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ADAPTIVE PROTECTION SCHEME FOR A REAL-WORLD MICROGRID
WITH 100% INVERTER-BASED RESOURCES

A Thesis
Presented to
the Graduate School of
Clemson University

In Partial Fulfillment
of the Requirements for the Degree
Master of Science
Electrical Engineering

by
Trupal Patel
December 2020

Accepted by:
Dr. Sukumar Brahma, Committee Chair
Dr. Johan Enslin
Dr. Ramtin Hadidi

Abstract

The integration of renewable and distributed energy resources to the electric power system is expected to increase, especially at the distribution level. As more renewable generation connects to distribution systems, it is imminent that existing distribution feeders will be converted to microgrids. Microgrids are systems, typically at distribution voltage level, sustained by distributed and often renewable sources, that can operate in grid-connected and islanded modes. Microgrids offer resilience by providing the flexibility of supporting the grid in normal operation and operating as self-sustained islands when the grid is disconnected.

As the grid transforms to a modular system consisting of many microgrids, these microgrids will likely evolve from existing distribution feeders, and hence will be unbalanced in nature. As the world moves towards cleaner and renewable generation, some of these microgrids may be supplied by 100% inverter-based resources (IBRs). To increase resiliency and reliability, these microgrids will need to operate in both grid-connected and islanded modes. However, inverter control and feeder protection will need to be tuned to the operating modes of the microgrid. Protection system design for microgrids pose significant challenges due to bi-directional power flow and fault currents, lower fault current due to the inverter-based resources, and wide range of fault currents during different modes of operation.

This work offers an insight into the issues involved, by taking a case study of a real-world feeder located in the southwestern US that was converted to a microgrid with three solar PV units connecting to the feeder. Different inverter control configurations and adaptive protection using different settings for different operating conditions are proposed for safe operation of this microgrid. The solution also helps to create a framework for protection and coordination of other similar microgrids.

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Nomenclature

DER	-	Distributed Energy Resources
IBR	-	Inverter Based Resources
RPS	-	Renewable Portfolio Standards
$LOHO$	-	Test Feeder name
PCC	-	Point of Common Coupling
OC	-	Overcurrent
UV	-	Undervoltage
$3PHF$	-	3-phase fault
LLF	-	Line-Line fault
$SLGF$	-	Single line to ground fault
VSC	-	Voltage Source Converter
U_{ref}	-	Reference signal for VSC converter
TCC	-	Time Current Curves
Rn_F	-	Relay "n" forward direction setting
Rn_R	-	Relay "n" reverse direction setting
Ot	-	device operating time
TDS	-	Time Dial Setting
MOC	-	Minimum Operating current / Pickup current

Chapter 1

Introduction and Literature Review

There has been a significant push in many parts of the world to start using more renewable energy resources due to rising concerns regarding the environmental effects of fossil-based energy production and the decreasing cost of renewable energy sources. More than half the states in the United States (US) have enacted legislation to increase the share of renewables in their energy mix; for example, Washington DC, California, and Hawaii have increased their Renewable Portfolio Standards (RPS) target to 100% renewable before 2045. Figure 1.1 shows the states with RPS targets or similar regulations in the United States. Many of the RPS targets also include specific requirements for solar PV based generation to ensure variety in their energy generation [1].

In the US and around the world renewable energy generation is expected to increase over the next few decades, with IBRs such as solar and wind generation, in particular, driving the conversion from traditional fossil fuel-based sources [2]. Figures 1.2 and

Figure 1.1: States with RPS or similar policies [1]

1.3 show the projected growth of renewables in the US. As power grids around the world continue to integrate more renewable energy resources. The increase in demand for more sustainable, reliable, and resilient power has led to a subset of the power grid known as a microgrid, powered by renewable energy sources.

Figure 1.2: Projected energy mix [2]

Figure 1.3: Projected renewables mix [2]

1.1 Inverter based resources and microgrids

As renewables continue to replace or augment traditional fossil-fuel-based resources on the eclectic grid, a larger percent of the grid's energy mix will be inverter-based resources (IBRs) such as solar, wind, and battery energy storage systems (BESS). IBRs are sources that are interfaced with the electric grid through an inverter to convert and regulate the energy generated by renewable sources such as solar and wind. IBRs unlike traditional generation methods, are typically located close to loads and often connected at the distribution level. These IBRs and neighboring loads on a feeder can be grouped together into a subnetwork known as a microgrid.

Microgrids are a combination of generation resources and load, forming an electrically sustainable grid that can function either connected to the larger grid or in an islanded mode. An example of 100% inverter feed microgrid is shown in figure 1.4. As renewables gain popularity and distributed generation becomes more commonplace, it is expected that microgrids will be created by adding Distributed Energy Resources (DERs) at the distribution level and converting existing feeders to microgrids. In grid-connected mode, a microgrid shares its load and generation resources, whereas in islanded mode it is disconnected from the utility grid and is self-sufficient. Distribution level microgrids tend to have a significant amount of their energy generation from solar PV and/or storage, which connect through inverters. When multiple IBRs connect to microgrids, their control in grid-connected and islanded modes need to be carefully designed for smooth operation and transition between modes. Due to the distinctly different fault response of IBRs, which includes limiting the positive-sequence current to values comparable to its rated output and blocking of negative-sequence and zero-sequence currents, the protection of microgrids also needs careful attention.

Figure 1.4: Possible 100% IBR microgrid Setup

1.2 Microgrid protection literature review

A wide array of protection schemes have been proposed for microgrids. Each assumes a certain topology, source-type, and operating conditions [3]. A summary of such schemes is provided in [4]. The schemes are based on overcurrent, undervoltage, a combination of the two, distance, differential, harmonic-content, and traveling waves, many using various communication infrastructure. Shiles *et al.* [5] provide an overview of the protection methods used in various microgrid projects across North America. Several principles and methods are mentioned based on undervoltage, voltage-restrain, impedance, differential, directional overcurrent, and adaptive, some even including fault current limiters. It underscores that the protection methods are highly dependent on the type of sources used in the system, and the system topology. None of the methods discussed has selective protection for an islanded microgrid. A protection scheme for micro-grids which depends primarily on undervoltage relays for islanded operation and overcurrent relays for grid-connected operation is proposed in [6]. A key aspect of the protection proposed in [6] is that it does not require communication or adaptive protective devices; however, the proposed method is for

low voltage (120V) microgrids and undervoltage coordination can be very difficult to achieve. Laaksonen *et al.* [7] present an adaptive protection and control scheme using communication, developed for the Hailuoto Island microgrid, where the relay settings are modified depending on the mode of operation. Sources, in this case, consist of diesel generators and wind turbines. The literature survey reveals that protection schemes suitable for realistic microgrids with 100% IBRs have not been sufficiently explored. Brahma *et al.* [8, 9] provides some insight into protection of islanded, unbalanced microgrids with 100% IBRs, but does not model a test system with multiple inverters to illustrate the control and protection aspects.

Overall while many methods have been proposed in literature, few of the papers explore the case of a 100% inverter-based realistic microgrids with multiple inverter-based resources on a realistic system. A microgrid's ability to switch from grid-connected to islanded mode of operation poses several challenges from a protection perspective ranging for fault detection, selectivity, security, and device coordination. Inverter based sources pose an additional challenge due to the limit on the amount of current supplied during a fault to protect their power electronics components [10]. The limited current poses challenges as it drastically reduces the amount of fault current observed by traditional protective devices, which heavily rely on current magnitude for fault detection, creating difficulties in identifying and isolating faults in the microgrid. Due to low fault currents, most of the conventional protection principles fail to provide reliable protection [11]. The low fault current during islanded mode compared to grid-connected mode also pose challenges in terms of protective device coordination, as the coordination ranges grow large due to the low fault current during islanded mode and high fault current during grid-connected mode. In many cases depending on the microgrid composition, a singular protection scheme for both grid-connected and islanded modes may not be possible.

1.3 Goals

The primary goal of this project is to analyze the protection of a real-life distribution system being converted to a microgrid. In order to do this, the real-world LOHO feeder located in the southwestern US needs to be modeled in MATLAB Simulink. The model can then be converted to a microgrid by connecting three solar PV units of varying capacity. The inverter models used to convert the feeder to a microgrid will mimic the dynamics of commercially available inverters tested at Sandia National Laboratories (SNL). Once the inverters are modeled and connected to the feeder, the existing protection scheme of the feeder can be analyzed in the presence of the inverters in grid-connected and islanded modes. This analysis will highlight how and why the existing protection scheme will not work in the proposed microgrid. Finally, based on the analysis an adaptive protection scheme will be created, including selective protection for the island, using protective devices available in the market today.

Chapter 2

LOHO Test System & Modeling

2.1 System overview

The real-world 12.47 kV , 15-bus distribution feeder used for this study, referenced henceforth as LOHO is shown in figure 2.1. It is proposed to be converted into a microgrid by adding PV generation of 258 kW , 1 MW , 10 MW at buses 15, 12 and 14 respectively. This feeder has a total load of approximately 3 MVA, so in grid-connected mode, the microgrid will feed its load and feed power back to the utility system, all inverters operating at unity power factor. In islanded mode, it will curtail its real power output and supply the required real and reactive power to the microgrid, while maintaining voltage and frequency at acceptable values. Inverters at buses 12 and 14 connect to the system through 480 V/12.47 kV , YG/YG transformers, whereas the IBR at bus 15 connects at 480 V through a YG/YG transformer. The system is modeled in MATLAB/Simulink using Simscape power systems library. The grid is modeled as a three-phase 115 kV source connected through a 115 kV /12.47 kV Δ/YG substation transformer rated at 30 MVA . The lines are modeled as PI sections. The loads are modeled as wye-connected constant impedances.

Figure 2.1: 12.47 kV utility distribution feeder considered for conversion to a microgrid.

2.2 Lines

The system is a reduced model of a real feeder which consists of 12 distribution lines. The lines are modeled as three-phase PI section lines. The individual line parameters are shown in table 2.1 except the positive and zero sequence line shunt capacitance (C_1 and C_0) which were set to $1.12E - 7$ for all lines. The three-phase PI section line” available in Simulink implements a balanced three-phase transmission line model with parameters lumped in a PI section. While the balanced lines don’t capture all the detail of the unbalanced distribution feeder, this approximation was made due to the limitation of software. A diagram of the three-phase PI section line is shown in figure 2.2. Line parameters are calculated based on equation 2.1.

$$\begin{aligned}
 R_s &= \frac{(2R_1 + R_0)}{3} \\
 L_s &= \frac{(2L_1 + L_0)}{3} \\
 R_m &= \frac{(R_0 - R_1)}{3} \\
 L_m &= \frac{(L_0 - L_1)}{3} \\
 C_p &= C_1 \\
 C_g &= \frac{3C_1C_0}{(C_1 - C_0)}
 \end{aligned} \tag{2.1}$$

Figure 2.2: Three-phase PI line model

Name	Length (km)	R1 (Ω/km)	R0 (Ω/km)	L1 (H/km)	L0 (H/km)
L149	0.001	0.0803806	0.2004593	0.0002976	0.0001758
L150	3.57	0.0768443	0.3632861	0.0009390	0.0032733
L135	0.05	0.4373360	0.8034780	0.0013541	0.0042251
L105	3.45	0.7137992	1.0845650	0.0013745	0.0042357
L59	1.09	0.0744751	0.3484252	0.0009825	0.0034924
L188	0.35	0.0744751	0.3484252	0.0009825	0.0034924
L97	0.08	0.0744751	0.3484252	0.0009825	0.0034924
L88	0.08	0.0744751	0.3484252	0.0009825	0.0034924
L4	0.32	0.0815039	0.3488770	0.0009068	0.0030888
L164	0.03	0.1049869	0.3267717	0.0003150	0.0002237
L167	0.04	0.1463255	0.4202756	0.0010548	0.0035646
L196	0.03	0.1820739	0.3053387	0.0005815	0.0005143

Table 2.1: LOHO system line parameters

2.3 Loads

The system consists of 6 loads which are used to represent a variety of loads on the actual feeder. Additionally, 2 capacitor banks are also included. Table 2.2 shows the individual load parameters. The loads are modeled using the series RLC load for each phase creating an unbalanced wye-connected constant impedance load. The load impedance is determined using the nominal voltage (V), active power (P), and reactive power(Q) specified using the equation 2.2. Figure 2.3 shows the series RLC Load model.

$$Z = R + jX = \frac{V^2}{P} + j\frac{V^2}{Q} \quad (2.2)$$

Figure 2.3: Three-phase load model

Load	Pa (kW)	Qa (kVAR)	Pb (kW)	Qb (kVAR)	Pc (kW)	Qc (kVAR)
136	0	0.003	3.860	0.489	2.670	0.302
139	0.028	-0.009	2.288	0.413	0.394	0.154
142	97.118	22.060	100.579	22.407	116.317	25.615
133	107.384	11.558	108.561	11.911	118.930	12.605
19	27.700	16.900	27.700	16.900	27.700	16.900
20	628.333	430.666	628.333	430.666	628.333	430.666

Table 2.2: LOHO load ratings

2.4 Transformers

The system contains a substation transformer and a distribution transformer, along with the two interfacing transformers to be added to connect the PV systems to the microgrid. All transformers are modeled as three single-phase transformers using the Simscape "Three-Phase Transformer (Two Windings)" transformer. The parameters of the transformers are shown in table 2.3.

Transformer Name	Transformer1	Transformer2	T_{Inv1}	T_{Inv2}
winding 1 connection	Δ	Yg	Yg	Yg
winding 2 connection	Yg	Yg	Yg	Yg
Nominal Power (kVA)	30000	1000	1500	5000
Winding 1 Voltage (kV)	115	12.47	12.47	12.47
Winding 2 Voltage (kV)	12.47	0.480	0.480	0.480
Winding 1 Resistance (pu)	0.00025	0.002	0.005	0.005
winding 2 Resistance (pu)	0.00025	0.002	0.005	0.005
winding 1 Inductance (pu)	0.07755	0.035	0.01	0.01
winding 2 Inductance (pu)	0.07755	0.035	0.01	0.01
Magnetization resistance (pu)	500	500	500	500
Magnetization inductance (pu)	500	500	500	500
Bus1 name	Bus1	Bus10	Bus12	Bus14
Bus2 name	Bus2	Bus15	Inv2	Inv3

Table 2.3: Substation transformer parameters

2.5 Grid source

The utility grid is modeled as a swing generator to emulate the grid's capabilities to supply and absorb a large amount of power when needed. The swing generator is also configured to match the utility fault current characteristics. The generator is modeled using the Simscape electrical "Three-Phase Source" model with the parameters shown in table 2.4.

Configuration	Yg
Base voltage (kV)	115
Phase A angle ($^{\circ}$)	0
Frequency (Hz)	60
Source resistance (Ω)	1.5
Source inductance (H)	0.02
3-Phase MVA_{sc} (MVA)	1624.8
X/R Ratio	5

Table 2.4: Utility source parameters

2.6 Existing protection elements in the system

The LOHO system has several typical distribution protection devices in the system. The feeder's main protection device is an overcurrent (OC) relay located at bus2 labeled "R1" in figure 2.1. This relay serves as the ultimate backup protection which coordinates with the devices downstream. A recloser is located at bus 5 labeled "REC" in figure 2.1. This recloser acts as the primary protection for buses 9, 10 and 15. The recloser is coordinated with the Relay R1 which operates as the backup if recloser REC fails to operate. The system also contains a sectionilizer located at bus 8 labeled as "SEC" in figure 2.1. The sectionalizer works in conjunction with the relay R1's re-closing function to count. The sectionalizer acts as the primary protection for buses 7, 3, 4 and 12 with once again the relay R1 acting as a backup

if the sectionilizer fails to lockout. The system is also protected by a number of load fuses used to isolate loads from the feeder if a fault occurs in the loads. These load fuses are coordinated with the recloser whenever possible, however, many of the load fuses are not coordinated with upstream protection devices.

2.7 Base case steady-state & fault simulations

The LOHO system was simulated without the addition of the PV systems to set a base case for comparison to the microgrid cases. This case also represents the system when the PV is unavailable during a period of low irradiance or night. The system line currents and load currents are shown in table 2.5 and table 2.6, respectively. The system draws roughly 122 A of current on each phase with 1% unbalance at the low voltage side of the substation transformer.

Line #	IA (A)	IB (A)	IC (A)
T1 (HV)	13.45	13.53	13.5
149	120.8	122.1	123.1
150	120.6	121.5	122.6
135	32.65	33.28	34.26
105	18.84	19	17.79
T2 (HV)	4.5	4.5	1.55
T2(LV)	115.3	115.3	38.69
59	90.36	90.3	90.37
167	N/A PV not connected		
196	N/A PV not connected		
188	90.27	90.21	90.28
97	90.24	90.18	90.25
88	105.6	105.5	105.6
4	105.6	105.6	105.6
164	N/A PV not connected		

Table 2.5: Base case steady-state line currents

In order to measure the fault currents supplied by the grid when IBRs are not available

Load #	IA (A)	IB (A)	IC (A)
136	0.001	0.54	0.37
139	0.004	0.32	0.06
142	13.83	14.30	16.54
133	14.89	15.04	16.51
19	115.30	115.20	38.68
cap7	83.37	83.32	83.38
cap3	Not connected		
20	105.7	105.60	105.70

Table 2.6: Base case steady-state load currents

faults were simulated on each bus of the system. A 3ph fault, LL fault on phase A-B and SLG fault on phase A were simulate the fault currents supplied by the grid are shown in table 2.7. The maximum fault current of 8292 A is observed at bus 2 as expected. The lowest fault current of 234 A was observed on bus 15 which is the furthest point on the feeder from the substation and is behind a transformer. Overall it can be seen that the grid provides a large amount of fault current compared to the load current in almost all cases, exceeding the load current by a factor of 20.

Bus #	3phGF (A)	LLF (A)	SLGF (A)
2	8011	6943	8292
11	8010	6941	8291
5	3296	2855	2240
9	3249	2814	2204
10	1478	1280	1003
15 (LV)	7121	6152	6086
15(HV)	274	237	234
6	2770	2400	1808
13	2753	2384	1795
14	2745	2378	1791
8	2634	2282	1702
7	2605	2257	1680
3	2578	2233	1660
4	2483	2151	1594
12	2480	2148	1593

Table 2.7: Fault currents without IBR contribution

2.8 Parallel system simulation Method

Once the system was modeled in MATLAB/Simulink the system needed to be run repeatedly to test the various scenarios ranging from steady-state cases for each microgrid operating mode to fault simulation on each bus in each microgrid mode. These simulations can be computationally intensive and require a large amount of computation capability to complete in a reasonable time frame. Additionally, these simulations produce a considerable amount of data as the voltage and currents seen by each protective device and IBR needed to be recorded for later use in the protection coordination. On a personal laptop computer with 6 cores and 12 threads operating at 4.1 GHz, 16GB of ram, and an NVMe SSD for rapid storage each 15-second fault simulation with a time step of $1\ \mu\text{s}$ took roughly 45 minutes to complete producing a 1GB file for each simulation. $1\ \mu\text{s}$ time step was needed to simulate the short lines and for the detailed modeling of inverters.

To perform a complete fault analysis in each microgrid operating mode at a minimum 90 simulations needed to be carried out, 45 faults per simulation mode, 3 faults (3phF, LLF, SLGF) at 15 buses. If these were performed on a single computer these would require 100GB of local storage, and more importantly roughly 70 hours of simulation time alone with additional time to analyze and process the output for each variation of the model, i.e. different fault resistances, modified IBR parameters, etc. Therefore to reduce the time for the fault analysis the fault simulations were carried out in parallel using Clemson University's Palmetto cluster computing system. The fault simulations were carried out using the palmetto batch job system (PBS) using a bash script provided in Appendix A.1. The script runs all 16 simulations simultaneously, 15 fault simulation, one at each bus, and a steady-state case. Multiple jobs can be submitted at once; therefore 3 jobs, one for each fault type can be submitted leading to all faults being simulated in parallel. On the palmetto cluster computer, the

simulation jobs typically took around 30 minutes to complete all simulations. This greatly reduces the amount of time spent on simulation and fault data generation.

The bash script takes Simulink model files (.slx) as inputs and simulates the models in parallel based on the setting in the bash script. The simulation models for different fault types and resistances were auto-generated from a single model file, in which the fault block was placed and connected programmatically, and the setting set according to the selected inputs. The MATLAB code to generate the fault simulation models used to simulate faults and perform fault analysis can be found in Appendix A.2.

Chapter 3

Inverter Controls and Modeling

In order to convert the feeder described in Chapter 2 to a microgrid, distributed renewable generation is added to the system. Three inverter based resources are added at buses 15, 12, 14 with a capacity of $258kW$, $1MW$, $10MW$ respectively. These IBRs need to be capable of operating in grid-forming and grid-following control modes. During the microgrids grid-connected mode, the inverters will operate in grid-following mode providing the set-point real power to the microgrid, while the system reactive power demand is supplied by the utility grid. During the islanded mode, the inverters operate in grid-forming mode, where they behave like the grid-source, providing voltage and frequency regulation. Therefore two types of control modes are designed for inverter models a grid-following mode to be used during grid-connected microgrid operation, and grid-forming, to be used in islanded mode. Figure 3.1 shows the updated feeder converted to microgrid with the addition of the IBRs.

3.1 Grid-following inverter model

During the grid-connected mode, the inverters operate in grid-following mode providing the rated or set-point real power to the microgrid, while reactive power is supplied by the utility grid. The grid-following mode inverter-models are based on [12] and [13] as average models using MATLAB's Simscape Electrical Specialized Power Systems library. The overview of the grid-following mode IBR connection and setup is shown in figure 3.2. The grid following mode inverter uses a synchronous reference frame phase-locked loop (PLL) to track the voltage and frequency at the inverter's point of common coupling (PCC). The measured voltage is used as the reference by the PLL to synchronize the inverter PI controllers that regulate the injection of real and reactive power at the PCC. The grid following mode controller is shown in figure 3.3.

Figure 3.2: Grid-following IBR connection diagram

The controller converts the measured output voltage (V_{abc}) and current (I_{abc}) signals to the dq reference frame utilizing a PLL and reference frame conversation as shown in figure 3.4 to calculate V_d, V_q, I_d, I_q and ωt . The calculated voltages and current values along side the reference currents I_d^* and I_q^* are used by the current controller shown in figure 3.5 to generate the voltage references V_d^* and V_q^* using the equations

Figure 3.3: Grid-following IBR controller

Figure 3.4: Grid-following IBR PLL & measurements

listed in equation 3.1.

$$\begin{aligned}
 V_d^* &= V_d + I_d * R_{tot} - I_q * L_{tot} + PI(I_d^* - I_d) \\
 V_q^* &= V_q + I_q * R_{tot} - I_d * L_{tot} + PI(I_q^* - I_q)
 \end{aligned} \tag{3.1}$$

During grid-connected operation, I_q^* is typically set to 0 to achieve unity power factor in grid-following mode. The current control loop is based on a dq current-controlled scheme with feed-forward compensation for both, the grid voltage, and the i_d and i_q cross-coupling terms that are intrinsic to the analysis of the system in the dq -frame [14]. The current controller also implements a current-limiting feature with a simple saturation limit on the reference current generated by the current controller, limiting the current to 2 per unit (pu), based on the inverter rating. This limit is consistent

Figure 3.5: Grid-following IBR current controller

with inverters tested at SNL [10]. The reactive support during low voltage ride through (LVRT) is also incorporated as described in [12]. Once the reference converter voltages V_d^* and V_q^* is calculated by the current controller they are then converted to the signal that drives the average model voltage source converter as shown in figure 3.6. The reference generation converts the dq reference frame voltage to the 3 phase reference signal (U_{abc}^*) used to drive the VSC which outputs the commanded voltage and current to the grid through an inductive filter and an interconnection transformer.

Figure 3.6: Grid-following IBR VSC reference signal generation

3.2 Fault response of IBR in grid-following mode

IBR's fault response in grid following mode was tested by simulating a three-phase to ground fault at the inverter terminals when the microgrid was in grid connected mode. The inverter terminal voltage, output current, real, and reactive power output were monitored. Figure 3.7 shows that when the fault is initiated the voltage quickly drops to near 0 as expected for a bolted fault at the inverter terminal, the current controller's lag in the grid following mode can be seen as it takes the IBR 0.3s after the fault to reach its peak fault current value of 1.9 pu. It can also be seen that during the fault the IBRs real power output drops as the voltage drops to near 0 and the IBR starts supplying reactive power as required by IEEE 1547 standard. The reactive output is limited by due to the current limit combined with the reduced voltage.

Figure 3.7: Fault response of grid following IBR

3.3 Impact of grid-following IBRs on the micro-grid in grid connected mode

The Grid following inverter models were added to the LOHO system. The system was simulated with the IBRs to observe the impact of the distributed generation on the microgrid feeder. This case represents the grid-connected mode operation of the microgrid. In this case, the IBRs are supplying power at unity power factor, supplying the real power demand of the system and exporting the excess real power to the utility grid. The reactive power demand of the microgrid is supplied by the utility grid. The system line currents and power flow when IBRs are operating in grid following mode are shown in table 3.1 where, negative values for P and Q represent power flowing back to the grid. Table 3.2 shows the load currents when IBRs are operating in grid following mode.

Due to the large size of the IBRs in comparison to the system load there is a drastic change in the line flows in the system when comparing to the base case discussed in chapter 2. The power flow direction has changed for most lines, current magnitude also shows a drastic change. In this case with the IBRs connected the microgrid delivers 8335 kW of power to the utility grid while also supplying its own load. Before the IBRs were connected the system used to draws roughly 122 A of current on each phase with 1% unbalance at the low voltage side of the substation transformer. Now with the IBRs connected the microgrid delivers 390 A to the utility grid. In grid following mode the IBRs are operating at unity power factor, producing only real power.

In order to measure the fault currents supplied by the grid and IBRs in grid-connected microgrid mode faults were simulated on each bus of the system. Similarly to the base case, a 3phF, LLF on phase A-B, and SLGF on phase A were simulated on each bus

Line #	IA (A)	IB (A)	IC (A)	P (kW)	Q (kVar)
T1 (HV)	42.06	41.98	42.01	-8335.00	791.80
149	391.20	389.80	389.10	-8396.00	367.40
150	391.20	390.30	389.40	-8402.00	366.60
135	21.68	22.31	23.16	471.00	131.50
105	7.79	7.95	6.44	172.30	219.70
T2 (HV)	8.36	5.35	10.57	-191.50	46.16
T2(LV)	217.90	217.80	275.60	-192.80	39.66
59	412.20	412.20	412.20	-9002.00	-319.50
167	454.60	454.70	454.70	-9992.00	13.45
196	454.60	454.70	454.70	-9995.00	3.94
188	49.52	49.45	49.50	948.50	-532.30
97	49.47	49.40	49.45	948.60	-530.80
88	74.47	74.43	74.52	948.60	1335.00
4	74.49	74.49	74.49	948.20	1335.00
164	45.55	45.54	45.55	-999.90	-0.15
Inv3 10MW	454.60	454.70	454.70	-9999.00	0.00
Inv2 1MW	45.55	45.54	45.55	-999.90	0.00
Inv1 258kW	309.10	309.00	308.50	-258.10	0.00

Table 3.1: Line currents and power flow for grid connected microgrid with grid-following mode IBRs

Load #	IA (A)	IB (A)	IC (A)	P (kW)	Q (kVar)
136	0.00	0.54	1.37	6.50	0.79
139	0.00	0.33	0.06	2.77	0.57
142	14.00	14.47	16.74	321.40	77.17
133	15.13	15.29	16.77	340.60	36.70
19	117.30	117.30	39.36	64.99	39.66
cap7	84.85	84.85	84.86	0.00	-1865.00
20	107.6	107.50	107.60	1948.00	1335.00

Table 3.2: Load currents and power for grid connected microgrid with grid-following mode IBRs

with a fault resistance of 0.01Ω , a summary of the resulting fault currents is shown in table 3.3. The maximum fault current of 8196 A is observed after the substation as expected. The lowest fault current of 241 A was observed on bus 15 which is the farthest point on the feeder from the substation and is behind a transformer. While the peak fault current was reduced by roughly 100 A on average the fault currents in the microgrid with the grid following IBRs were higher due to the fault current contribution of the IBRs. Overall it can be seen that the grid still provides the bulk of the fault current in grid-connected mode with a small amount of fault current being supplied by the IBRs in grid following mode. Similar to the base case, the large amount of fault current compared to the load current was observed in almost all cases exceeding the load current by a factor of 20, however now the fault current is multi-sourced due to the presence of IBRs. In the event of a fault, those IBRs will also need to be isolated from the faults along with the utility grid.

Bus #	3phF (A)	LLF (A)	SLGF (A)
2	8011.00	6968.00	8196.00
11	8010.00	6966.00	8181.00
5	3296.00	3042.00	2290.00
9	3249.00	3010.00	2249.00
10	1478.00	1332.00	1013.00
15 (LV)	8320.00	6962.00	6273.00
15(HV)	320.26	267.98	241.46
6	2770.00	2461.00	1875.00
13	2869.00	2472.00	1645.00
14	3240.00	2971.00	1942.00
8	2641.00	2345.00	1728.00
7	2631.00	2316.00	1709.00
3	2612.00	2302.00	1683.00
4	2596.00	2200.00	1637.00
12	2590.00	2198.00	1635.00

Table 3.3: Fault currents with grid-following mode IBRs

3.4 Grid-forming inverter model

During islanded conditions, the inverters operate in grid-forming mode, where they provide voltage and frequency regulation for the islanded microgrid to operate properly. In this mode, the real and reactive power injections are based upon the conventional droop characteristics presented in [15]. The grid forming IBRs are modeled as average models using MATLAB's Simscape Electrical Specialized Power Systems library. Figure 3.8 shows the grid forming connection and overview diagram. The grid forming IBRs are connected to the microgrid through an LCL filter and an interfacing transformer. The grid forming IBR controller utilizes a CERTS control scheme described in [16]. A diagram of the controller is shown in figure 3.9. The controller

Figure 3.8: Grid-forming IBR connection diagram

transforms the measured output voltage (V_0) and currents (I_0) to the $\alpha\beta$ reference frame to obtain $V_{0\alpha}$, $V_{0\beta}$, $I_{0\alpha}$ and $I_{0\beta}$. The transformed parameters are used to calculate the power output using equation 3.2. The controller also calculates the peak voltage (V_{0peak}) using the equation 3.3, which is used with a PI controller to regulate the voltage reference provided by the voltage droop stage, this improves voltage regulation by minimizing circulating currents throughout the system. The peak current (I_{0peak}) is calculated similarly to the peak voltage using the equation 3.4, which will

be used to control the fault current. A diagram of the calculations can be seen in figure 3.10.

Figure 3.9: Grid-forming IBR controller

Figure 3.10: Grid-forming IBR power, voltage, current calculation

$$\begin{aligned}
 P &= \frac{3}{2}(V_{o\alpha}I_{o\alpha} + V_{o\beta}I_{o\beta}) \\
 Q &= \frac{3}{2}(-V_{o\alpha}I_{o\beta} + V_{o\beta}I_{o\alpha})
 \end{aligned} \tag{3.2}$$

$$V_{0peak} = \sqrt{V_{0\alpha}^2 + V_{0\beta}^2} \quad (3.3)$$

$$I_{0peak} = \sqrt{I_{0\alpha}^2 + I_{0\beta}^2} \quad (3.4)$$

After the real power, reactive power, and peak voltage are calculated a droop control is performed to using the equation 3.5, where m_p is the droop power-frequency characteristic. A voltage drop is also performed using the equation 3.6, where m_q is the voltage-power droop characteristic. The output of the voltage droop stage is used by a PI-based voltage control to generate the amplitude for the reference signal (E_{mod}). The amplitude and ω from the droop control stage are used to create the modulation signals used to drive the IBR as shown in figure 3.11.

$$\omega = \omega_{ref} + m_p * (P_{set} - P) \quad (3.5)$$

$$V = V_{set} - (m_q * Q) \quad (3.6)$$

Figure 3.11: Grid-forming IBR modulation signal generation

A virtual impedance current limiting scheme discussed in [17] was used to limit the currents at 2 pu. The virtual impedance method is an alternative to the current reference limitation used in the grid following inverter. A transient virtual impedance such as a resistor, with two threshold values for the current amplitude, where the first threshold value activates the virtual impedance and the second disconnects the

inverter in case of severe faults. Since the grid forming inverter should never disconnect from the microgrid the second threshold is ignored leaving only one threshold to activate the virtual impedance. When the current output of the inverter is below the threshold value, virtual impedance is not active. When the output current exceeds the threshold value the virtual resistance is activated so that the inverter's output current is limited to below the maximum allowable current limit. This is achieved by reducing the commanded voltage reference generated by the droop control by modifying the droop control equation from equation 3.6 to equation 3.7, where I_{th} represents the threshold current and R_v is the virtual impedance. For the LOHO system the virtual impedance was chosen to be $R_v = 0.7pu$ and the threshold was set to $I_{th} = 1.2pu$.

$$V = V_{set} - (m_q * Q) - I_{0peak} * \begin{cases} R_v & I_{0peak} \geq I_{th} \\ 0 & I_{0peak} \leq I_{th} \end{cases} \quad (3.7)$$

3.5 Grid-forming mode IBRs fault response

In grid forming mode the IBRs need to act as the main source of fault current as the grid source is disconnected. However, fault current has to be limited in order to protect the inverter's electronics. The grid forming mode IBR's fault response was tested by simulating a three-phase to ground fault at the inverter terminals when the microgrid was in islanded mode. The inverter terminal voltage, output current, real, and reactive power output were monitored. Figure 3.12 shows that when the fault is initiated the voltage drops to near 0 as expected for a bolted fault at the inverter terminal. The current output increases dramatically at first as the filtering capacitor is drained and then is limited to below 2pu by the virtual impedance. Once the fault is cleared the system returns back to steady-state. In comparison to the grid following inverter, the grid forming inverter model acts much more like a traditional generator,

at the initiation of the fault the current rises quickly like a traditional generator unlike the grid following which gradually increased its current output.

Figure 3.12: Grid-forming IBR fault response

3.6 Impact of grid-forming IBRs on the microgrid in islanded mode

The grid forming inverter models were added to the LOHO system. The system was simulated with the IBRs to observe the operation of the microgrid with only the distributed generation available. This case represents the islanded mode operation of the microgrid when the microgrid is disconnected from the grid source by opening the

breaker located on bus 2. In this case, the IBRs are supplying both real and reactive power demand for the system. The IBRs use the droop control scheme to regulate their power output to meet the system demand and maintain healthy voltage and frequency. The system line currents and power flow when IBRs are operating in grid forming mode are shown in table 3.4 where negative values for P and Q represent power flowing towards the grid (not actually to the grid as its disconnected). Table 3.5 shows the load currents and load flow when IBRs are operating in grid forming mode.

Line #	IA (A)	IB (A)	IC (A)	P (kW)	Q (kVar)
T1 (HV)	Disconnected				
149	4.63	3.06	4.04	-57.97	-57.84
150	4.63	3.52	4.28	-64.28	-58.61
135	28.76	29.42	30.63	628.5	19.96
105	15.56	15.78	15.06	528.4	209.6
T2 (HV)	2.50	2.67	4.20	2.125	-61.89
T2(LV)	65.76	70.00	110.60	1.119	-63.51
59	32.51	32.71	33.31	-695.4	-56.4
167	111.10	111.60	112.00	-2280	655.9
196	111.10	111.60	112.00	-2280	655.5
188	81.61	81.56	81.61	1584	-707
97	81.57	81.51	81.57	1583	-707
88	89.30	89.11	89.06	1584	1043
4	89.31	89.13	89.08	1583	1042
164	14.87	14.79	14.94	-236.8	-208.9
Inv3 10 MW	111.10	111.60	112.00	-2280	655.4
Inv2 1 MW	14.87	14.79	14.94	-236.8	-208.8
Inv1 258 kW	144.90	147.30	143.20	-61.67	-101.9

Table 3.4: Line currents and power flow for islanded microgrid with grid-forming mode IBRs

Due to the lack of grid source the power flow direction for the microgrid is reversed in the islanded mode compared to the base case discussed in chapter 2. In the base case where all power and therefore currents were sourced for the grid, now the direction reverses as all power and currents are sourced from the IBRs located at the ends of

Load #	IA (A)	IB (A)	IC (A)	P (kW)	Q (kVar)
136	0.00	0.53	0.37	6.31	0.77
139	0.00	0.32	0.06	2.62	0.54
142	13.61	14.06	16.28	303.70	67.97
133	14.68	14.83	16.29	320.80	34.65
19	115.40	115.20	38.69	62.79	38.44
cap7	82.30	82.36	82.17	-0.36	-1750.00
20	104.1	103.90	104.00	1820.00	1251.00

Table 3.5: Load currents and power for islanded microgrid with grid-forming mode IBRs

the feeder laterals. In the islanded mode case the inverters deliver 2578.47 kW of real power and absorb a total of 344.7 kVar of reactive power output from the capacitor at bus 7. In islanded mode, the IBRs easily supply the required amount of power to sustain the microgrid as the IBRs were sized in order to export power to the grid. In fact in islanded mode the IBRs limit their power output to maintain the system voltage and frequency. Table 3.6 shows the bus voltage during steady-state islanded microgrid operation. It can be seen that during steady-state operation the IBRs keep the voltage across the system within the specified IEEE 1547 DER standard [18]. IEEE 1547 standard states that the voltages must remain within 0.9 pu and 1.1 pu and the frequency must be within 58.5 Hz and 60 Hz.

In order to measure the fault currents supplied by the IBRs in islanded microgrid mode faults were simulated on each bus of the system. Similarly to the base case a 3phF, LLF on phase A-B and SLGF on phase A were simulated on each bus with a fault resistance of 0.01Ω , a summary of the resulting fault currents is shown in table 3.7.

The maximum fault current of 882 A is observed at bus 6, rather than at the inverter terminals. The fault current is the highest at bus 6 rather than the largest inverters terminals due to the fault current limiting method of the inverters. The virtual

Bus #	Va (pu)	Vb (pu)	Vc (pu)
1	Disconnected		
2	0.997	0.997	0.998
11	0.998	0.998	0.999
5	0.998	0.998	0.999
9	0.999	0.998	1.000
10	0.998	0.999	0.999
15 (LV)	1.000	1.000	1.008
6	0.999	0.998	1.000
13	0.999	0.998	1.000
14	0.999	0.998	1.000
8	1.000	0.999	1.000
7	1.000	0.999	1.001
3	1.000	0.999	1.001
4	0.999	0.998	1.000
12	0.998	0.997	1.000

Table 3.6: Bus voltages for islanded microgrid with grid-forming mode IBRs

Bus #	3phF (A)	LLF (A)	SLGF (A)
2	638	815	334
11	638	815	334
5	667	867	365
9	664	866	364
10	595	758	308
15 (LV)	3275	3305	1177
15	126	127	65
6	693	882	374
13	695	882	374
14	695	882	374
8	686	878	374
7	685	877	374
3	683	875	374
4	677	872	374
12	677	871	374

Table 3.7: Fault currents with grid forming mode IBRs in islanded microgrid state

impedance fault current limits the fault current to a lower value when the voltage drop is more severe, therefore for fault at the inverter terminals the fault current contribution from that inverter is limited to a lesser value compared to a fault a few lines away from the inverter terminals. The lowest fault current of 65 A was observed on bus 15 due to low fault current contributions from the largest inverters as they are furthest from bus 15 and the inverter at bus 15 is limited to a maximum of roughly 23 A of fault current contribution. Compared to the base case and the grid connected case the fault currents in the islanded mode are considerably lower. Due to the lack of a strong grid source, on average the fault currents in the islanded microgrid with the grid forming IBRs are typically an order of magnitude lower. Overall it can be seen that unlike the base case where a large amount of fault current compared to the load current was present, in islanded mode many of the fault current values are closer to load current. For example for a 3ph fault on bus 15 the fault current observed by the recloser REC in grid connected mode is 1013 A, in islanded mode its reduced to 120 A. However, due to the large size of the IBRs compared to the load on the system, there is still sufficient fault current to use OC relays.

Chapter 4

Analysis of Existing Protection Devices

Traditional protection devices such as overcurrent relays, Differential Relays, and Distance relays each face unique challenges when present in a microgrid setting [19].

4.0.1 Overcurrent Elements

Overcurrent relays and other overcurrent based protection devices suffer from large coordination ranges due to the switching nature of a microgrid, where a microgrid can switch from grid-connected to islanded state and vice-versa either intentionally or unintentionally. The switch from one state to another changes the sources of fault current available to the system and thus the amount of fault current observed by an OC relay element. Generally, the fault current available in grid-connected mode is many times greater than the fault current available in islanded mode, leading to large coordination ranges for OC based protection devices [19].

4.0.2 Differential Protection

Differential protection offers a solution that is free from the issues faced by conventional OC based protection; however, differential protection has its own shortcomings. Differential protection of feeders requires data sharing between devices either through digital communication or through physical wires between devices to achieve coordination. This may be feasible for geographically small microgrids [19]. Differential protection for a microgrid, while feasible in principle, in actuality can become impractical due to the cost associated with the intensive communication needed for differential protection. In general, cost of differential protection is higher compared to other protective devices.

4.0.3 Distance Protection

Distance protection also offers a solution that is free from fault current fluctuations; however, it does not lend itself naturally to radial distribution feeders with tapped load laterals. Distribution feeders such as the LOHO system shown in figure 2.1, can cause the distance relays to under-reach due to current infeeds and can also suffer from blind spots due to the presence of DER. Additionally, depending on the DER and fault location, a distance relay may not even see the fault. It is conventional for a tapped feeder to either be protected by a differential scheme, or a distance scheme using intertripping. A communication network between the devices is necessary for intertripping; therefore, there is little to no advantage to using distance protection over differential protection in this scenario [19].

4.1 Issues faced by the existing protection in the LOHO system

As per the standard protection methods for distribution feeders, the test feeder is protected using a relay at the substation, a recloser, a sectionalizer, and load fuses, as shown in Fig. 2.1. Overcurrent (OC) relay *R1 with reclosing function* is located at bus 2 and is coordinated with the sectionalizer *SEC* at bus 8 and the recloser *REC* at bus 5. The loads are protected using appropriate load fuses. The fuses and relays are set to operate for permanent faults. The recloser and sectionalizer are set to save fuses by clearing temporary faults. While these devices adequately protect the feeder when it is only fed by the grid, they cannot protect the proposed microgrid due to reasons outlined in this section.

4.1.1 Bidirectional current

Multiple sources create bidirectional fault currents, making simple overcurrent based protection difficult (or impossible) in many situations. Figure 4.1 highlights the issues caused by multiple sources and bidirectional fault currents; fault currents for a fault on bus 9 are shown in red and fault currents for a fault on Line 149 are shown in green. Taking the recloser "REC" as an example to illustrate the issue of bidirectional fault current. The recloser *REC* is only supposed to operate for faults downstream on buses 9, 10, 15, and load laterals associated with these buses as per conventional protection. These faults would all have a similar fault current path as the fault on bus 9 from the perspective of the recloser. However, when IBR is added at bus 15, that recloser now also needs to operate for upstream faults on bus 2, bus 11, line 149 line and 150 in order to isolate the IBR on bus 15 from the fault-point. These faults would

Figure 4.1: LOHO system with bidirectional fault current example

in general follow the fault path shown in green for a fault on line 149. The recloser now must operate for both types of faults upstream and downstream with reverse and forward fault current respectively. Thus, as the system changes from single-sourced to multi-sourced, the protection also needs to go from simple OC to at least directional OC. This often requires different settings for both directions because fault current from IBR for upstream faults may be very limited. Taking the same recloser as an example, the recloser sees a load current of approximately 30 A flowing towards bus 9 from bus 5. However, depending on the fault location and fault resistance the current observed by the recloser can drop to as low as 10 A in the reverse direction as the 258 kW inverter feeds the faults upstream from the recloser. Similarly, the Relay R1 at bus 2 needs to be able to isolate the microgrid from the utility system if a fault occurs on the utility grid but continue to operate for downstream faults at bus 5, 6, 8, 11, and 13. Applying the same logic to the rest of the system with three IBRs, the existing protection fails to isolate the faults on buses 3, 4, 5, 6, 7 and 8. Protection must be enhanced to isolate faults from the IBR-side.

Bidirectional currents can also make existing devices misoperate. For example, sectionalizer *SEC* at bus 8 (see Fig. 4.1), which previously operated in conjugation with the relay *R1*, cannot be coordinated with two more reclosers *REC* and *IR* for faults downstream of *SEC*. The sectionalizer also cannot be coordinated with any device downstream in order to operate for faults upstream such as the fault on Line 149 shown in green in figure 4.1. Additionally, the sectionalizer could miscount due to the low fault current contribution from the DER on bus 12 being interpreted as load current in the event of an upstream fault. Therefore, the sectionilizer is removed and replaced with a directional overcurrent relay *R3* to provide better selectivity to the proposed protection. Additionally relays *R2* and *R4* shown in Fig. 4.3 are added to the existing protection scheme to ensure faults could be isolated from the IBR-side. A relay could be added at bus 14 as well; however, because the utility had already

added an intelligent recloser at bus 13 and no load is present on bus 14, it was kept at bus 13 as it severs essentially the same role.

4.1.2 Low fault current

Since IBRs limit their current output to low values (2 pu in this study), they pose challenges for device coordination in both grid-connected and islanded modes. This is true especially in islanded mode due to lack of adequate fault currents. For example, the maximum fault current in the grid-connected mode for the feeder is around 8000 A. However, the majority of the fault current in grid-connected mode is from the grid. The fault current contribution from the inverters is limited to a maximum of 93 A, 925 A, and 24 A for the 1 MW, 10 MW, and 258 kW inverters, respectively. Low fault current from the inverters creates challenges in fault detection from the inverter side as the fault current from the inverters can be similar to or even lower than load current. For example, for a fault on bus 11 shown in figure 4.2, in grid-connected mode the total fault current is 5489 A. However, majority of that fault current is sourced from the grid while the DERs only supply a combined 620 A of fault current. Additionally, 591 A of the DER supplied fault current is sourced from inverter 2, with only 12 A and 21 A of fault current being sourced from inverter 1 and inverter 3 respectively. The fault current observed at bus 8 is lower than the nominal load current at bus 8, This makes fault detection using conventional non-direction overcurrent relays impossible. Therefore, in the presence of DER, at least directional overcurrent relays must be used.

The maximum fault current in the islanded mode is reduced to roughly 880 A. The low fault current during islanded mode can lead to difficulties in fault detection or long tripping times for OC elements if settings are based on fault currents observed for grid-connected mode. On the other hand, if settings are based on fault currents

Figure 4.2: Example fault current in grid connected mode

observed in islanded mode, the OC element can misoperate or fail to coordinate properly in grid-connected mode.

4.1.3 Large coordination ranges

Due to the limited fault currents from IBRs, coordination ranges can become large and lead to difficulties in coordination, often resulting in excessive operating time, as illustrated in [19]. In the test case under discussion, the coordination range for *REC* can span from 3500 A to 120 A due to large differences in fault current profiles in grid-connected and islanded modes.

4.2 Summary of updates to the protection devices

Based on the issues discussed in section 4.1 several changes were made to the LOHO systems protection devices. First, and most importantly, all devices were made to be directional so settings can be set for both upstream (reverse) and downstream (forward) direction faults. Directional overcurrent relays were placed at the IBR terminals for inverter 1 and inverter 3, inverter 2 did not have a relay placed at its terminals as it already has an intelligent recloser on bus 13. The sectionalizer was replaced with a directional OC relay. The changes to the protection devices essentially split the system into 5 protection zones highlighted in figure 4.3.

Figure 4.3: LOHO system with updated protection elements

Chapter 5

Proposed Protection Method

It is clear from the discussion in Section 4.1.1 that bidirectional protective devices are needed to protect the microgrid. It is also clear that settings will need to be different for different operating modes due to a large difference in fault currents, thus requiring an adaptive design. Based on the available protective devices, the microgrid was divided into 5 protection zones as shown in Fig. 4.3. Relays $R1$, $R2$, and reclosers REC and IR will have different settings for different fault-current directions. Also, all devices will have different settings for grid-connected mode and islanded mode.

For the purpose of this discussion, the direction downstream of the feeder will be called "forward" and the direction upstream will be called "reverse". Numerical relay manufacturers have relays and other protective devices that can store multiple settings that can be activated and deactivated using communication. For example, the SEL 751 relays have the capacity to set the max phase time overcurrent with directional control (51P). These relays also allow the user to create the logic which is used to generate a trip signal based on the output of different relaying elements such as inverse-time overcurrent, under-voltage, and directional. Therefore, a relay can be set to operate, for example, if the directional element indicates a forward current *and*

the OC criteria are met, *and* the voltage has dropped below the set threshold. Using these programmable trip conditions and multiple group settings, the same relay can be adaptively programmed to operate differently for different modes of operation. A minimum of 2 setting groups should be stored in a relay, 1 for grid-connected mode, and 1 for islanded mode. Each setting group is further broken down into settings for forward (F) and reverse (R) direction. This results in 4 sets of Minimum Operating Current (MOC) settings and Time Dial (TDs) settings for each device that needs to operate for fault current in both directions as shown in figure 5.1 [20]. A flow chart of which settings are active and how a trip signal is generated is shown in figure 5.2.

Depending on the microgrid operating mode, either the grid-connected or islanded mode settings will be active. The signal used to switch the inverter operating mode can be used to activate/deactivate the appropriate mode-setting. In the case of loss of signal, relays can be set up either to trip or to default to islanded mode protection. If the relay is tripped due to loss of signal then the breaker associated with the relay is opened, isolating the section of the system protected by that relay. If the relays default to islanded mode protection then the relays could trip unintentionally trip during overload conditions however, they will still be able to isolate any fault that occurs in the system. This is preferable to being an able to isolate a fault if a fault occurs.

In islanded mode, faults are isolated by the operation of the appropriate devices using their islanded mode setting by isolating the faulted section of the microgrid. If the faulted section includes a DER, then the DER will be isolated by the protective elements placed on the DER connection terminals (Relays $R2, R4$, and IR). In grid-connected mode, there are two options for isolating faults inside the microgrid. Relay $R1$ can be set to operate instantaneously to disconnect the grid, transitioning the microgrid into islanded mode and isolating the faulted zone based on settings for the

Figure 5.1: Settings groups for bidirectional protective devices.

Figure 5.2: Flow chart of relay trip signal generation

islanded mode. Alternatively, $R1$ can coordinate with the devices inside the microgrid to isolate the faulted zone. The first option is more likely, as utilities do not coordinate with the protection of customer-owned systems. However, as microgrids proliferate, it is likely that microgrids may be owned by utilities, in which case, the second option may become feasible. Both options will be discussed here. For the second option, for the microgrid under study, $R1$ will backup $R3$, IR , and REC for faults in zones 5, 4, and 3, respectively.

5.1 Example settings calculation

As an example for a fault on bus 9 in islanded mode, the recloser REC_F forward direction (REC_F) setting needs to operate. In islanded mode, REC has a load current of 35 A with a fault current ranging from 120 A to 950 A. Therefore the minimum operating current (MOC) for REC_F is set to 1.5 times load current at 53 A. As REC_F is set to allow for fuse saving with the fuse protecting transformer T2, operating time of 0.30s and 0.03s are chosen for the slow and fast curves respectively, based on the operating time of the fuse for the coordination range of 120 A - 610 A. Based on the chosen operating time (O_t), MOC, and coordination range, a curve is selected from the set of U.S TCC curves. Equations 5.1 - 5.5 representing U1: Moderately Inverse (MI), U2: Inverse (I), U3: Very Inverse (VI), U4: Extremely Inverse (EI), and U5: Short-Time Inverse (STI) respectively are used to calculate the time dial setting for the protection devices, where t_p is the operating time, TD is the time-dial setting and M is the multiples of pickup current. For REC_F fast curve a Short-Time Inverse (STI) Curve is selected with a Time Dial setting (TDS) of 0.5 is chosen and for the slow curve, an Extremely Inverse (VI) curve is selected with a TDS of 2.250.

$$t_p = TD * \left(0.02260 + \frac{0.0104}{M^{0.02} - 1} \right) \quad (5.1)$$

$$t_p = TD * \left(0.18000 + \frac{5.95}{M^2 - 1} \right) \quad (5.2)$$

$$t_p = TD * \left(0.09630 + \frac{3.88}{M^2 - 1} \right) \quad (5.3)$$

$$t_p = TD * \left(0.03520 + \frac{5.67}{M^2 - 1} \right) \quad (5.4)$$

$$t_p = TD * \left(0.00262 + \frac{0.00342}{M^{0.02} - 1} \right) \quad (5.5)$$

Similarly, for a fault on bus 5, the recloser RECs reverse direction REC_R needs to operate; however, this time the fault current seen by the recloser is limited to 15 A - 20 A. This is due to the low fault current capacity of the Inverter1. Also, in this case REC_R needs to backup $R3_F$ and IR_F . As the load current REC_R is 0 (load current in islanded mode should always flow in the forward direction for REC), MOC for REC_F is set to 5A, and the Ot is set to be the 0.3s more than the Ot for $R3_F$ or IR_F , whichever is greater. Operating time of 0.7s and 0.1s are chosen for the slow and fast curves respectively. Based on the operating curves and the different coordination ranges for both $R3_F$ and IR_F along with the MOC, for the fast curve, an STI curve with a TDS of 1.02 is chosen and for the slow curve, an STI curve with a time dial setting of 7.25 is chosen.

In grid-connected mode, RECs forward direction (REC_F) setting needs to operate for faults on bus 9, bus 10, line 135, and line 105. REC has a load current of 35 A in the forward direction when the IBRs are disconnected or not producing power and 25 A when IBRs are connected and operational. Also, the fault current in the forward direction ranges from 1013 A - 3290 A. Therefore, the minimum operating current (MOC) for REC_F is set to 1.5 times the load current for the higher of the

2 grid-connected cases at 60 A. As REC_F is set to allow for fuse saving with the fuse protecting transformer T2. Operating time of 0.5s and 0.03s are chosen for the slow and fast curves respectively, based on the operating time of the fuse for the coordination range of 235 A - 350 A. Based on the chosen operating time (Ot), MOC, and coordination range, a curve is selected and the TDS for the fast and slow curves is calculated for the recloser in grid-connected mode. For REC_F fast curve, a Short-Time Inverse (STI) Curve is selected with a Time Dial setting (TDS) of 0.5 and for the slow curve, a Short-Time Inverse (STI) curve is selected with a calculated TDS of 5.53.

In grid-connected mode, RECs reverse direction (REC_R) setting needs to operate for faults on bus 2, bus 11, line 149, and line 150 and backup the $R3_F$ and IR_F . Also, the fault current observed in reverse direction ranges from 10 A to 30 A supplied by the Inverter1 located at bus 15. The load current REC_R is 0 (load current in the grid-connected mode in steady-state should always flow in the forward direction); therefore, MOC for REC_F is set to 5 A, and the Ot is set to be the 0.3s more than the OT for $R3_F$ or IR_F , whichever is greater. Operating time of 0.7s and 0.1s are chosen for the slow and fast curves respectively. Based on the operating curves and the different coordination ranges for both $R3_F$ and IR_F along with the MOC; for the fast curve, an STI curve with a TDS of 1.57 is chosen and for the slow curve, an STI curve with a TDS of 7.27 is chosen. A summary of the recloser REC settings is shown in table 5.1.

Additionally, for each setting group calculated in this section, an Instantaneous trip (IT) setting is calculated when possible. If the maximum fault current seen by the device is at least 1.3 times greater than the maximum coordination range, then the instantaneous trip was set to the larger of 6 times the load current or 1.25 times the maximum coordination range. For the case of the recloser REC in grid-connected

mode in forward direction, the maximum fault current of 3290 A is much larger than the max coordination range of 390 A coordinating with the Transformer Fuse F2, therefore the instantaneous trip is set to $1.25 * 390 \approx 487$.

For reverse direction setting in grid-connected mode, the maximum fault current is observed to be 30 A from the DER on bus 15 with no load current in the reverse direction. In grid-connected mode, load current always flows in the forward direction across the recloser. Traditionally no instantaneous setting would be set because the max coordination range is the same as the max fault current. Since any current in the reverse direction is likely due to a fault, an IT setting is set for this special case at $1.25 * 390 \approx 38A$. In islanded mode, the maximum fault current observed in the forward direction is 950 A with a load current of 35A and a coordination range of 125-610A. The ratio of the maximum fault current to the maximum coordination range is greater than 1.3 therefore, the instantaneous trip was set at $1.25 * 610 \approx 762A$.

Similarly to the reverse direction case in grid-connected mode, in islanded mode IT for the reverse direction was set at 38 A. Figure 5.3, 5.4, 5.5, and 5.6 show the coordinated TCC curves for recloser REC in grid-connected forward, grid-connected reverse, islanded forward, and islanded reverse setting respectively. In all the TCC curves figures, the coordination ranges and other protection devices curves are shifted to account for the different fault currents seen by the individual devices. For example, when the recloser REC_R is backing up $R3_F$ for a fault on bus 7, the fault current seen by the recloser $R3_F$ is a summation of the currents seen by REC_R and IR_R . Therefore, the x-axis of the TCC curves will be miss-aligned and need to be shifted. Figures 5.3 - 5.6 are shifted to align with TCC curves of the recloser REC using the ratio of the main device (REC in this figures) fault current to the secondary device fault current (IR , $R3$ and $F2$ in this figures).

Using the setting in table 5.1 for a 3ph fault on bus 10 in grid-connected mode, the

fault current seen by the recloser is in the forward direction and has a magnitude of 1450 A. In this situation, settings corresponding to mode GC and direction F in the table will be activated, which translates to MOC of 60 A, and TDS of 5.53 and 0.5 for the fast and slow curves, respectively. The inverse time OC element will activate when the current exceeds the MOC and will trip after a time delay dictated by the TDS setting. However, in this case, the fault current is sufficiently large to activate the instantaneous trip, operating as quickly as possible.

Similarly, to the method shown in this section, the 4 sets of settings for each device can be calculated based on the fault currents observed by each device. The coordination between devices and their settings will be covered in section 5.2 and 5.3.

Figure 5.3: Grid connected REC_F TCC

Figure 5.4: Grid connected REC_R TCC

Figure 5.5: Islanded REC_F TCC

Figure 5.6: Islanded REC_R TCC

Table 5.1: Example settings For recloser REC at bus 5

Group #	Mode	Direction	MOC (A)	TDS	Curve
Slow Settings					
1	GC	F	60	5.53	STI
1	GC	R	5	7.27	STI
2	IS	F	53	2.25	VI
2	IS	R	5	7.25	STI
Fast Settings					
1	GC	F	60	0.5	STI
1	GC	R	5	1.57	STI
2	IS	F	53	0.5	EI
2	IS	R	5	1.02	STI

5.2 Grid-Connected mode coordination & settings

In the grid-connected mode, zone 1 represents the grid, and thus any fault in zone 1 is detected by the PCC controller (using reverse setting of $R1$) and the microgrid is instantaneously disconnected from the grid and switched to islanded mode with appropriate protection settings. In the grid-connected mode, for a fault inside the microgrid (zone 2-5) two scenarios can occur: the microgrid is disconnected from the grid, or the microgrid remains connected but the fault is isolated. In the case where the microgrid is disconnected from the utility grid when a fault is detected, the microgrid switches from grid-connected mode to islanded mode along with the protection. The fault is then isolated in islanded mode. In the case where the microgrid remains connected to the utility grid, it must selectively isolate the faulted part of the microgrid and remove DGs feeding that fault in order to keep the remaining part of the microgrid grid-connected. Depending on the standards and the agreement between the microgrid operator and the connected utility, either of these methods can be used. In cases when the microgrid is islanded from the system, islanded protection will be used which is covered in section 5.3.

The scenario where the microgrid is islanded and then the fault is isolated in islanded mode is more likely. This is because the utility to which the microgrid is connected will probably not want to rely on the microgrid protection to isolate the fault from their system and likely disconnect as quickly as possible. However, as microgrids become more popular this may no longer be feasible and utilities may need to allow the microgrid to remain connected. For example, in the case of LOHO system, if the utility decides to isolate the microgrid from the system instantaneously for any fault on the microgrid, then in cases like a fault on bus 1, the utility would be unnecessarily removing the 11 MW of generation from the system that was previously contributing a majority of its output to the utility grid.

In grid-connected mode, for any faults in zone 2 (in LOHO system), the fault is isolated by the combined operation of REC , IR , and $R3$ on their respective reverse settings. REC is backed up by $R2$, and $R3$ is backed up by $R4$. The microgrid is isolated by the forward operation of $R1$. In this case, for the inverter-control adopted in this study, the microgrid is forced to go into a blackout as all the IBRs must be disconnected from the grid and lose the grid signal needed to operate in grid-following mode. This is unavoidable as zone 2 is the main feeder section from where the laterals originate and thus is fed by all the inverters and the grid. Therefore, during a fault, all the IBRs must be disconnected along with the grid from the microgrid in this scenario. Figure 5.7 shows the protection coordination plot for zone 2, the TCC curves are shifted to account for different percentages of the fault current seen by each device as explained in section 5.1.

Figure 5.7: Grid connected zone 2 protection coordination

A fault in zone 3 is isolated by the forward operation of *REC* followed by operation of *R2*. *REC* is backed up by the reverse operation of *IR* and *R3*, and forward operation of *R1*, in the event *REC* fails to operate. For a fault in zone 3, only the lateral originating from Bus 5 is disconnected from the utility grid and the IBR located at bus 15 is also disconnected. However, the rest of the system is left connected to the utility grid. Figure 5.8 shows the Protection coordination plot for zone 3.

Figure 5.8: Grid connected zone 3 protection coordination

A fault in zone 4 is isolated by the forward operation of *IR*, backed up by the reverse operation of *REC*, *R3*, and the forward operation of *R1*. For a fault in zone 4, if the primary protection fails, then the backups must operate which creates a scenario similar to a zone 2 fault. In this case, the microgrid must be disconnected from the grid and all DERs. Figure 5.9 shows the Protection coordination of zone 4.

A fault in zone 5 is isolated by the forward operation of *R3* and operation of *R4*. *R3*

Figure 5.9: Grid connected zone 4 protection coordination

is backed up by the reverse operation of REC and IR and forward direction of $R1$. In the case of a zone 5 fault, the lateral originating at bus 8 is disconnected and the IBR on bus 12 is disconnected leaving the rest of the system to remain connected to the utility grid. Figure 5.10 shows the Protection coordination plot for zone 5.

The grid-connected mode setting calculation was largely automated using a MATLAB script that uses the information obtained from fault analysis such as fault current range, coordination range if acting as backup, load current, etc. The calculation is done following the steps outlined in section 5.1 to calculate the protective device settings. The recloser calculation function and relay calculation function are available in the Appendix B.1 and B.2, respectively. Table 5.2 summarizes the setting calculated for the devices in grid-connected mode. Table 5.3 shows the operating times for devices for faults at each bus.

Figure 5.10: Grid connected zone 5 protection coordination

Table 5.2: Settings for protective devices in grid-connected mode

Device	Direction	MOC (A)	TDS	Curve
R1	F	440	7.47	STI
R2	R	14.8	3.84	STI
R2	F	35	0.5	EI
R3	R	6	10.41	STI
R3	F	126	5.60	STI
R4	R	56	3.00	STI
R4	F	6	0.50	EI
REC Slow	R	5	7.27	STI
REC Fast	R	5	1.04	STI
REC Slow	F	60	5.53	STI
REC Fast	F	60	0.50	STI
IR Slow	R	432	2.45	STI
IR Fast	R	432	0.50	STI
IR Slow	F	78	8.05	STI
IR Fast	F	78	0.50	STI

Table 5.3: Operating times for a 3ph fault during grid-connected operation ^{a,b}

Bus Zone	Main Device	OT (s)	Backup Device	OT (s)	Backup Device	OT (s)
2 Z2	REC_R IR_R $R3_R$ $R1_F$	0.16, 1.11 0.25, 1.22 1.26 0.03	$R2_R$ $R4_R$	2.22 2.24		
11 Z2	REC_R IR_R $R3_R$ $R1_F$	0.16, 1.11 0.25, 1.22 1.26 0.03	$R2_R$ $R4_R$	2.22 2.23		
5 Z2	REC_R IR_R $R3_R$ $R1_F$	0.16, 1.11 0.07, 1.19 1.30 0.03	$R2_R$ $R4_R$	1.12 2.04		
6 Z2	REC_R IR_R $R3_R$ $R1_F$	0.15, 1.02 0.18, 0.88 0.73 0.03	$R2_R$ $R4_R$	1.23 2.24		
13 Z2	REC_R IR_R $R3_R$ $R1_F$	0.15, 1.04 0.18, 0.88 0.73 0.03	$R2_R$ $R4_R$	1.3 2.24		
8 Z2	REC_R IR_R $R3_R$ $R1_F$	0.16, 1.09 0.18, 0.88 0.73 0.03	$R2_R$ $R4_R$	1.3 2.25		
5 Z3	REC_F $R2_R$	0.03 1.23	IR_R	0.21, 1.02	$R3_R$	0.77
9 Z3	REC_F $R2_R$	0.03 1.23	IR_R	0.21, 1.02	$R3_R$	0.77
10 Z3	REC_F $R2_R$	0.03, 0.35 0.69	IR_R	0.25, 1.22	$R3_R$	1.29
15 Z3	$FT2$ $R2_R$	0.9 0.62	REC_F	0.15, 2.43		
13 Z4	IR_F	0.03	REC_R	0.15, 1.04	$R3_R$	0.73
14 Z4	IR_F	0.03	REC_R	0.15, 1.04	$R3_R$	0.73
8 Z5	$R3_F$ $R4_R$	0.31 2.24	IR_R	0.18, 0.88	REC_R	0.16, 1.08
7 Z5	$R3_F$ $R4_R$	0.31 2.24	IR_R	0.18, 0.88	REC_R	0.16, 1.08
3 Z5	$R3_F$ $R4_R$	0.31 2.24	IR_R	0.18, 0.88	REC_R	0.16, 1.08
4 Z5	$R3_F$ $R4_R$	0.31 2.24	IR_R	0.18, 0.88	REC_R	0.17, 1.17
12 Z5	$R3_F$ $R4_R$	0.31 2.24	IR_R	0.18, 0.88	REC_R	0.18, 1.25

^aF - Forward Direction, R - Reverse direction.

^b#, # - Represents recloser operating times for fast, slow actions.

Overall in grid-connected mode, most faults are isolated from the grid side within 0.2s with some faults taking longer, specifically faults on the low voltage side of the transformer. The transformer impedance and the current in-feed from the DER on bus 15 dramatically reduce the fault current observed to near load current levels. However, as fuse saving for the Fuse $FT2$ was achieved, the recloser will operate before the fuse in case of a temporary fault within 0.15s. For permanent faults on bus 15, it would take the Fuse $FT2$ 0.9s to operate. In grid-connected mode, most DERs are isolated within 1.2s, with only the DER on bus 12 taking up to 2.25s to isolate the DER from the system. This high operating time is due to the relay $R4_R$ backing up relay $R3_R$ while both of them observe near-identical currents, which remain below 2pu thus to maintain the coordination CTI the relay $R4_R$ has a larger delay before operating. It is clear that the fault clearing times are unconventionally large in some cases, especially for backup protection, but the fault currents in those cases are also unconventionally small. The fault current values in lines for such cases did not exceed 1.8 times the maximum load current values observed in the lines. This obviates the possibility of equipment-damage. The coordination scheme in grid-connected mode is capable of isolating the faults at every location in the feeder from the utility grid and the DERs present with selectivity.

5.3 Islanded mode coordination & settings

In islanded mode, all fault contributions are from IBRs operating in grid-forming mode, each providing at the most 2 pu fault current, drastically reducing the fault currents and thus requiring reductions in minimum operating currents (MOC) used by devices to detect faults in the microgrid. For example, the pickup current for REC for faults in zone 3 is 80 A in grid-connected mode but reduces to 53 A in islanded

mode. For faults in all zones (zone 2-5), main and backup devices will remain the same as proposed for grid-connected mode, but with different settings as well as the exclusion of $R1$. The coordination plot for zone 2 can be seen in figure 5.11, with the device curves shifted.

Figure 5.11: Islanded mode zone 2 protection coordination

For a fault in zone 3, the fault is isolated by REC_F , and the DER at bus 15 is isolated by $R2_R$. In the case of a zone 3 fault, the microgrid can continue to operate with the faulted section removed as the remaining part of the microgrid can still sustain itself. The coordination plot for zone 3 can be seen in figure 5.12.

For a fault in zone 4, the fault is isolated by IR_F which also isolates the largest DER Inverter3 in the microgrid. In this case either the microgrid needs to begin load shedding to maintain stability or reconnect to the utility grid, as the amount of distributed generation is not sufficient to supply the full load. The coordination plot for zone 3 can be seen in figure 5.13.

Figure 5.12: Islanded mode zone 3 protection coordination

Figure 5.13: Islanded mode zone 4 protection coordination

For a fault in zone 5, the fault is isolated by $R3_F$, and the DER at bus 12 is isolated by $R4_R$. In the case of a zone 5 fault, the microgrid can continue to operate with the faulted section removed as the remaining part of the microgrid can still sustain itself. The coordination plot for zone 5 can be seen in figure 5.14.

Figure 5.14: Islanded mode zone 5 protection coordination

similarly to the grid-connected mode, Islanded mode setting calculation was largely automated using a MATLAB script that uses the information obtained from fault analysis including the fault current range and coordination range if acting as backup. The script follows the steps outlined in section 5.1 to calculate the protective device settings. The recloser calculation function and relay calculation function are available in the Appendix B.1 B.2, respectively.

Table 5.2 summarizes the setting calculated for the devices in grid-connected mode.

Table 5.3 shows the operating times for devices for faults at each bus.

Table 5.4: Settings for protective devices in islanded mode

Device	Direction	MOC (A)	TDS	Curve
R2	R	175	8.78	STI
R2	F	161	0.50	EI
R3	R	6	14.95	EI
R3	F	126	3.55	STI
R4	R	25	10.86	STI
R4	F	56	0.50	EI
REC Slow	R	5	7.25	STI
REC Fast	R	5	1.02	STI
REC Slow	F	53	2.25	VI
REC Fast	F	53	0.50	STI
IR Slow	R	180	5.48	STI
IR Fast	R	180	0.50	STI
IR Slow	F	30	3.32	STI
IR Fast	F	30	0.50	STI

Overall, in islanded mode, most faults are isolated 0.18s with some faults taking longer, specifically faults on the Low voltage side of the transformer. The transformer impedance and the current in-feed from the DER on bus 15 dramatically reduce the fault current observed to near load current levels. However, as fuse saving for the Fuse $FT2$ was achieved, the recloser REC_F will operate within 0.1s in case of a temporary fault. For permanent faults on bus 15, it will take the Fuse $FT2$ 2s to operate due to the fuse having been selected based on the transformer it's protecting rather than the load current. In Islanded mode, most DERs are isolated within 1.2s, with only the DER on bus 15 taking up to 2.23s to isolate the DER from the system. Similar to the grid-connected mode, the high fault clearing times, especially for backup protection, are due to less than 2pu fault current being supplied by the DER being isolated. The fault current values in such cases are too low to cause damage to equipment. Therefore, some longer times to isolate faults were deemed

Table 5.5: Operating times for a 3ph fault at all buses during islanded operation^{a,b}

Bus Zone	Main Device	OT(s)	Backup Device	OT (s)	Backup Device	OT (s)
2 Z2	REC_R IR_R $R3_R$	0.18, 1.33 0.07, 1.26 1.81	$R2_R$ $R4_R$	1.5 2.13		
11 Z2	REC_R IR_R $R3_R$	0.17, 1.24 0.07, 1.26 1.81	$R2_R$ $R4_R$	1.47 2.23		
5 Z2	REC_R IR_R $R3_R$	0.17, 1.17 0.07, 1.19 1.30	$R2_R$ $R4_R$	1.53 2.04		
6 Z2	REC_R IR_R $R3_R$	0.17, 1.17 0.07, 1.12 1.12	$R2_R$ $R4_R$	1.53 1.95		
13 Z2	REC_R IR_R $R3_R$	0.17, 1.17 0.07, 1.12 1.12	$R2_R$ $R4_R$	1.53 1.95		
8 Z2	REC_R IR_R $R3_R$	0.17, 1.17 0.07, 1.12 1.23	$R2_R$ $R4_R$	1.53 1.95		
5 Z3	REC_F $R2_R$	0.03, 0.35 1.53	IR_R	0.07, 1.17	$R3_R$	1.30
9 Z3	REC_F $R2_R$	0.03, 0.35 1.53	IR_R	0.07, 1.19	$R3_R$	1.29
10 Z3	REC_F $R2_R$	0.04, 0.38 1.53	IR_R	0.07, 1.27	$R3_R$	1.30
15 Z3	$FT2$ $R2_R$	2.02 1.73	REC_F	0.10, 2.23		
13 Z4	IR_F	0.09, 0.57	REC_R	0.17, 1.17	$R3_R$	1.1225
14 Z4	IR_F	0.09, 0.57	REC_R	0.17, 1.17	$R3_R$	1.1225
8 Z5	$R3_F$ $R4_R$	0.38 1.95	IR_R	0.07, 1.27	REC_R	0.17, 1.17
7 Z5	$R3_F$ $R4_R$	0.38 1.95	IR_R	0.07, 1.12	REC_R	0.17, 1.17
3 Z5	$R3_F$ $R4_R$	0.38 1.95	IR_R	0.07, 1.12	REC_R	0.17, 1.17
4 Z5	$R3_F$ $R4_R$	0.38 1.95	IR_R	0.07, 1.19	REC_R	0.17, 1.17
12 Z5	$R3_F$ $R4_R$	0.38 1.95	IR_R	0.07, 1.19	REC_R	0.17, 1.17

^aF - Forward Direction, R - Reverse direction.

^b#,# - Represent recloser operating times for fast,slow actions.

acceptable. The coordination scheme in islanded mode is capable of isolating the faults at every location in the feeder from the DERs present with selectivity. However, it must be stated that in many of these cases the microgrid may not be able to sustain itself without load shedding or reconnecting the utility due to the loss of DERs.

Chapter 6

Conclusion

The project explores the challenges faced when converting an existing real-world feeder to an IBR-fed microgrid from a control and protection perspective. A Real world 12.47 kV distribution feeder is modeled and studied to highlight the challenges involved in protecting a feeder converted to microgrid with 100% inverter based resources. An adaptive protection solution is proposed with the constraint of using off-the-shelf equipment and minimal communication. The adaptive protection system consists for directional overcurrent relays with multiple settings which can adapt to the changing microgrid operating modes. The proposed protection scheme requires at minimum 2 setting groups, one for grid-connected mode and one for islanded mode, with individual setting for forward and reverse faults in each mode. The Directional OC relays were coordinated with each other to create a protection scheme that splits the system into 5 protection zones, each zone can be selectively removed from the microgrid, allowing for selective clearing of faults in the microgrid by removing the faulted zone from the microgrid.

Results show that the solution works well under the unusual fault profile resulting from the IBRs and the mismatch in the load and generation capacity. This study may

be used as a guideline for other similar cases. The number of protective devices to be used and the number of zones to be created have an obvious cost-benefit trade-off. The success of the scheme also heavily depends on the fault current limits imposed by inverters and the inverter controls. Considering the extensive amount of calculation and analysis needed for this relatively small system, more complex systems are most likely to require more sophisticated solutions involving communications.

Appendix A

Appendix A: Code Used to Simulate Faults

A.1 Bash Script used to submit batch jobs to the palmetto cluster

```
1  #!/bin/bash
2  #
3  #PBS -N IS_VZ_Combo_Runs_w_Trans
4  #PBS -l select=3:ncpus=24:mem=100gb:interconnect=fdr
5  #PBS -l walltime=2:00:00
6  #PBS -j oe
7  #PBS -M trupalp@clemson.edu
8  #PBS -m abe
9
10 cd $PBS_O_WORKDIR
11
12 module add matlab/2018b
13 module add gnu-parallel_201903
14
15 parallel -a input.txt -j16 'taskset -c 0-3 matlab -nodisplay
    -nosplash -r "sim({})" '
```

A.2 Code to generate fault simulation files

```
1
2 % File      : Set_Faults
3 %
4 % Author1   : Trupal Patel
5 % Date      : 09/2019
6 %
7 % Description :
8 % The code is ment ot be used in conjuction with a simulink
9 % model of a power system to place fault of varing
10 % resistances and type at
11 % diffrent Buses in the system.
12 %
13 % Requirments :
14 % 1) The Power system model must contain Three-Phase Fault
15 % blocks named as:
16 % "Three-Phase Fault","Three-Phase Fault1","Three-Phase
17 % Fault2",
18 % "Three-Phase Fault3".
19 % 2) A three-phase VI measurment block named "F" to which
20 % all fault Blocks
21 % must be connected to in parallel to the Lcon ports of
22 % the meter
23 % (Upper case ABC side).
24 % 3) A To file block to which all mesurment being recorder
25 % are set to as a
26 % structure named "To File".
27 % 4) All fault location must be three-phase VI measurment
28 % blocks named
29 % "Bus#" example: Bus12
30 %
31 % Additional comments:
32 % 1) The Stiings of the faults and simulation stop time are
33 % hardcoded and
34 % can be changed from withen the program by modifying the
35 % appropriate parmenters.
36
37 %% Cleanup
38 clc;
39 clear;
40 close all;
41
42 %% Main Program
```

```

34
35 % Extract file name form path
36 [original_filename,Path] = uigetfile('E:\GoogleDrive\2020
    _Spring\*.slx',...
37                                     'Select System Model'
                                     ,...
38                                     'MultiSelect', 'off');
39 if(original_filename==0)
40     fprintf('\nError: No file selected or invalid file
        selected\n')
41     return;
42 end
43 [~,name,~] = fileparts(original_filename);
44
45 % load and find system and present options to select buses to
    simulate
46 % faults
47 fprintf('\n Loading system %s \n',name)
48 load_system(name);
49 sys = find_system(name);
50 for ii=1:length(sys)
51     sys_index(1,ii) = contains(sys{ii},'/Bus') && ~contains(
        sys{ii},'Creator');
52 end
53 Buslist = sys(sys_index);
54 [indx,tf] = listdlg('PromptString','Select Buses to simulate
    fault at',...
55                     'ListString',Buslist,...
56                     'ListSize',[max(cellfun('length',Buslist)
        )*12,300]);
57 if(tf == 0)
58     fprintf('\nError: No Buses selected\n')
59     return;
60 end
61 Fault_location_list = NaN(length(indx),1);
62 for ii=1:length(indx)
63     Fault_location_list(ii) = str2double(erase(Buslist{indx(
        ii)},'LOHO.IS_VZM/Bus'));
64 end
65
66 % Ask user for Combo or individual
67 Function_list ={'All Fault Types in one File';...
68                 'Each Fault Type in individual files'};
69 [indxF,tfF] = listdlg('PromptString','Select Mode',...
70                       'ListString',Function_list,...

```

```

71         'SelectionMode', 'single', ...
72         'ListSize', [max(cellfun('length',
                                   Function_list))*12, 300]);
73 if(tfF == 0)
74     fprintf('\nError: No Buses selected\n')
75     return;
76 end
77
78 % Ask uer for Fault types if Individual
79 if(indxF == 2)
80     Fault_List = {'3ph Fault (A-B-C) ' ; ...
81                  'LL Fault (B-C) ' ; ...
82                  'SLG Fault (A-G) ' ; ...
83                  '3phG Fault(ABC-G) ' ; ...
84                  'LLG Fault (LL-G) ' };
85     [indxFu, tfFu] = listdlg('PromptString', 'Select Fault
                              types', ...
                              'ListString', Fault_List, ...
                              'ListSize', [max(cellfun('length',
                                                         Fault_List))*12, 300]);
86
87     if(tfFu == 0)
88         fprintf('\nError: No Fault Types Selected\n')
89         return;
90     end
91 end
92 end
93
94 % Ask uer for Fault Resistance
95 prompt = {'Enter Fault Resistance in Ohms'};
96 dlgtitle = 'Input Fault Resistance';
97 dims = [1 35];
98 defininput = {'0.1', 'hsv'};
99 Fres = inputdlg(prompt, dlgtitle, dims, defininput);
100
101 % Start Par pool & Create Fault Simulation Files
102 parpool()
103 parfor ii = 1:length(Fault_location_list)
104     if(indxF == 1)
105         new_name = [name, '_Bus', num2str(Fault_location_list(
106             ii)), '_combo'];
107         %Create Combo fault files
108         Fault_Res = Fres{1};
109         Create_Combined_Fault_Sims(name, Fault_Res, new_name,
110             Fault_location_list(ii));
111     elseif(indxF == 2)
112         %Create Individuale fault files

```

```

111         StopTime = '10';      %simulation stop time
112         FaultTime = '[(3*60)/60 (6*60)/60]'; % Fault start
            and dent time
113         Fault_Res = Fres{1}; % fault resistance
114         for jj=1:length(indxFu)
115             Type = indxFu(jj);
116             Create_Individual_Fault_Sims(name,Type,Fault_Res ,
                FaultTime ,StopTime , Fault_location_list(ii))
117         end
118     else
119         fprintf('\nError: Function Error indxF returned %d\n',
                ,indxF)
120     end
121     fprintf('\n Finished - %s \n',name)
122 end
123
124 % End parallel pool
125 poolobj = gcp('nocreate');
126 delete(poolobj);
127
128 %% Functions
129 function Create_Individual_Fault_Sims(name,type,res,FT,ST,
        Fault_location)
130 %Load system
131 load_system(name);
132
133 % set_param([name,'/Grid Forming Inverter1/Frequency and
        Voltage Control/Switch'],'Threshold','1.2')
134 % set_param([name,'/Grid Forming Inverter2/Frequency and
        Voltage Control/Switch'],'Threshold','1.2')
135 % set_param([name,'/Grid Forming Inverter3/Frequency and
        Voltage Control/Switch'],'Threshold','1.2')
136
137 % % COMMENT OUT Grid
138 % set_param([name,'/Three-Phase Source'],'commented','on')
139 % set_param([name,'/Bus1'],'commented','on')
140 % set_param([name,'/Display22'],'commented','on')
141 % set_param([name,'/Subsystem11'],'commented','on')
142 % set_param([name,'/Three-Phase Transformer (Two Windings)
        3'],'commented','on')
143 % % Comment out cap 7
144 % set_param([name,'/Series Load19'],'commented','on');
145 % set_param([name,'/Series Load20'],'commented','on');
146 % set_param([name,'/Series Load21'],'commented','on');
147

```

```

148 %Connect Fault block to Correct Bus
149 B = get_param([name, strcat('/Bus', num2str(Fault_location))], '
    PortHandles');
150 F = get_param([name, '/F'], 'PortHandles');
151 add_line(name, F.RConn, B.RConn, 'autorouting', 'smart')
152
153 if(type == 1)
154     if ~exist('ph', 'dir')
155         mkdir('ph')
156     end
157     % Comment out unnecessary faults & set Fault timing
158     set_param([name, '/Three-Phase Fault'], 'commented', 'on')
159     set_param([name, '/Three-Phase Fault1'], 'commented', 'on')
160     set_param([name, '/Three-Phase Fault2'], 'SwitchTimes', FT)
161     set_param([name, '/Three-Phase Fault3'], 'commented', 'on')
162     set_param([name, '/Three-Phase Fault4'], 'commented', 'on')
163
164     % Set fault type
165     set_param([name, '/Three-Phase Fault2'], 'FaultA', 'on')
166     set_param([name, '/Three-Phase Fault2'], 'FaultB', 'on')
167     set_param([name, '/Three-Phase Fault2'], 'FaultC', 'on')
168     set_param([name, '/Three-Phase Fault2'], 'GroundFault', 'off
        ')
169
170     % Set fault reistance
171     set_param([name, '/Three-Phase Fault2'], 'FaultResistance',
        res)
172
173     %set Output File
174     OUT_File = [erase(name, 'LOHO_'), '_Bus', num2str(
        Fault_location), '_ ', res, '_3ph.mat'];
175     set_param([name, '/To File'], 'Filename', OUT_File);
176
177
178     % Set simulation stop time
179     set_param(name, 'StopTime', ST)
180     save_system(name, ['.\ph\'', name, '_Bus', num2str(
        Fault_location), '_3ph']);
181
182     %close system if open
183     close_system(['.\ph\'', name, '_Bus', num2str(Fault_location)
        , '_3ph'], 0);
184
185 elseif(type == 2)
186     if ~exist('LL', 'dir')

```

```

187         mkdir( 'LL' )
188     end
189     % COMMENT OUT FAULTS
190     set_param( [name, '/Three-Phase Fault'], 'commented', 'on')
191     set_param( [name, '/Three-Phase Fault1'], 'SwitchTimes', FT)
192     set_param( [name, '/Three-Phase Fault2'], 'commented', 'on')
193     set_param( [name, '/Three-Phase Fault3'], 'commented', 'on')
194     set_param( [name, '/Three-Phase Fault4'], 'commented', 'on')
195
196     % Set Fault Type
197     set_param( [name, '/Three-Phase Fault1'], 'FaultA', 'off')
198     set_param( [name, '/Three-Phase Fault1'], 'FaultB', 'on')
199     set_param( [name, '/Three-Phase Fault1'], 'FaultC', 'on')
200     set_param( [name, '/Three-Phase Fault1'], 'GroundFault', 'off')
201
202     % Set Fault reisitance
203     set_param( [name, '/Three-Phase Fault1'], 'FaultResistance',
204         res)
205
206     %set Output File
207     OUT_File = [erase(name, 'LOHO_'), '_Bus', num2str(
208         Fault_location), '_', res, '_LL.mat'];
209     set_param( [name, '/To File'], 'Filename', OUT_File);
210
211     % Set Stop Tlme
212     set_param(name, 'StopTime', ST)
213     save_system(name, ['.\LL\ ', name, '_Bus', num2str(
214         Fault_location), '_LL']);
215
216     %close system
217     close_system(['.\LL\ ', name, '_Bus', num2str(Fault_location)
218         , '_LL'], 0);
219 elseif(type == 3)
220     if ~exist('SLG', 'dir')
221         mkdir('SLG')
222     end
223     % COMMENT OUT FAULTS
224     set_param( [name, '/Three-Phase Fault'], 'SwitchTimes', FT)
225     set_param( [name, '/Three-Phase Fault1'], 'commented', 'on')
226     set_param( [name, '/Three-Phase Fault2'], 'commented', 'on')
227     set_param( [name, '/Three-Phase Fault3'], 'commented', 'on')
228     set_param( [name, '/Three-Phase Fault4'], 'commented', 'on')
229
230     % Set Fault Type

```

```

227 set_param([name, '/Three-Phase Fault'], 'FaultA', 'on')
228 set_param([name, '/Three-Phase Fault'], 'FaultB', 'off')
229 set_param([name, '/Three-Phase Fault'], 'FaultC', 'off')
230 set_param([name, '/Three-Phase Fault'], 'GroundFault', 'on')
231
232 % Set Fault resistance
233 set_param([name, '/Three-Phase Fault'], 'FaultResistance',
           res)
234
235 %set Output File
236 OUT_File = [erase(name, 'LOHO_'), '_Bus', num2str(
           Fault_location), '_ ', res, '_SLG.mat'];
237 set_param([name, '/To File'], 'Filename', OUT_File);
238
239 %Set Stop Time
240 set_param(name, 'StopTime', ST)
241 save_system(name, ['.\SLG\ ', name, '_Bus', num2str(
           Fault_location), '_SLG']);
242
243 %close system
244 close_system(['.\SLG\ ', name, '_Bus', num2str(Fault_location
           ), '_SLG'], 0);
245 elseif(type == 4)
246     if ~exist('phG', 'dir')
247         mkdir('phG')
248     end
249     % COMMENT OUT FAULTS
250     set_param([name, '/Three-Phase Fault'], 'commented', 'on')
251     set_param([name, '/Three-Phase Fault1'], 'commented', 'on')
252     set_param([name, '/Three-Phase Fault2'], 'commented', 'on')
253     set_param([name, '/Three-Phase Fault3'], 'SwitchTimes', FT)
254     set_param([name, '/Three-Phase Fault4'], 'commented', 'on')
255
256 % Set Fault Type
257 set_param([name, '/Three-Phase Fault3'], 'FaultA', 'on')
258 set_param([name, '/Three-Phase Fault3'], 'FaultB', 'on')
259 set_param([name, '/Three-Phase Fault3'], 'FaultC', 'on')
260 set_param([name, '/Three-Phase Fault3'], 'GroundFault', 'on',
           )
261
262 % Set Fault resistance
263 set_param([name, '/Three-Phase Fault3'], 'FaultResistance',
           res)
264
265 %set Output File

```



```

266     OUT_File = [erase(name, 'LOHO_'), '_Bus ', num2str(
                Fault_location), '_ ', res, '_phG.mat'];
267     set_param([name, '/To File'], 'Filename', OUT_File);
268
269     %Set Stop TIme
270     set_param(name, 'StopTime', ST)
271     save_system(name, [ '.\phG\' , name, '_Bus ', num2str(
                Fault_location), '_phGF' ]);
272
273     %close system
274     close_system([ '.\LLG\' , name, '_Bus ', num2str(Fault_location
                ), '_phGF'], 0);
275 elseif (type == 5)
276     if ~exist('LLG', 'dir')
277         mkdir('LLG')
278     end
279     % COMMENT OUT FAULTS
280     set_param([name, '/Three-Phase Fault'], 'commented', 'on')
281     set_param([name, '/Three-Phase Fault1'], 'commented', 'on')
282     set_param([name, '/Three-Phase Fault2'], 'commented', 'on')
283     set_param([name, '/Three-Phase Fault3'], 'commented', 'on')
284     set_param([name, '/Three-Phase Fault4'], 'SwitchTimes', FT)
285
286     % Set Fault Type
287     set_param([name, '/Three-Phase Fault4'], 'FaultA', 'off')
288     set_param([name, '/Three-Phase Fault4'], 'FaultB', 'on')
289     set_param([name, '/Three-Phase Fault4'], 'FaultC', 'on')
290     set_param([name, '/Three-Phase Fault4'], 'GroundFault', 'on'
                )
291
292     % Set Fault resistance
293     set_param([name, '/Three-Phase Fault3'], 'FaultResistance',
                res)
294
295     %set Output File
296     OUT_File = [erase(name, 'LOHO_'), '_Bus ', num2str(
                Fault_location), '_ ', res, '_LLG.mat'];
297     set_param([name, '/To File'], 'Filename', OUT_File);
298
299     %Set Stop TIme
300     set_param(name, 'StopTime', ST)
301     %Save system as new file
302     save_system(name, [ '.\LLG\' , name, '_Bus ', num2str(
                Fault_location), '_LLGF' ]);
303

```

```

304     %close system
305     close_system([ '.\LLG\' ,name, '_Bus' ,num2str(Fault_location
        ), '_LLGF' ],0);
306 else
307     fprintf('—————*—————*—————*—————ERROR
        —————*—————*—————*—————')
308 end
309 end
310
311 function Create_Combined_Fault_Sims(name, res ,new_name ,
        Fault_location)
312 load_system(name);
313 % Get curretn parmameters
314 % A ={get_param([name, '/ Three-Phase Fault '], 'SwitchTimes')
        ;...
315 %     get_param([name, '/ Three-Phase Fault1 '], 'SwitchTimes')
        ;...
316 %     get_param([name, '/ Three-Phase Fault2 '], 'SwitchTimes')
        ;...
317 %     get_param([name, '/ Three-Phase Fault3 '], 'SwitchTimes') };
318 %fprintf('%s old parms AGF: %s , BCF:%s , ABCF:%s , ABCGF%s\n
        ',name, A{1} , A{2} , A{3} , A{4})
319 %Change VZ trigger
320 % set_param([name, '/ Grid Forming Inverter1/Frequency and
        Voltage Control/Switch '], 'Threshold', '1.3')
321 % set_param([name, '/ Grid Forming Inverter2/Frequency and
        Voltage Control/Switch '], 'Threshold', '1.3')
322 % set_param([name, '/ Grid Forming Inverter3/Frequency and
        Voltage Control/Switch '], 'Threshold', '1.3')
323 %% COMMENT OUT Grid if Necessary
324 % set_param([name, '/ Three-Phase Source '], 'commented', 'on')
325 % set_param([name, '/ Bus1 '], 'commented', 'on')
326 % set_param([name, '/ Display22 '], 'commented', 'on')
327 % set_param([name, '/ Subsystem11 '], 'commented', 'on')
328 % set_param([name, '/ Three-Phase Transformer (Two Windings)
        3'], 'commented', 'on')
329 %% Comment out cap 7
330 % set_param([name, '/ Series Load19'], 'commented', 'on');
331 % set_param([name, '/ Series Load20'], 'commented', 'on');
332 % set_param([name, '/ Series Load21'], 'commented', 'on');
333 % Set fault timings
334 set_param([name, '/ Three-Phase Fault'], 'SwitchTimes', '[(3*60)
        /60 (6*60)/60]')
335 set_param([name, '/ Three-Phase Fault1'], 'SwitchTimes', '
        [(13*60)/60 (16*60)/60]')

```

```

336 set_param([name, '/Three-Phase Fault2'], 'SwitchTimes', '
      [(23*60)/60 (26*60)/60]')
337 set_param([name, '/Three-Phase Fault3'], 'SwitchTimes', '
      [(33*60)/60 (36*60)/60]')
338 set_param([name, '/Three-Phase Fault3'], 'SwitchTimes', '
      [(43*60)/60 (46*60)/60]')
339 % Set Fault Resistance
340 set_param([name, '/Three-Phase Fault'], 'FaultResistance', res)
341 set_param([name, '/Three-Phase Fault1'], 'FaultResistance', res)
342 set_param([name, '/Three-Phase Fault2'], 'FaultResistance', res)
343 set_param([name, '/Three-Phase Fault3'], 'FaultResistance', res)
344 %Connect Fault block to Correct Bus
345 B = get_param([name, strcat('/Bus', num2str(Fault_location))], '
      PortHandles');
346 F = get_param([name, '/F'], 'PortHandles');
347 add_line(name, F.RConn, B.RConn, 'autorouting', 'smart')
348 % Set Stop Time
349 set_param(name, 'StopTime', '50')
350 % Set Output File
351 OUT_File = [erase(new_name, 'LOHO_'), '_', res, '.mat'];
352 set_param([name, '/To File'], 'Filename', OUT_File);
353 % Save as copy
354 if ~exist('Combo', 'dir')
355     mkdir('Combo')
356 end
357 save_system(name, ['./Combo\ ', new_name]);
358 close_system(['./Combo\ ', new_name], 0);
359 fprintf('\n Created %s \n', new_name)
360 end

```

Appendix B

Appendix B: Code to Calculate Device Settings

B.1 Function to calculate recloser settings

```
1 %% Function Name: Recloser_ph
2 % Descreption: Calculate Recloser settings and Device curves
3 % Assumptions: You know how to use This
4 % Inputs: Recloser Structure Conintaning:
5     % REC.CTR – Recloser CT ratio
6     % REC.I_Load – Recloser load curretn in Amps
7     % REC.Min_fault – Maximm Fault Curretn in Amps
8     % REC.Max_fault – Minimum Fault Curretn in Amps
9     % REC.Max_Range – Maximum Coordination Range (optional)
10    % REC.Min_Range – Minimum Coordiantion Range (optional)
11    % REC.DownStrem_Ot – Downstream Device setting (optional)
12 % Outputs: Recloser Structure
13 %
-----
14 function REC = Recloser_ph(REC)
15 if (~isfield(REC, 'Backup'))
16     REC.Backup.Ot = -0.3+1/60;
17     REC.Backup.xTC = [];
```

```

18     REC.Backup.yTC = [];
19 else
20     if(~isfield(REC.Backup,'xTC'))
21         if(isfield(REC.Backup,'xEIcurve'))
22             REC.Backup.xTC = REC.Backup.xEIcurve;
23             REC.Backup.yTC = REC.Backup.yEIcurve;
24             REC.Backup.xMM = REC.Backup.xEIcurve;
25             REC.Backup.yMM = REC.Backup.yEIcurve;
26         end
27     elseif(~isfield(REC.Backup,'xMM'))
28         if(isfield(REC.Backup,'xTC'))
29             REC.Backup.xMM = REC.Backup.xTC;
30             REC.Backup.yMM = REC.Backup.yTC;
31         end
32     end
33 end
34
35
36 REC.MOC = 1.5*REC.I_Load;
37 if(REC.MOC>REC.Min_fault && REC.Min_fault>REC.I_Load)
38     REC.MOC = Min_fault;
39 elseif(REC.MOC>REC.Min_fault && REC.Min_fault<REC.I_Load)
40     fprintf('Setting Error');
41     return;
42 end
43 % check MOC
44 if(~isempty(REC.Max_Range))
45     if(REC.MOC > 0.5*REC.Max_Range)
46         fprintf('\nImoc = %0.2f > %0.2f\n',REC.MOC,0.5*REC.
47             Max_Range)
48         REC.MOC = 0.5*REC.Max_Range;
49     end
50 else
51     REC.Max_Range = REC.Max_fault;
52     REC.Min_Range = REC.Min_fault;
53 end
54 %SET TV,MOC, MTV_max,MTV_min
55 REC.TV = round(REC.MOC/REC.CTR,1);
56 REC.MOC = REC.TV*REC.CTR;
57 REC.MTV_max = (REC.Max_Range/REC.CTR)/REC.TV;
58 REC.MTV_min = (REC.Min_Range/REC.CTR)/REC.TV;
59
60 Curve_List={'STI','EI','VI','MI','I'};% ,[]];
61

```

```

62 if (isempty(REC.Backup.xTC))
63     REC.Fast.Curve_Type = 'STI';
64     [REC.Fast.TDS,REC.Fast.xEIcurve,REC.Fast.yEIcurve]=...
65         Generate_TCC_Curve(0.01,...
66             REC.MTV_max,...
67             REC.MOC,'STI');
68     REC.Slow.Curve_Type = 'STI';
69     [REC.Slow.TDS,REC.Slow.xEIcurve,REC.Slow.yEIcurve]=...
70         Generate_TCC_Curve(0.4,...
71             REC.MTV_max,...
72             REC.MOC,'STI');
73
74 else
75 % select Slow Curve;
76     REC.Slow.Ot = REC.Backup.Ot+0.3;
77     for ii = 1:length(Curve_List)
78         Type = Curve_List{ii};
79         if(ii>5)
80             REC.Slow.Ot = REC.Slow.Ot+0.1;
81             ii=1;
82             Type = Curve_List{ii};
83         end
84         [REC.Slow.TDS,REC.Slow.xEIcurve,REC.Slow.yEIcurve
85             ]=...
86             Generate_TCC_Curve(REC.Slow.Ot,REC.
87                 MTV_max,REC.MOC, Type);
88     C1GTC2 = check_curve(REC.Slow.xEIcurve,REC.Slow.
89         yEIcurve,REC.Backup.xTC,REC.Backup.yTC,REC.
90         Min_Range,REC.Max_Range);
91     if(C1GTC2 == 1)
92         REC.Slow.Curve_Type = Type;
93         break;
94     end
95
96 % select Fast curve
97     REC.Fast.Ot = REC.Backup.Ot-0.3;
98     if(REC.Fast.Ot <0.015)
99         REC.Fast.Ot = 0.015;
100     end
101     for ii = 1:length(Curve_List)
102         Type = Curve_List{ii};
103         if(ii>5)
104             REC.Fast.Ot = REC.Fast.Ot+0.1;
105             ii=1;

```

```

103         Type = Curve_List{ii};
104     end
105     [REC.Fast.TDS,REC.Fast.xEIcurve,REC.Fast.yEIcurve
106         ] = ...
107         Generate_TCC_Curve(REC.Fast.Ot,REC.
108             MTV_max,REC.MOC, Type);
109     C1GTC2 = check_curve(REC.Backup.xMM,REC.Backup.yMM,
110         REC.Fast.xEIcurve,REC.Fast.yEIcurve,REC.Min_Range
111         ,REC.Max_Range);
112     if(C1GTC2 == 1)
113         REC.Fast.Curve_Type = Type;
114         break;
115     end
116 end
117 end
118 if(~isempty(REC.Slow.xEIcurve))
119     REC.Slow.Ot = REC.Slow.yEIcurve(closest_val_index(REC.Slow
120         .xEIcurve,REC.Max_fault));
121 end
122 if(~isempty(REC.Fast.xEIcurve))
123     REC.Fast.Ot = REC.Fast.yEIcurve(closest_val_index(REC.Fast
124         .xEIcurve,REC.Max_fault));
125 end
126
127 % Check IT (find IT)
128 if((REC.Max_fault/REC.Max_Range) > 1.3)
129     REC.IT = max(6*REC.I_Load,1.25*REC.Max_Range);
130     REC.MTVIT = (REC.IT/REC.CTR)/REC.TV;
131     REC.xIT = [REC.IT,REC.IT];
132     REC.yIT = [0.0001,((REC.Slow.TDS)/7)*((28.2/((REC.MTVIT)
133         ^2-1))+0.1217)];
134 elseif (REC.Max_fault == REC.Max_Range)
135     REC.IT = REC.Max_fault*1.25;
136     REC.MTVIT = (REC.IT/REC.CTR)/REC.TV;
137     REC.xIT = [REC.IT,REC.IT];
138     REC.yIT = [0.0001,((REC.Slow.TDS)/7)*((28.2/((REC.MTVIT)
139         ^2-1))+0.1217)];
140 else
141     REC.IT = [];
142 end
143
144 %stop curve at IT setting
145 if(~isempty(REC.IT))

```

```

140     REC.Slow.curve_start = closest_val_index(REC.Slow.
        xEIcurve,REC.MOC);
141     REC.Slow.curve_end = closest_val_index(REC.Slow.xEIcurve,
        REC.IT);
142     REC.Fast.curve_start = closest_val_index(REC.Fast.
        xEIcurve,REC.MOC);
143     REC.Fast.curve_end = closest_val_index(REC.Fast.xEIcurve,
        REC.IT);
144     REC.Slow.yEIcurve(REC.Slow.curve_end:end) = 10-3;
145     REC.Fast.yEIcurve(REC.Fast.curve_end:end) = 10-3;
146 else
147     REC.Slow.curve_start = 1;
148     REC.Slow.curve_end = length(REC.Slow.xEIcurve);
149     REC.Fast.curve_start = 1;
150     REC.Fast.curve_end = length(REC.Fast.xEIcurve);
151 end
152
153
154 end
155 % Recloser End
156 %

```

B.2 Function to calculate relay settings

```

1 %% Function Name: OC_Relay_ph
2 % Descreption: Calculate OC Relay settings and Device curves
3 % Assumptions: You know how to use This
4 % Inputs: Relay Structure Conintaning:
5     % Rph.CTR – Recloser CT ratio
6     % Rph.I_Load – Recloser load curretn in Amps
7     % Rph.Min_fault – Maxim Fault Curretn in Amps
8     % Rph.Max_fault – Minimum Fault Curretn in Amps
9     % Rph.Max_Range – Maximum Coordination Range (optional)
10    % Rph.Min_Range – Minimum Coordiantion Range (optional)
11    % Rph.Backup – Down stream Device settings (optional)
12    % Rph.Backup.Ot – Down stream Device operating time
13    % Rph.Backup.xTC – Down stream Device operating Curve
        Curretn
14    % Rph.Backup.yTC – Down stream Device operating Curve
        time

```



```

15 % Outputs:Relay Structure
16 %
-----

17 function Rph= OC_Relay_ph(Rph)
18 %if no back up device
19 if(~ isfield(Rph, 'Backup'))
20     Rph.Backup.Ot = -0.3+1/60;
21     Rph.Backup.xTC = [];
22     Rph.Backup.yTC = [];
23 else
24     if(~ isfield(Rph.Backup, 'xTC'))
25         if( isfield(Rph.Backup, 'xEIcurve'))
26             Rph.Backup.xTC = Rph.Backup.xEIcurve;
27             Rph.Backup.yTC = Rph.Backup.yEIcurve;
28             Rph.Backup.xMM = Rph.Backup.xEIcurve;
29             Rph.Backup.yMM = Rph.Backup.yEIcurve;
30         end
31     end
32 end
33
34 Rph.MOC = 1.25*Rph.I_Load;
35 if(Rph.MOC>Rph.Min_fault && Rph.Min_fault>Rph.I_Load)
36     Rph.MOC = Rph.Min_fault;
37 elseif(Rph.MOC>Rph.Min_fault && Rph.Min_fault<Rph.I_Load)
38     fprintf('Setting Error');
39     return;
40 end
41
42 % check MOC
43 if(~ isempty(Rph.Max_Range))
44     if(Rph.MOC > 0.5*Rph.Max_Range)
45         fprintf('\nImoc = %0.2f > %0.2f\n',Rph.MOC,0.5*Rph.
46             Max_Range)
47         if(Rph.MOC > Rph.Min_Range)
48             Rph.MOC = Rph.Min_Range;
49         end
50     end
51 else
52     Rph.Max_Range = Rph.I_Load*6;
53 end
54 %SET TV,MOC, MTV_max
55 Rph.TV = round(Rph.MOC/Rph.CTR,1);
56 Rph.MOC = Rph.TV*Rph.CTR;

```

```

57 Rph.MTV_max = (Rph.Max_Range/Rph.CTR)/Rph.TV;
58
59 Curve_List={'STI','EI','VI','MI','I',[]};
60 % select Curve check coordination;
61
62 Rph.Ot = Rph.Backup.Ot+0.3;
63 if(Rph.Ot <0.015)
64     Rph.Ot = 0.015;
65 end
66 if(~isempty(Rph.Backup.xTC))
67     Temp_Ot = Rph.Backup.yTC(closest_val_index(Rph.Backup.xTC
68         ,Rph.Max_Range))+0.3;
69     if(Temp_Ot > Rph.Ot)
70         Rph.Ot = Temp_Ot;
71     end
72 end
73 if(isempty(Rph.Backup.xTC))
74     [Rph.TDS,Rph.xEICurve,Rph.yEICurve]=...
75     Generate_TCC_Curve(Rph.Ot,Rph.MTV_max,Rph.MOC,'EI');
76     Rph.Curve_Type = 'EI';
77 else
78     ii=1;
79     C1GTC2=0;
80     while(C1GTC2==0 && Rph.Ot<=3) %ii = 1:length(Curve_List)
81         Type = Curve_List{ii};
82         if(ii >5)
83             Rph.Ot = Rph.Ot+0.1;
84             ii=1;
85             Type = Curve_List{ii};
86         end
87         [Rph.TDS,Rph.xEICurve,Rph.yEICurve]=...
88             Generate_TCC_Curve(Rph.Ot,Rph.MTV_max,
89                 Rph.MOC,Type);
90
91         C1GTC2 = check_curve(Rph.xEICurve,Rph.yEICurve,...
92             Rph.Backup.xTC,Rph.Backup.yTC,
93             Rph.Min_Range,Rph.Max_Range);
94         if(C1GTC2 == 1)
95             Rph.Curve_Type = Type;
96             break;
97         end
98         ii=ii+1;
99     end
100 end

```

```

99
100 if (~isempty(Rph.xEIcurve))
101     Rph.Ot = Rph.yEIcurve(closest_val_index(Rph.xEIcurve,Rph.
        Max_fault));
102 end
103
104 % Check IT (find IT)
105 if ((Rph.Max_fault/Rph.Max_Range) > 1.3)
106     Rph.IT = max(6*Rph.I_Load, 1.25*Rph.Max_Range);
107     Rph.xIT = [Rph.IT, Rph.IT];
108     Rph.yIT = [0.01, Rph.yEIcurve(closest_val_index(Rph.
        xEIcurve, Rph.IT))];
109 elseif (Rph.Max_fault == Rph.Max_Range)
110     Rph.IT = Rph.Max_fault * 1.25;
111     Rph.xIT = [Rph.IT, Rph.IT];
112     Rph.yIT = [0.01, Rph.yEIcurve(closest_val_index(Rph.
        xEIcurve, Rph.IT))];
113 else
114     Rph.IT = [];
115 end
116 %stop curve at IT setting
117 if (~isempty(Rph.IT))
118     Rph.curve_start = closest_val_index(Rph.xEIcurve, Rph.MOC)
        ;
119     Rph.curve_end = closest_val_index(Rph.xEIcurve, Rph.IT);
120     Rph.yEIcurve(Rph.curve_end:end) = 10^-3;
121 else
122     Rph.curve_start = 1;
123     Rph.curve_end = length(Rph.xEIcurve);
124 end
125
126 end
127 %Phase Relay End
128 %

```

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