactive output power to approximately j4kVAr (A=0.9kVAr B=1.6kVAr C=1.5kVAr) to satisfy the critical loads. Not the sign change from negative to positive for Gen-set A1 reactive power when the microgrid is isolated from the utility. This sign change is due to the utility no longer supplying the reactive power for the critical loads

but by Gen-set A1. Meter 3 was approximately -2.35kW (A=-0.75kW B=-1.2kW C=-0.4kW) – j3.6kVAr (A=-0.8kVAr B=-1.4kVAr C=-1.4kVAr). Negative power recorded at Meter 3 indicates that all the critical loads in the microgrid were being satisfied by Gen-set A1. All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6 by 50% (i.e., 75% from balanced load value). The measured values for the A-phase load reduction in Load Bank 6 are in Table 26.

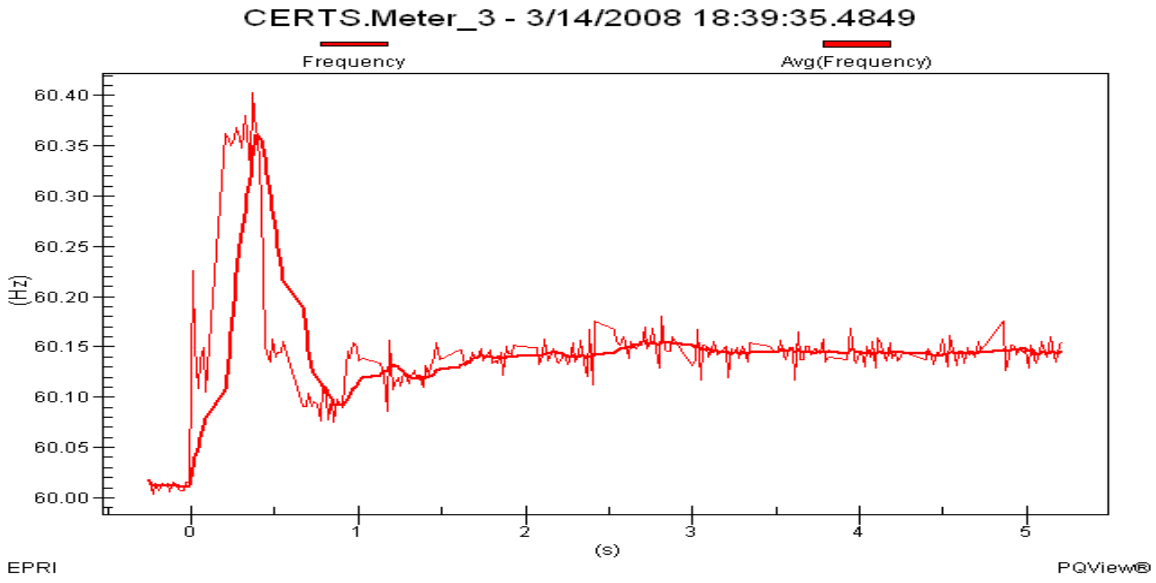

Figure 19b - Meter 3 Frequency Before/After the Static Switch Opened for Test 10.4.17

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	17.25	0	28.1	0	-2.395	0	14.75	0	27.8
1 Phase kW	A=4.25 B=6.8 C=6.2	A=0 B=0 C=0	A=3.8 B=12.1 C=12.2	A=0 B=0 C=0	A=-0.8 B=-1.125 C=-0.47	A=0 B=0 C=0	A=3.4 B=5.75 C=5.6	A=0 B=0 C=0	A=3.8 B=12 C=12
3 Phase kVAr	3.935	0	0.788	0	-3.73	0	0.215	0	0.519
1 Phase kVAr	A=0.86 B=1.55 C=1.525	A=0 B=0 C=0	A=0.078 B=0.368 C=0.342	A=0 B=0 C=0	A=-0.87 B=-1.44 C=-1.42	A=0 B=0 C=0	A=-0.01 B=0.125 C=0.1	A=0 B=0 C=0	A=0.01 B=0.268 C=0.261

Table 26 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 6 by 75% for Test 10.4.17

In Table 26, Meter 1 real power decreased from approximately 30.95kW (A=6.4kW B=12.25kW C=12.3kW) to 28.1kW (A=3.8kW B=12.1kW C=12.2kW) because of the A-phase reduction in Load Bank 6 which was approximately 27.8kW (A=3.8kW B=12kW C=12kW) + j0.519kVAr (A=-0.01kVAr B=0.268kVAr C=0.261kVAr). Voltages and frequencies remained relatively the same in both the utility and microgrid when Load Bank 6 A-phase was reduced to 3.8kW because nothing changed in the CERTS microgrid down stream of the static switch and the utility is a stiff system.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 3 by 50% (i.e., 75% from balanced load value). The measured values for the A-phase reduction for Load Bank 3 are in Table 27.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	15.5	0	28.1	0	-2.435	0	13.1	0	27.8
1 Phase kW	A=2.6 B=6.8 C=6.1	A=0 B=0 C=0	A=3.8 B=12.1 C=12.2	A=0 B=0 C=0	A=-0.84 B=-1.125 C=-0.47	A=0 B=0 C=0	A=1.75 B=5.75 C=5.6	A=0 B=0 C=0	A=3.8 B=12 C=12
3 Phase kVAr	3.93	0	0.788	0	-3.695	0	0.235	0	0.519
1 Phase kVAr	A=0.875 B=1.575 C=1.48	A=0 B=0 C=0	A=0.078 B=0.368 C=0.342	A=0 B=0 C=0	A=-0.87 B=-1.45 C=-1.375	A=0 B=0 C=0	A=0.01 B=0.125 C=0.1	A=0 B=0 C=0	A=0.01 B=0.268 C=0.261

Table 27 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 3 by 75% for Test 10.4.17

In Table 27, Load Bank 3 was approximately 13.1kW (A=1.75kW B=5.75kW C=5.6kW) + j0.235kVAr (A=0.01kVAr B=0.125kVAr C=0.1kVAr) after the A-phase was reduced by 50% (i.e., 75% from balanced load value). Gen-set A1 decreased from approximately 17.25kW (A=4.25kW B=6.8kW C=6.2kW) + j3.935kVAr (A=0.86kVAr B=1.55kVAr C=1.525kVAr) to 15.5kW (A=2.6kW B=6.8kW C=6.1kW) + j3.93kVAr (A=0.875kVAr

B=1.575kVAr C=1.48kVAr) due to the reduction of 1.65kW in the A-phase of Load Bank 3. The reduction in Load Bank 3 did not cause the frequency to increase which was approximately 60.14Hz. Voltage within the microgrid during these measurements was approximately 273V on A-phase, 273V on B-phase and 269.8V on C-phase. Load Bank 6 load demands were not changed at this time, therefore, all the measured values for Load Bank 6, Meter 1 and Meter 2 did not change from the previous load reduction in Load Bank 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 6 by 100%. The measured values for the A-phase load reduction for Load Bank 6 are in Table 28.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	15.4	0	24.3	0	-2.435	0	13.05	0	24.3
1 Phase kW	A=2.5 B=6.8 C=6.1	A=0 B=0 C=0	A=0 B=12.1 C=12.2	A=0 B=0 C=0	A=-0.84 B=-1.125 C=-0.47	A=0 B=0 C=0	A=1.7 B=5.75 C=5.6	A=0 B=0 C=0	A=0 B=12.1 C=12.2
3 Phase kVAr	3.935	0	0.808	0	-3.67	0	0.2	0	0.535
1 Phase kVAr	A=0.88 B=1.575 C=1.48	A=0 B=0 C=0	A=0.09 B=0.359 C=0.359	A=0 B=0 C=0	A=-0.85 B=-1.37 C=-1.45	A=0 B=0 C=0	A=0.004 B=0.102 C=0.094	A=0 B=0 C=0	A=0.001 B=0.269 C=0.265

Table 28 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 6 by 100% for Test 10.4.17

In Table 28, Meter 1 real power decreased from approximately 28.1kW (A=3.8kW B=12.1kW C=12.2kW) to 24.3kW (A=0kW B=12.1kW C=12.2kW) because of the A-phase reduction in Load Bank 6 which was approximately 24.3kW (A=0kW B=12.1kW C=12.2kW) + j0.535kVAr (A=0.001kVAr B=0.269kVAr C=0.265kVAr). Voltages and frequencies remained the same in both the utility and microgrid when Load Bank 6 A-phase was reduced to 0kW because nothing changed in the CERTS microgrid downstream of the static switch and the utility is a stiff system.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the A-phase was reduced in Load Bank 3 by 100%. The measured values for the A-phase load reduction for Load Bank 6 are in Table 28.

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
3 Phase kW	13.7	0	24.3	0	-2.41	0	11.4	0	24.3
1 Phase kW	A=0.8 B=6.9 C=6	A=0 B=0 C=0	A=0 B=12.1 C=12.2	A=0 B=0 C=0	A=-0.85 B=-1.12 C=-0.44	A=0 B=0 C=0	A=0 B=5.8 C=5.6	A=0 B=0 C=0	A=0 B=12.1 C=12.2
3 Phase kVAr	3.9	0	0.808	0	-3.68	0	0.196	0	0.535
1 Phase kVAr	A=0.86 B=1.59 C=1.45	A=0 B=0 C=0	A=0.09 B=0.359 C=0.359	A=0 B=0 C=0	A=-0.87 B=-1.47 C=-1.34	A=0 B=0 C=0	A=0 B=0.102 C=0.094	A=0 B=0 C=0	A=0.001 B=0.269 C=0.265

Table 29 - Measured Values after Static Switch Opened and A-phase Reduced in Load Bank 3 by 100% for Test 10.4.17

In Table 29, Load Bank 3 was approximately 11.4kW (A=0kW B=5.8kW C=5.6kW) + j0.196kVAr (A=0kVAr B=0.102kVAr C=0.094kVAr) after the A-phase was reduced by 100%. Gen-set A1 decreased from approximately 15.4kW (A=2.5kW B=6.8kW C=6.1kW) + j3.935kVAr (A=0.88kVAr B=1.575kVAr C=1.548kVAr) to 13.7kW (A=0.8kW B=6.9kW C=6kW) + j3.9kVAr (A=0.86kVAr B=1.59kVAr C=1.45kVAr) due to the reduction of 1.7kW in the A-phase of Load Bank 3. The reduction in Load Bank 3 did not cause the frequency to increase which was approximately 60.14Hz. Voltage within the microgrid during these measurements was approximately 273.3V on A-phase, 274V on B-phase and 268.8V on C-phase. Load Bank 6 load demands were not changed at this time, therefore, all the measured values for Load Bank 6, Meter 1 and Meter 2 did not change from the previous load reduction in Load Bank 6.

All data was verified and recorded into the DAS Database. The microgrid ran for a couple of minutes in this electrical state before the manual open signal was released and allowed the static switch to synchronize and close back into the utility grid. Shortly after the static switch closed back into the utility it tripped on a reverse power due to the A-

phase on Load Banks 3 and 6 equaling 0kW shown in Figure 19c. The measured values are provided in Table 30.

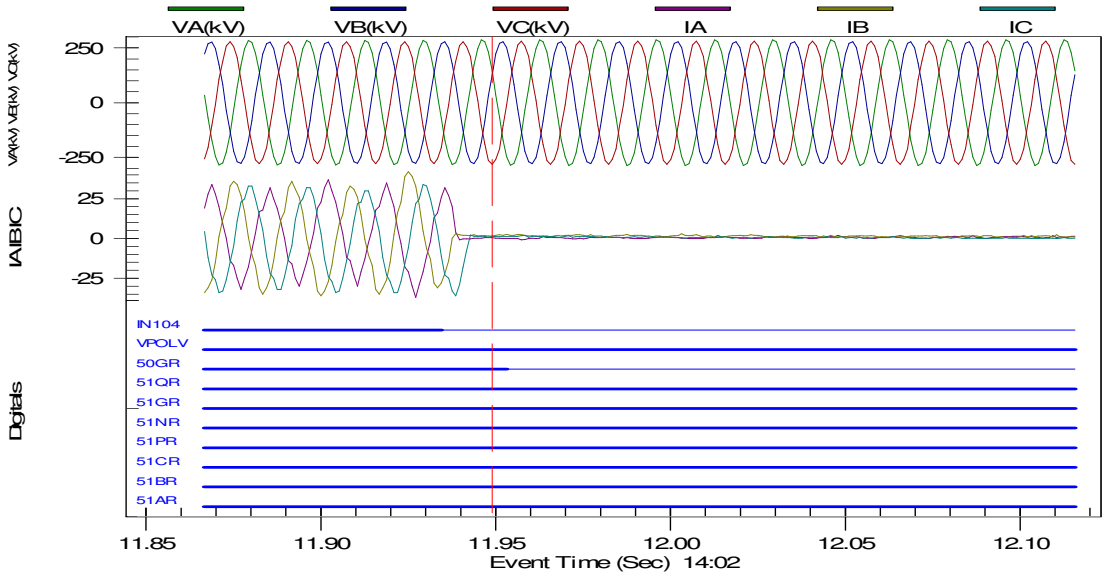

Figure 19c - Relay 2 (Static Switch) Tripping on a Reverse Power Condition during Island to Utility Connected mode for Test 10.4.17

Meter	Gen-set A1	Gen – set A2	Meter 1	Meter 2	Meter 3	Meter 4	LB 3	LB 4	LB 6
Before Static Switch Synchronization and Close									
3 Phase kW	14	0	24.2	0	-2.15	0	11.4	0	24.2
1 Phase kW	A=1 B=7 C=6	A=0 B=0 C=0	A=0 B=12.1 C=12.1	A=0 B=0 C=0	A=-0.75 B=-1 C=-0.4	A=0 B=0 C=0	A=0 B=5.8 C=5.6	A=0 B=0 C=0	A=0 B=12 C=12.2
3 Phase kVAr	4	0	0.9	0	-3.6	0	0.215	0	0.533
1 Phase kVAr	A=0.9 B=1.6 C=1.5	A=0 B=0 C=0	A=0.1 B=0.4 C=0.4	A=0 B=0 C=0	A=-0.8 B=-1.5 C=-1.3	A=0 B=0 C=0	A=0 B=0.122 C=0.093	A=0 B=0 C=0	A=0 B=0.269 C=0.264
Static Switch Synchronized and Closed									

3 Phase kW	32.25	0	6.7	-17	-20	0	12.1	0	23.9
1 Phase kW	A=5.75 B=15.5 C=11	A=0 B=0 C=0	A=-4.8 B=4 C=7.5	A=-4.7 B=-8 C=-4.3	A=-5.75 B=-9.25 C=-5	A=0 B=0 C=0	A=0 B=6.1 C=6	A=0 B=0 C=0	A=0 B=12 C=11.9
3 Phase kVAr	-13.65	0	20.55	19.95	14.1	0	0.227	0	0.526
1 Phase kVAr	A=-5 B=-2.9 C=-5.75	A=0 B=0 C=0	A=6.75 B=5.4 C=8.4	A=6.75 B=5.2 C=8	A=5.2 B=3.1 C=5.8	A=0 B=0 C=0	A=0 B=0.127 C=0.1	A=0 B=0 C=0	A=0 B=0.266 C=0.26
Static Switch After Reverse Power Condition Trip									
3 Phase kW	14	0	24.2	0	-2.15	0	11.4	0	24.2
1 Phase kW	A=1 B=7 C=6	A=0 B=0 C=0	A=0 B=12.1 C=12.1	A=0 B=0 C=0	A=-0.75 B=-1 C=-0.4	A=0 B=0 C=0	A=0 B=5.8 C=5.6	A=0 B=0 C=0	A=0 B=12 C=12.2
3 Phase kVAr	4	0	0.9	0	-3.6	0	0.215	0	0.533
1 Phase kVAr	A=0.9 B=1.6 C=1.5	A=0 B=0 C=0	A=0.1 B=0.4 C=0.4	A=0 B=0 C=0	A=-0.8 B=-1.5 C=-1.3	A=0 B=0 C=0	A=0 B=0.122 C=0.093	A=0 B=0 C=0	A=0 B=0.269 C=0.264

Table 30 - Measured Values before/after Static Switch Synchronized and Closed back into the utility and after Static Switch Tripped on Reverse Power Condition for Test 10.4.17

Voltage and frequency in the microgrid increased from approximately 273.3V on A-phase, 274V on B-phase and 268.8V on C-phase and 60.08Hz when islanded to 284V on A-phase, 281V on B-phase and 278.9V on C-phase and 59.98Hz when utility connected at Meter 3 shown in Figures 19d and 19e. This change in frequency is due to the frequency

no longer being established by Gen-set A1 using the CERTS algorithm but by the utility. Gen-set A1 is in zone power control mode therefore when the static switch closed back into the utility Gen-set A1 produced real power based on a set-point for the power flow through Zone 3 initialized at the beginning of the test. The output power for Gen-set A1 was relatively close to the value at the beginning of the test with Gen-set A1 producing approximately 32.25kW (A=5.75kW B=15.5kW C=11kW) – j13.65kVAr (A=-5kVAr B=-2.9kVAr C=-5.75kVAr).

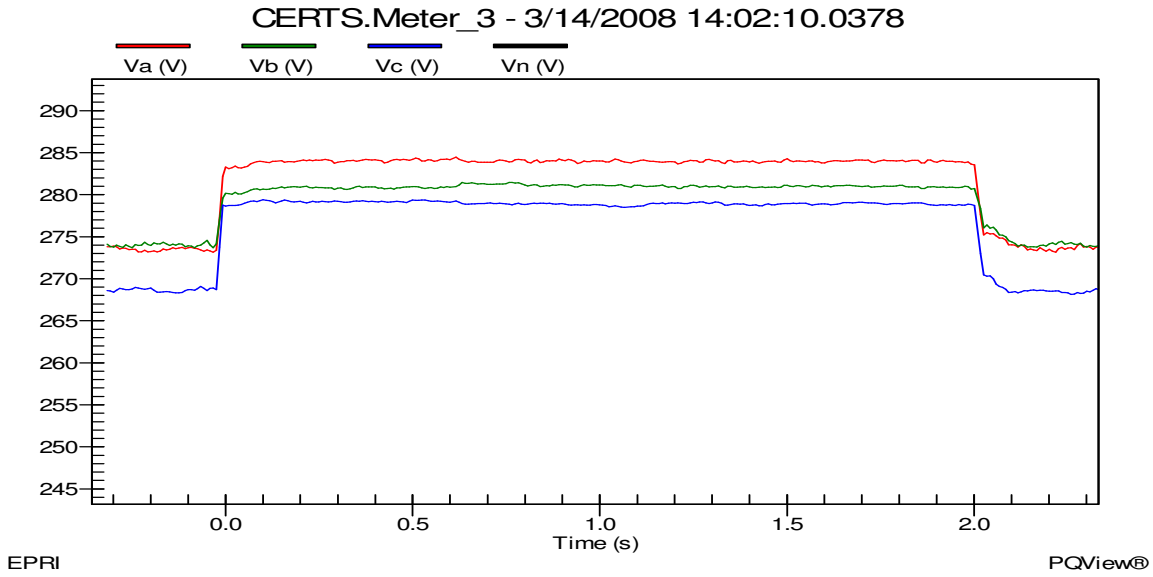

Figure 19d - Meter 3 Line-to-Ground Voltages during Islanded to Utility Connected mode for Test 10.4.17

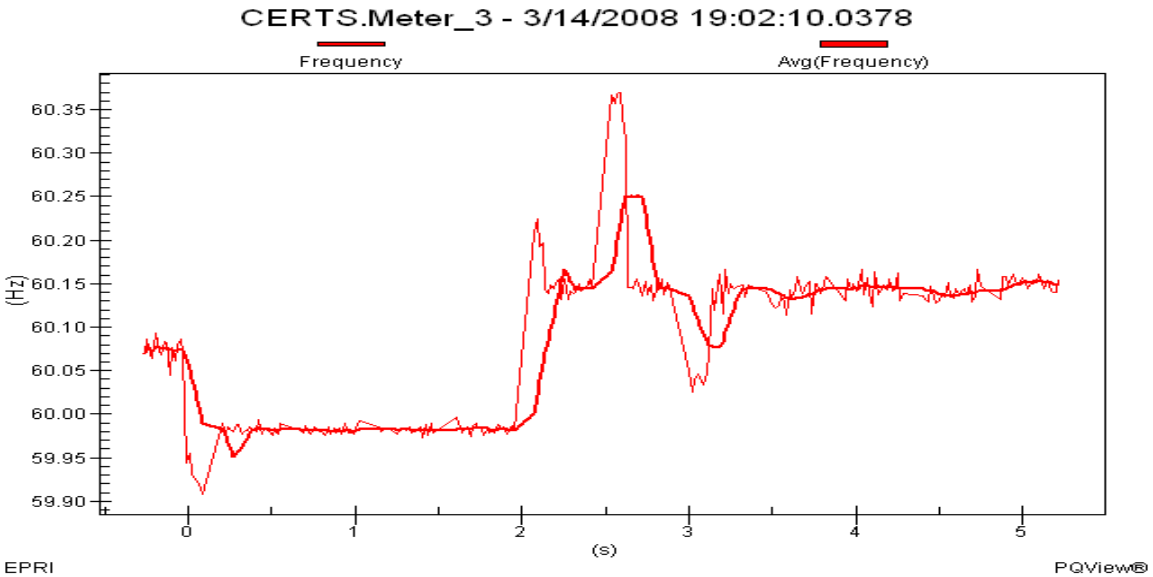

Figure 19e - Meter 3 Frequency during Islanded to Utility Connected mode for Test 10.4.17

Meter 2 recorded real power decreasing from approximately 0kW (A=0kW B=0kW C=0kW) to -17kW (A=-4.7kW B=-8kW C=-4.3kW) and reactive power increasing from approximately j0kVAr (A=0kVAr B=0kVAr C=0kVAr) to j19.95kVAr (A=6.75kVAr B=5.2kVAr C=8kVAr) after the static switch closed shown in Figure 19f. Gen-set A1 was producing power for all the critical loads in the microgrid and approximately 17kW (A=4.7kW B=8kW C=4.3kW) of Load Bank 6 load demands. Load Bank 6 was approximately 23.9kW (A=0kW B=12kW C=11.9kW) + j0.526kVAr (A=0kVAr B=0.266kVAr C=0.26kVAr) which is less than the power supplied by Gen-set A1 on the A-phase recorded by Meter 1 which was approximately 6.7kW (A=-4.8kW B=4kW C=7.5kW). This caused a reverse power condition which opened the static switch in 2.0 seconds islanding the CERTS microgrid from the utility grid shown in Figure 19g.

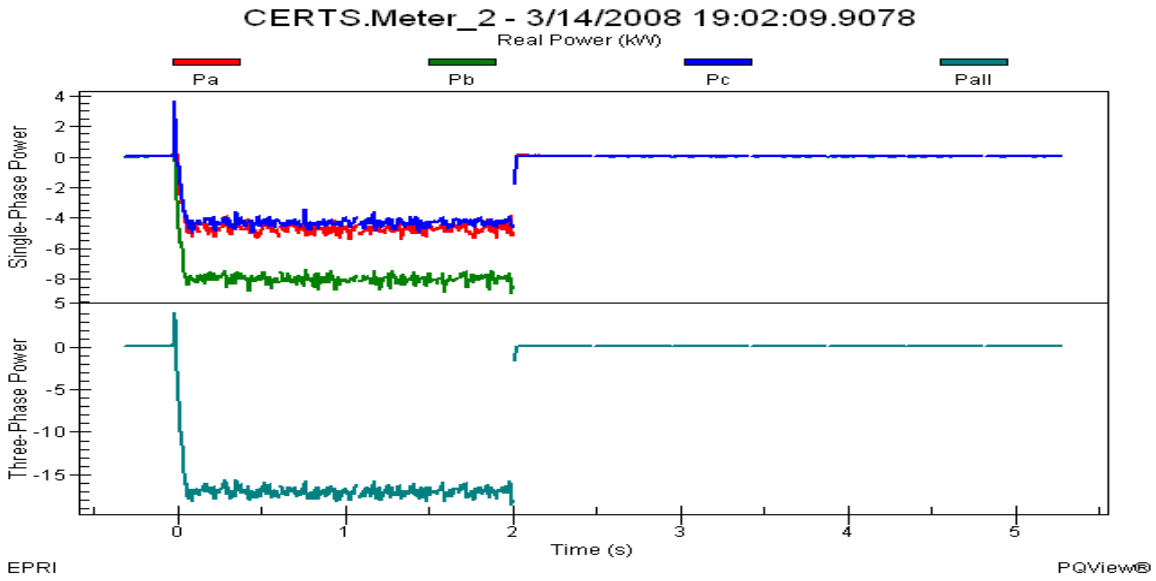

Figure 19f - Static Switch Real Power during Islanded to Utility Connected mode for Test 10.4.17

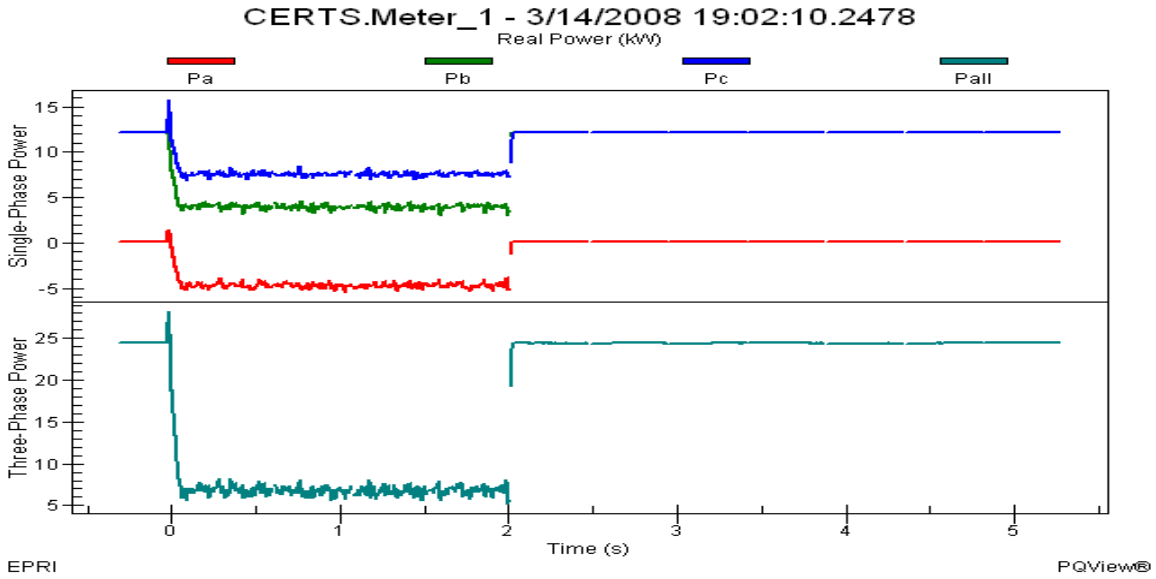

Figure 19g - Meter 1 Real Power during Islanded to Utility Connected mode for Test 10.4.17

In Table 30 after the static switch opened due to the reverse power trip condition, 0kW (A=0kW B=0kW C=0kW) + j0kVAr (A=0kVAr B=0kVAr C=0kVAr) was recorded at Meter 2 indicating that power was not flowing through the static switch. Meter 1 real power increased from approximately 6.7kW (A=-4.8kW B=4kW C=7.5kW) to 24.2kW (A=0kW B=12.1kW C=12.1kW) and reactive power decreased from approximately j20.55kVAr (A=6.75kVAr B=5.4kVAr C=8.4kVAr) to j0.9kVAr (A=0.1kVAr B=0.4kVAr C=0.4kVAr). The change in power is because the microgrid is no longer supplying the power for the load demands of Load Bank 6 which was approximately 24.2kW (A=0kW B=12kW C=12.2kW) + j0.533kVAr (A=0kVAr B=0.269kVAr C=0.264kVAr).

The power produced by the Gen-set was very similar to the measured value before the static switch manual open was released which was approximately 14kW (A=1kW B=7kW C=6kW) + j4kVAr (A=0.9kVAr B=1.6kVAr C=1.5kVAr) for Gen-set A1. Also, the voltage and frequency returned to measured values before the static switch manual open was released which was 273.5V on A-phase, 274V on B-phase and 268.7V on C-phase and 60.15Hz. After all the data was verified and recorded into the DAS Database Gen-set and Load Banks 3 and 6 were turned off.

7.0 CONCLUSION

The tests in section 10.0 "Difficult Load Tests" were all successfully performed to as predicted. These tests have proven that the CERTS microgrid can handle a 10Hp

induction motor turning on while utility connected or islanded with balanced or unbalanced loads. Also, the static switch will trip on reverse power if a phase is reduced to zero and that the microgrid is still functional and electrically stable while isolated from the utility grid as the critical load demand of a single phase is reduced to 0kW.



Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Test Log

APPENDIX N

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Commission Contract No. 500-03-024

Prepared For:
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DTC Registered Procedure - CERTS Microgrid Test Plan Appendix C: TEST LOG			
Dolan Technology Center	Document No: DTC212812.207.01A		
Written by: AEP	Effective Date: 23 Feb 2007	Target Group: Assigned	
Approved by: K. P. Loving	Procedure Review Date: 23 Feb. 2008		

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Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
6.1.1.1	3/9/07				S		GWP	LB3:40kW,LB6:40kW,59.86Hz Islanded
6.1.1.2	3/9/07	14:23	6.1.1.3	6.1.1.4, 6.1.1.5	S	14:28	GWP	60.01Hz Connected, Meter 1 52kW, Meter 2 16kW, Meter A1 20kW,
6.1.2.1	3/9/07	14:29	6.1.2.2	6.1.2.3	S	14:35	GWP	
6.1.2.4	3/9/07	14:36	6.1.2.5	6.1.2.6	S	14:37	GWP	Event logger didn't capture 1547 Voltage test, SS indicates that it did occur, Caused CB51 to Under voltage Trip: Recommend Increasing Under voltage delay to 30 cycles
6.1.2.7	3/9/07	14:48	6.1.2.8	6.1.2.9, 6.1.2.10	S	14:49	GWP	Waited 5mins.
6.1.3.1	3/9/07	15:07	6.1.3.2,	6.1.3.3	S	15:08	GWP	Triggered at 3.33kW
6.1.3.4	3/9/07		6.1.3.5	6.1.3.6	S		GWP	
6.1.3.7	3/9/07	3:39	6.1.3.8	6.1.3.9	S	15:40	GWP	
6.1.4.1	3/13/07	9:03	6.1.4.2	6.1.4.3, 6.1.4.4	S	9:11	DAK	LB3:40kW, LB4:40kW, Meter 1 Initial 53kW, Final 18kW, No reverse trip occured

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6.1.4.5	**3/13/07**	**9:12**	**6.1.4.6**	**6.1.4.7, 6.1.4.8**	**S**	**9:17**	**DAK**	**SS opened after second reduction of load in LB3 to 30kW, Status was fault with PES alarm and Anti-islanding Microgrid settings. The EMS Event Logger did record a reverse power event. CB14 did open.**
6.1.4.9	**3/13/07**	**9:18**	**6.1.4.10**	**6.1.4.11**	**S**	**9:29**	**DAK**	**LB3:40kW, LB6:0kW, SS reset successfully, and reconnected after the start command was issued. LB6 was at 0kW load instead of 40kW. Two triggers were captured when one was expected. Test was repeated to confirm that absence of 40kW in LB6 had no effect.**
6.1.4.9	**3/13/07**	**9:42 am**	**6.1.4.10**	**6.1.4.11**	**S**	**9:53**	**DAK**	**LB3:40kW, LB6:40kW, SS reset successfully, and reconnected after the start command was issued. LB6 was confirmed at 40kW. A trigger was noted on reset of the SS prior to the Start command being issued. The SS was issued the start command and successfully closed causing the second trigger.**
6.1.5.1	**3/13/07**	**9:56 am**	**6.1.5.2**		**S**	**9:56**	**DAK**	**LB3:40kW, LB6:40kW**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:

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6.1.5.3	**3/13/07**	**9:57 am**	**6.1.5.4**	**6.1.5.5**	**S**	**10:02 am**	**DAK**	**SS opened with a PES Alarm. Gen A1 shutdown successfully. DG Side Dead Bus and DG PLL not locked events were active. CB 51 opened when Gen A1 shutdown. SS remained open with a dead bus.**
6.1.5.6	**3/13/07**	**10:04 am**	**6.1.5.7**		**S**	**10:15 am**	**DAK**	**SS was reset to remove PES Alarm. Manual Open removed and SS remained Open. Dead Bus Reclose was Enabled, the SS closed and with all events disappeared.**
6.1.6.1	**4/16/07**	**1:25 pm**	**6.1.6.2**	**6.1.6.3**	**S**	**2:00 pm**	**DAK**	**Loads correct, Genset setup correctly, 59.77Hz prior to close of SS, 60.00Hz after.**
6.1.6.4	**4/16/07**	**2:02 pm**	**6.1.6.5**	**6.1.6.6**	**S**	**2:08 pm**	**DAK**	**Event logger didn't capture Power Quality, Relay2 Trip or IEEE 1547 Voltage Trip, SS indicates that a PQ event did occur. Data collection triggered.**
6.1.6.7	**4/16/07**	**2:13 pm**	**6.1.6.8**	**6.1.6.9, 6.1.6.10**	**S**	**2:18 pm**	**DAK**	**IEEE 1547 Voltage Test shut off after CB1 was reclosed, SS waited 5 mins to reconnect, Data collection was triggered on the SS closure**
7.1.1	**4/23/07**	**12:30 pm**	**7.1.2, 7.1.3**	**7.1.4, 7.1.5**	**S**	**2:00 pm**	**DAK**	
7.1.6	**4/25/07**	**8:30 am**	**7.1.7, 7.1.8**	**7.1.9**	**S**	**10:00 am**	**DAK**	**Found blown fuse on PT 17 Phase B secondary. Corrected Meter CT ratios to correct values instead of x10. Corrected Kep server on EMS to fix readout of MG unit and feeder mode droop settings. Fault key armed.**

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7.1.10	**4/25/07**	**10:01 am**	**7.1.11**	**7.1.12, 7.1.13**		**10:20 am**	**DAK**	**Timer set to 99 secs. Once fault was initiated the meter trigger remained on for the duration of the fault timer. When the protection relays opened due to the tests event their meter triggers were missed because the fault timer remained high. Also the SS and CB41 opened during the test. The SS was not expected to open.**
7.1.6R	**4/27/07**	**9:37 am**	**7.1.7R, 7.1.8R**	**7.1.9R**	**S**	**9:53 am**	**DAK**	**Corrected PLC Trigger wiring and code to allow proper protection triggers during faults. LB4: 60kW, SS closed, Load verified, Fault key armed**
7.1.10R	**4/27/07**	**9:53 am**	**7.1.11R**	**7.1.12R, 7.1.13R**	**S**	**10:10 am**	**DAK**	**Timer set to 99 sec. Fault initiated CB41 opened, Also SS and CB51 Opened**
7.1.19	**4/27/07**	**10:30 am**	**7.1.20**	**7.1.21**	**S**	**11:10 am**	**DAK**	**LB4 : 60kW SS closed, Load verified. Removed phases B and C from within fault load bank. Fault key armed.**
7.1.22	**4/27/07**	**11:10 am**	**7.1.23**	**7.1.24, 7.1.25**	**S**	**11:15 am**	**DAK**	**Timer set to 10 sec. Fault initiated, SS opened, CB41 opened, CB 51 opened.**
7.1.26	**4/27/07**	**12:15 pm**	**7.1.27, 7.1.28**	**7.1.29, 7.1.30**	**S**	**12:40 pm**	**DAK**	**Reconnected all 3 phases within fault load bank**
7.2.1	**4/27/07**	**12:40 pm**	**7.2.2,**	**7.2.4,**	**S**	**12:45 pm**	**DAK**	**Moved fault load bank to Zone 3.**

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			7.2.3	7.2.5				Fault key armed.
7.2.6	4/27/07	12:45 pm	7.2.7, 7.2.8	7.2.9	S	12:49 pm	DAK	LB3: 60kW, LB4: 60kW, SS closed, Load verified
7.2.10	4/27/07	12:49 pm	7.2.11	7.2.12, 7.2.13	S	12:57 pm	DAK	Timer set to 99 sec. Fault initiated, SS opened, CB31 did not open, CB51 opened. Relay 2 appears to be causing the SS to open. The SS seems to open when the fault breaker opens, there may be a large transient associated with this which causes the SS to open.
7.2.14	4/27/07	12:58 pm	7.2.15, 7.2.16	7.2.17, 7.2.18	S	1:10 pm	DAK	Disconnected phases A and C from fault load bank.

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
7.2.19	4/27/07	1:25 pm	7.2.20	7.2.21	S	1:33 pm	DAK	LB3: 60kW, LB4: 60kW, SS closed, Load verified
7.2.22	4/27/07	1:33 pm	7.2.23	7.2.24, 7.2.25	S	1:40 pm	DAK	Timer set to 10 sec. Fault initiated, SS opened, CB31 did not open, CB51 opened, CB41 did not open
7.2.26	4/27/07	1:40 pm	7.2.27, 7.2.28	7.2.29, 7.2.30	S	1:55 pm	DAK	Phases A and C reconnected within fault load bank and fault load bank removed from Zone 3

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7.3.1	**4/30/07**	**12:30 pm**	**7.3.2, 7.3.3**	**7.3.4, 7.3.5**	**S**	**12:35 pm**	**DAK**	**Fault load bank moved to zone 5. All three phases connected within fault load bank.**
7.3.6	**4/30/07**	**12:35 pm**	**7.3.7, 7.3.8**	**7.3.9**	**S**	**12:39 pm**	**DAK**	**LB5: 60kW, SS closed, Load verified.**
7.3.10	**4/30/07**	**12:39 pm**	**7.3.11**	**7.3.12, 7.2.13**	**S**	**12:53 pm**	**DAK**	**Timer set to 99 sec. Fault key armed. Fault initiated. SS opened, CB51 opened. CB41 and CB31 remained closed. EMS event log shows Reverse power as reason for SS opening.**
7.3.14	**4/30/07**	**12:53 pm**	**7.3.15, 7.3.16**	**7.3.17, 7.3.18**	**S**	**1:05 pm**	**DAK**	**Phases A and B were removed within the fault load bank.**
7.3.19	**4/30/07**	**1:20 pm**	**7.3.20**	**7.3.21**	**S**	**1:25 pm**	**DAK**	**LB5: 60kW, SS closed, Load verified.**
7.3.22	**4/30/07**	**1:25 pm**	**7.3.23**	**7.3.24, 7.3.25**	**S**	**1:32 pm**	**DAK**	**Timer set to 10 sec. Fault key armed. Fault initiated. SS opened. CB51 opened. CB31 and CB41 remained closed. EMS event logger shows SS opened due to relay 2.**
7.3.26	**4/30/07**	**1:32 pm**	**7.3.27, 7.3.28**	**7.3.29, 7.3.30**	**S**	**1:45 pm**	**DAK**	**Fault load bank was removed from zone 5.**
7.1.1R	**7/06/07**	**9:00 am**	**7.1.2R, 7.1.3R**	**7.1.4R, 7.1.5R**	**S**	**9:07 am**	**DAK**	
7.1.6R	**7/06/07**	**9:07 am**	**7.1.7R, 7.1.8R**	**7.1.9R**	**S**	**9:13 am**	**DAK**	**Fault key armed. Dead Bus close successful. LB4: 60kW.**

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7.1.10R	**7/06/07**	**9:13 am**	**7.1.11R**	**7.1.12R, 7.1.13R**	**S**	**9:26 am**	**DAK**	**Timer set to 99 secs. Fault initiated. CB41 opened. The SS opened from relay 2 and was not expected to open. CB 51 also opened after the SS opened.**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
								The ground over-current and neutral over-current have all been delayed 2 cycles from original settings. Note the negative sequence trip for relay 2 had previously and continues to be delayed 8 cycles due to problems from the inrush when dead bus energizing the microgrid.
7.1.1R	**7/11/07**	**9:20 am**	**7.1.2R, 7.1.3R**	**7.1.4R, 7.1.5R**	**S**	**9:24 am**	**DAK**	
7.1.6R	**7/11/07**	**9:24 am**	**7.1.7R, 7.1.8R**	**7.1.9R**	**S**	**9:27 am**	**DAK**	**Fault key armed. Dead Bus close successful. LB4: 60kW.**
7.1.10R	**711/07**	**9:27 am**	**7.1.11R**	**7.1.12R, 7.1.13R**	**S**	**9:35 am**	**DAK**	**Timer set to 99 secs. Fault initiated. CB41 opened. The SS opened from Reverse Power. CB 51 also opened after the SS opened. The test procedure was modified to add a small load in LB6 to prevent**

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								reverse power trips. Changed SS reverse power setting to zero.
7.1.1R	**7/11/07**	**10:38: am**	**7.1.2R, 7.1.3R**	**7.1.4R, 7.1.5R**	**S**	**10:40 am**	**DAK**	
7.1.6R	**7/11/07**	**10:40 am**	**7.1.7R, 7.1.8R**	**7.1.9R**	**S**	**10:42am**	**DAK**	**Fault key armed. Dead Bus close successful. LB4: 60kW. LB6:10kW.**
7.1.10R	**711/07**	**10:42 am**	**7.1.11R**	**7.1.12R, 7.1.13R**	**S**	**10:50 am**	**DAK**	**Timer set to 99 secs. Fault initiated. CB41 opened. The SS and CB 51 remained closed as expected.**
7.1.19R	**711/07**	**11:47: am**	**7.1.20R**	**7.1.21R**	**S**	**11:51 am**	**DAK**	**LB4:60kW LB6:10kW SS closed, Load verified. Removed phases B and C from within fault load bank. Fault key armed.**
7.1.22R	**7/11/07**	**11:51 am**	**7.1.23R**	**7.1.24R, 7.1.25R**	**S**	**12:00 pm**	**DAK**	**Timer set to 10 sec. Fault initiated, SS opened from a relay 2 trip, CB 51 opened after SS. CB41 remained closed.**
7.1.26R	**7/11/07**	**12:00 pm**	**7.1.27R, 7.1.28R**	**7.1.29R, 7.1.30R**	**S**	**12:15 pm**	**DAK**	**Reconnected all 3 phases within fault load bank**
7.2.1R	**7/11/07**	**12:15 pm**	**7.2.2R, 7.2.3R**	**7.2.4R, 7.2.5R**	**S**	**12:20 pm**	**DAK**	**Moved fault load bank to Zone 3. Fault key armed.**
7.2.6R	**7/11/07**	**12:20 pm**	**7.2.7R, 7.2.8R**	**7.2.9R**	**S**	**12:24 pm**	**DAK**	**LB3: 60kW, LB4: 60kW, LB6:10kW SS closed, Load verified**
7.2.10R	**7/11/07**	**12:24 pm**	**7.2.11R**	**7.2.12R,**	**S**	**12:34 pm**	**DAK**	**Timer set to 99 sec. Fault initiated, No protection**

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				7.2.13R				operated. The overload is likely to small to trip the protection. The trip point for breaker 3 is 225A and we were just below that at 216A.
7.2.1R	7/11/07	1:10 pm	7.2.2R, 7.2.3R	7.2.4R, 7.2.5R	S	1:12 pm	DAK	Moved fault load bank to Zone 3. Fault key armed.
7.2.6R	7/11/07	1:12 pm	7.2.7R, 7.2.8R	7.2.9R	S	1:15 pm	DAK	LB3: 75kW, LB4: 75kW, LB6:10kW SS closed, Load verified
7.2.10R	7/11/07	1:15 pm	7.2.11R	7.2.12R, 7.2.13R	S	1:30 pm	DAK	Timer set to 99 sec. Fault initiated, CB 31 opened. SS, CB41, and CB51 remained closed.
7.2.14R	7/11/07	1:30 pm	7.2.15R, 7.2.16R	7.2.17R, 7.2.18R	S	1:45 pm	DAK	Disconnected phases A and C from fault load bank.
7.2.19R	7/11/07	1:45 pm	7.2.20R	7.2.21R	S	2:01 pm	DAK	LB3: 60kW, LB4: 60kW, SS closed, Load verified
7.2.22R	7/11/07	2:01 pm	7.2.23R	7.2.24R, 7.2.25R	S	2:10 pm	DAK	Timer set to 10 sec. Fault initiated, SS opened, all other breakers remained closed.
7.2.26R	711/07	2:10 pm	7.2.27R, 7.2.28R	7.2.29R, 7.2.30R	S	2:25 pm	DAK	Phases A and C reconnected within fault load bank and fault load bank removed from Zone 3
7.3.1R	7/18/07	10:34 am	7.3.2R, 7.3.3R	7.3.4R, 7.3.5R	S	10:35 am	DAK	Fault load bank moved to zone 5. All three phases connected within fault load bank.
7.3.6R	7/18/07	10:35 am	7.3.7R, 7.3.8R	7.3.9R	S	10:37 am	DAK	LB5: 60kW, SS closed, Load verified.
7.3.10R	7/18/07	10:37 am	7.3.11R	7.3.12R, 7.2.13R	S	10:43 am	DAK	Timer set to 99 sec. Fault key armed. Fault initiated.

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								CB51 opened. The SS, CB41 and CB31 remained closed.
7.3.14R	**7/18/07**	**11:48 am**	**7.3.15R, 7.3.16R**	**7.3.17R, 7.3.18R**	**S**	**11:50 am**	**DAK**	**Phases A and B were removed within the fault load bank.**
7.3.19R	**7/18/07**	**11:50 am**	**7.3.20R**	**7.3.21R**	**S**	**11:52 am**	**DAK**	**LB5: 60kW, SS closed, Load verified.**
7.3.22R	**7/18/07**	**11:52 am**	**7.3.23R**	**7.3.24R, 7.3.25R**	**S**	**12:02 pm**	**DAK**	**Timer set to 10 sec. Fault key armed. Fault initiated. CB51 opened. The SS, CB31 and CB41 remained closed.**
7.3.26R	**7/18/07**	**12:02 pm**	**7.3.27R, 7.3.28R**	**7.3.29R, 7.3.30R**	**S**	**12:10 pm**	**DAK**	**Fault load bank was removed from zone 5.**
7.4.1	**7/30/07**	**9:49 am**	**7.4.2 7.4.3**	**7.4.4 7.4.5**	**S**	**10:10 am**	**DAK**	**Fault load connected, armed, and verified.**
7.4.6	**7/30/07**	**10:10 am**	**7.4.7, 7.4.8**	**7.4.9**	**S**	**10:18 am**	**DAK**	**SS Open, Gensets setup and verified. Loads connected and verified**
7.4.10	**7/30/07**	**10:18 am**	**7.4.11**	**7.4.12**	**S**	**11:55 am**	**DAK**	**Genset A1 connected at 10:25. Genset A2 connected at 10:31, causing CB41 to open and shutdown A2. Genset A1 remained online serving zones 2,3, and 5. The primary side fuses of PT42 were found blown. The primary and secondary fuses were swapped on the PT and new fuses were installed. CB41 was reclosed without triggering and the test sequence was picked up where we left off.**

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								Genset A2 was restarted and successfully connected at 11:42. SS was enabled and connected at 11:48
7.4.13	**7/30/07**	**11:55 am**	**7.4.14, 7.4.15**	**7.4.16**	**S**	**1:00 pm**	**DAK**	**Fault timer at 99 sec. LB4 was increased to 65kW due to load drift and generation offset. This was done to insure enough load to trip CB41 under overload. The fault was applied at 11:55 am. Gen A1 tripped off on a low oil pressure alarm which appears as a false alarm. LB4 was reduced to 0 to prevent CB41 from opening and causing another trigger. Genset A1 was checked and restarted. Once started Genset A1 seemed to operate well off its RPM range. Tecogen was contacted.**
7.4.1R	**7/31/07**	**8:45 am**	**7.4.2R, 7.4.3R**	**7.4.4R, 7.4.5R**	**S**	**9:01 am**	**DAK**	**Fault load connected, armed, and verified.**
7.4.6R	**7/31/07**	**9:01 am**	**7.4.7R, 7.4.8R**	**7.4.9R**	**S**	**9:09 am**	**DAK**	**SS Open, Gensets setup and verified. Genset A2 changes its Power Flow mode to "0" constantly, even though the Microgrid Control Status returns unit control mode. Loads connected and verified**
7.4.10R	**7/31/07**	**9:09 am**	**7.4.11R**	**7.4.12R**	**S**	**10:00 am**	**DAK**	**Genset A1 connected at 9:15. Genset A2 connected at 9:20, causing CB41 to open and shutdown A2. Genset A1 remained online serving zones 2,3, and 5. The secondary side phase A fuse of PT42 was found blown. A new fuse was installed. CB41 was reclosed, triggering a capture at 9:33 am and the test**

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								sequence was picked up where we left off. Genset A2 was restarted and successfully connected at 9:49. SS was enabled and connected at 9:55.
7.4.13R	**7/31/07**	**10:00 am**	**7.4.14R, 7.4.15R**	**7.4.16R**	**S**	**10:03 am**	**DAK**	**Fault timer at 99 sec. LB4 was increased to 65kW due to load drift and generation offset. This was done to insure enough load to trip CB41 under overload. The fault was applied at 10: 01am. CB41 opened tripping off Genset A2. The SS opened shortly afterwards on a reverse power trip. CB31 and CB51 remained closed and Genset A1 remained online serving the remaining load.**
7.4.17	**7/31/07**	**10:03 am**			**S**	**10:08am**	**DAK**	**Genset A1 was shutdown causing CB51 to open on undervoltage trip at 10:03**
7.5.1	**7/31/07**	**11:27 am**	**7.5.2, 7.5.3**	**7.5.4, 7.5.5, 7.5.6**	**S**	**11:28 am**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.5.7	**7/31/07**	**11:28 am**	**7.5.8**	**7.5.9**	**S**	**11:29 am**	**DAK**	**LB3: 40kW, LB6:40kW**
7.5.10	**7/31/07**	**11:29 am**	**7.5.11**	**7.5.12**	**S**	**11:41 am**	**DAK**	**Genset A1 connected at 11:32, SS connected at 11:37. Meter1:51kW, Meter2:15kW**
7.5.13	**7/31/07**	**11:41 am**	**7.5.14, 7.5.15**	**7.5.16**	**S**	**11:59 am**	**DAK**	**Fault timer set to 10 sec. SS opened by relay 2 trip, CB31 opened and Genset A1 shutdown. CB51 opened on undervoltage. Ignore accidentally created event at 11:44. Meter1:36kW, Meter2:0kW**
7.5.17	**7/31/07**	**11:59 am**			**S**	**12:02 pm**	**DAK**	

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7.6.1	**7/31/07**	**12:02 pm**	**7.6.2**	**7.6.3**	**S**	**12:10 am**	**DAK**	**Gensets A1 and A2 setup. Fault key armed.**
7.6.4	**7/31/07**	**12:10 pm**	**7.6.5**	**7.6.6, 7.6.7**	**S**	**12:23 pm**	**DAK**	**Triggers disabled, Genset A1 connected at 12:15, Genset A2 connected at 12:19. LB3:40kW, LB4:40kW, LB6:40kW. SS connected at 12:22. Meter1:69kW, Meter2:35kW. Triggers armed**
7.6.8	**7/31/07**	**12:23 pm**	**7.6.9, 7.6.10**	**7.6.11**	**S**	**12:30 pm**	**DAK**	**Fault timer set to 10 sec Fault initiated at 12:25. SS opened, CB31 opened, CB41 Opened, and CB51 opened. Gensets A1 and A2 shutdown. Meter1:36kW, Meter2:0kW**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
7.6.12	**7/31/07**	**12:30**			**S**	**12:35 pm**	**DAK**	
								Test 7.7 and 7.8 were skipped on 7/31/07 because Genset B1 was not operational and replacement parts had not yet arrived. Replacement parts installed 8/7/07
7.7.1	**8/7/07**	**9:22 am**	**7.7.2, 7.7.3**	**7.7.4, 7.7.5, 7.7.6**	**S**	**9:30 am**	**DAK**	**Fault load verified and connected, Fault key armed**
7.7.7	**8/7/07**	**9:30 am**	**7.7.8**	**7.7.9**	**S**	**9:37 am**	**DAK**	**LB3:40kW, LB6:40kW, Genset B1 setup**

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7.7.10	**8/7/07**	**9:37 am**	**7.7.11**	**7.7.12**	**S**	**9:56 am**	**DAK**	**Genset connected at 9:55 with SS shortly after in same trigger Meter1:52kW Meter2:16kW**
7.7.13	**8/7/07**	**9:56 am**	**7.7.14, 7.7.15**	**7.7.16**	**S**	**10:15 am**	**DAK**	**Fault armed, Fault triggered at 10:09. CB51 opened and Genset B1 shutdown. SS and remaining breakers remained closed.**
7.7.17	**8/7/07**	**10:15 am**			**S**	**10:20 am**	**DAK**	
7.8.1	**8/7/07**	**11:20 am**	**7.8.2**	**7.8.3**	**S**	**11:22 am**	**DAK**	**Breakers closed, Fault key armed.**
7.8.4	**8/7/07**	**11:23 am**	**7.8.5**	**7.8.6, 7.8.7**	**S**	**11:42 am**	**DAK**	**Gensets started, LB3:40kW, LB4:40kW, LB6:40kW SS connected, Meter1:61kW, Meter2:26kW. Note while starting the gensets the SS was left in a disconnect state with manual open asserted. After starting the gensets the SS was found to be in the OFF state. This happened a few times before it would remain in the disconnect state reliable for a period of time. There were no alarms present during this process.**
7.8.8	**8/7/07**	**11:42 am**	**7.8.9, 7.8.10**	**7.8.11**	**S**	**11:47 am**	**DAK**	**Fault timer at 10 sec. Fault triggered at 11:44. CB51 opened and Genset B1 shutdown. SS and remaining breakers remained closed. Meter1:83kW, Meter2:49kW**
7.8.12	**8/7/07**	**11:47 am**			**S**	**12:00 pm**	**DAK**	**Triggers disabled. Before we were able to shutdown the Genset A1 and remove the loads, the Genset shut itself down on a No Field Fault and the SS opened with a PES SCR Failure alarm. From the**

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								relay files it appears that the SS opened first on an SCR alarm, then Genset A1 shutdown due to the overload that remained.
7.9.1	**7/31/07**	**12:36 pm**	**7.9.2, 7.9.3**	**7.9.4, 7.9.5, 7.9.6**	**S**	**12:42 pm**	**DAK**	**Fault load verified, key armed, All breakers closed.**
7.9.7	**7/31/07**	**12:42 pm**	**7.9.8**	**7.9.9**	**S**	**12:49 pm**	**DAK**	**Gensets setup, Triggers disabled, Genset A1 connected at 12:46. Genset A2 connected at 12:48**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
7.9.10	**7/31/07**	**12:49 pm**	**7.9.11**	**7.9.12**	**S**	**12:55 pm**	**DAK**	**LB3:40kW, LB4:40kW, LB6:40kW, SS connected at 12:54. Meter1:71kW, Meter2:36kW**
7.9.13	**7/31/07**	**12:55 pm**	**7.9.14**	**7.9.15, 7.9.16**	**S**	**1:05 pm**	**DAK**	**Triggers enabled Fault timer set to 10 sec. Fault initiated at 12:57. SS, CB12, and CB51 opened. Genset A1 and A2 shutdown with Skipp 1 faults. CB12 only opens under manual command or under high instantaneous fault current from the utility. This was not the expected outcome of this test.**
7.9.1R	**7/31/07**	**1:35 pm**	**7.9.2R,**	**7.9.4R,**	**S**	**1:42 pm**	**DAK**	**Fault load verified, key armed, All breakers closed.**

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			7.9.3R	7.9.5R, 7.9.6R				
7.9.7R	7/31/07	1:42 pm	7.9.8R	7.9.9R	S	1:47 pm	DAK	Gensets setup, Triggers disabled, Genset A1 connected at 1:44. Genset A2 connected at 1:47
7.9.10R	7/31/07	1:47 pm	7.9.11R	7.9.12R	S	1:51 pm	DAK	LB3:40kW, LB4:40kW, LB6:40kW, SS connected at 1:50. Meter1:69kW, Meter2:34kW
7.9.13R	7/31/07	1:51 pm	7.9.14R	7.9.15R, 7.9.16R	S	2:08 pm	DAK	Triggers enabled. Fault timer set to 10 sec. Fault initiated at 12:57. SS opened, CB41 opened. Genset A2 shutdown. CB31 and CB51 remained closed, Genset A1 remained online serving the remaining load. The SS then reclosed. Also of note even those the fault timer was set to 10 seconds the fault remained on for approximately 1.5 mins. A check needs to be made to determine of the fault timers are working properly.
7.9.17	7/31/07	2:08 pm			S	2:12 pm	DAK	
7.10.1	8/7/07	12:10 pm	7.10.2, 7.10.3	7.10.4, 7.10.5, 7.10.6	S	12:39 pm	DAK	Fault load verified and connected, Fault key armed
7.10.7	8/7/07	12:39 pm	7.10.8	7.10.9	S	12:46 pm	DAK	SS continues to put itself in an OFF state without being commaneded to do so. Gensets started at 12:45
7.10.10	8/7/07	12:46 pm	7.10.11	7.10.12	S	12:48 pm	DAK	LB3:40kW, LB4:40kW, LB6:40kW SS closed at

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								12:47. Meter1:71kW, Meter2:35kW
7.10.13	**8/7/07**	**12:48 pm**	**7.10.14, 7.10.15**	**7.10.16**	**S**	**12:55 pm**	**DAK**	**Fault timer set to 10 sec. Fault initiated at 12:49. SS, CB31, and CB51 opened, Gensets A1 and B1 shutdown.**
7.10.17	**8/7/07**	**12:55 pm**			**S**	**1:05 pm**	**DAK**	
7.11.1	**8/15/07**	**11:32 am**	**7.11.2, 7.11.3**	**7.11.4, 7.11.5, 7.11.6**	**S**	**12:34 pm**	**DAK**	**Fault load verified and connected, Fault key armed.**
7.11.7	**8/15/07**	**12:34 pm**	**7.11.8**	**7.11.9**	**S**	**12:36 pm**	**DAK**	**Genset A1 was found non responsive to the EMS system. An open fuse on the 208V control power feed was found and replaced. The control power battery with the genset was found to be below 6V due to a prolonged power outage. After refusing the battery was allowed to charge for 2 hours before testing was attempted. LB3:40kW, LB6:40kW**
7.11.10	**8/15/07**	**12:36 pm**	**7.11.11**	**7.11.12**			**DAK**	**Genset faulted on a "DC Undervoltage fault". Genset fault cleared and restarted. It was found that due to the significant depletion of the control battery the genset was not able to remain operational. It was decided to allow the battery to continue to charge overnight and to test at a later date.**
7.11.1R	**8/20/07**	**12:20 pm**	**7.11.2, 7.11.3**	**7.11.4, 7.11.5,**	**S**	**12:26 pm**	**DAK**	**Genset A1 was test run successfully prior to beginning this testing.**

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				7.11.6				Fault load verified and connected, Fault key armed.
7.11.7R	8/20/07	12:26 pm	7.11.8	7.11.9	S	12:29 pm	DAK	LB3:40kW, LB6:40kW
7.11.10R	8/20/07	12:29 pm	7.11.11	7.11.12	S	12:32 pm	DAK	Genset A1 connected at 12:30, SS closed at 12:31. Meter1:55kW, Meter2:19kW
7.11.13	8/20/07	12:32 pm	7.11.14, 7.11.15	7.11.16	S	12:48 pm	DAK	Triggers set, Fault timer to 99 sec, Fault initiated at 12:38. SS tripped open by relay 2, Check to confirm that the SS should have opened, After the SS opened there was a short delay,~20 sec and the SS attempted to reconnect. The SS faulted during the reconnect showing the "Fault" state and "PES Alarm". The applied fault continued in Zone 6. After 99 seconds the Zone 6 fault was removed by the PLC and CB13 remained closed. It is believed there was not enough load to trip the CB13 breaker. The C phase current was measured at 135A during the fault.
7.11.1R	8/20/07	12:48:pm	7.11.2, 7.11.3	7.11.4, 7.11.5, 7.11.6	S	12:52 pm	DAK	Additional load was added to LB6 to increase the current on CB13. Fault load verified and connected, Fault key armed.
7.11.7R	8/20/07	12:52 pm	7.11.8	7.11.9	S	12:55 pm	DAK	LB3:40kW, LB6:60kW
7.11.10R	8/20/07	12:55 pm	7.11.11	7.11.12	S	1:00 pm	DAK	Genset A1 remained running from above, The SS was reset clearing the fault and closed at 12:59. Meter1:71kW, Meter2:18kW
7.11.13R	8/20/07	1:00 pm	7.11.14, 7.11.15	7.11.16	S	1:08 pm	DAK	Triggers set, Fault timer to 99 sec, Fault initiated at 1:02. SS opened from relay 2 and faulted. Fault was

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								the control state and the status was PES Alarm. CB13 opened a short while later followed by K62, the fault breaker. Genset A1 did increase and picked up the entire load in Zone 3.
7.11.17	**8/20/07**	**1:08 pm**			**S**	**1:10 pm**	**DAK**	

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
7.12.1	**8/20/07**	**1:10 pm**	**7.12.2, 7.12.3**	**7.12.4**	**S**	**1:28 pm**	**DAK**	**Fault load verified and Fault key armed, Gensets A1 and B1 started first prior to load to make sure generation was greater than load. Genset A1 still running from above, Genset B1 connected at 1:28. LB3:40kW, LB5:40kW, LB6:60kW**
7.12.5	**8/20/07**	**1:28 pm**	**7.12.6**	**7.12.7**	**S**	**1:45 pm**	**DAK**	**SS placed itself in the OFF state position. Reset and Start commands resulted in TEST state followed by OFF state. While troubleshooting the SS both Genset A1 and B1 shut down. A1 showed a No Field Signal, which in the past has meant overload, and Genset B1 showed an External Trip. As the Meter triggers were disabled only the relay files may be of**

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								use.
7.12.1R	**8/20/07**	**1:45 pm**	**7.12.2, 7.12.3**	**7.12.4**	**S**	**2:00 pm**	**DAK**	**Fault load verified and Fault key armed, Gensets A1 and B1 started first prior to load to make sure generation was greater than load. Genset A1 still running from above, Genset B1 connected at 1:28. LB3:40kW, LB5:40kW, LB6:60kW**
7.12.5R	**8/20/07**	**2:00 pm**	**7.12.6**	**7.12.7**	**S**	**2:45 pm**	**DAK**	**SS placed itself in the OFF state position. Reset and Start commands resulted in TEST state followed by OFF state. While troubleshooting the SS both Genset A1 and B1 shut down. A1 showed a No Field Signal, which in the past has meant overload, and Genset B1 showed an External Trip. As the Meter triggers were disabled only the relay files may be of use. We were not able to get the SS to function properly and are waiting for further assistance from the team.**
								The source of the SS problem was found to be an 24v input module between the NPS DSP and the SandC SS. The enable input component was replaced within the SandC SS and the SS was returned to normal operation.
7.12.1R2	**9/05/07**	**12:15 pm**	**7.12.2, 7.12.3**	**7.12.4**	**S**	**1:35 pm**	**DAK**	**Fault load verified and Fault key armed. The SS was returned to normal service however Genset A1 would not operate correctly. At first the generator would attempt to start and then give a**

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								Ground/External fault. After checking the signaling between Relay 3 and the genset all connections and signals appeared to be correct. Relay 3's contact responsible for shutting the generator off was cycled a few times and the generator was started successfully. However before the inverter connected to the microgrid a DC Low Fault was issued. Repeated attempts to reset and restart were unsuccessful with the same DC Low Fault being issued each time. Youtility was contacted.
	9/7/07	**12:00 pm**				**12:45 pm**	**DAK**	**After talking to Youtility is was decided to measure the bus voltages. A scopemeter was attached to the DC bus and the genset was started. The first attempt to start the genset resulted in a Ground/External Fault, the second attempt resulted in a successful start. The DC bus voltages were both measured as 433v positive and negative within 2 volts. Genset B1 was also found to have a Logic Level Fault which was cleared with a power reset. Capture at 12:36 is the engine shutting down normally. Capture at 12:38 is the closing of CB31.**
7.12.1R3	**9/7/07**	**12:45 pm**	**7.12.2, 7.12.3**	**7.12.4**				**Fault load verified and Fault key armed, Gensets A1 and B1 started first prior to load to make sure generation was greater than load. Genset A1 was connected and LB3 set to 40kW, then Genset B1**

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								was connected. Next 40kW of load was applied to LB5 which caused the shutdown of both gensets. Genset A1 had a CAN Bus Comms fault and Genset B1 had a Low Oil Pressure alarm. The gensets were restarted. Loads were removed and genset A1 was restarted. Genset A1 then faulted on SA Operation fault. Genset A1 was reset and restarted. Genset A1 then faulted again on SA Operation fault. Genset A1 was reset and restarted.
7.12.5R3	**8/20/07**	**1:28 pm**	**7.12.6**	**7.12.7**				**SS placed itself in the OFF state position. Reset and Start commands resulted in TEST state followed by OFF state. While troubleshooting the SS both Genset A1 and B1 shut down. A1 showed a No Field Signal, which in the past has meant overload, and Genset B1 showed an External Trip. As the Meter triggers were disabled only the relay files may be of use.**
7.12.1R4	**10/3/07**	**10:26 am**	**7.12.2R4, 7.12.3R4**	**7.12.4R4**	**S**	**10:35 am**	**DAK**	**Fault load verified and Fault key armed, Gensets A1 and B1 started first prior to load to make sure generation was greater than load. LB3:40kW, LB5:40kW, LB6:40kW**
7.12.5R4	**10/3/07**	**10:35 am**	**7.12.6R4**	**7.12.7R4**	**S**	**10:42am**	**DAK**	**SS connected at 10:36. Meter1:70kW, Meter2:34kW Fault triggered at 10:39. The SS opened issuing a PES alarm fault. The fault load cleared but CB13 remained closed. The SS remained open and**

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								faulted, the gensets remained online, increased from 20kW to 36kW to serve LB3 and LB5
7.12.1R5	**10/3/07**	**10:42 am**	**7.12.2R5, 7.12.3R5**	**7.12.4R5**	**S**	**10:45 am**	**DAK**	**Fault load verified and Fault key armed, Gensets A1 and B1 started first prior to load to make sure generation was greater than load. LB3:40kW, LB5:40kW, LB6:60kW**
7.12.5R5	**10/3/07**	**10:45 am**	**7.12.6R5**	**7.12.7R5**	**S**	**10:58 am**	**DAK**	**SS fault cleared and reconnected at 10:46. LB 6 increased to 60kW Meter1:88kW, Meter2:34kW Fault triggered at 10:56. The SS opened issuing a PES alarm fault. CB12 opened and the fault was cleared.**
7.12.8	**10/3/07**	**10:58 am**	**7.12.9, 7.12.10**	**7.12.11, 7.12.12 7.12.13**	**S**	**11:01 am**	**DAK**	**Prior to intentionally shutting down the gensets both shutdown with a No field fault on A1 and a Boost fault on B1. Waveforms were captured at 10:59**
7.13.1	**10/3/07**	**1:26 pm**	**7.13.2, 7.13.3**	**7.13.4, 7.13.5, 7.13.6**	**S**	**1:37 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.13.7	**10/3/07**	**1:37 pm**	**7.13.8**	**7.13.9, 7.13.10**	**S**	**1:43 pm**	**DAK**	**Genset A1 and A2 setup and connected. LB3:40kW, LB4:40kW, LB6:40kW**
7.13.11	**10/3/07**	**1:43 pm**	**7.13.12**		**S**	**1:47 pm**	**DAK**	**SS closed. Meter1:63kW, Meter2:27kW**
7.13.13	**10/3/07**	**1:48 pm**	**7.13.14, 7.13.15**	**7.13.16**	**S**	**1:55 pm**	**DAK**	**Fault initiated at 1:48. SS remained closed, CB41 and CB31 opened shutting down both gensets.**
7.13.17	**10/3/07**	**1:55 pm**			**S**	**1:57 pm**	**DAK**	

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7.13.1R1	**10/3/07**	**2:00 pm**	**7.13.2R1, 7.13.3R1**	**7.13.4, 7.13.5, 7.13.6**	**S**	**2:06 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.13.7R1	**10/3/07**	**2:06 pm**	**7.13.8R1**	**7.13.9 R1, 7.13.10 R1**	**S**	**2:09 pm**	**DAK**	**Genset A1 and A2 setup and connected. LB3:40kW, LB4:40kW, LB5:20kW, LB6:40kW**
7.13.11R1	**10/3/07**	**2:09 pm**	**7.13.12 R1**		**S**	**2:11 pm**	**DAK**	**SS closed. Meter1:79kW, Meter2:43kW**
7.13.13R1	**10/3/07**	**1:48 pm**	**7.13.14 R1, 7.13.15 R1**	**7.13.16 R1**				**Fault initiated at 2:12. SS remained closed, CB41 and CB31 opened shutting down both gensets.**
7.13.17R1	**10/3/07**	**2:11 pm**			**S**	**2:12 pm**	**DAK**	
7.14.1	**10/3/07**	**2:25 pm**	**7.14.2, 7.14.3**	**7.14.4, 7.14.5, 7.14.6**	**S**	**2:28 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.14.7	**10/3/07**	**2:28pm**	**7.14.8**	**7.14.9, 7.14.10**	**S**	**4:01 pm**	**DAK**	**Gensets A1 and A2 connected at 4:00. LB3:40kW, LB4:40kW, LB6:40kW**
7.14.11	**10/3/07**	**4:01 pm**	**7.14.12**		**S**	**4:08 pm**	**DAK**	**SS closed, Meter1:65kW, Meter2:30kW**
7.14.13	**10/3/07**	**4:08 pm**	**7.14.14, 7.14.15**	**7.14.16**	**S**	**4:15 pm**	**DAK**	**Fault initiated at 4:09. SS remained closed. CB31 and CB41 opened. Both gensets shutdown.**
7.14.17	**10/3/07**	**4:15 pm**			**S**	**4:18 pm**	**DAK**	

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Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
7.15.1	10/3/07	4:18 pm	7.15.2, 7.15.3	7.15.4, 7.15.5, 7.15.6	S	4:20 pm	DAK	Fault load connected and verified. Fault key armed.
7.15.7	10/3/07	4:20 pm	7.15.8	7.15.9, 7.15.10	S	4:25 pm	DAK	Gensets A1 and B1 connected at 4:24. LB3:40kW, LB5:40kW, LB6:40kW
7.15.11	10/3/07	4:25 pm	7.15.12		S	4:26 pm	DAK	SS closed, Meter1:64kW, Meter2:28kW
7.15.13	10/3/07	4:26pm	7.15.14, 7.15.15	7.15.16	S	4:28 pm	DAK	Fault initiated at 4:28. SS opened. Gensets picked up load. Fault removed after 10 seconds. SS reconnected. The setup returned to the pre-fault conditions
7.15.1R1	10/3/07	4:28 pm	7.15.2R1, 7.15.3R1	7.15.4R1, 7.15.5R1, 7.15.6R1	S	4:30 pm	DAK	Retested to confirm results. Fault load connected and verified. Fault key armed.
7.15.7R1	10/3/07	4:30 pm	7.15.8	7.15.9R1, 7.15.10R1	S	4:32 pm	DAK	Gensets A1 and B1 still connected. LB3:40kW, LB5:40kW, LB6:40kW
7.15.11R1	10/3/07	4:32 pm	7.15.12R1		S	4:34 pm	DAK	SS still closed, Meter1:64kW, Meter2:28kW

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7.15.13	**10/3/07**	**4:33pm**	**7.15.14R, 7.15.15R1**	**7.15.16R1**	**S**	**4:42 pm**	**DAK**	**Fault initiated at 4:41. SS opened. Gensets picked up load. Fault removed after 10 seconds. SS reconnected.**
7.15.17	**10/3/07**	**4:42 pm**			**S**	**4:45 pm**	**DAK**	
7.16.1	**10/3/07**	**4:45 pm**	**7.16.2, 7.16.3**	**7.16.4, 7.16.5, 7.16.6**	**S**	**4:47 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.16.7	**10/3/07**	**4:47 pm**	**7.16.8**	**7.16.9, 7.16.10**	**S**	**4:49 pm**	**DAK**	**Gensets A1 and B1 still connected. LB3:40kW, LB5:40kW, LB6:40kW**
7.16.11	**10/3/07**	**4:49 pm**	**7.16.12**		**S**	**4:51 pm**	**DAK**	**SS still closed, Meter1:65kW, Meter2:28kW**
7.16.13	**10/3/07**	**4:51 pm**	**7.16.14, 7.16,15**	**7.16.16**		**4:55 pm**		**Fault initiated at 4:54. SS opened. CB51 opened and shutdown genset B1. CB41, CB31 and SS remained closed and genset A1 continued to serve load.**
7.16.17	**10/3/07**	**4:55 pm**			**S**	**4:56 pm**	**DAK**	
7.6.1R	**1/23/08**	**2:02 pm**	**7.6.2R**	**7.6.3R**	**S**	**2:10 am**	**DAK**	**Gensets A1 and A2 setup. Fault key armed.**
7.6.4R	**1/23/08**	**2:10 pm**	**7.6.5R**	**7.6.6R, 7.6.7R**	**S**	**2:15 pm**	**DAK**	**Triggers disabled, Genset A1 and A2 connected. LB3:40kW, LB4:40kW, LB6:40kW. SS connected. Meter1:66kW, Meter2:31kW. Triggers armed**
7.6.8R	**1/23/08**	**2:15 pm**	**7.6.9R, 7.6.10R**	**7.6.11R**	**S**	**2:25 pm**	**DAK**	**Fault timer set to 10 sec Fault initiated at 2:16. SS opened, CB31 opened, CB41 Opened, and CB51 opened. Gensets A1 shutdown on External Trip and A2 shutdown on Low Oil Pressure (Stall). Meter1:37kW, Meter2:0kW**

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7.6.12	**1/23/08**	**2:25 pm**			**S**	**2:35 pm**	**DAK**	
7.9.1R	**1/30/08**	**2:40 pm**	**7.9.2R, 7.9.3R**	**7.9.4R, 7.9.5R, 7.9.6R**	**S**	**2:45 pm**	**DAK**	**Fault load verified, key armed, All breakers closed.**
7.9.7R	**1/30/08**	**2:45 pm**	**7.9.8R**	**7.9.9R**	**S**	**2:50 pm**	**DAK**	**Gensets setup, Triggers disabled, Genset A1 and A2 connected**
7.9.10R	**1/30/08**	**2:50 pm**	**7.9.11R**	**7.9.12R**	**S**	**3:15 pm**	**DAK**	**LB3:40kW, LB4:40kW, LB6:40kW, SS connected at 1:41. Meter1:73kW, Meter2:37kW**
7.9.13R	**1/30/08**	**3:15 pm**	**7.9.14R**	**7.9.15R, 7.9.16R**	**S**	**4:00 pm**	**DAK**	**Triggers enabled. Fault timer set to 10 sec. Fault initiated but breaker K42 failed to close in the fault load. The breaker was manually exercised a few times. During this Genset A2 suddenly shutdown with a Skipp3 fault. The fault was cleared and the genset restarted. The Genset shutdown again with a Skipp3 fault and further investigation was performed. The output filter cap was found to be damaged and Youtility was contacted for replacement.**
								The filter capacitors from A2 were replaced with those from B1. The Genset was tested and returned to service. Replacement capacitor filters were order for B1.
7.9.1R	**1/31/08**	**1:35 pm**	**7.9.2R,**	**7.9.4R,**	**S**	**1:38 pm**	**DAK**	**Fault load verified, key armed, All breakers closed.**

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			7.9.3R	7.9.5R, 7.9.6R				
7.9.7R	1/31/08	1:38 pm	7.9.8R	7.9.9R	S	1:40 pm	DAK	Gensets setup, Triggers disabled, Genset A1 and A2 connected
7.9.10R	1/31/08	1:40 pm	7.9.11R	7.9.12R	S	1:42: pm	DAK	LB3:40kW, LB4:40kW, LB6:40kW, SS connected at 3:13. Meter1:71kW, Meter2:33kW
7.9.13R	1/31/08	1:42 pm	7.9.14R	7.9.15R, 7.9.16R	S	1:46 pm	DAK	Triggers enabled. Fault timer set to 10 sec. Fault initiated. SS opened. CB41 opened and Genset A2 Shutdown. CB31 and 51 remained closed. Genset A1 remained online serving the load in Zone 3. The SS reclosed shortly afterwards.
7.9.17R	1/31/08	1:46 pm			S	2:00 pm	DAK	
7.4.1R	1/31/08	2:00 pm	7.4.2R, 7.4.3R	7.4.4R, 7.4.5R	S	2:02 pm	DAK	Fault load connected, armed, and verified.
7.4.6R	1/31/08	2:02 pm	7.4.7R, 7.4.8R	7.4.9R	S	2:07 pm	DAK	Genset A1 and A2 connected. SS closed.
7.4.10R	1/31/08	2:07 pm	7.4.11R	7.4.12R	S	2:10 pm	DAK	LB3:10kW, LB4:65kW, LB6:40kW, Meter1:37kW, Meter2:1kW
7.4.13R	1/31/08	2:10 pm	7.4.14R, 7.4.15R	7.4.16R	S	2:15 pm	DAK	Fault timer at 99 sec. LB4 was increased to 65kW due to load drift and generation offset. This was done to insure enough load to trip CB41 under overload. The fault was applied at 2:11 pm. CB41 opened and Genset A2 shutdown. The SS, CB31, and CB51 remained closed and Genset A1 and the

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								utility serving the load. The SS opened after about 50 seconds due to anti-islanding. Genset A1 continued to serve the 10kW load in Zone 3
7.4.17	**1/31/08**	**2:15 am**			**S**	**2:20 pm**	**DAK**	
7.5.1R	**1/31/08**	**2:20 pm**	**7.5.2R, 7.5.3R**	**7.5.4R, 7.5.5R, 7.5.6R**	**S**	**2:36 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.5.7R	**1/31/08**	**2:36 pm**	**7.5.8R**	**7.5.9R**	**S**	**2:37 pm**	**DAK**	**LB3: 40kW, LB6:40kW**
7.5.10R	**1/31/08**	**2:37 pm**	**7.5.11R**	**7.5.12R**	**S**	**2:39 pm**	**DAK**	**Genset A1 connected, SS connected at 2:38pm. Meter1:56kW, Meter2:19kW**
7.5.13R	**1/31/08**	**2:39 pm**	**7.5.14R, 7.5.15R**	**7.5.16R**	**S**	**2:55 pm**	**DAK**	**Fault timer set to 10 sec. Triggers armed. Fault initiated at 2:50pm. The SS opened. CB31 opened shutting down Genset A1. CB41 remained closed. CB51 opened. Meter1:37kW, Meter2:0kW**
7.5.17R	**1/31/08**	**2:55 pm**			**S**	**3:00 pm**	**DAK**	
7.6.1R	**1/31/08**	**3:00 pm**	**7.6.2R**	**7.6.3R**	**S**	**3:03 pm**	**DAK**	**Gensets A1 and A2 setup. Fault key armed.**
7.6.4R	**1/31/08**	**3:03 pm**	**7.6.5R**	**7.6.6R, 7.6.7R**	**S**	**3:06 pm**	**DAK**	**Genset A1 and A2 connected. LB3:40kW, LB4:40kW, LB6:40kW. SS connected. Meter1:70kW, Meter2:34kW. Triggers armed**
7.6.8R	**1/31/08**	**3:06 pm**	**7.6.9R, 7.6.10R**	**7.6.11R**	**S**	**3:09 pm**	**DAK**	**Fault timer set to 10 sec Fault initiated at 3:07. SS opened. CB41 opened and Genset A2 shutdown. CB 31 opened and Genset A1 shutdown. CB 51 opened. Meter1:37kW, Meter2:0kW**

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7.6.12R	**1/31/08**	**3:09 pm**			**S**	**3:15 pm**	**DAK**	
7.13.1R	**2/1/08**	**2:00 pm**	**7.13.2R, 7.13.3R**	**7.13.4, 7.13.5, 7.13.6**	**S**	**2:10 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.13.7R	**2/1/08**	**2:10 pm**	**7.13.8R**	**7.13.9R, 7.13.10R**	**S**	**2:14 pm**	**DAK**	**Genset A1 and A2 setup and connected. LB3:40kW, LB4:40kW, LB6:40kW**
7.13.11R	**2/1/08**	**2:14 pm**	**7.13.12 R**		**S**	**2:15 pm**	**DAK**	**SS closed at 2:15. Meter1:73kW, Meter2:36kW**
7.13.13R	**2/1/08**	**2:15 pm**	**7.13.14 R, 7.13.15 R**	**7.13.16R**	**S**	**2:19 pm**	**DAK**	**Fault timer set to 10 sec. Triggers armed. Fault initiated at 2:17. SS opened. Genset A1 and A2 picked up the load and remained online. The fault load opened after 10 seconds and the SS reconnected shortly thereafter. All breakers remained closed, all generators remained running.**
7.13.17R	**2/1/08**	**2:19 pm**			**S**	**2:30 pm**	**DAK**	
7.14.1R	**2/1/08**	**2:30 pm**	**7.14.2R, 7.14.3R**	**7.14.4R, 7.14.5R, 7.14.6R**	**S**	**2:33 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.14.7R	**2/1/08**	**2:33 pm**	**7.14.8R**	**7.14.9R, 7.14.10R**	**S**	**2:34 pm**	**DAK**	**Gensets A1 and A2 connected. LB3:40kW, LB4:40kW, LB6:40kW**
7.14.11R	**2/1/08**	**2:34 pm**	**7.14.12R**		**S**	**2:35 pm**	**DAK**	**SS closed, Meter1:71kW, Meter2:35kW**
7.14.13R	**2/1/08**	**2:35 pm**	**7.14.14R, 7.14.15R**	**7.14.16R**	**S**	**2:38 pm**	**DAK**	**Fault timer set 10 sec. Triggers enabled. Fault initiated at 2:36. SS opened. CB41 opened and**

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								Genset A2 shutdown. CB31 and CB51 remained close with Genset A1 serving the load. The SS reconnect shortly thereafter.
7.14.17R	**2/1/08**	**2:38 pm**			**S**			
7.15.1R	**2/6/08**	**12:20 pm**	**7.15.2R, 7.15.3R**	**7.15.4R, 7.15.5R, 7.15.6R**	**S**	**12:25 pm**	**DAK**	**Fault load connected and verified. Fault key armed**
7.15.7R	**2/6/08**	**12:25 pm**	**7.15.8R**	**7.15.9R, 7.15.10R**	**S**	**12:30 pm**	**DAK**	**Gensets A1 and B1 connected. LB3:40kW, LB5:40kW, LB6:40kW**
7.15.11R	**2/6/08**	**12:30 pm**	**7.15.12R**		**S**	**12:35 pm**	**DAK**	**SS closed at 12:35, Meter1:73kW, Meter2:37kW**
7.15.13R	**2/6/08**	**12:35 pm**	**7.15.14R, 7.15.15R**	**7.15.16R**	**S**	**12:43 pm**	**DAK**	**Triggers armed, Fault initiated at 12:38. The SS remained closed. All Gensets and Breakers remained online and closed. No operations, other than the fault load application and removal, occurred.**
7.15.17R	**2/6/08**	**12:43 pm**			**S**	**12:45 pm**	**DAK**	
7.16.1R	**2/6/08**	**12:45 pm**	**7.16.2R, 7.16.3R**	**7.16.4R, 7.16.5R, 7.16.6R**	**S**	**12:47 pm**	**DAK**	**Fault load connected and verified. Fault key armed.**
7.16.7R	**2/6/08**	**12:47 pm**	**7.16.8R**	**7.16.9R, 7.16.10R**	**S**	**12:49 pm**	**DAK**	**Gensets A1 and B1 connected. LB3:40kW, LB5:40kW, LB6:40kW**
7.16.11R	**2/6/08**	**12:49 pm**	**7.16.12R**		**S**	**12:50 pm**	**DAK**	**SS closed, Meter1:70kW, Meter2:34kW**
7.16.13R	**2/6/08**	**12:50 pm**	**7.16.14R,**	**7.16.16R**	**S**	**12:55 pm**	**DAK**	**Triggers armed. Fault initiated at 12:53. SS opened.**

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			7.16.15R					CB51 opened and Genset B1 shutdown. Genset A1 remained online carrying the load. CB 31 and 41 remained closed. SS reconnected shortly thereafter.
7.16.17R	2/6/08	12:55 pm			S	12:58 pm	DAK	
7.7.1R	2/6/08	1:55 pm	7.7.2R, 7.7.3R	7.7.4R, 7.7.5R, 7.7.6R	S	2:00 pm	DAK	Fault load verified and connected, Fault key armed
7.7.7R	2/6/08	2:00 pm	7.7.8R	7.7.9R	S	2:01 pm	DAK	LB3:40kW, LB6:40kW, Genset B1 connected
7.7.10R	2/6/08	2:01 pm	7.7.11R	7.7.12R	S	2:02 pm	DAK	SS closed. Meter1:52kW Meter2:16kW
7.7.13R	2/6/08	2:02 pm	7.7.14R, 7.7.15R	7.7.16R	S	2:06 pm	DAK	Triggers armed. Fault initiated at 2:04. SS opened. CB51 opened and genset B1 shutdown. CB31 and CB41 remained closed. SS remained opened as a Dead Bus was present.
7.7.17R	2/6/08	2:06 pm			S	2:09 pm	DAK	
7.8.1	2/6/08	2:09 pm	7.8.2	7.8.3	S	2:11 pm	DAK	Fault load verified and connected, Fault key armed
7.8.4	2/6/08	2:11 pm	7.8.5	7.8.6, 7.8.7	S	2:15 pm	DAK	Genset A1 and B1 connected, LB3:40kW, LB4:40kW, LB6:40kW. SS closed. Meter1:52kW Meter2:16kW
7.8.8	2/6/08	2:15 pm	7.8.9, 7.8.10	7.8.11	S	2:18 pm	DAK	Triggers armed. Fault initiated at 2:17. CB51 opened and Genset B1 shutdown. SS, CB31 and CB41 remained closed and Genset A1 remained connected.
7.8.12	2/6/08	2:18 pm			S	2:25 pm	DAK	

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7.10.1	**2/6/08**	**2:25 pm**	**7.10.2, 7.10.3**	**7.10.4, 7.10.5, 7.10.6**	**S**	**2:28pm**	**DAK**	**Fault load verified and connected, Fault key armed**
7.10.7	**2/6/08**	**2:28 pm**	**7.10.8**	**7.10.9**	**S**	**2:30 pm**	**DAK**	**Gensets A1 and B1 connected**
7.10.10	**2/6/08**	**2:30 pm**	**7.10.11**	**7.10.12**	**S**	**2:33 pm**	**DAK**	**LB3:40kW, LB4:40kW, LB6:40kW. SS closed. Meter1:70kW, Meter2:34kW**
7.10.13	**2/6/08**	**2:33 pm**	**7.10.14, 7.10.15**	**7.10.16**	**S**	**2:36 pm**	**DAK**	**Triggers armed, Fault initiated at 2:34. SS opened, CB51 opened and Genset B1 shutdown, CB31 opened and Genset A1 shutdown. CB41 remained closed.**
7.10.17	**2/6/08**	**2:36 pm**			**S**	**2:40 pm**	**DAK**	

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Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.1.1	**2/19/08**	**12:30 pm**	**8.1.2**	**8.1.3**	**S**	**12:33 pm**	**DAK**	**CB1, CB12, CB31, CB41, and CB51 Closed, All LBs 0kW, SS Open**
8.1.4	**2/19/08**	**12:33 pm**	**8.1.5**		**S**	**12:40 pm**	**DAK**	**Genset A1 connected, Triggers armed, LB3:20kW**

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								Load increased at 12:36 pm
8.1.6	**2/19/08**	**12:40 pm**	**8.1.7**		**S**	**12:46 pm**	**DAK**	**Triggers armed, LB3:40kW, Load increased at 12:41 pm**
8.1.8	**2/19/08**	**12:46 pm**	**8.1.9**		**S**	**12:54 pm**	**DAK**	**Triggers armed, LB3:60kW, Load increased at 12:48 pm**
8.1.10	**2/19/08**	**12:54 pm**			**S**	**12:59 pm**	**DAK**	**LB3:0kW Voltage set to 291V (+5%)**
8.1.10(8.1.4)	**2/19/08**	**12:59 pm**	**8.1.10(8.1.5)**		**S**	**1:08 pm**	**DAK**	**Triggers armed, LB3:20kW, Load increased at 1:04 pm**
8.1.10(8.1.6)	**2/19/08**	**1:08 pm**	**8.1.10(8.1.7)**		**S**	**1:13 pm**	**DAK**	**Triggers armed, LB3:40kW, Load increased at 1:09 pm**
8.1.10(8.1.8)	**2/19/08**	**1:13 pm**	**8.1.10(8.1.9)**		**S**	**1:20 pm**	**DAK**	**Triggers armed, LB3:60kW, Load increased at 1:14 pm**
8.1.11	**2/19/08**	**1:20 pm**			**S**	**1:21 pm**	**DAK**	**LB3:0kW Voltage set to 263V (-5%)**
8.1.11(8.1.4)	**2/19/08**	**1:21 pm**	**8.1.11(8.1.5)**		**S**	**1:27 pm**	**DAK**	**Triggers armed, LB3:20kW, Load increased at 1:23 pm**
8.1.11(8.1.6)	**2/19/08**	**1:27 pm**	**8.1.11(8.1.7)**		**S**	**1:36 pm**	**DAK**	**Triggers armed, LB3:40kW, Load increased at 1:29 pm**
8.1.11(8.1.8)	**2/19/08**	**1:36 pm**	**8.1.11(8.1.9)**		**S**	**1:50 pm**	**DAK**	**Triggers armed, LB3:60kW, Load increased at 1:45 pm**

Start Test	Test	Start	Verify/	Verify/	Status	End	Initials	Test Event Comments:

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

Sequence No.	Date	Time	Action	Action	S or U	Time		
8.1.12	2/19/08	1:50 pm			S	2:02 pm	DAK	LB3:0kW, Genset A1 shutdown
8.1.13(8.1.4)	2/19/08	2:02 pm	8.1.13(8.1.5)		S	2:23 pm	DAK	Genset A2 connected, Triggers armed, LB4:20kW Load increased at 2:19 pm
8.1.13(8.1.6)	2/19/08	2:23 pm	8.1.13(8.1.7)		S	2:29 pm	DAK	Triggers armed, LB4:40kW, Load increased at 2:24 pm
8.1.13(8.1.8)	2/19/08	2:29 pm	8.1.13(8.1.9)		S	2:36 pm	DAK	Triggers armed, LB4:60kW, Load increased at 2:30 pm
8.1.13(8.1.10)	2/19/08	2:36 pm			S	2:37 pm	DAK	LB4:0kW Voltage set to 291V (+5%)
8.1.13(8.1.10(8.1.4))	2/19/08	2:37 pm	8.1.13(8.1.10(8.1.5))		S	2:43 pm	DAK	Triggers armed, LB4:20kW, Load increased at 2:38 pm
8.1.13(8.1.10(8.1.6))	2/19/08	2:43 pm	8.1.13(8.1.10(8.1.7))		S	2:53 pm	DAK	Triggers armed, LB4:40kW, Load increased at 2:49 pm
8.1.13(8.1.10(8.1.8))	2/19/08	2:53 pm	8.1.13(8.1.10(8.1.9))		S	2:59 pm	DAK	Triggers armed, LB4:60kW, Load increased at 2:54 pm
8.1.13(8.1.11)	2/19/08	2:59 pm			S	3:00 pm	DAK	LB4:0kW Voltage set to 263V (-5%)
8.1.13(8.1.11(8.1.4))	2/19/08	3:00 pm	8.1.13(8.1.11(8.1.5))		S	3:04 pm	DAK	Triggers armed, LB4:20kW, Load increased at 3:00 pm
8.1.13(8.1.11(8.1.6))	2/19/08	3:04 pm	8.1.13(8.1.11(8.1.7))		S	3:12 pm	DAK	Triggers armed, LB4:40kW, Load increased at 3:07 pm

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DTC Registered Procedure - CERTS Microgrid Test Plan Appendix C: TEST LOG			
Dolan Technology Center	Document No: DTC212812.207.01A		
Written by: AEP	Effective Date: 23 Feb 2007	Target Group: Assigned	
Approved by: K. P. Loving	Procedure Review Date: 23 Feb. 2008		

Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.1.13(8.1.11(8.1.8))	2/19/08	3:12 pm	8.1.13(8.1.11(8.1.9))		S	3:17 pm	DAK	Triggers armed, LB4:60kW, Load increased at 3:12 pm
8.1.14	2/19/08	3:17 pm			S	3:25 pm	DAK	LB4:0kW, Genset A2 shutdown
8.1.15(8.1.4)	2/21/08	9:45 am	8.1.15(8.1.5)		S	9:57 am	DAK	Genset B1 connected, Triggers armed, LB5:20kW Load increased at 9:52 am
8.1.15(8.1.6)	2/21/08	9:57 am	8.1.15(8.1.7)		S	10:08 am	DAK	Triggers armed, LB5:40kW, Load increased at 10:03 am
8.1.15(8.1.8)	2/21/08	10:08 am	8.1.15(8.1.9)		S	10:14 am	DAK	Triggers armed, LB5:60kW, Load increased at 10:09 am
8.1.15(8.1.10)	2/21/08	10:14 am			S	10:15 am	DAK	LB5:0kW Voltage set to 291V (+5%)

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8.1.15(8.1.10(8.1.4))	**2/21/08**	**10:15 am**	**8.1.15(8.1.10(8.1.5))**		**S**	**10:22 am**	**DAK**	**Triggers armed, LB5:20kW, Load increased at 10:17 am**
8.1.15(8.1.10(8.1.6))	**2/21/08**	**10:22 am**	**8.1.15(8.1.10(8.1.7))**		**S**	**10:26 am**	**DAK**	**Triggers armed, LB5:40kW, Load increased at 10:22 am**
8.1.15(8.1.10(8.1.8))	**2/21/08**	**10:26 am**	**8.1.15(8.1.10(8.1.9))**		**S**	**10:31 am**	**DAK**	**Triggers armed, LB5:60kW, Load increased at 10:27 am**
8.1.15(8.1.11)	**2/21/08**	**10:31 am**			**S**	**10:33 am**	**DAK**	**LB5:0kW Voltage set to 263V (-5%)**
8.1.15(8.1.11(8.1.4))	**2/21/08**	**10:33 am**	**8.1.15(8.1.11(8.1.5))**		**S**	**10:39 am**	**DAK**	**Triggers armed, LB5:20kW, Load increased at 10:34 am**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.1.15(8.1.11(8.1.6))	**2/21/08**	**10:39 am**	**8.1.15(8.1.11(8.1.7))**		**S**	**10:44 am**	**DAK**	**Triggers armed, LB5:40kW, Load increased at 10:40 am**

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

8.1.15(8.1.11(8.1.8))	**2/21/08**	**10:44 am**	**8.1.15(8.1.11(8.1.9))**		**S**	**10:49 am**	**DAK**	**Triggers armed, LB5:60kW, Load increased at 10:45 am**
8.1.16	**2/21/08**	**10:49 am**			**S**	**10:50 am**	**DAK**	**LB5:0kW, Genset B1 shutdown**
8.2.1	**2/21/08**	**10:50 am**	**8.2.2**		**S**	**11:10 am**	**DAK**	**Weak grid. SS, CB12, CB31, CB41, CB51 Closed. Gensets in unit mode and setup. LB3:20kW, LB4:20kW, LB6:30kW, LB6 increased to 30kW to prevent reverse power condition at SS. This was necessary due to unbalance power at the PCC. Meter 1:6kW**
8.2.3	**2/21/08**	**11:10 am**	**8.2.4**	**8.2.5**	**S**	**11:16 am**	**DAK**	**Triggers armed. SS manual open asserted at 11:11 am. SS opened with a Fault Status and PES alarm. Genset A1:0kW, Genset A2:37kW Meter1:0kW**
8.2.6	**2/21/08**	**11:16 am**	**8.2.7**	**8.2.8**	**S**	**11:28 am**	**DAK**	**SS was reset. Triggers armed. Manual open was removed at 11:23 am. SS closed. Genset A1:5kW Genset A2:55kW, Meter1:7kW. At 11:25 the SS opened unexpectedly under reverse power.**
8.2.9	**2/21/08**	**11:28 am**			**S**	**11:40 am**	**DAK**	**Genset A1 was shutdown. The SS was allowed to reconnect. A trigger was setup when Genset A2 was shutdown to get a baseline of the unbalance due solely to the utility. The event occurred at 11:36 am**
8.3.1	**2/21/08**	**11:40 am**	**8.3.2**		**S**	**11:43 am**	**DAK**	**Weak grid. SS, CB12, CB31, CB41, CB51 Closed. Gensets in unit mode and setup. LB3:60kW,**

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								LB4:40kW. Meter 1:34kW
8.3.3	**2/21/08**	**11:43 am**	**8.3.4**	**8.3.5**	**S**	**11:49 am**	**DAK**	**Triggers armed. SS manual open asserted at 11:45 am. SS opened with a Fault Status and PES alarm. Genset A1:29kW, Genset A2:60kW Meter1:0kW**
8.3.6	**2/21/08**	**11:49 am**	**8.3.7**	**8.3.8**	**S**	**12:03 pm**	**DAK**	**SS was reset. Triggers armed. Manual open was removed at 11:50 am. SS closed. Genset A1:4kW Genset A2:53kW, Meter1:35kW. Triggers disabled. Genset A2 shutdown on an overfield fault at 11:54.**
8.3.9	**2/21/08**	**12:03 pm**			**S**	**12:05 pm**	**DAK**	**Genset A1 was shutdown normally. All loads removed.**

(S =Successful; U = Unsuccessful)

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.4.1	**2/26/08**	**10:26 am**	**8.4.2**		**S**	**10:46 am**	**DAK**	**SS manual open asserted. CB12, CB31, CB41, CB51 closed. Gensets setup and connected. LB3:60kW, MeterA1:13kW, MeterA2:43kW**
8.4.3	**2/26/08**	**10:46 am**	**8.4.4**	**8.4.5**	**S**	**10:51 am**	**DAK**	**Triggers armed. Load decreased at 10:48 am. MeterA1:4kW, MeterA2:34kW**
8.4.6	**2/26/08**	**10:51 am**						**LB3:0kW, Genset A1 and A2 shutdown.**

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8.5.1	**2/26/08**	**11:03 am**	**8.5.2**		**S**	**11:05 am**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:35kW, LB4:35kW**
8.5.3	**2/26/08**	**11:05 am**	**8.5.4**	**8.5.5**	**S**	**11:20 am**	**DAK**	**Meter3:57kW, MeterA1:5kW, MeterA2:6kW, Triggers armed. LB3:85kW Load increased at 11:15 am. Meter3:58kW, MeterA1:48kW, MeterA2:6kW**
8.5.6	**2/26/08**	**11:20 am**			**S**	**11:22 am**		**A mistake with the dispatch was noticed. Genset A1 was accidentally set for 0kW in feeder mode. The test was repeated. Gensets were not shutdown but instead redispatched.**
8.5.1R	**2/26/08**	**11:22 am**	**8.5.2R**		**S**	**11:28 am**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:35kW, LB4:35kW, Meter3:51kW, MeterA1:10kW, MeterA2:6kW,**
8.5.3R	**2/26/08**	**11:28 am**	**8.5.4R**	**8.5.5R**	**S**	**11:36 am**	**DAK**	**Triggers armed. LB3:85kW Load increased at 11:31 am. Meter3:52kW, MeterA1:52kW, MeterA2:7kW**
8.5.6R	**2/26/08**	**11:36 am**			**S**	**11:37 am**	**DAK**	
8.6.1	**2/26/08**	**11:37 am**	**8.6.2**		**S**	**11:38 am**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:75kW, LB4:35kW, Meter3:51kW, MeterA1:44kW, MeterA2:7kW**
8.6.3	**2/26/08**	**11:38 am**	**8.6.4**	**8.6.5**	**S**	**11:45 am**	**DAK**	**Triggers armed. LB4:55kW Load increased at 11:39 am. Meter3:58kW, MeterA1:58kW,**

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								MeterA2:5kW
8.6.6	**2/26/08**	**11:45 am**			**S**	**11:46 am**	**DAK**	**Gensets and loads redispatched instead of shutdown**
8.7.1	**2/26/08**	**11:46 am**	**8.7.2**		**S**	**11:49 am**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:85kW, LB4:35kW, Meter3:54kW, MeterA1:51kW, MeterA2:6kW**
8.7.3	**2/26/08**	**11:49 am**	**8.7.4**	**8.7.5**	**S**	**12:02 pm**	**DAK**	**Manually triggered at 11:52. Setpoint changed at 11:53 am. Manually triggered at 11:57. Meter3:103kW, MeterA1:0kW, MeterA2:6kW**
8.7.6	**2/26/08**	**12:02 pm**			**S**	**12:03 pm**	**DAK**	**Gensets and loads redispatched instead of shutdown**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.8.1	**2/26/08**	**12:03 pm**	**8.8.2**		**S**	**12:07 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:35kW, LB4:35kW, Meter3:47kW, MeterA1:14kW, MeterA2:6kW**
8.8.3	**2/26/08**	**12:07 pm**	**8.8.4**	**8.8.5**	**S**	**12:15 pm**	**DAK**	**Triggers armed. Manual Open asserted at 12:08. Meter3:-2kW, MeterA1:9kW, MeterA2:58kW**

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								At approx 12:10 both gensets shutdown, Low Oil Pressure on A1, and Underspeed on A2. Testing repeated.
8.8.6	**2/26/08**	**12:15 pm**	**8.8.7**	**8.8.8**	**S**	**12:20 pm**	**DAK**	**Gensets shutdown unexpectedly, Loads were removed.**
8.8.1	**2/26/08**	**12:03 pm**	**8.8.2**		**S**	**12:07 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:35kW, LB4:35kW, Meter3:47kW, MeterA1:14kW, MeterA2:6kW**
8.8.3	**2/26/08**	**12:07 pm**	**8.8.4**	**8.8.5**	**S**	**12:15 pm**	**DAK**	**Triggers armed. Manual Open asserted at 12:08. Meter3:-2kW, MeterA1:9kW, MeterA2:58kW At approx 12:10 both gensets shutdown, Low Oil Pressure on A1, and Underspeed on A2. Testing repeated.**
8.8.1R	**2/26/08**	**1:08 pm**	**8.8.2R**		**S**	**1:18 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:35kW, LB4:35kW, Meter3:48kW, MeterA1:14kW, MeterA2:56kW**
8.8.3R	**2/26/08**	**1:18 pm**	**8.8.4R**	**8.8.5R**	**S**	**1:25 pm**	**DAK**	**Triggers armed. Manual Open asserted at 1:21. Meter3:-2kW, MeterA1:9kW, MeterA2:59kW, Freq 59.57Hz**
8.8.6R	**2/26/08**	**1:25 pm**	**8.8.7R**	**8.8.8R**	**S**	**1:32 pm**	**DAK**	**Manual Open removed at 1:27. SS Closed. Meter3:49kW, MeterA1:14kW, MeterA2:4kW**
8.8.9R	**2/26/08**	**1:32 pm**			**S**	**1:33 pm**	**DAK**	**Gensets and loads redispatched instead of shutdown.**

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8.9.1	**2/26/08**	**1:33 pm**	**8.9.2**		**S**	**1:40 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:60kW, LB4:60kW, Meter3:55kW, MeterA1:51kW, MeterA2:4kW**
8.9.3	**2/26/08**	**1:40 pm**	**8.9.4**	**8.9.5**	**S**	**1:52 pm**	**DAK**	**Triggers armed. Manual Open asserted at 1:42 pm. SS opened. Genset A1 shutdown with a Overload Alarm, Genset A2 shutdown with a Low Oil Pressure alarm. Test repeated**
8.9.1R	**2/26/08**	**1:52 pm**	**8.9.2R**		**S**	**2:02 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:60kW, LB4:60kW, Meter3:51kW, MeterA1:52kW, MeterA2:9kW**
8.9.3R	**2/26/08**	**2:02 pm**	**8.9.4R**	**8.9.5R**	**S**	**208 pm**	**DAK**	**Triggers armed. Manual Open asserted at 2:03 pm. SS opened. Meter3:-2kW, MeterA1:47kW, MeterA2:60kW**
8.9.6R	**2/26/08**	**2:08 pm**	**8.9.7R**	**8.9.8R**	**S**	**2:14 pm**	**DAK**	**Manual Open removed at 2:09. SS Closed. Meter3:56kW, MeterA1:48kW, MeterA2:3kW**
8.9.9R	**2/26/08**	**2:14 pm**			**S**	**2:15 pm**	**DAK**	**Genset A2 shutdown, Genset A1 and loads redispatched.**
8.10.1	**2/26/08**	**2:15 pm**	**8.10.2**		**S**	**2:27 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:40kW, LB5:50kW, Meter3:36kW, MeterA1:0kW, Meter5:10kW, MeterB1:37kW**
8.10.3	**2/26/08**	**2:27 pm**	**8.10.4**	**8.10.5**	**S**	**2:35 pm**	**DAK**	**Triggers armed. Manual Open asserted at 2:30 pm. SS opened. Meter3:13kW, MeterA1:21kW, Meter5: -15kW, MeterB1:61kW.**

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8.10.6	**2/26/08**	**2:35**	**8.10.7**	**8.10.8**	**S**	**2:40 pm**	**DAK**	**Manual Open removed at 2:36. SS Closed. Meter3:36kW, MeterA1:0kW, Meter5:12kW, MeterB1:34kW**
8.10.9	**2/26/08**	**2:40 pm**			**S**	**2:50 pm**	**DAK**	**Gensets shutdown.**

(S =Successful; U = Unsuccessful)

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.11.1	**2/26/08**	**3:00 pm**	**8.11.2**		**S**	**3:07 pm**	**DAK**	**SS closed, All breakers closed, Gensets setup and connected, LB3:20kW, LB5:40kW, LB6:20kW. Meter3:-25kW, MeterA1:43kW, Meter5:22kW, MeterB1:14kW, Meter2:-1kW, Meter1:18kW**
8.11.3	**2/26/08**	**3:07 pm**	**8.11.4**	**8.11.5**	**S**	**3:15 pm**	**DAK**	**Triggers armed. Manual Open asserted at 3:11 pm. SS opened with PES Alarm. Meter3:-25kW, MeterA1:43kW, Meter5:23kW, MeterB1:12kW, Meter2:0kW, Meter1:19kW**
8.11.6	**2/26/08**	**3:15 pm**	**8.11.7**	**8.11.8**	**S**	**3:21 pm**	**DAK**	**Manual Open removed at 3:16. SS Closed. Meter3:-26kW, MeterA1:45kW, Meter5:21kW, MeterB1:15kW, Meter2:-2kW, Meter1:16kW**
8.11.9	**2/26/08**	**3:21 pm**			**S**	**3:22 pm**	**DAK**	**Gensets shutdown and loads removed.**

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8.12.1	**2/27/08**	**9:54 am**	**8.12.2**		**S**	**10:31 am**	**DAK**	**CB12 open, Gensets setup to 20kW in unit control and connected.**
8.12.3	**2/27/08**	**10:31 am**			**S**	**10:34 am**	**DAK**	**LB3:25kW, 10kVar, LB4:25kW, 10kVar, LB5:25kW, 10kVar, LB6:5kW, 10kVar. Load was added to LB6 to pull the isolated bus voltage down to near zero volts, it was floating near 80 volts prior. Manual open removed.**
8.12.4	**2/27/08**	**10:34 am**	**8.12.5**		**S**	**10:49 am**		**CB12 closed at 10:38:10. SS closed at 10:43:10**
8.12.6	**2/27/08**	**10:49 am**			**S**	**11:12 am**		**DAS system did trigger on the closing of the SS. At 11:01 the SS opened on reverse power and locked out. The meter triggers were disabled and only the relays captured this event.**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
8.13.1	**2/27/08**	**11:12 am**	**8.13.2**		**S**	**11:16 am**	**DAK**	**CB12 opened, Genset setup to 20kW unit control.**
8.13.3.1	**2/27/08**	**11:16 am**	**8.13.3.2**		**S**	**11:18 am**	**DAK**	**Manual Open asserted. LB3:20kW ,20kVar**

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8.13.3.3	**2/27/08**	**11:18 am**	**8.13.3.4**		**S**	**11:24 am**	**DAK**	**Triggers armed. Genset A1 connected at 11:20 am Meter3:-2kW, -3kVar, MeterA1:20kW 20kVar, LoadMeter3:17kW 18kVar**
8.13.3.5	**2/27/08**	**11:24 am**	**8.13.3.6**		**S**	**11:25 am**	**DAK**	**Genset A1 shutdown. LB3:35kW, 20kVar**
8.13.3.7	**2/27/08**	**11:25 am**	**8.13.3.8**		**S**	**11:31 am**	**DAK**	**Triggers armed. Genset A1 connected at 11:26 am Meter3:-2kW, -3kVar, MeterA1:33kW, 21kVar LoadMeter3:31kW, 18kVar**
8.13.3.9	**2/27/08**	**11:31 am**	**8.13.3.10**		**S**	**11:45 am**	**DAK**	**Genset A1 shutdown. LB3:55kW, 20kVar**
8.13.3.11	**2/27/08**	**11:45 am**	**8.13.3.12**		**S**	**11:52 am**	**DAK**	**Triggers armed. Genset A1 connected at 11:47 am Meter3:-2kW, -3kVar, MeterA1:51kW 21kVar, LoadMeter3:47kW 18kVar**
8.13.3.13	**2/27/08**	**11:52 am**	**8.13.3.14**		**S**	**11:54 am**	**DAK**	**Genset A1 shutdown. LB3:60kW, 30kVar**
8.13.3.15	**2/27/08**	**11:54 am**	**8.13.3.16**		**S**	**12:00 pm**	**DAK**	**Triggers armed. Genset A1 connected at 11:55 am Meter3:-2kW, -2kVar, MeterA1:50kW 29kVar, LoadMeter3:47kW 26kVar**
8.13.3.13 B	**2/27/08**	**12:00 am**	**8.13.3.14 B**		**S**	**12:02 pm**	**DAK**	**Genset A1 shutdown. LB3:70kW, 30kVar. Load was increased a final time as the actual load is always less than that which is dispatched.**
8.13.3.15B	**2/27/08**	**12:02 pm**	**8.13.3.16 B**		**S**	**12:09 pm**	**DAK**	**Triggers armed. Genset A1 connected at 12:04 pm Meter3:-2kW, -2kVar, MeterA1:60kW 29kVar, LoadMeter3:57kW 26kVar**

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8.13.3.17	**2/27/08**	**12:09 pm**			**S**	**12:20 pm**	**DAK**	**Genset A1 shutdown and loads removed.**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
9.1.7(9.1.1)	**3/5/08**	**10:28 am**	**9.1.7(9.1.2)**		**S**	**11:12 am**	**DAK**	**Gensets setup an d connected. SS closed. LB3:40kW 20kVar, LB4:40kW 20kVar, LB5:40kW 20kVar, LB6:20kW 10kVar, Meter2:28kW, Meter3:17kW, Meter4:6kW, Meter5:9kW**
9.1.7(9.1.3)	**3/5/08**	**11:12 am**	**9.1.7(9.1.4)**		**S**	**11:37 am**	**DAK**	**Triggers armed, Manual Open asserted at 11:16. SS opened with PES Alarm. Meter2:0kW, Meter3:-2kW, Meter4:-4kW, Meter5:0kW Meters triggered when SS was reset.**
9.1.7(9.1.5)	**3/5/08**	**11:37 am**	**9.1.7(9.1.6)**		**S**	**11: 43 am**	**DAK**	**Triggers armed, Manual Open removed at 11:38. SS closed. Meter2:29kW, Meter3:17kW, Meter4:6kW, Meter5:10kW**
9.1.8(9.1.1)	**3/5/08**	**11:43 am**	**9.1.8(9.1.2)**		**S**	**11:51 am**	**DAK**	**Gensets setup an d connected. SS closed. LB3:20kW 10kVar, LB4:40kW 20kVar, LB5:50kW 20kVar, LB6:20kW 10kVar, Meter2:21kW, Meter3:-8kW,**

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								Meter4:7kW, Meter5:25kW
9.1.8(9.1.3)	**3/5/08**	**11:51 am**	**9.1.8(9.1.4)**		**S**	**12:01 pm**	**DAK**	**Triggers armed, Manual Open asserted at 11:54. SS opened with PES Alarm. Meter2:0kW, Meter3:-21kW, Meter4:0kW, Meter5:18kW**
9.1.8(9.1.5)	**3/5/08**	**12:01 pm**	**9.1.8(9.1.6)**		**S**	**12:15 pm**	**DAK**	**Triggers armed, Manual Open removed at 12:09. SS closed. Meter2:14kW, Meter3:-12kW, Meter4:5kW, Meter5:23kW**
9.1.9(9.1.1)	**3/5/08**	**1:10 pm**	**9.1.9(9.1.2)**		**S**	**1:17 pm**	**DAK**	**Gensets setup an d connected. SS closed. LB3:20kW 10kVar, LB4:15kW 10kVar, LB5:50kW 20kVar, LB6:30kW 10kVar, Meter2:-12kW, Meter3:-32kW, Meter4:-15kW, Meter5:17kW**
9.1.9(9.1.3)	**3/5/08**	**1:17 pm**	**9.1.9(9.1.4)**		**S**	**1:24 pm**	**DAK**	**Triggers armed, Manual Open asserted at 1:19. SS opened with PES Alarm. Meter2:0kW, Meter3:-23kW, Meter4:-11kW, Meter5:21kW**
9.1.9(9.1.5)	**3/5/08**	**1:24 pm**	**9.1.9(9.1.6)**		**S**	**1:31 pm**	**DAK**	**Triggers armed, Manual Open removed at 1:26. SS closed. Meter2:-17kW, Meter3:-35kW, Meter4:-17kW, Meter5:16kW**
9.1.10(9.1.1)	**3/5/08**	**1:31 pm**	**9.1.10(9.1.2)**		**S**	**1:43 pm**	**DAK**	**Gensets setup an d connected. SS closed. LB3:50kW 20kVar, LB4:40kW 20kVar, LB5:25kW 10kVar, LB6:30kW 10kVar, Meter2:19kW, Meter3:34kW, Meter4:15kW, Meter5:-18kW**
9.1.10(9.1.3)	**3/5/08**	**1:43 pm**	**9.1.10(9.1.4)**		**S**	**1:54 pm**	**DAK**	**Triggers armed, Manual Open asserted at 1:45. SS opened with PES Alarm. Meter2:0kW,**

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								Meter3:21kW, Meter4:10kW, Meter5:-23kW
9.1.10(9.1.5)	**3/5/08**	**1:54 pm**	**9.1.10(9.1 .6)**		**S**	**2:05 pm**	**DAK**	**Triggers armed, Manual Open removed at 2:00. SS closed. Meter2:14kW, Meter3:30kW, Meter4:14kW, Meter5:??kW. Genset B1 shutdown on Low Oil Pressure approx 30 secs after the SS closed.**

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DTC Registered Procedure - CERTS Microgrid Test Plan Appendix C: TEST LOG			
Dolan Technology Center	Document No: DTC212812.207.01A		
Written by: AEP	Effective Date: 23 Feb 2007	Target Group: Assigned	
Approved by: K. P. Loving	Procedure Review Date: 23 Feb. 2008		

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Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.2.1	3/13/08	2:20 pm	10.2.2	10.2.3	S	2:25 pm	DAK	Weak Grid Installed.
10.2.12(10.1.1)	3/18/08	11:40 am	10.2.12(10.1.2)	10.2.12(10.1.3)	S	11:44 am	DAK	Test revised to remove unavailable Genset B1. Genset A1 and A2 setup and connected. LB3:10kW, LB4:40kW, LB6:40kW. LB5 is unused. LB6 increased to prevent reverse power trip. SS closed
10.2.12(10.1.4)	3/18/08	11:44 am	10.2.12(10.1.5)		S	11:50 am	DAK	Dyno set to 100%, Triggers enabled. Motor started at 11:45. Meter1:23kW 25kVar, Meter3:-18kW 19kVar, Meter4:6kW 2kVar
10.2.12(10.1.6)	3/18/08	11:50 am	10.2.12(10.1.7)		S	11:56am	DAK	SS manual open asserted at 11:51. SS opened with a fault and PES alarm. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:15kW -7kVar
10.2.12(10.1.8)	3/18/08	11:56am	10.2.12(10.1.9)		S	12:04 pm	DAK	Motor started at 11:59. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:11kW 10kVar
10.2.12(10.1.10)	3/18/08	12:04 pm	10.2.12(10.1.11)		S	12:10 pm	DAK	SS manual open removed at 12:06. Meter1:24kW 27kVar, Meter3:-14kW 21kVar, Meter4:6kW 3kVar
10.2.14(10.1.1)	3/14/08	8:02 am	10.2.14(10.1.2)	10.2.14(10.1.3)	S	8:16 am	DAK	Genset A1 setup LB3:10kW, LB6:40kW. LB6 increased to prevent reverse power trip.
10.2.14(10.1	3/14/08	8:16 am	10.2.14(10.		S	8:26 am	DAK	Dyno set to 100%, Triggers enabled. Motor started at

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.4)			**1.5)**					**8:21. Meter3:-21kW 19kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.2.14(10.1 .8)	**3/14/08**	**8:33 am**	**10.2.14(1 0.1.9)**		**S**	**8:39 am**	**DAK**	**Motor started at 8:34. Meter3:-2kW -3kVar**
10.2.14(10.1 .10)	**3/14/08**	**8:39 am**	**10.2.14(1 0.1.11)**		**S**	**8:46 am**	**DAK**	**SS manual open removed at 8:41. Meter3:-21kW 19kVar**
10.2.15(10.1 .1)	**3/18/08**	**12:10 pm**	**10.2.15(1 0.1.2)**	**10.2.15(1 0.1.3)**	**S**	**12:15 am**	**DAK**	**Test revised to remove unavailable Genset B1 and test the gensets closer to capacity. Genset A1 and A2 setup and connected. LB3:50kW, LB4:50kW, LB6:40kW, LB5 is unused. LB6 increased to prevent reverse power trip. SS closed**
10.2.15(10.1 .4)	**3/18/08**	**12:15 am**	**10.2.15(1 0.1.5)**		**S**	**12:21 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 12:16. Meter1:69kW 21kVar, Meter3:29kW 15kVar, Meter4:14kW -1kVar**
10.2.15(10.1 .6)	**3/18/08**	**12:21 pm**	**10.2.15(1 0.1.7)**		**S**	**12:32 pm**	**DAK**	**SS manual open asserted at 12:26. SS opened with a fault and PES alarm. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:2kW -7kVar**

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10.2.15(10.1.8)	**3/18/08**	**12:32 pm**	**10.2.15(10.1.9)**		**S**	**12:38 pm**	**DAK**	**Motor started at 12:33. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:-1kW 10kVar**
10.2.15(10.1.10)	**3/18/08**	**12:38 pm**	**10.2.15(10.1.11)**		**S**	**12:43 pm**	**DAK**	**SS manual open removed at 12:38. Meter1:70kW 22kVar, Meter3:31kW 16kVar, Meter4:16kW 0kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.2.16(10.1.8)			**10.2.16(10.1.9)**					
10.2.16(10.1.10)			**10.2.16(10.1.11)**					
10.2.17(10.1.1)	**3/14/08**	**8:46 am**	**10.2.17(10.1.2)**	**10.2.17(10.1.3)**	**S**	**8:54 am**	**DAK**	**Genset A1 setup LB3:20kW, LB6:40kW, LB6 increased to prevent reverse power trip.**
10.2.17(10.1.4)	**3/14/08**	**8:54 am**	**10.2.17(10.1.5)**		**S**	**9:00 am**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 8:55. Meter3:-13kW 18kVar**
10.2.17(10.1.6)	**3/14/08**	**9:00 am**	**10.2.17(10.1.7)**		**S**	**9:07 am**	**DAK**	**SS manual open asserted at 9:02. Meter3:-2kW -3kVar. The motor was still running for this capture.**
10.2.17(10.1.8)	**3/14/08**	**9:07 am**	**10.2.17(10.1.9)**		**S**	**9:13 am**	**DAK**	**Motor started at 9:09. Meter3:-2kW -3kVar**

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10.2.17(10.1.10)	**3/14/08**	**9:13 am**	**10.2.17(10.1.11)**		**S**	**9:20 am**	**DAK**	**SS manual open removed at 9:14. Meter3:-11kW 17kVar**
10.2.18(10.1.1)	**3/18/08**	**12:43 pm**	**10.2.18(10.1.2)**	**10.2.18(10.1.3)**	**S**	**12:46 pm**	**DAK**	**Test revised to remove unavailable Genset B1.Genset A1 and A2 setup and connected. LB3:20kW, LB4:40kW, LB6:40kW, LB5 is unused. LB6 increased to prevent reverse power trip. SS closed**
10.2.18(10.1.4)	**3/18/08**	**12:46 pm**	**10.2.18(10.1.5)**		**S**	**12:51 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 12:46. Meter1:33kW 25kVar, Meter3:-5kW 19kVar, Meter4:13kW 1kVar**
10.2.18(10.1.6)	**3/18/08**	**12:51 pm**	**10.2.18(10.1.7)**		**S**	**12:58 pm**	**DAK**	**SS manual open asserted at 12:53. SS opened with a fault and PES alarm. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:17kW -7kVar**
10.2.18(10.1.8)	**3/18/08**	**12:58 pm**	**10.2.18(10.1.9)**		**S**	**1:14 pm**	**DAK**	**Motor started at 1:09. Meter1:37kW 1kVar, Meter3:-2kW -4kVar, Meter4:17kW 11kVar**
10.2.18(10.1.10)	**3/18/08**	**1:14 pm**	**10.2.18(10.1.11)**		**S**	**1:20 pm**	**DAK**	**SS manual open removed at 1:15. Meter1:32kW 29kVar, Meter3:-8kW 21kVar, Meter4:10kW 3kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:

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10.2.19(10.1.1)			**10.2.19(10.1.2)**	**10.2.19(10.1.3)**				
10.2.19(10.1.4)			**10.2.19(10.1.5)**					
10.2.19(10.1.6)			**10.2.19(10.1.7)**					
10.2.19(10.1.8)			**10.2.19(10.1.9)**					
10.2.19(10.1.10)			**10.2.19(10.1.11)**					
10.2.20(10.1.1)	**3/14/08**	**9:20 am**	**10.2.20(10.1.2)**	**10.2.20(10.1.3)**	**S**	**9:36 am**	**DAK**	**Genset A1 setup LB3:20kW, LB6:40kW. LB6 increased to prevent reverse power trip.**
10.2.20(10.1.4)	**3/14/08**	**9:36 am**	**10.2.20(10.1.5)**		**S**	**9:42 am**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 9:37. Meter3:-16kW 18kVar**
10.2.20(10.1.6)	**3/14/08**	**9:42 am**	**10.2.20(10.1.7)**		**S**	**9:48 am**	**DAK**	**SS manual open asserted at 9:43. Meter3:-2kW -4kVar.**
10.2.20(10.1.8)	**3/14/08**	**9:48 am**	**10.2.20(10.1.9)**		**S**	**9:55 am**	**DAK**	**Motor started at 9:50. Meter3:-2kW -3kVar**
10.2.20(10.1.10)	**3/14/08**	**9:55 am**	**10.2.20(10.1.11)**		**S**	**10:03 am**	**DAK**	**SS manual open removed at 9:57. Meter3:-15kW 18kVar**

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DTC Registered Procedure - CERTS Microgrid Test Plan Appendix C: TEST LOG			
Dolan Technology Center	Document No: DTC212812.207.01A		
Written by: AEP	Effective Date: 23 Feb 2007	Target Group: Assigned	
Approved by: K. P. Loving	Procedure Review Date: 23 Feb. 2008		

Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.3.12(10.1.1)	3/18/08	1:20 pm	10.3.12(10.1.2)	10.3.12(10.1.3)	S	1:31 pm	DAK	Test revised to remove unavailable Genset B1. Genset A1 and A2 setup and connected. LB3:20kW, LB4:10AkW 15BkW 15CkW, LB6:10AkW 20BkW 10CkW. LB5 is unused. LB6 increased to prevent reverse power trip. SS closed
10.3.12(10.1.4)	3/18/08	1:31 pm	10.3.12(10.1.5)		S	1:39 pm	DAK	Dyno set to 100%, Triggers enabled. Motor started at 1:33. Meter1:36kW 27kVar, Meter3:-3kW 21kVar, Meter4:8kW 2kVar
10.3.12(10.1.6)	3/18/08	1:39 pm	10.3.12(10.1.7)		S	1:44 pm	DAK	SS manual open asserted at 1:39. SS opened. Meter1:38kW 1kVar, Meter3:-2kW -4kVar, Meter4:12kW -7kVar
10.3.12(10.1.8)	3/18/08	1:44 pm	10.3.12(10.1.9)		S	1:49 pm	DAK	Motor started at 1:44. Meter1:38kW 1kVar, Meter3:-1kW -4kVar, Meter4:9kW 10kVar
10.3.12(10.1.10)	3/18/08	1:49 pm	10.3.12(10.1.11)		S	1:55 pm	DAK	SS manual open removed at 1:50. Meter1:32kW 24kVar, Meter3:-7kW 18kVar, Meter4:6kW 1kVar

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:

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10.3.14(10.1.1)	**3/14/08**	**10:03 am**	**10.3.14(10.1.2)**	**10.3.14(10.1.3)**	**S**	**10:09 am**	**DAK**	**Genset A1 setup LB3:10kW, LB6:10AkW 20BkW 10CkW. LB6 increased to prevent reverse power trip.**
10.3.14(10.1.4)	**3/14/08**	**10:09 am**	**10.3.14(10.1.5)**		**S**	**10:15 am**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 10:10. Meter3:-19kW 18kVar**
10.3.14(10.1.6)	**3/14/08**	**10:15 am**	**10.3.14(10.1.7)**		**S**	**10:21 am**	**DAK**	**SS manual open asserted at 10:16. Meter3:-2kW -4kVar.**
10.3.14(10.1.8)	**3/14/08**	**10:21 am**	**10.3.14(10.1.9)**		**S**	**10:27 am**	**DAK**	**Motor started at 10:22. Meter3:-2kW -3kVar**
10.3.14(10.1.10)	**3/14/08**	**10:27 am**	**10.3.14(10.1.11)**		**S**	**10:35 am**	**DAK**	**SS manual open removed at 10:28. Meter3:-19kW 19kVar**
10.3.15(10.1.1)	**3/18/08**	**1:55 pm**	**10.3.15(10.1.2)**	**10.3.15(10.1.3)**	**S**	**1:56 pm**	**DAK**	**Test revised to remove unavailable Genset B1 and test the gensets closer to capacity. Genset A1 and A2 setup and connected. LB3:50kW, LB4:10AkW 20BkW 20CkW, LB6: 10AkW 20BkW 10CkW. LB5 is unused. LB6 increased to prevent reverse power trip. SS closed**
10.3.15(10.1.4)	3/18/08	**1:56 pm**	**10.3.15(10.1.5)**		**S**	**2:01 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 1:56. Meter1:69kW 20kVar, Meter3:29kW 14kVar, Meter4:14kW -1kVar**
10.3.15(10.1.6)	3/18/08	**2:01 pm**	**10.3.15(10.1.7)**		**S**	**2:07 pm**	**DAK**	**SS manual open asserted at 2:02. SS opened with a fault and a PES alarm. Meter1:38kW 1kVar, Meter3:-1kW -4kVar, Meter4:2kW -9kVar**
10.3.15(10.1.8)	3/18/08	**2:07 pm**	**10.3.15(10.1.9)**		**S**	**2:13 pm**	**DAK**	**Motor started at 2:08. Meter1:38kW 1kVar, Meter3:-2kW -4kVar, Meter4:-2kW -9kVar**

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

10.3.15(10.1 .10)	**3/18/08**	**2:13 pm**	**10.3.15(1 0.1.11)**		**S**	**2:19 pm**	**DAK**	**SS manual open removed at 2:14. Meter1:66kW 23kVar, Meter3:26kW 16kVar, Meter4:13kW 0kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.3.17(10.1 .1)	**3/14/08**	**11:58 am**	**10.3.17(1 0.1.2)**	**10.3.17(1 0.1.3)**	**S**	**12:02 pm**	**DAK**	**Genset A1 setup LB3:20kW, LB6:10AkW 20BkW 10CkW, LB6 increased to prevent reverse power trip.**
10.3.17(10.1 .4)	**3/14/08**	**12:02 pm**	**10.3.17(1 0.1.5)**		**S**	**12:09 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 12:04. Meter3:-9kW 18kVar**
10.3.17(10.1 .6)	**3/14/08**	**12:09 pm**	**10.3.17(1 0.1.7)**		**S**	**12:16 pm**	**DAK**	**SS manual open asserted at 12:10. Meter3:-2kW -4kVar.**
10.3.17(10.1 .8)	**3/14/08**	**12:16 pm**	**10.3.17(1 0.1.9)**		**S**	**12:22 pm**	**DAK**	**Motor started at 12:17. Meter3:-2kW -3kVar**
10.3.17(10.1 .10)	**3/14/08**	**12:22 pm**	**10.3.17(1 0.1.11)**		**S**	**12:28 pm**	**DAK**	**SS manual open removed at 12:22. Meter3:-12kW 18kVar**
10.3.18(10.1 .1)	**3/18/08**	**2:19 pm**	**10.3.18(1 0.1.2)**	**10.3.18(1 0.1.3)**	**S**	**2:20 pm**	**DAK**	**Test revised to remove unavailable Genset B1. Genset A1 and A2 setup and connected. LB3:20kW, LB4:10AkW 15BkW, 15CkW, LB6: 10AkW 20BkW, 10CkW, LB5 is unused. LB6 increased to prevent reverse power trip. SS closed**

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10.3.18(10.1 .4)	**3/18/08**	**2:20 pm**	**10.3.18(1 0.1.5)**		**S**	**2:26 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 2:21. Meter1:32kW 25kVar, Meter3:-8kW 19kVar, Meter4:9kW 2kVar**
10.3.18(10.1 .6)	**3/18/08**	**2:26 pm**	**10.3.18(1 0.1.7)**		**S**	**2:32 pm**	**DAK**	**SS manual open asserted at 2:27. SS opened with a fault and a PES alarm. Meter1:38kW 1kVar, Meter3:-2kW -4kVar, Meter4:17kW -8kVar**
10.3.18(10.1 .8)	**3/18/08**	**2:32 pm**	**10.3.18(1 0.1.9)**		**S**	**2:37 pm**	**DAK**	**Motor started at 2:32. Meter1:38kW 1kVar, Meter3:-2kW -4kVar, Meter4:17kW 11kVar**
10.3.18(10.1 .10)	**3/18/08**	**2:37 pm**	**10.3.18(1 0.1.11)**		**S**	**2:**	**DAK**	**SS manual open removed at 2:38. Meter1:33kW 27kVar, Meter3:-8kW 21kVar, Meter4:10kW 2kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.3.20(10.1 .1)	**3/14/08**	**12:28 pm**	**10.3.20(1 0.1.2)**	**10.3.20(1 0.1.3)**	**S**	**12:29 pm**	**DAK**	**Genset A1 setup LB3:20kW, LB6:10AkW 20BkW 10CkW, LB6 increased to prevent reverse power trip.**
10.3.20(10.1 .4)	**3/14/08**	**12:29 pm**	**10.3.20(1 0.1.5)**		**S**	**12:34 pm**	**DAK**	**Dyno set to 100%, Triggers enabled. Motor started at 12:29. Meter3:-14kW, 19kVar**
10.3.20(10.1 .6)	**3/14/08**	**12:34 pm**	**10.3.20(1 0.1.7)**		**S**	**12:40 pm**	**DAK**	**SS manual open asserted at 12:35. Meter3:-2kW, -4kVar.**
10.3.20(10.1 .8)	**3/14/08**	**12:40 pm**	**10.3.20(1 0.1.9)**		**S**	**12:45 pm**	**DAK**	**Motor started at 12:40. Meter3:-2kW, -3kVar**

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

10.3.20(10.1 .10)	**3/14/08**	**12:45 pm**	**10.3.20(1 0.1.11)**		**S**	**12:51 pm**	**DAK**	**SS manual open removed at 12:45. Meter3:-16kW, 19kVar**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.4.12(10.1 .1)	**3/20/08**	**8:30 am**	**10.4.12(1 0.1.2)**	**10.4.12(1 0.1.3)**	**S**	**8:35 am**	**DAK**	**Genset A1 setup. LB3:3.3AkW 3.3BkW 3.3CkW, LB4:13.3AkW 13.3BkW 13.3CkW, LB6:13.3AkW 13.3BkW 13.3CkW. LB6 increased to prevent reverse power trip.**
10.4.12(10.4 .2)	3/20/08	**8:35 am**	**10.4.12(1 0.4.3)**		**S**	**8:45 am**	**DAK**	**LB3:1.6AkW 3.3BkW 3.3CkW, LB6:6.66AkW 13.3BkW 13.3CkW. Triggers enabled. SS opened shortly afterward on reverse power. SS opened with a fault and a PES alarm. LB4 was still at 40kW load prior to the SS opening.**
10.4.12(10.4 .4)	3/20/08	**8:45 am**	**10.4.12(1 0.4.5)**		**S**	**8:46 am**	**DAK**	**SS reset and started with manual open asserted**
10.4.12(10.4 .6)	3/20/08	**8:46 am**	**10.4.12(1 0.4.7)**		**S**	**8:51 am**	**DAK**	**LB3:0AkW 3.3BkW 3.3CkW, LB6:3.3AkW 13.3BkW 13.3CkW.Triggers enabled. LB4 reduced at 8:46. LB4:3.33AkW, 13.3BkW, 13.3CkW**
10.4.12(10.4 .8)	3/20/08	**8:51 am**	**10.4.12(1 0.4.9)**		**S**	**8:56 am**	**DAK**	**LB3:0AkW 3.3BkW 3.3CkW, LB6:3.3AkW 13.3BkW 13.3CkW.Triggers enabled. LB4 reduced at 8:51. LB4:3.33AkW, 13.3BkW, 13.3CkW**

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

10.4.12(10.4.10)	**3/20/08**	**8:56 am**	**10.4.12(10.4.11)**		**S**	**9:01 am**	**DAK**	**SS manual open removed at 8:56. SS closed. SS opened shortly afterward on reverse power trip. SS opened with a fault and a PES alarm.**

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.4.14(10.1.1)	**3/14/08**	**12:51 pm**	**10.4.14(10.1.2)**	**10.4.14(10.1.3)**	**S**	**1:01 pm**	**DAK**	**Genset A1 setup. LB3:3.3AkW, 3.3BkW, 3.3CkW, LB6:13.3AkW, 13.3BkW, 13.3CkW. LB6 increased to prevent reverse power trip.**
10.4.14(10.4.2)	**3/14/08**	**1:01 pm**	**10.4.14(10.4.3)**		**S**	**1:13 pm**	**DAK**	**LB6:6.6AkW, 13.3BkW, 13.3CkW. Triggers enabled. SS opened on reverse power at 1:08. Load step altered to prevent reverse power trip.**
10.4.14(10.4.2R)	**3/14/08**	**1:13 pm**	**10.4.14(10.4.3R)**		**S**	**1:21 pm**	**DAK**	**LB3:1.6AkW, 3.3BkW, 3.3CkW. Triggers enabled. LB6 reduced at 1:16. LB6:6.6AkW, 13.3BkW, 13.3CkW. SS opened shortly afterward on reverse power. SS opened with a fault and a PES alarm.**
10.4.14(10.4.4)	**3/14/08**	**2:07 pm**	**10.4.14(10.4.5)**		**S**	**2:18 pm**	**DAK**	**Test skipped briefly and returned to at 2:10pm. SS reset and started with manual open asserted**
10.4.14(10.4.6)	**3/14/08**	**2:18 pm**	**10.4.14(10.4.7)**		**S**	**2:23 pm**	**DAK**	**LB6:3.3AkW, 13.3BkW, 13.3CkW. Triggers enabled. LB3 reduced at 2:18. LB3:0AkW, 3.3BkW, 3.3CkW**
10.4.14(10.4	**3/14/08**	**2:23 pm**	**10.4.14(1**		**S**	**2:29 pm**	**DAK**	**LB3:0kW, 3.3BkW, 3.3CkW. Triggers enabled. LB6**

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Appendix C - "CERTS Microgrid Test Bed - Test Log" (S =Successful; U = Unsuccessful)

.8)			0.4.9)					reduced at 2:24. LB6:0AkW, 13.3BkW, 13.3CkW.
10.4.14(10.4 .10)	3/14/08	2:29 pm	10.4.14(1 0.4.11)		S	2:37 pm	DAK	SS manual open removed at 2:31. SS closed. SS opened shortly afterward on reverse power trip.

Start Test Sequence No.	Test Date	Start Time	Verify/ Action	Verify/ Action	Status S or U	End Time	Initials	Test Event Comments:
10.4.17(10.1 .1)	3/14/08	1:21 pm	10.4.17(1 0.1.2)	10.4.17(1 0.1.3)	S	1:30 pm	DAK	Genset A1 setup. LB3:6.6AkW, 6.6BkW, 6.6CkW, LB6:13.3AkW, 13.3BkW, 13.3CkW. LB6 increased to prevent reverse power trip.
10.4.17(10.4 .2)	3/14/08	1:30 pm	10.4.17(1 0.4.3)		S	1:38 pm	DAK	LB3:3.3AkW, 6.6BkW, 6.6CkW. Triggers enabled. LB6 reduced at 1:33. LB6:6.6AkW, 13.3BkW, 13.3CkW.
10.4.17(10.4 .4)	3/14/08	1:38 pm	10.4.17(1 0.4.5)		S	1:49 pm	DAK	SS manual open asserted at 1:39. SS opened with a fault and a PES alarm. SS reset and started
10.4.17(10.4 .6)	3/14/08	1:49 pm	10.4.17(1 0.4.7)		S	1:56 pm	DAK	LB6:3.3AkW, 13.3BkW, 13.3CkW. Triggers enabled. LB3 reduced at 1:51. LB3:1.6AkW, 6.6BkW, 6.6CkW
10.4.17(10.4 .8)	3/14/08	1:56 pm	10.4.17(1 0.4.9)		S	2:01 pm	DAK	LB6:0AkW, 13.3BkW, 13.3CkW. Triggers enabled. LB3 reduced at 1:56. LB3:0kW, 6.6BkW, 6.6CkW
10.4.17(10.4 .10)	3/14/08	2:01 pm	10.4.17(1 0.4.11)		S	2:07 pm	DAK	SS manual open removed at 2:02. SS closed. SS opened shortly afterward on reverse power trip.

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Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Technical Advisory Committee Meeting Summary and Review Comments

APPENDIX O

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Fifth Meeting of the
Technical Advisory Committee for the
California Energy Commission Public Interest Energy Research
CERTS Microgrid Test Bed Project

30 April 2008
Lawrence Berkeley National Laboratory
Building 90 Room 4133
1 Cyclotron Road, Berkeley, CA

Meeting Summary

Participants

Technical Advisory Committee	
	Merrill Smith and Steve Waslo, U.S. Department of Energy
	Ben Kroposki, National Renewable Energy Laboratory
	Mohammed Vaziri, Pacific Gas and Electric Co.
	Tom Dossey, Southern California Edison
	Mark McGranaghan, EPRI Solutions
Guests	Eric Wong, Cummins
	Dave Potter, Chevron Energy Solutions
CEC	Bernard Treanton, Steve Ghadiri
CERTS	Joe Eto, LBNL
	Ben Schenkman, Sandia National Laboratories
	Robert Lasseter, University of Wisconsin/PSERC
	Ed Linton, Northern Power
	Bob Panora and Jean Roy, Tecogen
	Dave Klapp and Ray Hayes, American Electric Power

Meeting Purpose: Introduce test bed results; initiate technical review process

Summary of TAC, CEC, and guest's overall impressions/comments

Concepts are elegant, yet simple. Simple translates to more affordable.

Demonstration that static switch can comply with 1547, with non-compliant generation behind it, is a major accomplishment. The team has confirmed that a static switch is very fast. It is recognized that ground fault testing on the utility side of the static switch is still missing from this aspect of 1547 compliance.

Inverter controls are impressive.

Test plan was well laid-out. A wide range of concerns that were identified have now been successfully addressed. In particular, motor starting was a challenging test and the results are very encouraging. Should be a major contribution to the literature.

The test bed platform should be used for future research.

Next Steps – CEC Final Report

Technical review comments due to J. Eto on May 23, 2008

Be careful to ensure consistent presentation of transient information alongside of steady state information in graphics and tables reporting testing results

Explain clearly why inverters were observed to put out such apparently high fault currents and what options do or do not exist to limit them within the current inverter design.

Next Steps – DOE RDSI award (as part of already specified tasks to: reduce internal protection costs, optimize DC storage, examine AC storage, and incorporate non-inverter-based synchronous generation sources)

Determine whether and how to conduct ground fault testing on utility side of static switch.

Conduct harmonic testing.

Conduct longer term tests in an effort to capture microgrid response to power quality events.

Next Steps - general

Conduct outreach. Publish results in refereed archival literature (e.g., IEEE Transactions). Prepare functional specifications defining core elements and performance requirements of the CERTS Microgrid Concept.

Support DOE and CEC in developing presentation materials they can use in describing work to lay- and non-technical audiences and to help defend research budgets.

Expand research focus to include role of energy manager. Consider, specifically, automatic adjustment of inverter power and voltage setpoints to regulate real and reactive power at the PCC

Examine flows onto the grid.

Explore physical and cyber security issues that might be addressed by microgrids.

Additional comments from Southern California Edison, received May 16, 2008

Thank you for the opportunity to review the tests that have been performed on the CERTS Microgrid. As demonstrated in the documentation provided and especially through the detailed procedures of the test plan developed by AEP, this testing appears to have been comprehensive and adequate to demonstrate the operational capabilities of the systems and designs.

We note that for the most part the components of CERTS Microgrid performed as expected, and could transition from a grid-connected to an autonomous operating mode without adversely affecting the quality of the power supplied to the test loads. This is an important step and such operation will be a necessary feature of a commercial system. We would also like to highlight the very desirable concept demonstrated through your project and testing: i.e. the use of simple existing communication and control concepts where applicable, such as the use of local/device frequency droop controls. We applaud your technical progress that supports an outlook that a smart grid is not necessarily a complex grid dependent on extensive custom engineering and systems.

We look forward to the next steps in the development trail and will be pleased to continue to support the concept and project.

Please feel free to contact either of us if you have questions.

Tom Dossey, Charlie Vartanian
Southern California Edison
Distributed Energy Resources

Additional comments from Pacific Gas and Electric, received May 24, 2008

Based on the notes I took during our April 30, 2008 advisory committee meeting, my comments are as follows:
1 - The results from the tests conducted so far seemed reasonable and in many cases better than anticipated.
2 - The static switch seemed to have successfully paralleled the systems without any troubles or need for a centralized communication system. This is certainly a positive result with good potential.
3 - For the phase and ground fault tests within the micro grid system, the results seemed correct and reasonable.
4 - For documentation purposes, the conditions (such open/closed switches, loading conditions, etc.) for each test case should be identified on the corresponding diagram to avoid any confusion.
5 - There was some confusion about the maximum output from the inverter based units. In some cases, up to 6.0 P.U. outputs was reported and discussed which was surprising to some of attendees. Careful measurements should be taken during faults to clarify this.
6 - Still to be verified is the following:

Tests need to be conducted to verify "Detection and timely clearing of Phase-Phase, 3 Phase, and especially Line-Ground faults on the Utility System, while the micro grid is in parallel operation with the utility." With a "Delta" connection on the utility side windings of the main interface transformer, conventional detection of ground faults on the utility system would require a grounding transformer. This has been pointed out all along from the beginning of the project. All Generating facilities are required by IEEE 1547 to detect and isolate their systems from an electrical fault on the utility system.

Regards,
Moh

Response to Pacific Gas and Electric, sent by project team on June 4, 2008

Thank you for attending the TAC meeting at LBNL and your comments below. Let me see if I can help clarify some of the questions that you mention below regarding the testing done so far.

4 - For documentation purposes, the conditions (such open/closed switches, loading conditions, etc.) for each test case should be identified on the corresponding diagram to avoid any confusion.

We completely agree with this. We will be working on the information presentation for the future phases of the project so that its both easier to understand as well as explain to others.

5 - There was some confusion about the maximum output from the inverter based units. In some cases, up to 6.0 P.U. outputs was reported and discussed which was surprising to some of attendees. Careful measurements should be taken during faults to clarify this.

We have discussed this further with Tecogen and Youtility. Their position is that this test result was expected. The inverters are 125kW rated devices although we are artificially limiting them to half that. They are also currently setup to deliver ~2.5pu fault current. This works out to ~550A peak, close to the ~600A number we were discussing. Tecogen is formalizing a more detailed response for the TAC group which will be included in the final report for this phase. In the next phase we are planning to adjust the inverters and retest to prove that the inverter fault current can be controlled to a desired level as needed by installed application. If you have suggestions as to what this fault contribution should be please let me know.

6 - Tests need to be conducted to verify "Detection and timely clearing of Phase-Phase, 3 Phase, and especially Line-Ground faults on the Utility System, while the micro grid is in parallel operation with the utility." With a "Delta" connection on the utility side windings of the main interface transformer, conventional detection of ground faults on the utility system would require a grounding transformer. This has been pointed out all along from the beginning of the project. All Generating facilities are required by IEEE 1547 to detect and isolate their systems from an electrical fault on the utility system.

The detection and times of the clearing for the different types of faults on the system are in the CERTS Microgrid Report Section 7.0 that I have attached to this email. We will have to figure out how to test a single line-to-ground fault on the utility side because I don't think AEP will just allow us to deliberately put a fault on their system.

The protection testing performed to date does show that the microgrid detects; phase to phase, 3 phase, and phase to ground faults within the microgrid. As you know in a wye-wye system these types of faults would appear very similar whether in the utility or within the microgrid. The biggest difference would be the measured magnitude of the fault which depends on a large number of variables. To date the faults we have tested have also been very low grade faults better described as overloads to the system. This was done to minimize the risk to the system while we worked out the protection scheme. At some point in the future we will be performing higher grade faults up to and including bolted faults. This has been the plan all along but we have just not reached it yet. Your point about the delta transformer is also well taken and we are looking into alternatives, a grounding transformer is one possibility. My hope is to replace the delta this with a wye-wye and monitor the microgrid operation during unscheduled utility faults. As Ben stated our company will not let us intentionally fault our own distribution system but there is no reason we can't try to capture a naturally occurring one.

Ben Schenkman
Dave Klapp

Additional comments from National Renewable Energy Laboratory, received May 28, 2008

Sorry for the delay. I have been too busy getting ready for Kythnos. I am in Greece now, so my comments will be short.

1) Add labels to the components of the aerial photo of the CERTS microgrid. This would make the good photo used throughout the report more useful to people not familiar with the project.
2) Add conclusions section to Sections 6,7,8 and 9. In the conclusions section add a summary table that summarizes the tests and important results. This is in the text, but difficult to find as presently written.
3) Recommendations: additional test to determine fault current level and time from the DGs.
4) Overall this is very important work. I think it would be useful to include a report or link to a description of the droop control method that is being used by the DGs. Bob's presentation at the meeting discussed this a little but I don't see it included in the reports. This would make for a more complete package.

Ben Kroposki
NREL



Arnold Schwarzenegger
Governor

CERTS MICROGRID LABORATORY TEST BED

Microgrid Fault Protection Based on Symmetrical and Differential Current Components

APPENDIX P

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Lawrence Berkeley National Laboratory

CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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Microgrid Fault Protection Based on Symmetrical and Differential Current Components

Prepared for
Public Interest Energy Research
California Energy Commission

Prepared by

Hassan Nikkhajoei and Robert H. Lasseter

Wisconsin Power Electronics Research Center
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December 2006

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions with funding support from the California Energy Commission, Public Interest Energy Research Program, under Contract No. 500-03-024.

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1. Introduction

The objective of this study is to develop a systematic approach for protecting a microgrid, in particular the AEP microgrid, against Single Line-to-Ground (SLG) and Line-to-Line (LL) faults. A microgrid is a part of a large power system in which a number of sources, usually attached to a power electronic converter, and loads are clustered so that the microgrid can operate independent of the main power system [1], [2]. In general, a microgrid can operate in both the grid-connected mode and the islanded mode where the microgrid is disconnected from the main power system by a fast semiconductor switch called static switch, Fig. 1.

It is essential to protect a microgrid in both the grid-connected and the islanded modes of operation against for all SLG and LL faults. The philosophy of protection is to disconnect the static switch for all classes of faults. With the static switch open (islanded mode), output currents of the microgrid sources are limited by the corresponding power electronic converter to 2.0 pu. Therefore, a microgrid cannot be protected against faults based on traditional over-current protection since there is not adequate fault currents in the islanded mode of operation.

The main challenge for protecting a microgrid arises from the fact that power can flow in both directions in each feeder of a microgrid. Close to each local load, there may exist two or more sources that contribute to the load power, Fig. 1. The sources can be located in both sides of the load and therefore, power flows in opposite directions from the two sources towards the load. As a results, in a section of the feeder, e.g. Zone 3 of Fig. 1, that is between the source A_1 and the load, power flows in one direction and in the other section, i.e. Zone 4, power flows in an opposite direction. It is to be noted that, in conventional distribution systems, power always flows in one direction, from the distribution substation towards the loads.

It was initially thought that a microgrid can be protected, at least for SLG faults, based on differential components of phase currents. However, studies showed that each relay, which corresponds to a microgrid protection zone, e.g. the Relay 4 of Fig. 1, can only detect SLG faults that occur in the up-stream zone of the relay, i.e. Zone 4 of Fig. 1. The relays do not detect an SLG fault in a down-stream zone, e.g. Zone 3 for the Relay 4, since the fault current does not pass through Zone 4 and therefore, the differential current component detected by the Relay 4 is zero. Details of a study that demonstrates the inability of protecting a microgrid based on differential current components can be found in [3]. In addition to inability for protecting against down-stream SLG faults, the relays do not detect a differential current component for LL faults in any of the microgrid protection zones, Fig. 1.

An alternative solution is to protect a microgrid against SLG and LL faults based on symmetrical current components [4]. A broad range of studies have been conducted on the AEP microgrid and it was concluded that SLG faults in down-stream zones of relays and all LL faults can be detected based on symmetrical current components. The SLG

and LL faults are detected from the zero-sequence component and the negative-sequence components of currents, respectively. However, zero- and negative-sequence components of current are also non-zero under normal operating conditions of a microgrid. This is due to the fact that a microgrid may, in general, include single-phase loads or three-phase unbalanced loads.

A study has been conducted for the AEP microgrid, in which the values of zero- and negative-sequence components of currents flowing through all relays of the microgrid were obtained for a maximum unbalanced load power of 20 percents. To ensure that the microgrid protection does not command for a trip under unbalanced load conditions, a threshold was assigned for each of the symmetrical current components. With the thresholds being set for all relays, each of them commands for breaker trip only when the corresponding zero-sequence or negative-sequence component exceeds a threshold. This guarantees that the protection system clears the SLG and LL faults in all protective zones while it does not command for an unwanted trip under unbalanced load conditions.

Based on the studies carried out for differential and symmetrical current components, a symmetric approach for protecting a microgrid against all SLG and LL faults has been developed. The developed microgrid protection approach employs the differential and zero-sequence current components as primary protection against SLG faults and the negative-sequence current component as a primary protection for LL faults.

If the microgrid primary protection fails, the time integral of current, i.e. I^2t, as a back-up protects the microgrid for all classes of fault [5]. A secondary back-up for the protection system is the conventional over-current protection. The over-current (I_{max}) protection usually commands for a trip after the I^2t protection, except for extremely high-current faults for which the over-current protection detects a fault fast. It is to be noted that, the I^2t and over-current protections are also back-up for the static switch in case that it fails to trip based on differential and symmetrical current protections.

In the following sections, first, structure of the AEP microgrid and its protection zones are described. Then, the results obtained for the symmetrical current components related to unbalanced load conditions and SLG and LL faults in all protection zones are presented. Coordination of the protective relays of the AEP microgrid, based on the results obtained for symmetrical current components, are also discussed. The results of studies carried out on the AEP microgrid for SLG and LL faults in all protection zones of the microgrid are presented. Conclusions are stated in the last section of the report.

2. AEP CERTS Microgrid

Fig. 1 shows a single-line representation of the AEP CERTS microgrid. The microgrid includes three microsources, specified as A_1, A_2 and B_1, and three local loads, specified as L_1, L_2 and L_3. Each microsource can provide a maximum output power of 60 kW and each load can consume a power up to a maximum amount of 120 kW, where the total load of microgrid should not exceed 180 kW. The microgrid is connected through a fast

semiconductor switch, that is called static switch, to the main grid. The combination of microgrid and the main grid has six protection zones that are specified as Zone 1 to Zone 6, Fig. 1.

CERTS Microgrid has two critical components, the static switch and the microsource. The static switch has the ability to autonomously island the microgrid from disturbances such as faults, IEEE 1547 events or power quality events. After islanding, the reconnection of the microgrid is achieved autonomously after the tripping event is no longer present. This synchronization is achieved by using the frequency difference between the islanded microgrid and the utility grid insuring a transient free operation without having to match frequency and phase angles at the connection point. Each microsource can seamlessly balance the power on the islanded microgrid using a power vs. frequency droop controller. This frequency droop also insures that the microgrid frequency is different from the grid frequency to facilitate reconnection to the utility.

To enhance reliability, a peer-to-peer and plug-and-play model is used for each component of the microgrid. The peer-to-peer concept insures that there are no components, such as a master controller or central storage unit that is critical for operation of the microgrid. This implies that the microgrid can continue operating with loss of any component or generator. With one additional source, (N+1), we can insure complete functionality with the loss of any source. Plug-and-play implies that a unit can be placed at any point on the electrical system without re-engineering the controls thereby reducing the chance for engineering errors. The plug-and-play model facilitates placing generators near the heat loads thereby allowing more effective use of waste heat without complex heat distribution systems such as steam and chilled water pipes.

Peer-to-peer and plug-and-play concepts also impact the protection design. The peer-to-peer concept insures that there are no protection components, such as a master coordinator or communication system critical to the protection of the microgrid. Plug-and-play implies that a unit can be placed at any point on the electrical system without re-engineering the protection thereby reducing the chance for engineering errors. This implies that microgrid protection is part of each source.

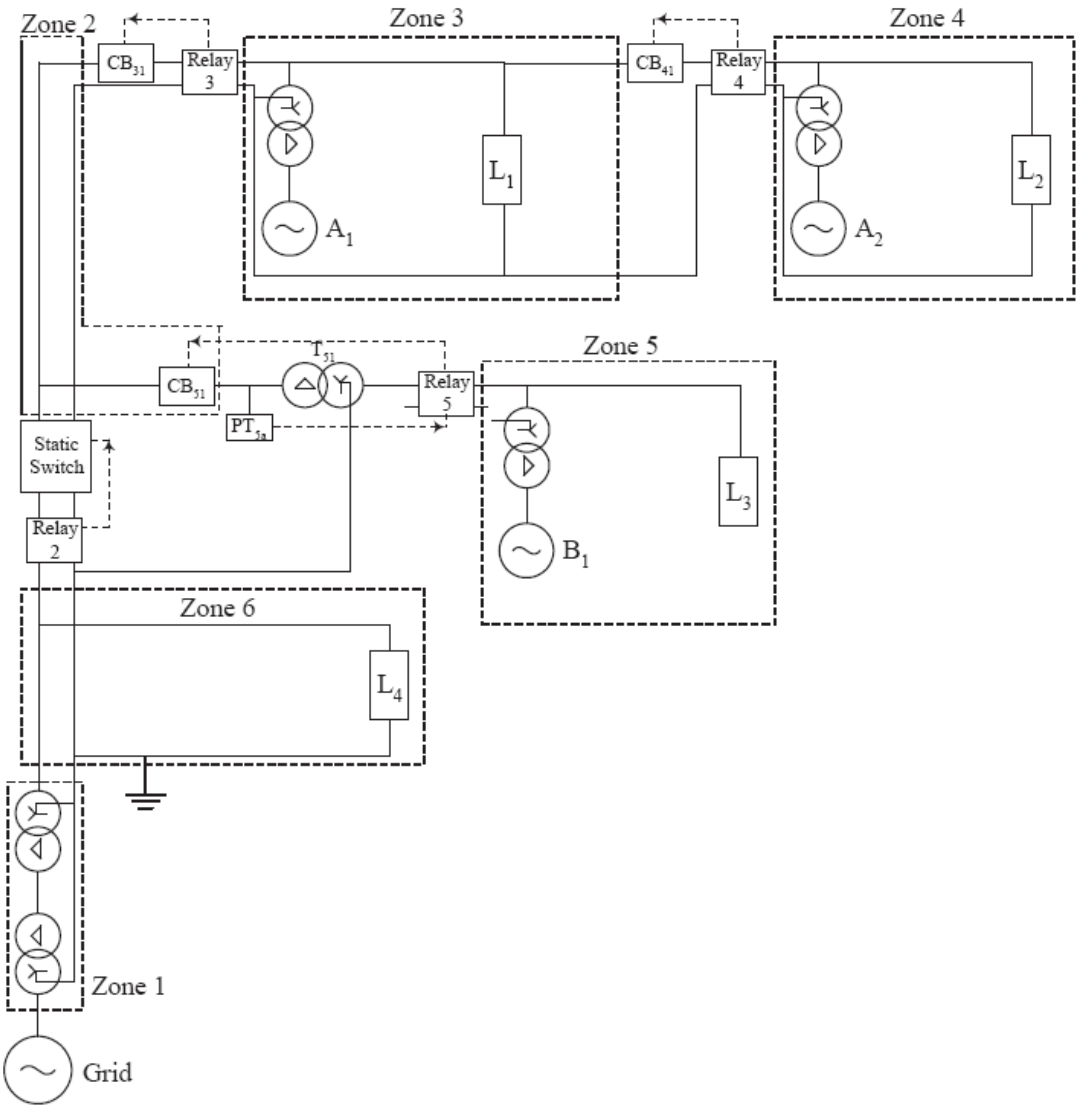

Figure 1: Schematic representation of the AEP CERTS microgrid

3. Basic Protection Issues

In general, a microgrid can operate in both the grid-connected mode and the islanded mode where the microgrid is interfaced to the main power system by a fast semiconductor switch called static switch, (SS). It is essential to protect a microgrid in both the grid-connected and the islanded modes of operation against all types of faults. The major issue arises in island operation with inverter-based sources. Inverter fault currents are limited by the ratings of the silicon devices to around 2 p.u. rated current. Fault currents in islanded inverter based microgrids may not have adequate magnitudes to use traditional over-current protection techniques. This possibility requires an expanded protection strategy.

The philosophy for protection is to have the same protection strategies for both islanded and grid-connected operation. The static switch is designed to open for all faults. With the static switch open, faults within the microgrid need to be cleared with techniques that do not rely on high fault currents. Fig. 1 shows a simple microgrid. The SS (static switch) separates the utility from the microgrid. The islanded part contains two loads and the inverter based sources. The microgrid assumes that the sources have adequate ratings to meet the load demands while in island mode. This example shows two sources in series with impedances between the sources using a four-wire configuration with a common ground point and one source in parallel.

In this example, we assume four protection zones with circuit breakers between Zone 2 and Zone 3, Zone 3 and Zone 4 and between Zone 2 and Zone 5. The system could be designed without these circuit breakers but the protection zones remain the same. In either case, sources feeding the fault must shut down without communications. For example, for a fault in Zone 2 we would expect the SS in Zone 2 to open in ½ to 2 cycles, the circuit breakers between Zones 2-3, 3-4 and 2-5 to open with the inverter-based sources in all Zones shutting down. If the fault was in Zone 4, ideally the SS would open and the circuit breaker between Zones 3 and 4 would open but the breaker between Zones 2 and 3 would not. The source in Zone 4 would also shut down. This would result in Zone 2, Zone 3 and Zone 5 operating as an island.

3.1. Single Line-to-Ground (SLG) Faults

The basic fault sensors for each zone are; a current sensors for each phase and a current sensor summing the three phases and the neutral in zones 2, 3 and 40. It was initially thought that a microgrid could be protected, at least for SLG faults, based on differential component of current I_d, ($I_d = \sum_{k=a,b,c,n} |I_k|$) for any number of sources in series. For example, in Fig.1, a SLG fault in Zone 4 would generate a non-zero differential current in zones 2, 3 and 4. This would result in Relay-2 opening the SS in ½ - 2 cycles followed by Relay-4 opening its circuit breaker and shutting down the source in Zone 4. Using a delay in Relay-3 would allow the section(s) of the microgrid up-stream of the fault to remain operating. This section could then reconnect to the utility autonomously since the faulted section is no longer connected. The problem with this concept is that any zones down-stream of the fault will not see the effect of ground currents. The I_d, sum of the three phase currents and neutral current, will be zero.

For example a SLG fault in Zone 3 will create differential current signals for the SS and Relay-3 to open and shut down the source in Zone 3, but the Zone 4 relay will not see the fault. The fault's ground current does not pass through Zone 4 and therefore, the differential current component detected by the Relay-4 is zero. This would leave Zones 3 and 4 energized as a faulted sub-island. For the case of a microgrid, which does not have breakers between zones, the SS would open and source in Zone 3 would be shut down but the source in Zone 4 would not shut down. It would continue to operate and feed the fault. If the fault were of high impedance, such back-up detection methods as over current and I^2t would not trip the source in Zone 4. Under-voltage protection could possible provide some back up, but again this would have problems. This problem requires using zero-sequence current detection for SLG faults. In this case, this is defined as the vector sum of the three phase currents.

As an example, consider the system in Fig.1 where the loads in all zones are 40 kW and the source in Zone 3 is dispatched at 40 kW and the Zones 4 and 5 are at 20 kW. The nominal line-to-line voltage is 480 volts. This implies that the grid provides 40 kW. When a high impedance SLG (~28 kW) fault is applied to phase A, in Zone 3, Relay-2 will see the fault, $I_d > 0$, and open the SS in 5-10 milliseconds. The resulting sequence voltages and currents seen by each relay are shown below;

FAULT CURRENTS SEEN BY THE RELAYS FOR A SLG FAULT IN ZONE 3 AND SS OPEN

Signal	Relay 2	Relay 3	Relay 4
$\|I_a\|(A)$	0	3.5	59.6
$\|I_b\|(A)$	0	20.8	4.8
$\|I_c\|(A)$	0	21.4	9.2
$I_d(A)$	0	**32.2**	0
$3\|I_0\|(A)$	0	0	**54.4**
$\|V_+\|(volts)$	391.6	392.1	391.2
$\|V_-\|(volts)$	0	4.8	5

Relay-4 has a 3-cycle delay to insure that the SS will open first. Relay 3 has a 10-cycle delay to insure that Zone 4 will shut down first. From the table, we see that Relay-4's differential current is zero but the zero sequence current provides the trip signal. Note that the voltage unbalance is small, (~1%) due to the local voltage control at each source. The usual relationship between the differential currents and the zero sequence currents is a function of the placement of the cts and the neutral conductors connection to the inverters' transformers.

Coordination between unbalanced loads and zero sequence currents is important. Unbalanced loads cause a zero sequence trip. The differential current detection does not see unbalanced loads.

3.2. Line-to-Line (L-to-L) Faults

Using I^2t protection for L-to-L faults is effective for low impedance faults but in many cases the time to trip will be long causing unnecessary disturbances to the loads and utility. High impedance fault current magnitudes will not be adequate to provide a trip. The our approach is to use negative sequence current to detect line-to-line faults.

Using the negative-sequence current, all L-to-L faults can be detected except the fault in Zone 3. In the microgrid of Fig. 1, no load exists between the static switch and Relay 3. When the static switch trips in response to a L-to-L fault in Zone 3, no current flows through Relay 3 and therefore, the relay does not command the corresponding breaker to trip. As a result, the microsource A_1 is not shut down and continues to provide the fault current.

4. Protection Based on Symmetrical Components

An SLG or LL fault imbalances phase currents of a number of protection zones of a microgrid. For the analysis of unbalanced currents, the concept of symmetrical components is usually employed [4]. The symmetrical components analysis uses a transformation matrix which converts phase components of an unbalanced three-phase current to equivalent positive-, negative- and zero-sequence current components [4]. The positive-sequence component represents a three-phase current that rotates in the same direction as the unbalanced three-phase current, while the negative-sequence component represents a three-phase current that rotates in an opposite direction with respect to the unbalanced three-phase currents. The zero-sequence component represents a system of three currents that have the same phase-angle.

An SLG fault generates usually zero- and negative-sequence current components, and an LL fault generates only a negative-sequence current component. The zero- and negative-sequence components of currents at the protective relays can be employed to detect SLG and LL faults in different protection zones of a microgrid. It is to be emphasized that zero- and negative-sequence current components are also generated and detected by relays under unbalanced load conditions. The microgrid concept is currently used for the distribution level of power systems which usually operates under unbalanced load conditions. Therefore, a protection approach based on symmetrical current components must distinguish between faulty and unbalanced operating conditions. In other words, the microgrid protection system must be coordinated such that it does not command for a trip under unbalanced load conditions while the protection system should detect SLG and LL faults in all zones of the microgrid.

For the AEP microgrid of Fig. 1, the zero- and negative-sequence components of currents at all relays, including Relay 2 that is attached to the static switch, are obtained for unbalanced load and SLG and LL fault conditions. The values of symmetrical current components are obtained based on digital-time domain simulations of the microgrid in the EMTP software environment. To comply with values measured by the real-world protective relays [6]-[8], magnitudes of all symmetrical components measured in the EMTP are multiplied by a factor of 3. Thus, each relay detects three times of the

magnitudes of symmetrical current components, i.e. $3|I_+|$, $3|I_-|$ and $3|I_0|$ which are referred to as magnitudes of positive, negative and zero components of currents herein after.

Magnitudes of the positive, negative and zero current components at all relays for a maximum load power unbalance of 20 percents and for SLG and LL faults in all protection zones have been obtained for the AEP microgrid and the results are presented in the following sections. For all the study cases, powers of the microsources A_1, A_2 and B_1 and powers of the loads L_1, L_2 and L_3 have been set at the following values: P_{A1} = 40 kW, P_{A2} = 20 kW, P_{B1} = 0 kW, P_{L1} = 40 kW, P_{L2} = 60 kW, and P_{L3} = 40 kW.

4.1. Unbalanced Load

In this case study, the phase resistances of load L_3 are changed such that it provides a power unbalance of 20 percents, while its total power remains at 60 kW. Table I gives the values of three-phase currents at the Relays 2, 3, 4 and 5 and magnitudes of the corresponding positive-, negative- and zero-sequence current components as well as the positive- and negative-sequence voltage components at all relays. It is seen from the results that the zero- and negative-sequence current components have maximum values of 11.9 and 26 A, respectively, and they correspond to the currents flowing through the Relay 4. If one of the other loads, i.e. L_1 or L_2, are 20 percents unbalanced, then current of the closest relay to the unbalanced load will have maximum zero- and negative-sequence components which do not exceed the maximum values obtained for the case of an unbalanced load L_3. When using symmetrical current components for detecting faults, the threshold of all relays must be selected above the maximum zero- and negative-sequence current magnitudes of 11.9 and 26 A. This ensures that the protection system does not trip any of the breakers when the AEP microgrid operates under a maximum load power unbalance of 20 percents.

TABLE I: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR A 20 PERCENTS UNBALANCED LOAD L3

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
Relay 2	179.2	162.7	164.9	506.8	21.8	9.3	391.3	0.22
Relay 3	112.3	94.7	97.3	304.2	23.7	9.3	391.3	0.22
Relay 4	114	93.9	96.7	304.4	26	11.9	389.3	0.37
Relay 5	67.3	67.4	68.3	203	2	0	390.8	0.18

4.2. Single Line-to-Ground Fault

This section presents the results obtained from the EMTP based simulation of the AEP microgrid of Fig. 1 for an SLG fault in one of the protection Zones 2, 3, 4 and 5. The AEP microgrid operates under steady-state conditions with the source and load parameters given in Section 3. An SLG fault with a power of 28.5 kW (R_f = 2.695 Ohms) occurs in one of the protection zones at t = 1 s when the microgrid operates under steady-state conditions. Magnitudes of the phase currents, the symmetrical current components $3|I_+|$, $3|I_-|$ and $3|I_0|$ and the symmetrical voltage components $|V_+|$ and $|V_-|$ at all relays are

recorded when the microgrid operates under steady-state conditions subsequent to the SLG fault. Values of the parameters for the grid-connected (SS open) and the islanded (SS open) modes, when the static switch trips after the fault, are given in Tables II, III, IV and V for an SLG fault in Zones 4, 3, 2 and 5, respectively.

TABLE II: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN SLG FAULT IN ZONE 4

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	211.6	117	116.9	445	102.8	88.1	391.3	1.05
Relay 3	147	47.6	50	242.7	112	88.1	391.3	1.05
Relay 4	158.8	42.4	42.7	242.8	123.3	111.4	389.6	1.76
Relay 5	66	66.3	70.7	202.9	9.2	0	390.9	0.88
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	2.4	20.8	21.6	33	40	0	392.1	4.5
Relay 4	81.5	4	8.5	72	88.4	85.4	391.1	5
Relay 5	13	11.6	24.4	33.2	40	0	392	3.8

TABLE III: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN SLG FAULT IN ZONE 3

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	215.6	116.6	116.2	448	106.5	93.5	391.3	1.1
Relay 3	151.2	47.2	49.2	245.6	116	93.5	391.3	1.09
Relay 4	22.6	41.8	41.5	104.8	17	26	389.8	1.6
Relay 5	66	66.2	70.8	202.9	9.5	0	390.9	0.9
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	3.5	20.8	21.4	31.2	41.5	0	392.1	4.8
Relay 4	59.6	4.8	9.2	72	53	54.4	391.2	5
Relay 5	13	11.9	24.2	31.3	41.5	0	392	4.8

The results given in Tables II, III, IV and V indicate that magnitudes of zero-sequence current components of all relays that must trip for a close-by up-stream SLG fault are well above the maximum zero-sequence current component of 11.9 A that is related to the maximum load power unbalance of 20 percents. This means that a zero-sequence current threshold can be selected for all relays such that they can detect up-stream SLG faults in all microgrid protection zones. It is to be noted that the relays do not detect SLG faults that are located in their down-stream area after the static switch trips. However, the

down-stream faults are detected based on the differential current components at the relays.

TABLE IV: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN SLG FAULT IN ZONE 2

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	221.6	114.5	113.2	449	112	105.8	391.3	1.1
Relay 3	16	45	45.8	105	23.3	39.6	391.1	1.1
Relay 4	26.7	39.3	37.3	103.2	11.3	12.2	390.2	1.1
Relay 5	65.8	66.3	71	203	10	0	390.8	1.0
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	140.6	21.7	21.4	175.6	101.5	144.8	392	5
Relay 4	55	7.5	11.2	71.6	49.4	44.7	391.6	4.8
Relay 5	12.6	13.2	24.7	30.7	43.5	0	391.8	4.2

TABLE V: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN SLG FAULT IN ZONE 5

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	161.5	118.4	168.6	444	90.4	0	391.3	0.92
Relay 3	34.5	40.8	30.3	104.8	18.9	0	391.3	0.92
Relay 4	33.7	37.4	32.3	103.2	9.2	0	390.2	0.87
Relay 5	198	74.6	72.2	343.2	109.3	141.7	390.4	3
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	74.6	30.4	75.8	173	82	0	392	4
Relay 4	32.2	9.8	31.7	69.4	40	0	391.7	3.8
Relay 5	132	28.1	25.3	173.2	82.3	142	391.4	5.5

4.3. Line-to-Line Fault

This section presents the results obtained from the EMTP based simulation of the AEP microgrid of Fig. 1 for an LL fault in one of the protection Zones 2, 3, 4 and 5. The AEP microgrid operates under steady-state conditions with the source and load parameters given in Section 3. An LL fault with a power of 85.5 kW (R_f = 2.695 Ohms) occurs in one of the protection zones at t = 1 s when the microgrid operates under steady-state conditions. Magnitudes of the phase currents, the symmetrical current components $3|I_+|$, $3|I_-|$ and $3|I_0|$ and the symmetrical voltage components $|V_+|$ and $|V_-|$ at all relays are recorded when the microgrid operates under steady-state conditions subsequent to the LL fault. Values of the parameters for the grid-connected (SS closed) and the islanded (SS open) modes, when the static switch trips after the fault, are given in Tables VI, VII, VIII

and IX for an LL fault in Zones 4, 3, 2 and 5, respectively. The results indicate that magnitudes of negative-sequence current components of all relays that must trip for a close-by LL fault are well above the maximum negative-sequence current component of 26 A that is related to the maximum load power unbalance of 20 percents. In particular, magnitudes of the negative-sequence current components become much higher after the static switch trips. This means that a negative-sequence current threshold can be selected for all relays such that the AEP microgrid is protected against LL faults in all microgrid protection zones.

TABLE VI: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN LL FAULT IN ZONE 4

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	310	296	140	719	304	0	391	3.1
Relay 3	253	239	63.7	516	330	0	391	3.1
Relay 4	262	249	52.5	517	364	0	388.1	5.2
Relay 5	72	58.6	73.2	203	27	0	390.6	2.6
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	75	72	6.7	135	118	0	391.4	14
Relay 4	157	152	6.9	275	260	0	389.5	15
Relay 5	45.2	85	40	136	118	0	391.8	11

TABLE VII: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN LL FAULT IN ZONE 3

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	318	304	139	733	318	0	391	3.1
Relay 3	262	247	63	530	346	0	391	3.2
Relay 4	22.1	43.4	51.3	112	50.7	0	388.5	4.8
Relay 5	72.2	58.2	73.4	203	28.4	0	390.6	2.7
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	77.6	75	6.4	140	124	0	391.3	14
Relay 4	85.6	90	5.6	147	157	0	390	15
Relay 5	46.6	88	42	140	124	0	391.7	12

TABLE VIII: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN LL FAULT IN ZONE 2

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	324	309	135	737	335	0	390.9	3.4
Relay 3	21.6	41.6	58.2	109	70	0	390.9	3.4
Relay 4	27.8	34	45.8	105	34	0	389.8	3.2
Relay 5	72.3	57.8	74	203	30	0	390.5	2.8
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	170	172	4.5	290	302	0	390.8	15
Relay 4	83	85	2.3	145	147	0	390.8	14
Relay 5	47.2	90	44	142	130	0	391.4	12

TABLE IX: SYMMETRICAL SEQUENCE CURRENT COMPONENTS AT THE AEP MICROGRID RELAYS FOR AN LL FAULT IN ZONE 5

Device	$\|I_a\|$(A)	$\|I_b\|$(A)	$\|I_c\|$(A)	$3\|I_+\|$(A)	$3\|I_-\|$(A)	$3\|I_0\|$(A)	$\|V_+\|$(A)	$\|V_-\|$(A)
SS Closed								
Relay 2	327	196	222	716	266	0	390.9	2.7
Relay 3	22	53	41.1	109	55.6	0	390.9	2.7
Relay 4	26.6	42.1	37.6	105	27	0	389.8	2.6
Relay 5	280	270	99	616	322	0	389	8.8
SS Open								
Relay 2	0	0	0	0	0	0	391.6	0
Relay 3	173	85	89	276	242	0	391.2	12
Relay 4	85.2	43	43	138	117	0	391.2	11
Relay 5	151	148	11.5	276	242	0	390.1	16

5. Coordination of Protection

This section presents a summary of the items that are considered when the protection system of the AEP microgrid is coordinated. Based on the results presented in Section 3.1 and Section 3.2, a threshold of $3|I_0|$=35 A is selected for all relays for detecting a down-stream SLG fault based on a zero-sequence current component. The up-stream SLG faults that are close to a relay are detected based on a differential current component for which a threshold of $|I_d|$ =15 A is chosen. Also, based on the result presented in Section 3.1 and Section 3.3, a threshold of $3|I_-|$=95 A is considered for all relays when detecting an LL fault based on a negative-sequence current component. The thresholds considered for the symmetrical and differential current components guarantee that the protection system detects all SLG faults with a power more than 28.5 kW/phase and all LL faults with a power greater than 85.5 kW that occur in any of the microgrid protection zones.

To prevent detecting instantaneous or short faults and transients, a delay of 50 ms (3 cycles) is set for all relays before detecting an SLG or LL fault. In other words, if a

symmetrical component remains greater than the corresponding threshold longer than 50 ms, then the relay will command the corresponding circuit breaker to trip. The delay of 50 ms is considered for all relays except the Relay 3, for the case of SLG faults only, for which a delay of 167 ms (10 cycles) is chosen. The longer delay considered for the Relay 3 ensures that the relay does not command for a trip for SLG faults in Zone 4, Fig. 1, as such faults are cleared by the Relay 4 in less than 10 cycles. It is to be noted that the delay considered for detecting an LL fault by the Relay 3 is the same as that of the other relays, i.e. 50 ms. It should also be noted that no delay is considered for the SLG and LL faults that are detected by the Relay 2, that is attached to the static switch, since the switch is expected to clear a fault within a maximum period of 8 ms (half a cycle).

When a trip signal is sent by a relay to the corresponding breaker, a delay of 30 ms is considered before starting to open phase switches of the corresponding breaker. The reason for considering the delay of 30 ms is that magnitudes of the symmetrical current components of the relays have different rise times and thus, each of them exceeds the corresponding threshold at a different time than the others. If no delay is considered, one of the relays may not command for a necessary trip since the corresponding symmetrical component does not stay above the threshold more than 50 ms prior to the fault clearance by another breaker. This causes one of the microsources to continue its operation in a stand-alone mode after the fault clearance, which is not desirable. To ensure that all relays which are expected to command for a trip have sufficient time to detect a fault, the delay of 30 ms is considered before disconnecting a circuit breaker.

Once a symmetrical current component with a magnitude greater than the corresponding threshold lasts more than 3 cycles, the corresponding relay sends a trip command to the circuit breaker. The 3-cycle delay is considered for all relays, except the Relay 3 which has a 10-cycle delay for SLG faults, and the Relay 2 which has no delay for all types of fault. When the breaker receives a trip command, its controller considers a delay of 30 ms before starting the procedure of disconnecting the breaker phases. The 30 ms delay is considered for all the breakers except the static switch which has no delay. After a delay of 30 ms, the three-phase circuit breaker who has received a trip command is opened, one phase at a time. To open a circuit breaker, currents of all three phases of the breaker are measured and when a phase current crosses zero, the corresponding phase switch is opened. The disconnection procedure is the same for all the breakers including the static switch.

TABLE X: RELAY SETTINGS

Protection	Relay	Up-stream SLG faults	Down-stream SLG faults	Line-to-Line faults
Primary	2	$I_d > 15A$ delay=0 ms	$3\|I_0\| > 35A$ delay=0 ms	$3\|I_-\| > 95A$ Delay=0 ms
	3	$I_d > 15A$ delay=167 ms	$3\|I_0\| > 35A$ delay=167 ms	$3\|I_-\| > 95A$ delay=50 ms
	4	$I_d > 15A$ delay=50 ms	$3\|I_0\| > 35A$ delay=50 ms	$3\|I_-\| > 95A$ Delay=50 ms
	5	$I_d > 15A$ delay=50 ms	$3\|I_0\| > 35A$ delay=50 ms 50% volts dip	$3\|I_-\| > 95A$ Delay=50 ms
1st Back-up	2	I^2t activation level $\|I\| > 480A$		
	3	I^2t activation level $\|I\| > 225A$		
	4	I^2t activation level $\|I\| > 125A$		
	5	I^2t activation level $\|I\| > 125A$		
2nd Back-up and under voltage protection	2	Peak current $\|I\| > 750A$	Voltage power quality levels	
	3		50% under voltage delay 30 cycles	
	4		50% under voltage delay 20 cycles	
	5		50% under voltage delay 20 cycles	

6. Study Cases

This section evaluates performance of the protection system of the AEP microgrid based on digital time-domain simulation studies in the EMTP software environment. Performance of the protection system is studied for SLG and LL faults in all the microgrid protection zones, i.e. Zones 2, 3, 4, 5 and 6 of Fig. 1. All SLG and LL faults have a resistance of 2.695 Ohms which corresponds to a 28.5 kW/phase power for SLG faults and a 85.5 kW power for LL faults, respectively. The fault resistance is equal to the resistance used for experimenting faults at the real-world microgrid test site in Ohio.

For all study cases of this section, powers of the microsources A_1, A_2 and B_1 and powers of the loads L_1, L_2 and L_3 are set at the following values: P_{A1} = 40 kW, P_{A2} = 20 kW, P_{B1} = 10 kW, P_{L1} = 40 kW, P_{L2} = 40 kW, and P_{L3} = 40 kW. For each study case, the results are shown in four figures and each figure shows the operating parameters related to the relay that is attached to the static switch or one of the Relays 3, 4 and 5. Each figure shows the three-phase voltages and currents, the real and reactive components of power, and the frequency at one of the relays. Each figure also shows normalized magnitudes of the differential and zero- and negative-sequence current components

measured at a relay as well as the relay output signal that can command a breaker to trip or to continue its operation. The figure that corresponds to the Relay 5 also shows normalized magnitude of the phase voltage that is measured at the delta side of the transformer T_{51}, Fig. 1. The phase voltage is measured for detecting SLG faults in Zone 2 for which the Relay 5 does not detect a differential or zero-sequence current component.

6.1. SLG Faults

SLG Fault in Zone 4

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an SLG fault with a resistance of 2.695 Ohms is applied in Zone 4 at t=1.0 s. Figs. 3(a)-(e) to Figs. 6(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the SLG fault.

Fig. 2(f) shows that the Relay 2 commands the static switch to trip right after the fault since the relay detects a differential current component that exceeds 1.0 pu (15 A). Fig. 3(f) shows that the Relay 3 does not command for a trip since it has a built-in delay of 10 cycles and magnitude of the differential current component detected by the relay falls below 1.0 pu before 10 cycle when the breaker CB_{41} clears the fault. Fig. 4(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitudes of both the differential and zero-sequence current components at the relay are greater than 1.0 pu for a period more than 50 ms (3 cycles). However, the relay trip command is due to the differential current component since it exceeds 1.0 pu earlier than the zero-sequence current component. Fig. 5(f) shows that the Relay 5 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceed the threshold of 1.0 pu.

For the case of SLG fault in Zone 4, the static switch islands the microgrid and the breaker CB_{41} disconnects Zone 4 of the microgrid and shuts down the microsource A_2. The Zones 2, 3 and 5 of the microgrid and the microsources A_1 and B_1 continue the operation subsequent to the fault detection and its clearance. The results shown in Fig. 2 to Fig. 5 demonstrate that the developed protection system is able to protect the AEP microgrid against an SLG fault in Zone 4 with a power of 28.5 kW/phase by clearing the fault and isolating the microgrid from the main grid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all SLG faults in Zone 4 with a power more than or equal to 28.5 kW/phase.

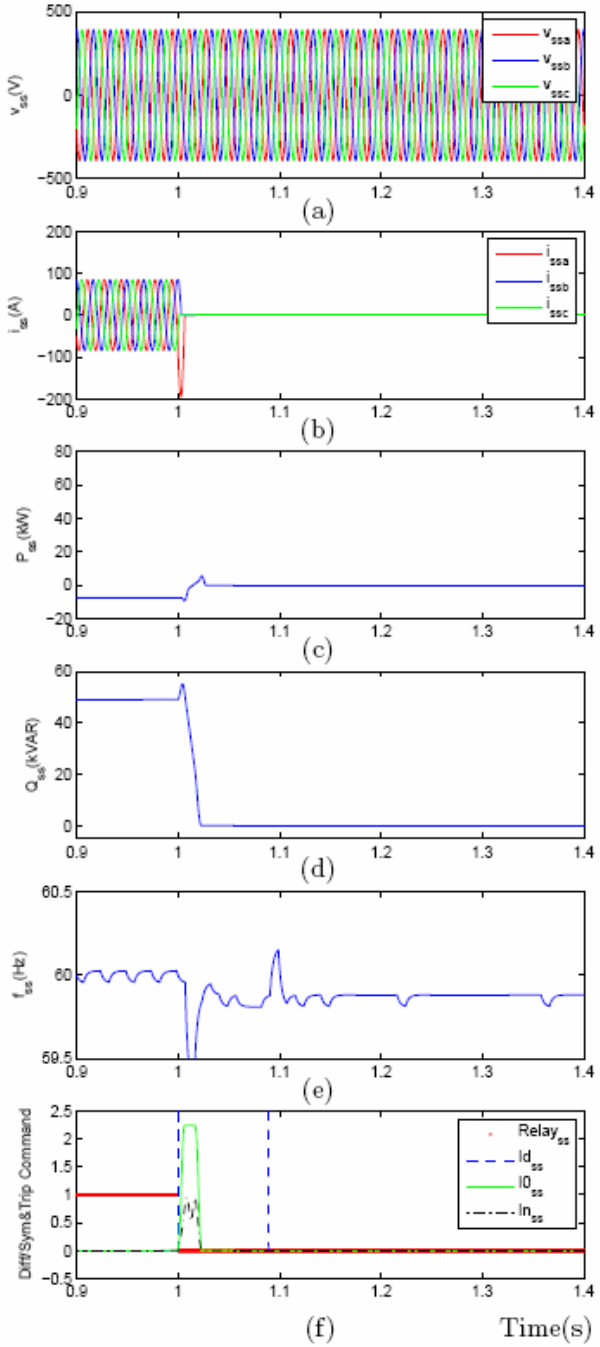

Figure 2 : Response of the Relay 2 to a 28.5 kW SLG fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

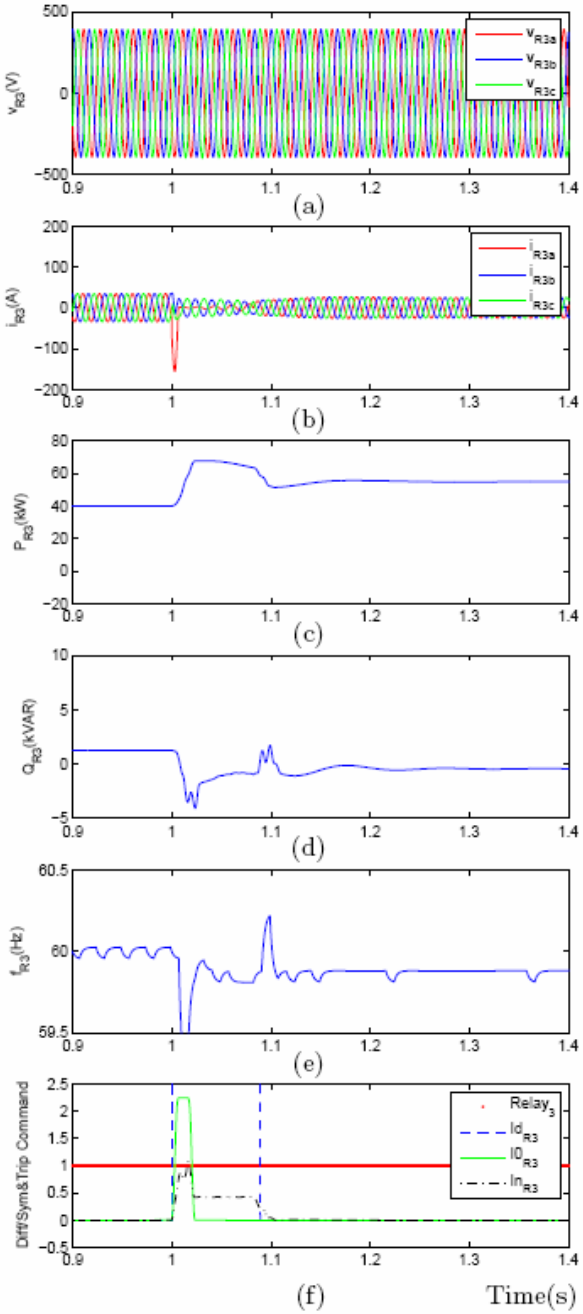

Figure 3: Response of the Relay 3 to a 28.5 kW SLG fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

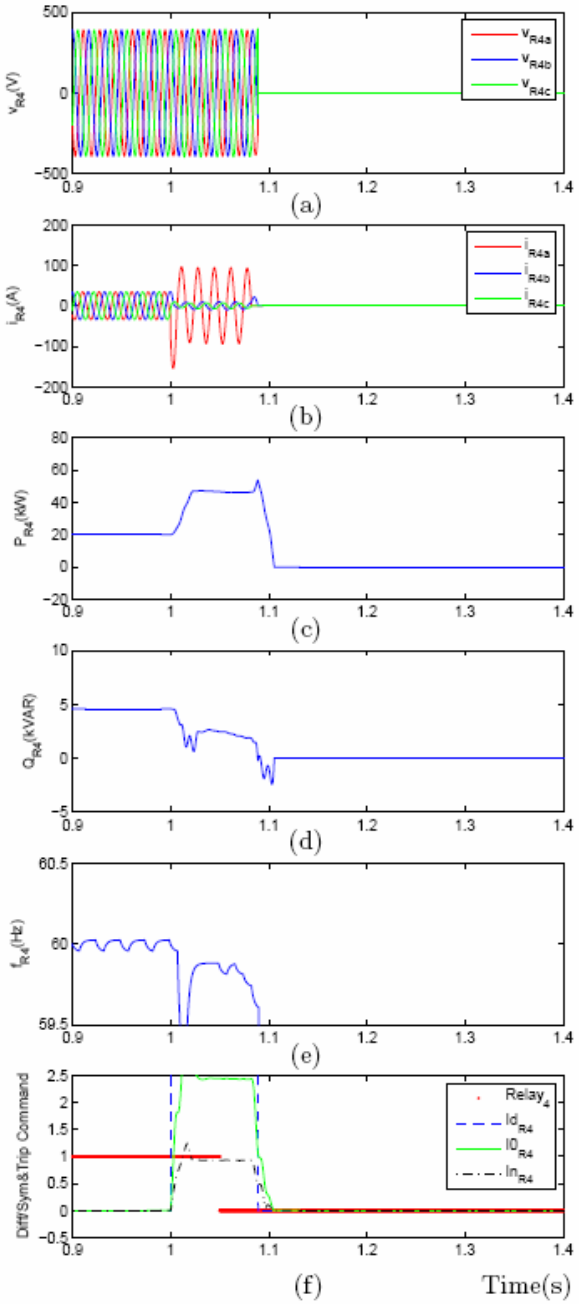

Figure 4: Response of the Relay 4 to a 28.5 kW SLG fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

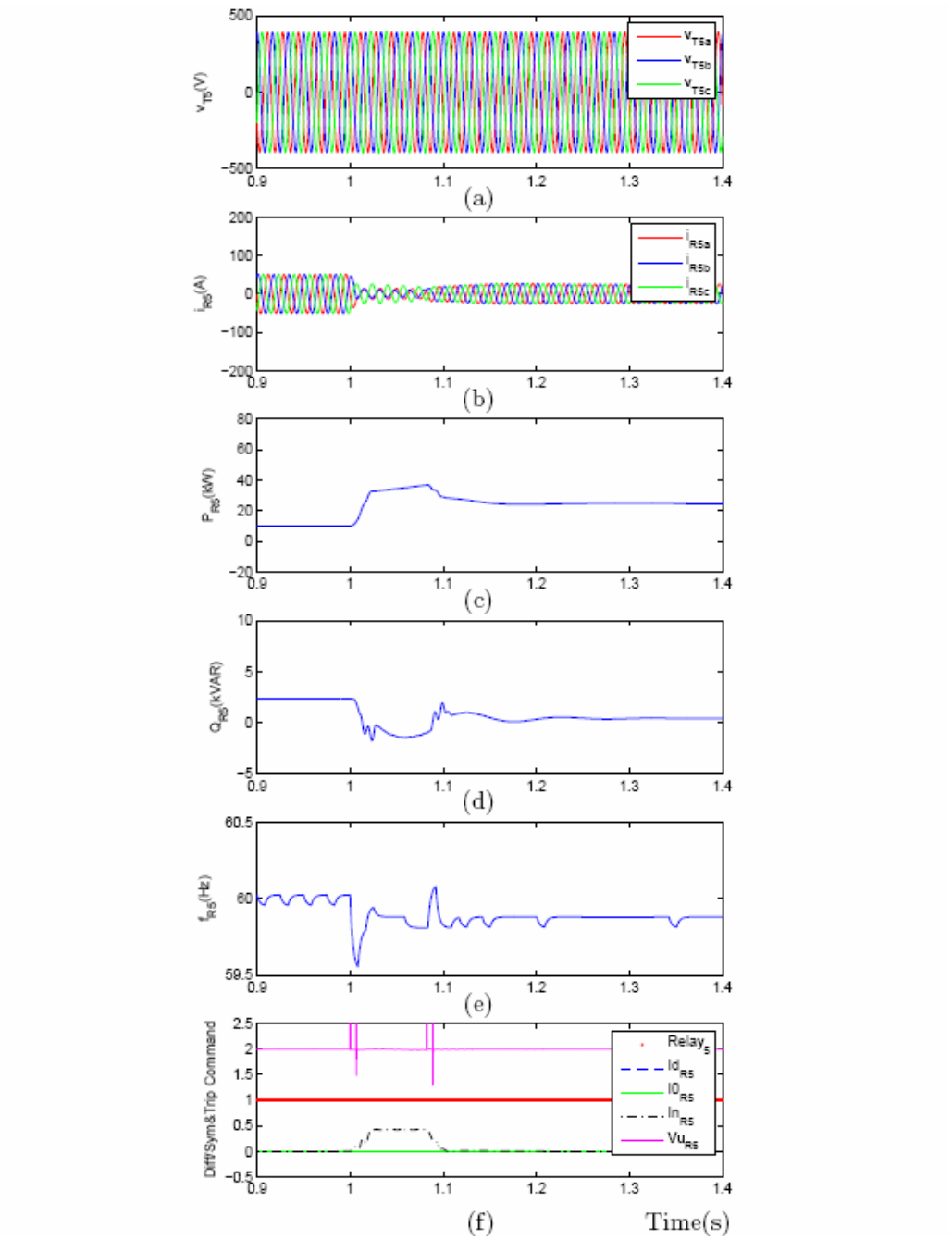

Figure 5: Response of the Relay 5 to a 28.5 kW SLG fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

SLG Fault in Zone 3

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 0.5 and an SLG fault with a resistance of 2.695 Ohms is applied in Zone 3 at t=1.0 s. Figs. 7(a)-(e) to Figs. 10(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the SLG fault.

Fig. 6(f) shows that the Relay 2 commands the static switch to trip right after the fault since the relay detects a differential current component that exceeds 1.0 pu (15 A). Fig. 7(f) shows that the Relay 3 commands for a trip since even when the circuit breaker CB_{41} trips, the fault is not cleared in the protection Zone 3 and the relay still detects a differential current component. Fig. 8(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the zero-sequence current component at the relay is greater than 1.0 pu (35 A) for a period more than 50 ms (3 cycles). Fig. 9(f) shows that the Relay 5 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu.

For the case of SLG fault in Zone 3, the static switch islands the microgrid and the breakers CB_{31} and CB_{41} disconnect Zones 3 and 4 of the microgrid and shut down the microsources A_1 and A_2. The Zones 2 and 5 of the microgrid and the microsource B_1 continue the operation subsequent to the fault detection and its clearance. The results shown in Fig. 6 to Fig. 9 demonstrate that the developed protection system is able to protect the AEP microgrid against an SLG fault in Zone 3 with a power of 28.5 kW/phase by clearing the fault and isolating the microgrid from the main grid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all SLG faults in Zone 3 with a power more than or equal to 28.5 kW/phase.

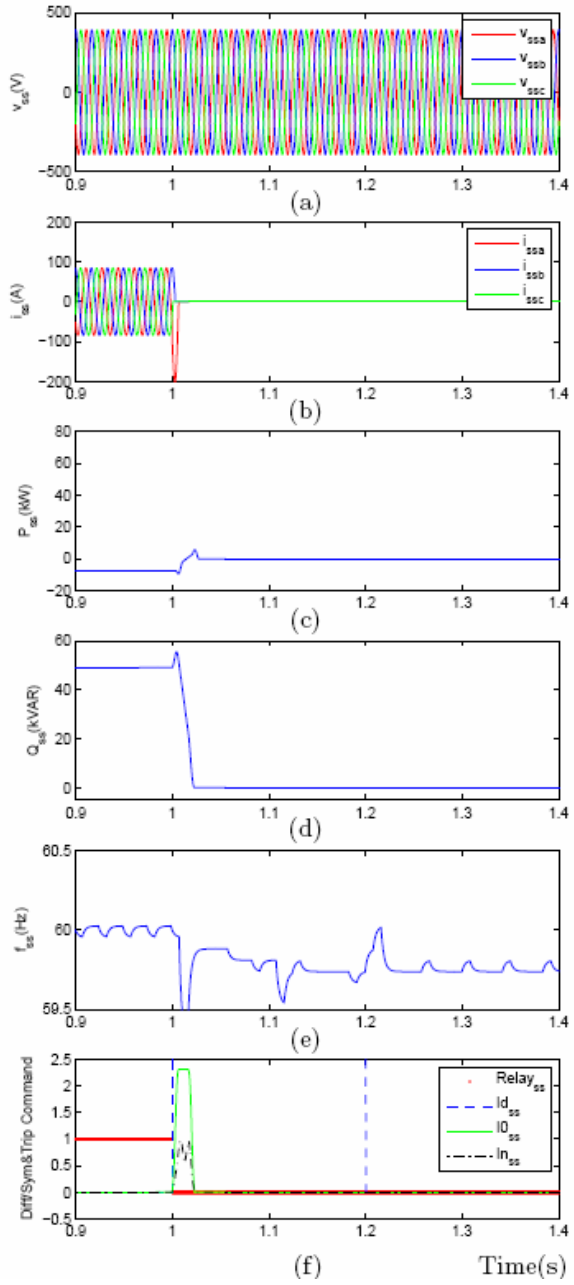

Figure 6: Response of the Relay 2 to a 28.5 kW SLG fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

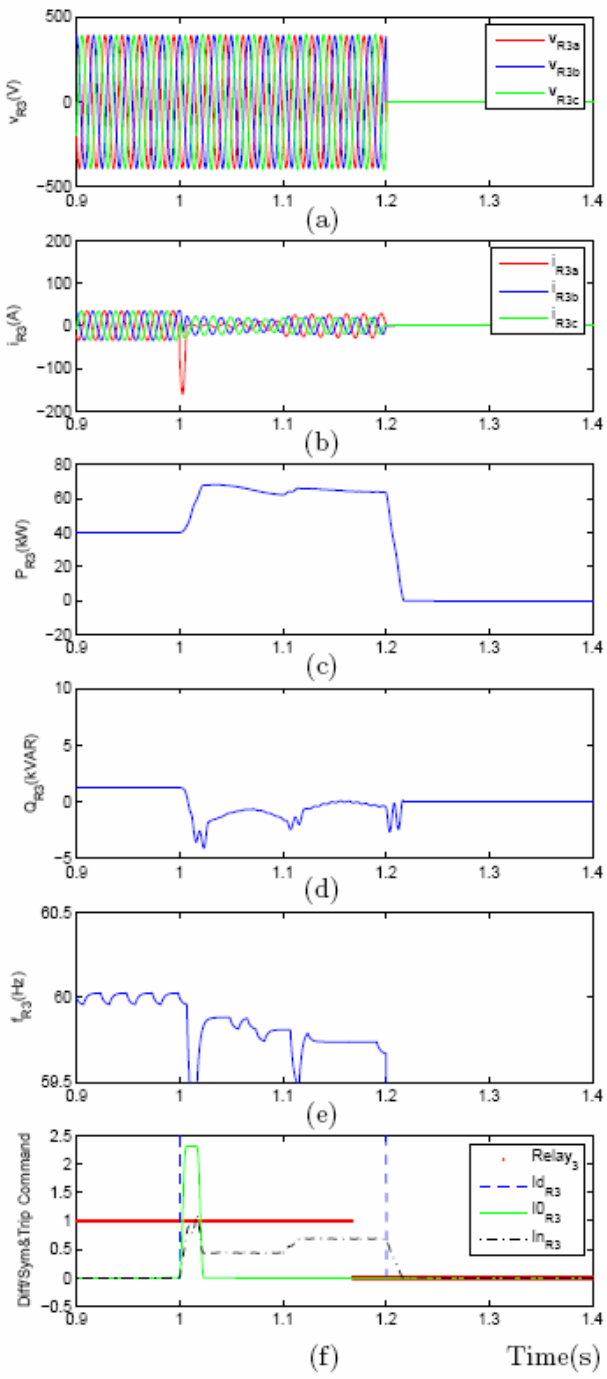

Figure 7: Response of the Relay 3 to a 28.5 kW SLG fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

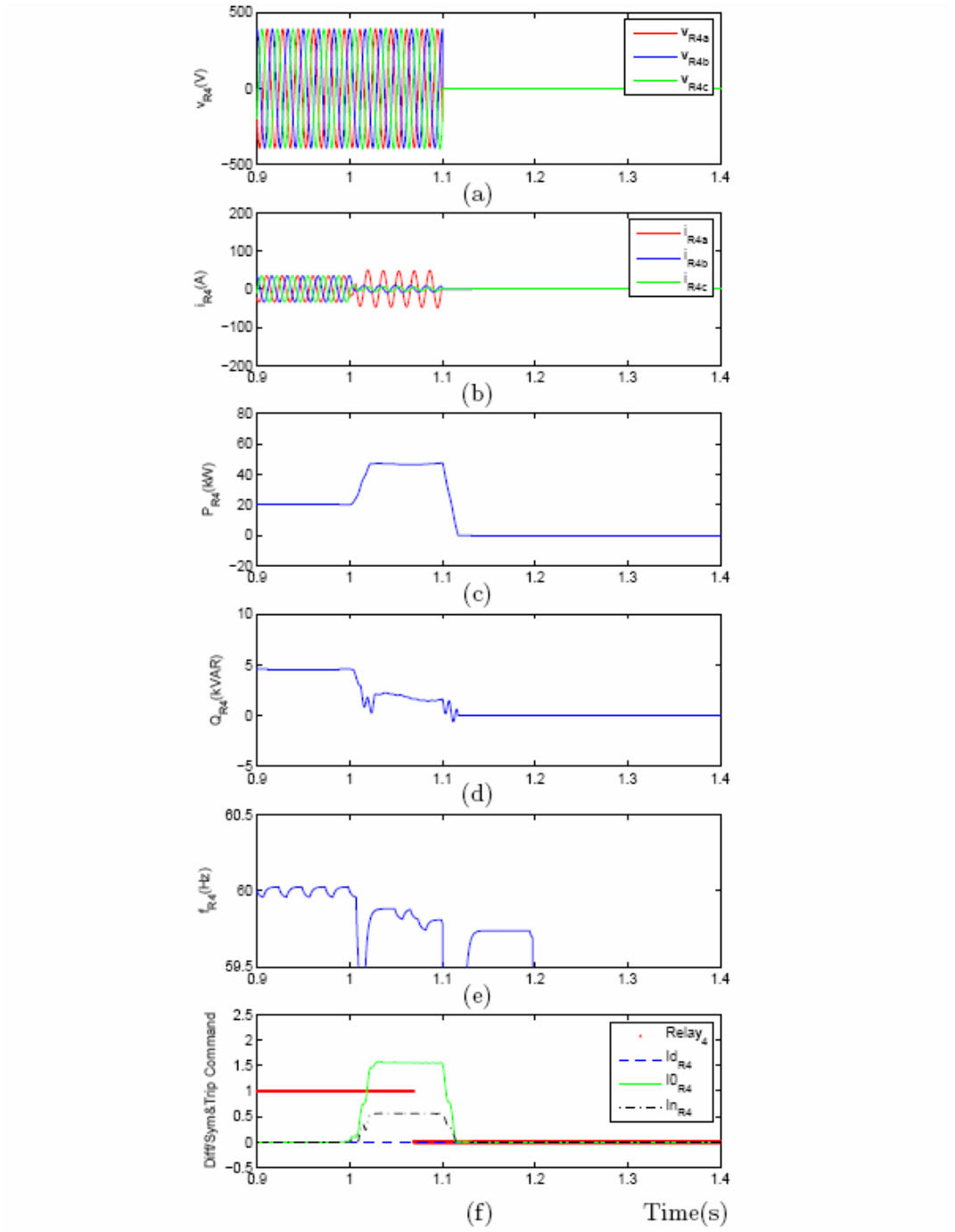

Figure 8: Response of the Relay 4 to a 28.5 kW SLG fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

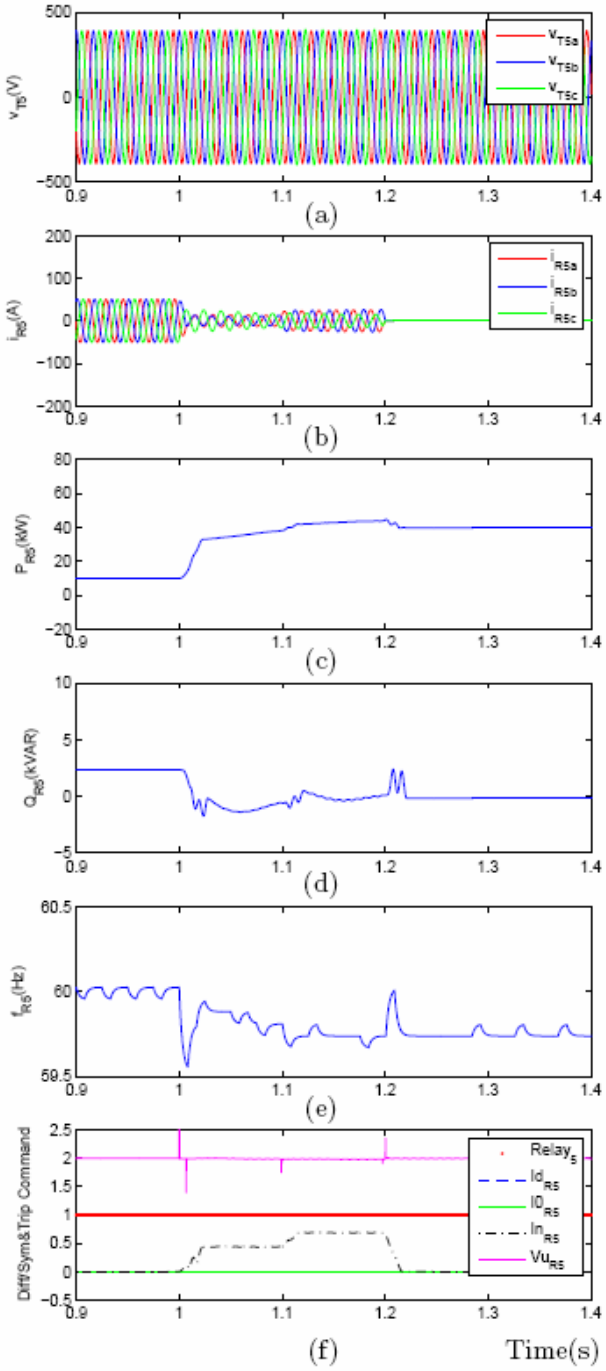

Figure 9: Response of the Relay 5 to a 28.5 kW SLG fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

SLG Fault in Zone 2

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an SLG fault with a resistance of 2.695 Ohms is applied in Zone 2 at t=1.0 s. Figs. 11(a)-(e) to Figs. 14(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the SLG fault.

Fig. 10(f) shows that the Relay 2 commands the static switch to trip right after the fault since the relay detects a differential current component that exceeds 1.0 pu (15 A). Fig. 11(f) shows that the Relay 3 sends a trip command to the circuit breaker CB_{31} since magnitude of the negative-sequence current component at the relay is greater than 1.0 pu (95 A) for a period more than 50 ms (3 cycles). Fig. 12(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the zero-sequence current component at the relay is greater than 1.0 pu (35 A) for a period more than 50 ms. Fig. 13(f) shows that the Relay 5 sends a trip command to the circuit breaker CB51 since magnitude of the phase voltage at the delta-side of transformer T_{51} falls below 1.0 pu (196 V) for a period more than 20 cycles.

For the case of SLG fault in Zone 2, the static switch islands the microgrid and the breakers CB_{31}, CB_{41} and CB_{51} disconnect all three zones of the microgrid and shut down all the microsource located inside the microgrid. The results shown in Fig. 10 to Fig. 13 demonstrate that the developed protection system is able to protect the AEP microgrid against an SLG fault in Zone 2 with a power of 28.5 kW/phase by clearing the fault and isolating the microgrid from the main grid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all SLG faults in Zone 2 with a power more than or equal to 28.5 kW/phase.

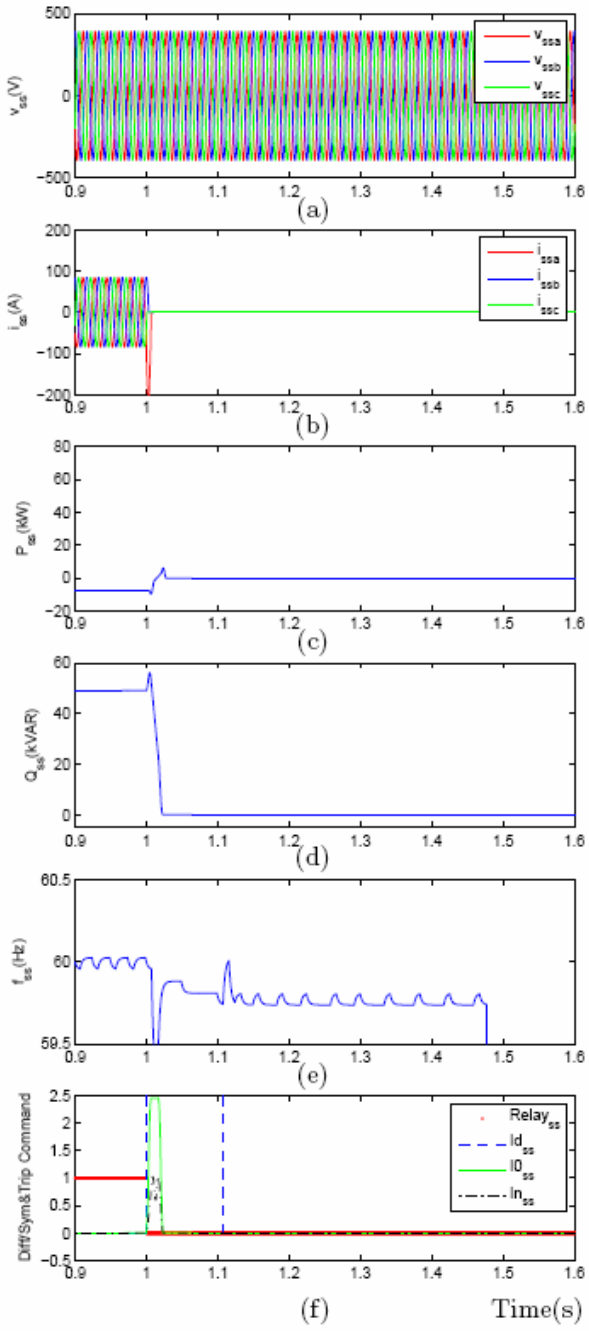

Figure 10: Response of the Relay 2 to a 28.5 kW SLG fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

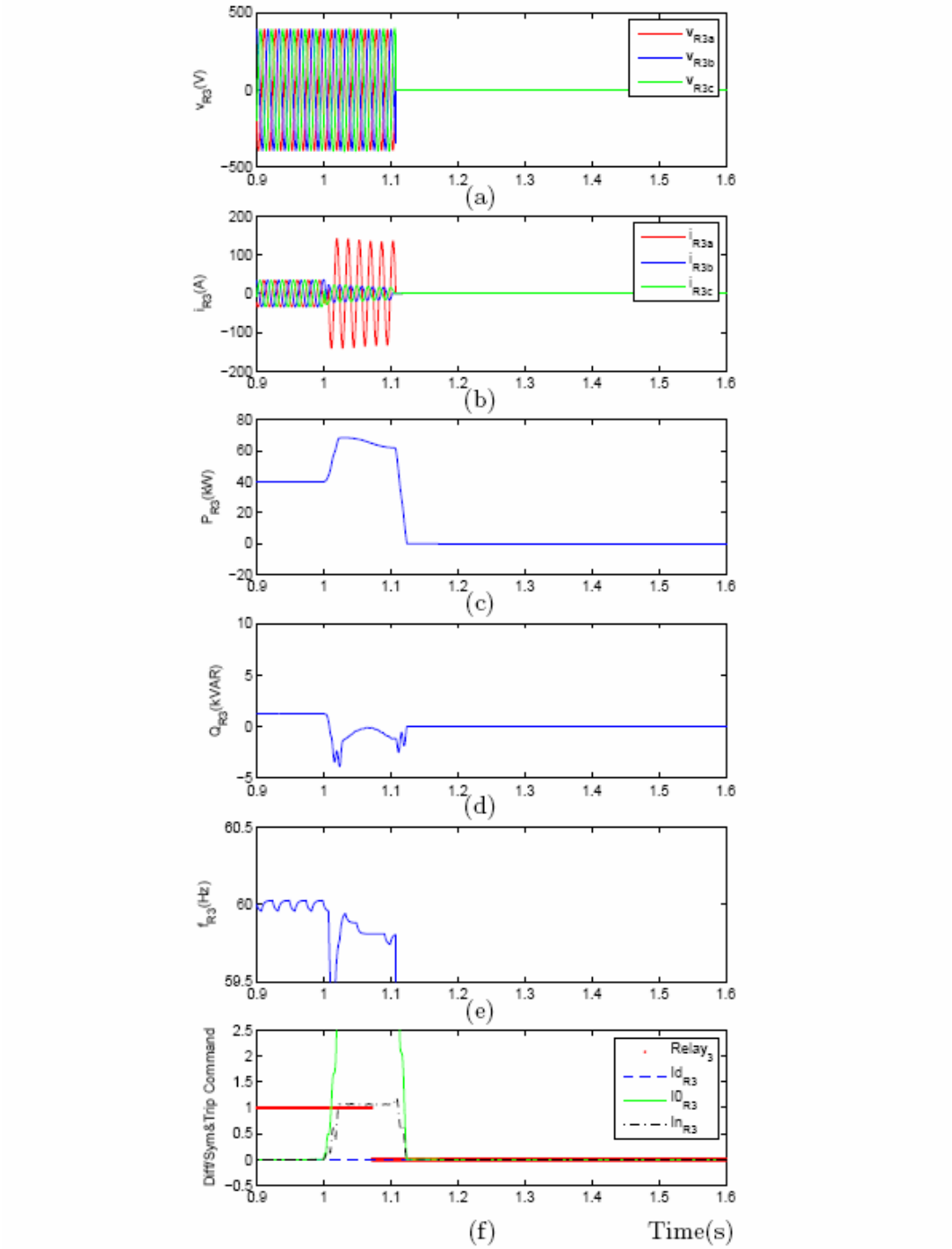

Figure 11: Response of the Relay 3 to a 28.5 kW SLG fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

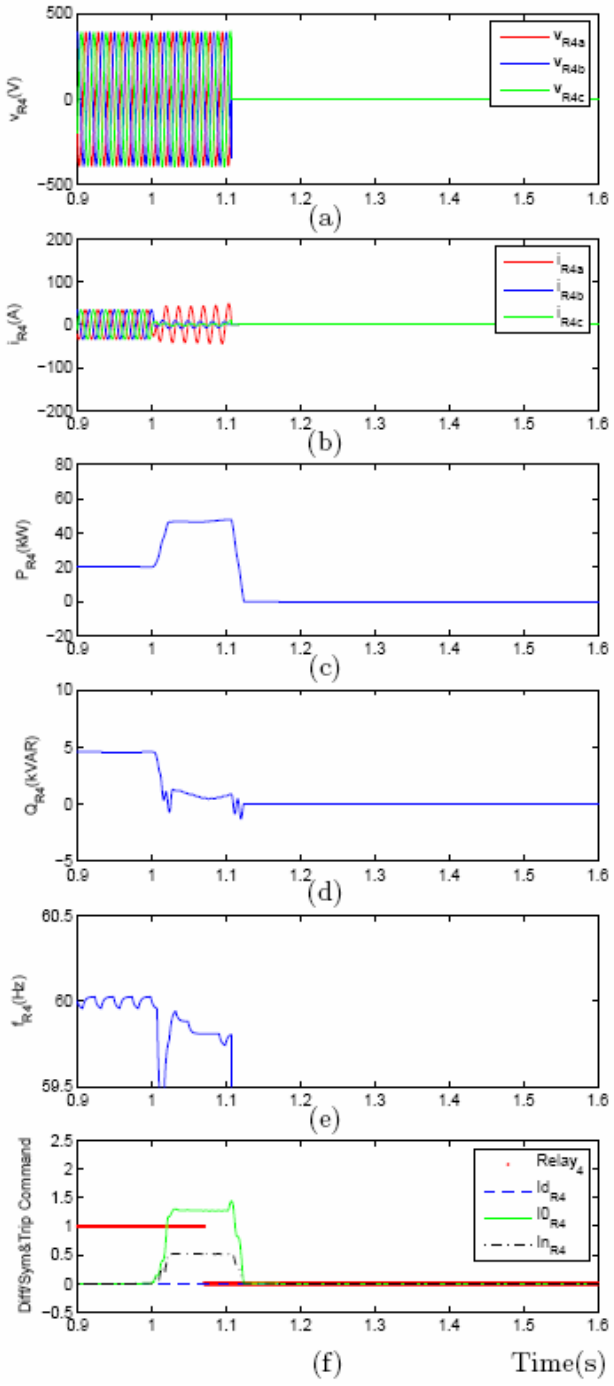

Figure 12: Response of the Relay 4 to a 28.5 kW SLG fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

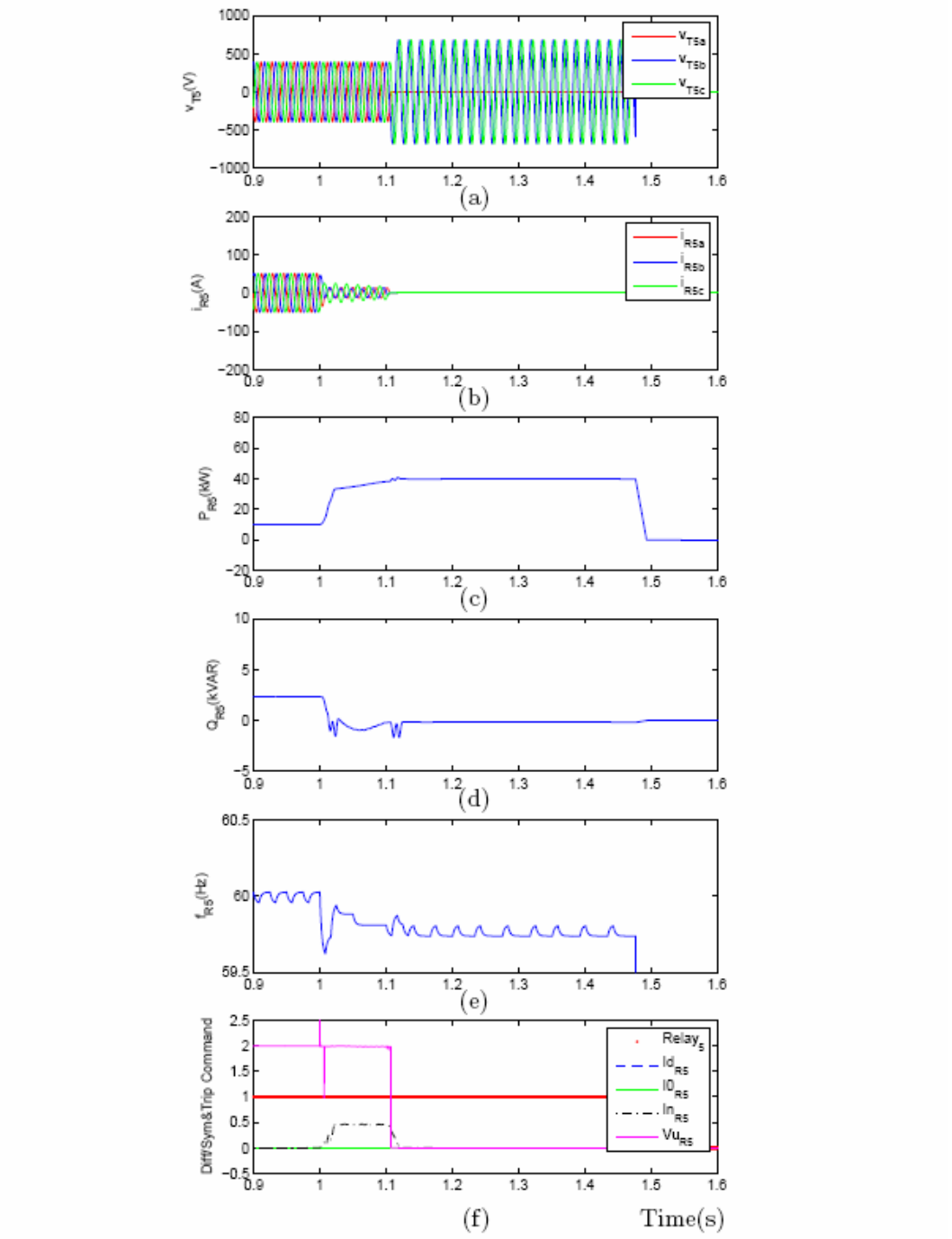

Figure 13: Response of the Relay 5 to a 28.5 kW SLG fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

SLG Fault in Zone 5

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an SLG fault with a resistance of 2.695 Ohms is applied in Zone 5 at t=1.0 s. Figs. 15(a)-(e) to Figs. 18(a)-(e) show variations of the three- phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the SLG fault.

Fig. 14(f) shows that the Relay 2 commands the static switch to trip when CB_{51} trips since the relay detects an instantaneous negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 15(f) shows that the Relay 3 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 16(f) shows that the Relay 4 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 17(f) shows that the Relay 5 commands for a trip to the circuit breaker CB_{51} since magnitude of the differential current component at the relay is above the threshold of 1.0 pu (15 A) for a period more than 50 ms.

For the case of SLG fault in Zone 5, the static switch islands the microgrid and the breaker CB_{51} disconnects Zone 5 of the microgrid and shuts down the microsource B_1. The Zones 2, 3 and 4 of the microgrid and the microsources A_1 and A_2 continue the operation subsequent to the fault detection and its clearance. The results shown in Fig. 14 to Fig.17 demonstrate that the developed protection system is able to protect the AEP microgrid against an SLG fault in Zone 5 with a power of 28.5 kW/phase by clearing the fault and isolating the microgrid from the main grid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all SLG faults in Zone 5 with a power more than or equal to 28.5 kW/phase.

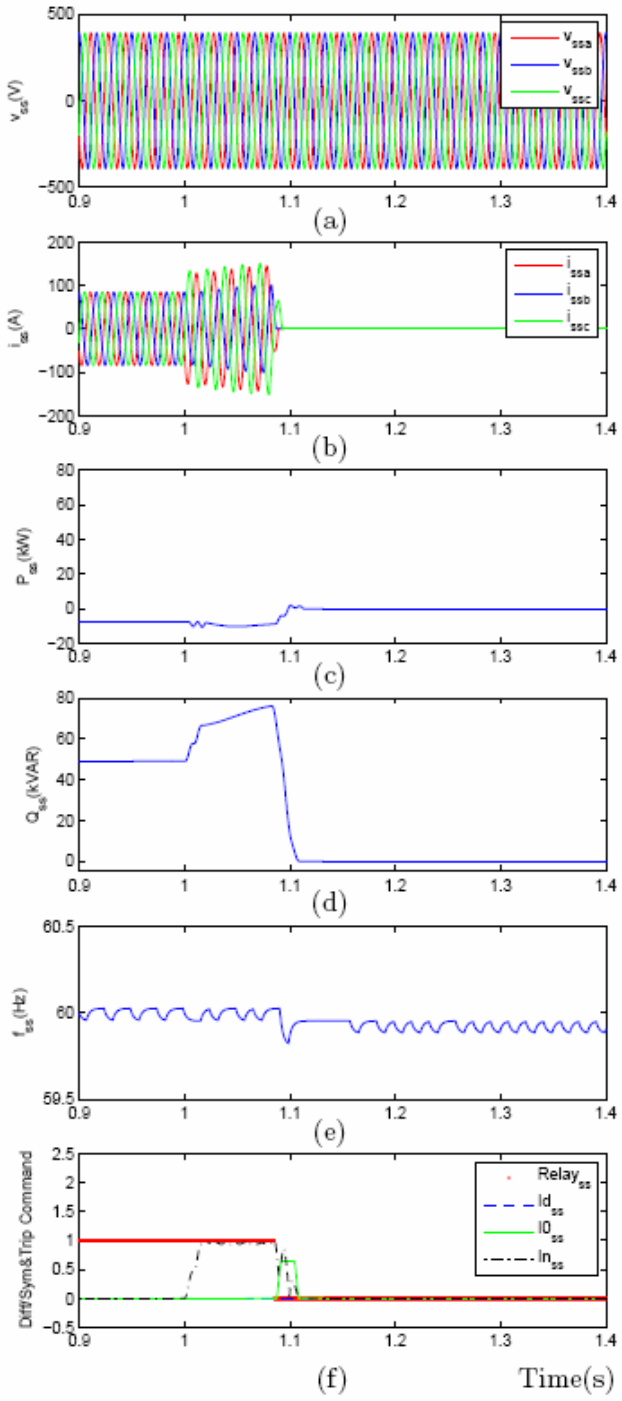

Figure 14: Response of the Relay 2 to a 28.5 kW SLG fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

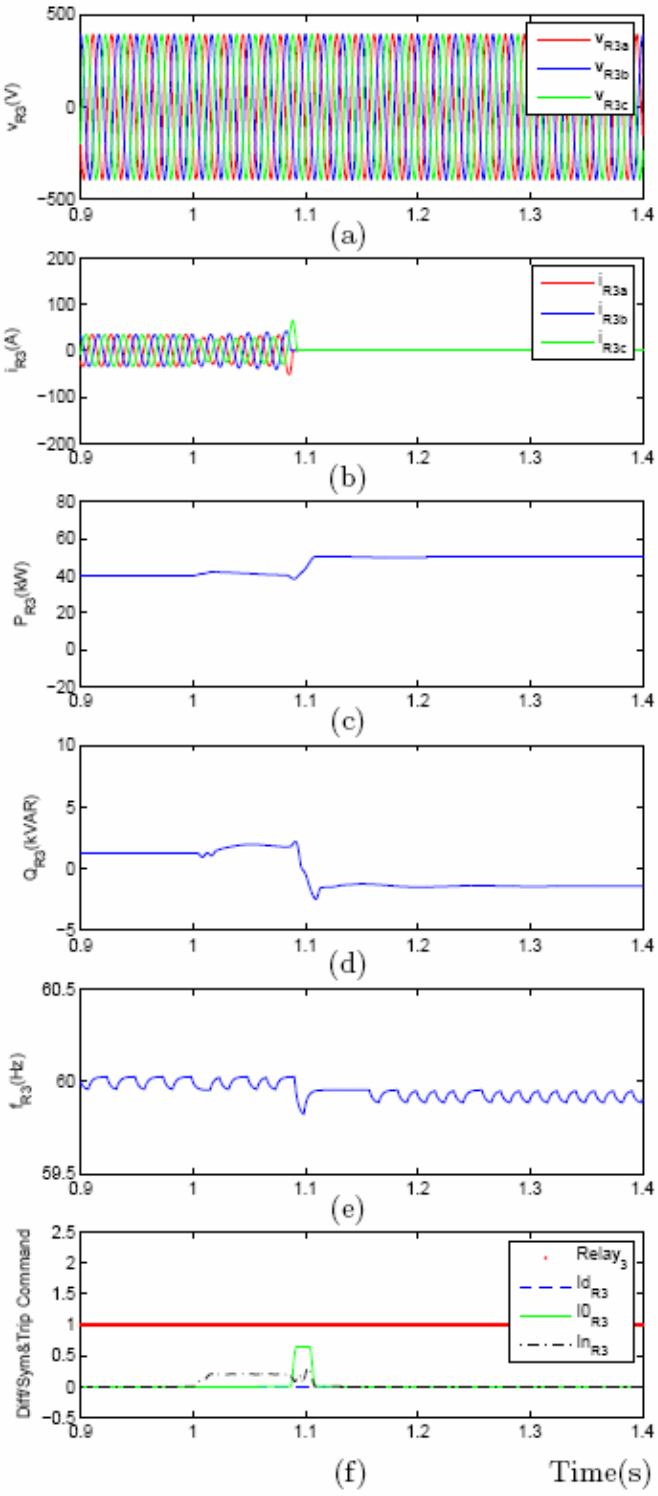

Figure 15: Response of the Relay 3 to a 28.5 kW SLG fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

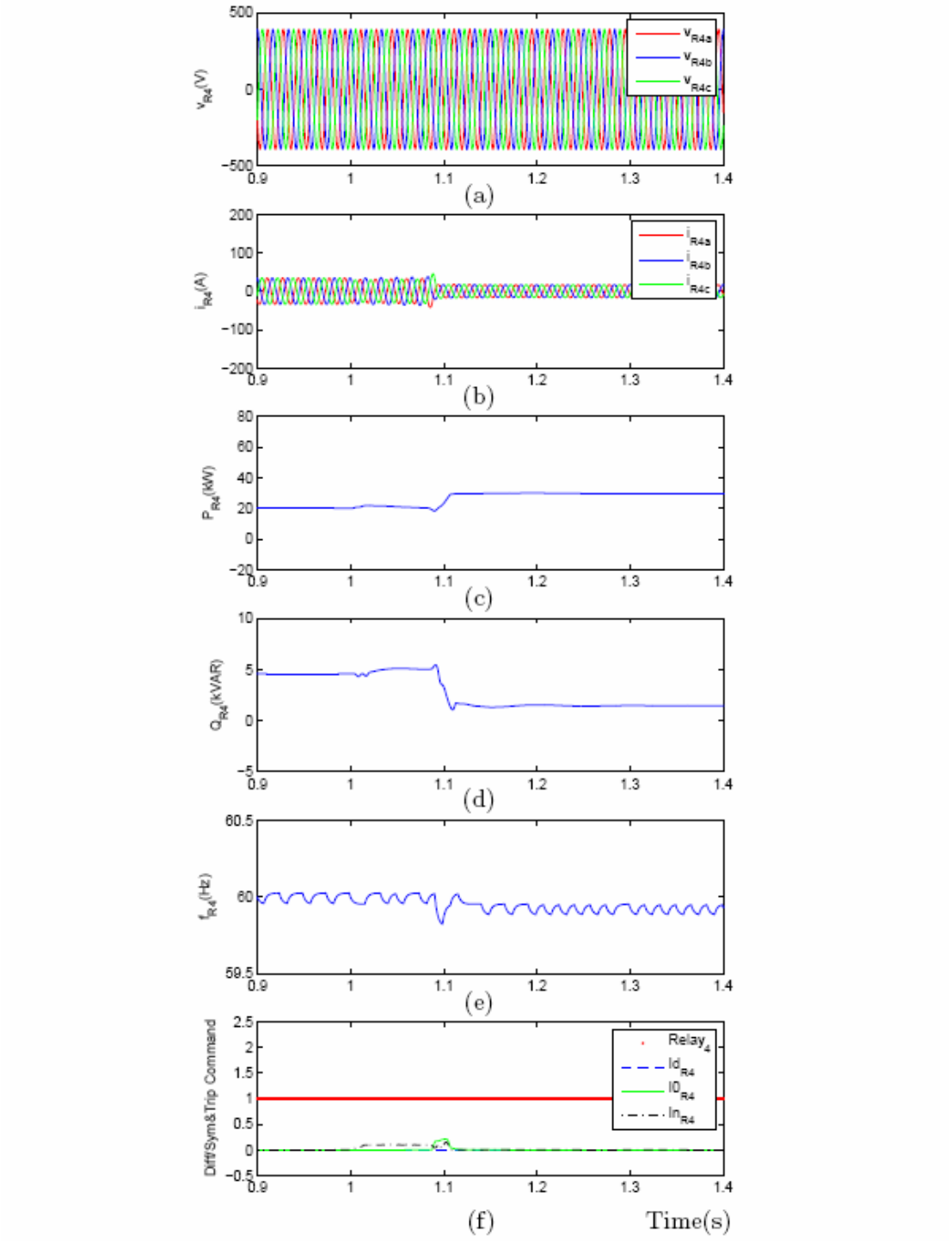

Figure 16: Response of the Relay 4 to a 28.5 kW SLG fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

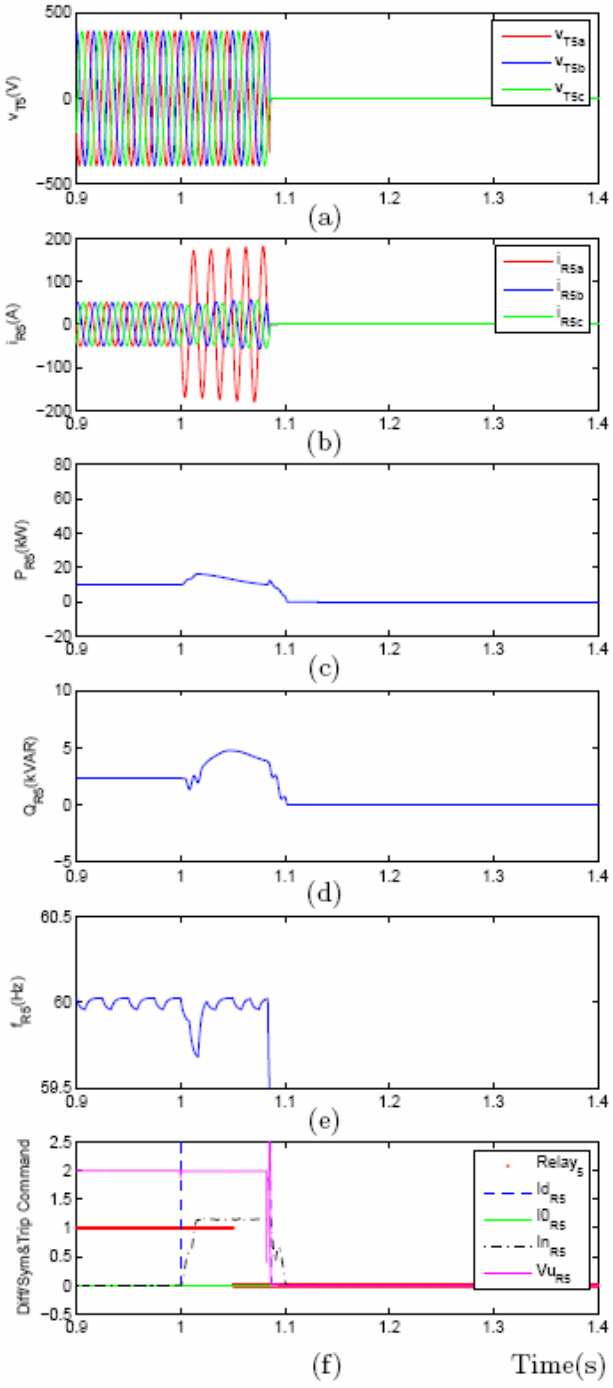

Figure 17: Response of the Relay 5 to a 28.5 kW SLG fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

SLG Fault in Zone 6

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an SLG fault with a resistance of 2.695 Ohms is applied in Zone 6 at t=1.0 s. Figs. 19(a)-(e) to Figs. 22(a)-(e) show variations of the three- phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the SLG fault.

Fig. 18(f) shows that the Relay 2 commands the static switch to trip since the relay detects an instantaneous negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 19(f) shows that the Relay 3 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 20(f) shows that the Relay 4 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 21(f) shows that the Relay 5 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu.

For the case of SLG fault in Zone 6, the static switch islands the microgrid. The Zones 2, 3, 4 and 5 of the microgrid and the microsources A_1, A_2 and B_1 continue the operation subsequent to the fault detection and its clearance. The results shown in Fig. 18 to Fig. 21 demonstrate that the developed protection system is able to protect the AEP microgrid against an SLG fault in Zone 6 with a power of 28.5 kW/phase by isolating the microgrid from the main grid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all SLG faults in Zone 6 with a power more than or equal to 28.5 kW/phase.

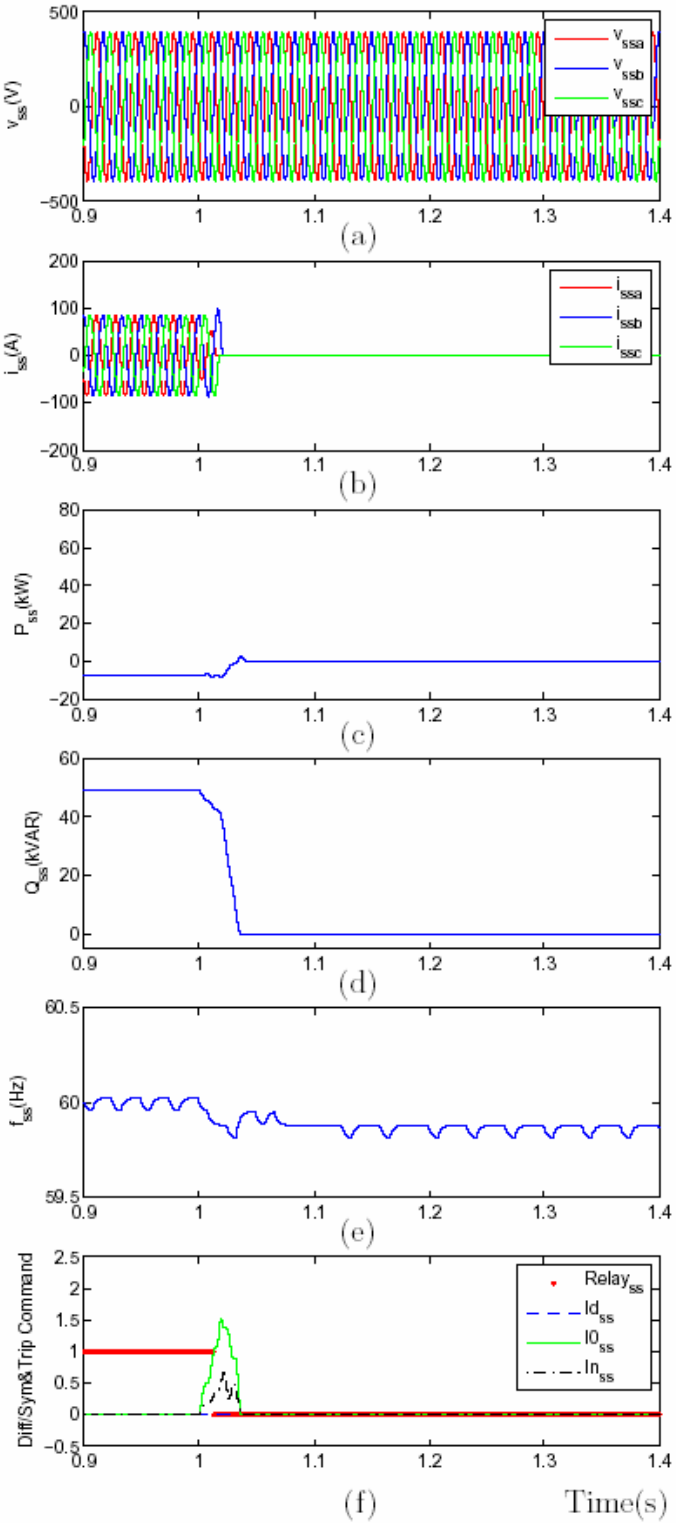

Figure 18: Response of the Relay 2 to a 28.5 kW SLG fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

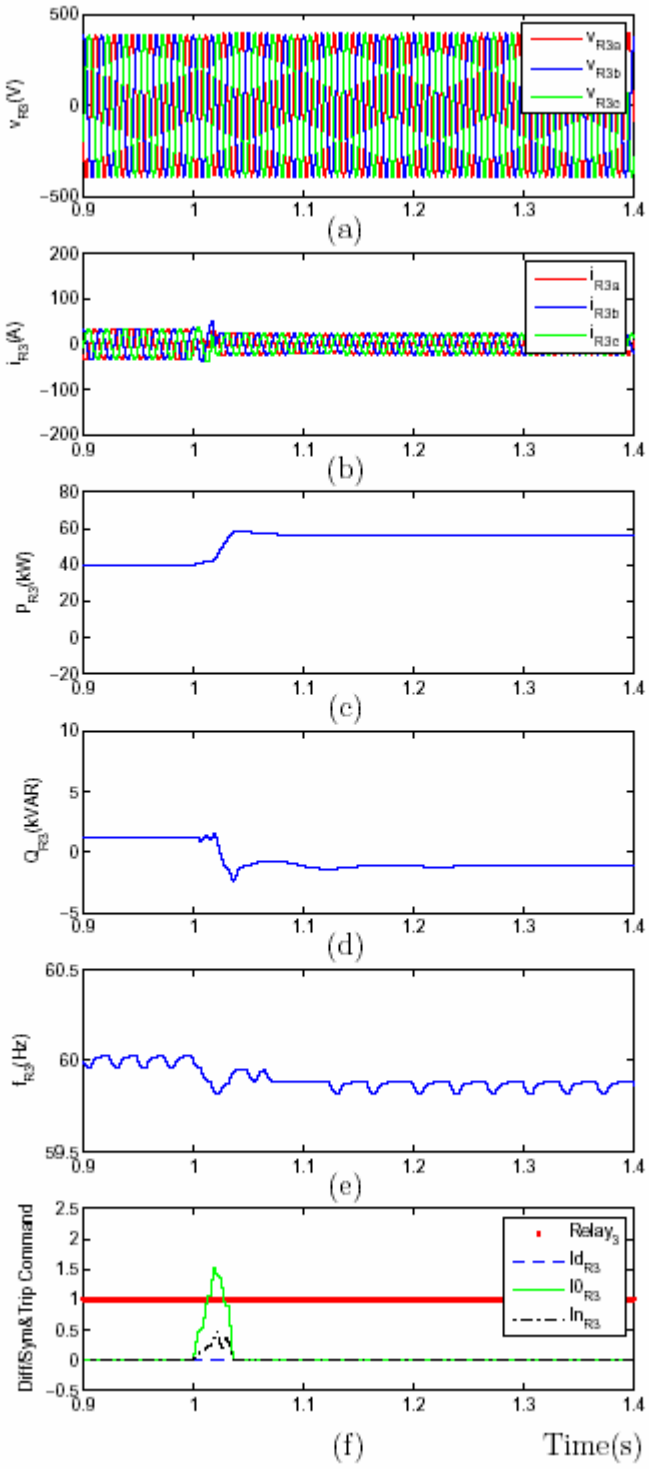

Figure 19: Response of the Relay 3 to a 28.5 kW SLG fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

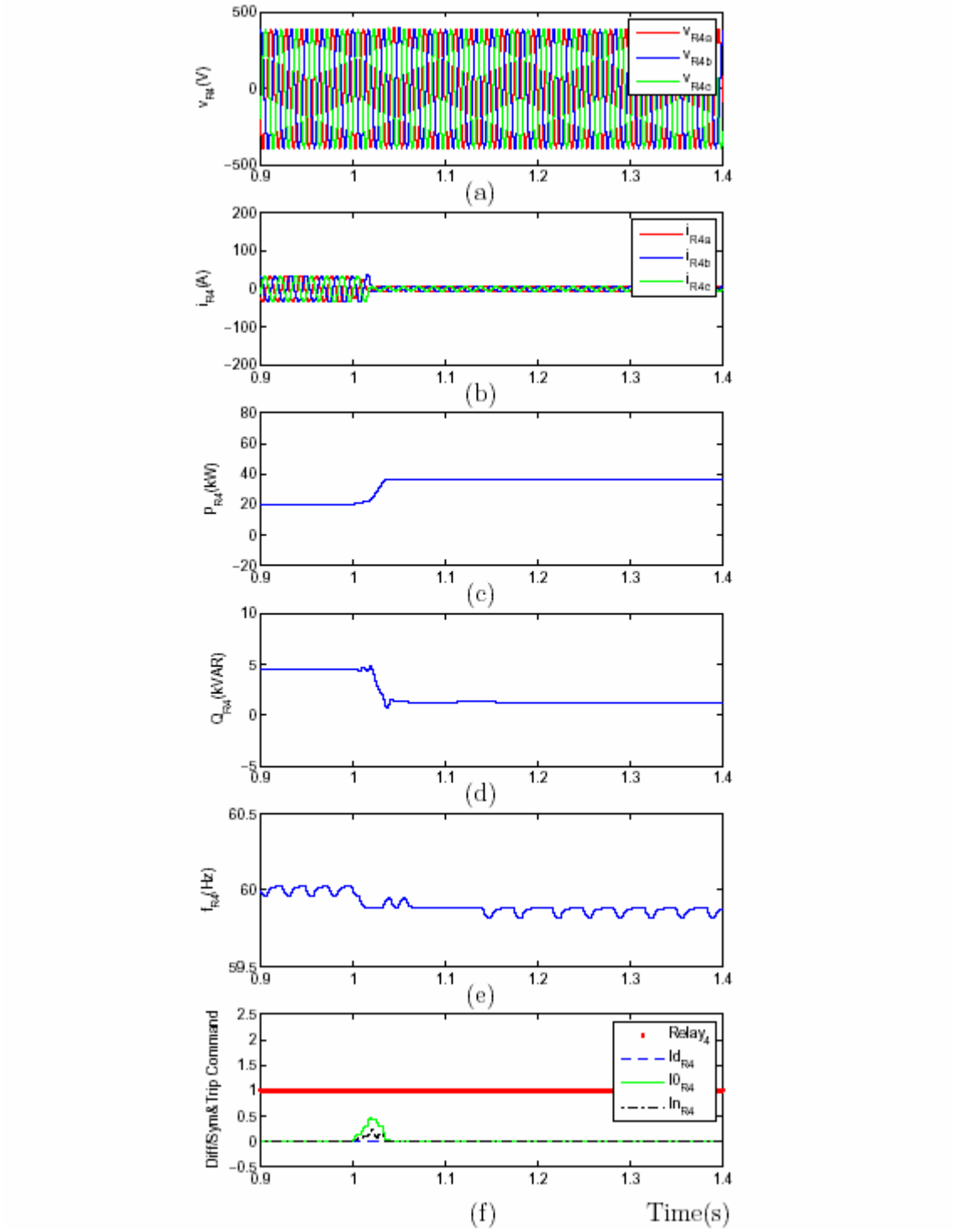

Figure 20: Response of the Relay 4 to a 28.5 kW SLG fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

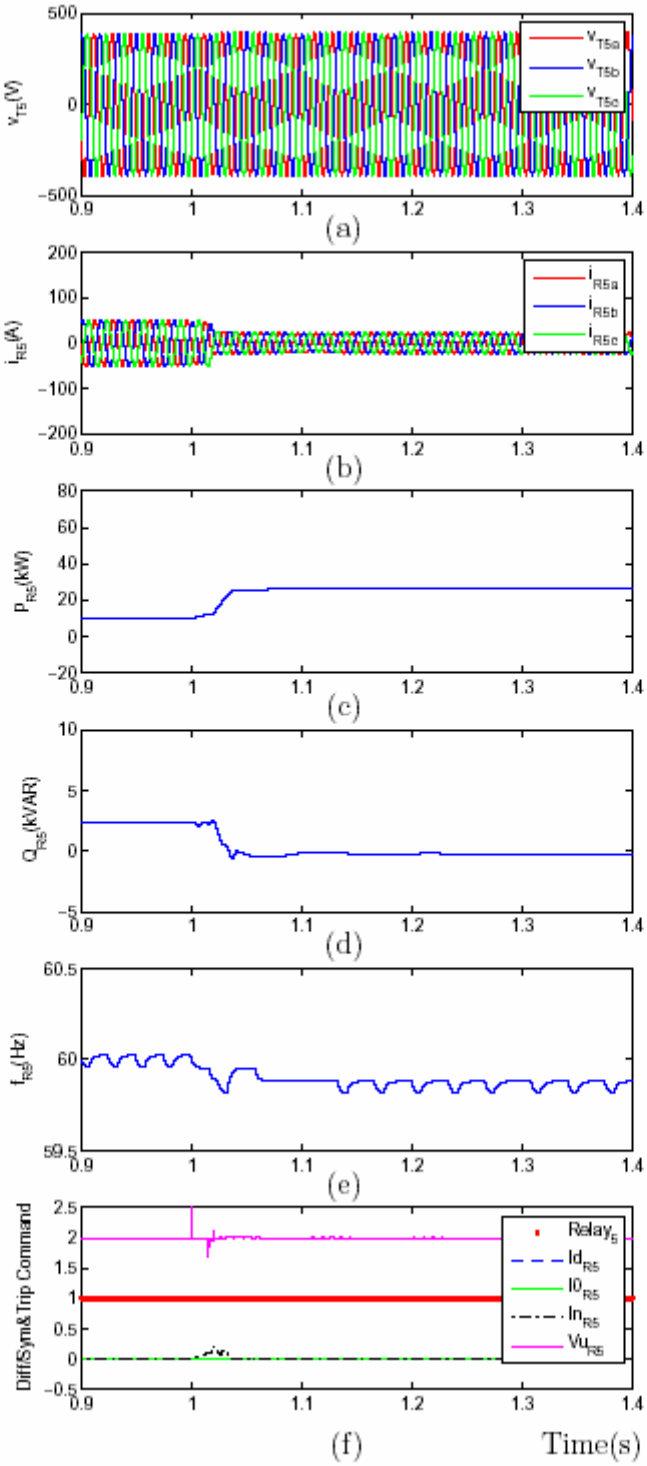

Figure 21: Response of the Relay 5 to a 28.5 kW SLG fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

6.2. Line-to-Line Faults

Line-to-Line Fault in Zone 4

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an LL fault with a resistance of 2.695 Ohms is applied in Zone 4 at t=1.0 s. Figs. 23(a)-(e) to Figs. 26(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the LL fault.

Fig. 22(f) shows that the Relay 2 commands the static switch to trip shortly after the fault when the relay detects a negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 23(f) shows that the Relay 3 commands CB_{31} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms (3 cycles). Fig. 24(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the negative-sequence current component at the relay is greater than 1.0 pu for a period more than 50 ms. Fig. 25(f) shows that the Relay 5 commands CB_{51} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms. Magnitudes of the differential and zero-sequence current components of all relays do not exceed the corresponding threshold of 15 A and 35 A.

For the case of an LL fault in Zone 4, the static switch islands the microgrid and the breakers CB_{31}, CB_{41} and CB_{51} disconnects all zones of the microgrid and shut down all the microsource located inside the microgrid. The results shown in Fig. 22 to Fig. 25 demonstrate that the developed protection system is able to protect the AEP microgrid against an LL fault in Zone 4 with a power of 85.5 kW by clearing the fault and disconnecting all protection zones of the microgrid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all LL faults in Zone 4 with a power more than or equal to 85.5 kW.

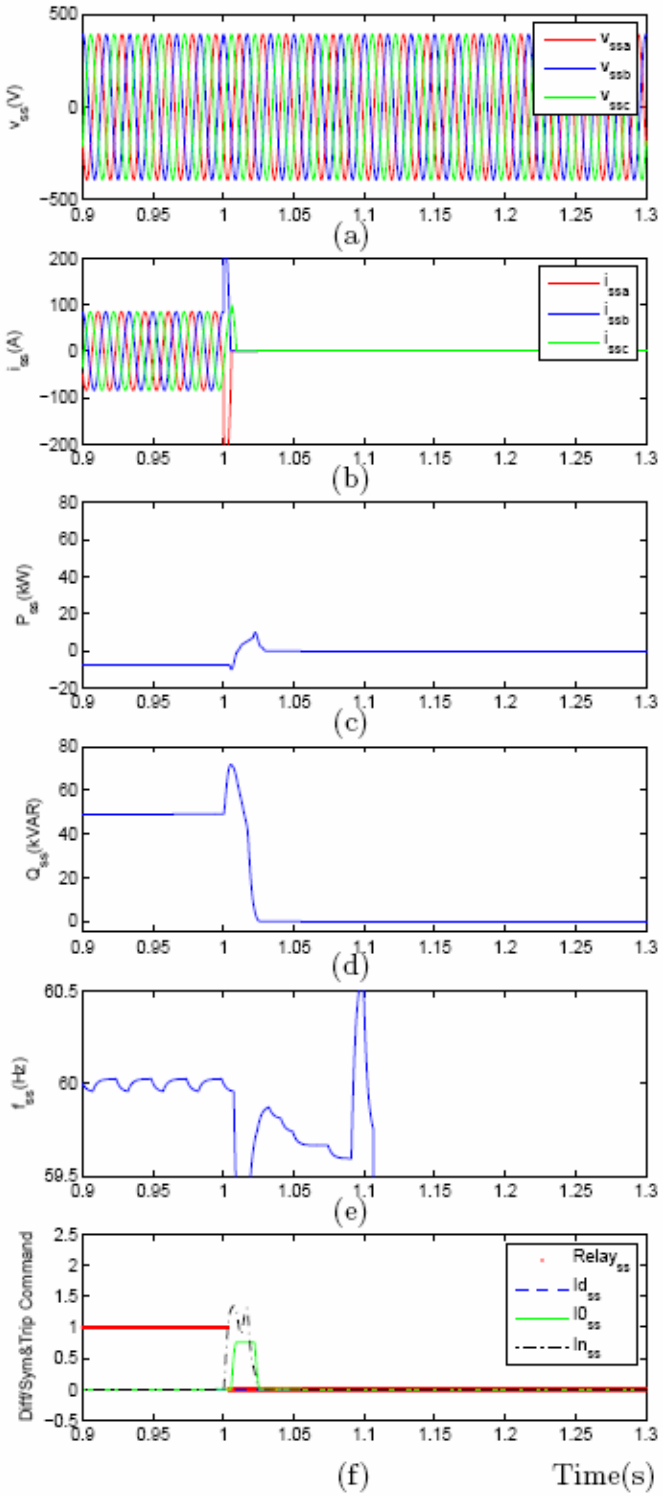

Figure 22: Response of the Relay 2 to a 85.5 kW LL fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

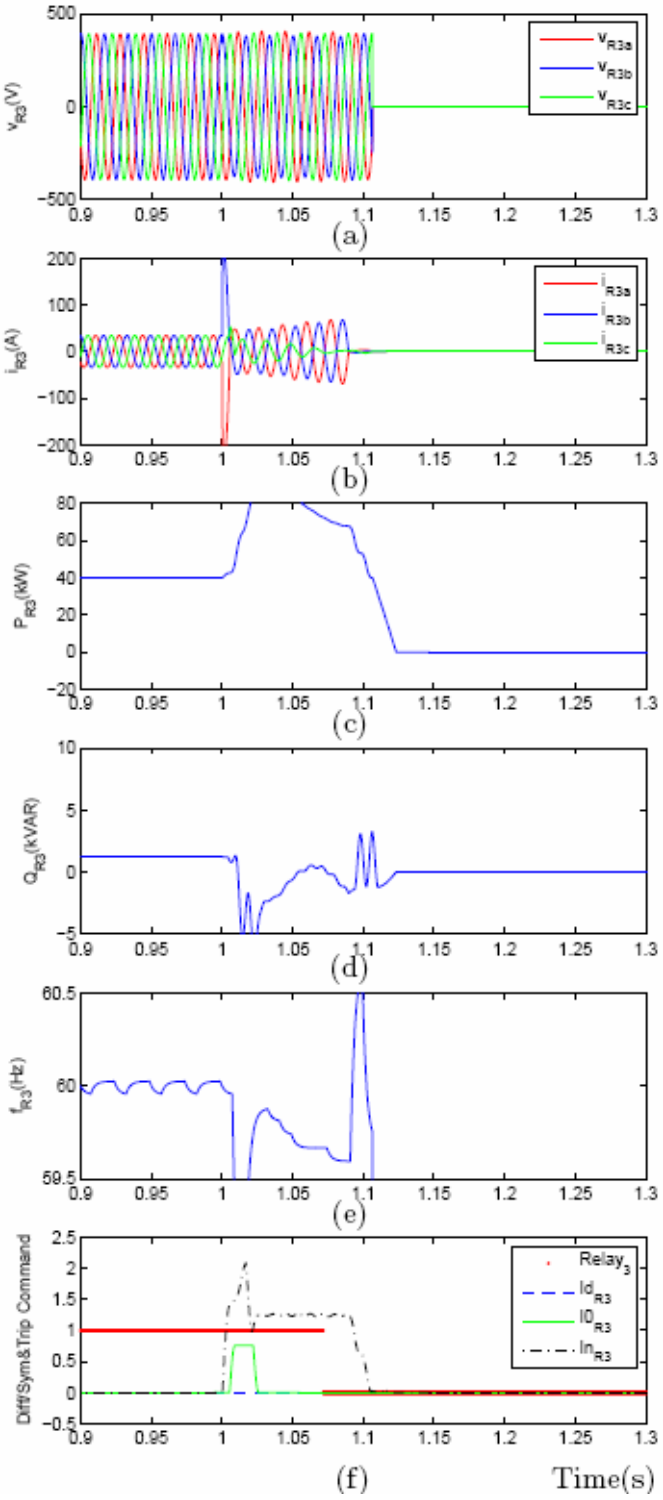

Figure 23: Response of the Relay 3 to a 85.5 kW LL fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

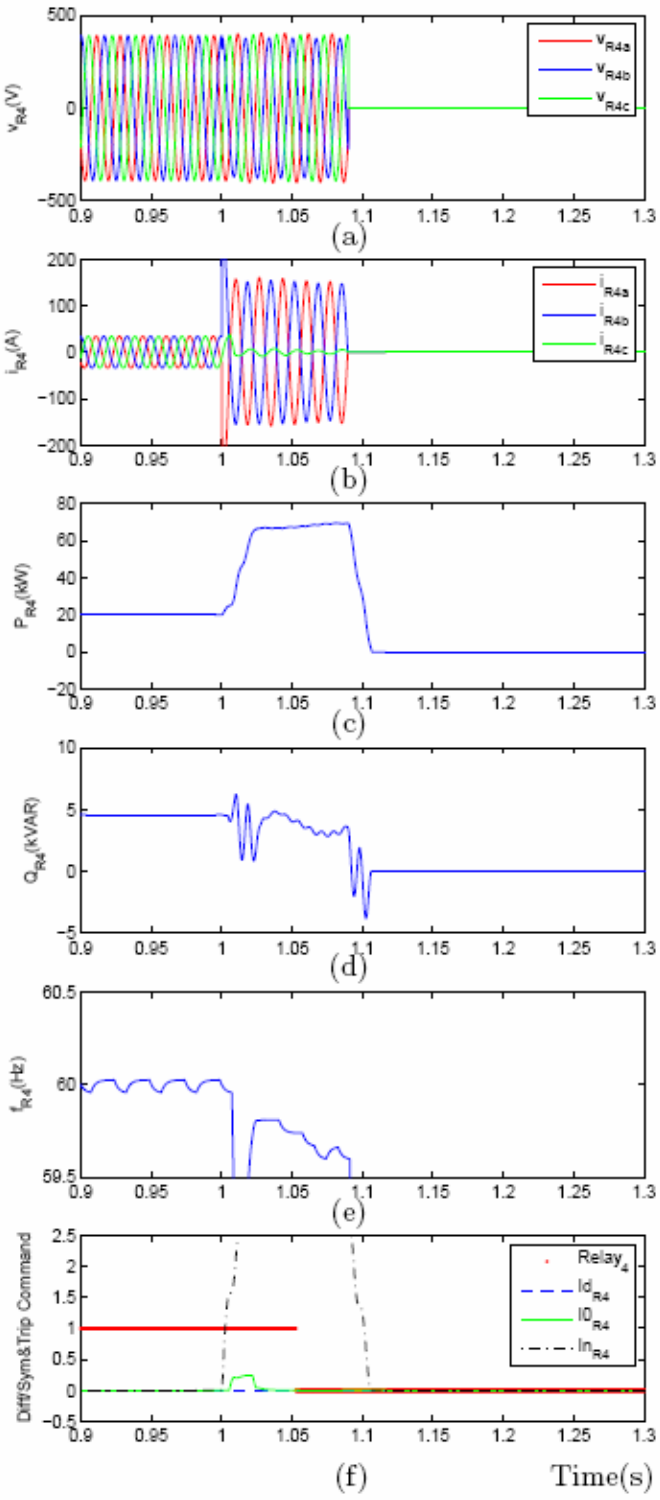

Figure 24: Response of the Relay 4 to a 85.5 kW LL fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

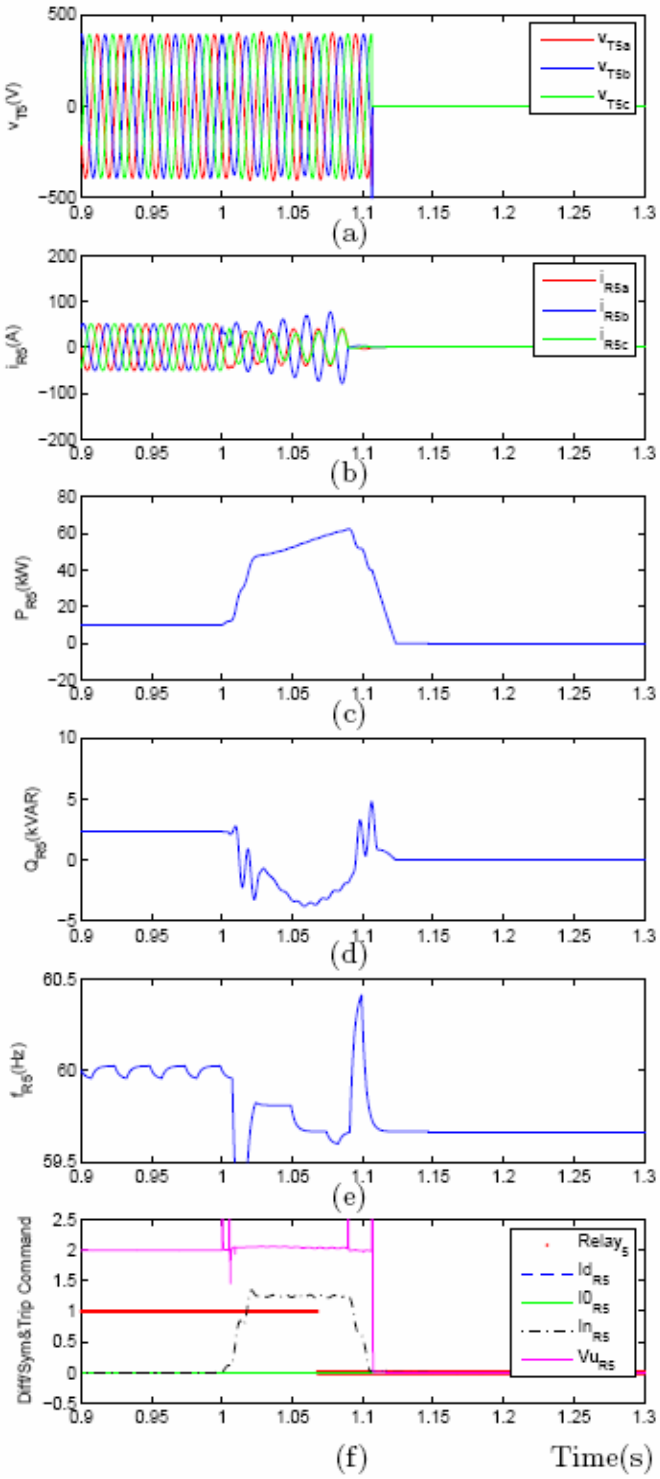

Figure 25: Response of the Relay 5 to a 85.5 kW LL fault in Zone 4: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

Line-to-Line Fault in Zone 3

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an LL fault with a resistance of 2.695 Ohms is applied in Zone 3 at t=1.0 s. Figs. 27(a)-(e) to Figs. 20(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the LL fault.

Fig. 26(f) shows that the Relay 2 commands the static switch to trip shortly after the fault when the relay detects a negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 27(f) shows that the Relay 3 commands CB_{31} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms (3 cycles). Fig. 28(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the negative-sequence current component at the relay is greater than 1.0 pu for a period more than 50 ms. Fig. 29(f) shows that the Relay 5 commands CB_{51} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms. Magnitudes of the differential and zero-sequence current components of all relays do not exceed the corresponding thresholds of 15 A and 35 A.

For the case of an LL fault in Zone 3, the static switch islands the microgrid and the breakers CB_{31}, CB_{41} and CB_{51} disconnects all zones of the microgrid and shut down all the microsource located inside the microgrid. The results shown in Fig. 26 to Fig. 29 demonstrate that the developed protection system is able to protect the AEP microgrid against an LL fault in Zone 3 with a power of 85.5 kW by clearing the fault and disconnecting all protection zones of the microgrid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all LL faults in Zone 3 with a power more than or equal to 85.5 kW.

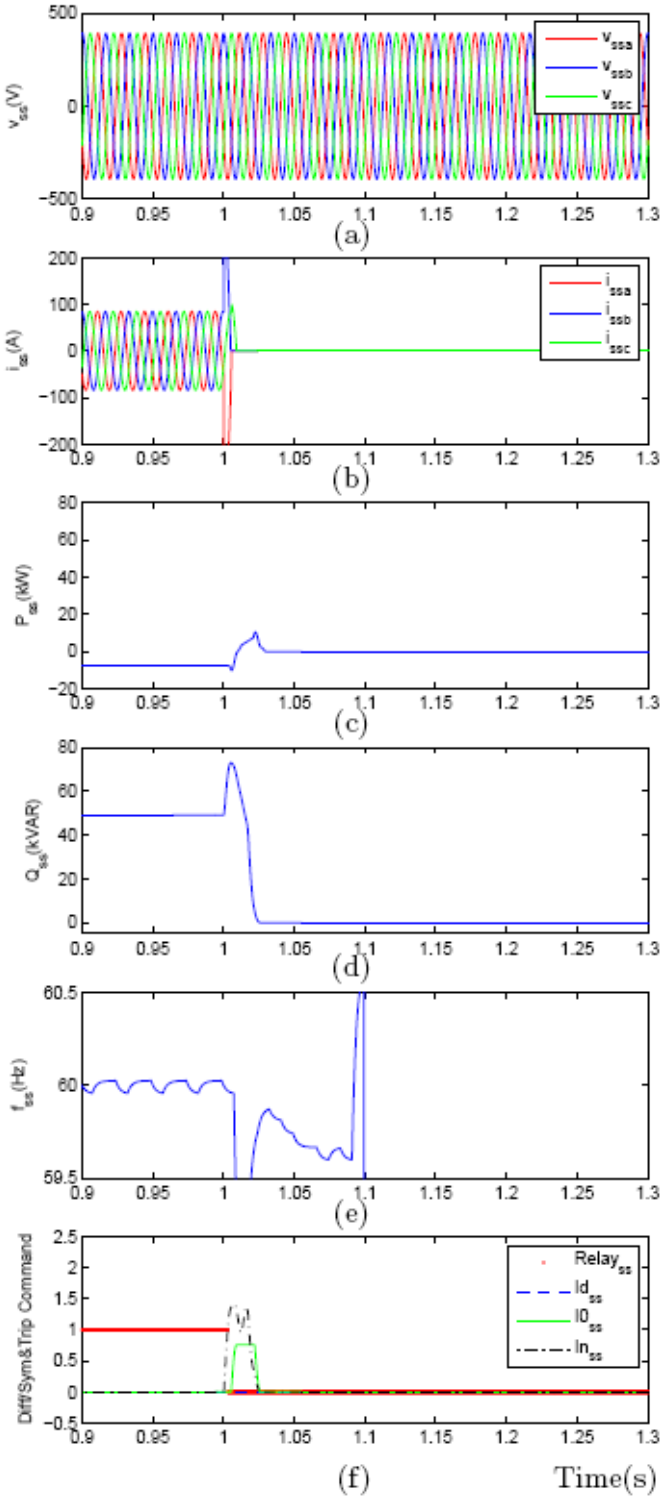

Figure 26: Response of the Relay 2 to a 85.5 kW LL fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

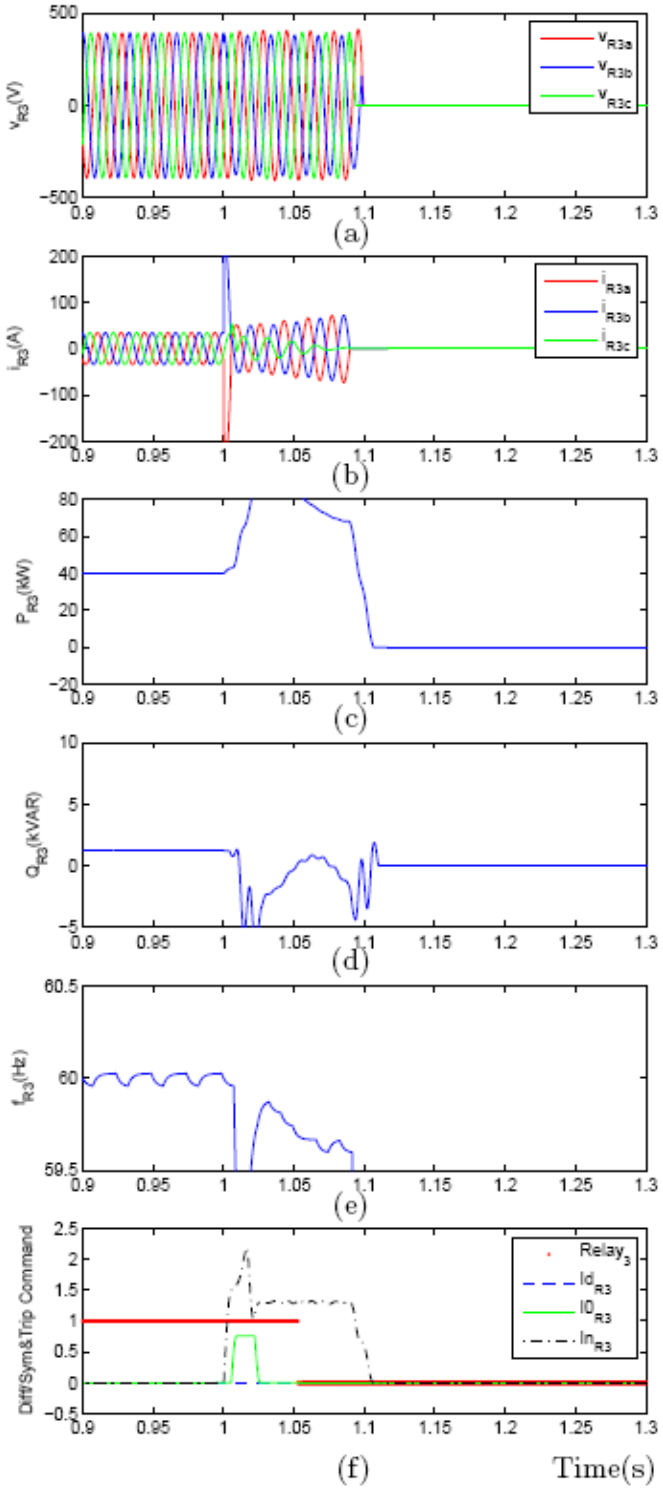

Figure 27: Response of the Relay 3 to a 85.5 kW LL fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

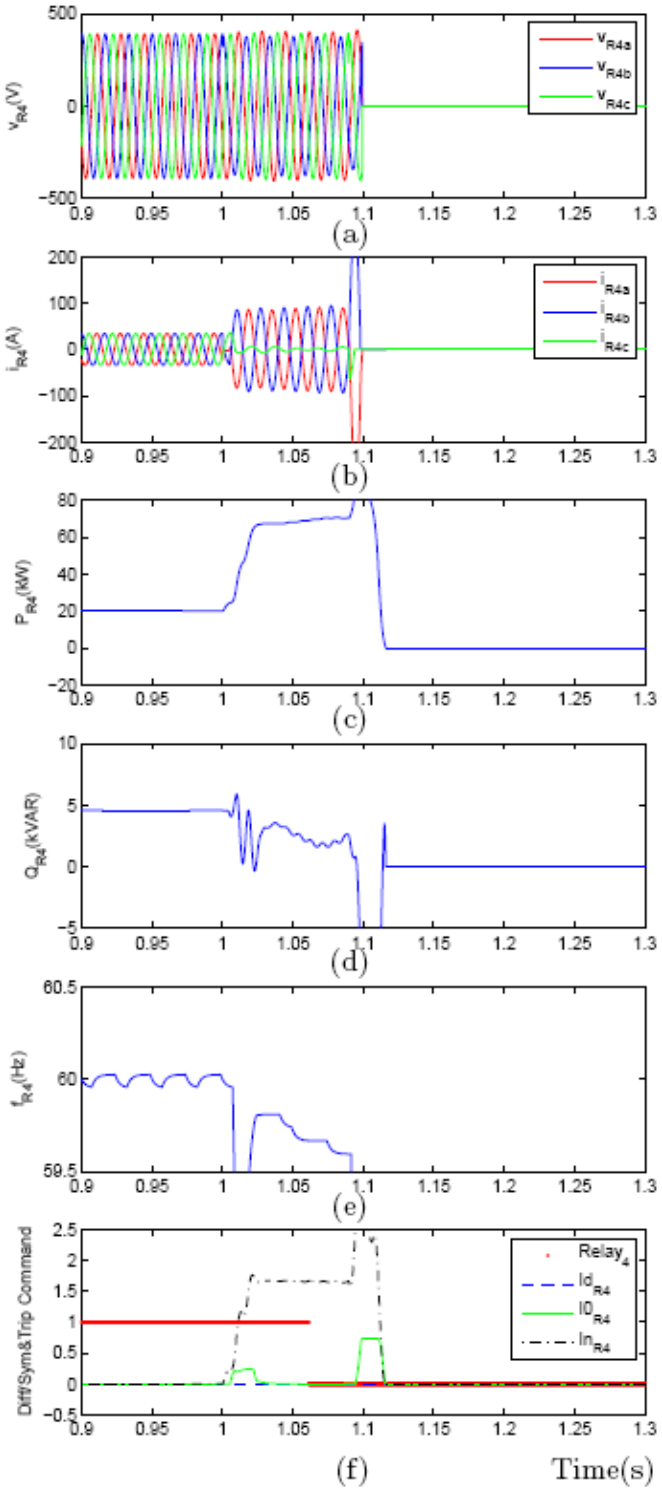

Figure 28: Response of the Relay 4 to a 85.5 kW LL fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

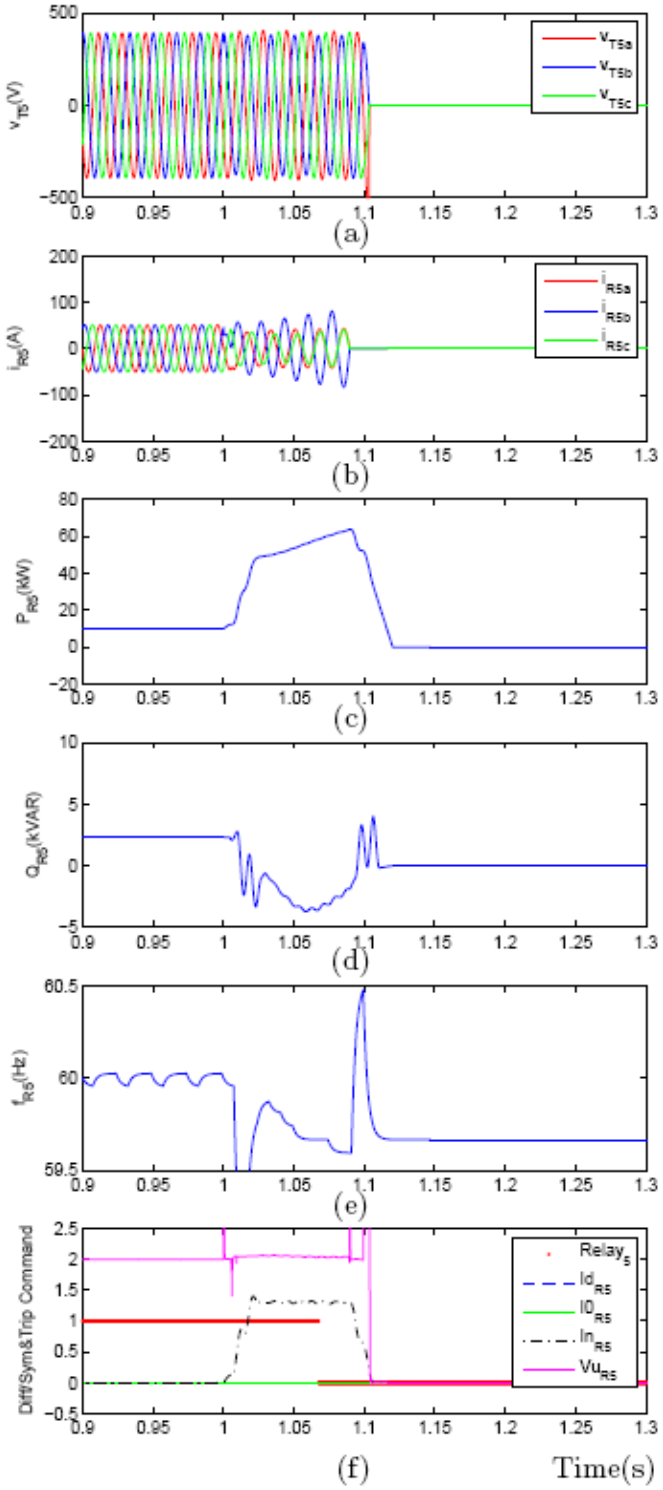

Figure 29: Response of the Relay 5 to a 85.5 kW LL fault in Zone 3: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

Line-to-Line Fault in Zone 2

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an LL fault with a resistance of 2.695 Ohms is applied in Zone 2 at t=1.0 s. Figs. 31(a)-(e) to Figs. 34(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the LL fault.

Fig. 30(f) shows that the Relay 2 commands the static switch to trip shortly after the fault when the relay detects a negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 31(f) shows that the Relay 3 commands CB_{31} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms (3 cycles). Fig. 32(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the negative-sequence current component at the relay is greater than 1.0 pu for a period more than 50 ms. Fig. 33(f) shows that the Relay 5 commands CB_{51} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms. Magnitudes of the differential and zero-sequence current components of all relays do not exceed the corresponding thresholds of 15 A and 35 A.

For the case of an LL fault in Zone 2, the static switch islands the microgrid and the breakers CB_{31}, CB_{41} and CB_{51} disconnects all zones of the microgrid and shut down all the microsource located inside the microgrid. The results shown in Fig. 30 to Fig. 33 demonstrate that the developed protection system is able to protect the AEP microgrid against an LL fault in Zone 2 with a power of 85.5 kW by clearing the fault and disconnecting all protection zones of the microgrid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all LL faults in Zone 2 with a power more than or equal to 85.5 kW.

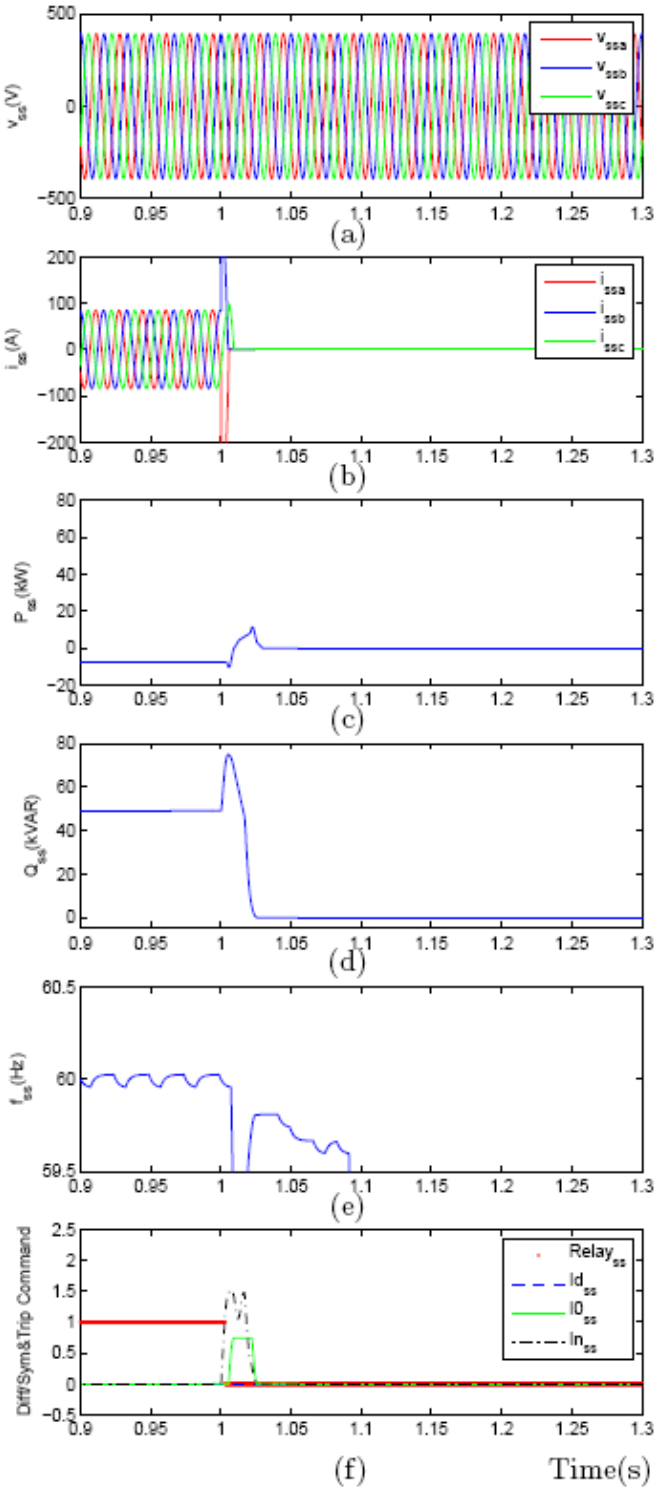

Figure 30: Response of the Relay 2 to a 85.5 kW LL fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

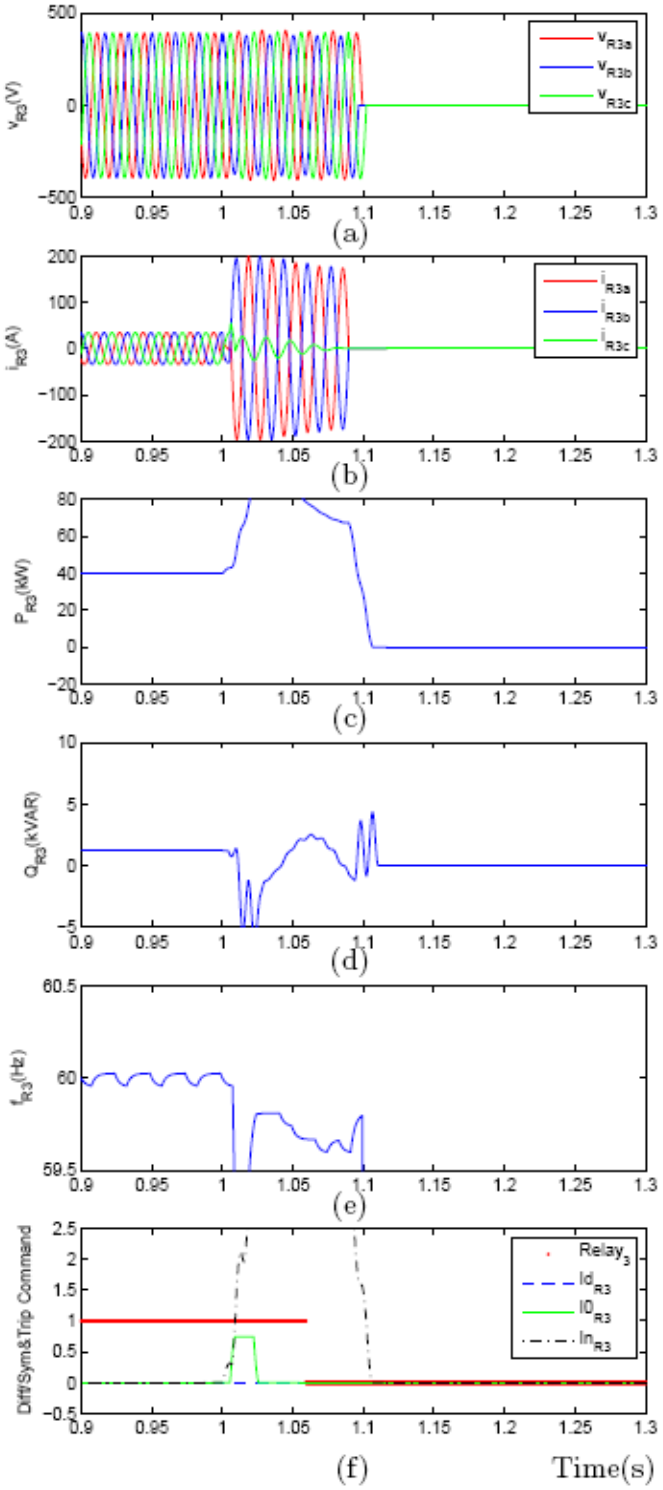

Figure 31: Response of the Relay 3 to a 85.5 kW LL fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

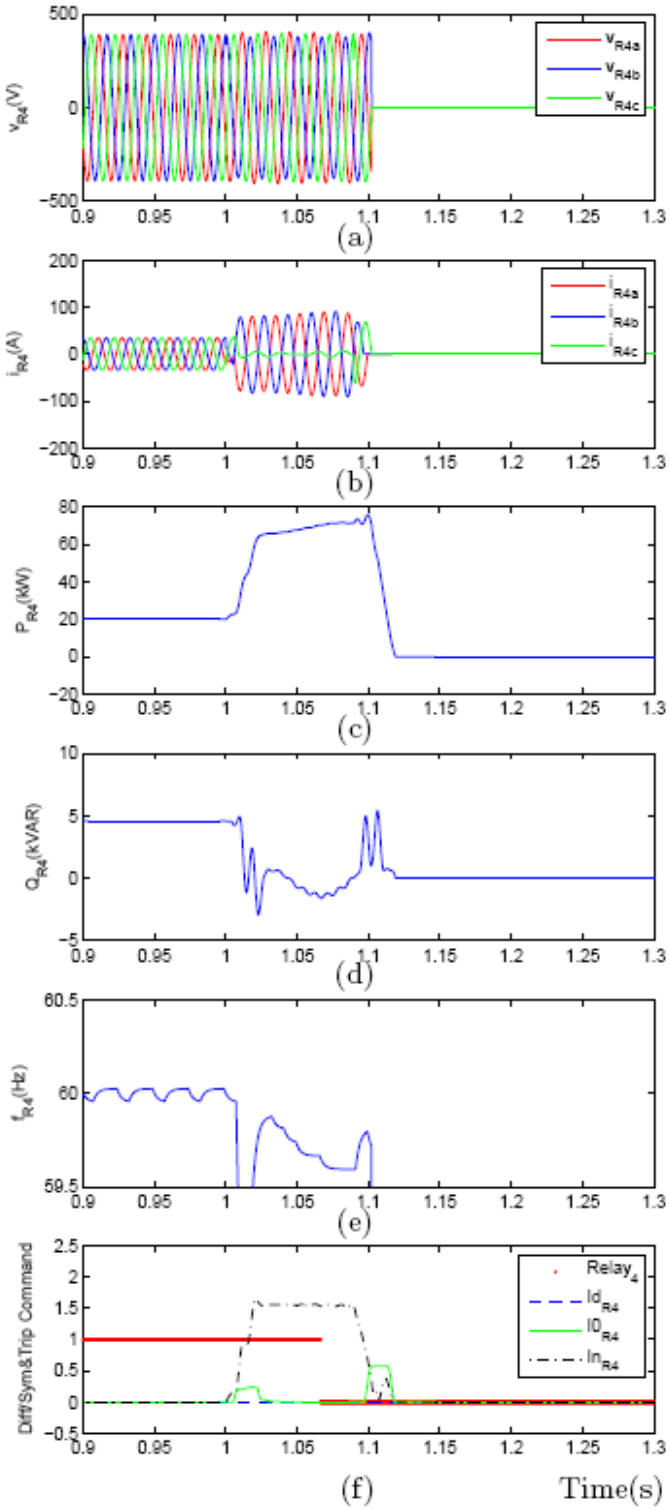

Figure 32: Response of the Relay 4 to a 85.5 kW LL fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

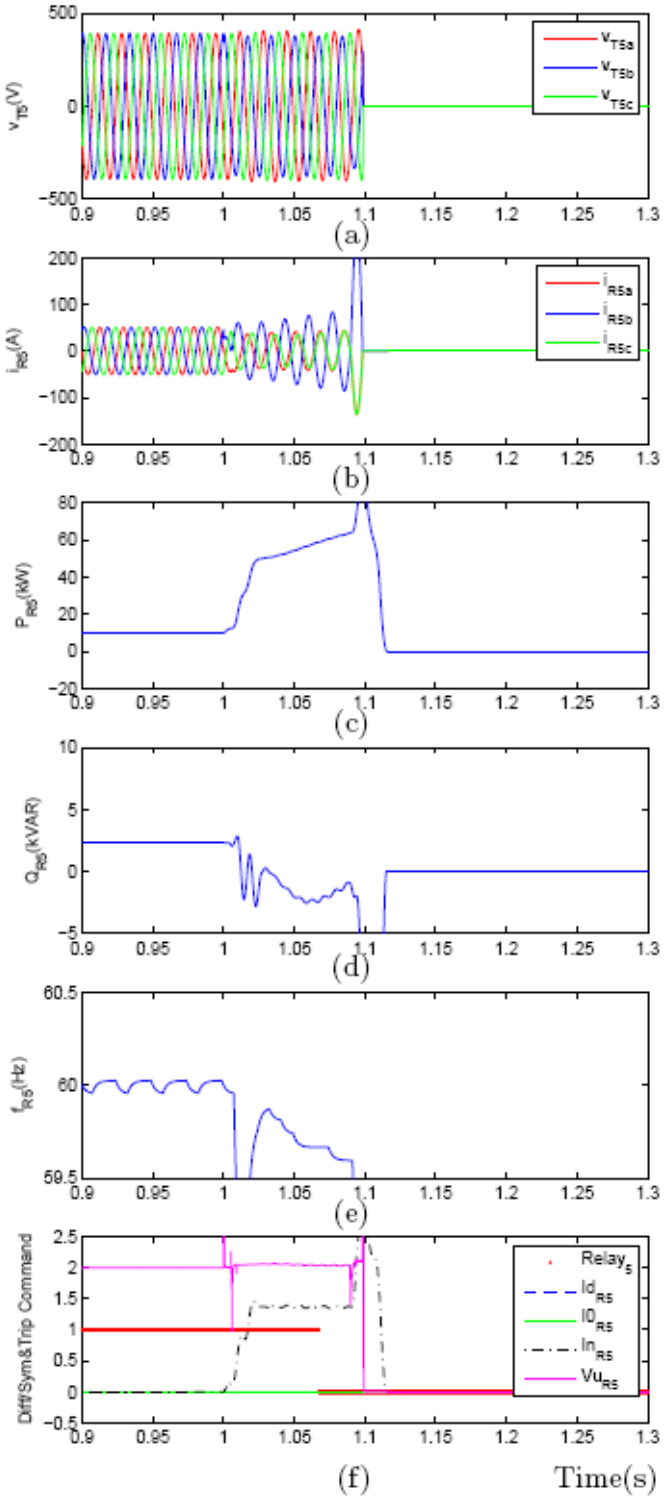

Figure 33: Response of the Relay 5 to a 85.5 kW LL fault in Zone 2: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer T_{51} and output command of the relay

Line-to-Line Fault in Zone 5

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an LL fault with a resistance of 2.695 Ohms is applied in Zone 5 at t=1.0 s. Figs. 35(a)-(e) to Figs. 38(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the LL fault.

Fig. 34(f) shows that the Relay 2 commands the static switch to trip shortly after the fault when the relay detects a negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 35(f) shows that the Relay 3 commands CB_{31} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms (3 cycles). Fig. 36(f) shows that the Relay 4 sends a trip command to the circuit breaker CB_{41} since magnitude of the negative-sequence current component at the relay is greater than 1.0 pu for a period more than 50 ms. Fig. 37(f) shows that the Relay 5 commands CB_{51} to trip since magnitude of the negative-sequence current component at the relay is above 1.0 pu for a period more than 50 ms. Magnitudes of the differential and zero-sequence current components of all relays do not exceed the corresponding thresholds of 15 A and 35 A.

For the case of an LL fault in Zone 5, the static switch islands the microgrid and the breakers CB_{31}, CB_{41} and CB_{51} disconnects all zones of the microgrid and shut down all the microsource located inside the microgrid. The results shown in Fig. 34 to Fig. 37 demonstrate that the developed protection system is able to protect the AEP microgrid against an LL fault in Zone 5 with a power of 85.5 kW by clearing the fault and disconnecting all protection zones of the microgrid. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all LL faults in Zone 5 with a power more than or equal to 85.5 kW.

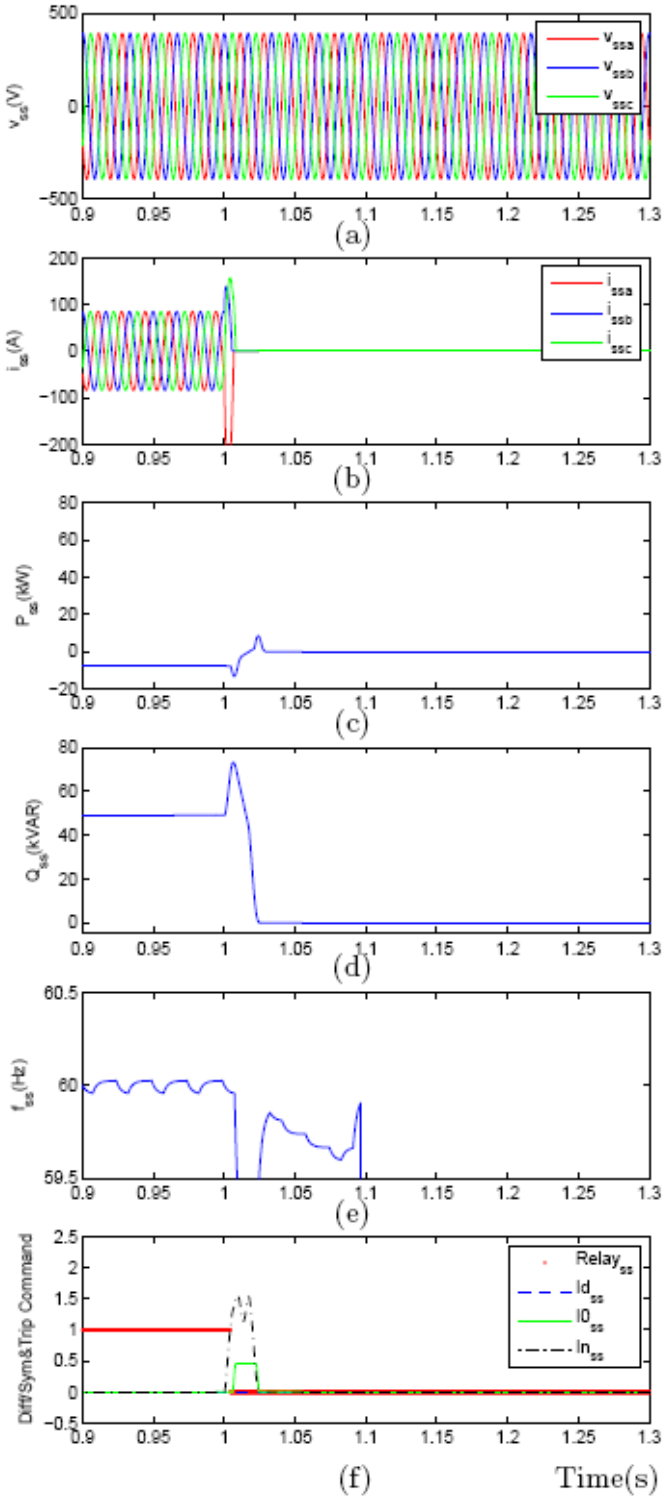

Figure 34: Response of the Relay 2 to a 85.5 kW LL fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

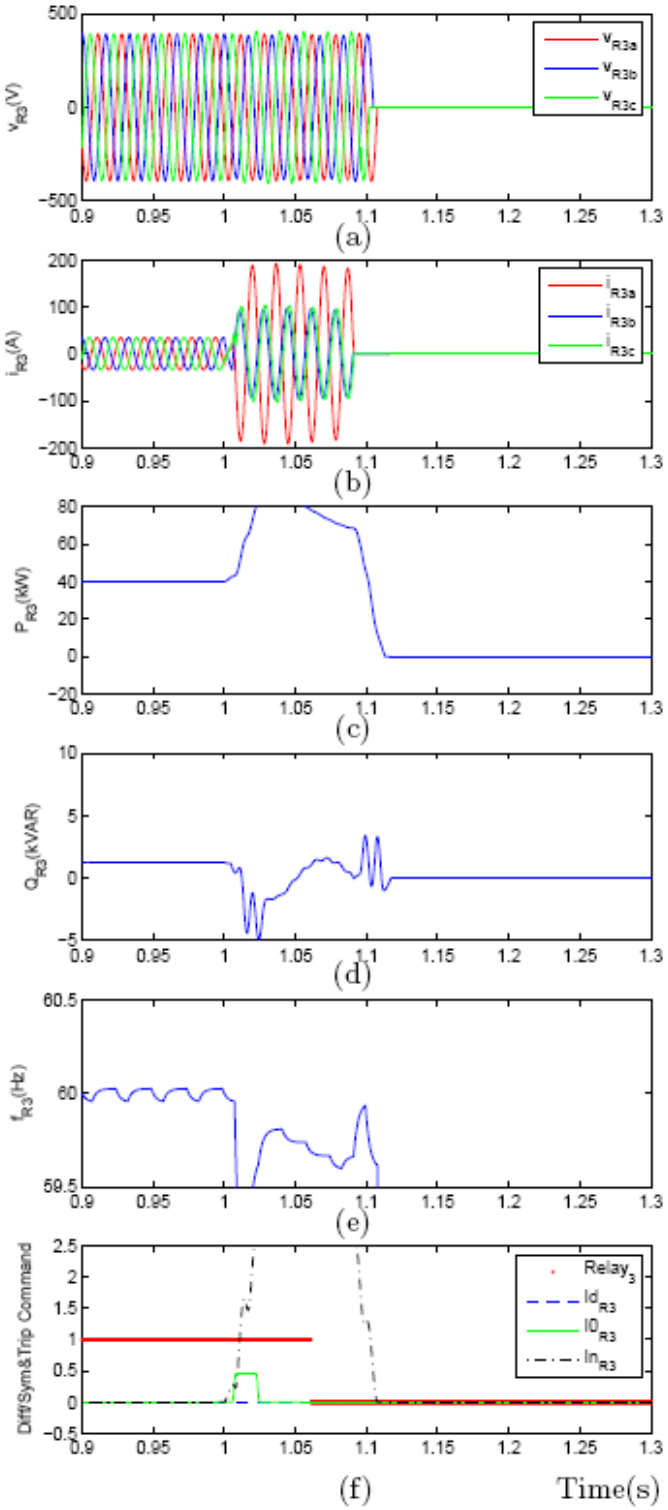

Figure 35: Response of the Relay 3 to a 85.5 kW LL fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

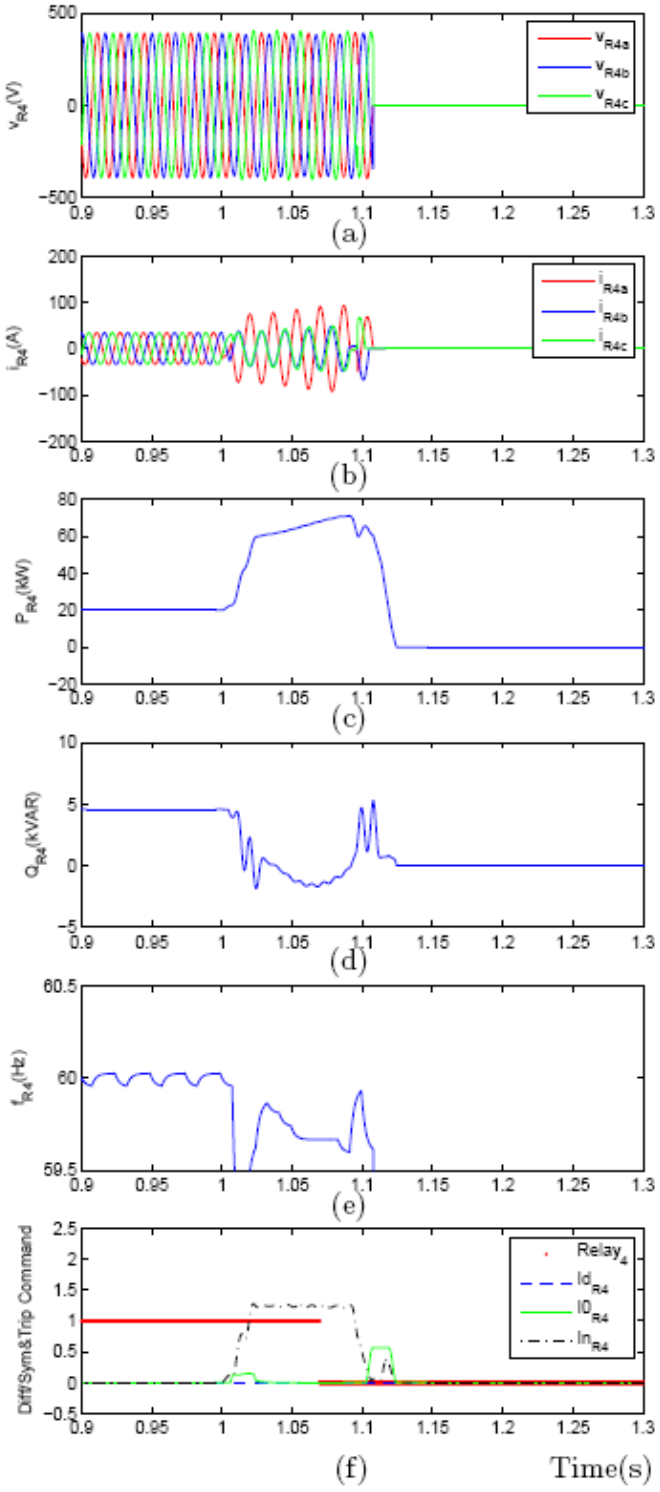

Figure 36: Response of the Relay 4 to a 85.5 kW LL fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

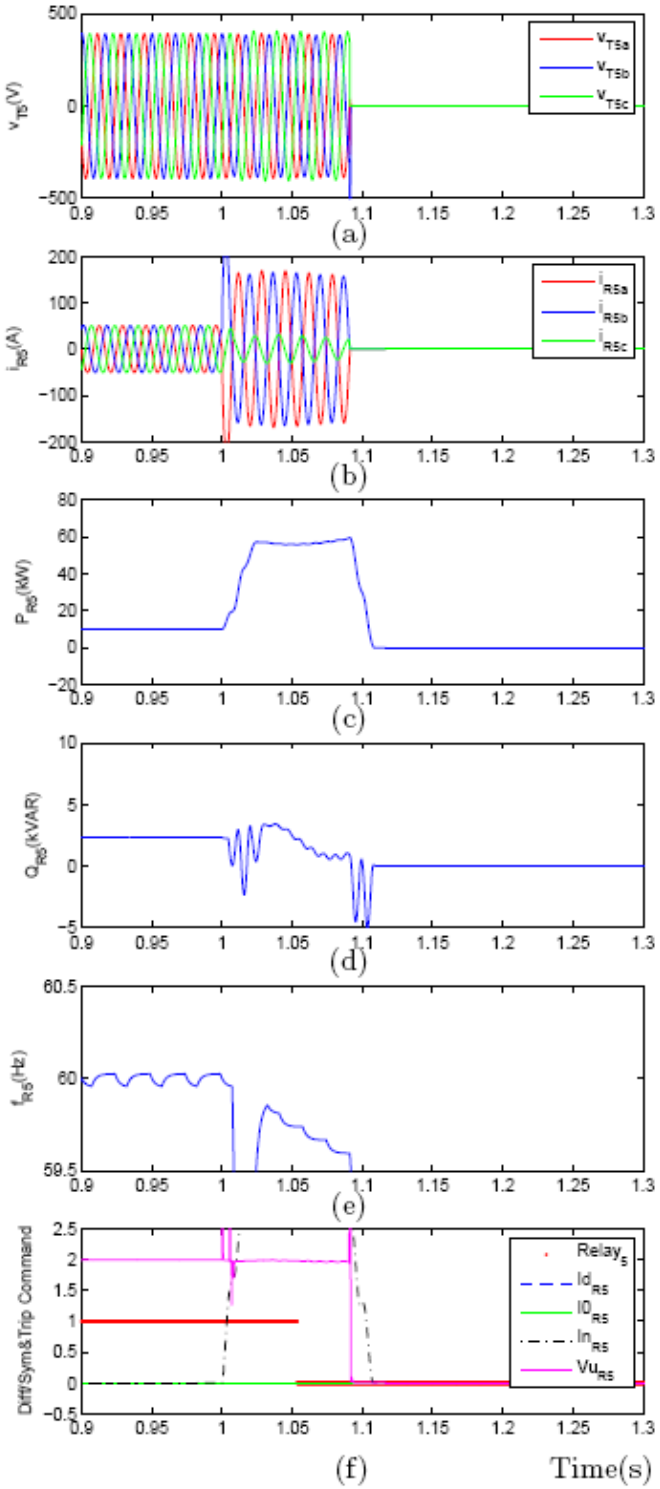

Figure 37: Response of the Relay 5 to a 85.5 kW LL fault in Zone 5: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer *T*51 and output command of the relay

Line-to-Line Fault in Zone 6

The AEP microgrid of Fig. 1 is operating at steady-state conditions with the source and load settings as explained in Section 5 and an LL fault with a resistance of 2.695 Ohms is applied in Zone 6 at t=1.0 s. Figs. 39(a)-(e) to Figs. 42(a)-(e) show variations of the three-phase voltages and currents, the real and reactive power components, and the frequencies measured at the Relays 2, 3, 4 and 5, respectively, in response to the LL fault.

Fig. 38(f) shows that the Relay 2 commands the static switch to trip shortly after the fault when the relay detects a negative-sequence current component that exceeds 1.0 pu (95 A). Fig. 39(f) shows that the Relay 3 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 40(f) shows that the Relay 4 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu. Fig. 41(f) shows that the Relay 5 does not command for a trip since none of its fault detection parameters, i.e. the differential and symmetrical current components, exceeds the threshold of 1.0 pu.

For the case of an LL fault in Zone 6, the static switch islands the microgrid. The Zones 2, 3, 4 and 5 of the microgrid and the microsources A_1, A_2 and B_1 continue the operation subsequent to the fault detection and its clearance. The results shown in Fig. 38 to Fig. 41 demonstrate that the developed protection system is able to protect the AEP microgrid against an LL fault in Zone 6 with a power of 85.5 kW by disconnecting the static switch. Since the fault current increases as the fault power increases, it is concluded that the microgrid protection system is able to protect all LL faults in Zone 6 with a power more than or equal to 85.5 kW.

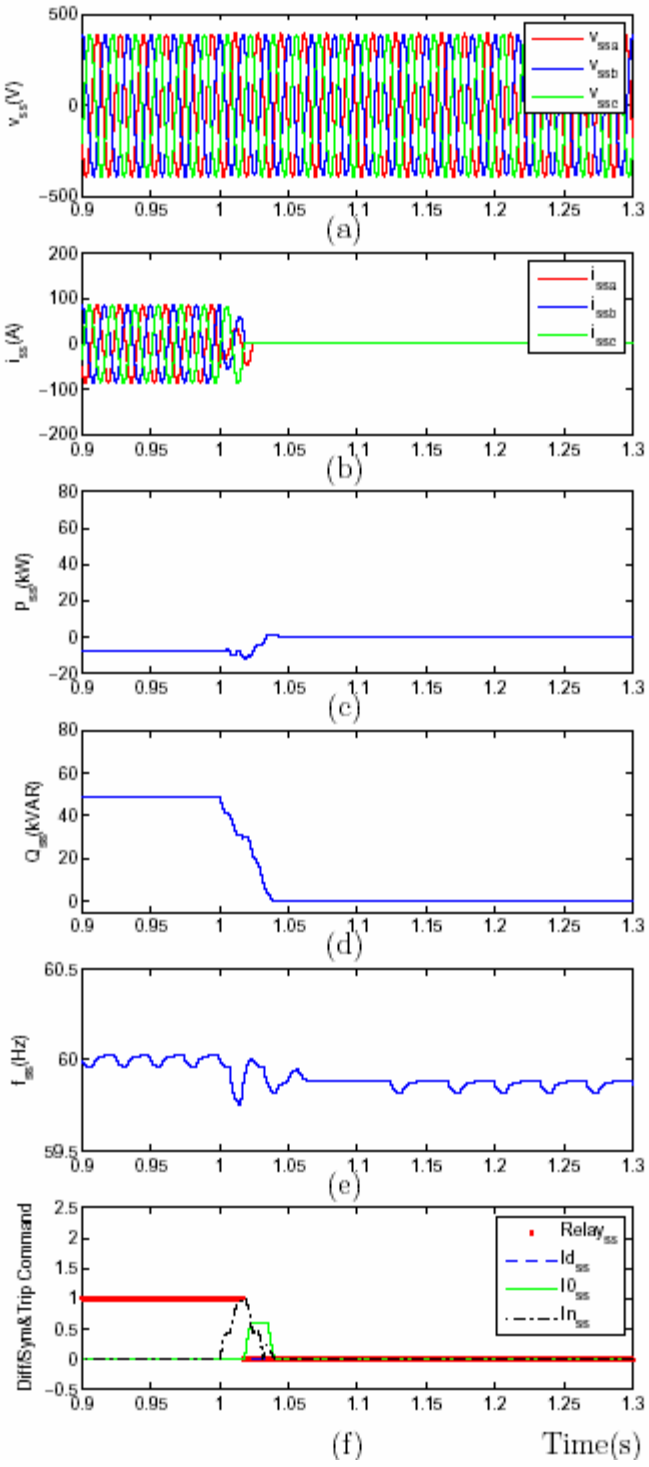

Figure 38: Response of the Relay 2 to a 85.5 kW LL fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

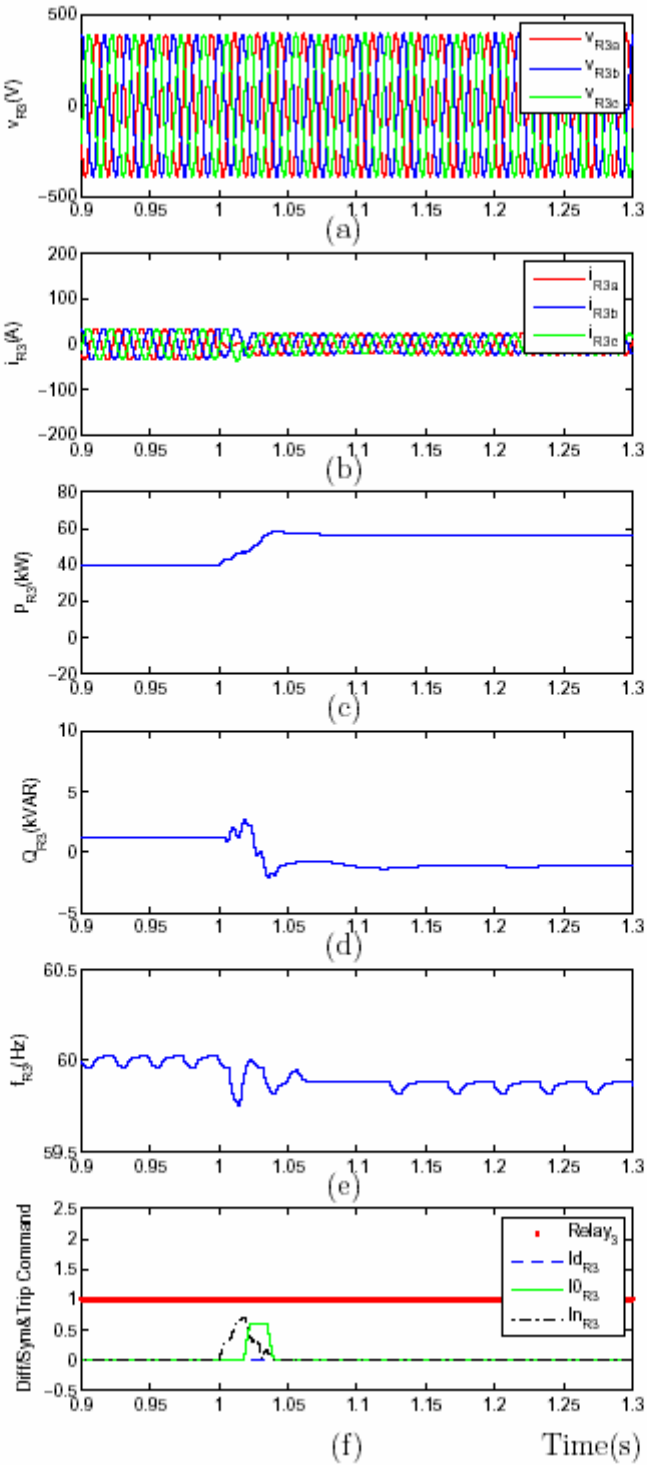

Figure 39: Response of the Relay 3 to a 85.5 kW LL fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

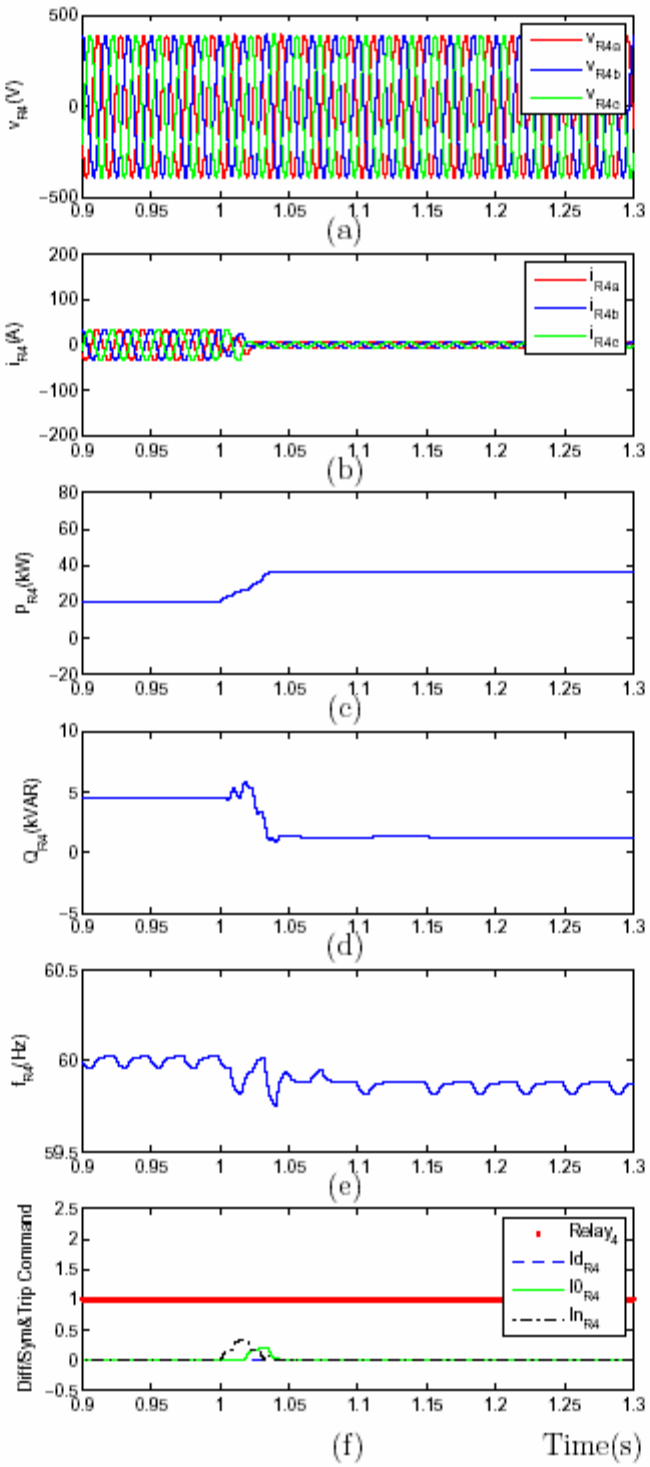

Figure 40: Response of the Relay 4 to a 85.5 kW LL fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components and output command of the relay

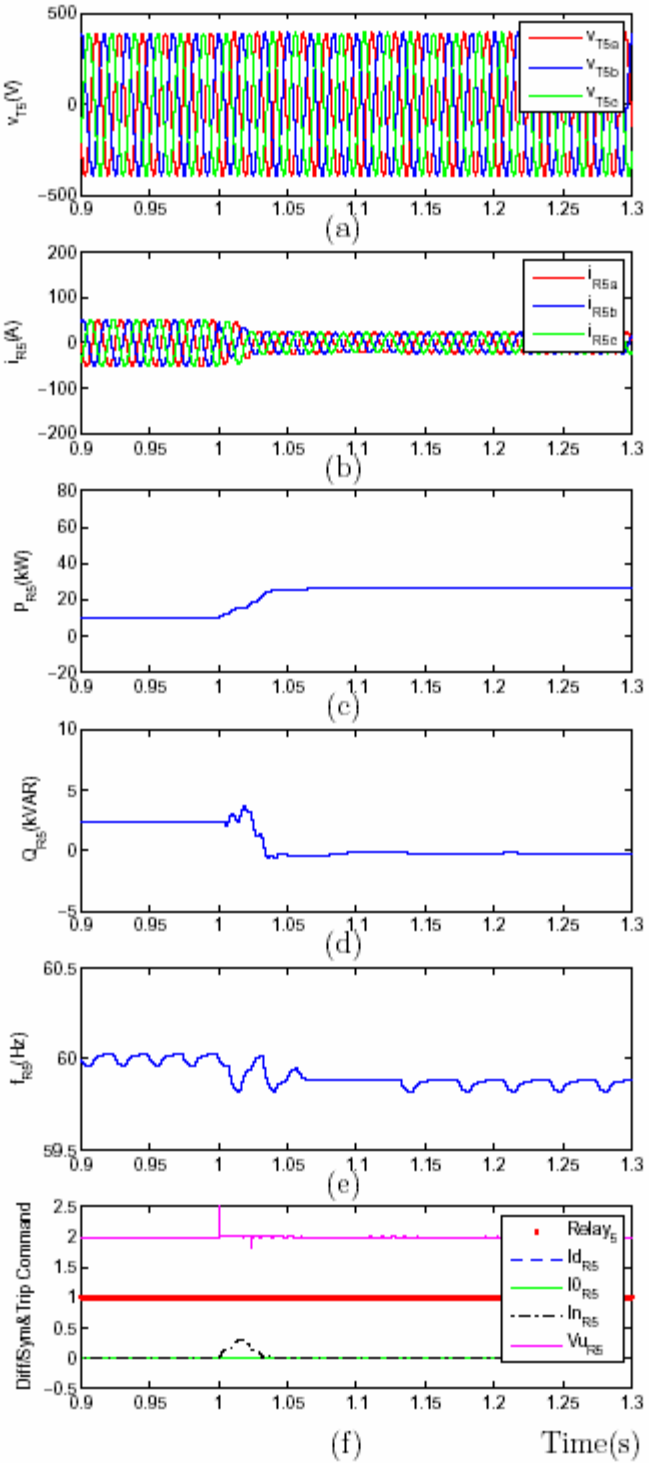

Figure 41: Response of the Relay 5 to a 85.5 kW LL fault in Zone 6: (a,b) three-phase voltages and currents, (c,d) real and reactive power components, (e) frequency, and (f) differential and zero- and negative-sequence current components, negative-sequence voltage component at the transformer *T*51 and output command of the relay

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