PROTECTION, AUTOMATION, AND FREQUENCY STABILITY ANALYSIS OF A LABORATORY MICROGRID SYSTEM

A Thesis

presented to

the Faculty of California Polytechnic State University,

San Luis Obispo

In Partial Fulfillment

of the Requirements for the Degree

Master of Science in Electrical Engineering

by

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May 2018

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ABSTRACT

Protection, Automation, and Frequency Stability Analysis of a Laboratory Microgrid System

Christopher Eric Osborn

Due to increasing changes in the power industry, Cal Poly San Luis Obispo's electrical engineering department introduced a set of initiatives to adequately equip students with the skills and knowledge to interact with new technologies. Specifically, the department proposed a microgrid and power systems protection and automation laboratory to strengthen students' knowledge of microprocessor-based relays. This paper outlines a microgrid laboratory system that fulfills the initiative's goal and proposes a collection of laboratory experiments for inclusion in a new laboratory course at Cal Poly. The experiments provide students with practical experience using Schweitzer Engineering Laboratory (SEL) relays and teach fundamental concepts in semi-automated generator synchronization and power system data acquisition. The microgrid laboratory system utilizes SEL relays and a centralized SEL controller to automate frequency regulation through load shedding, power factor correction, generator and utility synchronization, and relay protection group switching.

ACKNOWLEDGMENTS

Thank you to Kenan Pretzer for providing invaluable advice and insight into SEL relays and general protection schemes. Thank you to Matt Guevara for spending countless hours in the lab assisting in troubleshooting and providing motivation when nothing seemed to work right. Thank you to Nathan Martinez for testing experiments to ensure they were clear and correct. Thank you to Dr. Ali Shaban, Dr. Ahmad Nafisi, and Dr. Taufik for providing guidance and feedback in the writing and development of this thesis. Thank you to Taylor Osborn for diligently proofreading this thesis and providing feedback.

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Chapter 1: Introduction

1.1 History of the U.S. Electric Power Grid

After its inception in 1882, the power grid in the U.S. evolved over time from a single, central, source to a sprawling, interconnected system [1]. While the magnitude of the system changed, centralized generation did not. Because of economic benefits and efficiency advantages, large, centralized power plants remained more popular than small, distributed generators. A centralized and interconnected power grid provides engineering advantages such as the ability to match demand and generation relatively easily. The electric grid eventually spanned the entire U.S. with high-voltage transmission lines and divided into three separate electric grids connected through interconnects. As illustrated in Figure 1, the eight regional entities of the North American Electric Reliability Corporation (NERC) are tasked with creating standards to coordinate the reliability of the electric power grid [2].

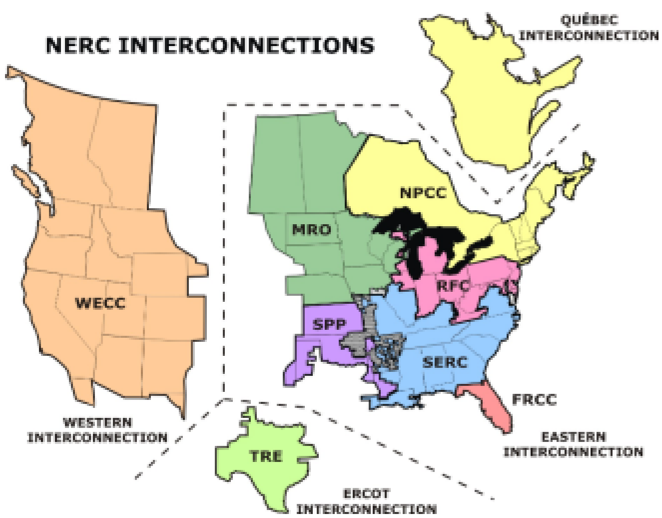

Figure 1: Map of NERC regional entities and interconnections [3]

While NERC provides the integrity standards for the whole system, individual Independent System Operators (ISO) and Regional Transmission Organizations (RTO) oversee the dispatch of electricity in most of the U.S. Although 70% of electricity in the U.S. is generated and consumed in regions managed by Independent System Operators (ISO) and Regional Transmission Organizations (RTO), some areas are managed by vertically integrated utilities. As illustrated in

Figure 2, the colored regions show which geographical areas have ISOs and RTOs, while vertically integrated utilities oversee the non-colored areas [2]. Based on marginal cost bids, RTOs, ISOs and vertically integrated utilities oversee the dispatch of electricity [2]. Having a centralized authority to direct and manage a large grid makes matching demand and generation simpler, and the scale of each grid necessitates it.

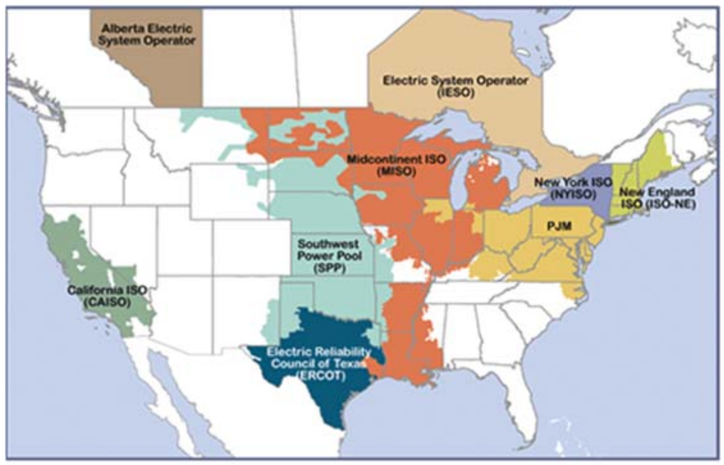

Figure 2: Map of ISO and RTO regions [4]

While economics and technology dictated a centralized electric grid at its inception, today it poses several disadvantages. One main issue is the proliferation of renewable energy sources that ISOs and utilities have no control over. Solar panels on individual homes and businesses, private solar farms, and wind farms are examples of uncontrollable energy sources always connected to the grid. Although these sources can reduce the net load, they turn a traditionally radial system into an incredibly complex networked system with uncontrollable variable generation sources. When these sources are all generating high amounts of energy at times when electricity usage is low, over generation can occur. Figure 3 illustrates how renewable sources decrease the net load on the grid, potentially creating an imbalance between generation and load. Another issue is inherent to the centralized nature of the grid. When a centralized power plant collapses, it is difficult to replace the plant’s generation since it requires a large amount of energy. This can lead to a widespread blackout that potentially affects millions of people simultaneously [5]. While multiple mitigation plans already exist to prevent blackouts, a single, cost effective, and easy to implement solution in the current grid infrastructure remains elusive.

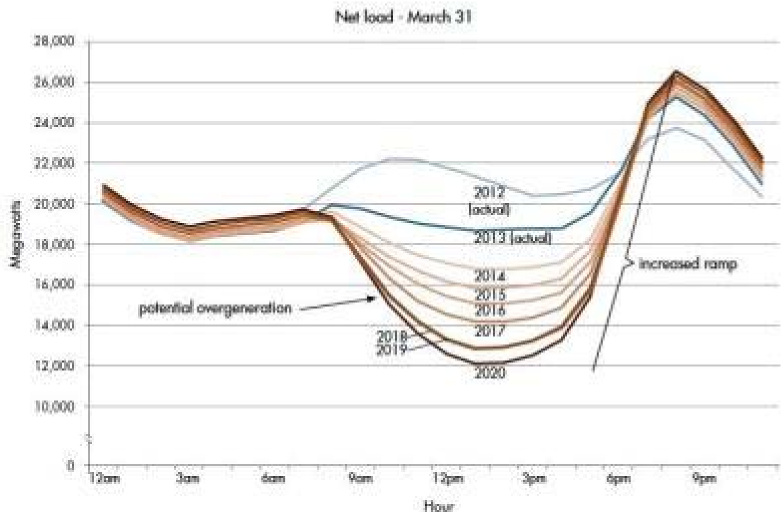

Figure 3: CALISO Duck Curve illustrating potential for overgeneration [6]

Historically, utilities in the United States reject innovation of electric power distribution. This reluctance results from arguably the most important goal of the grid: reliability. Utilities resist infrastructure innovation to avoid new technologies and ideas that could compromise the vigorously tested reliability of their systems. As a result, the power grid becomes outdated and the infrastructure ages. Although new relay and power electronic technologies have permeated the industry, the infrastructure design has remained relatively constant. Recently, however, an idea that has existed for a few decades has become popular among utilities: the microgrid.

1.2 The Emergence of Microgrids

While multiple definitions of microgrids exist, this paper defines them as “a localized group of electricity sources and sinks (loads) that typically operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and maintain operation autonomously as physical and/or economic conditions dictate” [7]. Microgrids address many of the previously mentioned problems that a centralized grid proposes, primarily by its ability to disconnect from the grid in the event of a disturbance. This allows universities, businesses, military bases, and cities to have complete isolation and independence from the grid in the presence of faults on the main grid. Local generation and consumption also increase energy efficiency and decrease loss [7]. Although microgrids have existed for many years, microprocessor relay technology has spurred advanced communication and decision making within the microgrid system. When a microgrid system is islanded, frequency stability becomes an important factor in maintaining its reliability. Microprocessor relays placed throughout the system can provide standard protection against faults and gather information such as frequency. The relays send this information to a central communications processor, where decisions dictate load shedding to balance generation with consumption while maintaining the system's frequency. These technological advances coupled with government regulations to decrease negative environmental impact drive utilities toward viewing microgrids as a solution to handling decentralized resources on the grid. According to a survey conducted by Utility Dive, 35% of utilities plan to either develop, own, or operate a microgrid within the next 5 years [8]. Figure 4 illustrates the full breakdown of utilities' plans to build microgrids, showing a stark contrast between those with upcoming plans and those without plans. While some utilities lack plans to develop microgrids, their increasing prominence makes them an important fixture in grid infrastructure.

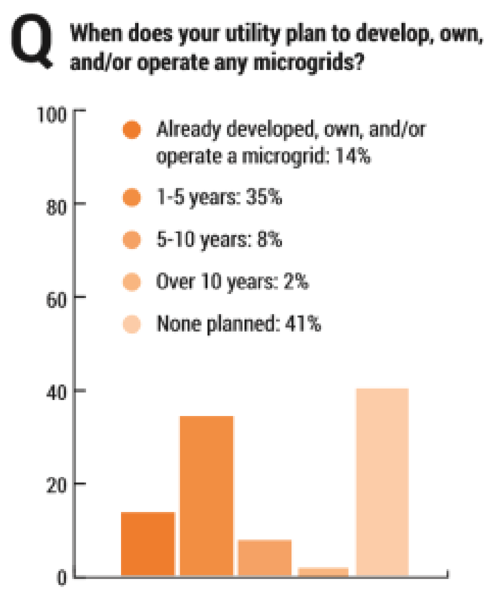

Figure 4: Utility involvement in microgrids [8]

1.3 University Power Systems Courses

Although the power industry adopts the advanced technology of microgrids into their infrastructure, universities have fallen behind. Universities primarily teach electric machines and power systems analysis with the assumption that the grid remains largely electro-mechanically controlled. This results from a lack of modern power systems equipment and accompanying laboratory material to teach its use. The protective relays in laboratories typically don't utilize microprocessors, making modern control and protection schemes hard to teach. While the industry has adopted new technologies to address problems associated with centralized generation, a new wave of electrical engineers lacks the knowledge to interact with and understand the modernized grid.

Chapter 2: Background

2.1 Disparity Between Industry and Academia

California Polytechnic State University (Cal Poly) San Luis Obispo currently offers eight lecture courses and 3 laboratory courses covering power systems topics. These courses range from basic to advanced analysis of grid tied power systems, renewable energy integration with the grid, electric machine energy conversion, and protection schemes [9]. While these courses thoroughly teach traditional power system analysis techniques and integrate both renewable and traditional generation sources, they do not teach the modern methods industry utilizes to optimize the reliability and control of power systems. As previously mentioned, this is not solely an issue at Cal Poly, but rather a systematic issue of electrical engineering programs in the U.S. Cal Poly's electrical engineering program is ranked number three in the nation by U.S News and World Report [10] for universities offering master's degrees as the highest degree, illustrating that its lack of modern power systems coursework is representative of other universities in the U.S.

A multitude of researchers and industry professionals have studied the evolving power grid looking for solutions to the inherent challenges microgrids present [11]. However, very little of this research focuses on creating an environment to effectively teach these new solutions to electrical engineering students. More specifically, these new solutions depend on advanced control and automation techniques traditionally not taught in universities. Papers such as [12], [13], and [14] describe different control methods for frequency and voltage stability in an islanded microgrid system. The advanced microgrid control methods can't be effectively taught in a university course due to their advanced techniques, highlighting the need for literature aimed at teaching the basics of these new concepts to students at an understandable and appropriate complexity level. This paper intends to solve this problem by proposing several experiments designed to teach students modern power systems concepts. In addition, this paper presents a microgrid fixture that supports and reinforces concepts learned through the experiments.

2.2 Microgrid Student Laboratory

This paper expands the work of [15] to include laboratory experiments relating to generator protection, generator synchronization, and system load shedding, illustrating microgrid automation and protection techniques. Reference [15] proposes several power systems protection experiments and a basic laboratory model of a bidirectional power system. The experiments in this paper, however, teach fundamental power systems concepts using industry-standard protection and automation equipment while using a microgrid as the backdrop for learning. The goal of each experiment is two-fold: to support theoretical power systems concepts with hands-on learning, and to expose students to microprocessor relays that enable the automation of power systems. Individual experiment student learning outcomes include: applying classical power systems analysis techniques to automate relay detection of faults; exposure to relay settings and automation program writing; and comprehending key parameter measurements in generator auto-synchronization. These experiments also share many of the learning objectives described in [15], including developing experience in wiring circuits and operating industry standard relays. Laying the foundation for a microgrid laboratory at Cal Poly, these experiments intend to equip students with the knowledge and experience to interact with the quickly changing power industry landscape.

Additionally, this paper describes the development of a permanent microgrid fixture that serves as a learning tool for students and faculty members at universities. Its purpose is to replicate the functionality of a microgrid and aid the facilitation of learning by providing a tangible system that students can interact with to supplement learning achieved through completion of written experiments. The following sections describe work related to both the experiments and microgrid fixture.

Chapter 3: Design Requirements

3.1 Customer Needs Assessment

This project directly benefits Cal Poly electrical engineering students by supplementing current coursework (specifically EE 518) with laboratory experiments. It arose from the electrical engineering department's expressed desire for a new laboratory course that teaches students modern power systems protection and automation concepts. The faculty determined these concepts are best taught through experiments that utilize relays donated by Schweitzer Engineering Laboratories, Inc. (SEL) and focus on microgrid systems. Further discussions with faculty revealed that the experiments must specifically cover system islanding and synchronization automation experiments, adding to the physical system and literature of the microgrid protection framework as described in [15]. The following section describes specific requirements determined in consultation with Cal Poly faculty.

3.2 Requirements and Specifications

A thorough review of the electrical engineering department's needs revealed the experiments must be safe, understandable, and completable in a standard three-hour lab period. The experiments consider the students' general lack of experience. The system utilizes industry standard relays, uses commonly implemented protection schemes, and interfaces with voltage levels found in university laboratories. To accurately represent a simple microgrid system, a load is connected between an infinite bus and a generator. Both sources normally provide power to the load, but the generator can power the load by itself if the infinite bus is removed from the system. The static portion of the load can be shed if the system frequency drops considerably when the infinite bus is disconnected. Table 1 lists full requirements and specifications. Table 1's format derives from [25], Chapter 3.

Table 1: Requirements and Specifications

Marketing Requirements	Engineering Specifications	Justification
10	At least one 3-phase $208VAC_{rms}$ generator provides a minimum of 450W average power.	Standard low voltage values accessible by universities include 208VAC. 450W ensures support for a reasonable load at 208VAC.
10	All generators must be 3-phase $208VAC_{rms}$	Standard low voltage values accessible by universities include 208V.
11	A load is connected between an infinite bus and generator.	Requirement for a microgrid system.
3	System frequency is regulated within ±.5% of 60 Hz without connection to utility for total system load less than 450W.	Ensures system can perform islanding.
4	All protection elements utilize either General Electric or Schweitzer Engineering Laboratory microprocessor relays.	General Electric and Schweitzer Engineering Laboratory relays are the two most commonly used relays in the power systems industry.
5	Generator and infinite bus relays-synchronize to a 60Hz system within 3 seconds of command issuance.	A 3 second window ensures the maximum synchronization point is found without compromising the response time of the system.
1	Experiments take less than 3 hours for 400/500 level electrical engineering students to complete.	Standard lab periods at Cal Poly are 3 hours.
1-2	All non-relay terminals are compatible with 4mm banana plugs and 1/4 inch or smaller stud spade connecters.	Ensures multiple connections to one node in a safe manner
6	Relays communicate with communications processor via either serial or ethernet ports.	Standard communication ports used in the power systems industry include serial and ethernet.
2	A separate fault ground and chassis ground must be used for all equipment connections.	Ensures fault current does not flow through chassis ground when system fault occurs.
3	If total system load exceeds total generation and system frequency is not within ±.5% of 60Hz while disconnected from the infinite bus, static loads are shed until power consumption is balanced with generation and system frequency is within ±.5% of 60Hz.	Ensures system stability while islanded.
11	Relays synchronize event time stamps using a satellite clock.	Most microgrid systems synchronize event time stamps using a satellite clock.
9	Experiments teach synchronism-	Standard requirements of a modern

Marketing Requirements	Engineering Specifications	Justification
	checking using SEL-421 at generator terminals.	power system include synchronism-checking.
9	Experiments teach synchronism-checking using SEL-700G	Standard requirements of a modern power system include synchronism-checking.
9	Experiments teach data acquisition concepts in a microgrid.	Modern power systems and microgrids typically require load shedding capability.
9	Experiments require students to physically interact with the microgrid.	Physical interaction ensures students gain hands-on experience with the modern power systems equipment.
2	All wire sizes must comply with NEC 2014 table 310.15(B)(16)	Prevents wires from melting due to high heat dissipation.

Marketing Requirements
1. Easy to use
2. Safe
3. Complete islanding ability
4. Utilizes microprocessor relays
5. Auto-synchronization and reclosing capability
6. Relay programming through communications processor
7. Generator protection
8. Infinite bus protection
9. Interactive, modern power systems experiments
10. Installable in a U.S. university laboratory environment
11. Models a microgrid system

3.3 Functional Decomposition

The system provides protection and automation functionality to a microgrid while also supplying written experiments to enhance student learning. 3-phase 208VAC, 125VDC, and 1-phase 120VAC provide power to the system. Fault signals and existing microgrid protection and automation schemes model the system input, while breaker status and the tested experiments indicate system output. Figure 5 depicts the level zero block diagram of the system and Figure 6 abstracts the system to level one. Figure 6 shows the fault signal processed by a relay, sending a corresponding trip or close signal to the breaker. Table 2 summarizes overall functionality and lists inputs and outputs. Table 3, Table 4, and Table 5 summarize individual module functionality and list corresponding inputs and outputs. All AC voltages and currents listed in Table 2 through Table 5 consist of continuous, root-mean-square values.

Table 2: Summary of Inputs, Outputs, and Functionality

Module	Microgrid Protection and Automation
Inputs	3-phase 208 VAC, 10A 125 VDC, 3A 1-phase 120V, 15A Satellite Synchronized Clock Electrical Fault Signal Microgrid Protection and Automation Schemes
Outputs	Circuit Breaker Status 3 Tested Microgrid Protection and Automation Experiments
Functionality	Protect the 240 VAC 3-phase system against the faults described in Table 1 by opening appropriate 125 VDC circuit breaker. Circuit breakers automatically close once a fault is removed or system is synchronizing. All relays are time synchronized using a satellite clock. Protection and automation experiments teach utility and generator protection and automation topics to electrical engineering students.

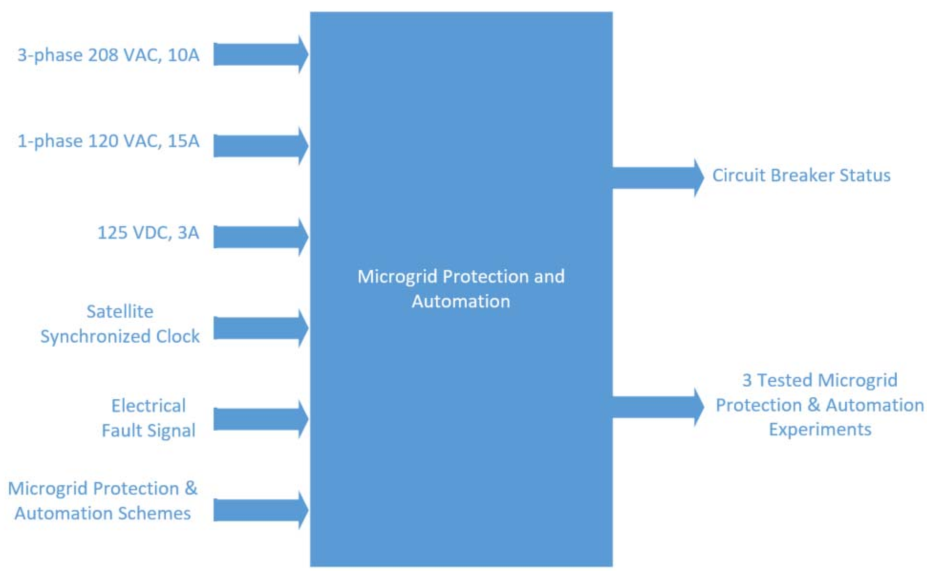

Figure 5: Level 0 Block Diagram

Table 3: Circuit Breaker Functionality

Module	Circuit Breakers
Inputs	125 VDC, 3A 3-Phase 208 VAC. 10A Trip Signal

Module	Circuit Breakers
	Close Signal
Outputs	Circuit Breaker Status
Functionality	Interrupt 3-phase power flow when Trip Signal is received from Relay. Permit 3-phase power flow when Close Signal is received from Relay.

Table 4: Relay Functionality

Module	Relays
Inputs	1-phase 120V, 15A Electrical Fault Signal Satellite Synchronized Clock
Outputs	Trip Signal Close Signal
Functionality	Send trip signal to Circuit Breaker when any of the faults described in table 1 occur. Send close signal to Circuit Breaker when a fault is removed, or system is synchronizing.

Table 5: "Write 3 Experiments" Functionality

Module	Write 3 Experiments
Inputs	Microgrid Protection & Automation Schemes
Outputs	Written Experiments
Functionality	Turn common Microgrid Protection and Automation schemes into understandable written experiments.

Table 6: "Test Experiments" Functionality

Module	Test Experiments
Inputs	Written Experiments
Outputs	3 Tested Microgrid Protection and Automation Experiments
Functionality	Test written experiments by having students perform them and provide feedback.

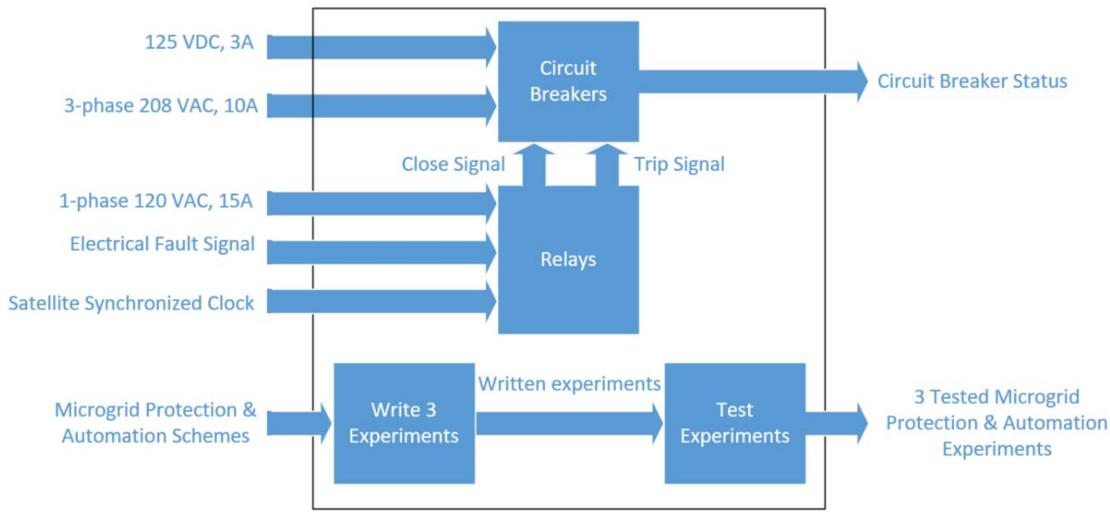

Figure 6: Level 1 Block Diagram

Chapter 4: Equipment

4.1 Schweitzer Engineering Laboratories Devices

Multiple Schweitzer Engineering Laboratory (SEL) relays are used to provide protection and automation features in the microgrid. SEL is the leading manufacturer of microprocessor relays in the United States and using them enables students to gain hands-on experience with industry leading equipment. The SEL-700G, SEL-421, and SEL Real Time Automation Controller (RTAC) are all added to the system described in [15]. The functionality of the SEL-710 changes slightly from the design in [15] and is described in this section. All relays are time-synchronized using the SEL-2407 Satellite Clock. For specific information regarding the existing relays used in the microgrid, please refer to [15].

The SEL-700G is a generator protection relay that features many functions related to generator protection, but this project only implements a few selected functions. The following elements are implemented in the microgrid: synchronism-check, under/over frequency, loss of excitation, and power.

The SEL-421 is a protection relay primarily used for distance protection. However, it also has many other functions. In the proposed microgrid system, the synchronism-check is the only implemented element.

The SEL-710 is a motor protection relay. In this system, its functionality is adapted from that described in [15] to offer a slightly different function. Instead of using the under/overvoltage element to turn off the motor, it is used to turn the capacitor bank on and off, thus correcting the adverse voltage condition without interrupting power flow to the load.

The RTAC functions as an advanced communications processor. It is used as a conduit for programming the relays. All relays are connected serially to the RTAC, and the RTAC has a serial connection to a computer terminal. Using SEL structured text, the RTAC transfers key data between individual relays. Specific implementations of the RTAC program are discussed later in this Chapter.

4.2 Circuit Breakers

While the SEL relays detect undesirable conditions in the system and generate corresponding trip signals, they don't physically interrupt current flow in the circuit. Circuit interruption is performed by a circuit breaker designed by former Cal Poly student Ozro Corulli [16]. As shown in Figure 7, the circuit breakers are powered by 125VDC and feature LEDs to indicate its status. All connections utilize standard banana or spade terminals. The circuit breaker can be manually opened and closed and has inputs designed to interface with SEL output contacts. Figure 8 shows that a fault switch can be used to connect the three phase connections in the lower left corner together. A fault can be wired to the black terminals in the lower left, and the switch then controls when a fault is injected into the system. The innovative design adds functionality to the circuit breaker by providing a safe location to fault the system. All circuit breaker chassis grounds are wired separately from other equipment chassis grounds as the circuit breaker grounds are used to perform ground faults. The two grounds are tied at only one point to provide a common reference voltage. For more information relating to the circuit breakers, refer to [16].

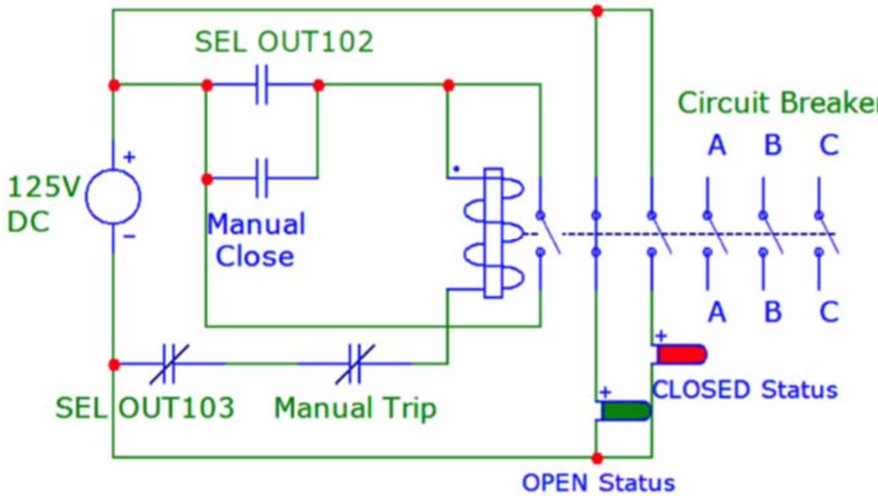

Figure 7: Circuit Breaker Schematic [16]

Figure 8: Circuit Breaker Front Panel [16]

4.3 Machines

Three different machines are used in the microgrid: a three-phase DC motor, three-phase synchronous generator, and three-phase induction motor. The DC motor is rated for 125V, 2.4A and 300W. The synchronous generator is rated for 208V, 1.7A armature current, .6A field current, 250W, and 60Hz. The synchronous generator can be connected in either wye or delta, but for the purposes of this system it is connected in a wye configuration. 125VDC is supplied to an external rheostat to provide the synchronous generator field current. The DC motor uses an internal rheostat and external 125VDC supply to provide its field current. To start the motor, a separate DC motor starter is used. The three phase induction motor is rated at 208VAC, 1.7A, 1/3HP, and 60Hz. All three machines and the motor starter have chassis grounds that are used appropriately.

Chapter 5: Microgrid and Experiment Design

5.1 Overview

Figure 9 shows the proposed microgrid system. Expanding the basic system described in [15], this system removes the infinite bus on one side and replaces it with two parallel synchronous generators. It also adds a capacitor bank to supply reactive power to the motor that is automatically switched on and off using SEL-710. SEL-700G is added to protect the synchronous generators and provides the following functionality: synchronism-check, generator reverse power protection, generator under/over frequency protection, and loss of field protection. The RTAC automates load shedding and switches relay protection groups. The system models a basic microgrid with bidirectional power flow between the infinite bus and synchronous generators. A static load and induction motor in the middle of the transmission line model utility customers. Transformers with one-to-one ratios are used to model step up transformers commonly used in distribution and transmission. The three proposed experiments utilize additional circuits. The microgrid system in conjunction with the experiments satisfiy the design requirements described in *Chapter 3*. The remainder of this chapter describes the protection and automation elements added to the microgrid system in addition to the content of the experiments.

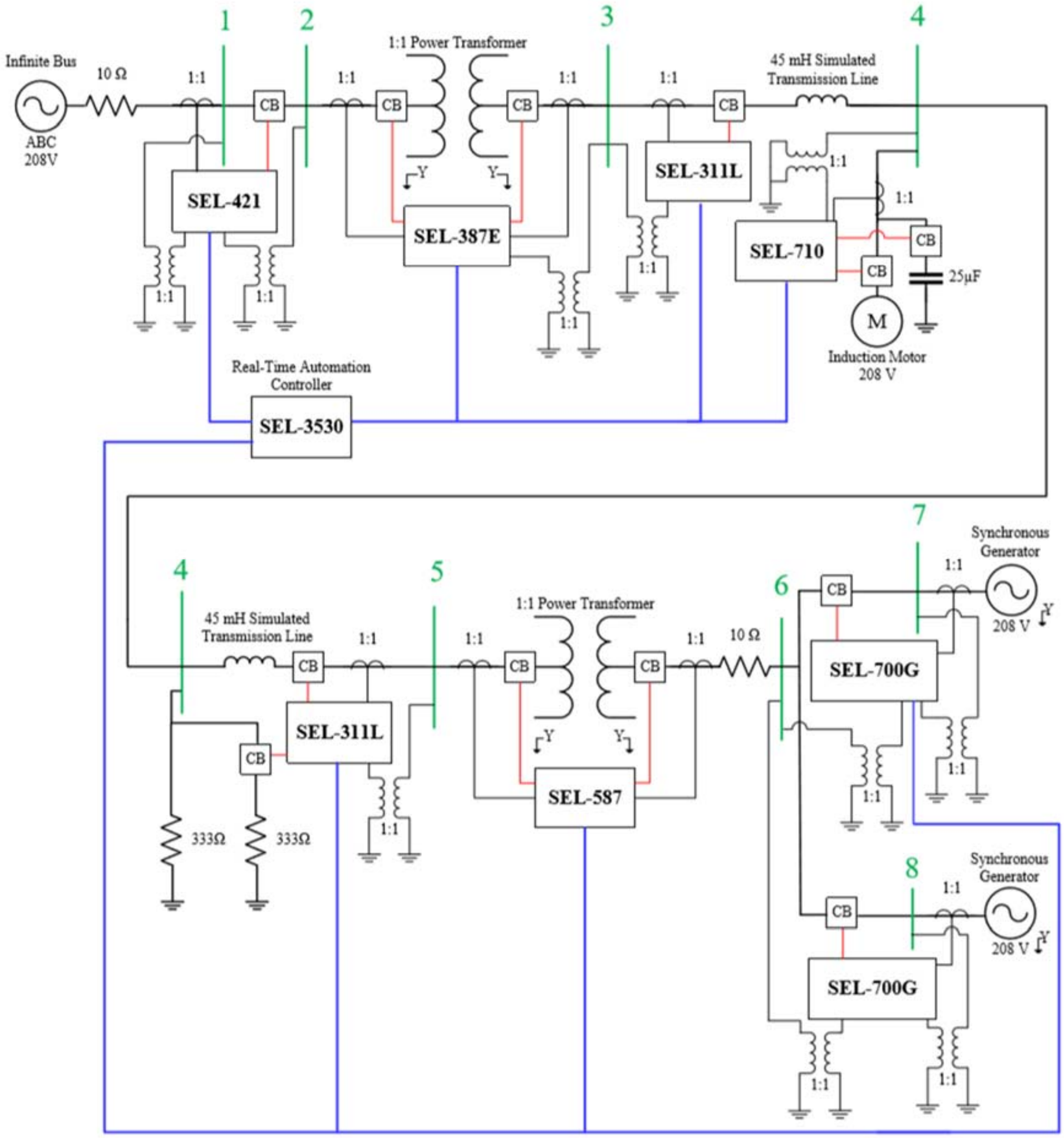

Figure 9: Microgrid One-Line Diagram

5.2 Synchronous Generator Automation and Protection

To safely connect the synchronous generators to the microgrid, many conditions must be met. Before circuit breaker closure, the generator and microgrid must have the same voltage magnitude, the same direction of rotation, and the same phase. While it is possible to check these conditions manually, it is common practice in industry to automate comparison between the voltage magnitude and phase. The SEL-700G relays used in this microgrid utilize the synchronism-check element to ensure the proper synchronization conditions are met before the circuit breaker closes. Although the voltage and frequency of the generators must be adjusted manually, the relay automatically closes the circuit breaker once the synchronization conditions are met. The direction of phasor rotation is not checked by the SEL-700G since it is industry standard to manually verify the directions are identical before the system is energized. Figure 10 summarizes the synchronization process in a signal flow diagram. Refer to Appendix A: SEL-700G Settings for specific settings.

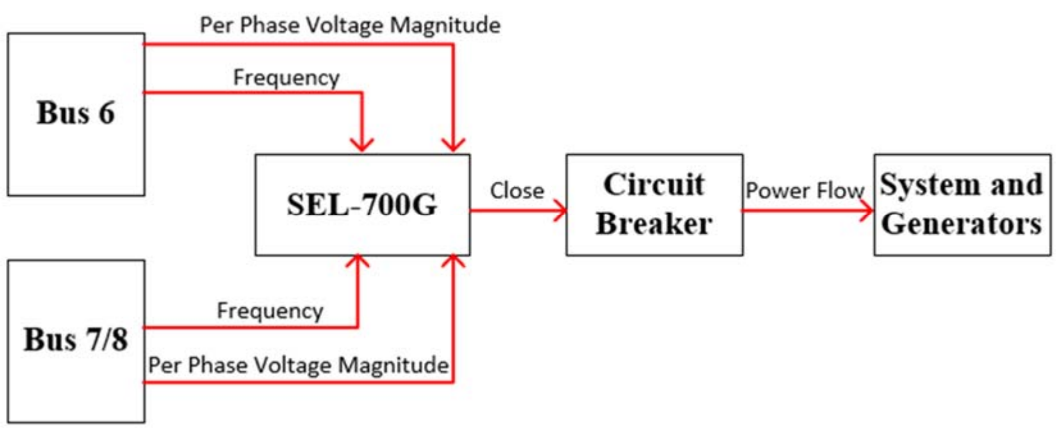

Figure 10: Synchronism-Check Signal Flow Diagram

If a synchronous generator loses its excitation field, it operates as an induction generator. This causes the generator to absorb reactive power and decreases the active power output. It also induces high currents in the rotor and stator, causing overheating to occur quickly. To protect the generator, it is typically disconnected from the system. The synchronous generators in Figure 11 use the loss of excitation element in the SEL-700G to detect when this condition occurs. The element works by using positive mho circles to detect the loss of excitation condition. As shown in Figure 11, two zones are typically used: one for light loading and one for heavy loading conditions. Under normal operating conditions, the generator is operating in the upper right quadrant. When loss of field occurs, it will shift to either the bottom right or bottom left quadrant. Settings for the generators in the microgrid system are determined experimentally and can be referenced in Appendix A: SEL-700G Settings. While two zones are implemented, the system currently only operates under light load, therefore only tripping the zone two element. Zone one can be adjusted to adequately protect for loss of excitation during heavy loading conditions if more load is added to the system in the future.

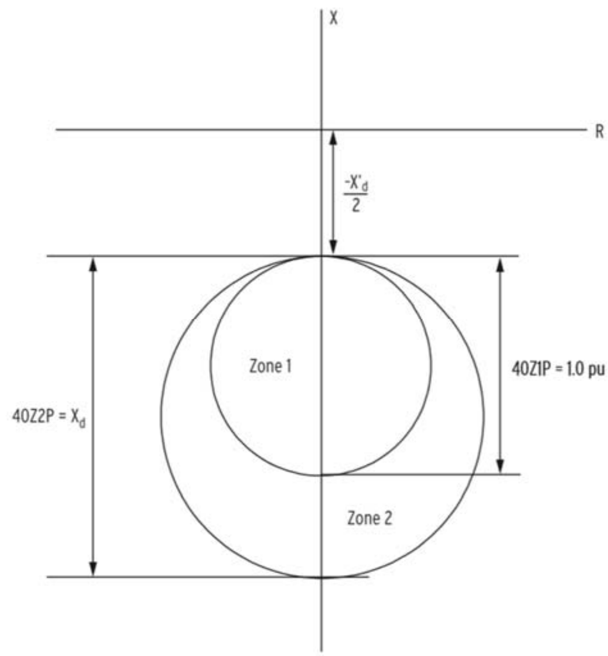

Figure 11: Loss of Excitation Zones [17]

The generators are also protected from under/over frequency conditions using the SEL-700G under/over frequency element. When the utility is connected to the microgrid, the frequency is fixed at 60Hz. However, when the system is islanded, small disturbances on the system can cause the frequency to change. SEL-700G detects these frequency deviations by directly measuring the frequency and opening the circuit breaker to protect the generator if the frequency exceeds safe operating parameters. The over/under frequency element has a delay so that transient disturbances are ignored by the relay. For specific settings, refer to Appendix A: SEL-700G Settings.

SEL-700G is also equipped with a power element that can be configured to protect the generator from adverse power conditions. In this system, it is used to protect the generator from reverse power and loss of prime mover conditions. Both reverse power and loss of prime mover conditions force the generator to “motor”, driving large amounts of real power into it and causing severe damage. The reverse power element also has a delay to avoid nuisance tripping for transient conditions. Figure 12 shows the operating characteristic of the real power elements. The shaded area indicates the point that the element asserts and sends an open command to the circuit breaker protecting the generator. For specific settings, refer to Appendix A: SEL-700G Settings.

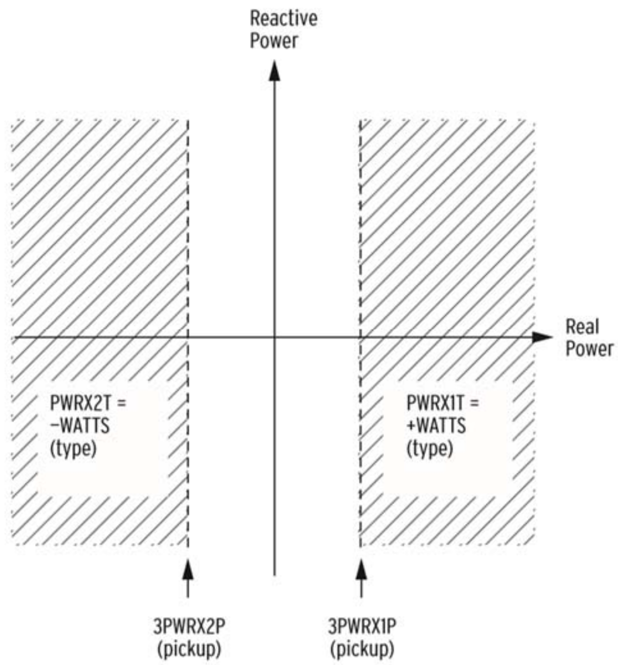

Figure 12: Real Power Element Operating Characteristic [17]

5.3 Microgrid Automation

The work described in [15] primarily focuses on providing basic protection to a bidirectional power system. Using distance, differential, and overcurrent protection, the system is protected from faults at many locations. The system doesn’t, however, have any automation capability. It also can’t be classified as a microgrid, since the only power source is the utility. The system described in this section adds synchronous generators to allow the microgrid to operate in two configurations: utility-connected and islanded. These two configurations necessitate the automation of many microgrid operations to provide reliable and consistent power. The following tasks are automated: power factor correction, load shedding, relay group switching, utility synchronization, and generator synchronization. To support the voltage throughout the microgrid when the motor is running, a capacitor bank is added. The SEL-710 uses the under/over voltage element to automate the capacitor bank switching. Figure 13 shows the signal flow diagram for capacitor bank automation. When the voltage at bus four in Figure 9 drops below 174 volts (line to line), the capacitor bank is turned on. When the voltage rises above 214 volts (line to line), the capacitor bank turns off. These values are chosen experimentally by testing the voltages at bus four with the motor running and no power factor correction, and with the motor not running and power factor correction active. Table 7 shows the values used in Eq. (1) to calculate the value of the capacitance bank. Based on the calculation, a capacitance value of 25μF is selected. The power factor capacitors are connected in a wye configuration.

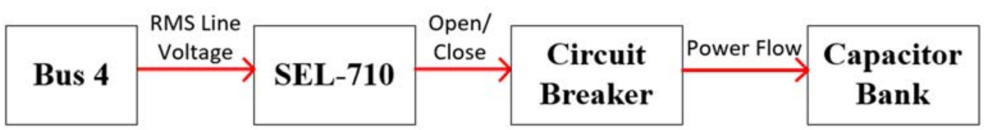

Figure 13: Capacitor Bank Automation

$$C_{phase} = \frac{Q}{3 * (2\pi * f * V^2)} \tag{1}$$

Table 7: Power Factor Correction Calculation Values:

Symbol	Description	Value
Q	Reactive Power	369VAR
F	Frequency	60Hz
V	Nominal Phase Voltage	120V
C	Capacitance per phase	22.7μF

To achieve system frequency stability when the system switches from grid-connected to an island, a load shedding scheme is used. When the system islands, any power the utility provides must be picked up by the distributed generators. However, stand-alone generators have an inverse relationship between frequency and power, so an increase in the load power decreases the generator frequency. Since it is desirable to maintain the system frequency at 60Hz, some form of regulation must occur to restore the frequency to 60Hz. In this microgrid system, the RTAC is used to shed the load. Disconnecting load from the system decreases the power output needed from the synchronous generators and increases the frequency. To accomplish load shedding, a program running on the RTAC monitors the frequency data stored in the SEL-700G. The RTAC program is written in Structured Text and provides a simple way to automate key functions in the microgrid system. RTAC programs are separated into two windows: program and logic. Figure 14 shows the program window where the load shed variables and various other measurement variables are defined. The measurement variables are used to monitor various system values and confirm that the system is operating properly.

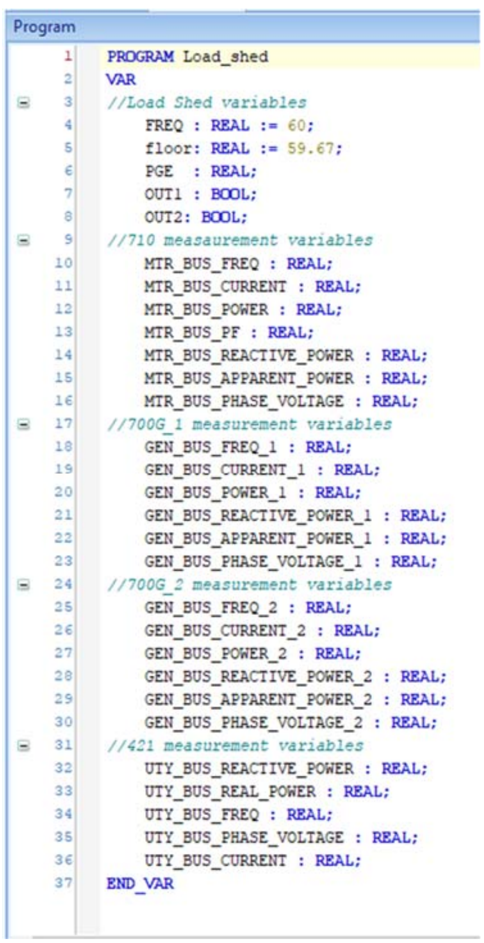

Figure 14: RTAC Program Variable Declaration

Figure 15 through Figure 17 show the logic window of the RTAC program. Figure 15 shows the variable assignments for both the load shedding and measurement variables. All real type variables are instantaneous system values measured by the corresponding relay, while boolean type variables are used to trigger changes in the output contacts of the relays. Figure 16 and Figure 17 show multiple if statements that are used to dictate load shedding. If the SEL-700G frequency is below 59.67Hz, then the RTAC sends a signal to the SEL-311L to trip the circuit breaker connecting one of the static 333 ohm loads to the system. To transmit the signal, the RTAC toggles a remote bit in the SEL-311L corresponding to its output contact connected to the 333 ohm static load circuit breaker.

Program

RTAC Automation

```
//Load Shed variable initiliazation
FREQ := SEL_700G_1_SEL.FM_INST_FREQS.instMAg;
PGE  := SEL_421_1_SEL.FM_INST_P_WATTS.instMag;
SEL_311L_2_SEL.FO_RB_RB2.operPulse.pulseConfig.onDur := 500;
//Motor Bus Measurement Data
MTR_BUS_FREQ := SEL_710_1_SEL.FM_INST_FREQ.instMag;
MTR_BUS_CURRENT := SEL_710_1_SEL.FM_INST_IA.instMag;
MTR_BUS_POWER := SEL_710_1_SEL.FM_INST_P.instMag;
MTR_BUS_PF := SEL_710_1_SEL.FM_INST_PF.instMag;
MTR_BUS_REACTIVE_POWER := SEL_710_1_SEL.FM_INST_Q.instMag;
MTR_BUS_APPARENT_POWER := SEL_710_1_SEL.FM_INST_S.instMag;
MTR_BUS_PHASE_VOLTAGE := SEL_710_1_SEL.FM_INST_VA.instMag;
//Generator 1 Bus Measurement Data
GEN_BUS_FREQ_1 := SEL_700G_1_SEL.FM_INST_FREQX.instMag;
GEN_BUS_CURRENT_1 := SEL_700G_1_SEL.FM_INST_IAX.instMag;
GEN_BUS_POWER_1 := SEL_700G_1_SEL.FM_INST_P3X.instMag;
GEN_BUS_REACTIVE_POWER_1 := SEL_700G_1_SEL.FM_INST_Q3X.instMag;
GEN_BUS_APPARENT_POWER_1 := SEL_700G_1_SEL.FM_INST_S3X.instMag;
GEN_BUS_PHASE_VOLTAGE_1 := SEL_700G_1_SEL.FM_INST_VAX.instMag;
//Generator 2 Bus Measurement Data
GEN_BUS_FREQ_2 := SEL_700G_2_SEL.FM_INST_FREQX.instMag;
GEN_BUS_CURRENT_2 := SEL_700G_2_SEL.FM_INST_IAX.instMag;
GEN_BUS_POWER_2 := SEL_700G_2_SEL.FM_INST_P3X.instMag;
GEN_BUS_REACTIVE_POWER_2 := SEL_700G_2_SEL.FM_INST_Q3X.instMag;
GEN_BUS_APPARENT_POWER_2 := SEL_700G_2_SEL.FM_INST_S3X.instMag;
GEN_BUS_PHASE_VOLTAGE_2 := SEL_700G_2_SEL.FM_INST_VAX.instMag;
//Utility Bus Measurement Data
UTY_BUS_REACTIVE_POWER := SEL_421_1_SEL.FM_INST_Q_VARS.instMag;
UTY_BUS_REAL_POWER := SEL_421_1_SEL.FM_INST_P_WATTS.instMag;
UTY_BUS_FREQ := SEL_421_1_SEL.FM_INST_FREQ.instMag;
UTY_BUS_PHASE_VOLTAGE := SEL_421_1_SEL.FM_INST_VA.instCVal.mag;
UTY_BUS_CURRENT := SEL_421_1_SEL.FM_INST_IA1.instCVal.mag;
```

Figure 15: RTAC Program Code - 1/3

```
UTY_BUS_CURRENT := SEL_421_1_SEL.FM_INST_IA1.instCVal.mag;

IF (FREQ < floor) THEN //(Shed Load)
    SEL_311L_2_SEL.FO_RB_RB1.operClear.ctlVal := FALSE;
    SEL_311L_2_SEL.FO_RB_RB1.operSet.ctlVal := TRUE;
    OUT1 := 1;
    IF (PGE < 80) THEN //(Group 1 Settings)
        SEL_710_1_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; //Set RB01 for 710 to FALSE
        SEL_710_1_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
        SEL_311L_2_SEL.FO_RB_RB3.operSet.ctlVal := FALSE; //Set RB3 for 311L-2 to FALSE
        SEL_311L_2_SEL.FO_RB_RB3.operClear.ctlVal := TRUE;
        SEL_700G_1_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; // Set RB01 for 700G-1 to FALSE
        SEL_700G_1_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
        SEL_700G_2_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; // Set RB01 for 700G-2 to FALSE
        SEL_700G_2_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
    END_IF
END_IF

IF (PGE > 80) THEN //(Reconnect Load & Group 2 settings)
    SEL_311L_2_SEL.FO_RB_RB2.operSet.ctlVal := FALSE;
    SEL_311L_2_SEL.FO_RB_RB2.operClear.ctlVal := TRUE;
    SEL_311L_2_SEL.FO_RB_RB2.operPulse.ctlVal := TRUE;
    OUT2 := 0;
    SEL_710_1_SEL.FO_RB_RB1.operSet.ctlVal := TRUE; //Set RB01 for 710 to TRUE
    SEL_710_1_SEL.FO_RB_RB1.operClear.ctlVal := FALSE;
    SEL_311L_2_SEL.FO_RB_RB3.operSet.ctlVal := TRUE; //Set RB3 for 311L-2 to TRUE
    SEL_311L_2_SEL.FO_RB_RB3.operClear.ctlVal := FALSE;
    SEL_700G_1_SEL.FO_RB_RB1.operSet.ctlVal := TRUE; // Set RB01 for 700G-1 to TRUE
    SEL_700G_1_SEL.FO_RB_RB1.operClear.ctlVal := FALSE;
    SEL_700G_2_SEL.FO_RB_RB1.operSet.ctlVal := TRUE; // Set RB01 for 700G-2 to TRUE
    SEL_700G_2_SEL.FO_RB_RB1.operClear.ctlVal := FALSE;
END_IF
```

Figure 16: RTAC Program Code - 2/3

```
IF (FREQ > floor) THEN //(De-assert Trip Equation)
    SEL_311L_2_SEL.FO_RB_RB1.operSet.ctlVal := FALSE;
    SEL_311L_2_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
    OUT1 := 0;

    IF (PGE < 80) THEN //(Shed Load & Group 1 settings)
        SEL_311L_2_SEL.FO_RB_RB2.operClear.ctlVal := FALSE;
        SEL_311L_2_SEL.FO_RB_RB2.operSet.ctlVal := TRUE;
        SEL_311L_2_SEL.FO_RB_RB2.operPulse.ctlVal := TRUE;
        OUT2 := 1;
        SEL_710_1_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; //Set RB01 for 710 to FALSE
        SEL_710_1_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
        SEL_311L_2_SEL.FO_RB_RB3.operSet.ctlVal := FALSE; //Set RB3 for 311L-2 to FALSE
        SEL_311L_2_SEL.FO_RB_RB3.operClear.ctlVal := TRUE;
        SEL_700G_1_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; // Set RB01 for 700G-1 to FALSE
        SEL_700G_1_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
        SEL_700G_2_SEL.FO_RB_RB1.operSet.ctlVal := FALSE; // Set RB01 for 700G-2 to FALSE
        SEL_700G_2_SEL.FO_RB_RB1.operClear.ctlVal := TRUE;
    END_IF
END_IF
```

Figure 17: RTAC Program Code - 3/3

The load shedding process is summarized in a signal flow diagram in Figure 18. The red arrows refer to signals only involved in the load shedding process, while the purple arrows refer to signals involved in both the group switching and load shedding processes.

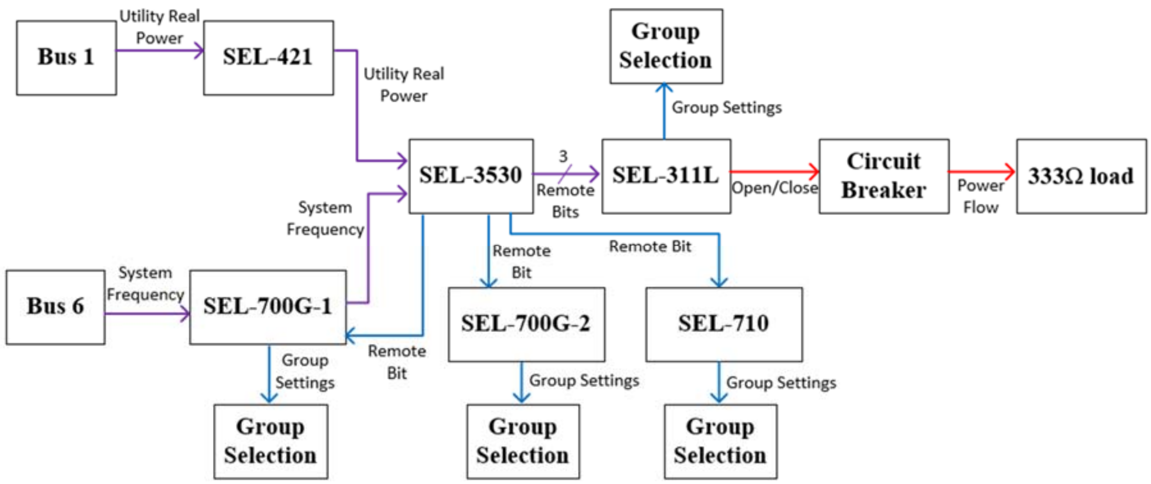

Figure 18: RTAC Automation Signal Flow Diagram

Since synchronous generators supply much less fault current than an infinite bus utility, the overcurrent settings are adjusted from those of reference [15] to reflect the lower fault current magnitudes. Different overcurrent settings are used depending on the microgrid system configuration to guarantee maximum protection. SEL relays utilize groups to organize different protection settings so that multiple settings can be stored in the relay at one time. The active group determines which protection settings are used by the relay. In addition to the overcurrent settings, all other relevant settings, such as distance protection, are set according to the system configuration. The blue arrows in Figure 18 show the signals involved only in group switching, while the purple lines show signals involved in both load shedding and group switching. In this system, Group 2 contains settings for the utility-connected system while Group 1 contains settings for the islanded system. Figure 19 shows an example of where the groups are located in the SEL AcSELerator software used to program the relays. Table 8 shows the active groups for each relay depending on the configuration. The relays that don’t change groups are considered inactive while the system is in an island mode since there is no power flow through the relays. The SEL-587 doesn’t have the capability to use different protection groups and a value is not shown for it. For a full list of relay settings, refer to the Appendices.

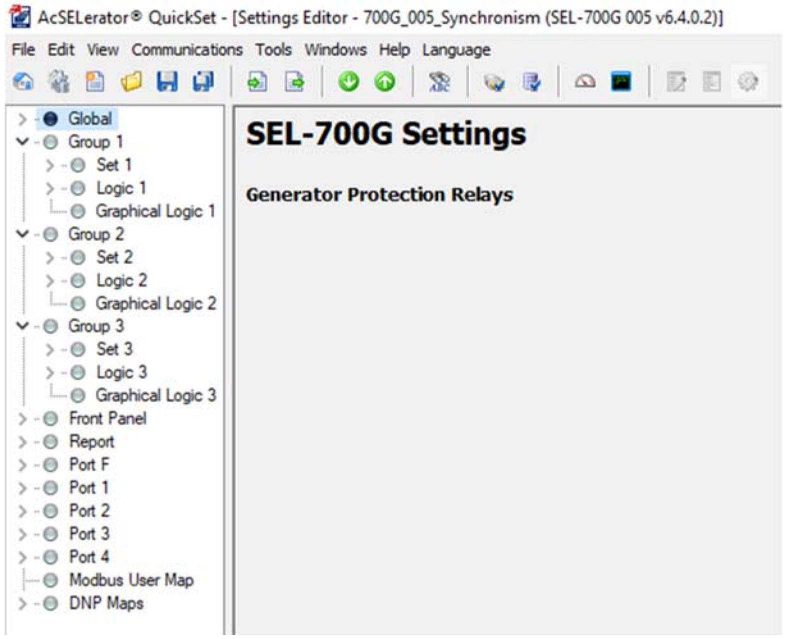

Figure 19: Groups in SEL AcSELerator software

The relay groups are automatically changed depending on the system configuration using the RTAC. As shown in Figure 15 through Figure 17, a program running on the RTAC collects real power data from the SEL-421, using this as an indicator of the status of the utility. If the power is greater than 80 watts, the utility is considered on. Conversely, if the power is less than 80 watts, the utility is considered off. The threshold of 80 watts is used as it corresponds to the magnetization current that both power transformers draw. The utility voltage must be present at bus six, thus requiring the non-load circuit breakers between the utility and bus six to be closed, causing the magnetizing current to flow. During generator synchronization of the system, it is also required that all loads are turned off. The RTAC program must therefore ignore the transformer magnetization power consumption and keep the 333Ω circuit breaker open during the synchronization process. The other 333Ω load is turned on manually after the system is synchronized.

Table 8: Relay Group Selection

Configuration	Relay	Active Group
Utility Connected	SEL-387E	2
	SEL-311L (line 1)	2
	SEL-710	2

Configuration	Relay	Active Group
	SEL-311L (line 2)	2
	SEL-587	N/A
	SEL-700G (generator 1)	2
	SEL-700G (generator 2)	2
	SEL-421	2
Islanded	SEL-387E	2
	SEL-311L (line 1)	2
	SEL-710	1
	SEL-311L (line 2)	1
	SEL-587	N/A
	SEL-700G (generator 1)	1
	SEL-700G (generator 2)	1
	SEL-421	2

Once the system is islanded, it needs to synchronize to the utility without interrupting any load. SEL-421 synchronism-check element is used to facilitate and automate this process. Like the generator synchronization procedure, the relay checks for the phase difference and voltage magnitude difference before synchronizing the utility and the microgrid system. The signal flow diagram for this process is shown in Figure 20. Specific settings for the SEL-421 synchronism-check element can be found in Appendix B: SEL 421 Settings.

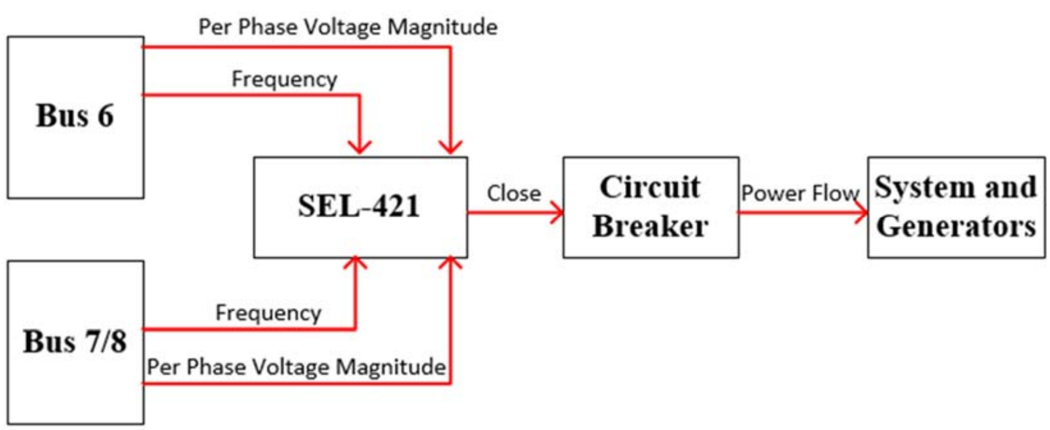

Figure 20: SEL-421 Synchronization Signal Flow Diagram

5.4 Experiments

Each proposed experiment requires students to use a relay to detect either fault conditions or proper synchronism conditions in a three-phase circuit, and trip or close the appropriate circuit breaker. Within a three-hour lab period, students program the relay, build the required circuit, and collect all requested data. Background information and relevant equations are provided before starting the experiment. Additionally, calculations to be completed before the experiment are included, as well as discussion questions to be answered after completion. As part of each experiment, students analyze the oscillogram data read from the relay and overlay it with the digital signals triggered by the specific event being studied in the experiment. Student learning outcomes for each proposed experiment are summarized in Table 9. For the full experiments, refer to Appendix H through Appendix J.

One experiment teaches the concept of the synchronism-check element using the SEL-700G. A circuit breaker that is initially open connects the generator to the utility. Voltage from the utility is distributed through the system and is present on the output of the circuit breaker, while the generator voltage is present on the circuit breaker input. Students set multiple parameters including maximum slip, voltage window, and percent voltage difference to instruct the relay when to close the circuit. Students must measure physical voltage quantities at the open circuit breaker bus and compare to theoretical values. Once settings are determined, students must adjust generator frequency and voltage to match the utility and trigger safe circuit breaker closure.

Like the first experiment, a second experiment uses the SEL-421 to teach students the concept of the synchronism-check element. While the synchronism-check settings are identical to that of the SEL-700G experiment, the SEL-421 requires students to interact with a more complex interface when programming relays. While the elements are the same, students gain exposure to using different relays to accomplish the same task. As in the previous experiment, students set multiple parameters including maximum slip, voltage window, and percent voltage difference to instruct the relay when to close the circuit. Students must again measure physical voltage quantities at the open circuit breaker bus and compare to theoretical values. Once settings are determined, students adjust generator frequency and voltage to match the utility and trigger safe circuit breaker closure.

Using the SEL-710, a third experiment builds on an experiment proposed in [15]. Students use the SEL-3530 Real Time Automation Controller (RTAC) to read real time system values during islanding. Students write a basic RTAC program that reads real time data from the SEL-710. Students learn to interface the RTAC with SEL relays using a serial connection and to write structured text to read data from SEL relays.

Table 9: Experiment Learning Outcomes

Lab	Device(s) involved	Expected Learning Outcomes
1	SEL-700G	• Identify requirements for successful synchronization • Implement synchronism-check element • Interpret synchronization report and develop recommendations to improve synchronism results
2	SEL-421	• Identify requirements for successful synchronization • Implement synchronism-check element • Interpret synchronization report and develop recommendations to improve synchronism results
3	SEL-3530 (RTAC), SEL 710	• Identify correct communication parameters to interface relays and RTAC • Implement a real time data acquisition system • Compare relay acquired values with individually measured values

Chapter 6: SEL-700G Hardware Test and Results

To test synchronism, the utility voltage is supplied through the system to bus six, while the generator voltage is applied at bus seven. The circuit breaker between bus six and seven remains open until synchronism conditions are met. The field current of the generator is adjusted to bring the terminal voltage to approximately 108V line-to-neutral, while the field current of the DC motor is adjusted to bring the generator frequency to a value between 60.01Hz and 60.4Hz. Once synchronism conditions are met, the SEL-700G triggers the circuit breaker between bus six and bus seven to close. Table 10 summarizes the synchronization results. To synchronize the second generator, the same process is applied between bus six and bus eight.

The system voltage at bus 6 is approximately 108V before synchronization due to voltage drops caused by the transformer magnetization current, leading to the same voltage value being chosen on the generator side. The frequency range is selected so that the generator is always operating at a slightly higher frequency than the 60Hz system. It also provides a wide enough frequency range for synchronization to occur without being too large to cause large power flow upon circuit breaker closure. All frequency parameters are within the specified regions and the percent difference between the generator and system voltage is very small. A comparison between the slip compensated phase angle difference and uncompensated phase angle difference show that the inclusion of the circuit breaker closing time decreases the phase angle difference. Comparing the breaker close time to the programmed time of 35ms, it is apparent the experimental time is much higher. However, the average time of 40.66ms is much closer and justifies the 35ms setting. The breaker closing time is well within the required 3 seconds. For specific settings, refer to Appendix A: SEL-700G Settings.

Table 10: Synchronism-Check Report

Parameter	**Value**
Slip Frequency	.39Hz
Generator Frequency	60.36Hz
System Frequency	59.98Hz

Parameter	Value
Voltage Difference	1.97%
Generator Voltage	.11kV phase
System Voltage	.11kV phase
Uncompensated Phase Angle Difference	-5.86 degrees
Slip Compensated Phase Angle Difference	-2.24 degrees
Breaker Close Time	62.58ms
Average Breaker Close Time	40.66ms
Close Operations	111

Each synchronous generator is equipped with a switch that changes it from an induction machine to a synchronous machine. To simulate loss of field, the switch is changed from synchronous to induction while the generator is running. As shown in Figure 21, the loss of field pickup asserts before the associated trip variable asserts approximately 30 cycles later. Specific settings can be reviewed in Appendix A: SEL-700G Settings. These settings adequately protect the generators from loss of excitation.

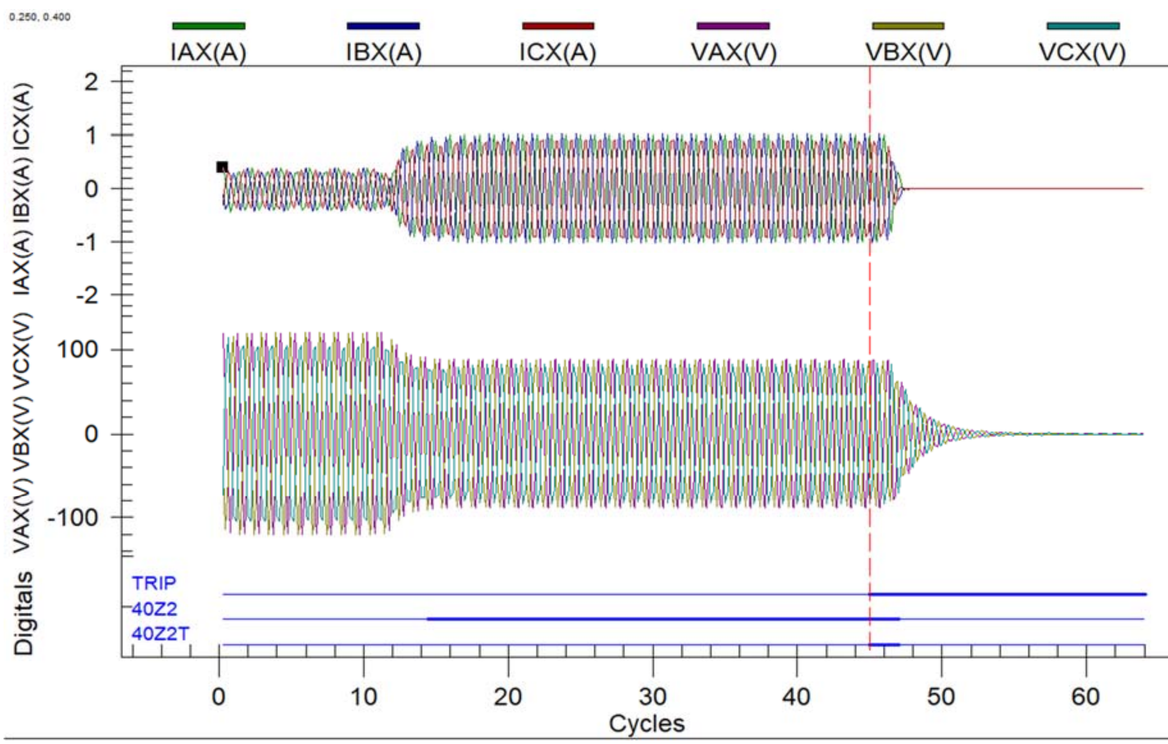

Figure 21: Loss of Excitation Oscillogram

To test the under and over frequency settings, the field current of the DC motor is adjusted. Changing the DC motor field current while the generators are disconnected from the utility changes their frequency. Figure 22 shows the under frequency trip variable asserting and tripping the circuit breaker connecting the generator to the system. The element de-asserts shortly after the circuit breaker opens since the generator frequency increases due to the loss of output power. Because there is a three second delay associated with the frequency elements, the SEL-700G does not capture or display the time between the pickup and trip element asserting.

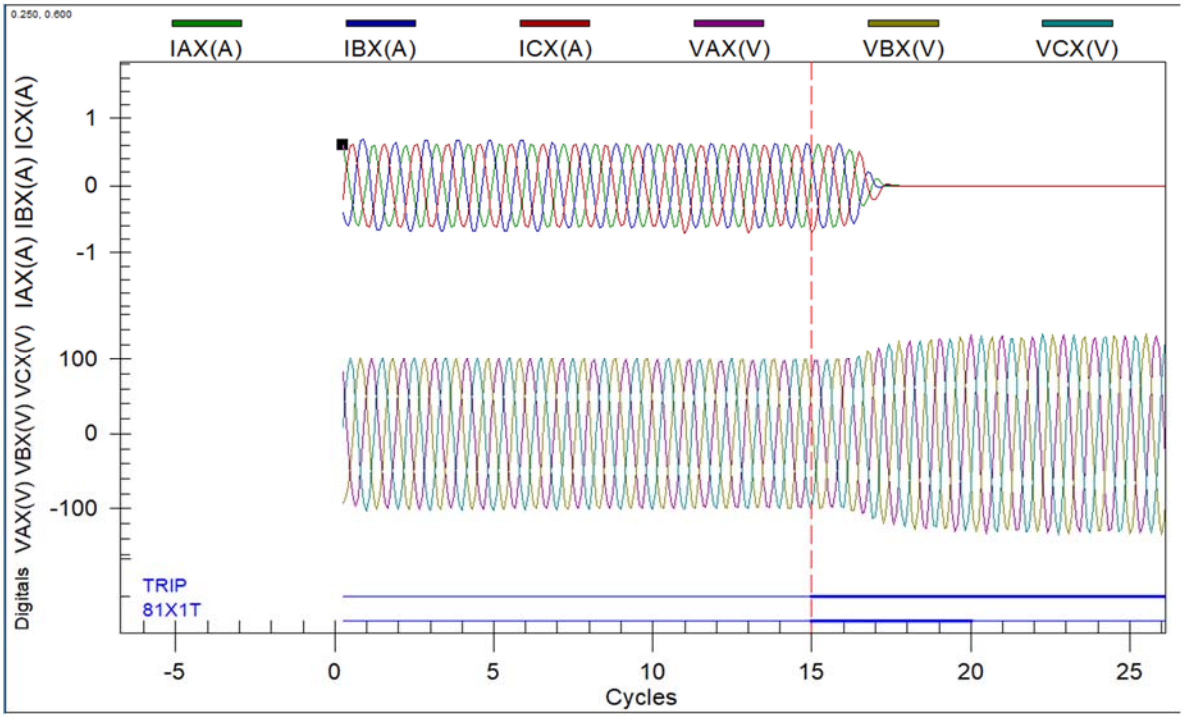

Figure 22: Under Frequency Oscillogram

Figure 23 shows the over frequency trip variable asserting and tripping the circuit breaker connecting the generator to the system. The element stays asserted after the circuit breaker opens since the generator frequency increases due to the decrease in output power. Because there is a three second delay associated with the frequency elements, the SEL-700G does not capture or display the time between the pickup and trip element asserting. For specific settings related to the frequency element, refer to Appendix A: SEL-700G Settings.

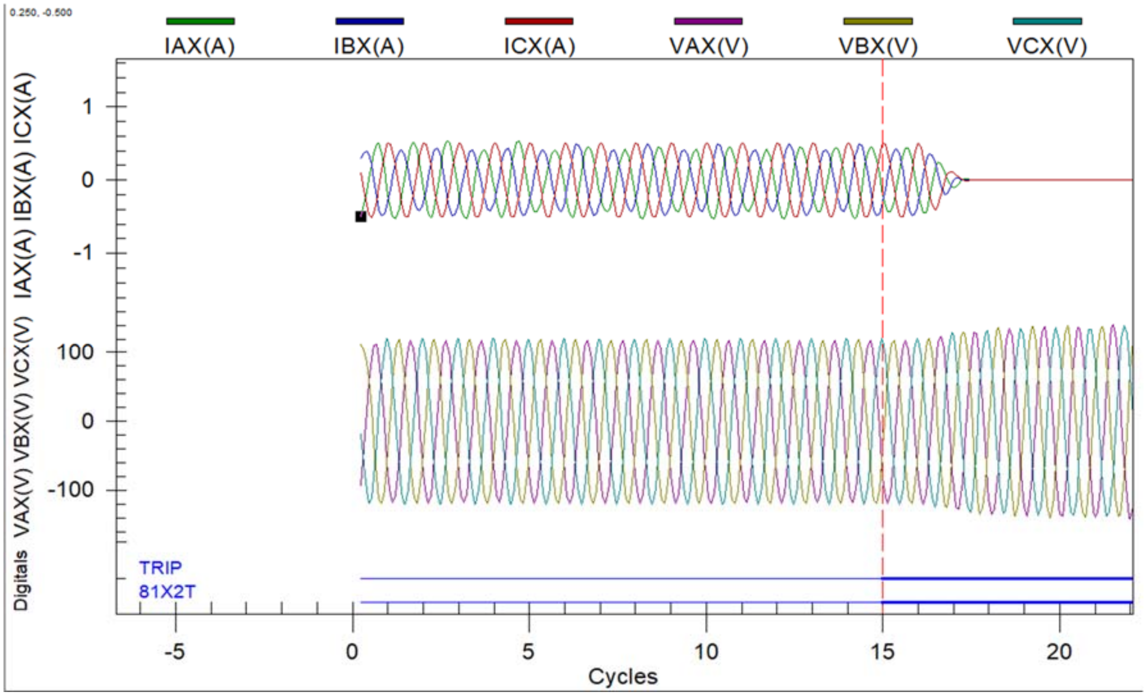

Figure 23: Over Frequency Oscillogram

Each synchronous generator is a 250W machine that is powered by a DC motor. To simulate a loss of prime mover condition, the DC motor is turned off while the generator is running. Figure 24 shows the resulting oscillogram. The SEL-700G asserts the power element pickup, and the associated trip variable asserts approximately five cycles later. Refer to Appendix A: SEL-700G Settings for specific pickup and delay values. These settings ensure that the generator is protected from motoring for both the loss of the prime mover and the general reverse power conditions.

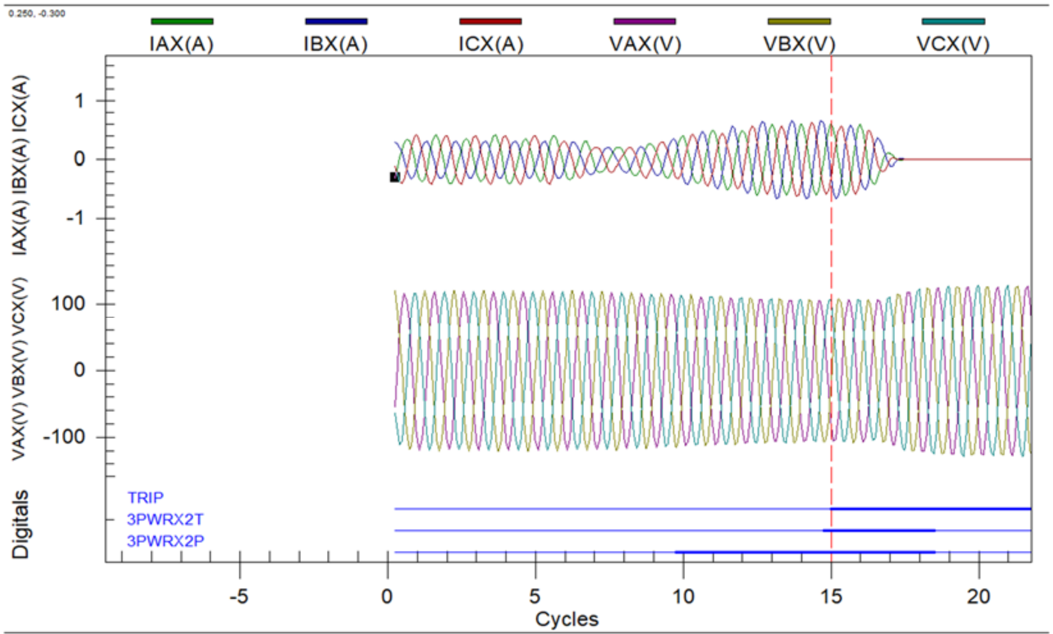

Figure 24: Loss of Prime Mover and Reverse Power Oscillogram

Chapter 7: Microgrid System Hardware Tests and Results

Because the real power output of the generators is fully controllable when the utility is connected to the system, a set operating point is determined. The real power of the generators is regulated at 200W and the terminal voltage is regulated at 208V. To examine the transient, unregulated conditions, data is collected before regulation occurs. Generator power and terminal voltage are both regulated manually. The presented data examines the normal operating parameters of the system, the system's frequency stability during islanding, and the effect of power factor correction on the generators. Values are recorded at three locations: the SEL-710, bus six, and the infinite bus. Wattmeters are connected at bus 6 and the infinite bus to measure system values, while the SEL-710 provides a convenient way to measure the effect of power factor correction as it directly measures the source current contribution to the motor.

Table 11 shows the key values of the microgrid at various locations while operating under normal load conditions and connected to the utility. All static loads are active, and the motor is running under no load with power factor correction. The total real power supplied by the generator and utility is slightly less than 400W, while the total reactive power is approximately 185VAR.

Table 11: Microgrid Standard Operating Values

Location	**Real Power [W]**	**Current [A]**	**Voltage [V]**	**Reactive Power [VAR]**	**Apparent Power [VA]**	**Power Factor**	**Frequency [Hz]**
Generator	200	.6	208	130	250	.799	60
Utility	184.9	.562	206.4	58.5	232.5	.797	60
SEL-710	76.9	.268	187	40	87	.88	60

When the capacitor bank is inactive and the motor is running, the total reactive power supplied by the sources increased to 440VAR. The generator and utility contribution to the motor current also increases by .792A. Most importantly, the power factor of both sources decreases significantly when the capacitor bank is inactive. Table 12 summarizes the system operating values with no power factor correction and all loads running, while Table 13 shows a comparison of key system values with and without power factor correction.

Table 12: Microgrid Operating Data - No Power Factor Correction

Location	Real Power [W]	Current [A]	Voltage [V]	Reactive Power [VAR]	Apparent Power [VA]	Power Factor	Frequency [Hz]
Generator	200	.814	208	214	337	.593	60
Utility	161	.774	205.7	226	318	.502	60
SEL-710	65.7	1.06	173.2	308.3	315.2	.208	60

Table 13: Effect of Power Factor Correction

Location	Without Pf Correction	With Pf Correction
Generator Power Factor	.593	.799
Utility Power Factor	.502	.797
SEL-710 Power Factor	.208	.88
Total Source Reactive Power	440VAR	189VAR
Total Source Current Feeding Motor	1.06A	.268A

To investigate the frequency stability of the microgrid during the islanding process, multiple points are examined to capture both transient and steady state conditions. To island the system, a switch connecting the utility to the system is opened. Table 14 shows the system operating data immediately after islanding and before load shedding. The generator frequency drops .667Hz and the power increases by 104W. Table 15 shows the operating data after the load is shed but before voltage and power regulation occurs. It indicates that the frequency increases .5Hz and the power output of the generators decreases. Once regulation of generator voltage, power, and frequency occurs, the microgrid is operating at acceptable values as shown in Table 16. The islanding process allows a constant power supply to the high priority induction motor, while shedding lower priority static load.

Table 14: Transition Microgrid Data Immediately After Islanding – Before Load Shedding

Location	Real Power [W]	Current [A]	Voltage [V]	Reactive Power [VAR]	Apparent Power [VA]	Power Factor	Frequency [Hz]
Generator	304	.978	194	98	380	.8	59.33
Utility	0	0	0	0	0	0	0
SEL-710	52.28	.190	162.1	13.53	54.01	.968	59.33

Table 15: Microgrid Data Immediately After Islanding - After Load Shedding

Location	Real Power [W]	Current [A]	Voltage [V]	Reactive Power [VAR]	Apparent Power [VA]	Power Factor	Frequency [Hz]
Generator	235	.759	200.3	161	303	.772	59.83
Utility	0	0	0	0	0	0	0
SEL-710	61.88	.219	174	18.47	64.5	.958	59.83

Table 16: Islanded Microgrid Data

Location	Real Power [W]	Current [A]	Voltage [V]	Reactive Power [VAR]	Apparent Power [VA]	Power Factor	Frequency [Hz]
Generator	254	.792	208	171	330	.769	59.9
Utility	0	0	0	0	0	0	0
SEL-710	69.76	.245	180	28.08	75.2	.927	59.9

To re-synchronize the system, the circuit breaker connecting the utility to the system is opened, and the utility switch is closed. The SEL-421 checks for proper synchronization conditions between the utility and system and closes the circuit breaker. Table 17 shows the resulting data after the utility is synchronized and before the system is regulated. At this point, the utility is primarily providing magnetization current to the transformer as can be noted from the low power output and small power factor. The load that is shed during islanding has not been reconnected to the system yet as the RTAC still considers the utility to be off due to its low power output. To reset the system to normal operating conditions, the generator output power and voltage are reduced to 200W and 208V. Full system values are shown in Table 18. These values are almost identical to the values shown in Table 11 since the system has been restored to the same operating point where it started.

Table 17: Re-synchronized System Data - Before Regulation

Location	**Real Power [W]**	**Current [A]**	**Voltage [V]**	**Reactive Power [VAR]**	**Apparent Power [VA]**	**Power Factor**
Generator	238	.670	216.7	66.4	290	.814
Utility	55.6	.296	206.6	95.9	123.5	.458
SEL-710	86.78	.312	194	58.7	104.75	.828

Table 18: Re-synchronized System Data - After Regulation

Location	**Real Power [W]**	**Current [A]**	**Voltage [V]**	**Reactive Power [VAR]**	**Apparent Power [VA]**	**Power Factor**
Generator	200	.603	208	129.8	253	.802
Utility	180.7	.550	205.8	56.1	225.1	.798
Motor	75.84	.271	187.4	42.82	87.1	.87

During the islanding process, pertinent relays change protection groups as outlined in Table 8. This is done by using remote bits in the relay settings group selection and having the RTAC change the remote bit values depending on the state of the system as shown in Figure 15 through Figure 17.

Chapter 8: Conclusion

8.1 Difficulties Encountered

Many challenges encountered during this project occurred due to basic misunderstandings of equipment operation. When implementing the loss of excitation element on the SEL-700G, the torque control element was set to deactivate if a loss of voltage occurred. While not known at the time, if a torque control element is de-asserted, the element it controls is deactivated. Since the synchronous generator loss of excitation condition decreased the voltage by greater than 25% (the threshold for loss of voltage to be recognized in the SEL-700G), the torque control element de-asserted. To solve this problem, the torque control element was set to a constant value of “one”, preventing it from disabling the loss of excitation element.

Another example of a misunderstanding of basic equipment operation occurred when programming the RTAC. The RTAC is interfaced with SEL relays using a direct transparent connection. When a user logs onto a relay through the RTAC, this connection type disables any communication between the relay and the RTAC that is initiated by an RTAC program. The user that is logged onto the relay takes precedence over the RTAC program, preventing the program from requesting data from the relay. This caused many intermittent issues in the system as it was common to log onto the relays to send updated settings files while the RTAC program was running. Because of a lack of understanding related to direct transparent connections, the RTAC program often stopped working since a user was logged onto the relays. After the problem was identified, it was easily remedied by logging off of the relays immediately after sending a settings file.

The biggest problem in this project was caused by the delta-delta connected transformer used in [15]. When unloaded, the output of the delta-delta connected transformer had unbalanced line to ground voltages. When initially energizing the system, the output of the delta-delta connected transformer is connected to the input of an open circuit breaker. The output of that circuit breaker is connected to a wye-grounded synchronous generator. To close the circuit breaker and synchronize the generator to the system, the SEL-700G uses its synchronism-check element. The synchronism-check element can compare either line to line voltages or line to neutral voltages to ensure proper synchronization parameters are met. However, to use the line to line comparison, delta connected potential transformers must be used. Since this microgrid system does not utilize potential transformers (PT) and relay PT inputs are directly connected to the system, the relays must be set to use a wye configuration. This forces the synchronism-check element to compare line to neutral voltages during synchronization. Since the delta-delta transformer has unbalanced line to ground voltages and the generator is wye-grounded, this makes it impossible to have equal line to ground voltages between each individual transformer phase and the corresponding generator phase prior to synchronization. To fix this issue, the delta-delta transformer was changed to a wye-wye configuration. This resulted in balanced phase to ground voltages at both the input and output of the transformer and allowed for proper generator synchronization.

8.2 Recommended Future Work

While the laboratory-scale microgrid system presented in this work is an adequate model of an industry standard microgrid, additions to the system could improve its accuracy. To expand the system, different types of generation and storage must be added. A photo-voltaic system models the increasing number of renewable energy sources used in microgrids and can be coupled with a battery storage system to offset over-generation. Expanding the system also requires adding more loads. Loading the motor and adding loads at different buses in the system is one example of this. Placing a variable frequency drive on the motor creates harmonics and can more accurately represent the noise that is present on microgrid systems. Additionally, directional protection on the transmission lines can provide an enhanced and more reliable protection scheme.

8.3 Analysis of Requirements

The project requirements specified in Table 1 describe the required operation of the microgrid system. Industry Standard SEL relays were used to protect and automate the system at the generator, utility, and load buses. The SEL-700G protects the generators from under/over frequency, reverse power, loss of excitation conditions, and enables synchronization within 1 second of command issuance via the synchronism-check element. The SEL-421 enables synchronization under 1 second of command issuance at the utility bus, and SEL-710 enables automated power factor correction. The RTAC regulates the system frequency within ±0.5% of 60Hz through load shedding. Each relay has a common timing reference that ensures all event reports have unified time stamps. The experiments teach students how to use the synchronism-check element in both the SEL-700G and the SEL-421. The experiments also teach students how to acquire data from relays using the RTAC.

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Appendix A: SEL-700G Settings

Global			
			Top
Setting	**Description**	**Range**	**Value**
FNOM	Rated Frequency	Select: 50, 60	60
DATE_F	Date Format	Select: MDY, YMD, DMY	MDY
FAULT	Fault Condition	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIP
EMP	Messenger Points Enable	Range = 1 to 32, N	N
TGR	Group Change Delay	Range = 0 to 400	1
SS1	Select Settings Group1	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT RB01
SS2	Select Settings Group2	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	RB01
SS3	Select Settings Group3	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
EPMU	Enable Synchronized Phasor Measurement	Select: Y, N	N
IRIGC	IRIG-B Control Bits Definition	Select: NONE, C37.118	NONE
UTC_OFF	Offset From UTC	Range = -24.00 to 24.00	0.00
DST_BEGM	Month To Begin DST	Range = 1 to 12, OFF	OFF
52ABF	52A Interlock in BF Logic	Select: Y, N	N
BFDX	Breaker X Failure Delay	Range = 0.00 to 2.00	0.50
BFIX	Breaker X Failure Initiate	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	R_TRIG TRIPX
IN101D	IN101 Debounce	Range = 0 to 65000, AC	10
IN102D	IN102 Debounce	Range = 0 to 65000, AC	10
EBMONX	Enable Breaker X Monitor	Select: Y, N	Y
BKMONX	Control Breaker Monitor	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIPX
COSP1X	Close/Open Operations Set Point 1-max	Range = 0 to 65000	10000
COSP2X	Close/Open Operations Set Point 2-mid	Range = 0 to 65000	150
COSP3X	Close/Open Operations Set Point 3-min	Range = 0 to 65000	12
KASP1X	kA(pri) Interrupted Set Point 1-min	Range = 0.00 to 999.00	1.20
KASP2X	kA(pri) Interrupted Set Point 2-mid	Range = 0.00 to 999.00	8.00
KASP3X	kA(pri) Interrupted Set Point 3-max	Range = 0.00 to 999.00	20.00

Global			Top
Setting	**Description**	**Range**	**Value**
RSTTRGT	Reset Targets	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
RSTENRGY	Reset Energy	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
RSTMXMN	Reset Max/Min	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
RSTDEM	Reset Demand	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
RSTPKDEM	Reset Peak Demand	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
DSABLSET	Disable Settings	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
TIME_SRC	IRIG Time Source	Select: IRIG1, IRIG2	IRIG1
Global			Top

Group 1			Top
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier	Range = ASCII string with a maximum length of 16.	SEL-700G
TID	Terminal Identifier	Range = ASCII string with a maximum length of 16.	GEN 1 RELAY / GEN 2 RELAY
CTRN	Neutral CT Ratio	Range = 1 to 10000	1
PTRS	Synchronizing Voltage PT Ratio	Range = 1.00 to 10000.00	1.00
PTRN	Neutral PT Ratio	Range = 1.00 to 10000.00	1.00
CTRX	X Side Phase CT Ratio	Range = 1 to 10000	1
PTRX	X Side PT Ratio	Range = 1.00 to 10000.00	1.00
CTRY	Y Side Phase CT Ratio	Range = 1 to 10000	1
INOM	Nominal Generator Current	Range = 1.0 to 10.0	1.7
VNOM_X	X Side Nominal L-L Voltage	Range = 0.02 to 1000.00	0.21
PHROT	Phase Rotation	Select: ABC, ACB	ACB
X_CUR_IN	X Side Phase CT Location	Select: NEUT, TERM	TERM
DELTAY_X	X Side PT Connection	Select: DELTA, WYE	WYE
CTCONY	Y Side Phase CT Connection	Select: DELTA, WYE	WYE

E40	Enable Loss-of-Field Protection	Select: Y, N	Y
40Z1P	Zone 1 Mho Diameter	Range = 0.1 to 100.0, OFF	50.0
40XD1	Zone 1 Offset Reactance	Range = -50.0 to 0.0	-12.0
40Z1D	Zone 1 Pickup Time Delay	Range = 0.00 to 400.00	0.00
40Z2P	Zone 2 Mho Diameter	Range = 0.1 to 100.0, OFF	100.0
40XD2	Zone 2 Offset Reactance	Range = -50.0 to 50.0	-12.0
40Z2D	Zone 2 Pickup Time Delay	Range = 0.00 to 400.00	0.50
40ZTC	40Z Element Torque Control	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	1
EPWRX	Enable Three Phase Power Elements	Select: 1-4, N	2
3PWRX1P	Three Phase Power Element Pickup	Range = 1.0 to 6500.0, OFF	10.0
PWRX1T	Power Element Type	Select: +WATTS, -WATTS, +VARS, -VARS	-WATTS
PWRX1D	Power Element Time Delay	Range = 0.00 to 240.00	0.25
3PWRX2P	Three Phase Power Element Pickup	Range = 1.0 to 6500.0, OFF	25.0
PWRX2T	Power Element Type	Select: +WATTS, -WATTS, +VARS, -VARS	-WATTS
PWRX2D	Power Element Time Delay	Range = 0.00 to 240.00	0.08
E81X	Enable Frequency Elements	Select: 1-6, N	2
81XTC	81 Element Torque Control	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	1
81X1TP	Frequency Pickup Level 1	Range = 15.00 to 70.00, OFF	59.58
81X1TD	Frequency Delay 1	Range = 0.00 to 240.00	3.00
81X2TP	Frequency Pickup Level 2	Range = 15.00 to 70.00, OFF	60.43
81X2TD	Frequency Delay 2	Range = 0.00 to 240.00	3.00
E81RX	Enable Rate-of-Change of Frequency Elements	Select: 1-4, N	N
E81ACC	Number of Frequency Accumulator Bands	Select: 1-6, N	N
LOPBLKX	X-Side Loss of Potential Block Condition Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
E25X	Synchronism Check Enable	Select: Y, N	Y
25VLOX	Voltage Window - Low Threshold	Range = 0.00 to 300.00	104.00

25VHIX	Voltage Window - High Threshold	Range = 0.00 to 300.00	112.00
25VDIFX	Maximum Voltage Difference	Range = 1.0 to 15.0, OFF	5.0
25RCFX	Voltage Ratio Correction Factor	Range = 0.500 to 2.000	1.000
GENV+	Generator Voltage High Required	Select: Y, N	N
25SLO	Minimum Slip Frequency	Range = -1.00 to 0.99	0.00
25SHI	Maximum Slip Frequency	Range = -0.99 to 1.00	0.43
25ANG1X	Maximum Angle 1	Range = 0 to 80	15
25ANG2X	Maximum Angle 2	Range = 0 to 80	15
CANGLE	Target Close Angle	Range = -15 to 15	-3
SYNCPX	Synchronism Check Phase (VAX, VBX, VCX or deg lag VAX)	Select: 0, 30, 60, 90, 120, 150, 180, 210, 240, 270, 300, 330, VAX, VBX, VCX	VAX
TCLOSDX	Breaker Close Time for Angle Compensation	Range = 1 to 1000, OFF	35
CFANGLE	Close Fail Angle	Range = 3 to 120, OFF	OFF
BSYNCHX	Block Synchronism Check Elements	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	(NOT 3POX)
EAUTO	Enable Autosynchronism	Select: NONE, DIG	NONE
3POXD	Three-Pole Open Time Delay	Range = 0.00 to 1.00	0.00
TDURD	Minimum Trip Time	Range = 0.00 to 400.00	0.50
TR1	Trip 1 (Generator Field Breaker Trip) Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	SV06 OR SV07 OR SV08
TR2	Trip 2 (Prime Mover Trip) Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	SV06 OR SV07 OR LT06
TR3	Trip 3 (Generator Lockout Relay) Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	SV06 OR SV07
REMTRIP	Remote Trip	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
ULTR1	Unlatch Trip 1	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR1
ULTR2	Unlatch Trip 2	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR2
ULTR3	Unlatch Trip 3	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR3
CFDX	Close X Failure Time Delay	Range = 0.00 to 400.00	0.50

TRX	X-Side (Generator Main Circuit Breaker) Trip Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	3PWRX1T OR 3PWRX2T OR 40Z1T OR 40Z2T OR 81XT
ULTRX	Unlatch Trip X	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	3POX
52AX	Breaker X Status	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
CLX	Close X Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	25C
ULCLX	Unlatch Close X	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIPX
Group 1 Top			

Logic 1 Top			
Setting	**Description**	**Range**	**Value**
OUT101FS	OUT101 Fail-Safe	Select: Y, N	N
OUT101		Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	HALARM OR SALARM
OUT102FS	OUT102 Fail-Safe	Select: Y, N	Y
OUT102		Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIPX
OUT103FS	OUT103 Fail-Safe	Select: Y, N	Y
OUT103		Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT CLOSEX
Logic 1 Top			

Group 2			Top
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier	Range = ASCII string with a maximum length of 16.	SEL-700G
TID	Terminal Identifier	Range = ASCII string with a maximum length of 16.	GEN 1 RELAY / GEN 2 RELAY
CTRN	Neutral CT Ratio	Range = 1 to 10000	1
PTRS	Synchronizing Voltage PT Ratio	Range = 1.00 to 10000.00	1.00
PTRN	Neutral PT Ratio	Range = 1.00 to 10000.00	1.00
CTRX	X Side Phase CT Ratio	Range = 1 to 10000	1
PTRX	X Side PT Ratio	Range = 1.00 to 10000.00	1.00
CTRY	Y Side Phase CT Ratio	Range = 1 to 10000	1
INOM	Nominal Generator Current	Range = 1.0 to 10.0	1.7
VNOM_X	X Side Nominal L-L Voltage	Range = 0.02 to 1000.00	0.21
PHROT	Phase Rotation	Select: ABC, ACB	ACB
X_CUR_IN	X Side Phase CT Location	Select: NEUT, TERM	TERM
DELTAY_X	X Side PT Connection	Select: DELTA, WYE	WYE
CTCONY	Y Side Phase CT Connection	Select: DELTA, WYE	WYE
E40	Enable Loss-of-Field Protection	Select: Y, N	Y
40Z1P	Zone 1 Mho Diameter	Range = 0.1 to 100.0, OFF	50.0
40XD1	Zone 1 Offset Reactance	Range = -50.0 to 0.0	-12.0
40Z1D	Zone 1 Pickup Time Delay	Range = 0.00 to 400.00	0.00
40Z2P	Zone 2 Mho Diameter	Range = 0.1 to 100.0, OFF	100.0
40XD2	Zone 2 Offset Reactance	Range = -50.0 to 50.0	-12.0
40Z2D	Zone 2 Pickup Time Delay	Range = 0.00 to	0.50

Group 2			
			Top
Setting	**Description**	**Range**	**Value**
		400.00	
40ZTC	40Z Element Torque Control	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	1
EPWRX	Enable Three Phase Power Elements	Select: 1-4, N	2
3PWRX1P	Three Phase Power Element Pickup	Range = 1.0 to 6500.0, OFF	10.0
PWRX1T	Power Element Type	Select: +WATTS, -WATTS, +VARS, -VARS	-WATTS
PWRX1D	Power Element Time Delay	Range = 0.00 to 240.00	0.25
3PWRX2P	Three Phase Power Element Pickup	Range = 1.0 to 6500.0, OFF	25.0
PWRX2T	Power Element Type	Select: +WATTS, -WATTS, +VARS, -VARS	-WATTS
PWRX2D	Power Element Time Delay	Range = 0.00 to 240.00	0.08
E81X	Enable Frequency Elements	Select: 1-6, N	2
81XTC	81 Element Torque Control	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	1
81X1TP	Frequency Pickup Level 1	Range = 15.00 to 70.00, OFF	59.58
81X1TD	Frequency Delay 1	Range = 0.00 to 240.00	3.00
81X2TP	Frequency Pickup Level 2	Range = 15.00 to 70.00, OFF	60.43
81X2TD	Frequency Delay 2	Range = 0.00 to 240.00	3.00
E81RX	Enable Rate-of-Change of Frequency Elements	Select: 1-4, N	N
E81ACC	Number of Frequency Accumulator Bands	Select: 1-6, N	N

Group 2			Top
Setting	**Description**	**Range**	**Value**
E25X	Synchronism Check Enable	Select: Y, N	Y
25VLOX	Voltage Window - Low Threshold	Range = 0.00 to 300.00	104.00
25VHIX	Voltage Window - High Threshold	Range = 0.00 to 300.00	112.00
25VDIFX	Maximum Voltage Difference	Range = 1.0 to 15.0, OFF	5.0
25RCFX	Voltage Ratio Correction Factor	Range = 0.500 to 2.000	1.000
GENV+	Generator Voltage High Required	Select: Y, N	N
25SLO	Minimum Slip Frequency	Range = -1.00 to 0.99	0.00
25SHI	Maximum Slip Frequency	Range = -0.99 to 1.00	0.43
25ANG1X	Maximum Angle 1	Range = 0 to 80	15
25ANG2X	Maximum Angle 2	Range = 0 to 80	15
CANGLE	Target Close Angle	Range = -15 to 15	-3
SYNCPX	Synchronism Check Phase (VAX, VBX, VCX or deg lag VAX)	Select: 0, 30, 60, 90, 120, 150, 180, 210, 240, 270, 300, 330, VAX, VBX, VCX	VAX
TCLOSDX	Breaker Close Time for Angle Compensation	Range = 1 to 1000, OFF	35
CFANGLE	Close Fail Angle	Range = 3 to 120, OFF	OFF
BSYNCHX	Block Synchronism Check Elements	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	(NOT 3POX)
EAUTO	Enable Autosynchronism	Select: NONE, DIG	NONE
3POXD	Three-Pole Open Time Delay	Range = 0.00 to 1.00	0.00
TDURD	Minimum Trip Time	Range = 0.00 to 400.00	0.50
TR1	Trip 1 (Generator Field Breaker Trip) Equation	Valid range = The legal operators: AND OR NOT	SV06 OR SV07 OR SV08

Group 2			Top
Setting	**Description**	**Range**	**Value**
		R_TRIG F_TRIG	
TR2	Trip 2 (Prime Mover Trip) Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	SV06 OR SV07 OR LT06
TR3	Trip 3 (Generator Lockout Relay) Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	SV06 OR SV07
REMTRIP	Remote Trip	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
ULTR1	Unlatch Trip 1	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR1
ULTR2	Unlatch Trip 2	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR2
ULTR3	Unlatch Trip 3	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NOT TR3
CFDX	Close X Failure Time Delay	Range = 0.00 to 400.00	0.50
TRX	X-Side (Generator Main Circuit Breaker) Trip Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	3PWRX1T OR 3PWRX2T OR 40Z1T OR 40Z2T OR 81XT
ULTRX	Unlatch Trip X	Valid range = The legal	3POX

Group 2			
Setting	**Description**	**Range**	**Value**
		operators: AND OR NOT R_TRIG F_TRIG	
52AX	Breaker X Status	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
CLX	Close X Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	25C
ULCLX	Unlatch Close X	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIPX
Group 2 Top			

Top

Logic 2			
Setting	**Description**	**Range**	**Value**
OUT101FS	OUT101 Fail-Safe	Select: Y, N	N
OUT101		Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	HALARM OR SALARM
OUT102FS	OUT102 Fail-Safe	Select: Y, N	Y
OUT102		Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	TRIPX
OUT103FS	OUT103 Fail-Safe	Select: Y, N	Y
OUT103		Valid range = The legal	NOT CLOSEX

Top

Logic 2			Top
Setting	**Description**	**Range**	**Value**
		operators: AND OR NOT R_TRIG F_TRIG	
Logic 2			Top

Report			Top
Setting	**Description**	**Range**	**Value**
ER	Event Report Trigger	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	0
LER	Length of Event Report	Select: 15, 64, 180	64
PRE	Prefault Length	Range = 1 to 59	15
ESERDEL	Auto-Removal Enable	Select: Y, N	N
SER1		Valid range = 0, NA or a list of relay elements.	TRIPX, 3PWRX1T, 40Z1T, 40Z2T, 81XT
GSRTRG	Generator Sync Report Trigger	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	CLOSEX AND (25C OR 25AX1 OR 25AX2)
GSRR	Generator Sync Report Resolution	Select: 0.25, 1, 5	1
PRESYNC	Generator Sync Report Presync Length	Range = 1 to 4799	4790
Report			Top

Port 3			Top
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL,	SEL

Port 3			Top
Setting	**Description**	**Range**	**Value**
		MOD, DNP, EVMSG, PMU, MBA, MBB, MB8A, MB8B, MBTA, MBTB	
SPEED	Data Speed	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400	19200
BITS	Data Bits	Select: 7, 8	8
PARITY	Parity	Select: O, E, N	N
STOP	Stop Bits	Select: 1, 2	1
RTSCTS	Hardware Handshaking	Select: Y, N	N
T_OUT	Port Time-Out	Range = 0 to 30	5
AUTO	Send Auto Messages to Port	Select: Y, N	Y
FASTOP	Fast Operate	Select: Y, N	Y
Port 3			Top

Appendix B: SEL 421 Settings

Global			Top
Setting	**Description**	**Range**	**Value**
SID	Station Identifier (40 characters)	Range = ASCII string with a maximum length of 40.	Station A
RID	Relay Identifier (40 characters)	Range = ASCII string with a maximum length of 40.	Relay 1
NUMBK	Number of Breakers in Scheme	Select: 1, 2	1
BID1	Breaker 1 Identifier (40 characters)	Range = ASCII string with a maximum length of 40.	Breaker 1
NFREQ	Nominal System Frequency	Select: 50, 60	60
PHROT	System Phase Rotation	Select: ABC, ACB	ACB
DATE_F	Date Format	Select: MDY, YMD, DMY	MDY
FAULT	Fault Condition Equation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	51S1
EGADVS	Advanced Global Settings	Select: Y, N	N
EDCMON	Station DC Battery Monitor	Select: N, 1, 2	N
EICIS	Independent Control Input Settings	Select: Y, N	N
GINP	Input Pickup Level	Range = 15 to 265	85
GINDF	Input Drop Out Level	Range = 10 to 100	80
IN1XXD	Mainboard Debounce Time	Range = 0.0000 to 5.0000	0.1250
IN2XXD	Int Board # 1 Debounce Time	Range = 0.0000 to 5.0000	0.1250
IN3XXD	Int Board # 2 Debounce Time	Range = 0.0000 to 5.0000	0.1250
SS1	Select Setting Group 1	Valid range = The legal operators: AND OR NOT	NA

Global			
			Top
Setting	**Description**	**Range**	**Value**
		R_TRIG F_TRIG	
SS2	Select Setting Group 2	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	1
SS3	Select Setting Group 3	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
SS4	Select Setting Group 4	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
SS5	Select Setting Group 5	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
SS6	Select Setting Group 6	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
TGR	Group Change Delay	Range = 0 to 54000	180
EDRSTC	Data Reset Control	Select: Y, N	N
STALLTE	Time-Error Calculation	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
LOADTE	Load TECORR Factor	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
ESS	Current and Voltage Source	Select: Y, N, 1,	N

Global			Top
Setting	**Description**	**Range**	**Value**
	Selection	2	
EPMU	Synchronized Phasor Measurement	Select: Y, N	N
Global			Top

Group 2			Top
Setting	**Description**	**Range**	**Value**
CTRW	Current Transformer Ratio - Input W	Range = 1 to 50000	1
CTRX	Current Transformer Ratio - Input X	Range = 1 to 50000	1
PTRY	Potential Transformer Ratio - Input Y	Range = 1 to 10000	1
VNOMY	PT Nominal Voltage (L-L) - Input Y	Range = 60 to 300	208
PTRZ	Potential Transformer Ratio - Input Z	Range = 1 to 10000	1
VNOMZ	PT Nominal Voltage (L-L) - Input Z	Range = 60 to 300	208
Z1MAG	Pos.-Seq. Line Impedance Magnitude	Range = 0.05 to 255.00	7.80
Z1ANG	Pos.-Seq. Line Impedance Angle	Range = 5.00 to 90.00	84.00
Z0MAG	Zero-Seq. Line Impedance Magnitude	Range = 0.05 to 255.00	24.80
Z0ANG	Zero-Seq. Line Impedance Angle	Range = 5.00 to 90.00	81.50
EFLOC	Fault Location	Select: Y, N	N
ECVT	Transient Detection	Select: Y, N	N
ELOP	Loss-of-Potential	Select: Y, Y1, N	Y1
EADVS	Advanced Settings	Select: Y, N	N
E25BK1	Synchronism Check for Breaker 1	Select: Y, N	Y
SYNCP	Synch Reference	Select: VAY, VBY, VCY, VAZ, VBZ, VCZ	VAZ
25VL	Voltage Window Low Thresh	Range = 20.0 to 200.0	97.0
25VH	Voltage Window High Thresh	Range = 20.0 to 200.0	122.0

Group 2			Top
Setting	**Description**	**Range**	**Value**
SYNCS1	Synch Source 1	Select: VAY, VBY, VCY, VAZ, VBZ, VCZ	VAY
KS1M	Synch Source 1 Ratio Factor	Range = 0.10 to 3.00	1.00
KS1A	Synch Source 1 Angle Shift	Range = 0 to 330	0
25SFBK1	Maximum Slip Frequency - BK1	Range = 0.005 to 0.500, OFF	0.430
ANG1BK1	Maximum Angle Difference 1 -BK1	Range = 3.0 to 80.0	10.0
ANG2BK1	Maximum Angle Difference 2 -BK1	Range = 3.0 to 80.0	10.0
TCLSBK1	Breaker 1 Close Time	Range = 1.00 to 30.00	2.00
BSYNBK1	Block Synchronism Check - BK1	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	NA
Group 2			Top

Output			Top
Setting	**Description**	**Range**	**Value**
OUT101	Main Board Output OUT101	Valid range = The legal operators: AND OR NOT R_TRIG F_TRIG	25A1BK1
Output			Top

Port 1			Top
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL, DNP, MBA, MBB, RTD, PMU	SEL
SPEED	Data Speed (bps)	Select: 300, 600, 1200, 2400,	19200

Port 1 [Top](#)			
Setting	**Description**	**Range**	**Value**
		4800, 9600, 19200, 38400, 57600	
DATABIT	Data Bits	Select: 7, 8	8
PARITY	Parity	Select: Odd, Even, None	N
STOPBIT	Stop Bits	Select: 1, 2	1
RTSCTS	Enable Hardware Handshaking	Select: Y, N	N
TIMEOUT	Port Time-Out (minutes)	Range = 1 to 60, OFF	5
AUTO	Send Auto-Messages to Port	Select: Y, N	Y
FASTOP	Enable Fast Operate Messages	Select: Y, N	Y
TERTIM1	Initial Delay -Disconnect Sequence (seconds)	Range = 0 to 600	1
TERSTRN	Termination String - Disconnect Sequence	Range = ASCII string with a maximum length of 9.	\005
TERTIM2	Final Delay -Disconnect Sequence (seconds)	Range = 0 to 600	0
Port 1 [Top](#)			

Appendix C: SEL-710 Settings

Global			[Top]
Setting	**Description**	**Range**	**Value**
APP	Application WARNING: Nameplate sets most settings to Defaults, See on-line help.	Select: FULL, NAMEPLATE	FULL
PHROT	Phase Rotation	Select: ABC, ACB	ACB
FNOM	Rated Frequency (Hz)	Select: 50, 60	60
DATE_F	Date Format	Select: MDY, YMD, DMY	MDY
FAULT	Fault Condition (SELogic)		TRIP
TGR	Group Change Delay (seconds)	Range = 0-400	1
SS1	Select Settings Group1 (SELogic)		NOT RB01
SS2	Select Settings Group2 (SELogic)		RB01
SS3	Select Settings Group3 (SELogic)		0
IRIGC	IRIG-B Control Bits Definition	Select: NONE, C37.118	NONE
UTC_OFF	Offset from UTC (hours, in 0.25 hour increments)	Range = -24.00 to 24.00	0.00
DST_BEGM	Month To Begin DST	Range = OFF,1-12	OFF
52ABF	52A Interlock in BF Logic	Select: Y, N	N
BFD	Breaker Failure Delay (seconds)	Range = 0.00-2.00	0.50
BFI	Breaker Failure Initiate (SELogic)		R_TRIG TRIP
TIME_SRC	IRIG Time Source	Select: IRIG1, IRIG2	IRIG1
EBMON	Enable Breaker Monitor	Select: Y, N	N
Global			[Top]

Group 1			[Top]
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (16 characters)		SEL-710
TID	Terminal Identifier (16 characters)		MOTOR RELAY
CTR1	Phase (IA,IB,IC) CT Ratio	Range = 1-5000	1

Group 1			
			Top
Setting	**Description**	**Range**	**Value**
FLA1	Motor FLA [Full Load Amps] (amps)	Range = 0.2-5000.0	1.1
E2SPEED	Two-Speed Protection	Select: Y, N	N
CTRN	Neutral (IN) CT Ratio	Range = 1-2000	1
PTR	PT Ratio	Range = 1.00-250.00	1.00
VNOM	Line Voltage, Nominal Line-to-Line (volts)	Range = 100-30000	208
DELTA_Y	Transformer Connection	Select: WYE, DELTA	WYE
SINGLEV	Single Voltage Input	Select: Y, N	N
E49MOTOR	Thermal Overload Protection	Select: Y, N	Y
FLS	Full Load Slip (per unit Synchronous Speed)	Range = OFF,0.0010-0.1000	OFF
SETMETH	Thermal Overload Method	Select: RATING, RATING_1, CURVE	RATING
49RSTP	Thermal Overload Reset Level (%TCU)	Range = 10-99	75
SF	Service Factor	Range = 1.01-1.50	1.35
LRA1	Motor LRA (Locked Rotor Amps) (xFLA)	Range = 2.5-12.0	2.5
LRTHOT1	Locked Rotor Time (seconds)	Range = 1.0-600.0	3.0
TD1	ACCEL FACTOR	Range = 0.10-1.50	1.00
RTC1	Stator Time Constant (minutes)	Range = AUTO,1-2000	AUTO
TCAPU	Thermal Overload Alarm Pickup (%TCU)	Range = OFF,50-99	85
TCSTART	Start Inhibit Level (%TCU)	Range = OFF,1-99	OFF
COOLTIME	Stopped Cool Time (minutes)	Range = 1-6000	3
50P1P	Phase Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	1.81
50P2P	Phase Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50P1D	Phase Overcurrent Trip Delay (seconds)	Range = 0.00-5.00	0.00
50N1P	Neutral Overcurrent Trip Pickup (amps pri)	Range = OFF,0.01-25.00	OFF

Group 1 Top			
Setting	**Description**	**Range**	**Value**
50N2P	Neutral Overcurrent Alarm Pickup (amps pri)	Range = OFF,0.01-25.00	OFF
50G1P	Residual Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	0.66
50G2P	Residual Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50G1D	Residual Overcurrent Trip Delay (seconds)	Range = 0.00-5.00	0.10
50Q1P	Negative Sequence Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	0.73
50Q2P	Negative Sequence Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50Q1D	Negative Sequence Overcurrent Trip Delay (seconds)	Range = 0.10-120.00	0.20
E87M	Motor Differential Protection Enable	Select: Y, N	N
E47T	Phase Reversal Detection	Select: Y, N	Y
TDURD	Minimum Trip Time (seconds)	Range = 0.0-400.0	0.5
27P1P	UV TRIP LEVEL (Off, 0.02-1.00; xVnm)	Range = OFF,0.02-1.00 xVnm	OFF
27P2P	UV WARN LEVEL (Off, 0.02-1.00; xVnm)	Range = OFF,0.02-1.00 xVnm	OFF
59P1P	OV TRIP LEVEL (Off, 0.02-1.20; xVnm)	Range = OFF,0.02-1.20 xVnm	OFF
59P2P	OV WARN LEVEL (Off, 0.02-1.20; xVnm)	Range = OFF,0.02-1.20 xVnm	OFF
TR	Trip (SELogic)		(49T OR 50P1T OR 50G1T OR 50Q1T) OR STOP
REMTRIP	Remote Trip (SELogic)		0
ULTRIP	Unlatch Trip (SELogic)		0
52A	Contactor/Breaker Status (SELogic)		0
STREQ	Start (SELogic)		PB03
EMRSTR	Emergency Start (SELogic)		0
SPEED2	Speed 2 (SELogic)		0
SPEEDSW	Speed Switch (SELogic)		0
Group 1 Top			

Logic 1			[Top](#)
Setting	**Description**	**Range**	**Value**
OUT101FS	OUT101 Fail-Safe	Select: Y, N	Y
OUT102FS	OUT102 Fail-Safe	Select: Y, N	Y
OUT103FS	OUT103 Fail-Safe	Select: Y, N	Y
OUT101	(SELogic)		NOT (27P1T AND NOT LOP)
OUT102	(SELogic)		59P1T
OUT103	(SELogic)		TRIP OR PB04
Logic 1			[Top](#)

Group 2			[Top](#)
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (16 characters)		SEL-710
TID	Terminal Identifier (16 characters)		MOTOR RELAY
CTR1	Phase (IA,IB,IC) CT Ratio	Range = 1-5000	1
FLA1	Motor FLA [Full Load Amps] (amps)	Range = 0.2-5000.0	1.2
E2SPEED	Two-Speed Protection	Select: Y, N	N
CTRN	Neutral (IN) CT Ratio	Range = 1-2000	1
PTR	PT Ratio	Range = 1.00-250.00	1.00
VNOM	Line Voltage, Nominal Line-to-Line (volts)	Range = 100-30000	208
DELTA_Y	Transformer Connection	Select: WYE, DELTA	WYE
SINGLEV	Single Voltage Input	Select: Y, N	N
E49MOTOR	Thermal Overload Protection	Select: Y, N	Y
FLS	Full Load Slip (per unit Synchronous Speed)	Range = OFF,0.0010-0.1000	OFF
SETMETH	Thermal Overload Method	Select: RATING, RATING_1, CURVE	RATING
49RSTP	Thermal Overload Reset Level (%TCU)	Range = 10-99	75
SF	Service Factor	Range = 1.01-1.50	1.35
LRA1	Motor LRA (Locked Rotor	Range = 2.5-12.0	2.5

Group 2			Top
Setting	**Description**	**Range**	**Value**
	Amps) (xFLA)		
LRTHOT1	Locked Rotor Time (seconds)	Range = 1.0-600.0	1.0
TD1	ACCEL FACTOR	Range = 0.10-1.50	1.00
RTC1	Stator Time Constant (minutes)	Range = AUTO,1-2000	AUTO
TCAPU	Thermal Overload Alarm Pickup (%TCU)	Range = OFF,50-99	85
TCSTART	Start Inhibit Level (%TCU)	Range = OFF,1-99	OFF
COOLTIME	Stopped Cool Time (minutes)	Range = 1-6000	3
50P1P	Phase Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	5.25
50P2P	Phase Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50P1D	Phase Overcurrent Trip Delay (seconds)	Range = 0.00-5.00	0.00
50N1P	Neutral Overcurrent Trip Pickup (amps pri)	Range = OFF,0.01-25.00	OFF
50N2P	Neutral Overcurrent Alarm Pickup (amps pri)	Range = OFF,0.01-25.00	OFF
50G1P	Residual Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	0.88
50G2P	Residual Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50G1D	Residual Overcurrent Trip Delay (seconds)	Range = 0.00-5.00	0.10
50Q1P	Negative Sequence Overcurrent Trip Pickup (xFLA)	Range = OFF,0.10-20.00	0.88
50Q2P	Negative Sequence Overcurrent Alarm Pickup (xFLA)	Range = OFF,0.10-20.00	OFF
50Q1D	Negative Sequence Overcurrent Trip Delay (seconds)	Range = 0.10-120.00	0.20
E47T	Phase Reversal Detection	Select: Y, N	Y
27P1P	UV TRIP LEVEL (Off, 0.02-1.00; xVnm)	Range = OFF,0.02-1.00 xVnm	0.84
27P2P	UV WARN LEVEL (Off, 0.02-1.00; xVnm)	Range = OFF,0.02-1.00 xVnm	OFF
27P1D	UV TRIP DELAY (0.0-120.0; sec)	Range = 0.0-120.0 sec	0.7
59P1P	OV TRIP LEVEL (Off, 0.02-	Range =	1.03

Group 2			
			[Top]
Setting	**Description**	**Range**	**Value**
	1.20; xVnm)	OFF,0.02-1.20 xVnm	
59P2P	OV WARN LEVEL (Off, 0.02-1.20; xVnm)	Range = OFF,0.02-1.20 xVnm	OFF
59P1D	OV TRIP DELAY (0.0-120.0; sec)	Range = 0.0-120.0 sec	0.5
TDURD	Minimum Trip Time (seconds)	Range = 0.0-400.0	0.5
TR	Trip (SELogic)		(49T OR 50P1T OR 50G1T OR 50Q1T) OR STOP
REMTRIP	Remote Trip (SELogic)		0
ULTRIP	Unlatch Trip (SELogic)		0
52A	Contactor/Breaker Status (SELogic)		0
STREQ	Start (SELogic)		PB03
EMRSTR	Emergency Start (SELogic)		0
SPEED2	Speed 2 (SELogic)		0
SPEEDSW	Speed Switch (SELogic)		0
Group 2			
			[Top]

Logic 2			
			[Top]
Setting	**Description**	**Range**	**Value**
OUT101FS	OUT101 Fail-Safe	Select: Y, N	Y
OUT102FS	OUT102 Fail-Safe	Select: Y, N	Y
OUT103FS	OUT103 Fail-Safe	Select: Y, N	Y
OUT101	(SELogic)		NOT (27P1T AND NOT LOP)
OUT102	(SELogic)		59P1T
OUT103	(SELogic)		TRIP OR PB04
Logic 2			
			[Top]

Port 3			
			[Top]
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL, MOD, MBA,	SEL

Port 3			Top
Setting	Description	Range	Value
		MBB, MB8A, MB8B, MBTA, MBTB	
SPEED	Data Speed (bps)	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400	19200
BITS	Data Bits (bits)	Select: 7, 8	8
PARITY	Parity	Select: O, E, N	N
STOP	Stop Bits (bits)	Select: 1, 2	1
RTSCTS	Hardware Handshaking	Select: Y, N	N
T_OUT	Port Time-Out (minutes)	Range = 0-30	5
AUTO	Send Auto Messages to Port	Select: Y, N	Y
FASTOP	Fast Operate	Select: Y, N	Y
Port 3			Top

Front Panel			Top
Setting	Description	Range	Value
EDP	Display Points Enable	Range = N,1-32	4
ELB	Local Bits Enable	Range = N,1-32	N
FP_TO	Front-Panel Timeout	Range = OFF,1-30	15
FP_CONT	Front-Panel Contrast	Range = 1-8	4
FP_AUTO	Front-Panel Automessages	Select: OVERRIDE, ROTATING	OVERRIDE
RSTLED	Reset Trip-Latched LEDs On Close	Select: Y, N	Y
T01LEDL	Trip Latch T_LED	Select: Y, N	Y
T02LEDL	Trip Latch T_LED	Select: Y, N	Y
T03LEDL	Trip Latch T_LED	Select: Y, N	Y
T04LEDL	Trip Latch T_LED	Select: Y, N	Y
T05LEDL	Trip Latch T_LED	Select: Y, N	Y
T06LEDL	Trip Latch T_LED	Select: Y, N	Y
T01_LED	(SELogic)		49T OR AMBTRIP OR BRGTRIP OR OTHTRIP OR WDGTRIP
T02_LED	(SELogic)		50P1T OR 50N1T OR 50G1T
T03_LED	(SELogic)		46UBT OR 47T

Front Panel			
			Top
Setting	**Description**	**Range**	**Value**
T04_LED	(SELogic)		LOSSTRIP OR 37PT
T05_LED	(SELogic)		(NOT STOPPED AND 27P1T) OR 59P1T
T06_LED	(SELogic)		87M1T OR 87M2T
PB1A_LED	(SELogic)		PB01
PB2A_LED	(SELogic)		PB02
PB3A_LED	(SELogic)		PB03
PB4A_LED	(SELogic)		PB04
PB1B_LED	(SELogic)		0
PB2B_LED	(SELogic)		0
PB3B_LED	(SELogic)		STARTING OR RUNNING
PB4B_LED	(SELogic)		STOPPED
DP01	Display Point (60 characters)		RID, "{16}"
DP02	Display Point (60 characters)		TID, "{16}"
DP03	Display Point (60 characters)		IAV, "I MOTOR {6} A"
DP04	Display Point (60 characters)		TCUSTR, "Stator TCU {3} %"
Front Panel			Top

Appendix D: SEL-311L Line 1 Settings

Group 2			Top
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	SEL-311L
TID	Terminal Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	LINE 1 (BIDIRECTIONAL)
CTR	Local Phase (IA,IB,IC) CT Ratio, CTR:1	Range = 1 to 6000	1
APP	Application	Select: 87L, 87L21, 87L21P, 87LSP, 311L	87LSP
EADVS	Advanced Settings Enable	Select: Y, N	Y
EHST	High Speed Tripping	Select: SP1, SP2, N	N
EHSDTT	Enable High Speed Direct Transfer Trip	Select: Y, N	N
EDD	Enable Disturbance Detect	Select: Y, N	N
ETAP	Tapped Load Coordination	Select: Y, N	N
EOCTL	Enable Open CT Logic	Select: Y, N	N
PCHAN	Primary 87L Channel	Select: X, Y	X
EHSC	Hot-Standby Channel Feature	Select: Y, N	N
CTR_X	CTR at Terminal Connected to Channel X	Range = 1 to 6000	1
87LPP	Phase 87L (Amps secondary)	Range = 1.00 to 10.00, OFF	OFF
87L2P	3I2 Negative-Sequence 87L (Amps secondary)	Range = 0.50 to 5.00, OFF	OFF
87LGP	Ground 87L (Amps secondary)	Range = 0.50 to 5.00, OFF	OFF
CTALRM	Ph. Diff. Current Alarm Pickup (Amps secondary)	Range = 0.50 to 10.00	0.50
87LR	Outer Radius	Range = 2.0 to 8.0	6.0
87LANG	Angle (degrees)	Range = 90 to 270	195
CTRP	Polarizing (IPOL) CT Ratio, CTRP:1	Range = 1 to 6000	200
PTR	Phase (VA,VB,VC) PT Ratio, PTR:1	Range = 1.00 to 10000.00	1.00

Group 2			Top
Setting	**Description**	**Range**	**Value**
PTRS	Synch. Voltage (VS) PT Ratio, PTRS:1	Range = 1.00 to 10000.00	2000.00
Z1MAG	Pos-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	41.69
Z1ANG	Pos-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	88.00
Z0MAG	Zero-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	41.69
Z0ANG	Zero-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	88.00
LL	Line Length (unitless)	Range = 0.10 to 999.00	100.00
EFLOC	Fault Location Enable	Select: Y, N	N
E21P	Enable Mho Phase Distance Elements	Select: N, 1-4	3
ECCVT	CCVT Transient Detection Enable	Select: Y, N	N
Z1P	Reach Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	14.73
Z2P	Reach Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	43.00
Z3P	Reach Zone 3 (Ohms secondary)	Range = 0.05 to 64.00, OFF	5.00
50PP1	Phase-Phase Overcurrent Fault Detector Zone 1 (Amps secondary)	Range = 0.50 to 170.00	0.50
50PP2	Phase-Phase Overcurrent Fault Detector Zone 2 (Amps secondary)	Range = 0.50 to 170.00	0.50
50PP3	Phase-Phase Overcurrent Fault Detector Zone 3 (Amps secondary)	Range = 0.50 to 170.00	0.50
E21MG	Enable Mho Ground Distance Elements	Select: N, 1-4	3
Z1MG	Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	14.73
Z2MG	Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	43.00
Z3MG	Zone 3 (Ohms secondary)	Range = 0.05 to 64.00, OFF	5.00
E21XG	Enable Quad Ground Distance Elements	Select: N, 1-4	3
XG1	Zone 1 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	6.24

Group 2			Top
Setting	**Description**	**Range**	**Value**
XG2	Zone 2 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	9.36
XG3	Zone 3 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	1.87
RG1	Zone 1 Resistance (Ohms secondary)	Range = 0.05 to 50.00	2.50
RG2	Zone 2 Resistance (Ohms secondary)	Range = 0.05 to 50.00	5.00
RG3	Zone 3 Resistance (Ohms secondary)	Range = 0.05 to 50.00	6.00
XGPOL	Quad Ground Polarizing Quantity	Select: I2, IG	I2
TANG	Non-Homogenous Correction Angle (degrees)	Range = -45.0 to 45.0	-3.0
50L1	Zone 1 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50L2	Zone 2 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50L3	Zone 3 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ1	Zone 1 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ2	Zone 2 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ3	Zone 3 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
k0M1	Zone 1 ZSC Factor Mag (unitless)	Range = 0.000 to 6.000	0.726
k0A1	Zone 1 ZSC Factor Ang (degrees)	Range = -180.00 to 180.00	-3.69
k0M	Zone 2,3,&4 ZSC Factor Mag (unitless)	Range = 0.000 to 6.000	0.726
k0A	Zone 2,3,&4 ZSC Factor Ang (degrees)	Range = -180.00 to 180.00	-3.69
Z1PD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	OFF
Z2PD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	22.00
Z3PD	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	OFF

Group 2			
			Top
Setting	**Description**	**Range**	**Value**
Z1GD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2GD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3GD	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z1D	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2D	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3D	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
E51P	Enable Phase Time-Overcurrent Elements	Select: Y, N	Y
51PP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	4.50
51PC	Curve	Select: U1-U5, C1-C5	U1
51PTD	Time Dial	Range = 0.50 to 15.00	0.50
51PRS	Electromechanical Reset Delay	Select: Y, N	N
E51G	Enable Residual Ground Time-Overcurrent Elements	Select: Y, N	Y
51GP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51GC	Curve	Select: U1-U5, C1-C5	U1
51GTD	Time Dial	Range = 0.50 to 15.00	0.50
51GRS	Electromechanical Reset Delay	Select: Y, N	N
E51Q	Enable Negative-Sequence Time-Overcurrent Elements	Select: Y, N	Y
51QP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51QC	Curve	Select: U1-U5, C1-C5	U1
51QTD	Time Dial	Range = 0.50	0.53

Group 2			Top
Setting	**Description**	**Range**	**Value**
		to 15.00	
51QRS	Electromechanical Reset Delay	Select: Y, N	N
EOOS	Enable Out-of-Step Elements	Select: Y, N	N
ELOAD	Enable Load Encroachment Elements	Select: Y, N	N
E32	Enable Directional Control Elements	Select: Y, AUTO	AUTO
ELOP	Loss-Of-Potential Enable	Select: Y, Y1, N	Y1
EBBPT	Busbar PT LOP Logic Enable	Select: Y, N	N
DIR3	Level 3 Direction	Select: F, R	R
DIR4	Level 4 Direction	Select: F, R	F
ORDER	Ground Directional Element Priority	Select: I, Q, V, OFF	QVI
EVOLT	Enable Voltage Element Enables	Select: Y, N	N
ECOMM	Comm.-Assisted Trip Scheme Enables	Select: N, POTT, DCUB1, DCUB2, DCB	POTT
Z3RBD	Zone 3 Reverse Block Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	5.00
EBLKD	Echo Block Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	10.00
ETDPU	Echo Time Delay Pickup (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	2.00
EDURD	Echo Duration Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	4.00
EWFC	Weak-Infeed Enable	Select: Y, N	N
EZ1EXT	Zone 1 Extension	Select: Y, N	N
EDEM	Demand Metering Type	Select: THM, ROL	THM
DMTC	Time Constant (minutes)	Select: 5, 10, 15, 30, 60	60
TDURD	Minimum Trip Duration Time (cycles in 0.25 increments)	Range = 2.00 to 16000.00	9.00
TOPD	Trip Open Pole Dropout Delay (cycles in 0.25 increments)	Range = 2.00 to 8000.00	2.00
CFD	Close Failure Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00,	60.00

Group 2			Top
Setting	**Description**	**Range**	**Value**
		OFF	
3POD	Three-Pole Open Time Delay (cycles in 0.25 increments)	Range = 0.00 to 60.00	0.50
OPO	Open Pole Option	Select: 27, 52	52
50LP	Load Detection Phase Pickup (Amps secondary)	Range = 0.25 to 100.00, OFF	0.25
ELAT	SELogic Latch Bit Enables	Select: N, 1-16	16
EDP	SELogic Display Point Enables	Select: N, 1-16	16
ESV	SELogic Variable Timers Enables	Select: N, 1-16	1
SV1PU	SV1 Timer Pickup (cycles in 0.25 increments)	Range = 0.00 to 999999.00	14.00
SV1DO	SV1 Timer Dropout (cycles in 0.25 increments)	Range = 0.00 to 999999.00	0.00
Group 2			Top

SELogic 2			Top
Setting	**Description**	**Range**	**Value**
TR	Direct Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	M1P + M2PT + M3PT + 51PT + 51GT + 51QT
TRCOMM	Communications-Assisted Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	M2P
DTT	Direct Transfer Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0

SELogic 2			Top
Setting	**Description**	**Range**	**Value**
E3PT	Three-Pole Trip Enable	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
ULTR	Unlatch Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	SPO + 3PO
PT1	Permissive Trip 1 (used for ECOMM = POTT, DCUB1, or DCUB2)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	R1X
51PTC	Phase	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51GTC	Residual Ground	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51QTC	Negative-Sequence	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
87LTC	87L Torque Control Equation	Valid range =	1

SELogic 2			
			Top
Setting	Description	Range	Value
		Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
SV1	SELogic Control Equation Variable 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	KEY
OUT101	Output Contact 101	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!TRIP
SS1	Select Setting Group 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
SS2	Select Setting Group 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
ER	Event Report Trigger Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	/M2P + /Z2G + /51G + /51Q + /51P + /LOP + /M1P + /Z1G + /M3P + /Z3G
FAULT	Fault Indication	Valid range = Boolean	51G + 51Q + M2P + Z2G + 51P + M1P + Z1G + M3P + Z3G

SELogic 2			Top
Setting	**Description**	**Range**	**Value**
		equation using word bit elements and the legal operators: ! / \ ( ) * +	
BSYNCH	Block Synchronism Check Elements	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1X	87L Channel X, Transmit Bit 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	SV1T
T2X	87L Channel X, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3X	87L Channel X, Transmit Bit 3	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T4X	87L Channel X, Transmit Bit 4	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1Y	87L Channel Y, Transmit Bit 1	Valid range = Boolean equation using	0

SELogic 2			[Top](#)
Setting	**Description**	**Range**	**Value**
		word bit elements and the legal operators: ! / \ ( ) * +	
T2Y	87L Channel Y, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3Y	87L Channel Y, Transmit Bit 3	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T4Y	87L Channel Y, Transmit Bit 4	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
SELogic 2			[Top](#)

Global			[Top](#)
Setting	**Description**	**Range**	**Value**
TGR	Group Change Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	1800.00
NFREQ	Nominal Frequency (Hz)	Select: 50, 60	60
PHROT	Phase Rotation	Select: ABC, ACB	ACB
DATE_F	Date Format	Select: MDY, YMD	MDY
FP_TO	Front Panel Timeout (minutes)	Range = 0.00 to 30.00	15.00
SCROLD	Display Update Rate (seconds)	Range = 1 to 60	5

Global			
			Top
Setting	**Description**	**Range**	**Value**
LER	Length of Event Report (cycles)	Select: 15, 30, 60	60
PRE	Cycle Length of Prefault in Event Report (cycles in increments of 1)	Range = 1 to 59	10
DCLOP	DC Battery LO Voltage Pickup (Vdc)	Range = 20.00 to 300.00, OFF	OFF
DCHIP	DC Battery HI Voltage Pickup (Vdc)	Range = 20.00 to 300.00, OFF	OFF
IN101D	Input 101 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN102D	Input 102 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN103D	Input 103 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN104D	Input 104 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN105D	Input 105 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN106D	Input 106 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
EPMU	Synchronized Phasor Measurement	Select: Y, N	N
Global			
			Top

Channel X			
			Top
Setting	**Description**	**Range**	**Value**
EADDCX	Channel X Address Check	Select: Y, G, N	N
RBADXP	Continuous Dropout Alarm (Seconds)	Range = 1 to 1000	1
AVAXP	Packets Lost in Last 10,000 Alarm	Range = 1 to 5000	10
DBADXP	One Way Channel Delay Alarm (msec.)	Range = 1 to 24	10
TIMRX	Timing Source (I=Internal, E=External)	Select: I, E	E
Channel X			
			Top

Channel Y			Top
Setting	**Description**	**Range**	**Value**
EADDCY	Channel Y Address Check	Select: Y, G, N	N
RBADYP	Continuous Dropout Alarm (Seconds)	Range = 1 to 1000	1
AVAYP	Packets Lost in Last 10,000 Alarm	Range = 1 to 5000	10
DBADYP	One Way Channel Delay Alarm (msec.)	Range = 1 to 24	10
TIMRY	Timing Source (I=Internal, E=External)	Select: I, E	E
Channel Y			Top

Port 2			Top
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL, LMD, DNP, MBA, MB8A, MBGA, MBB, MB8B, MBGB	SEL
T_OUT	Minutes to Port Time-out	Range = 0 to 30	15
DTA	Meter Format	Select: Y, N	N
SPEED	Baud Rate	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400	19200
AUTO	Send Auto Messages to Port	Select: Y, N	Y
BITS	Data Bits	Select: 6-8	8
RTSCTS	Enable Hardware Handshaking	Select: Y, N	N
PARITY	(Odd, Even, None)	Select: O, E, N	N
FASTOP	Fast Operate Enable	Select: Y, N	N
STOP	Stop Bits	Select: 1, 2	1
Port 2			Top

Appendix E: SEL-311L Line 2 Settings

Group 1 [Top](#)			
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	SEL-311L
TID	Terminal Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	LINE 2 (RADIAL)
CTR	Local Phase (IA,IB,IC) CT Ratio, CTR:1	Range = 1 to 6000	1
APP	Application	Select: 87L, 87L21, 87L21P, 87LSP, 311L	311L
EADVS	Advanced Settings Enable	Select: Y, N	Y
E87L	Number of 87L Terminals	Select: 2, 3, 3R, N	N
CTRP	Polarizing (IPOL) CT Ratio, CTRP:1	Range = 1 to 6000	200
PTR	Phase (VA,VB,VC) PT Ratio, PTR:1	Range = 1.00 to 10000.00	1.00
PTRS	Synch. Voltage (VS) PT Ratio, PTRS:1	Range = 1.00 to 10000.00	2000.00
Z1MAG	Pos-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	24.37
Z1ANG	Pos-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	89.00
Z0MAG	Zero-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	24.37
Z0ANG	Zero-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	89.00
LL	Line Length (unitless)	Range = 0.10 to 999.00	100.00
EFLOC	Fault Location Enable	Select: Y, N	N
E21P	Enable Mho Phase Distance Elements	Select: N, 1-4, 1C-4C	3
ECCVT	CCVT Transient Detection Enable	Select: Y, N	N
Z1P	Reach Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	13.35
Z2P	Reach Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	22.90
Z3P	Reach Zone 3 (Ohms secondary)	Range = 0.05 to	5.00

Group 1			Top
Setting	**Description**	**Range**	**Value**
		64.00, OFF	
E21MG	Enable Mho Ground Distance Elements	Select: N, 1-4	3
Z1MG	Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	13.35
Z2MG	Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	22.90
Z3MG	Zone 3 (Ohms secondary)	Range = 0.05 to 64.00, OFF	5.00
E21XG	Enable Quad Ground Distance Elements	Select: N, 1-4	N
50L1	Zone 1 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50L2	Zone 2 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50L3	Zone 3 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ1	Zone 1 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ2	Zone 2 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ3	Zone 3 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
k0M1	Zone 1 ZSC Factor Mag (unitless)	Range = 0.000 to 6.000	0.726
k0A1	Zone 1 ZSC Factor Ang (degrees)	Range = -180.00 to 180.00	-3.69
k0M	Zone 2,3,&4 ZSC Factor Mag (unitless)	Range = 0.000 to 6.000	0.726
k0A	Zone 2,3,&4 ZSC Factor Ang (degrees)	Range = -180.00 to 180.00	-3.69
Z1PD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2PD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3PD	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z1GD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2GD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3GD	Zone 3 Time Delay (cycles in	Range = 0.00 to	5.00

Group 1			**Top**
Setting	**Description**	**Range**	**Value**
	0.25 increments)	16000.00, OFF	
Z1D	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2D	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3D	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
E51P	Enable Phase Time-Overcurrent Elements	Select: Y, N	Y
51PP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	2.00
51PC	Curve	Select: U1-U5, C1-C5	U1
51PTD	Time Dial	Range = 0.50 to 15.00	0.50
51PRS	Electromechanical Reset Delay	Select: Y, N	N
E51G	Enable Residual Ground Time-Overcurrent Elements	Select: Y, N	Y
51GP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51GC	Curve	Select: U1-U5, C1-C5	U1
51GTD	Time Dial	Range = 0.50 to 15.00	0.50
51GRS	Electromechanical Reset Delay	Select: Y, N	N
E51Q	Enable Negative-Sequence Time-Overcurrent Elements	Select: Y, N	Y
51QP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51QC	Curve	Select: U1-U5, C1-C5	U1
51QTD	Time Dial	Range = 0.50 to 15.00	0.53
51QRS	Electromechanical Reset Delay	Select: Y, N	N
EOOS	Enable Out-of-Step Elements	Select: Y, N	N
ELOAD	Enable Load Encroachment Elements	Select: Y, N	N
E32	Enable Directional Control Elements	Select: Y, AUTO	AUTO
ELOP	Loss-Of-Potential Enable	Select: Y, Y1, N	N
DIR3	Level 3 Direction	Select: F, R	R
DIR4	Level 4 Direction	Select: F, R	F

Group 1			Top
Setting	**Description**	**Range**	**Value**
ORDER	Ground Directional Element Priority	Select: I, Q, V, OFF	QVI
ECOMM	Comm.-Assisted Trip Scheme Enables	Select: N, POTT, DCUB1, DCUB2, DCB	N
EZ1EXT	Zone 1 Extension	Select: Y, N	N
DMTC	Time Constant (minutes)	Select: 5, 10, 15, 30, 60	60
PDEMP	Phase Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
GDEMP	Residual Ground Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
QDEMP	Negative-Sequence Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
TDURD	Minimum Trip Duration Time (cycles in 0.25 increments)	Range = 2.00 to 16000.00	2.00
TOPD	Trip Open Pole Dropout Delay (cycles in 0.25 increments)	Range = 2.00 to 8000.00	2.00
CFD	Close Failure Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	60.00
3POD	Three-Pole Open Time Delay (cycles in 0.25 increments)	Range = 0.00 to 60.00	0.50
OPO	Open Pole Option	Select: 27, 52	52
50LP	Load Detection Phase Pickup (Amps secondary)	Range = 0.25 to 100.00, OFF	0.25
ELAT	SELogic Latch Bit Enables	Select: N, 1-16	16
EDP	SELogic Display Point Enables	Select: N, 1-16	16
ESV	SELogic Variable Timers Enables	Select: N, 1-16	N
Group 1			Top

SELogic 1			Top
Setting	**Description**	**Range**	**Value**
TR	Direct Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	M1P + M2PT + 51PT + 51GT + 51QT
DTT	Direct Transfer Trip	Valid range =	0

SELogic 1			Top
Setting	**Description**	**Range**	**Value**
	Conditions	Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
ULTR	Unlatch Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!(50L + 51G)
51PTC	Phase	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51GTC	Residual Ground	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51QTC	Negative-Sequence	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
OUT101	Output Contact 101	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!TRIP
OUT102	Output Contact 102	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB1
OUT103	Output Contact 103	Valid range =	0

SELogic 1 [Top](#)			
Setting	**Description**	**Range**	**Value**
		Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
OUT104	Output Contact 104	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB2
SS1	Select Setting Group 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB3
SS2	Select Setting Group 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	RB3
ER	Event Report Trigger Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	/M2P + /Z2G + /51G + /51Q + /51P + /LOP + /M1P + /Z1G + /M3P + /Z3G
FAULT	Fault Indication	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	51G + 51Q + M2P + Z2G + 51P + M1P + Z1G + M3P + Z3G
BSYNCH	Block Synchronism Check Elements	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1X	87L Channel X, Transmit Bit 1	Valid range =	KEY

SELogic 1			Top
Setting	**Description**	**Range**	**Value**
		Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
T2X	87L Channel X, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3X	87L Channel X, Transmit Bit 3	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T4X	87L Channel X, Transmit Bit 4	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1Y	87L Channel Y, Transmit Bit 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T2Y	87L Channel Y, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3Y	87L Channel Y, Transmit Bit 3	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T4Y	87L Channel Y, Transmit Bit 4	Valid range =	0

SELogic 1			
			Top
Setting	Description	Range	Value
		Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
SELogic 1			
			Top

Group 2			
			Top
Setting	Description	Range	Value
RID	Relay Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	SEL-311L
TID	Terminal Identifier (30 chars)	Range = ASCII string with a maximum length of 30.	LINE 2 (BIDIRECTIONAL)
CTR	Local Phase (IA,IB,IC) CT Ratio, CTR:1	Range = 1 to 6000	1
APP	Application	Select: 87L, 87L21, 87L21P, 87LSP, 311L	311L
EADVS	Advanced Settings Enable	Select: Y, N	N
E87L	Number of 87L Terminals	Select: 2, 3, 3R, N	2
EHST	High Speed Tripping	Select: 1-6, N	N
EHSDTT	Enable High Speed Direct Transfer Trip	Select: Y, N	N
EDD	Enable Disturbance Detect	Select: Y, N	N
ETAP	Tapped Load Coordination	Select: Y, N	N
EOCTL	Enable Open CT Logic	Select: Y, N	N
PCHAN	Primary 87L Channel	Select: X, Y	X
EHSC	Hot-Standby Channel Feature	Select: Y, N	N
CTR_X	CTR at Terminal Connected to Channel X	Range = 1 to 6000	1
87LPP	Phase 87L (Amps secondary)	Range = 1.00 to 10.00, OFF	OFF
87L2P	3I2 Negative-Sequence 87L (Amps secondary)	Range = 0.50 to 5.00, OFF	OFF

Group 2			[Top](#)
Setting	**Description**	**Range**	**Value**
87LGP	Ground 87L (Amps secondary)	Range = 0.50 to 5.00, OFF	OFF
CTALRM	Ph. Diff. Current Alarm Pickup (Amps secondary)	Range = 0.50 to 10.00	0.50
87LR	Outer Radius	Range = 2.0 to 8.0	6.0
87LANG	Angle (degrees)	Range = 90 to 270	195
CTRP	Polarizing (IPOL) CT Ratio, CTRP:1	Range = 1 to 6000	200
PTR	Phase (VA,VB,VC) PT Ratio, PTR:1	Range = 1.00 to 10000.00	1.00
PTRS	Synch. Voltage (VS) PT Ratio, PTRS:1	Range = 1.00 to 10000.00	2000.00
Z1MAG	Pos-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	41.69
Z1ANG	Pos-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	88.00
Z0MAG	Zero-Seq Line Impedance Magnitude (Ohms secondary)	Range = 0.05 to 255.00	41.69
Z0ANG	Zero-Seq Line Impedance Angle (degrees)	Range = 5.00 to 90.00	88.00
LL	Line Length (unitless)	Range = 0.10 to 999.00	100.00
EFLOC	Fault Location Enable	Select: Y, N	N
E21P	Enable Mho Phase Distance Elements	Select: N, 1-4, 1C-4C	3
ECCVT	CCVT Transient Detection Enable	Select: Y, N	N
Z1P	Reach Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	14.50
Z2P	Reach Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	43.00
Z3P	Reach Zone 3 (Ohms secondary)	Range = 0.05 to 64.00, OFF	5.00
50PP1	Phase-Phase Overcurrent Fault Detector Zone 1 (Amps secondary)	Range = 0.50 to 170.00	0.50
E21MG	Enable Mho Ground Distance Elements	Select: N, 1-4	3
Z1MG	Zone 1 (Ohms secondary)	Range = 0.05 to 64.00, OFF	14.50
Z2MG	Zone 2 (Ohms secondary)	Range = 0.05 to 64.00, OFF	43.00

Group 2			Top
Setting	**Description**	**Range**	**Value**
Z3MG	Zone 3 (Ohms secondary)	Range = 0.05 to 64.00, OFF	5.00
E21XG	Enable Quad Ground Distance Elements	Select: N, 1-4	3
XG1	Zone 1 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	6.24
XG2	Zone 2 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	9.36
XG3	Zone 3 Reactance (Ohms secondary)	Range = 0.05 to 64.00, OFF	1.87
RG1	Zone 1 Resistance (Ohms secondary)	Range = 0.05 to 50.00	2.50
RG2	Zone 2 Resistance (Ohms secondary)	Range = 0.05 to 50.00	5.00
RG3	Zone 3 Resistance (Ohms secondary)	Range = 0.05 to 50.00	6.00
50L1	Zone 1 Phase Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
50GZ1	Zone 1 Residual Current FD (Amps secondary)	Range = 0.50 to 100.00	0.50
k0M1	Zone 1 ZSC Factor Mag (unitless)	Range = 0.000 to 6.000	0.726
k0A1	Zone 1 ZSC Factor Ang (degrees)	Range = -180.00 to 180.00	-3.69
Z1PD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	OFF
Z2PD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	22.00
Z3PD	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	OFF
Z1GD	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z2GD	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3GD	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z1D	Zone 1 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00,	5.00

Group 2 Top			
Setting	**Description**	**Range**	**Value**
		OFF	
Z2D	Zone 2 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
Z3D	Zone 3 Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	5.00
E51P	Enable Phase Time-Overcurrent Elements	Select: Y, N	Y
51PP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	2.00
51PC	Curve	Select: U1-U5, C1-C5	U1
51PTD	Time Dial	Range = 0.50 to 15.00	0.50
51PRS	Electromechanical Reset Delay	Select: Y, N	N
E51G	Enable Residual Ground Time-Overcurrent Elements	Select: Y, N	Y
51GP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51GC	Curve	Select: U1-U5, C1-C5	U1
51GTD	Time Dial	Range = 0.50 to 15.00	0.50
51GRS	Electromechanical Reset Delay	Select: Y, N	N
E51Q	Enable Negative-Sequence Time-Overcurrent Elements	Select: Y, N	Y
51QP	Pickup (Amps secondary)	Range = 0.25 to 16.00, OFF	0.25
51QC	Curve	Select: U1-U5, C1-C5	U1
51QTD	Time Dial	Range = 0.50 to 15.00	0.53
51QRS	Electromechanical Reset Delay	Select: Y, N	N
E32	Enable Directional Control Elements	Select: Y, AUTO	AUTO
ELOP	Loss-Of-Potential Enable	Select: Y, Y1, N	Y
EBBPT	Busbar PT LOP Logic Enable	Select: Y, N	N
DIR3	Level 3 Direction	Select: F, R	R
DIR4	Level 4 Direction	Select: F, R	F

Group 2			
			Top
Setting	**Description**	**Range**	**Value**
ORDER	Ground Directional Element Priority	Select: I, Q, V, OFF	QVI
EVOLT	Enable Voltage Element Enables	Select: Y, N	N
E25	Synchronism Check Enable	Select: Y, N	N
E81	Frequency Elements Enables	Select: N, 1-6	N
E79	Reclosures Enables	Select: N, 1-4	N
ESOTF	Enable Switch-Onto-Fault	Select: Y, N	N
ECOMM	Comm.-Assisted Trip Scheme Enables	Select: N, POTT, DCUB1, DCUB2, DCB	POTT
Z3RBD	Zone 3 Reverse Block Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	5.00
EBLKD	Echo Block Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	10.00
ETDPU	Echo Time Delay Pickup (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	2.00
EDURD	Echo Duration Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	4.00
EWFC	Weak-Infeed Enable	Select: Y, N	N
EZ1EXT	Zone 1 Extension	Select: Y, N	N
EDEM	Demand Metering Type	Select: THM, ROL	THM
DMTC	Time Constant (minutes)	Select: 5, 10, 15, 30, 60	60
PDEMP	Phase Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
GDEMP	Residual Ground Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
QDEMP	Negative-Sequence Pickup (Amps secondary)	Range = 0.50 to 16.00, OFF	OFF
TDURD	Minimum Trip Duration Time (cycles in 0.25 increments)	Range = 2.00 to 16000.00	9.00
TOPD	Trip Open Pole Dropout Delay (cycles in 0.25 increments)	Range = 2.00 to 8000.00	2.00
CFD	Close Failure Time Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00, OFF	60.00
3POD	Three-Pole Open Time Delay (cycles in 0.25 increments)	Range = 0.00 to 60.00	0.50

Group 2 Top			
Setting	**Description**	**Range**	**Value**
OPO	Open Pole Option	Select: 27, 52	52
50LP	Load Detection Phase Pickup (Amps secondary)	Range = 0.25 to 100.00, OFF	0.25
ELAT	SELogic Latch Bit Enables	Select: N, 1-16	16
EDP	SELogic Display Point Enables	Select: N, 1-16	16
ESV	SELogic Variable Timers Enables	Select: N, 1-16	1
Group 2 Top			

SELogic 2 Top			
Setting	**Description**	**Range**	**Value**
TR	Direct Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	M1P + M2PT + 51PT + 51GT + 51QT
TRCOMM	Communications-Assisted Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	M2P
DTT	Direct Transfer Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
ULTR	Unlatch Trip Conditions	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!(50L + 51G)

SELogic 2			Top
Setting	**Description**	**Range**	**Value**
PT1	Permissive Trip 1 (used for ECOMM = POTT, DCUB1, or DCUB2)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	R1X
51PTC	Phase	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51GTC	Residual Ground	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
51QTC	Negative-Sequence	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
87LTC	87L Torque Control Equation	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
SV1	SELogic Control Equation Variable 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	KEY
OUT101	Output Contact 101	Valid range =	!TRIP

SELogic 2 [Top](#)			
Setting	**Description**	**Range**	**Value**
		Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	
OUT102	Output Contact 102	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB1
OUT103	Output Contact 103	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
OUT104	Output Contact 104	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB2
SS1	Select Setting Group 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!RB3
SS2	Select Setting Group 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	RB3
ER	Event Report Trigger Conditions	Valid range = Boolean	/M2P + /Z2G + /51G + /51Q + /51P + /LOP + /M1P + /Z1G + /M3P + /Z3G

SELogic 2			
			Top
Setting	**Description**	**Range**	**Value**
		equation using word bit elements and the legal operators: ! / \ ( ) * +	
FAULT	Fault Indication	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	51G + 51Q + M2P + Z2G + 51P + M1P + Z1G + M3P + Z3G
BSYNCH	Block Synchronism Check Elements	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
CLMON	Close Bus Monitor	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
E32IV	Enable for V0 Polarized and IN Polarized Elements	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	1
ESTUB	Stub Bus Logic Enable	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1X	87L Channel X, Transmit Bit 1	Valid range = Boolean equation using	SV1T

SELogic 2			Top
Setting	**Description**	**Range**	**Value**
		word bit elements and the legal operators: ! / \ ( ) * +	
T2X	87L Channel X, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3X	87L Channel X, Transmit Bit 3	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T4X	87L Channel X, Transmit Bit 4	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T1Y	87L Channel Y, Transmit Bit 1	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T2Y	87L Channel Y, Transmit Bit 2	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
T3Y	87L Channel Y, Transmit Bit 3	Valid range = Boolean equation using word bit	0

SELogic 2			[Top](#)
Setting	Description	Range	Value
		elements and the legal operators: ! / \ ( ) * +	
T4Y	87L Channel Y, Transmit Bit 4	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	0
SELogic 2			[Top](#)

Global			[Top](#)
Setting	Description	Range	Value
TGR	Group Change Delay (cycles in 0.25 increments)	Range = 0.00 to 16000.00	1800.00
NFREQ	Nominal Frequency (Hz)	Select: 50, 60	60
PHROT	Phase Rotation	Select: ABC, ACB	ACB
DATE_F	Date Format	Select: MDY, YMD	MDY
FP_TO	Front Panel Timeout (minutes)	Range = 0.00 to 30.00	15.00
SCROLD	Display Update Rate (seconds)	Range = 1 to 60	5
LER	Length of Event Report (cycles)	Select: 15, 30, 60	60
PRE	Cycle Length of Prefault in Event Report (cycles in increments of 1)	Range = 1 to 59	10
DCLOP	DC Battery LO Voltage Pickup (Vdc)	Range = 20.00 to 300.00, OFF	OFF
DCHIP	DC Battery HI Voltage Pickup (Vdc)	Range = 20.00 to 300.00, OFF	OFF
IN101D	Input 101 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN102D	Input 102 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN103D	Input 103 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00

Global			
			Top
Setting	**Description**	**Range**	**Value**
IN104D	Input 104 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN105D	Input 105 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
IN106D	Input 106 Debounce Time (cycles in 0.25 increments)	Range = 0.00 to 2.00	0.00
EBMON	Breaker Monitor	Select: Y, N	N
EPMU	Synchronized Phasor Measurement	Select: Y, N	N
Global			
			Top

Channel X			
			Top
Setting	**Description**	**Range**	**Value**
EADDCX	Channel X Address Check	Select: Y, G, N	N
RBADXP	Continuous Dropout Alarm (Seconds)	Range = 1 to 1000	1
AVAXP	Packets Lost in Last 10,000 Alarm	Range = 1 to 5000	10
DBADXP	One Way Channel Delay Alarm (msec.)	Range = 1 to 24	10
TIMRX	Timing Source (I=Internal, E=External)	Select: I, E	E
Channel X			
			Top

Channel Y			
			Top
Setting	**Description**	**Range**	**Value**
EADDCY	Channel Y Address Check	Select: Y, G, N	N
RBADYP	Continuous Dropout Alarm (Seconds)	Range = 1 to 1000	1
AVAYP	Packets Lost in Last 10,000 Alarm	Range = 1 to 5000	10
DBADYP	One Way Channel Delay Alarm (msec.)	Range = 1 to 24	10
TIMRY	Timing Source (I=Internal, E=External)	Select: I, E	E
Channel Y			

Channel Y			
			[Top](#)
Setting	**Description**	**Range**	**Value**
			[Top](#)

Port 2			
			[Top](#)
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL, LMD, DNP, MBA, MB8A, MBGA, MBB, MB8B, MBGB	SEL
T_OUT	Minutes to Port Time-out	Range = 0 to 30	15
DTA	Meter Format	Select: Y, N	N
SPEED	Baud Rate	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400	19200
AUTO	Send Auto Messages to Port	Select: Y, N	Y
BITS	Data Bits	Select: 6-8	8
RTSCTS	Enable Hardware Handshaking	Select: Y, N	N
PARITY	(Odd, Even, None)	Select: O, E, N	N
FASTOP	Fast Operate Enable	Select: Y, N	Y
STOP	Stop Bits	Select: 1, 2	1
Port 2			
			[Top](#)

Appendix F: SEL-387E Settings

Global			Top
Setting	**Description**	**Range**	**Value**
LER	Length of Event Report	Select: 15, 29, 60	60
PRE	Length of Prefault in Event Report	1-59cyc	4
NFREQ	Nominal Frequency	Select: 50, 60	60
PHROT	Phase Rotation	Select: ABC, ACB	ACB
DELTA_Y	Phase Potential Connection	Select: Y, D	Y
DATE_F	Date Format	Select: MDY, YMD	MDY
SCROLD	Display Update Rate	1-60S	2
FP_TO	Front Panel Timeout	OFF, 0-30 min	16
TGR	Group Change Delay	0-900S	3
Global			Top

Group 2			Top
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (39 Characters)		387E_Y-Y
TID	Terminal Identifier (59 Characters)		BENCH5
E87W1	Enable Wdg1 in Differential Element	Select: N, Y, Y1	Y1
E87W2	Enable Wdg2 in Differential Element	Select: N, Y, Y1	Y1
E87W3	Enable Wdg3 in Differential Element	Select: N, Y, Y1	N
EOC1	Enable Wdg1 O/C Elements and Dmd. Thresholds	Select: N, Y	N
EOC2	Enable Wdg2 O/C Elements and Dmd. Thresholds	Select: N, Y	Y
EOC3	Enable Wdg3 O/C Elements and Dmd. Thresholds	Select: N, Y	N
EOCC	Enable Combined O/C Elements	Select: N, Y	N
E24	Enable Volts/Hertz Protection	Select: N, Y	N

Group 2			Top
Setting	**Description**	**Range**	**Value**
E27	Enable Undervoltage Protection	Select: N, Y	N
E59	Enable Overvoltage Protection	Select: N, Y	N
E81	Enable Frequency Protection	Select: N, 1-6	N
ESLS1	Enable SELogic Set 1	Select: N, Y	N
ESLS2	Enable SELogic Set 2	Select: N, Y	N
ESLS3	Enable SELogic Set 3	Select: N, Y	N
W1CT	Wdg 1 CT Connection	Select: D, Y	Y
W2CT	Wdg 2 CT Connection	Select: D, Y	Y
W3CT	Wdg 3 CT Connection	Select: D, Y	Y
CTR1	Wdg 1 CT Ratio	1-50000	1
CTR2	Wdg 2 CT Ratio	1-50000	1
CTR3	Wdg 3 CT Ratio	1-50000	1
MVA	Maximum Power Xfmr Capacity	OFF,0.2-5000.0 MVA	OFF
ICOM	Define Internal CT Connection Compensation	Select: N, Y	N
PTR	PT Ratio	1-6500	1
COMPANG	Compensation Angle	0-360deg	0
VIWDG	Voltage-Current Winding	Select: 1-3, 12	1
TPVI	Three Phase Voltage Input	Select: N, Y	Y
TAP1	Wdg 1 Current Tap	0.50-155.00	251.02
TAP2	Wdg 2 Current Tap	0.50-155.00	418.37
O87P	Restrained Element Current PU	0.10-1.00 TAP	0.30
SLP1	Restraint Slope 1 Percentage	5-100%	25
SLP2	Restraint Slope 2 Percentage	OFF,25-200%	50
IRS1	Restraint Current Slope 1 Limit	1.0-20.0 TAP	3.0
U87P	Unrestrained Element Current PU	1-20 TAP	3.0
PCT2	2nd Harmonic Blocking Percentage	OFF,5-100%	15
PCT4	4th Harmonic Blocking Percentage	OFF,5-100%	15
PCT5	5th Harmonic Blocking Percentage	OFF,5-100%	35
TH5P	5th Harmonic Alarm Threshold	OFF,0.02-3.2 TAP	OFF
DCRB	DC Ratio Blocking	Select: N, Y	Y

Group 2			Top
Setting	**Description**	**Range**	**Value**
HRSTR	Harmonic Restraint	Select: N, Y	Y
E32I	Enable 32I(SELogic Equation)		0
51P2P	Phase Inv-Time O/C PU	OFF,0.50-16.00A,sec	4.50
51P2C	Phase Inv-Time O/C Curve	Select: U1, U2, U3, U4, U5, C1, C2, C3, C4, C5	U1
51P2TD	Phase Inv-Time O/C Time-Dial	0.50-15.00	0.60
51P2RS	Phase Inv-Time O/C EM Reset	Select: N, Y	N
51P2TC	51P2 Torque Control (SELogic Equation)		1
51Q2P	Neg-Seq Inv-Time O/C PU	OFF,0.50-16.00A,sec	0.50
51Q2C	Neg-Seq Inv-Time O/C Curve	Select: U1, U2, U3, U4, U5, C1, C2, C3, C4, C5	U1
51Q2TD	Neg-Seq Inv-Time O/C Time-Dial	0.50-15.00	0.60
51Q2RS	Neg-Seq Inv-Time O/C EM Reset	Select: N, Y	N
51Q2TC	51Q2 Torque Control (SELogic Equation)		1
51N2P	Res. Inv-Time O/C PU	OFF,0.50-16.00A,sec	0.50
51N2C	Res. Inv-Time O/C Curve	Select: U1, U2, U3, U4, U5, C1, C2, C3, C4, C5	U1
51N2TD	Res. Inv-Time O/C Time-Dial	0.50-15.00	0.60
51N2RS	Res. Inv-Time O/C EM Reset	Select: N, Y	N
51N2TC	51N2 Torque Control (SELogic Equation)		1
TDURD	Trip Duration Delay	4.000-8000.000 cyc	9.000
TR1			87R + OC1
TR2			87R + 51P2T + OC2
TR3			51Q2T
TR4			51N2T
ER			/50P11 + /51P1 + /51Q1 + /51P2 + /51Q2 + /51N2 + /51P3
OUT101			!TRIP1

Group 2 Top			
Setting	**Description**	**Range**	**Value**
OUT102			!(TRIP2 + TRIP3 + TRIP4)
Group 2 Top			

Report Top			
Setting	**Description**	**Range**	**Value**
SER1			IN101, IN102, IN103, IN104, IN105, IN106
SER2			OUT101, OUT102, OUT103, OUT104, OUT105, OUT106, OUT107
SER3			51Q2T, 51Q2, 87R, 51P2T, 51P2, 51N2T, 51N2, TRIP1, TRIP2, TRIP3, TRIP4
SER4			0
Report Top			

Port 2 Top			
Setting	**Description**	**Range**	**Value**
PROTO	Protocol	Select: SEL, LMD, DNP	SEL
SPEED	Baud rate	Select: 300, 1200, 2400, 4800, 9600, 19200, 19.2	19200
BITS	Data bits	Select: 7, 8	8
PARITY	Parity	Select: N, E, O	N
STOP	Stop bits	Select: 1, 2	1
T_OUT	Timeout	0-30 min	30
AUTO	Send auto messages to port	Select: N, Y	Y
RTSCTS	Enable hardware handshaking	Select: N, Y	N
FASTOP	Fast operate enable	Select: N, Y	N
Port 2 Top			

Appendix G: SEL-587 Settings

Device			Top
Setting	**Description**	**Range**	**Value**
RID	Relay Identifier (12 characters)	Range = ASCII string with a maximum length of 12.	587_D-D
TID	Terminal Identifier (12 characters)	Range = ASCII string with a maximum length of 12.	BENCH5
MVA	Maximum Power Transformer Capacity (MVA)	Range = 0.2 to 5000.0, OFF	OFF
TRCON	Xfmr	Select: YY, YDAC, YDAB, DACDAC, DABDAB, DABY, DACY, OTHER	DACDAC
CTCON	CT Connection	Select: YY	YY
RZS	Remove I0 from Y Connection Compensation	Select: Y, N	N
CTR1	Winding 1 CT Ratio	Range = 1 to 50000	1
CTR2	Winding 2 CT Ratio	Range = 1 to 50000	1
TAP1	Winding 1 Current Tap	Range = 0.50 to 160.00	3.00
TAP2	Winding 2 Current Tap	Range = 0.50 to 160.00	3.00
O87P	Operating Current PU (TAP)	Range = 0.2 to 1.0	0.4
SLP1	Restraint Slope 1 (%)	Range = 5 to 100	40
SLP2	Restraint Slope 2 (%)	Range = 25 to 200, OFF	50
IRS1	Restraint Current Slope 1 Limit (TAP)	Range = 1.0 to 16.0	3.0
U87P	Inst Unrestrained Current PU (TAP)	Range = 1.0 to 16.0	10.0
PCT2	2nd Harmonic Blocking Percentage (%)	Range = 5 to 100, OFF	15
PCT4	4th Harmonic Blocking Percentage (%)	Range = 5 to 100, OFF	15
PCT5	5th Harmonic Blocking Percentage (%)	Range = 5 to 100, OFF	35
TH5	5th Harmonic Threshold	Range = 0.2 to	0.3

Device			**Top**
Setting	**Description**	**Range**	**Value**
	(TAP)	3.2	
TH5D	5th Harmonic Alarm TDPU (cyc)	Range = 0.000 to 8000.000	30.000
DCRB	DC Ratio Blocking	Select: Y, N	Y
HRSTR	Harmonic Restraint	Select: Y, N	Y
51P1P	Phase Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	OFF
50Q1P	Neg.-Seq. Def.-Time O/C PU (A)	Range = 0.5 to 80.0, OFF	OFF
51Q1P	Neg.-Seq. Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	OFF
51N1P	Residual Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	OFF
51P2P	Phase Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	2.0
51P2C	Phase Inv.-Time O/C Curve	Select: U1, U2, U3, U4, C1, C2, C3, C4	U1
51P2TD	Phase Inv.-Time O/C Time-Dial	Range = 0.50 to 15.00	0.60
51P2RS	Phase Inv.-Time O/C EM Reset	Select: Y, N	N
51Q2P	Neg.-Seq. Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	0.5
51Q2C	Neg.-Seq. Inv.-Time O/C Curve	Select: U1, U2, U3, U4, C1, C2, C3, C4	U1
51Q2TD	Neg.-Seq. Inv.-Time O/C Time-Dial	Range = 0.50 to 15.00	0.60
51Q2RS	Neg.-Seq. Inv.-Time O/C EM Reset	Select: Y, N	N
51N2P	Residual Inv.-Time O/C PU (A)	Range = 0.5 to 16.0, OFF	OFF
TDURD	Minimum Trip Duration Time Delay (cyc)	Range = 0.000 to 2000.000	9.000
NFREQ	Nominal Frequency (Hz)	Select: 50, 60	60
PHROT	Phase Rotation	Select: ABC, ACB	ACB
Device			**Top**

Logic [Top](#)			
Setting	**Description**	**Range**	**Value**
X	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	NA
Y	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	NA
MTU1	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	87R + OC1
MTU2	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	87R + 51P2T + 51Q2T + OC2
MTU3	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	51N2T
MER	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	87R + 51P2T + 51Q2T + 51N2T + 51P1P + 51Q2P + 51N2P
OUT1	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!TRP1

Logic			Top
Setting	**Description**	**Range**	**Value**
OUT2	(SELogic Equation)	Valid range = Boolean equation using word bit elements and the legal operators: ! / \ ( ) * +	!TRP2 * !TRP3
Logic			Top

Port			Top
Setting	**Description**	**Range**	**Value**
PROTOCOL	Port Protocol	Select: SEL, LMD	SEL
SPEED	Baud Rate (bps)	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400	19200
DATA_BITS	Number Data Bits	Select: 7, 8	8
PARITY	Parity	Select: O, E, N	N
STOP	Stop Bits (bits)	Select: 1, 2	1
TIMEOUT	Timeout (min)	Range = 0 to 30	10
AUTO	Auto Message Output	Select: Y, N	Y
RTS_CTS	Enable RTS/CTS Handshaking	Select: Y, N	N
FAST_OP	Enable Fast Operate	Select: Y, N	N
Port			Top

Appendix H: SEL-700G Synchronism Check Experiment Procedure

ELECTRICAL ENGINEERING DEPARTMENT
California Polytechnic State University
San Luis Obispo

EE 518 **Experiment #1**

Synchronism Check Using the SEL-700G

Learning Outcomes

- Implement the synchronism check element in the 700G.
- Identify the requirements for successful synchronization of a stand-alone generator to the grid.
- Interpret synchronization report and develop recommendations to improve synchronism results.

Background

In order for a stand-alone generator to connect to the grid, several requirements must be met. First, the rms voltage levels of the two sources must be very close together. If they are not, the generator will connect to the grid either under-excited or over-excited. Under-excitation means the generator is absorbing reactive power, while over-excitation indicates the generator is supplying reactive power to the grid. If the voltage imbalance before synchronization is high, then a large current will flow between the two voltage sources to supply this reactive power. The direction of current flow is determined by which source voltage is higher.

Second, the frequencies of the grid and generator must be almost identical. Differences in frequency cause the generator to either supply or receive real power after synchronization. If the generator frequency is higher than the grid frequency, it will supply power. If the generator frequency is lower than the grid frequency, it will absorb power. If the frequency difference is high enough, a large current will flow between the two sources to supply this power.

Third, the phase of the two sources must be the same. If the sources are not in phase when synchronized, the magnitudes of the voltages will not be equal. This, coupled with the inability of the grid to pull the phases together, causes an unstable voltage at the point of connection.

While measuring voltage magnitude and frequency is fairly easy to do manually, measuring the phase of a system is much more challenging. One of the original methods used for synchronization required wiring light bulbs in a specific pattern to determine when the grid and generator were in phase. Modern microprocessor relays make measuring phase much easier. In addition to measuring voltage and frequency directly, microprocessor relays can measure the phase angle of the voltage in real time. In fully automated synchronization schemes, microprocessor relays can adjust the voltage and frequency of a generator until it meets the requirements set in its software and synchronizes to the grid.

In this experiment, voltage and frequency will be manually adjusted due to limitations in the equipment being used. The SEL-700G relay is programmed appropriately to check synchronism requirements and close the circuit breaker when they are met. The ANSI device code for synchronism-check is 25.

Prelab

1. Review the background section and summarize, in your own words, the requirements for proper synchronization between two voltage sources.

Equipment

- Bag of Banana-Banana Short Leads (3x)
- Banana-Banana or Banana-Spade Leads (25x)
- Circuit Breaker (1x)
- Computer with AcSELerator QuickSet Software and a Serial Port
- Resistor Bank (1x)
- Synchronous Machine (208V, 250W)
- DC machine (1x)
- DC Starter (1x)
- Magtrol Torque-Adjust Unit (1x)
- SEL-700G Relay (1x)
- SEL-C234A Serial Cable (1x)
- Wattmeter (1x)

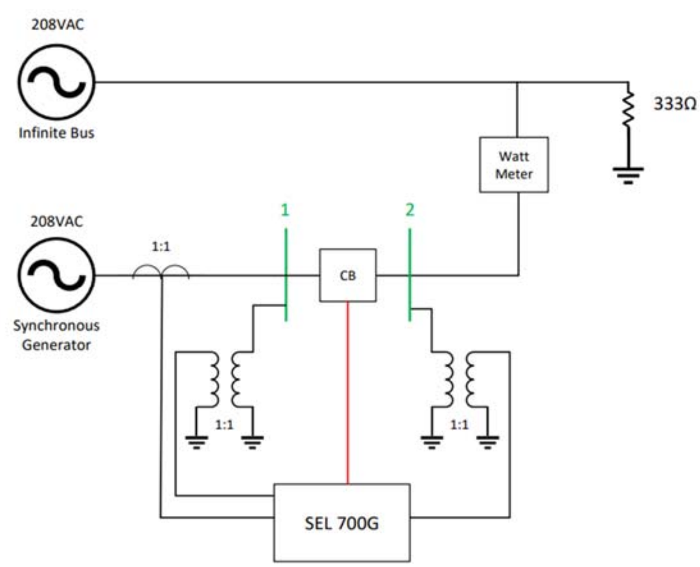

Figure 25: Circuit Diagram

<u>Procedure</u>

1. Plug in the power cord connected to the SEL-700G relay.

2. Connect an SEL-C234A serial cable between Port 3 on the back of the 700G and the main serial port on the back of the computer (surrounded by a light turquoise color).

3. On the computer, open the AcSELerator QuickSet software.

4. Determine the current baud rate for Port 3 on the 700G.
   a. On the front panel of the relay, press the enter button, labeled **<u>ENT</u>**.
   b. Use the down-arrow button to navigate to **<u>Set/Show</u>** on the front panel display. Press the enter button.
   c. Use the down-arrow button to navigate to **<u>Port</u>** on the front panel display. Press the enter button.
   d. Navigate to Port **<u>3</u>** and press the enter button.
   e. Navigate to **<u>Comm Settings</u>** and press the enter button.
   f. Use the down-arrow button to navigate through the current Port 3 settings. The baud rate (**SPEED**) is near the top of the list. If the baud rate is already set to 19200, press the **<u>ESC</u>** button several times to restore the screen to its normal display, and continue to the next step.
   g. If the current relay baud rate is not set to 19200, use the following steps to change the baud rate:
   h. With the relay's baud rate setting highlighted, press the enter key.
   i. Use the up, down, left, and right buttons to enter the relay's level 2 password (default is "**TAIL**" and is case-sensitive). Press the enter key to select each letter. Navigate to and select **<u>Accept</u>** after entering the password.
   j. Press the up/down-arrow buttons until <u>19200</u> (not 19.2) appears. Press the enter key.
   k. Press **<u>ESC</u>** twice, and select **<u>Yes</u>** to save the new port setting.

5. On the QuickSet main window (Figure 26), open the Communication Parameters window (<u>Communications</u>, <u>Parameters</u>) (Figure 27) to define and create a communication link with the 71. Enter the following information for a Serial Active Connection Type:
   a. Device: <u>COM1: Communications Port</u>
   b. SEL Bluetooth Device: Unchecked
   c. Data Speed: <u>19200</u>
   d. Data Bits: 8
   e. Stop Bits: 1
   f. Parity: None
   g. RTS/CTS: Off
   h. DTR: On
   i. XON/XOFF: On
   j. RTS: N/A (On)

k. Level 1 Password (Default **OTTER**)
l. Level 2 Password (Default **TAIL**)

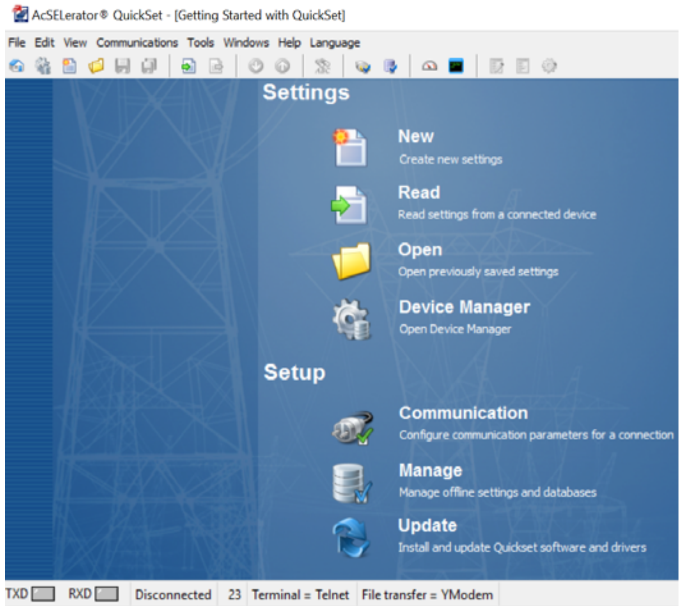

Figure 26: QuickSet Main Window

6. Click Apply at the bottom of the Communication Parameters window. Then click Ok. If the computer successfully connects to the relay, the connection status in the lower-left corner of the QuickSet main window should say “Connected.”

7. Create a new settings file for the SEL-700G relay.
   a. In the QuickSet main window, create a new settings file for the SEL-700G relay (File, New).
   b. Choose the Device Family, Model, and Version for this specific relay unit from the available menus, then click Ok (Figure 28). Look up the relay’s version number using the front-panel interface on the relay. Press the **ENT** button, and use the down-arrow button to navigate to the **STATUS** option.

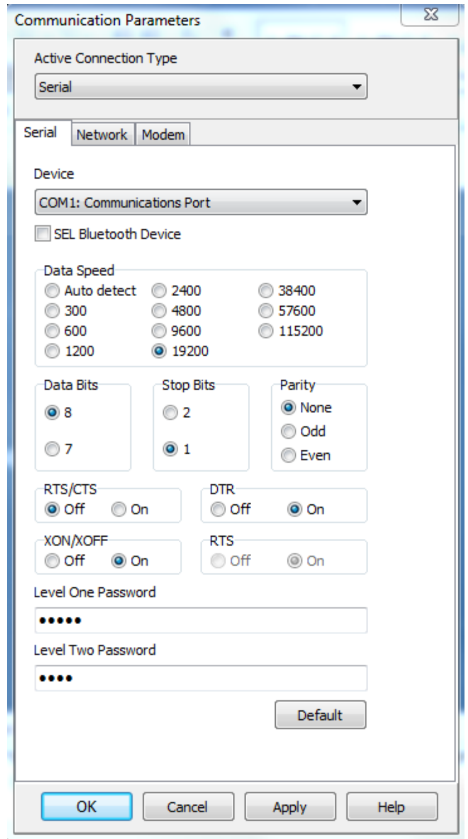

Figure 27: SEL-700G Communication Parameters Window

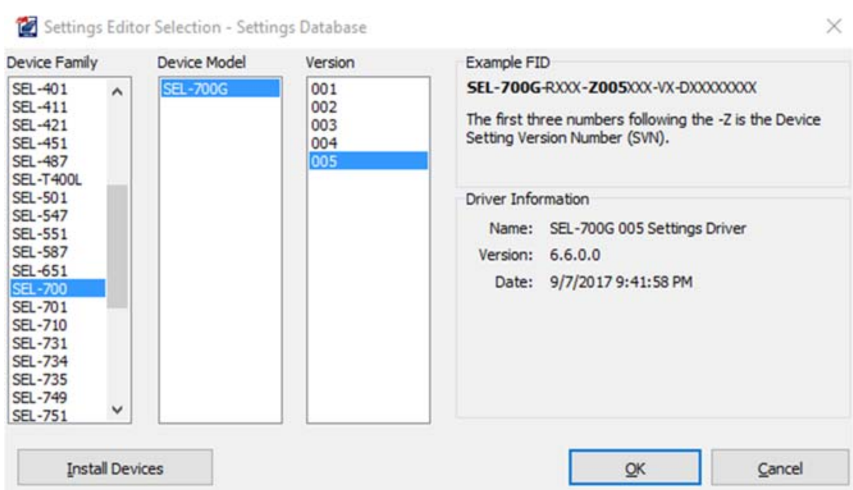

Figure 28: Select 700G Part Number

c. Press the enter button again. Select the **Relay Status** option. Navigate down to the **FID** option. Scroll across the relay's FID string until you come to the "Z-number." The first three digits following the 'Z' comprise the relay version number. Press the **ESC** button several times to restore the front-panel screen to its normal display. Note: if no devices are listed in the QuickSet drop-down menus, then the device drivers need to be installed using the SEL Compass software. Ask for assistance.

d. Enter the relay Part Number (Figure 29) printed on the serial number label (Figure 30) attached somewhere on the relay chassis. Note that the 5 A Secondary Input Current reflects the convention for American current transformers.

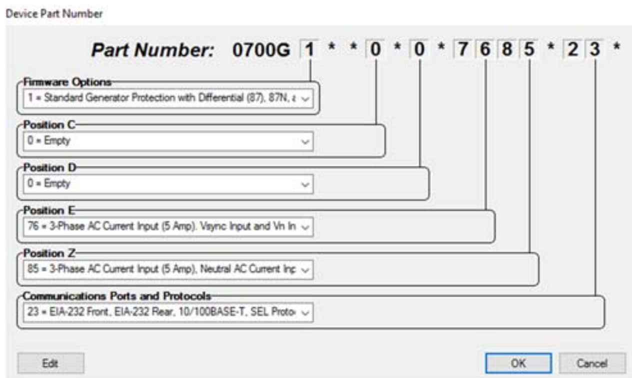

Figure 29: Identifying SEL-700G Relay Part Number

Figure 30: Example S/N Label with Relay Part Number

8. Save this relay settings database file (<u>File</u>, <u>Save As</u>; <u>New</u> if you do not want to use an existing settings database) in a location where it may be reused in future experiments. See Figure 31 and Figure 32. Then create a Settings Name for this settings file.

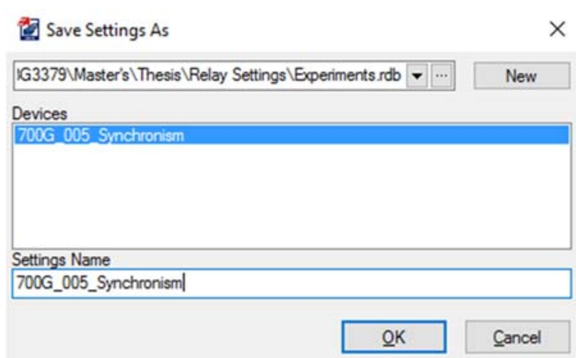

Figure 31: Saving SEL-700G Settings

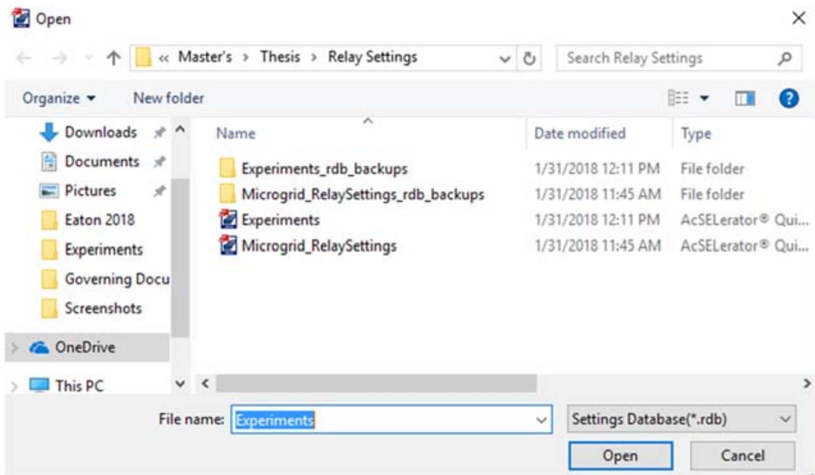

Figure 32: Choosing Location for New SEL-700G Settings Database

9. Open Global settings in the drop-down menu on the left side of the Settings Editor main window (Figure 33).
   a. Under General settings (Figure 34), replace the default Fault Condition (**FAULT**) contents with <u>TRIP</u>.
   b. Under Breaker Monitor settings (Figure 35), select <u>N</u> for the Enable Breaker Monitor (**EBMON**) setting.

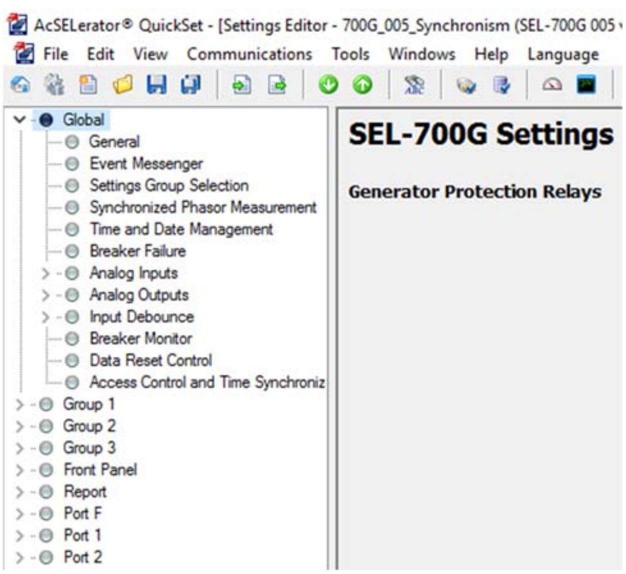

Figure 33: SEL-700G Settings Editor Main Window

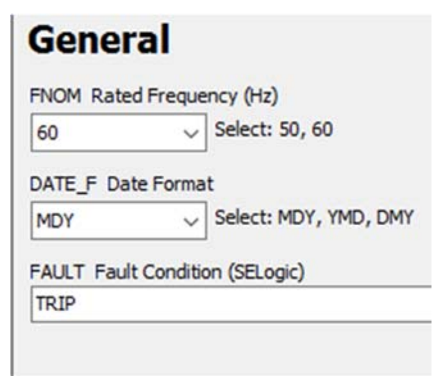

Figure 34: SEL 700G General Settings

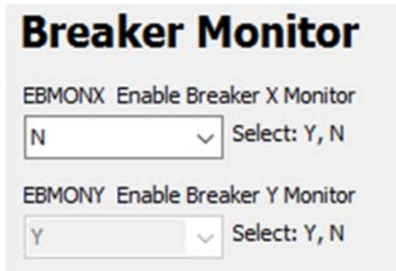

Figure 35: SEL-700G Breaker

Monitor Settings

10. Open the Group 1, Set 1 settings menu on the left side of the screen. Enter the following information in the Configuration Settings (Figure 37 and Figure 36).
    a. For **CTRN**, **PTRS**, **PTRN**, **CTRX**, **PTRX**, and **CTRY**, enter a value of 1, reflecting the fact that currents and voltages measured by the relay are the actual system currents and voltages (not stepped down). Current and potential transformers are not needed in this experiment because the system line currents and voltages are relatively low.
    b. For **INOM**, enter a value of 1.7A. for **VNOM_X** enter a value of .21kV.
    c. For **PHROT** enter ACB and for **X_CUR_IN** select TERM.
    d. For **DELTAY_X** and **CTCONY** select WYE
    e. For **EBUP** Select N

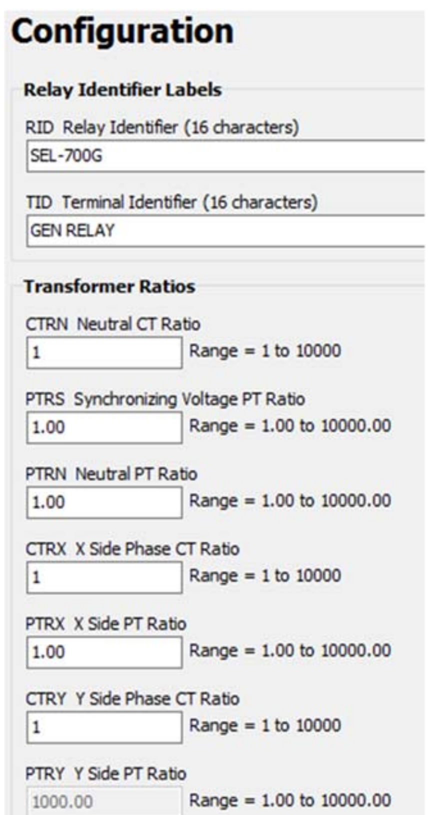

Figure 37: Configuration Settings

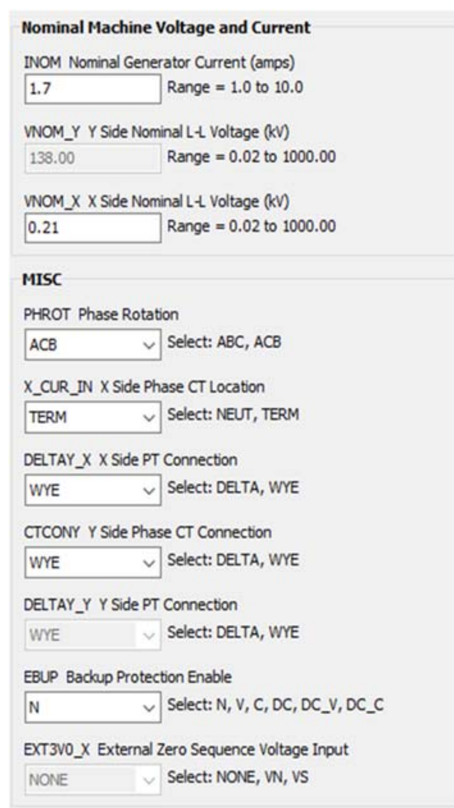

Figure 36: Configuration Settings 2

11. Under Set 1, Synchronism Check, select X Side Synchronism Check. Enter values as shown in Figure 38 and Figure 39.
    a. For **25VLOX**, enter a value of 117V.
    b. For **25VHIX**, enter a value of 123V.
    c. For **25VDIFX**, enter a value of 5.
    d. For **25RCFX**, enter a value of 1.
    e. For **GENV+** select N.
    f. For **25SLO** enter a value of 0.
    g. For **25SHI**, enter a value of .43
    h. For **25ANG1X** and 25ANG2X, enter a value of 0.
    i. For **CANGLE**, enter a value of 0.
    j. For **SYNCPX**, select VAX.
    k. For **TCLOSEDX**, enter 35ms.
    l. For **CFANGLE**, enter OFF.
    m. For **BSYNCHX**, type NOT 3POX.

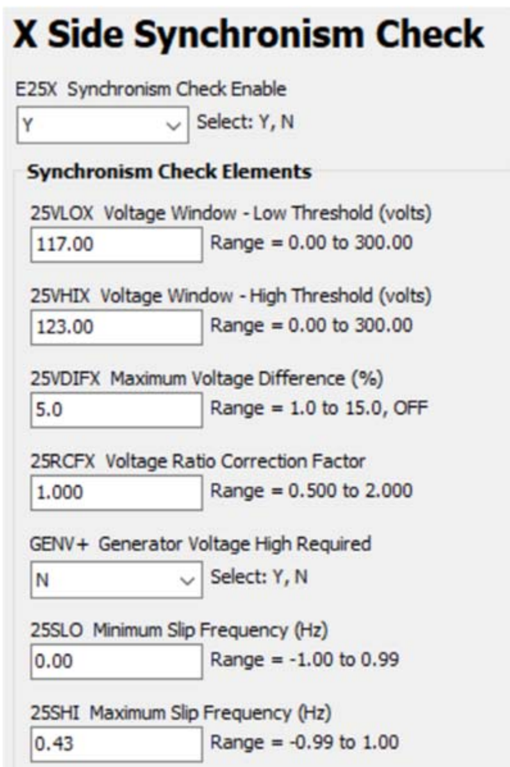

Figure 38: Synchronism Check Settings 1

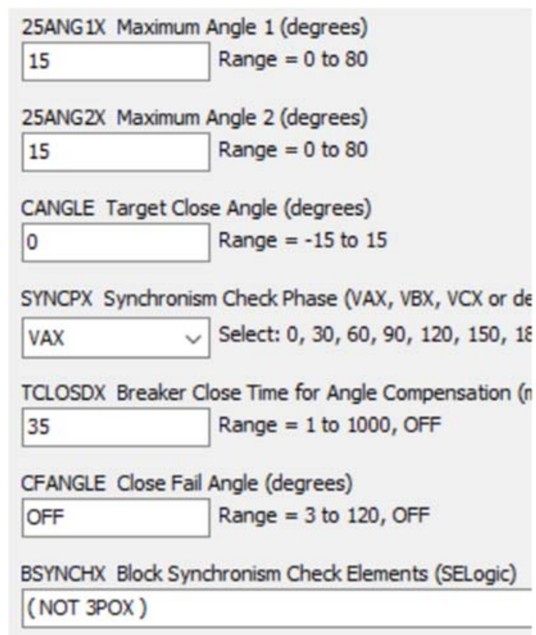

Figure 39: Synchronism Check Settings 2

12. Under Group 1, Set 1, set the following elements to N
    a. Stator Ground Elements (**E64G**)
    b. V/Hz Elements (**E24**)
    c. Differential Elements, Generator Phase (**E87**)

13. Under Group 1, Set 1, Trip and Close Logic, enter 25C in **CLX** as shown in Figure 40. All other values can be left as default.

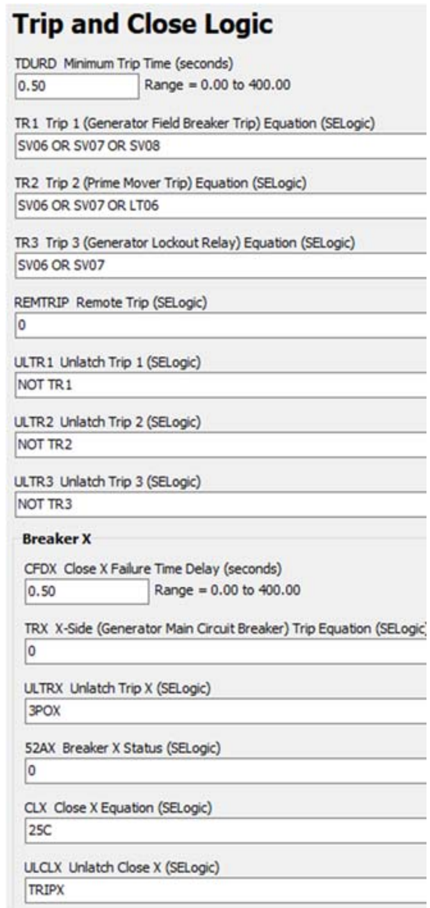

Figure 40: Trip and Close Logic

14. Under Group 1, Logic 1, Outputs, select Slot A. Enter the values as shown in Figure 41.
    a. For **OUT101FS**, select N.
    b. For **OUT101**, enter 0.
    c. For **OUT102FS**, select Y.
    d. For **OUT102**, enter 0.
    e. For **OUT103FS**, enter Y.
    f. For **OUT103**, enter NOT CLOSEX.

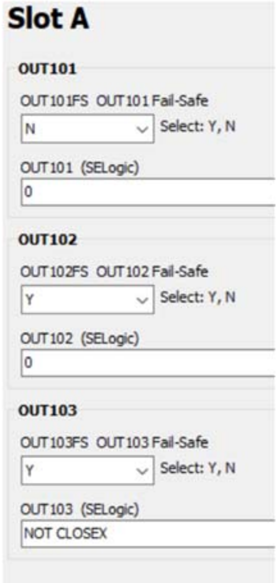

Figure 41: Output Configuration

15. Under the Report dropdown, select Generator Sync Report. Enter values as shown in Figure 42.
    a. For **GSRTRG**, enter <u>CLOSEX AND 25C</u>.
    b. For **GSRR**, select <u>1</u>.
    c. For **PRESYNC**, enter <u>4790</u>.

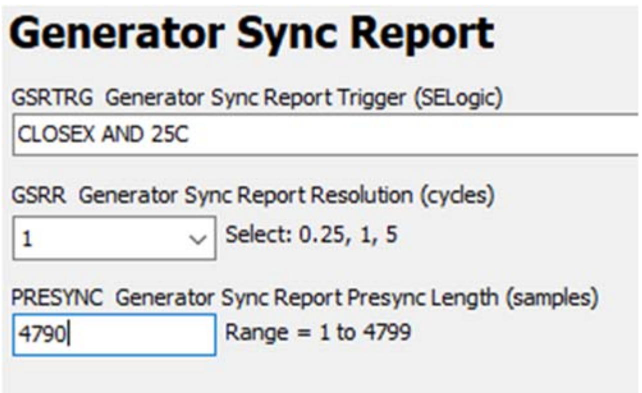

Figure 42: Generator Sync Report

16. Open the terminal window in the QuickSet software as shown in Figure 43 and do the following:
    a. Type ACC and press enter.
    b. Enter password OTTER and press enter.
    c. Type 2AC and press enter.

d. Enter password TAIL and press enter.

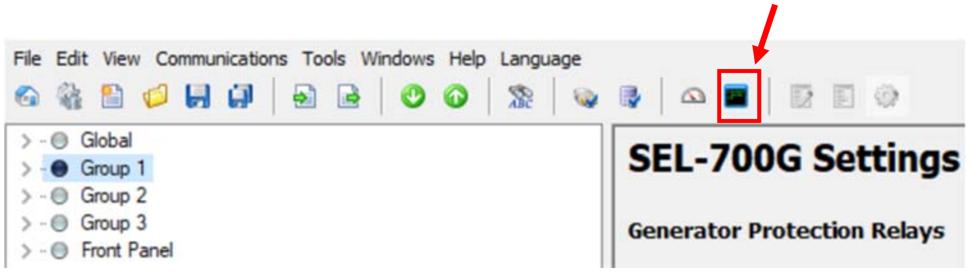

Figure 43: Open Terminal Window

17. Send the relay settings to the 700G by clicking the button as shown in Figure 44.

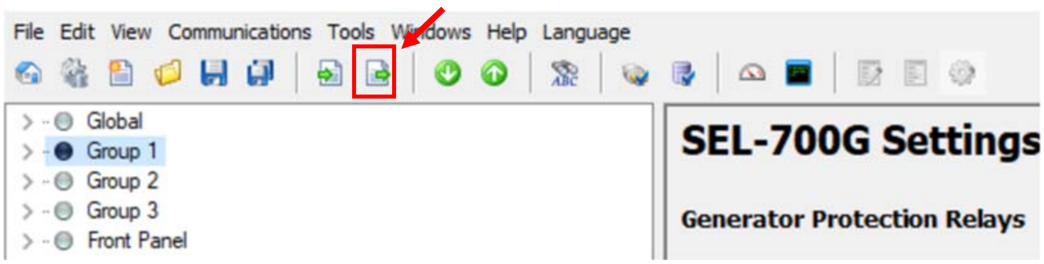

Figure 44: Send Settings to 700G

18. Select Global, Set 1, Logic 1, and Report as shown in Figure 45 and click OK.

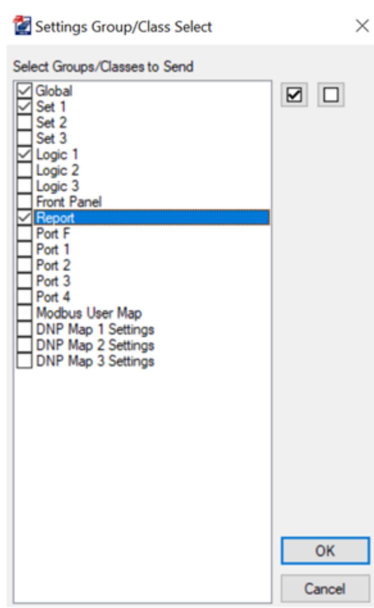

Figure 45: Select Settings to Send to

700G

19. Connect the three-phase circuit illustrated in Figure 1. Try to lay out the elements in the order illustrated in the schematic so that power flows across the bench from one end to the other. This linear arrangement limits the number of wires crossing each other and makes the path of the current low easier to review (and troubleshoot).

20. Start with the sequential connection points in Table 1, using the diagrams posted on the wattmeter at the lab bench for assistance.

Table 19: Per-Phase Sequential Points of Connection

Phase A	**Phase B**	**Phase C**
Generator stator voltage (left side)	Generator stator voltage (middle side)	Generator stator voltage (right side)
Relay Port **Z01** (Relay Input)	Relay Port **Z03** (Relay Input)	Relay Port **Z05** (Relay Input)
Relay Port **Z02** (Relay Output)	Relay Port **Z04** (Relay Output)	Relay Port **Z06** (Relay Output)
Circuit Breaker Input	Circuit Breaker Input	Circuit Breaker Input
Circuit Breaker Output	Circuit Breaker Output	Circuit Breaker Output
Wattmeter	Wattmeter	Wattmeter
Infinite Bus / 3-phase load	Infinite Bus / 3-phase load	Infinite Bus / 3 phase load

21. Make the following additional connections after completing the wiring in Table 1.
    a. Connect SEL-700G back panel ports **Z09**, **Z10**, and **Z11** to the circuit breaker inputs phase A, B, and C, respectively.
    b. Connect the SEL-700G back panel port **Z12** to the circuit breaker chassis ground terminal.
    c. Connect the SEL-700G back panel port **E07** the circuit breaker output phase A.
    d. Connect the SEL-700G back panel port **E08** to the circuit breaker chassis ground.
    e. Connect the circuit breaker chassis ground to the lab bench chassis ground.
    f. Connect SEL-700G back panel ports **A07** and **A08** to the close circuit breaker terminals.
    g. Connect the SEL 700G back panel ports **A05** and **A06** the trip circuit breaker terminals
    h. Position the DC motor to drive the synchronous generator. Make sure the synchronous generator is physically coupled with the magtrol torque adjust unit
    i. Connect one side of the generator stator in a wye configuration and connect this to chassis ground.

j. Connect the DC starter A1, A2, F1, and F2 terminals to the corresponding terminals on the DC motor.
k. Connect DC voltage to the DC starter.
l. Configure the potentiometer to provide variable field current to the synchronous generator using DC voltage on the bench.
m. Connect all equipment grounds to chassis ground.
n. Connect and configure a voltmeter to measure the voltage between phase A and the neutral of the generator.

22. Type HIS C in the Quickset terminal and press enter. When prompted, type Y and press enter to clear the event history in the 700G.

23. Have the instructor verify circuit connections before energizing the circuit.

24. Turn on the voltage at the Infinite Bus. Verify that the wattmeter is reading 208VAC.

25. Turn on the generator. Adjust the field current of the DC motor until the speed of the generator is slightly above 1800rpm, but below 1810rpm.

26. Adjust the field current of the generator until the voltage reading on the voltmeter is approximately 120V.

27. Iterate Steps 22 and 23 until the circuit breaker closes.

28. If the voltage on the wattmeter does not read approximately 208VAC after closing, turn off the AC power and check the circuit for wiring errors.

29. Turn off the AC and DC power at the lab bench.

30. Type SYN in the terminal window and copy the generated report for later use in your report.

31. Click on “Tools”, “Events”, and select “Get Event Files”. After a few seconds, a new screen will open. On the new screen, change Event type to Generator Synch Report as shown in Figure 46. With the file selected in Event History, click “Get Selected Events”. If no events appear, click “Refresh Event History” Save the file in a location you can easily access.

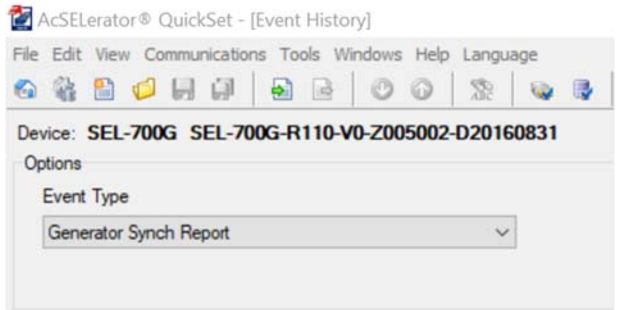

Figure 46: Change Event Type to Generator Synch

Report

Post-Lab

1. Compare the Oscillogram and synch report results to the parameters set in the synchronism check function on the 700G. What experimental values are furthest from ideal? How could they be improved?

Appendix I: SEL-421 Synchronism Check Experiment Procedure

ELECTRICAL ENGINEERING DEPARTMENT
California Polytechnic State University
San Luis Obispo

EE 518 **Experiment #2**

Synchronism Check Using the SEL-421

Learning Outcomes

- Implement the synchronism check element in the SEL-421.
- Identify the requirements for successful synchronization of a stand-alone generator to the grid.
- Interpret synchronization report and develop recommendations to improve synchronism results.

Background

In order for a stand-alone generator to connect to the grid, several requirements must be met. First, the rms voltage levels of the two sources must be very close together. If they are not, the generator will connect to the grid either under-excited or over-excited. Under-excitation means the generator is absorbing reactive power, while over-excitation indicates the generator is supplying reactive power to the grid. If the voltage imbalance before synchronization is high, then a large current will flow between the two voltage sources to supply this reactive power. The direction of current flow is determined by which source voltage is higher.

Second, the frequencies of the grid and generator must be almost identical. Differences in frequency cause the generator to either supply or receive real power after synchronization. If the generator frequency is higher than the grid frequency, it will supply power. If the generator frequency is lower than the grid frequency, it will absorb power. If the frequency difference is high enough, a large current will flow between the two sources to supply this power.

Third, the phase of the two sources must be the same. If the sources are not in phase when synchronized, the magnitudes of the voltages will not be equal. This, coupled with the inability of the grid to pull the phases together, causes an unstable voltage at the point of connection.

While measuring voltage magnitude and frequency is fairly easy to do manually, measuring the phase of a system is much more challenging. One of the original methods used for synchronization required wiring light bulbs in a specific pattern to determine when the grid and generator were in phase. Modern microprocessor relays make measuring phase much easier. In addition to measuring voltage and frequency directly, microprocessor relays can measure the phase angle of the voltage in real time. In fully automated synchronization schemes, microprocessor relays can adjust the voltage and frequency of a generator until it meets the requirements set in its software and synchronizes to the grid.

In this experiment, voltage and frequency will be manually adjusted due to limitations in the equipment being used. The SEL-421 relay is programmed appropriately to check synchronism requirements and close the circuit breaker when they are met. The ANSI device code for synchronism-check is 25.

Prelab

2. Review the background section and summarize, in your own words, the requirements for proper synchronization between two voltage sources.

Equipment

- Bag of Banana-Banana Short Leads (3x)
- Banana-Banana or Banana-Spade Leads (25x)
- Circuit Breaker (1x)
- Computer with AcSELerator QuickSet Software and a Serial Port
- Resistor Bank (1x)
- Synchronous Machine (208V, 250W)
- DC machine (1x)
- DC Starter (1x)
- Magtrol Torque-Adjust Unit (1x)
- SEL-421 Relay (1x)
- SEL-C234A Serial Cable (1x)
- Wattmeter (1x)

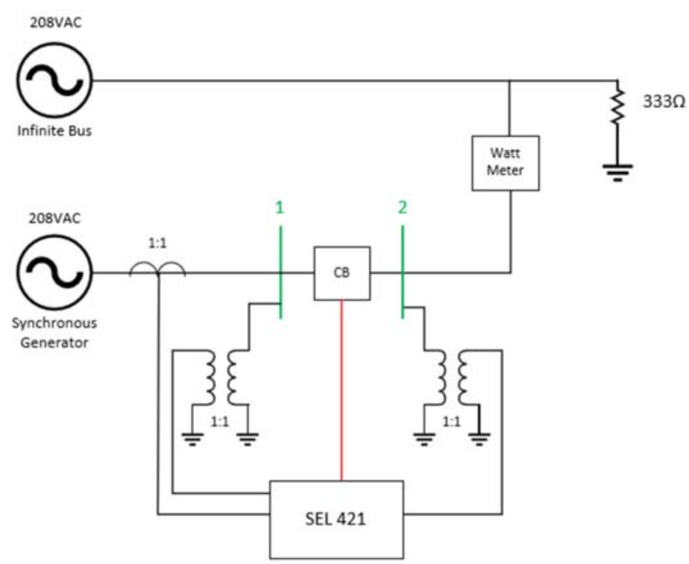

Figure 47: Circuit Diagram

Procedure

32. Plug in the power cord connected to the SEL-421 relay.

33. Connect an SEL-C234A serial cable between Port 1 on the back of the 421 and the main serial port on the back of the computer (surrounded by a light turquoise color).

34. On the computer, open the AcSELerator QuickSet software.

35. Determine the current baud rate for Port 1 on the 421.
    a. On the front panel of the relay, press the enter button, labeled **ENT**.
    b. Use the down-arrow button to navigate to **Set/Show** on the front panel display. Press the enter button.
    c. Use the down-arrow button to navigate to **Port** on the front panel display. Press the enter button.
    d. Navigate to Port **1** and press the enter button.
    e. Navigate to **Communication Settings** and press the enter button.
    f. Use the down-arrow button to navigate through the current Port 1 settings. The baud rate (**SPEED**) is near the top of the list. If the baud rate is already set to 19200, press the **ESC** button several times to restore the screen to its normal display, and continue to the next step.
    g. If the current relay baud rate is not set to 19200, use the following steps to change the baud rate:
    h. With the relay's baud rate setting highlighted, press the enter key.
    i. Use the up, down, left, and right buttons to enter the relay's level 2 password (default is "**TAIL**" and is case-sensitive). Press the enter key to select each letter. Navigate to and select **Accept** after entering the password.
    j. Press the up/down-arrow buttons until 19200 (not 19.2) appears. Press the enter key.
    k. Press **ESC** twice, and select **Yes** to save the new port setting.

36. On the QuickSet main window (Figure 48), open the Communication Parameters window (Communications, Parameters) (Figure 49) to define and create a communication link with the 421. Enter the following information for a Serial Active Connection Type:
    a. Device: COM1: Communications Port
    b. SEL Bluetooth Device: Unchecked
    c. Data Speed: 19200
    d. Data Bits: 8
    e. Stop Bits: 1
    f. Parity: None
    g. RTS/CTS: Off
    h. DTR: On
    i. XON/XOFF: On
    j. RTS: N/A (On)

k. Level 1 Password (Default **<u>OTTER</u>**)
l. Level 2 Password (Default **<u>TAIL</u>**)

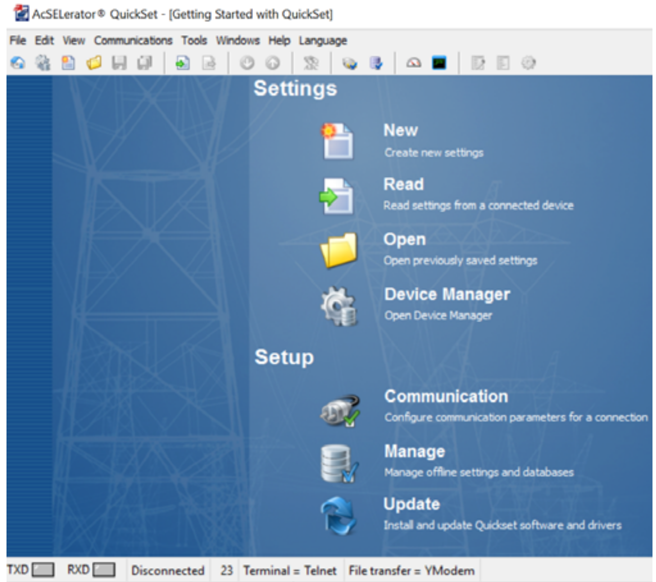

Figure 48: QuickSet Main Window

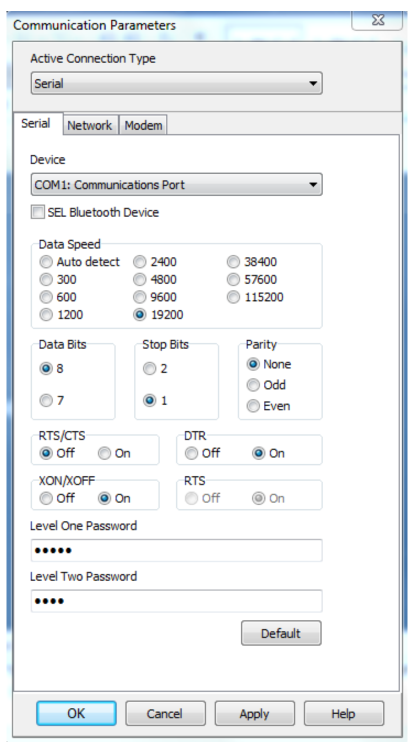

Figure 49: SEL-421 Communication Parameters Window

37. Click Apply at the bottom of the Communication Parameters window. Then click Ok. If the computer successfully connects to the relay, the connection status in the lower-left corner of the QuickSet main window should say "Connected."

38. Create a new settings file for the SEL-421 relay.
    e. In the QuickSet main window, create a new settings file for the SEL-421 relay (File, New).
    f. Choose the Device Family, Model, and Version for this specific relay unit from the available menus, then click Ok (Figure 50). Look up the relay's version number using the front-panel interface on the relay. Press the **ENT** button, and use the down-arrow button to navigate to the **STATUS** option. Press the enter button again. Select the **Relay Status** option. The first three digits following the 'Z' in the "Z-number" comprise the relay version number. Press the **ESC** button several times to restore the front-panel screen to its normal display. Note: if no devices are listed in the QuickSet drop-down menus, then the device drivers need to be installed using the SEL Compass software. Ask for assistance.

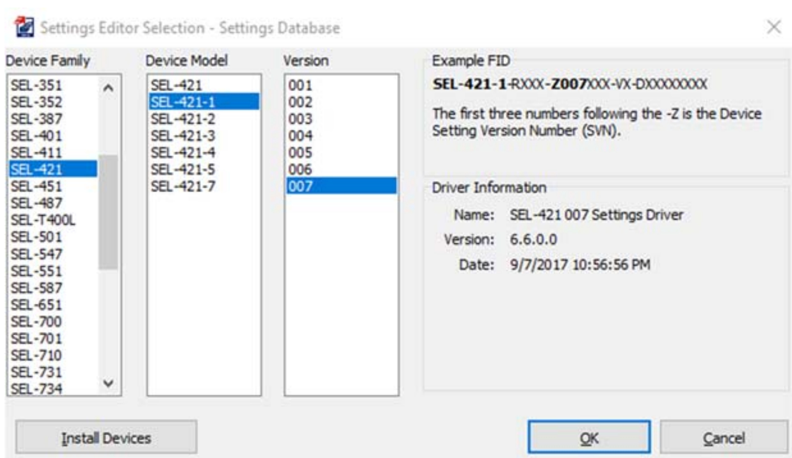

Figure 50: Select 421 Part Number

    g. Enter the relay Part Number (Figure 51) printed on the serial number label (Figure 52) attached somewhere on the relay chassis. Note that the 5 A Secondary Input Current reflects the convention for American current transformers.

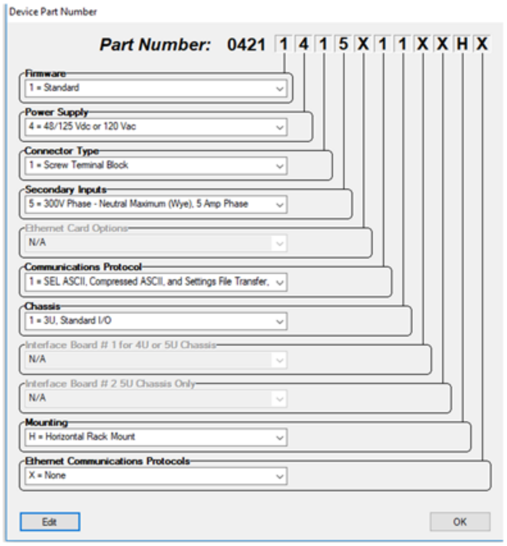

Figure 51: Identifying SEL-421 Relay Part Number

Figure 52: Example S/N Label

with Relay Part Number

39. Save this relay settings database file (File, Save As; New if you do not want to use an existing settings database) in a location where it may be reused in future experiments (Figure 53 and Figure 54). Next, create a Settings Name for this settings file.

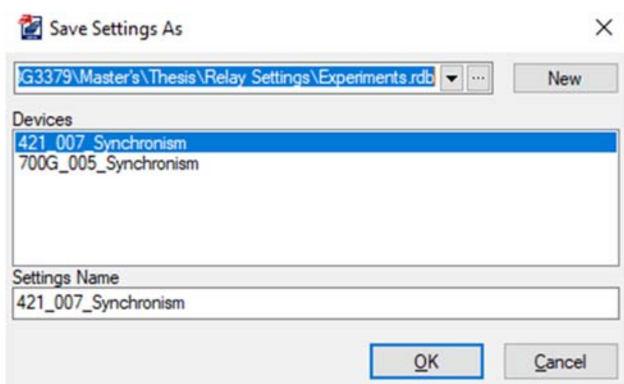

Figure 53: Saving SEL-421 Settings

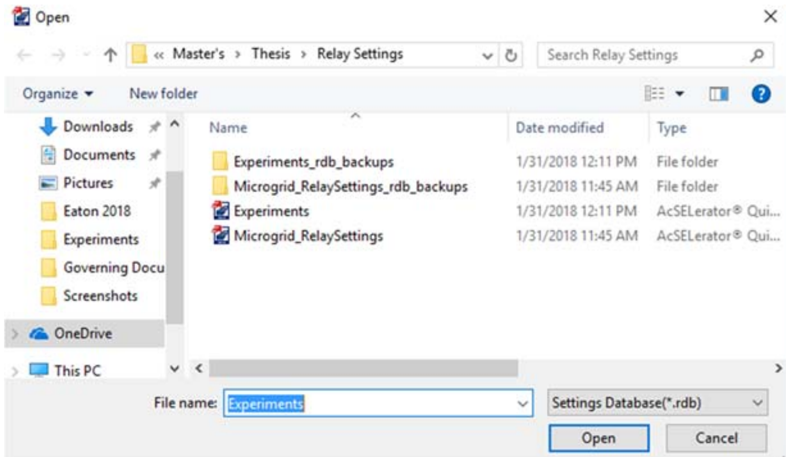

Figure 54: Choosing Location for New SEL-421 Settings Database

40. Open Global settings in the drop-down menu on the left side of the Settings Editor main window (Figure 55).
    c. Under General settings (Figure 56), enter the following values:
        i. For **NUMBK**, select <u>1</u>.
        ii. For **NFREQ**, select <u>60</u>.
        iii. For **PHROT**, select <u>ACB</u>.
    d. Under Settings Group Selection (Figure 57), enter <u>1</u> for **SS1** and <u>NA</u> for **SS2**.

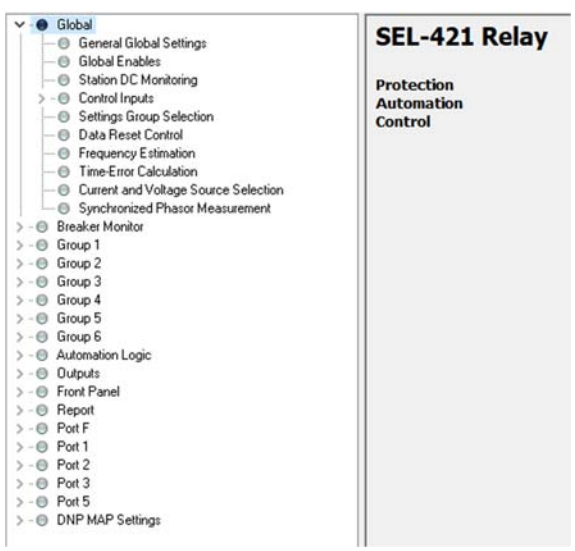

Figure 55: SEL-421 Settings Editor Main Window

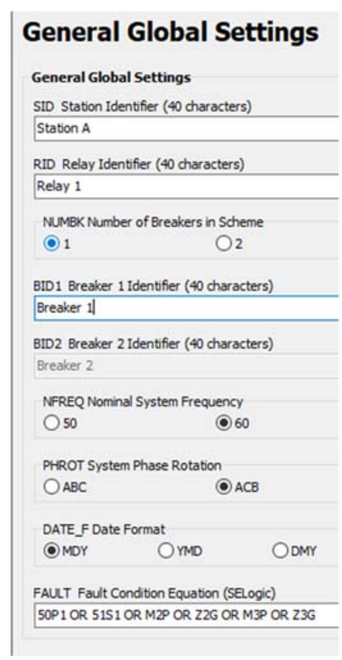

Figure 56: SEL 421 General

Settings

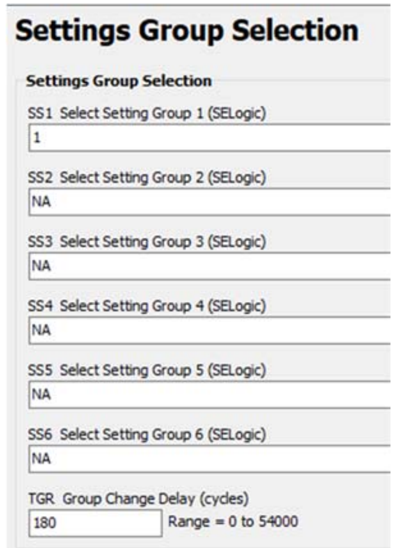

Figure 57: SEL-421 Breaker

Monitor Settings

41. Open the Group 1, Set 1. Line Configuration settings menu on the left side of the screen. Enter the following information in the Configuration Settings (Figure 58).
    a. For **CTRW**, **CTRX**, **PTRY**, and **PTRZ**, enter a value of 1, reflecting the fact that currents and voltages measured by the relay are the actual system currents and voltages (not stepped down). Current and potential transformers are not needed in this experiment because the system line currents and voltages are relatively low.
    b. For **VNOMY** and **VNOMZ**, enter a value of 208V.
    c. For **EFLOC** Select N.

Figure 58: Configuration Settings

42. Under Group 1, Set 1, Relay Configuration, Synchronism Check, set **E25BK1** to Y. Enter values as shown in Figure 59 and Figure 60.
    a. For **SYNCP**, enter a value of VAZ.
    b. For **25VL**, enter a value of 115V.
    c. For **25VH**, enter a value of 123.
    d. For **SYNCS1**, enter a value of 1.
    e. For **KS1M** enter a value of 1.
    f. For **KS1A** enter a value of 0.
    g. For **25SFBK1**, enter a value of .43
    h. For **ANG1BK1**, enter a value of 10.
    i. For **ANG2BK1**, enter a value of 10.
    j. For **TCLSBK1**, enter a value of 2.
    k. For **BSYNCHX**, type NA.

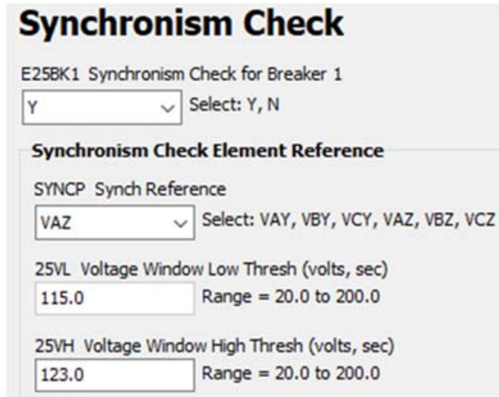

Figure 59: Synchronism Check 1

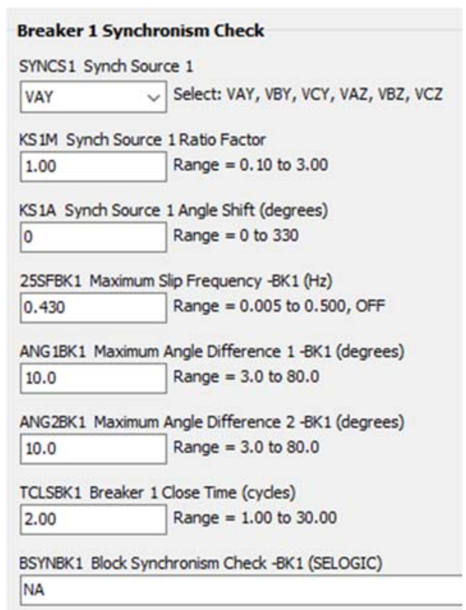

Figure 60: Synchronism Check 2

43. Under Outputs, Enter the values as shown in Figure 61.
    a. For **OUT101**, enter 25A1BK1.

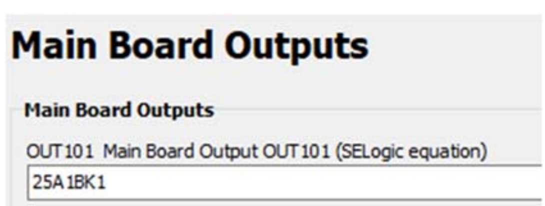

Figure 61: Output Configuration

44. Open the terminal window in the QuickSet software as shown in Figure 62 and do the following:
    a. Type ACC and press enter.
    b. Enter password OTTER and press enter.
    c. Type 2AC and press enter.
    d. Enter password TAIL and press enter.

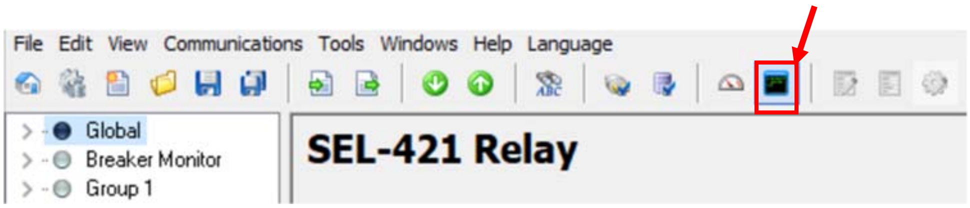

Figure 62: Open Terminal Window

45. Send the relay settings to the 421 by clicking the button as shown in Figure 63.

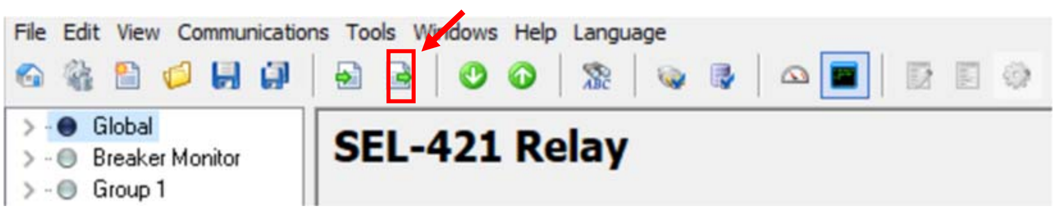

Figure 63: Send Settings to 421

46. Select Global, Set 1, and Outputs, as shown in Figure 64 and click OK.

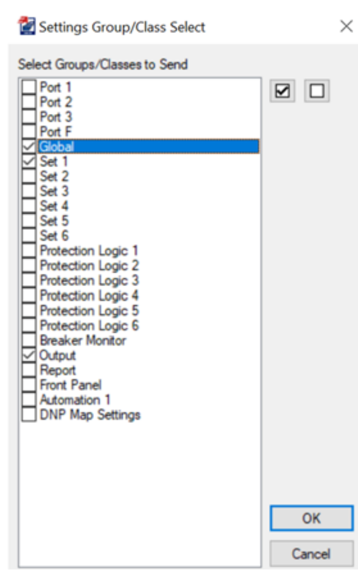

Figure 64: Select Settings to Send to 421

47. Connect the three-phase circuit illustrated in Figure 1. Try to lay out the elements in the order illustrated in the schematic so that power flows across the bench from one end to the other. This linear arrangement limits the number of wires crossing each other and makes the path of the current low easier to review (and troubleshoot).

48. Start with the sequential connection points in Table 1, using the diagrams posted on the wattmeter at the lab bench for assistance.

Table 20: Per-Phase Sequential Points of Connection

Phase A	Phase B	Phase C
Generator stator voltage (left side)	Generator stator voltage (middle side)	Generator stator voltage (right side)
Relay Port **Z01** (Relay Input)	Relay Port **Z03** (Relay Input)	Relay Port **Z05** (Relay Input)
Relay Port **Z02** (Relay Output)	Relay Port **Z04** (Relay Output)	Relay Port **Z06** (Relay Output)
Circuit Breaker Input	Circuit Breaker Input	Circuit Breaker Input
Circuit Breaker Output	Circuit Breaker Output	Circuit Breaker Output
Wattmeter	Wattmeter	Wattmeter
Infinite Bus / 3-phase load	Infinite Bus / 3-phase load	Infinite Bus / 3 phase load

49. Make the following additional connections after completing the wiring in Table 1.
    a. Connect SEL-421 back panel ports **Z13**, **Z15**, and **Z17** to the circuit breaker inputs phase A, B, and C, respectively.
    b. Connect the SEL-421 back panel port **Z14**, **Z16**, **Z18** to the lab bench chassis ground.
    c. Connect the SEL-421 back panel port **Z19** the circuit breaker output phase A.
    d. Connect the SEL-421 back panel port **Z20** to the circuit breaker chassis ground.
    e. Connect the circuit breaker chassis ground to the lab bench chassis ground.
    f. Connect SEL-421 back panel ports **A01** and **A02** to the close circuit breaker terminals.
    g. Connect the Circuit Breaker trip terminals together.
    h. Position the DC motor to drive the synchronous generator. Make sure the synchronous generator is physically coupled with the magtrol torque adjust unit
    i. Connect one side of the generator stator in a wye configuration and connect this to chassis ground.

j. Connect the DC starter A1, A2, F1, and F2 terminals to the corresponding terminals on the DC motor.
k. Connect DC voltage to the DC starter.
l. Configure the potentiometer to provide variable field current to the synchronous generator using DC voltage on the bench.
m. Connect all equipment grounds to chassis ground.
n. Connect and configure a voltmeter to measure the voltage between phase A and the neutral of the generator.

50. Have the instructor verify circuit connections before energizing the circuit.

51. Turn on the voltage at the Infinite Bus. Verify that the wattmeter is reading 208VAC.

52. Turn on the generator. Adjust the field current of the DC motor until the speed of the generator is slightly above 1800rpm, but below 1810rpm.

53. Adjust the field current of the generator until the voltage reading on the voltmeter is approximately 120V.

54. Iterate Steps 22 and 23 until the circuit breaker closes. Record the frequency and voltage of the generator immediately before the circuit breaker closes.

55. If the voltage on the wattmeter does not read approximately 208VAC after closing, turn off the AC power and check the circuit for wiring errors.

56. Turn off the AC and DC power at the lab bench.

Post-Lab

2. Compare the values of the generator frequency and voltage immediately before circuit breaker closure to the SEL-421 synchronism check settings.

    a. Which settings variables should the generator voltage be compared to?

    b. Which settings value(s) should the generator frequency be compared to?

    c. Do the pre-synchronization generator voltage and frequency values conform to the SEL-421 relay settings?

3. How does the value of TCLSBK1 affect synchronization?

Appendix J: SEL-710 Overcurrent and Undervoltage Protection Experiment with RTAC Data Acquisition

ELECTRICAL ENGINEERING DEPARTMENT
California Polytechnic State University
San Luis Obispo

EE 518 **Experiment #3**

Induction Motor Overcurrent and Undervoltage Protection Using the SEL-710

Learning Outcomes

- Identify, record, and eliminate bolted faults at the terminals of a 208 V induction motor using definite-time overcurrent protection
- Identify, record, and eliminate undervoltage operating conditions in an induction motor
- Analyze fault conditions from relay-generated event reports
- View real time data using the SEL Real Time Automation Controller

Background

The American National Standards Institute (ANSI) uses the designation '**50**' to denote *instantaneous overcurrent relays*. As a general rule, these relays trip immediately when a fault condition is detected. Traditional electromechanical relays illustrate this concept well: the presence of a sufficiently high pickup current activates a coil, which immediately switches a contact in the relay and trips the circuit breaker. Modern microprocessor-based relays (such as the SEL-710) replicate this functionality, but may also give the option to specify a finite amount of time between when the relay senses a sustained fault current and when the relay switches its contact to trip the circuit breaker. Relays with this delay option are known as *definite-time overcurrent relays*. Since definite-time overcurrent relays use constant delay times and immediately trip when that time expires, they fall under the ANSI category of instantaneous overcurrent relays. Individual overcurrent elements in many modern microprocessor-based relays, such as the SEL-710, are configured to detect overcurrent conditions in phase (50P) and neutral (50N) conductor currents, as well as calculated residual (50G) and negative-sequence (50Q) currents. As an aside, note that 50N denotes residual overcurrent in some other SEL relays. These particular designations are explained in the reference material (such as the instruction manual) for each relay.

Prelab

For calculations, ignore connections to the relay (i.e. circuit breakers, current transformers, and potential transformers). Assume that the motor is off when the faults occur.

a) Calculate the negative-sequence currents (in Amps) produced by bolted line-to-line and single-line-to-ground faults at Bus 1 in Figure 65.

b) Calculate the per-phase current (in Amps) of a triple-line-to-ground fault at the same location. Hint: use Ohm's law.
c) Calculate the phase current (in Amps) for the faulted phase in a single-line-to-ground fault at Bus 1 in Figure 65.

Equipment

- 25-Ω Single-Phase Power Resistor (3x)
- Bag of Banana-Banana Short Leads (3x) *
- Banana-Banana or Banana-Spade Leads (18x)
- Circuit Breaker (1x)
- Computer with AcSELerator QuickSet Software and a Serial Port
- Induction Motor: 208 V, 1/3 horsepower (1x), with Magtrol Torque-Adjust Unit (1x)
- SEL-710 Differential and Overcurrent Relay (1x)
- SEL-C234A Serial Cable (1x)
- Wattmeter (1x)

* Beware of extra flexible "small gauge" short leads, which can melt under fault conditions.

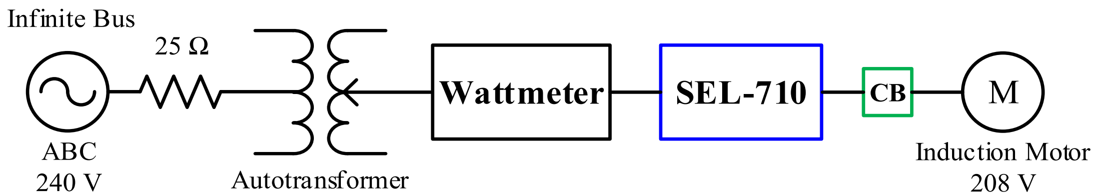

Figure 65: SEL-710 Procedure Single-Line Diagram

Procedure

57. Plug in the power cord connected to the SEL-710 relay.

58. Connect an SEL-C234A serial cable between Port 3 on the back of the 710 and the main serial port on the back of the computer (surrounded by a light turquoise color).

59. On the computer, open the AcSELerator QuickSet software.

60. Determine the current baud rate for Port 3 on the 710.
    a. On the front panel of the relay, press the enter button, labeled **ENT**.
    b. Use the down-arrow button to navigate to **Set/Show** on the front panel display. Press the enter button.
    c. Use the down-arrow button to navigate to **Port** on the front panel display. Press the enter button.
    d. Navigate to Port **3** and press the enter button.
    e. Navigate to **Comm Settings** and press the enter button.
    f. Use the down-arrow button to navigate through the current Port 3 settings. The baud rate (**SPEED**) is near the top of the list. If the baud rate is already set to 19200, press the **ESC** button several times to restore the screen to its normal display, and continue to the next step.
    g. If the current relay baud rate is not set to 19200, use the following steps to change the baud rate:
    h. With the relay's baud rate setting highlighted, press the enter key.

i. Use the up, down, left, and right buttons to enter the relay's level 2 password (default is "**TAIL**" and is case-sensitive). Press the enter key to select each letter. Navigate to and select **<u>Accept</u>** after entering the password.
j. Press the up/down-arrow buttons until <u>19200</u> (not 19.2) appears. Press the enter key.
k. Press **<u>ESC</u>** twice, and select **<u>Yes</u>** to save the new port setting.

61. On the QuickSet main window (Figure 66), open the Communication Parameters window (<u>Communications</u>, <u>Parameters</u>) (Figure 67) to define and create a communication link with the 710. Enter the following information for a Serial Active Connection Type:
    a. Device: <u>COM1: Communications Port</u>
    b. SEL Bluetooth Device: Unchecked
    c. Data Speed: <u>19200</u>
    d. Data Bits: 8
    e. Stop Bits: 1
    f. Parity: None
    g. RTS/CTS: Off
    h. DTR: On
    i. XON/XOFF: On
    j. RTS: N/A (On)
    k. Level 1 Password (Default **<u>OTTER</u>**)
    l. Level 2 Password (Default **<u>TAIL</u>**)

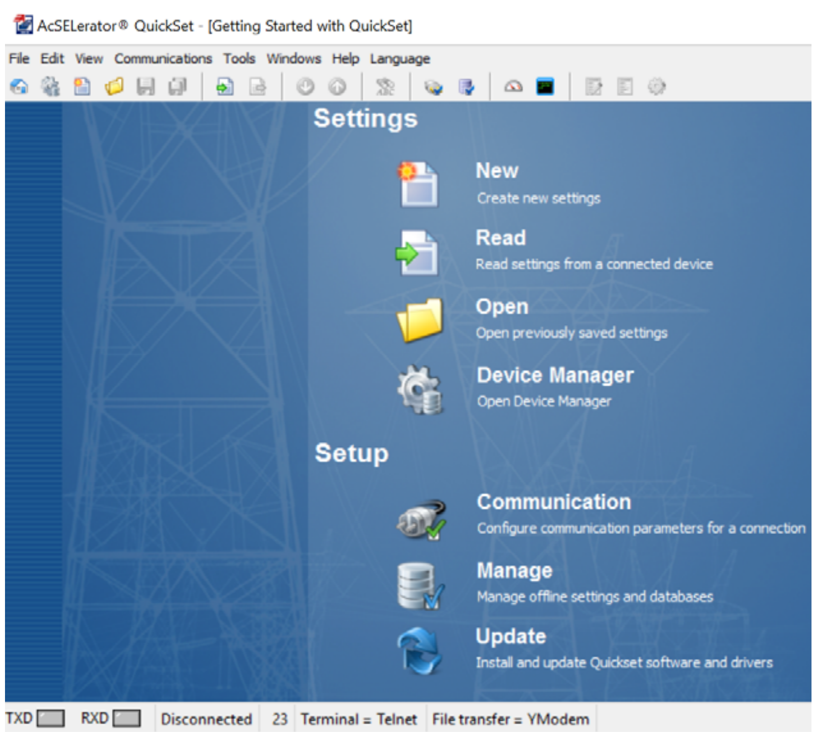

Figure 66: QuickSet Main Window

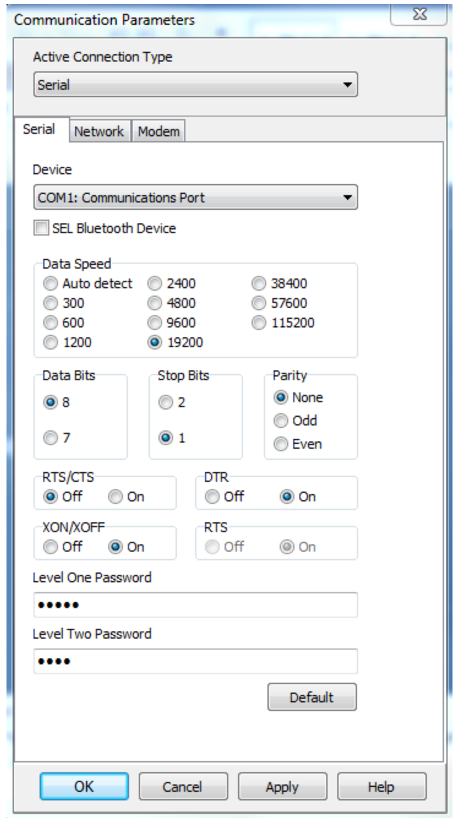

Figure 67: SEL-710 Communication Parameters Window

62. Click Apply at the bottom of the Communication Parameters window. Then click Ok. If the computer successfully connects to the relay, the connection status in the lower-left corner of the QuickSet main window should say "Connected."

63. Create a new settings file for the SEL-710 relay.
    a. In the QuickSet main window, create a new settings file for the SEL-710 relay (File, New).
    b. Choose the Device Family, Model, and Version for this specific relay unit from the available menus, then click Ok (Figure 68). Look up the relay's version number using the front-panel interface on the relay. Press the **ENT** button, and use the down-arrow button to navigate to the **STATUS** option. Press the enter button again. Select the **Relay Status** option. Navigate down to the **FID** option. Scroll across the relay's FID string until you come to the "Z-number." The first three digits following the 'Z' comprise the relay version number. Press the **ESC** button several times to restore the front-panel screen to its normal display. Note: if no devices are listed in the QuickSet drop-down menus, then the device drivers need to be installed using the SEL Compass software. Ask for assistance.

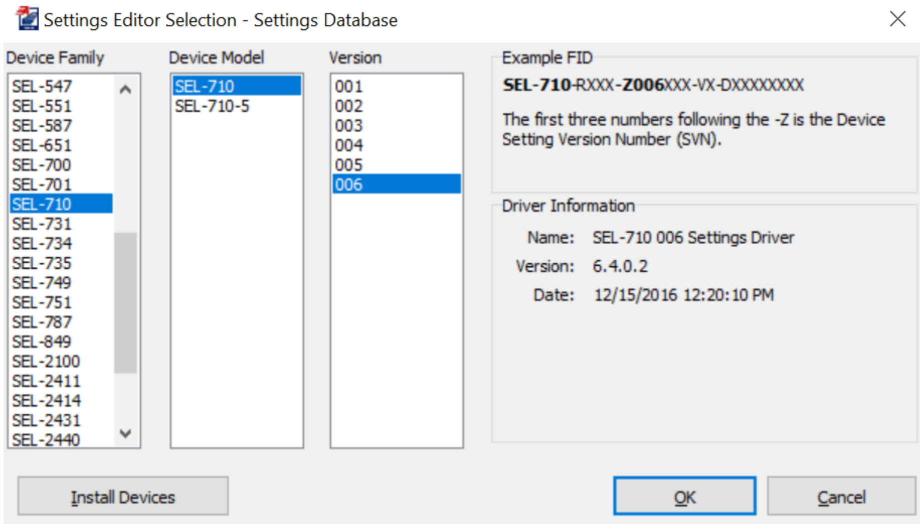

Figure 68: Identifying SEL-710 Relay Family, Model, and Version

c. Enter the relay Part Number (Figure 70) printed on the serial number label (P/N, Figure 69) attached somewhere on the relay chassis. Note that the 5 A Secondary Input Current reflects the convention for American current transformers.

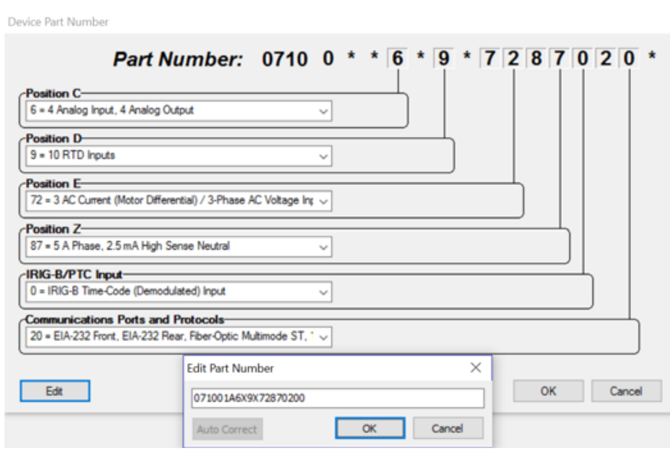

Figure 70: Identifying SEL-710 Relay Part Number

Figure 69: Example SEL-710 Label with Relay Part Number

64. Save this relay settings database file (<u>File</u>, <u>Save As</u>; <u>New</u> if you do not want to use an existing settings database) in a location where it may be reused in future experiments. See Figure 71 and Figure 72. Then create a Settings Name for this settings file.

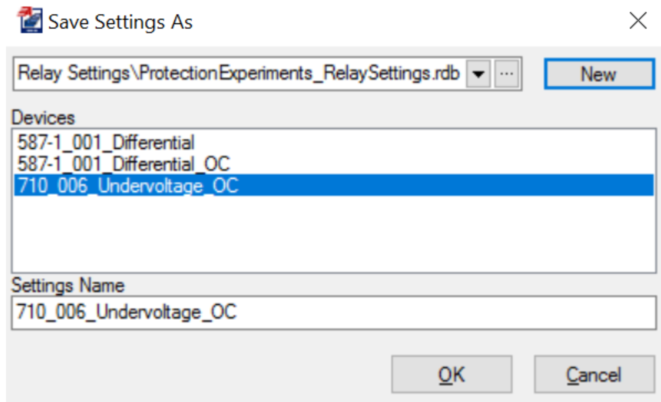

Figure 71: Saving SEL-710 Settings

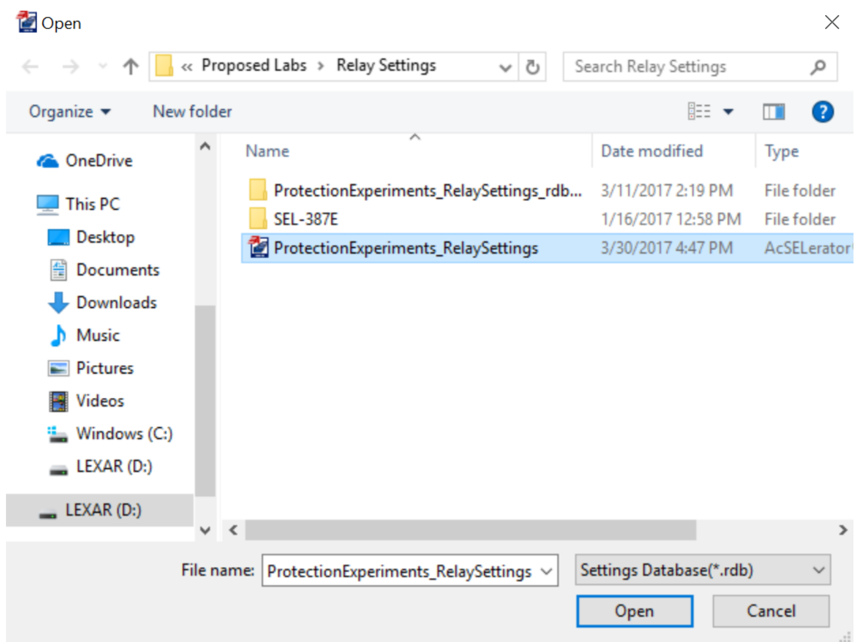

Figure 72: Choosing Location for New SEL-710 Relay Settings Database

65. Open Global settings in the drop-down menu on the left side of the Settings Editor main window (Figure 74).
    a. Under General settings (Figure 73), choose a Phase Rotation sequence (**PHROT**) of ACB. The frequency and phase rotation settings correspond to electrical properties of the utility. Replace the default Fault Condition (**FAULT**) contents with TRIP.
    b. Under Breaker Monitor settings (), select N for the Enable Breaker Monitor (**EBMON**) setting.

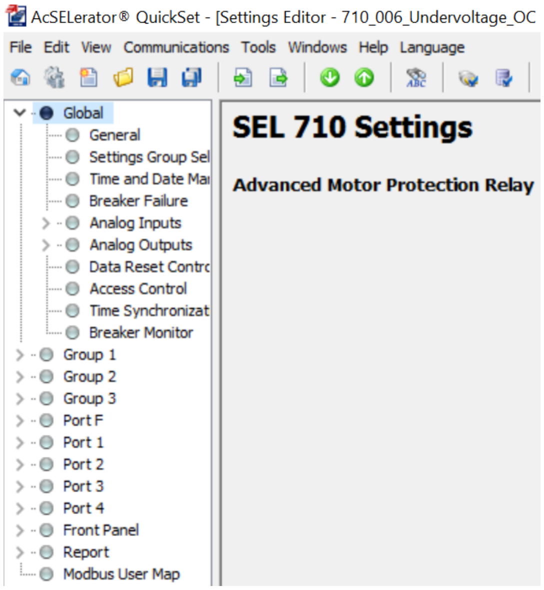

Figure 74: SEL-710 Settings Editor Main Window

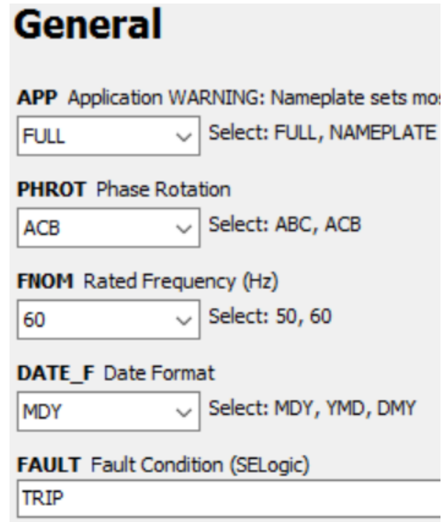

Figure 73: SEL-710 General Settings

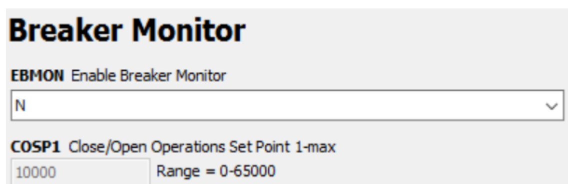

Figure 75: SEL-710 Breaker Monitor Settings

66. Open the Group 1, Set 1 settings menu on the left side of the screen.

67. Enter the following information in the Main Settings (Figure 76 and Figure 77).
   a. Enter a Phase Current Transformer Turns Ratio (**CTR1**) of 1, reflecting the fact that the currents measured by the relay are the actual system line currents (not stepped down). Current and potential transformers are not needed in this experiment because the system line currents and voltages (even during fault conditions) are relatively low.
   b. Enter a Motor Full Load Amps (**FLA1**) value of 1.6 A. This setting acts like the pickup current setting in traditional electromechanical relays, in addition to its role in multiple motor performance calculations made by the SEL-710.
   c. Enter a Neutral Current Transformer Turns Ratio (**CTRN**) of 1.
   d. Enter a Potential Transformer Turns Ratio (**PTR**) of 1, reflecting the fact that the voltages measured by the relay are the actual system voltages (not stepped down).
   e. Enter a Nominal Line-to-Line Voltage (**VNOM**) value of 208 V.

f. Select WYE as the Transformer Connection (**DELTA_Y**) for the potential transformer.

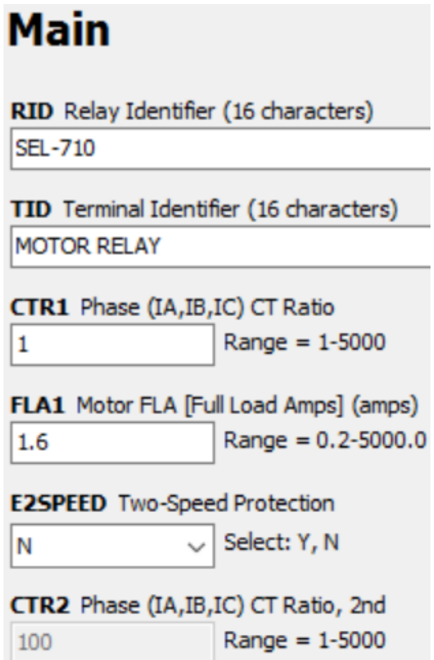

Figure 76: SEL-710 Main Settings

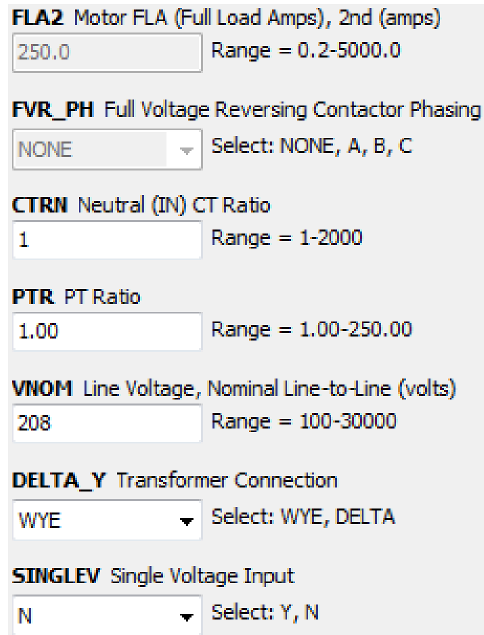

Figure 77: SEL-710 Main Settings, cont.

68. Enter the following information in the Overcurrent Elements section (Figure 78, Figure 79, and Figure 80).
  a. Under the Phase Overcurrent sub-heading, enter a Phase Overcurrent Pickup (**50P1P**) of 3.00 multiples of the full load amps setting. Leave the associated Trip Delay (**50P1D**) as its default value of 0.00 s.
  b. Under the Residual Overcurrent sub-heading, enter a Residual Overcurrent Pickup (**50G1P**) of 0.50 multiples of the full load amps setting. Set the associated Trip Delay (**50G1D**) to 0.10 s.
  c. Under the Negative-Sequence Overcurrent sub-heading, enter a Negative-Sequence Overcurrent Pickup (**50Q1P**) of 0.50 multiples of the full load amps setting. Set the associated Trip Delay (**50Q1D**) to 0.15 s. Turn OFF the Negative-Sequence Overcurrent Alarm Pickup (**50Q2P**).

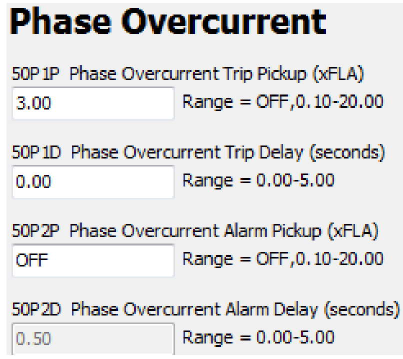

Figure 78: SEL-710 Phase Overcurrent Settings

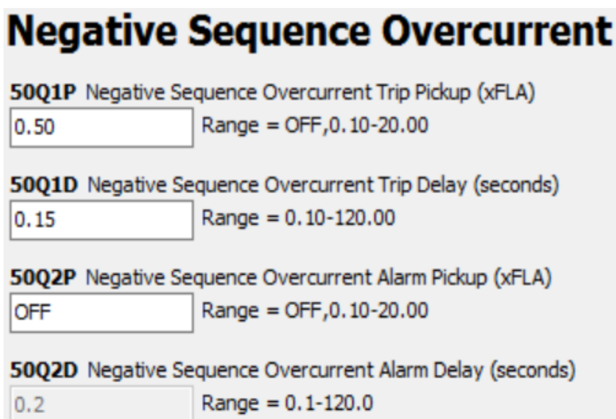

Figure 80: SEL-710 Negative-Sequence

Overcurrent Settings

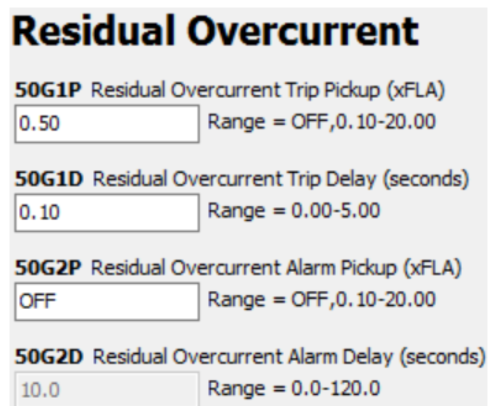

Figure 79: SEL-710 Residual

Overcurrent Settings

69. In the Undervoltage Elements, set the Undervoltage Trip Level (**27P1P**) to <u>0.80</u> multiples of the nominal motor voltage setting, VNOM (Figure 81). Increase the Undervoltage Trip Delay (**27P1D**) to <u>0.8</u> s to keep the relay from tripping due to effects of inrush current.

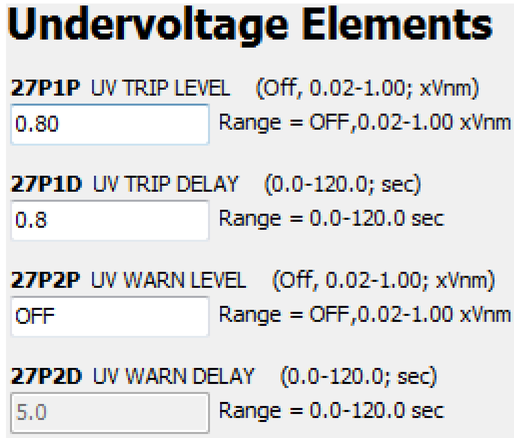

Figure 81: SEL-710 Undervoltage Elements

70. Under the Trip and Close Logic sub-heading, replace the default contents of the Trip (**TR**) equation with <u>50P1T OR 50G1T OR 50Q1T OR 27P1T OR STOP</u> (Figure 82).

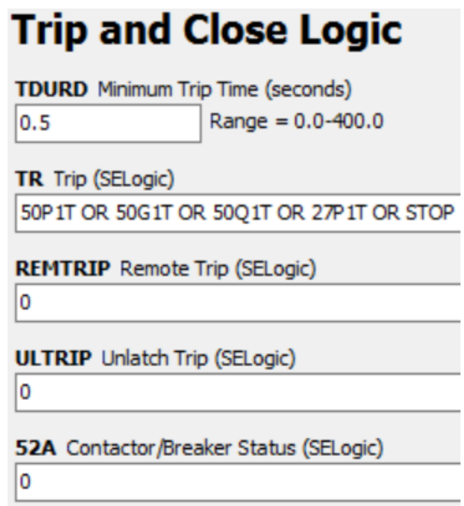

Figure 82: SEL-710 Trip and Close Logic

71. Enter the following information in the Logic 1, Slot A section (Figure 83).
    a. Select <u>N</u> for the OUT101 Fail-Safe (**OUT101FS**) option.
    b. Select <u>Y</u> for the OUT102 Fail-Safe (**OUT102FS**) option.
    c. Logically-invert the default **OUT102** signal to be <u>NOT START</u>. Logical inversion is necessary for interfacing the normally-open switch (OUT102) on the SEL-710 with the normally-open circuit breaker trip coil. This choice allows the SEL-710 front-panel START button to operate the Breaker Control Close contact on the circuit breaker through the relay's rear-panel ports A05 and A06.

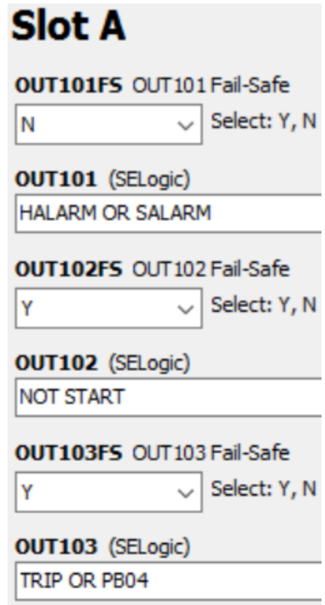

Figure 83: SEL-710 Logic 1, Slot A Output Logic

72. Open Port F settings in the menu on the left side of the Settings Editor main window. Set the Port F baud rate (**SPEED**) to 19,200. Change the **AUTO** setting to Y. Leave all other Port F settings as their default values (Figure 84).

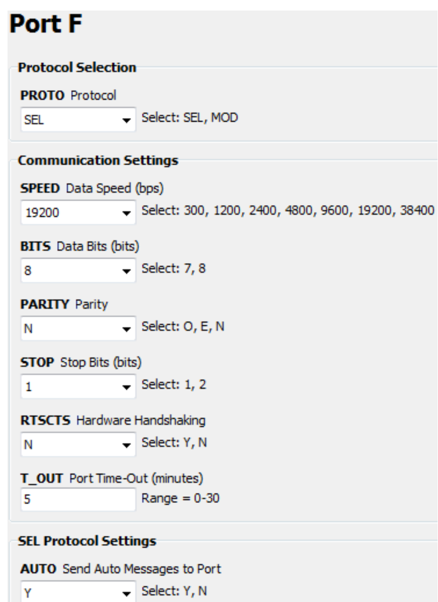

Figure 84: SEL-710 Port F Settings

73. Open the Port 3 settings on the left side of the Settings Editor main window. Set the Port 3 baud rate (**SPEED**) to 19,200. Change the **AUTO** setting to Y. Leave all other Port 3 settings as their default values.

74. Enter the following information in the Report on the left side of the Settings Editor main window (Figure 85 and Figure 86).

a. Under the SER, SER Trigger Lists headings, add TRIP to the existing contents of the first Sequential Event Recorder (**SER1**). This addition causes the SEL-710 to generate an event report for any of the conditions specified by the TR equation.
b. Under the Event Report heading, change the Length of Event Report (**LER**) setting to 64 cycles.
c. Increase the Prefault Length (**PRE**) data collection time to 10 cycles. This setting defines the amount of data saved in an event report before the relay trips for a fault.

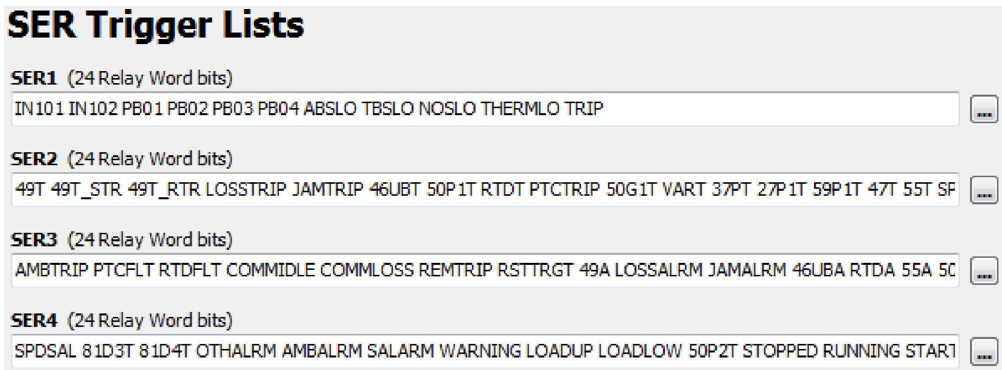

Figure 85: SEL-710 Trigger Lists Settings

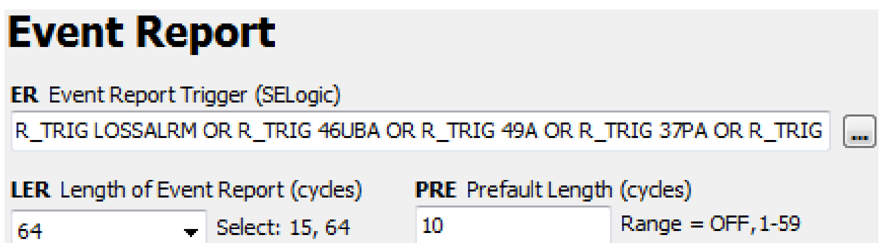

Figure 86: SEL-710 Event Report Settings

75. Save your settings (File, Save).

76. Send your settings (File, Send…) to the SEL-710. In the window that appears, check the boxes for the Set 1, Logic 1, Global, Port F, Port 3, and Report settings (Figure 87). Click Ok. Sending only the modified settings shortens the file transfer time. Ignore any error messages associated with changing the baud rate. Since it can take several minutes to transfer the relay settings, now is a good time to start constructing the circuit.

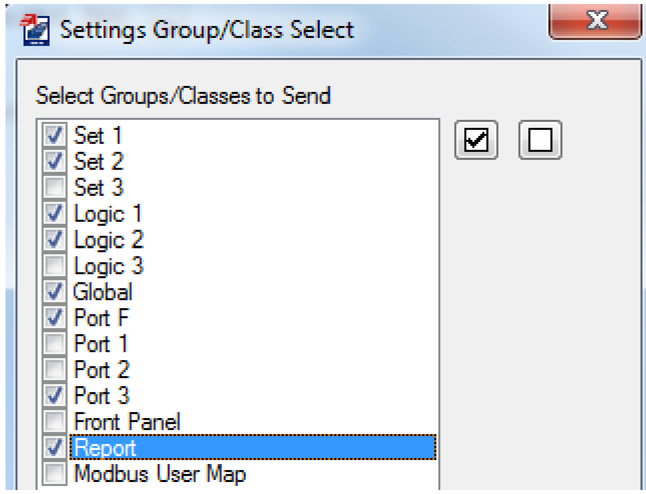

Figure 87: Send Modified Settings to the SEL-710

77. Connect the three-phase circuit illustrated in Figure 65. Try to lay out the elements in the order illustrated in the schematic so that power flows across the bench from one end to the other. This linear arrangement limits the number of wires crossing each other and makes the path of the current flow easier to review (and troubleshoot). Start with the sequential connection points in Table 21, using the diagrams posted on the wattmeter at the lab bench for assistance. Then add the following connections:
    a. Connect SEL-710 back-panel ports **E01**, **E02**, and **E03** to the red Circuit Breaker phase A, B, and C terminals (respectively) on the circuit breaker.
    b. Connect SEL-710 back-panel port **E05** to the green circuit breaker chassis ground terminal.
    c. Connect the green chassis ground terminals of the induction motor and circuit breaker together.
    d. Connect SEL-710 back-panel port **Z08** to the induction motor green chassis ground terminal.
    e. Connect SEL-710 back-panel port **Z07** to the green lab bench ground terminal.
    f. Connect SEL-710 back-panel port **A07** to the top Breaker Control Trip terminal on the circuit breaker. Connect the back-panel port **A08** to the bottom Breaker Control Trip terminal on the circuit breaker. These terminals correspond to the signal OUT102 in the SEL-710.
    g. Connect the positive (upper) Breaker Control 125 V_{DC} terminal to input terminal G on the lab bench. Connect the negative (lower) Breaker Control 125 V_{DC} terminal on both circuit breakers to terminal H.

Table 21: Per-Phase Sequential Points of Connection

Phase A	Phase B	Phase C
Input Voltage	Input Voltage	Input Voltage
25 Ω Resistor Input	25 Ω Resistor Input	25 Ω Resistor Input
25 Ω Resistor Output	25 Ω Resistor Output	25 Ω Resistor Output
Bench Variac Phase A Input	Bench Variac Phase B Input	Bench Variac Phase C Input
Bench Variac Phase A Output	Bench Variac Phase B Output	Bench Variac Phase C Output
Wattmeter	Wattmeter	Wattmeter
Relay Port **Z01** (Relay Input)	Relay Port **Z03** (Relay Input)	Relay Port **Z05** (Relay Input)
Relay Port **Z02** (Relay Output)	Relay Port **Z04** (Relay Output)	Relay Port **Z06** (Relay Output)
Circuit Breaker Red Terminal	Circuit Breaker Red Terminal	Circuit Breaker Red Terminal
Circuit Breaker Black Terminal	Circuit Breaker Black Terminal	Circuit Breaker Black Terminal
Induction Motor Stator Terminal, Phase A	Induction Motor Stator Terminal, Phase B	Induction Motor Stator Terminal, Phase C

78. Set the induction motor Magtrol Torque Adjust switch to the <u>OFF</u> position.

79. Verify the circuit connections and obtain instructor approval to apply power to the circuit.

80. Set the variac to provide the induction motor with its rated voltage.
    a. Rotate the variac control dial to its fully-counter-clockwise position. This action sets the autotransformer tap to its lowest available output voltage.
    b. Apply both 240 V_{AC} and 125 V_{DC} (if needed for the circuit breaker) power from the bench.
    c. Rotate the variac control dial clockwise until the wattmeter displays 208 V.
    d. Press the <u>TARGET RESET</u> button on the front panel of the SEL-710 to clear any previous undervoltage conditions.
    e. Close the circuit breaker (with the Manual Breaker Control Close button). Confirm that the three-phase power displayed on the wattmeter is approximately 1.5 A. If the displayed current exceeds 2 A, turn off the bench power and check the circuit wiring for errors.
    f. The induction motor should now be running; if so, proceed to the next step. If the SEL-710 immediately trips for an undervoltage condition, increase the value of the Undervoltage Trip Delay (**27P1D**) setting. This

delay keeps the relay from tripping in response to the extra voltage drop across the current-limiting resistors due to the temporary motor inrush current. If this potential solution fails, decrease the Undervoltage Trip Level (**27P1P**) setting.

g. Rotate the variac control dial clockwise until the line-to-line voltage displayed on the wattmeter (for the induction motor terminals) again reads 208 V. This action compensates for the voltage drop across the current-limiting resistors due to the current drawn by the induction motor.

81. Create a line-to-line fault at the induction motor.
    a. Turn off AC and DC power from the bench.
    b. Jumper the black Circuit Breaker terminals to the red Fault Connections terminals (if present) on the circuit breaker. Jumper two of the black Fault Connections terminals together (line-to-line fault configuration).
    c. Set the circuit breaker Fault Switch to the Normal position.
    a. Turn on AC and DC bench power. Press the TARGET RESET button on the front panel of the SEL-710 to clear any previous undervoltage conditions.
    d. Manually close the circuit breaker.
    e. Flip the circuit breaker Fault Switch to the Fault position.
    f. Watch the wattmeter to confirm that the SEL-710 trips the circuit breaker to clear the fault. If it does not, turn off AC bench power before sustained fault current damages circuit components.
    g. Once the relay clears the fault, turn off AC and DC bench power and flip the Fault Switch to the Normal position. Press the TARGET RESET button on the SEL-710 to clear the relay's front-panel LED display.
    h. Retrieve the event file from the SEL-710 (Step 82).
    i. Add the 50P1P and 50P1T digital signals to the oscillogram plot.

82. Retrieve the SEL-710 event file for the fault trip.
    a. In QuickSet, select Tools, Event Files, Get Event Files.
    b. In the window that comes up, select Refresh Event History.
    c. Choose an Event Type of 16 Samples / Cycle – Raw and an Event Length of 15 cycles.
    d. Check the boxes of the event file(s) corresponding to the fault. Event files are indexed, with '1' being the most recent event file saved by the relay.
    e. Click Get Selected Events. Save the events in a convenient location using either a default or custom naming convention.
    f. Double-click on the event report file in its file path location. The AcSELerator Analytic Assistant software automatically opens an oscillogram plot of the event.
    g. Click the Pref button in the lower-right corner of the oscillogram to add digital fault-trip signals to the plot. Left-click on the signal you wish to display (from the available list in the lower-left corner of the screen), then right-click-drag the signal to the Digital Axis list of signals to be displayed. Click Ok.

h. After saving the desired event files, enter the **HIS C** command in the QuickSet Terminal window (select Communications, Terminal) to clear previous event files from the relay's memory. If an error message appears about an invalid access level, type in **ACC**, the Enter key, the level relay 1 password (default for SEL-710 is "OTTER"), and the Enter key. Proceed to clear the event files.

83. Create a three-phase fault (not grounded) at the induction motor.
    a. Turn off AC and DC power from the bench.
    b. Jumper the black Circuit Breaker terminals to the red Fault Connections terminals (if present) on the circuit breaker. Jumper together the black Fault Connections terminals (three-phase fault configuration).
    c. Set the circuit breaker Fault Switch to the Normal position.
    d. Turn on AC and DC bench power. Press the TARGET RESET button on the front panel of the SEL-710 to clear any previous undervoltage conditions.
    e. Manually close the circuit breaker.
    f. Flip the circuit breaker Fault Switch to the Fault position.
    g. Watch the wattmeter to confirm that the SEL-710 trips the circuit breaker to clear the fault. If it does not, turn off AC bench power before sustained fault current damages circuit components.
    h. Once the relay clears the fault, turn off AC and DC bench power and flip the Fault Switch to the Normal position. Press the TARGET RESET button on the SEL-710 to clear the relay's front-panel LED display.
    i. Retrieve the event file from the SEL-710 (Step 82).
    j. Add the 50P1P and 50P1T digital signals to the oscillogram plot.

84. Create an undervoltage condition at the terminals of the induction motor.
    a. Turn on AC and DC bench power. Press the TARGET RESET button on the front panel of the SEL-710 to clear any previous undervoltage conditions.
    b. Manually close the circuit breaker.
    c. Rotate the variac control dial counter-clockwise to decrease the input voltage to the induction motor, while watching the motor's terminal voltage displayed on the voltmeter. Momentarily stop once the wattmeter reads 185 V. Proceed to slowly rotate the variac dial until the SEL-710 trips the circuit breaker. Record the approximate voltage at which trip occurred.
    d. Retrieve the event file from the SEL-710 (Step 82).
    e. Add the 27P1 and 27P1T digital signals to the oscillogram plot.

Postlab Questions

- Using your prelab calculations, justify the Phase and Negative-Sequence Overcurrent Trip Pickup settings used in this experiment.

- Explain why, for a three-phase fault, the SEL-710 trips on the phase overcurrent element before the undervoltage element. Hint: compare the chosen Phase Overcurrent Trip Delay (**50P1D**) and Undervoltage Trip Delay (**27P1D**) settings.

- Compare the line-to-line voltage measured at the terminals of the induction motor when the circuit breaker opened to the chosen Undervoltage Trip Level setting. Justify any difference between the two values. Hint: consider the Undervoltage Trip Delay (**27P1D**) setting.

Deliverables

Answer the postlab questions. Turn in oscillograms for the fault events described in the procedure. The bottom of each oscillogram should show the digital signal associated with the type of protection triggered by the fault. Give each plot a caption specifying the relay name, fault type and location, and type of protection triggered.

Save the relay settings for use in future experiments.

Additional RTAC Procedure: if time permits

DATA MONITORING USING SEL REAL TIME AUTOMATION CONTROLLER (RTAC)

85. Disconnect the SEL-C234 serial cable from the SEL-710 and connect it to Port 10 on the SEL-RTAC.

86. Connect the SEL-C273 serial cable between Port 3 on the RTAC and port 3 of the SEL-710.

87. Connect the USB cable between the RTAC USB B port and the computer USB A port.

88. Plug the RTAC power cord into a bench outlet.

89. Open the AcSELerator RTAC software on the computer.

90. Click "New SEL RTAC Project" to create a new project (Figure 88)

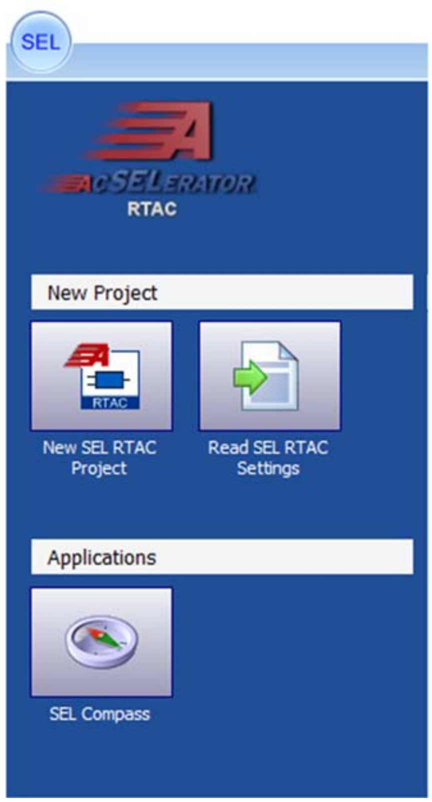

Figure 88: Create New Project

91. Select RTAC/Axion for the RTAC type, R139 for the firmware version, and default for the project type. Enter an appropriate project name and click "Create" (Figure 89).

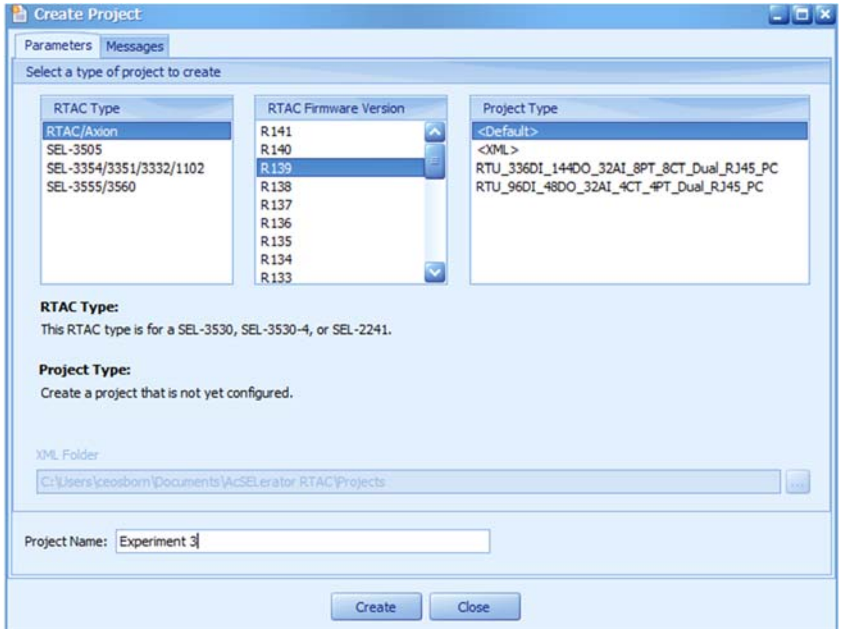

Figure 89: New Project Settings

92. On the Insert tab, select the SEL device dropdown and add the SEL-710 as a serial client using SEL Protocol (Figure 90 and Figure 91).

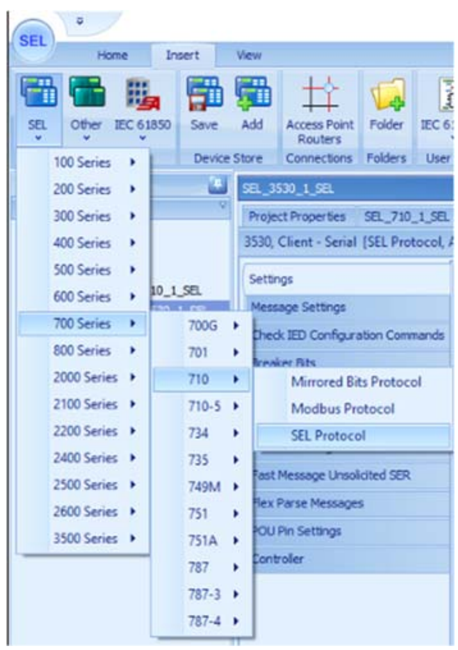

Figure 90: Add SEL-710 device

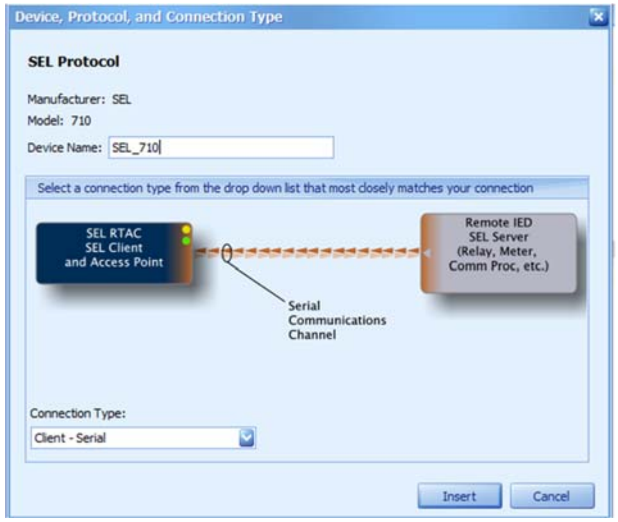

Figure 91: SEL-710 Connection Type

93. Select the SEL-710 device under the devices folder. Change the "Serial Communications Port Value" to Com_03 under the Settings tab as shown in Figure 92. Confirm that the baud rate is 19200. All other values can be left as default.

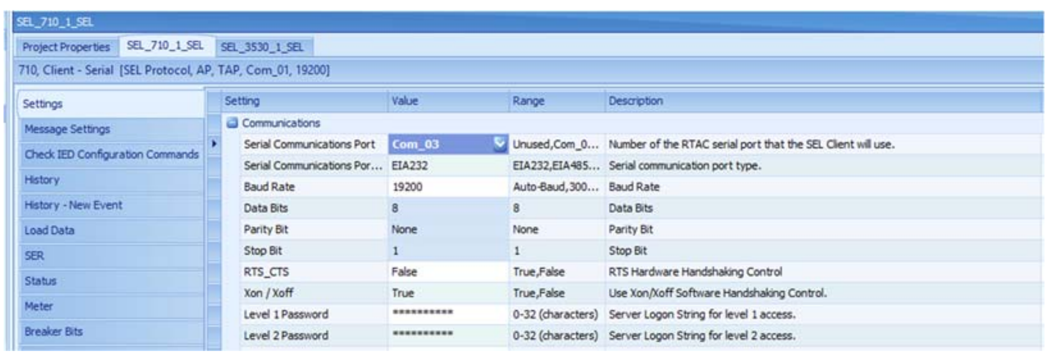

Figure 92: SEL-710 Port Selection

94. On the Insert tab, select the SEL device dropdown and add the SEL-3530 as a serial server using SEL Protocol (Figure 93 and Figure 94).

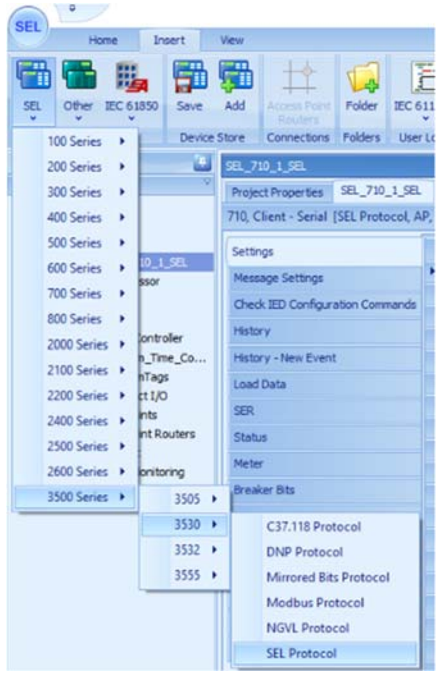

Figure 93: Add SEL-3530 Device

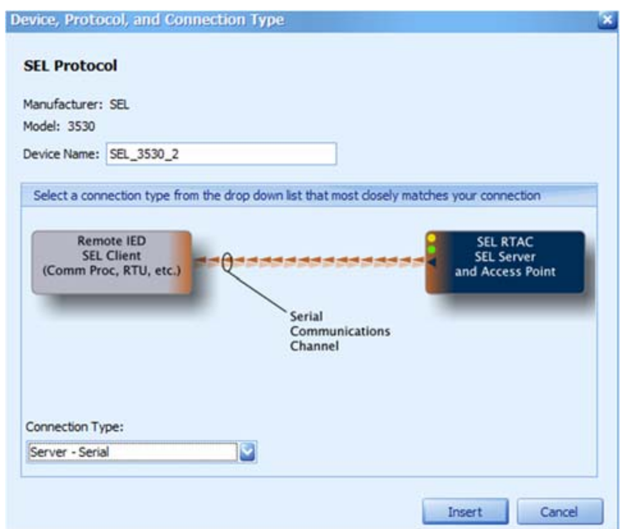

Figure 94: SEL-3530 Connection Type

95. Select the SEL-3530 device under the devices folder. Change the “Serial Communications Port Value” to Com_10 under the Settings tab as shown in Figure 95. Confirm that the baud rate is 19200. All other values can be left as default.

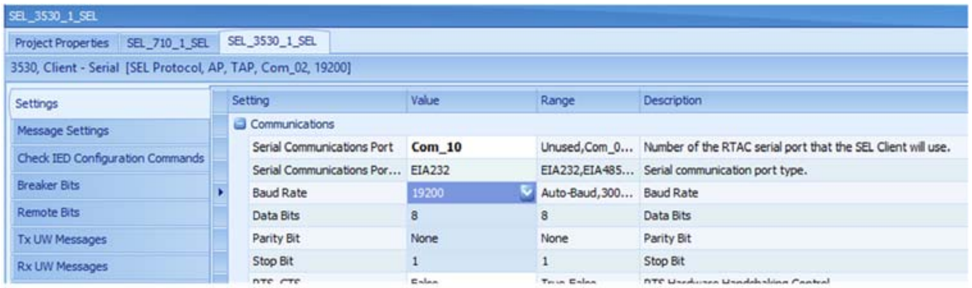

Figure 95: SEL-3530 Port Selection

96. Select the SEL-710 device and navigate to its meter tab. Find the "MV" tag Types and enable the following tags by selecting True in the Enable column (Figure 96).
    a. SEL_710_1_SEL.FM_INST_FREQ
    b. SEL_710_1_SEL.FM_INST_IA
    c. SEL_710_1_SEL.FM_INST_P
    d. SEL_710_1_SEL.FM_INST_PF
    e. SEL_710_1_SEL.FM_INST_Q
    f. SEL_710_1_SEL.FM_INST_S
    g. SEL_710_1_SEL.FM_INST_VA

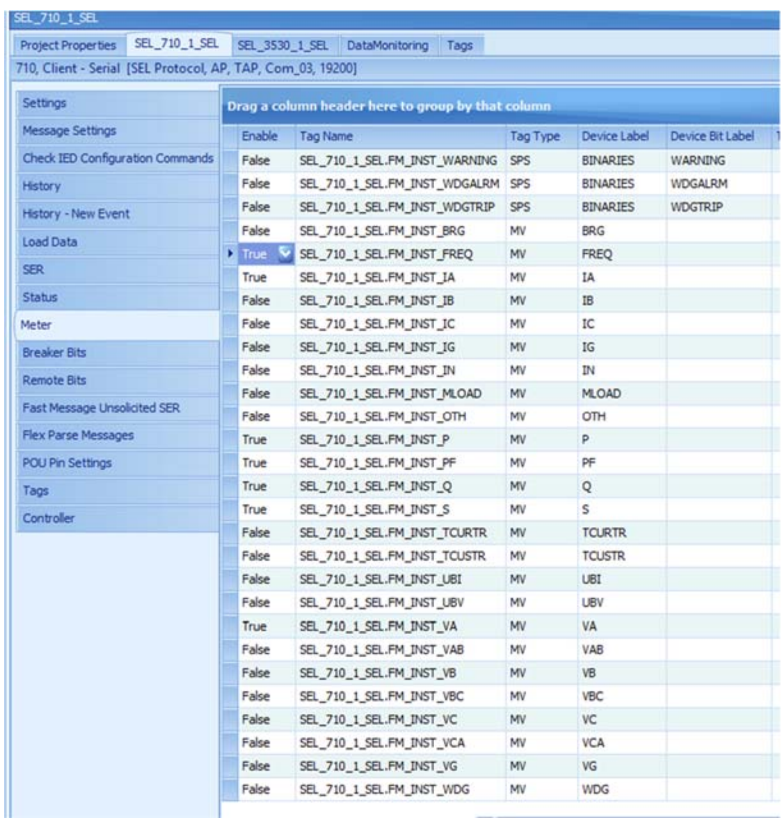

Figure 96: SEL-710 Meter Values

97. On the Insert tab, click the User Logic dropdown and select Program (Figure 97). Select ST (structured text) and enter an appropriate name. (Figure 98).

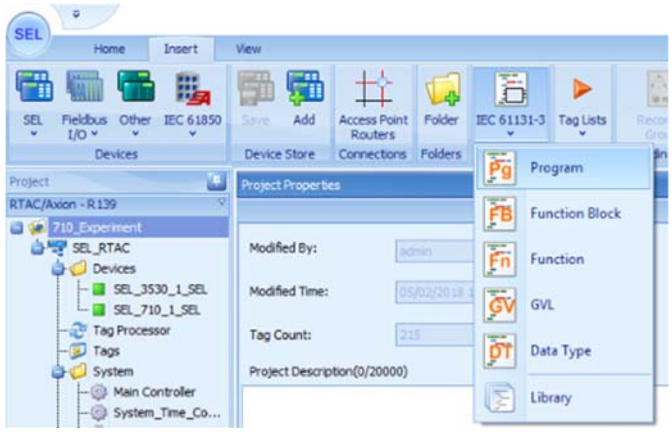

Figure 97: Create Program

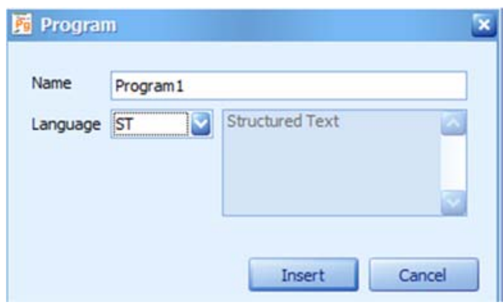

Figure 98: Select Program Language

98. Type CTRL+S to save the program. Copy the Tag names from the Tags tab of the SEL-710 device. Select the program under the User Logic folder and paste the tags into the bottom window of the program. Enter the text as shown in Figure 99. The program has two windows. Enter the variable declarations in the top window and the variable assignments in the bottom window.

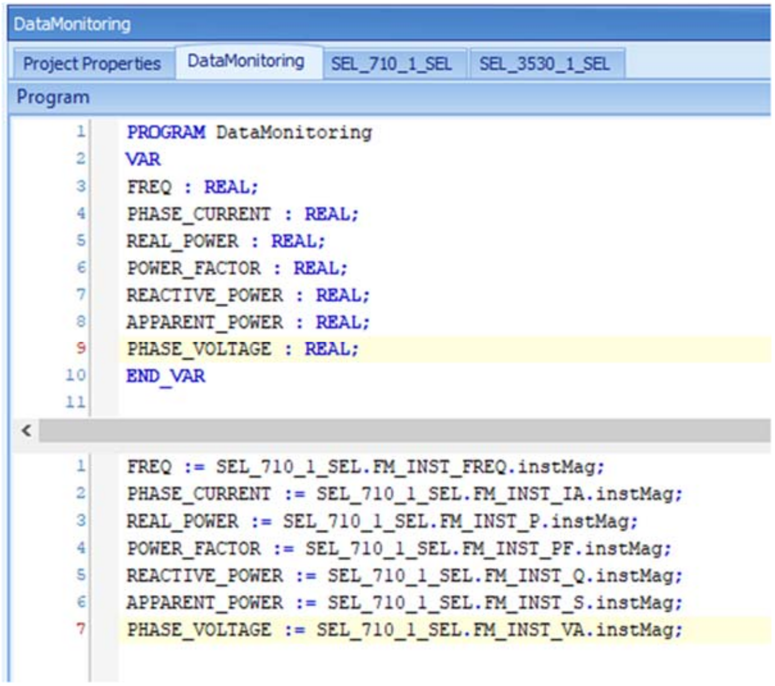

Figure 99: Program Code

99. Click the SEL button in the upper left of the screen and select “Save With Cross-task Checking” (Figure 100). In the bottom of the screen, confirm that zero errors and zero warnings occurred (Figure 101). If any exist, correct your code and save again.

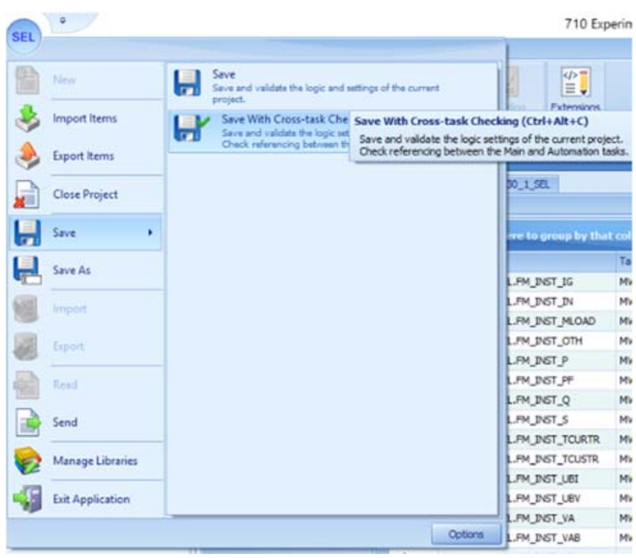

Figure 100: Save With Cross-task Checking

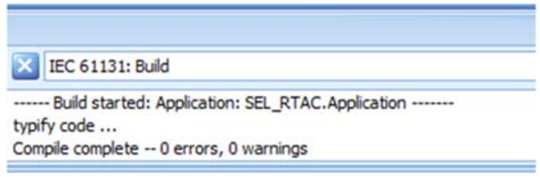

Figure 101: Program Build Results

100. Click the “Go Online” button (Figure 102) and enter the RTAC address “172.29.131.1”, username “sdittmann”, and password “RM102rtac!” (Figure 103). Select the “Login” button and then the “Go” button once you are logged on (Figure 104).

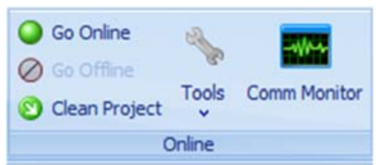

Figure 102: Go Online Button

Figure 103: Login Screen

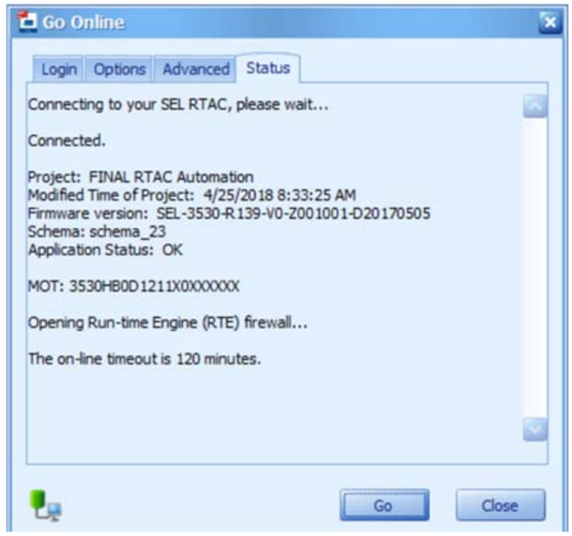

Figure 104: Go Online Screen

101. Turn the bench power on and set the variac to provide the induction motor with its rated voltage (Repeat step 80). Close the circuit breaker to turn the motor on.

102. To verify you are receiving data, go to the program window. The top window should show values for all the defined variables. Slowly change the variac and observe the changing values of the variables in the RTAC program.

Appendix K: Project Plan

Figure 105 shows the baseline timeline for the project starting September 14th, 2017 through December 12th, 2017. Figure 106 continues the baseline timeline for the project starting January 8th, 2018 and finishing May 18th, 2018. Task durations are calculated using the PERT method as described in Eq. (2). T_O corresponds to the most optimistic duration, T_L to the most likely, and T_P to the most pessimistic.

$$T_{PERT} = \frac{T_O + 4T_L + T_P}{6} \tag{2}$$

The project divides into six major phases: synchronous generator integration, SEL-700G integration, SEL-421 integration, RTAC integration, system coordination, and load shedding. Each project phase has research, design, and build identifiers. While design revisions apply to the entire project, research and build identifiers refer to specific phases. Phase identifiers create repeatable processes for individual phases and standardize the approach to each phase. Additionally, each project phase has two design and revision portions to allow for unanticipated obstacles.

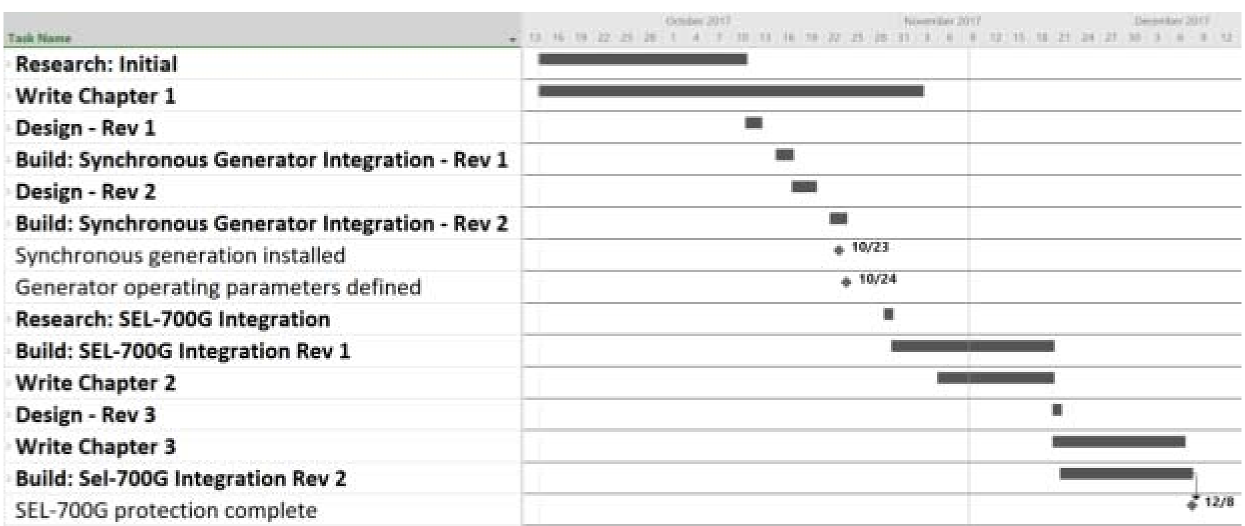

Figure 105: Gantt Chart 9/14/17-12/8/17

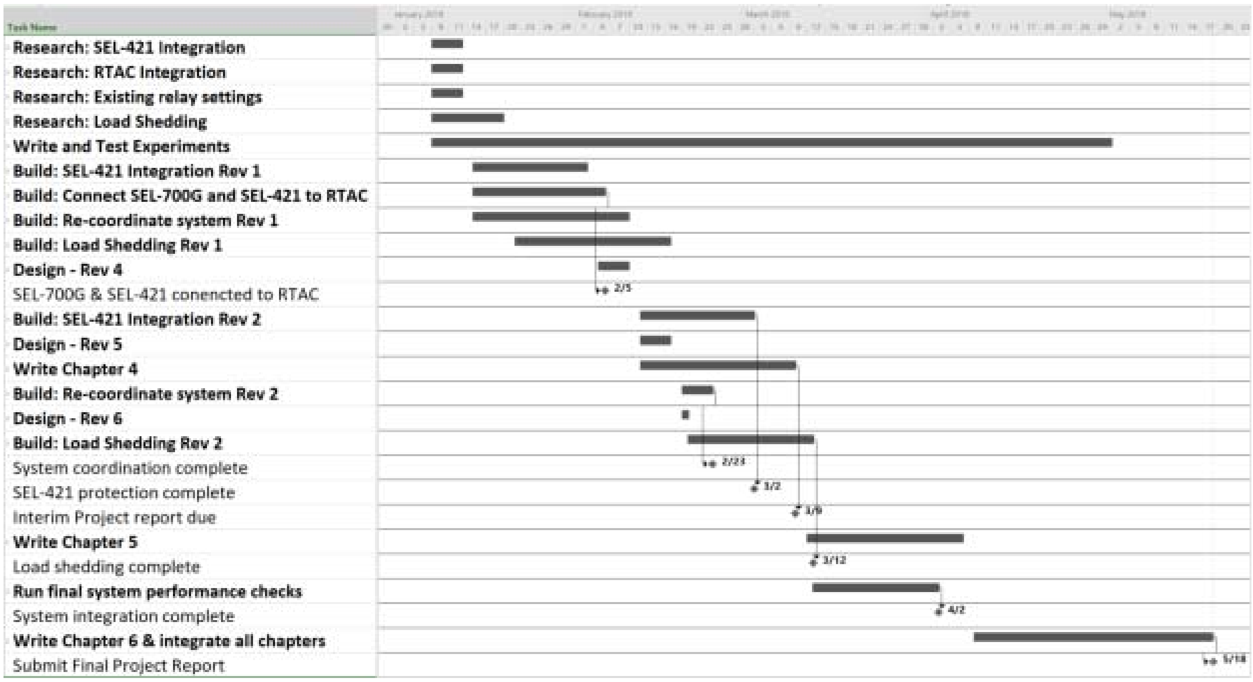

Figure 106: Gantt Chart 1/8/18-5/18/18

The budget in Table 22 shows estimated project costs. Equipment purchased or donated before the start of the project is not listed in Table 22. SEL-C234A and SEL-C273A serial cables interface relays and communications processors, while the wire and terminal connectors interface all power connections in the system. New circuit breakers built for the system use the breaker contactors.

Table 22: Budget

Item	Quantity	Cost
Labor	330 hours	$13,530
SEL-C234A	6	$154
SEL-C273A	24	$634
100ft 12 AWG black wire	1	$24.77
100ft 12 AWG white wire	1	$24.77
100ft 12 AWG red wire	1	$24.77
12-10 AWG #8-#10 spade connectors (50 pack)	1	$6.80

Item	Quantity	Cost
16-14 AWG #4-#6 spade connector (100 pack)	1	$8.53
16-14 AWG #8-#10 spade connector (100 pack)	1	$7.09
12-10 AWG ring connector (100 pack)	2	$16
Breaker Contactors	7	$742
Total	N/A	$15,172.73

Table 23 describes the high-level milestones and accompanying deadlines associated with the project's development. Project reports are submitted with demos at the end of each quarter, culminating with a thesis defense and poster presentation at the Sr. Project Expo in May.

Table 23: Deliverables

Delivery Date	Deliverable Description
10/9/17	Initial Thesis committee presentation
10/27/17	Design Review
10/30/17	ABET Sr. Project Analysis
3/9/18	EE 461 demo
3/9/18	EE 461 report
5/18/18	EE 462 demo
5/18/18	EE 462 report / Thesis Submission
5/21/18	Thesis Defense
5/25/18	Sr. Project Expo Poster

Appendix L: Analysis of Senior Project Design

Project Title: Protection, Automation, and Frequency Stability Analysis of a Laboratory Microgrid Laboratory

Student's Name: Eric Osborn Student's Signature: ____________________

Advisor's Name: Dr. Ali Shaban Advisor's Initials: _____ Date: ___/___/2018

Summary of Functional Requirements

Please see the *Functional Decomposition* section for a description of functional requirements.

Primary Constraints

Limited supply of equipment and previously purchased protective relays constrained the design of the microgrid with the protection system previously installed by Kenan Pretzer, Ian Hellman-Wylie and Joey Navarro as outlined in [15]. Implemented in a university laboratory environment, only low voltage power is available, meaning current transformers and potential transformers cannot be used. All new protective relays must also coordinate and integrate with installed SEL relays. When choosing a prime mover for the synchronous generators, DC motors emerge as a solution due to the prevalence of the machine in Cal Poly's electric machines laboratory. The project was additionally constrained by the customer needs and requirements specified in the *Customer Needs, Requirements, and Specifications* section.

Economic Impact

Initial project cost estimates appear in Table 22. The project timeline appears in Figure 105 and Figure 106. Generally, microgrids have many long-term positive economic benefits for cities, neighborhoods, businesses, and other activity hubs. By increasing local generation and storage, a microgrid can reduce the energy costs that consumers pay to utilities. While this benefits energy consumers, utilities suffer from an increase in consumer owned microgrids. This could potentially displace utility employees as the energy business model shifts from large scale, centralized utilities to distributed energy resources owned by energy consumers.

Industry support is required to make this project economically feasible. SEL's multiple relay donations offset initial project costs. Cal Poly students benefit indefinitely from the exposure to advanced power systems techniques if the project integrates into a future electrical engineering laboratory course at Cal Poly.

Manufacturability on a commercial basis

Since this project primarily focuses on education, the primary consumer is other universities. Assuming the university secures equipment donations, only labor and part costs remain. From Table 22, the total cost equals \$15,172.73. Setting a price point at \$16,000, the project profit equals \$827.27. If four universities install the microgrid system annually, annual profits amount to \$3,309.08.

Costs to operate this system depend on energy prices set by the utility. Assuming a fixed cost of 15 cents per kilowatt-hour for both $125V_{DC}$ and $208V_{rms}$ and average current of $1A_{rms}$ across all AC devices and $50mA_{rms}$ across all DC devices, the average system operation cost equals 5.5 cents per hour. Equation (3) derives from the senior project analysis completed in [15].

$$\text{Cost} = (\text{Price per kWh}) * (\text{Avg. Power Draw}) \tag{3}$$

$$\text{Cost} = (\text{Price per kWh}) * \frac{\left(\sqrt{3} * V_{rms} * I_{rms}\right) + (V_{DC} * I_{DC})}{1000}$$

$$\text{Cost} = \left(\frac{15\ \text{cents}}{\text{kwh}}\right) * \frac{\left(\sqrt{3} * 208 * 1\right) + (125 * .05)}{1000}$$

$$\text{Cost} = 5.5\,\frac{\text{cents}}{\text{hour}}$$

Environmental Considerations

Microgrids reduce energy waste by increasing energy efficiency through local generation [7]. Increased energy efficiency decreases air pollution, preserving earth's natural resources.

Microgrids also decrease the need for redundant high-voltage power lines crossing both urban and rural areas, eliminating the risk of fires due to a power line collapse. Microgrids can negatively impact the environment if placed in areas that have sensitive ecosystems. For example, if lots of foliage and trees are removed to install a solar field, the native ecosystem is disrupted. While this project doesn't explicitly teach techniques to avoid the negative impacts of a microgrid, it does teach students fundamental microgrid concepts and prepares them to design systems that typically make the environment cleaner and safer.

Manufacturability

Microgrid designs change depending on customer needs and system energy demands. Specifically, relay settings, type, and protection schemes differ for each customer. This makes manufacturing difficult as processes remain unstandardized. To create a flexible manufacturing environment, relay, control, and communications equipment selection should weight flexibility highly. Multipurpose devices with a variety of communication and control protocols ensure the system could meet many different customer requirements with minimal design changes. However, individual customer systems always necessitate specific protective relay settings.

Sustainability

While the manufacture of the microgrid system utilizes earth's natural resources, the system's relays typically remain in the field for the duration of their lifespans. If the system's lifespan exceeds the relays' lifespan, the relays can be reused in a variety of other systems by reprogramming the relay settings. While the electronic relays do have a negative impact on the environment, their reusability negates it enormously. Many microgrid systems utilize battery storage, negatively impacting the sustainability of the system as it is difficult to recycle and reuse batteries once they exceed their lifetime. The experiments written for this project are all stored and accessible electronically. It is intended for them to remain in an electronic format to reduce paper use and increase the sustainability of this project.

Ethicality

This project strongly upholds key components of the IEEE Code of Ethics. Its aim to educate students in microgrid automation, control, and protection concepts directly correlate to the IEEE desire to improve technical competence. It also aids in improving others' comprehension of microgrid technology and its appropriate use relating to the power systems industry. The SEL equipment used in this project also has a lifetime warranty to encourage users to report equipment issues. This policy directly corresponds with IEEE's desire for companies to seek out and accept honest feedback. One ethical dilemma, however, manifests when the project compares to the IEEE tenant that individuals and companies operate in the best interest of the public. The owner of a microgrid could refuse power delivery to medical services during a blackout if the services can't afford to pay, hurting the public.

Additionally, this project aligns with Utilitarian principles. Generally, microgrids provide a source of backup generation if the grid collapses. Since electricity powers traffic lights and security systems, microgrids provide enormous safety benefits during a blackout by preventing the likelihood of car accidents and looting. If operated inappropriately, however, microgrid owners could require customers to pay unreasonably high fees to receive power during a blackout. This would limit electricity access to those who could afford it, directly contradicting Utilitarian principles. With the goal of educating students on the use and application of microgrids, this project serves as a tool for increasing the general utility of all users of electricity by educating those who implement power distribution systems on the benefits of microgrids.

Health and Safety Considerations

Due to relatively high voltages and currents in power systems, this project inherently proposes health and safety risks. When interacting with the system, follow general safety practices. Safe practices include de-energization of live equipment when possible and wearing proper personal protective equipment. It is imperative that users of the system understand basic electrical safety concepts and are always accompanied by at least one other person when the system is energized. Having two people present reduces the risk of serious injury or death by allowing one to contact emergency services if the other becomes incapacitated. It is recommended that both people are trained in CPR and First Aid.

Social and Political Considerations

The direct stakeholders of the microgrid are the customers wanting to implement the microgrid system. All direct stakeholders benefit equally as microgrids reduce every customer's dependence on the central grid and provide constant electricity to all customers if a blackout occurs. Secondary stakeholders include utilities and other operators of traditional energy generation. For microgrids owned by third-parties, gross profits for utilities decrease with a decline in demand for traditional electricity generation. If the microgrid is owned by the utility, however, they benefit from a more flexible and robust system without profit loss. Employees of utilities are also stakeholders of the microgrid. In the scenario of utility profit loss, company workforce reduction negatively impacts employees and their dependents.

In this project specifically, students are the direct stakeholders. Secondary stakeholders include universities wanting to implement the microgrid system and companies that donate equipment to universities for the microgrid system. While universities pay for the installation of the project, students who directly benefit pay tuition at the university, reimbursing costs. Companies that donate equipment benefit by students' familiarity with their equipment's use and higher likelihood to purchase it once the student has entered the workforce.

Development

Knowledge of microprocessor relay settings and coordination tools requires extensive research. To design the system, understanding general power systems protection schemes and generator stability in an islanded system is also required. Many hours reviewing [20] revealed techniques to synchronize distributed generators to the infinite bus using Schweitzer Engineering

Laboratories' 700G relay. To complete the project, [15] and [23] require thorough review to understand the original system design and infinite bus protection. See [18]-[24] in the references section for a list of sources that support research topics.