

Autonomous grid-forming inverters in microgrids

by

Mehmetcan Gursoy

B.Sc., Yeditepe University, 2014

M.Sc., Southern Illinois University, 2019

AN ABSTRACT OF A DISSERTATION

submitted in partial fulfillment of the
requirements for the degree

DOCTOR OF PHILOSOPHY

Mike Wiegers Department of Electrical and Computer Engineering
Carl R. Ice College of Engineering

KANSAS STATE UNIVERSITY
Manhattan, Kansas

2024

Abstract

Inverters can be programmed to behave as an interface between energy sources and consumers, creating the voltage and frequency references. Therefore, they are capable of avoiding power outages and meeting demand using available generation units within distribution power grids. This operational strategy is known as grid-forming (GFM), and enables clustered grid configurations, such as self-powered or networked microgrids. In these setups, a set of inverters can form a power grid or reconnect to an existing microgrid to supply the loads in an isolated subdivision or commercial buildings, enabling black-start capabilities for a de-energized microgrid. During the presence of the utility grid, the inverters should change the mode of operation to grid-following (GFL), following the voltage magnitude and frequency measured at the point-of-common-coupling, for optimum power management. However, grid detection requires communication with utility supervisory controllers to close the synchro-check relays, which hinders plug-and-play compatibility of inverters while escalating more challenges such as adaptability, communication disruptions or cyberattacks. Therefore, a decentralized (communication-less) grid-reconnection detection operation is crucial to provide flexibility for inverters for changing the mode of operation from GFM to GFL when communication signal is lost.

In this dissertation, a novel synced-parallel control task concept is proposed for inverters that can autonomously detect grid-reconnection and islanding incidents, transitioning between GFL and GFM modes without external data communication or control units. The proposed controller, leverages a set of dual parallel control pathways, one path is dedicated for GFL operation while the other path is for GFM mode for both PWM voltage and angle reference generation. During the operation, one path is active (main path) and generates the reference signals, whereas the other path only runs in the background (inactive path) to match its outputs with the outputs of the active path. This active synchronization process

ensures seamless transitions between different modes of operations. Furthermore, an innovative autonomous grid-reconnection detection algorithm is developed to identify the presence of utility grid and perform a smooth transition from GFM mode to GFL. The efficacy of the proposed autonomous control scheme is validated through a multi-inverter three-phase hardware setups forming two microgrids. One microgrid consists of a 30 kVA grid emulator, two 5 kVA and one 10 kVA, 208 V three-phase inverters, one 5 kW static load, and three-phase 208 V 4-pole 1/3 HP induction motor, while the other microgrid setup consists of a grid emulator with the same rating and two 5 kVA 208 V inverters as well as the a 5 kW static load and a three-phase 208 V 4-pole 1/2 HP induction motor. Experimental outcomes verify that inverters equipped with this unique control architecture can autonomously identify grid reconnection and islanding situations, seamlessly transitioning between GFL and GFM modes. Furthermore, the islanding and grid-reconnection instances are detected although inverters are connected to different nodes within a microgrid. This means that the developed method are capable of identifying the reconnection of utility grid with direct access to the utility-side of the main circuit breaker in the microgrid.

This dissertation also comprehensively compares the performance of two common grid forming control strategies, i.e., direct and indirect control methods under static and dynamic loads, and different control parameter settings. To allow inrush current mitigation for the direct control method, a piece-wise linear virtual reactance technique is developed to mitigate inrush currents by allowing flexible voltage generation during a switched connection of an induction motor. On the other hand, outer loop coefficient settings of the indirect control method are changed to allow flexible voltage regulation at the output node, known as point of common coupling (PCC). This comparison procedures are completed experimentally and also using eigenvalue analysis. Statistical results on voltage recovery are also provided for comparison purposes. The outcomes verify that direct control method outperforms the indirect method while achieving simplicity in design, flexibility in controller gain selection, and more stable operation margin.

Autonomous grid-forming inverters in microgrids

by

Mehmetcan Gursoy

B.Sc., Yeditepe University, 2014

M.Sc., Southern Illinois University, 2019

A DISSERTATION

submitted in partial fulfillment of the
requirements for the degree

DOCTOR OF PHILOSOPHY

Mike Wieggers Department of Electrical and Computer Engineering
Carl R. Ice College of Engineering

KANSAS STATE UNIVERSITY
Manhattan, Kansas

2024

Approved by:

Major Professor
Prof. Behrooz Mirafzal

Copyright

© Mehmetcan Gursoy 2024.

Abstract

Inverters can be programmed to behave as an interface between energy sources and consumers, creating the voltage and frequency references. Therefore, they are capable of avoiding power outages and meeting demand using available generation units within distribution power grids. This operational strategy is known as grid-forming (GFM), and enables clustered grid configurations, such as self-powered or networked microgrids. In these setups, a set of inverters can form a power grid or reconnect to an existing microgrid to supply the loads in an isolated subdivision or commercial buildings, enabling black-start capabilities for a de-energized microgrid. During the presence of the utility grid, the inverters should change the mode of operation to grid-following (GFL), following the voltage magnitude and frequency measured at the point-of-common-coupling, for optimum power management. However, grid detection requires communication with utility supervisory controllers to close the synchro-check relays, which hinders plug-and-play compatibility of inverters while escalating more challenges such as adaptability, communication disruptions or cyberattacks. Therefore, a decentralized (communication-less) grid-reconnection detection operation is crucial to provide flexibility for inverters for changing the mode of operation from GFM to GFL when communication signal is lost.

In this dissertation, a novel synced-parallel control task concept is proposed for inverters that can autonomously detect grid-reconnection and islanding incidents, transitioning between GFL and GFM modes without external data communication or control units. The proposed controller, leverages a set of dual parallel control pathways, one path is dedicated for GFL operation while the other path is for GFM mode for both PWM voltage and angle reference generation. During the operation, one path is active (main path) and generates the reference signals, whereas the other path only runs in the background (inactive path) to match its outputs with the outputs of the active path. This active synchronization process

ensures seamless transitions between different modes of operations. Furthermore, an innovative autonomous grid-reconnection detection algorithm is developed to identify the presence of utility grid and perform a smooth transition from GFM mode to GFL. The efficacy of the proposed autonomous control scheme is validated through a multi-inverter three-phase hardware setups forming two microgrids. One microgrid consists of a 30 kVA grid emulator, two 5 kVA and one 10 kVA, 208 V three-phase inverters, one 5 kW static load, and three-phase 208 V 4-pole 1/3 HP induction motor, while the other microgrid setup consists of a grid emulator with the same rating and two 5 kVA 208 V inverters as well as the a 5 kW static load and a three-phase 208 V 4-pole 1/2 HP induction motor. Experimental outcomes verify that inverters equipped with this unique control architecture can autonomously identify grid reconnection and islanding situations, seamlessly transitioning between GFL and GFM modes. Furthermore, the islanding and grid-reconnection instances are detected although inverters are connected to different nodes within a microgrid. This means that the developed method are capable of identifying the reconnection of utility grid with direct access to the utility-side of the main circuit breaker in the microgrid.

This dissertation also comprehensively compares the performance of two common grid forming control strategies, i.e., direct and indirect control methods under static and dynamic loads, and different control parameter settings. To allow inrush current mitigation for the direct control method, a piece-wise linear virtual reactance technique is developed to mitigate inrush currents by allowing flexible voltage generation during a switched connection of an induction motor. On the other hand, outer loop coefficient settings of the indirect control method are changed to allow flexible voltage regulation at the output node, known as point of common coupling (PCC). This comparison procedures are completed experimentally and also using eigenvalue analysis. Statistical results on voltage recovery are also provided for comparison purposes. The outcomes verify that direct control method outperforms the indirect method while achieving simplicity in design, flexibility in controller gain selection, and more stable operation margin.

Table of Contents

List of Figures	xi
List of Tables	xviii
Acknowledgements	xix
Dedication	xx
1 Introduction	1
1.1 Motivation and Objectives	1
1.2 Literature Review	4
1.2.1 Control Schemes for GFM Mode of Operation	5
1.2.2 Synchronization Techniques for GFM Inverters	26
1.2.3 Restoration for GFM Inverters	28
1.2.4 Fault Ride-Through for GFM Inverters	30
1.3 Contributions	32
1.4 Organization of This Dissertation	36
2 Direct vs. Indirect Control Methods	37
2.1 Direct Control	38
2.1.1 Droop Control	38
2.1.2 Virtual-Inertia Control	39
2.2 Indirect Control	41
2.2.1 Controller Scheme for GFL Operation	41
2.2.2 Controller Scheme for GFM Operation	44

2.3	Dynamic Model Development	46
2.4	Synchronization of GFM Inverters	54
2.5	Performance Comparison	55
2.6	Insights and Discussions	66
2.7	Conclusion	68
3	Inrush Current Mitigation	69
3.1	Inrush Current Mitigation Using Direct Control	70
3.2	Inrush Current Mitigation Using Indirect Control	74
3.3	Experimental Analysis	74
3.3.1	Performance Analysis at the Baseline Settings	74
3.3.2	Sensitivity Analyses for Inrush Current Mitigation	78
3.3.3	Linear vs. Nonlinear Virtual Reactance for Direct Inrush Current Mit- igation	83
3.4	Analyses of the Outcomes	87
3.5	Conclusion	88
4	Autonomous Control for Inverters	89
4.1	Concept of Communication-Less Microgrids	90
4.2	Effectiveness of Synced Parallel Control Concept	92
4.3	Proposed Direct Control Scheme	98
4.3.1	Dual Control Paths for GFM and GFL Operations	100
4.4	Novel Autonomous Grid Reconnection Detection	107
4.5	Analytical Verification	110
4.5.1	Transition from GFL to GFM: Islanding	111
4.5.2	Transition from GFM to GFL: Grid Reconnection	112
4.6	Insights and Discussion	113
4.7	Conclusion	115

5	Experimental Verification	116
5.1	System Configuration	117
5.2	Experimental Analysis	120
5.2.1	Case 1: Grid-Interaction Through Another Microgrid	120
5.2.2	Islanding Performance Assessment	130
5.2.3	Grid Reconnection of Combined Microgrids	135
5.2.4	Interconnecting Microgrids in GFM Mode	139
5.3	Insights and Discussions	145
5.4	Conclusion	147
6	Conclusion and Prospects	148
6.1	Conclusion Remarks	149
6.2	Suggestions for Future Work	152
	Bibliography	154
A	Experimental Setup Development	177

List of Figures

1.1	Grid-forming inverters in a microgrid while maintaining power during utility outage [1].	4
1.2	Operational comparison between grid-following and grid-forming inverters. .	4
1.3	Block diagram representation of direct control strategy using a single regulator.	9
1.4	Graphical demonstration of $(P - \omega)$ and $(Q - V)$ droop control strategies. .	10
1.5	Block diagram representation of virtual inertia control method, where D represents the damping coefficient, and J is the inertia constant.	12
1.6	Block diagram representation of indirect control strategy using a regulators in series.	17
2.1	The direct control scheme after synchronization.	38
2.2	A demonstration of load-sharing between N number of inverters in a microgrid with different power ratings using $P - \omega$ droop control method.	39
2.3	Simplified single-line-diagram of a grid-interactive inverter.	41
2.4	The controller block diagram of indirect GFL control scheme.	43
2.5	The controller block diagram of indirect GFM control scheme.	45
2.6	Simplified indirect control block diagram for GFM inverters.	47
2.7	Signal flow graph representation for: (a) inductive and (b) capacitive equivalent circuits implementing the indirect method, as well as (c) inductive and (d) capacitive equivalent circuits implementing the direct method, all after syncing [2].	49
2.8	Simplified direct control block diagram for GFM inverters.	52

2.9	The output-sync method for synchronization implemented in direct or indirect control for GFM inverters.	55
2.10	A single-line diagram demonstration of the system under study after the inverters have been synchronized, featuring two grid-forming inverters, Inv_1 and Inv_2	56
2.11	The experimental laboratory-scale microgrid test setup, consisting of: (left) a side-view and (right) a bird's-eye view.	56
2.12	Experimental obtained baseline comparison performance of two control methods: (a) the indirect and (b) direct methods [2].	59
2.13	Experimental results for i_a and v_{ab} when outer loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].	60
2.14	Experimental results for P and Q when outer loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].	61
2.15	Eigenvalue analysis using the capacitive dynamic model when (a) outer and (b) inner loop coefficients of indirect method are increased [2].	62
2.16	Eigenvalue analysis using the inductive dynamic model when (a) outer and (b) inner loop coefficients of indirect method are increased [2].	62
2.17	Experimental results for i_a and v_{ab} when voltage regulator gains of the direct method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].	63
2.18	Experimental results for P and Q when voltage regulator gains of the direct method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].	64
2.19	Eigenvalue analysis using (a) capacitive and (b) inductive dynamic model when outer loop coefficients of direct method are increased [2].	64
2.20	Experimental results for i_a and v_{ab} when inner loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].	65

3.1	Inrush current mitigation concept for direct GFM control method, where (a) virtual reactance (b) with voltage recovery and (c) virtual impedance (d) with voltage recovery techniques are used.	71
3.2	Different inrush current mitigation implementations; (a) linear, (b) piece-wise linear, and (c) nonlinear virtual reactance techniques.	73
3.3	A single-line diagram of the system under study with two grid-forming inverters, Inv_1 and Inv_2 , one induction motor, and static load.	75
3.4	Experimental results showcasing the effectiveness of inrush current mitigation implementing indirect control with baseline gain settings; (a) measurement of line current at PCC_1 , (b) the active, (c) reactive power supplied by each inverter, (d) the angular frequency generated during transients, and (e) voltage at each PCC.	76
3.5	Experimental results showcasing the effectiveness of inrush current mitigation implementing direct control with baseline gain settings; (a) measurement of line current at PCC_1 , (b) the active, (c) reactive power supplied by each inverter, (d) the angular frequency generated during transients, and (e) voltage at each PCC.	79
3.6	Experimental results showcasing the effectiveness of inrush current mitigation implementing indirect control with 91.67% reduced outer loop gain settings; (a) measurement of line current at PCC_1 , (b) the active, (c) reactive power supplied by each inverter, and (d) the angular frequency generated during transients.	80
3.7	Experimental result demonstrating the PCC voltage regulation performance during inrush currents using the indirect method with reduced outer loop gain.	81
3.8	Experimentally observed voltage drop at each PCC when $J = 0.0001$ (baseline setting) for all inverters, alongside linear and nonlinear virtual reactance methods.	84

3.9	Experimentally observed voltage drop at each PCC when $J = 2$ for all inverters in the system, alongside linear and nonlinear virtual reactance methods. .	84
3.10	Experimental results for P and ω when J is at the baseline setting using; (a) linear and (b) nonlinear virtual reactance techniques.	85
3.11	Experimental results for P and ω when $J = 2$ using; (a) linear and (b) nonlinear virtual reactance techniques.	86
4.1	Transient performance during inverter connection; (a) voltage, (b) active power, and (c) reactive power when an inverter is not synchronized.	91
4.2	Block diagram representation of the developed synced parallel control concept using dual control paths.	93
4.3	Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , and the error between parallel paths e , when input $(n, \bar{n})$ are removed and synchronization is disabled (a) and enabled (b).	95
4.4	Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , and the error between parallel paths e , when input $(n, \bar{n})$ are implemented and synchronization is disabled (a) and enabled (b).	96
4.5	Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , for $(G_{p2} = 2.5/(s + 5))$ when input $(n, \bar{n})$ are removed and synchronization is disabled (a) and enabled (b).	97
4.6	Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , for $(G_{p2} = 2.5/(s + 5))$ and synchronization is disabled (a) and enabled (b).	98
4.7	Block diagram representation of the proposed unique control method for autonomous and seamless transitions between GFL and GFM modes.	99

4.8	Simplified block diagram of the unique synced-parallel control method, highlighting the main paths engaging the reference values and the background paths synchronizing the outputs during GFL operation.	105
4.9	Simplified block diagram of the unique synced-parallel control method, highlighting the main paths engaging the reference values and the background paths synchronizing the outputs during GFM operation.	107
4.10	Two possible grid-reconnection scenarios for an inverter operating in GFM mode; when active power injection ramps immediately after grid connection (left), or a load is changed (right).	108
4.11	Flowchart of the fully autonomous grid-reconnection detection algorithm. . .	110
5.1	Schematic diagram of the dual microgrid multi-inverter hardware testbed. . .	117
5.2	Developed microgrid setups used for experimental verification; (top) microgrid 1 and (bottom) microgrid 2.	118
5.3	Experimental results demonstrating; (a) the active power and (b) frequency of both microgrids, where Inv_5 and Inv_6 change their mode of operation from GFL to GFM after the grid of MG_2 is disconnected at t_1 , and from GFM to GFL after MG_2 is connected to MG_1 at t_2 , and detect the grid at t_3 , while the rest of the inverters operate in GFL mode.	122
5.4	Zoomed-in plots of (a) active power, (b) frequency, PCC line currents of (c) Inv_5 and (d) Inv_6 , and PCC line-to-line voltages of (e) Inv_5 and (f) Inv_6 around t_1 when the grid is disconnected and t_{1b} when mode of operation changes from GFL to GFM due to islanding detection.	123
5.5	Zoomed-in plots of synced parallel angle plots including active and inactive path outputs for (a) Inv_5 , (b) Inv_6 , and (c) the error in angle, e_θ , demonstrating the angle synchronization dynamics during grid disconnection.	125

5.6	Zoomed-in plots of PCC (a) line currents and (b) line-to-line voltages of all inverters in the system around t_4 when MG_2 is connected to MG_1 through CB7, while Inv_5 and Inv_6 still operates in GFM mode.	127
5.7	Zoomed-in plots of angle and voltage errors for (a) Inv_5 , (b) Inv_6 , and (c) the rest of the inverters that operate in GFL mode at $(t = t_5)$ and $(t = t_{5b})$ during Inv_5 and Inv_6 change their mode of operation from GFM to GFL.	128
5.8	Zoomed-in plots of (a) active power, (b) frequency, PCC line currents of (c) Inv_5 and (d) Inv_6 , and PCC line-to-line voltages of (e) Inv_5 and (f) Inv_6 during autonomous grid reconnection and mode of operation changes from GFM to GFL.	129
5.9	Zoomed-in plots of (a) angle and (b) voltage error dynamics for all inverters at $(t = t_6)$ when the grid is disconnected and $(t = t_{6b})$ during islanding detection and changing mode from GFL to GFM for lagging inactive path scenario. . .	131
5.10	Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages in of each inverter in RMS in the system during islanding for lagging inactive path angle.	132
5.11	Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter in the system during islanding. . . .	133
5.12	Zoomed-in plots of (a) angle and (b) voltage error dynamics for all inverters at $(t = t_1)$ when the grid is disconnected and $(t = t_{1b})$ during islanding detection and changing mode from GFL to GFM for leading inactive path scenario. . .	135
5.13	Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages in of each inverter in RMS in the system during islanding for leading inactive path angle.	136
5.14	Grid reconnection performance of the islanded microgrid when all inverters operate in GFM before the transition; (a) active power and (b) system frequency.	137

5.15	Grid reconnection performance of the islanded microgrid when all inverters are initially operate in GFM mode; (a) PCC line currents and (b) PCC line-to-line voltages during the transition.	138
5.16	Experimental results demonstrating; (a) the active power and (b) frequency of both microgrids, where the grid is disconnected at t_1 , MG ₁ and MG ₂ are separated at t_2 , MG ₁ and MG ₂ are reconnected in GFM mode at t_5 , and utility grid is reconnected at t_6 , and inverters detect the grid reconnection and changes their mode from GFL to GFM using the proposed autonomous technique after t_8	140
5.17	Experimental results demonstrating zoomed-in sections of; (a) the active power, b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter during the separation of both microgrids operating in GFM mode at t_2	141
5.18	Experimental results demonstrating zoomed-in sections of; (a) the active power, b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter during reconnection of both microgrids when they operate in GFM mode at t_6	143
5.19	Grid reconnection performance of the islanded and interconnected microgrid scenario when all inverters operate in GFM before the transition; (a) active power and (b) system frequency.	144
A.1	A set of inverter; (a) local control unit, (b) sensor board, and (c) LCL filter.	177
A.2	PCB schematics for; (a) sensor board and (b) LCL filter.	179
A.3	DC and AC sources used in the testbed; (a) DC supply and (b) grid emulator.	179
A.4	Static vs. inductive and dynamic load; (a) resistive load bank and (b) an induction motor as load.	180
A.5	Circuit breaker and tie-lines used in the setup.	180
A.6	Monitoring and data acquisition using; (top) oscilloscopes and (bottom) ControlDesk software.	181

List of Tables

2.1	System parameters.	57
2.2	Baseline tuning performance when the load is switched [2].	58
3.1	Experimentally obtained voltage recovery statistics for indirect method when outer loop gains coefficients are changed.	82
3.2	Experimentally obtained voltage recovery statistics for direct method when virtual reactance and voltage recovery coefficients are changed.	82
3.3	Implemented virtual reactance values for experimental analysis.	83
4.1	Switching states for $(n, \bar{n})$ and $(u, \bar{u})$ over one switching period, $T_p = T_{on} + T_{off}$	93
4.2	Conditions of grid reconnection detection.	109
5.1	System parameters	119
5.2	Controller parameters	120
5.3	Initial power setpoints for GFL operation	121
5.4	Selected active power setpoints for GFL operation at increased capacity.	134
5.5	Error statistics for generated PWM reference angle and voltage magnitude when mode of operation changes from GFM to GFL during grid reconnection.	139
5.6	Error statistics for generated PWM reference angle and voltage magnitude when mode of operation changes from GFM to GFL during grid reconnection for interconnecting microgrid case.	145

Acknowledgments

Foremost, I would like to begin with expressing my deepest gratitude to Prof. Behrooz Mirafzal for granting me the opportunity to pursue my doctoral study under his supervision, giving me a chance to work on this dissertation research that I absolutely enjoy every moment, and for his assistance and motivation throughout my academic journey. His technical expertise and unlimited guidance helped me overcome most of the academic challenges that I encountered. Additionally, I would like to extend my gratitude to my esteemed committee members Dr. Anil Pahwa, Dr. Fariba Fateh, and Dr. Andrzej Lozowski for their invaluable contribution and encouragement. The courses they taught and technical insights they provided greatly improved my technical skills and knowledge.

I am forever grateful to my deceased father, Hami Gursoy, who passed away during my doctoral studies, my wonderful mother, Lale Gursoy, and my lovely wife, Shima Soleimani. They have been constant sources of motivation, support, and upliftment, crucial for all my achievements and advancement to where I am now.

I sincerely thank my current and former Smart Power Electronics and Control Systems (SPECS) Research Team mates for their friendly personalities, which made our research laboratory an enjoyable environment. I owe my gratitude to Dr. Fahmid Sadeque for his unlimited assistance and contributions towards my research. My heartfelt thanks go to Dr. Tareq Hossen for his collaboration in research and teaching duties. Teaming up with him for the courses we enrolled in together was a pleasure. I extend my thanks to my current lab mates Mr. Milad Sadoughi and Ms. Arya Ponnarassery Sadasivan for assisting me with great patience they have. Besides our research group members, I would like to thank Dr. Mohammad Abujubbeh for productive technical discussions and coursework we enjoyed together. Including my dear lab mates and Dr. Abujubbeh, I would like to thank all my friends for the fun and great moments we shared together throughout this journey.

Dedication

To my beloved wife, whose love illuminates my world; my wonderful mother, whose love and unwavering support have been gifts beyond measure and my continuous inspiration; and the memory of my cherished father, whose spirit forever resides in the finest aspects of my being, while every remembrance is a source of strength and comfort for me.

Chapter 1

Introduction

The primary objective of this dissertation is to develop a unique control framework for inverters to enable autonomous and seamless transitions between their modes of operation, i.e., grid-forming (GFM) and grid-following (GFL), considering the communication with a utility operator or a supervisory controller is lost or compromised, while ensuring power availability and addressing technical challenges where robust and resilient operation is crucial in multi-inverter systems. The introduction of this dissertation is outlined in the following order. The motivation of having a particular interest in this research topic and objectives are discussed in Section 1.1. The concept of GFM inverters, the state-of-the-art GFM control methodologies for power management, synchronization, and voltage-frequency restoration are elaborated in Section 1.2. Next, the contribution of this doctoral research to address the existing challenges and inadequacy of the state-of-the-art methods are provided in Section 1.3. Finally, the organization of this dissertation is highlighted in Section 1.4.

1.1 Motivation and Objectives

Inverters have become the backbone of modern power infrastructure since they provide controllable interfaces between renewable energy sources, e.g., solar panels and wind turbines, and the power grid. As countries seek to expand their renewable energy generation capa-

bilities in the near future to reduce their carbon footprint, more inverter-based distributed generation units (DGU) are being integrated into the power system. To meet their goal-set, the residents and industries are incentivized as a form of reduced capital cost by the governmental authorities or profitable benefits from the utilities to install renewable power generation units or increase their total renewable generation [3–6]. Depending on the resource type, inverter-based power generation can be much cheaper compared to fuel-based power generation as the construction, equipment, and maintenance costs may dramatically be reduced. Therefore, integration of inverters to the power grid has been increasing for the last decade, and inverters are expected to play a dominant role in power generation while reducing the dependency to the conventional fossil-fuel-based generation within the next quarter-century [7].

Grid-interactive inverters have been programmed to inject their maximum available power to the grid, particularly for lower-power residential photovoltaic applications. In the presence of a grid or microgrid, inverters may function in a grid-following mode, where the grid’s voltage and frequency are followed while a supervisory controller may command the power injection based on an economic power dispatching algorithm [8–12]. In this mode of operation, a conventional GFL inverter rely on the presence of a stable grid to operate. However, increased implementation of DGUs in GFL mode may impose new challenges, such as voltage swells when generation exceeds the load and/or the hosting capacity, voltage sags when the renewable generation is insufficient to supply the demand, reverse power flow or circulating currents due to insufficient coupling reactance between each point-of-common-coupling (PCC), and etc. [13]. To address these challenges, maintain the reliable operation of the system, improve grid stability, and balance the generation and demand, inverters can be programmed to provide grid-supporting features, also known as ancillary services, such as voltage and frequency regulation, harmonics and negative-sequence compensations [3, 10, 14, 15].

Considering the case when the utility grid becomes unavailable due to a maintenance, fault, or catastrophic event in a multi-inverter system, inverters are required to be disconnected. Therefore, the system frequency and PCC voltage can no longer be regulated if

inverters operate in GFL mode if no energy storage units are equipped. In this case, inverters must be disconnected from the system when the PCC voltage and frequency violates the standards defined by the IEEE Std. 1547 [16], leading to a blackout until the grid is available again. Particularly in rural locations where there is a lack of back-up utility power sources, momentarily or long-term power blackout can be seen. The widespread power grid outage can also be extended to cases where cyber and physical attacks are performed [17, 18]. To survive the aftermath, an additional approach is essential to ensure the availability of power using the local generation units.

To prevent the grid outages and supply the demand using the available generation units owned by the same resident or industry, inverters may operate as primary power sources and generate their own voltage and frequency references [2, 19–21]. This mode of operation is known as grid-forming mode (GFM) and establishes the concept of clustered grid structures, i.e., self-powered or networked microgrids, where a group of inverters owned within in the same property can form or participate in a power network to meet the demand of an islanded subdivision or commercial building. An uninterrupted and reliable operation is also essential for critical loads in the system. In case of a power outage, this mode also enables the process of restoring power to a microgrid from a completely shut-down state, forming the concept of black start [22].

The GFM inverters may operate using a centralized approach where power dispatching is available using communication links or a decentralized approach where autonomous operation can be achieved [2, 23]. Controlling multiple inverters presents a challenging task in an islanded microgrid, as they must maintain the system frequency while collaboratively supplying power to loads. Furthermore, this mode requires seamless synchronization for each incoming inverter or microgrid unit to avoid excessive or reverse power injection and voltage distortion that can lead to inverter trips after a black start [20, 24]. On the other hand, inverters may be sensitive to sudden load variations in an islanded microgrid due to the zero-inertia nature of the inverters, particularly if the load is dynamic and inductive, which may result in a blackout [2, 25, 26]. Therefore, resilient and robust grid-forming control strategies are essential. In Fig. 1.1, the concept of GFM operation and its benefit is

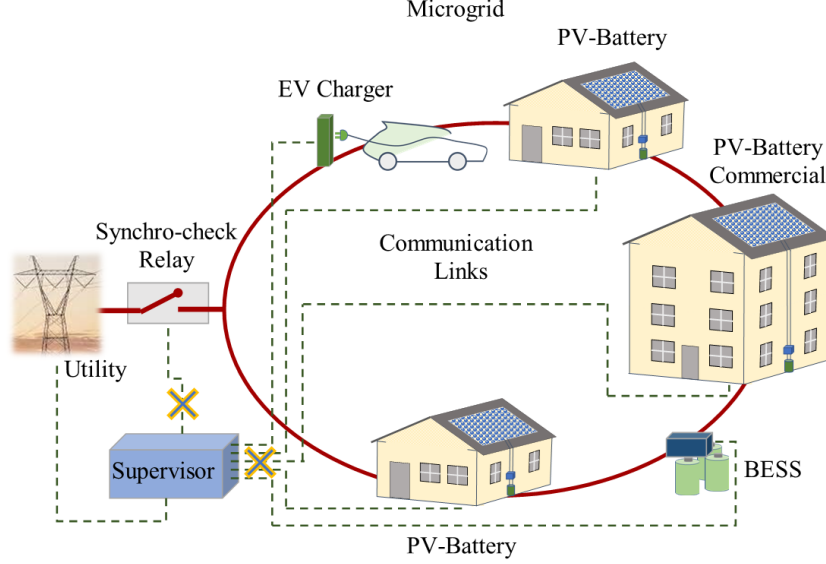


Figure 1.1: Grid-forming inverters in a microgrid while maintaining power during utility outage [1].

illustrated when a fault presents in the system, and the grid is disconnected. The conceptual difference between the GFL and GFM inverters are shown in Fig. 1.2.

The state-of-the-art control schemes, synchronization, and ancillary services developed for grid-following inverters are discussed in the following section.

1.2 Literature Review

In this section, a literature review of fundamental elements for grid-forming inverter operation is presented. Starting with control methodologies, e.g., direct and indirect control,

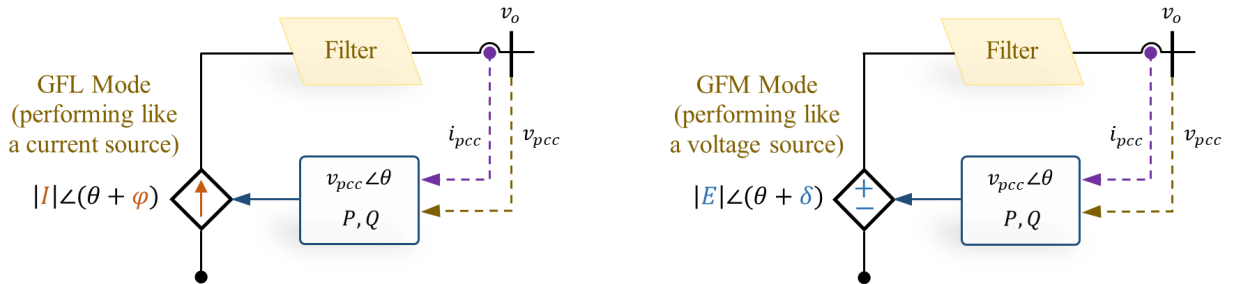


Figure 1.2: Operational comparison between grid-following and grid-forming inverters.

and followed by synchronization techniques, this section briefly describes the state-of-the-art technologies for the GFM inverters. Finally, the last subsection presents a comprehensive literature search on ancillary services developed for GFM inverters.

1.2.1 Control Schemes for GFM Mode of Operation

As the GFM inverters are expected to shape the future of the power systems with the capability of decentralized (autonomous) and islanded operation, an enhanced control capability becomes a critical task to facilitate stable and reliable power transmission. Actively regulating the grid voltage and frequency improves the overall flexibility and resiliency of the grid while enabling seamless integration of distributed energy resources and contributing the way for more sustainable and efficient energy generation [27].

The state-of-the-art control framework for GFM inverters can be divided into two main categories: (i) centralized and (ii) decentralized control, and the details are provided below.

Centralized Control Methods

While “centralized control” might initially suggest a single control unit employing an optimized power-flow algorithm to govern all inverters in a local area, using a communication network for economic dispatching and synchronization of distributed generation units across the microgrid system, a further clarification is needed as its definition stands broader. The centralized approach also encompasses hierarchical and master-slave control structures, which rely on local system information to update the controller scheme and perform executive actions [3, 23, 28–37]. Leveraging the centralized control approaches improves grid resiliency and enables data and health monitoring [3, 31]. However, reliability is the primary challenge, as a failure or cyber intrusion into the communication network can jeopardize the operation of the main control unit [38]. The efficiency of the centralized control structure heavily depends on the reliability of the communication network. Delays or failures in communication can lead to instability. Furthermore, the applicability of centralized controllers is inversely proportional to the size of the system, which is directly proportional to the cost

of installing a communication infrastructure [27, 39].

a) Supervisory control:

Energy management is the main motivation for the centralized control approach. In this concept, a supervisory control unit monitors the system status and performs power management at optimal equilibrium points. Economic dispatching can be applied in more comprehensive system level where coordination of multiple microgrid systems are considered by a distribution system operator. In such systems, the commands are sent to the local centralized controllers in each microgrid to achieve optimized power flow between each microgrid. This is also known as the tertiary control [30–32]. Investigations show that optimal planning at the tertiary level can be met using probabilistic and iterative methodologies [40], real-time online cooperative energy management algorithms [41], interactive multi-level [42] or model predictive control (MPC)-based optimized methodologies [43] for cooperative energy management systems.

b) Master-slave control:

The master-slave type of hierarchical control structures manage the operation and interaction of multiple inverters within the microgrid by exchanging data through a communication network [44–48]. The master unit is the primary inverter in the microgrid. It continuously monitors the status of the microgrid, and it is responsible for setting the reference values for key parameters like voltage and frequency, ensuring they remain within acceptable limits. Hereby, the master units can command slave inverters to increase or decrease their power output to balance the load. The master inverter often takes on the role of managing the grid's connection to the main power grid (if the microgrid is grid-connected) and ensuring stable operation during both grid-connected and islanded modes. The secondary units are known as the slave inverters. They adjust their output based on the reference values set by the master inverter. Slave inverters are typically responsible for managing specific energy sources or loads within the microgrid [3, 27]. As more inverters are added to the microgrid, managing them efficiently becomes more complex. The master inverter must be capable of handling increased data and control demands.

c) Secondary control:

From a local and supervised microgrid standpoint, the utility operator delivers the commands to each generation unit within the operational zone, also known as the secondary control structure [49]. This signals can include voltage and frequency set-point corrections for regulation purposes, measurement data, islanded detection or grid availability flags for seamless operation, etc. From the device level, a grid-forming inverter controller superimposes the external commands sent from the centralized control unit with its primary control layer, where the inverter can generate its voltage magnitude and frequency with or without communication. However, a deviation in magnitude and frequency from their nominal values can be observed when the secondary control inputs are lost. A cooperative operation strategy and synergistic flexible control with independent reactive power injection for multi-functional grid-interactive inverters are proposed in [50], where the inverters receive reference power factor (pf) at the PCC, reactive power (Q), and harmonic compensation adjustment set-points from the control center. In applications where safe operation must be ensured for energy storage systems, a multi-task operation has been developed at the supervised level for state-of-charge equalization, active power (P) curtailment, and load shedding [34].

d) Coordinated control:

On the other hand, distributed control architectures require local communication and enable an unsupervised centralized operation in inverters' local controllers to improve the system reliability by eliminating the need of a supervisory centralized control unit. Similar to the supervised operation, these controllers typically consist of a primary and secondary control structures, where the primary controller generates the inverter's PWM signal references, and the secondary control signals, e.g., voltage, frequency, etc., are exchanged between the local smart devices to adjust the deviations in voltage and frequency [32, 38, 39, 51–53]. A data-driven framework, that directly utilizes the measured data of the power grid without requiring the model structure or parameters of the grid, for optimized controller gain selection where the requirements for frequency and voltage control performance are expressed as frequency domain constraints on the two-norm, i.e., H_2 , of the weighted sensitivity functions

is developed in [51]. However, the developed technique entails computational-burden, and synchronization or (re)connection of the inverters are not considered. Alternatively, a fully distributed controller is employed in [53]. The primary controller utilizes a nonlinear sliding mode control (SMC) method is used to regulate the current and a mixed H_2/H_∞ -based voltage control loop implementing virtual impedance to provide damping. The secondary control unit utilizes a distributed-consensus-based economic automatic generation and voltage control that combines the benefits of both territory and secondary control concepts. However, implementation of a bounded nonlinear controllers are not common in practice, and their operation under communication delays must be comprehensively analyzed. Furthermore, a centralized MPC is used as a secondary controller unit to the primary decentralized droop control unit of each inverter to achieve smooth frequency response in purely inverter-based islanded microgrids [54]. However, no experimental results are presented, and the study assumes an ideal delay-free communication between the centralized MPC and inverters' local primary controllers, while requiring the controller frequency generated by each inverter's primary unit as feedback. This assumption leads to an impractical scenario and high risk in system reliability. Cyber interactions in distributed control approach possess a high risk of unreliable operation as jeopardized data may result in high transients and damage the system. A cyber-secure distributed controller is developed using weighted mean sub-sequence reduced algorithm for each inverter [38]. However, complexity becomes a challenge as the number of the inverters in the system increases.

The drawbacks of the centralized control methods can be summarized as follows;

- The adaptability required to accommodate the growing number and variety of new distributed generation units is insufficient.
- The communication network can lead to increased costs and making it less feasible in rural areas.
- Communication and decision delays are associated with the increasing distance between the inverters and supervisory controllers or nearby smart devices.
- The security of communication and cyber-physical operation can be at risk as the

number of entry points into the cyber-network increases.

Decentralized Control Methods

This subsection discusses the state-of-the-art autonomous (decentralized) control strategies developed for grid-forming inverters from fundamental to advanced level. Since the inverter functions like a voltage source, the basic control level, i.e., droop control, consists of a phase-angle reference path with integrated and predefined frequency setting and a feedback voltage control loop to linearly adjust the frequency and voltage amplitude references. Techniques can become more advanced and sophisticated to address technical challenges of GFM operation such as smooth transients during synchronization and load sharing, particularly in multi-inverter systems where no communication is utilized.

The decentralized control strategies for grid-forming inverters can be categorized under three groups, i.e., direct, indirect, and nonlinear control. In the direct control topology, the inverter is controlled as a voltage-source, and the PWM references are directly generated without using a cascaded control structure, see Fig. 1.3. The state-of-the-art GFM direct control strategies are listed below.

e) Droop control:

Droop control is a common and simple strategy implemented in grid-forming inverters for power management and stability assurance [55]. Inverters utilizing droop control can effectively emulate the governor action enabling parallel operation of synchronous generators and

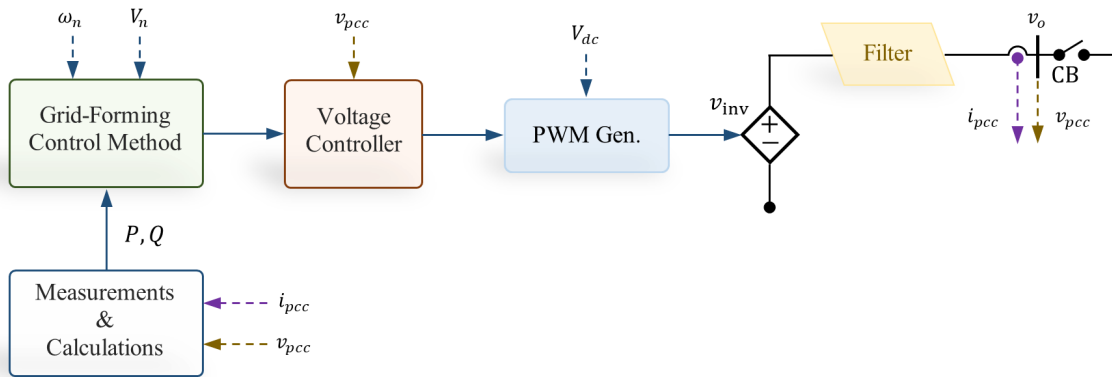


Figure 1.3: Block diagram representation of direct control strategy using a single regulator.

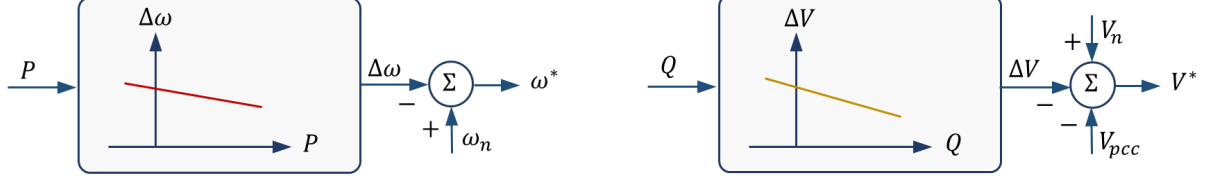


Figure 1.4: Graphical demonstration of $(P - \omega)$ and $(Q - V)$ droop control strategies.

maintain grid stability by responding to changes in load conditions [23]. In droop control method, the system's frequency is viewed as a universal parameter that determines the distribution of both active and reactive power. As shown in Fig. 1.4, the frequency and active power are linearly proportional using a $P - \omega$ curve in droop control strategy [20, 21, 56–61]; similarly, voltage and reactive power are proportionally related using a $Q - V$ curve, where $\Delta\omega$ and ΔV are the allowed variations in angular frequency and voltage at the PCC defined within the requirements of IEEE Std. 1547 [16] with respect to their nominal values, i.e., $\omega_n = 377 \text{ rad/s}$ and $V_n = 208 \text{ V}$ line-to-line in the North America, and ΔP and ΔQ are the difference between the desired power set-points and calculated power values for the active and reactive powers, respectively [3, 20, 28, 62–64]. In [59], the $P - f$ droop is modified to control the angle at each inverter's terminal to rapidly transfer the overload to the other generation units during a pulsed load events while ensuring the synchronization of each unit. The method uses an overload mitigation controller that consists of two PI controllers running simultaneously, one becomes active if the measured power exceeds the inverter's maximum capacity, and the other one becomes active when the power goes beyond the maximum active power absorption limits of the inverter. A similar concept is used for $Q - V$ droop to mitigate the circulating reactive power [65] between paralleled GFM inverters.

This self-governing approach can perform a balanced distribution of power among multiple inverters and reinforces the stability and resilience of the microgrid's operation. However, analyses show that output impedance of the inverters significantly impacts the stability of the system since the relationship between ω and P is valid if the system is inductive, i.e., $X \gg R$. A mixed-integer conic programming (MICP) approach for calculating real and reactive power droop parameters is proposed in [66], utilizing a stochastic optimization frame-

work. This method incorporates economic considerations into the droop settings, effectively addressing the voltage magnitude violation issue often encountered with conventional droop methods. On the other hand, a resilient voltage-current $V - I$ droop controller is presented in [67]. This solution aims to address the challenges posed by uncertain feeder line impedance and nonlinear loads, which often result in harmonic voltages and sub-optimal power sharing. At the heart of this approach is a robust feeder impedance shaping method designed to mitigate the effects of impedance uncertainties and voltage deviations at the point of common coupling. Alternatively, angle-based droop control is implemented in [68–70] to overcome the voltage sag challenges faced by the conventional droop.

The challenges in fundamental droop control method in inverter-based power systems can be summarized as follows:

- Sudden load changes, connection of inductive and dynamic loads, and sudden islanding can cause frequency transients due to zero-inertia feature of inverters. This can lead to excessive circulating currents and instability, especially in multi-inverter systems with a weak grid.
- Current control and overload mitigation techniques are necessary to mitigate high inrush currents and prevent overloading events.
- The system is desired to be inductive, i.e., $X \gg R$, to decouple active and reactive power for frequency and voltage generation, respectively.

f) Virtual inertia control:

This innovative control concept emulates the equation of motion to leverage the dynamic behavior of electric machines and address the zero-inertia challenges of inverter-based microgrids. The concept of virtual inertia control is also known as virtual synchronous generator (VSG) in the literature. The inertia and damping is artificially provided to changes in power demand using a virtual inertia and damping coefficients, see Fig. 1.5 [14, 26, 71]. By implementing virtual inertia concept, grid-forming inverters can operate in parallel with the other power generators in the grid with enhanced stability.

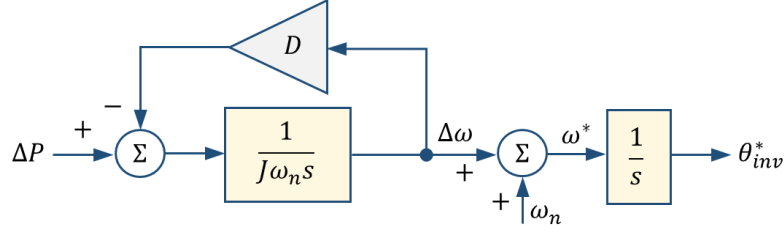


Figure 1.5: Block diagram representation of virtual inertia control method, where D represents the damping coefficient, and J is the inertia constant.

An experimental residential microgrid setup that consists of one 125 kVA synchronous generator behaving as the main power source and five 20 kVA inverters with battery energy systems, and three three-phase 50 kW loads is developed in [72]. The setup emulates the real load profile in Mutsuzawa, Japan, over 23 minutes. The performance of synchronization, frequency regulation, and power sharing are demonstrated when the inverters are all autonomously operated in the GFM mode or mixed GFM and GFL modes. Inertia is implemented by means of a first-order delay and phase compensation for open-loop phase margin. However, the modes of operations are initially set, and no performance results are provided when the mode change during operation. It is reported that virtual inertia controllers are prone to voltage and frequency instability, arising from the coupling between the d- and q-axes with the differential operator inherent in virtual inertia control, when used in weak grids [73]. A modified virtual inertia control by properly linking the grid frequency and voltage references of dc-link capacitors to address this instability issue.

On the other hand, a detailed voltage and frequency stability analyses for inverters using virtual inertia control in weak grid condition is provided in [74]. An impedance modeling in synchronously inertial reference frame and inertia-damping-strengthen control technique are developed to improve stability in voltage and frequency. Furthermore, a model predictive control (MPC) is implemented for a virtual energy storage system to provide virtual inertia and frequency regulation in a microgrid consisting of inverter- and generator-based units [75]. Similarly MPC is applied in a system where virtual inertia is emulated from an energy storage system [76]. To ensure rapid secondary frequency regulation in a low-inertia microgrid, an optimal non-integer MPC is applied in [77]. In this method, a modified heuristic

tic optimization algorithm is applied to tune the MPC controller parameters. Alternatively, an H_∞ -based controller method has been proposed for grid-forming inverters, which can enhance the virtual inertia provision capability for rapid load change in stand-alone mode and ensure damping of large overshoots and oscillations [78]. In this method, the frequency response of the plant is acquired, the controller's structure and order are defined, and a convex optimization problem is solved to derive the discrete-time controller. Adaptive virtual inertia is proposed in [79], where the dynamic process of frequency improvement is controlled by applying large inertia close to the frequency nadir and small inertia when the frequency is close to the nominal value. In [80], a comparative analysis of virtual synchronous generator (VSG) and droop control, focusing on the rate of change of frequency (RoCoF), is provided. The study reveals that emulating inertia with the RoCoF can potentially induce high-frequency vibrations due to the derivative controller implemented in PLL and destabilize the whole system if used in weak-grid conditions. However, implementation of the swing equation in VSG introduces new oscillation modes.

The transients of the VSG internal voltage and its impact on the transient angle stability are analyzed in [81] and, an enhanced control is developed by evaluating the influence of VSG in acceleration and deceleration areas. In [82], the authors analyze the impact of the inertia on power and angular frequency. Then, a dual-adaptivity inertia control strategy is proposed, where an adaptive deviation regulator and an adaptive priority setter is formulated to achieve balance between the frequency and power regulation. A unified state-space model is derived for VSG operating in grid-connected, stand-alone, and islanded modes, which can be used to provide mathematical and physical interpretation for different characteristics of the grid-forming inverters [83]. The VSG parameters of an inverter can be adaptively tuned using coordinated control strategies, optimization methods, or model predictive controls to provide ride-through capability under different mode operations [84–86]. Several data-driven, machine learning, artificial intelligence-based techniques have been developed for tuning the VSG parameters and providing enhanced stability [87–89]. However, the data-driven methods require offline training and high processing power which typically increases

the cost and reduces the reliability. Hence, these methodologies are typically uncommon in the industrial applications.

Above-mentioned investigations show that developed techniques mainly incorporate the innovative aspect of virtual inertia. Methodologies are improved to achieve better system dynamic behavior under various conditions, e.g., load uncertainties. The virtual inertia controllers can also be programmed to work as a droop controller if the coefficients are selected properly. Although a virtual inertia controller can provide smoother dynamics compared to a conventional droop controller which is vulnerable under pulsed load events that can result in tripping the inverter due to frequency, voltage, or power oscillations, there is no work in the literature demonstrating a complete control solution considering an autonomous plug-and-play functionality from black-start to supplying the demand regardless of mode of operation without requiring communication.

The challenges of virtual-inertia control method can be summarized as follow:

- Implementing only virtual inertia is insufficient to improve the dynamic performance of the system effectively and requires energy storage units such as batteries or large DC-bus capacitors to emulate the mechanical power exchanged with the prime mover.
- Similar to the droop control method, it is necessary to achieve an inductive, i.e., $X \gg R$, output impedance to decouple active and reactive power for frequency and voltage generation, respectively. Therefore, modifications are essential to increase output reactance virtually if needed.
- Virtual-inertia method is also insufficient to mitigate the inrush currents due to inductive and dynamic loads as the voltage regulation is achieved using droop method.

g) Virtual electric machines:

To extend the studies on virtually emulating the machine behavior for improved system dynamics, the concept of virtual electric machines (VEM) is developed. The VEM concept enables the power electronic converters to mathematically behave as synchronous machines [90].

The concept is first introduced in the literature as virtual synchronous machines (VSM) [91]. The voltages at the PCC is measured to calculate phase currents and then used as the current references for the PWM generation, where the inverter behaves as a current-source inverter. However, if a large current tracking error exists, the VSM operation is violated. In [92], a unique voltage-source inverter control (synchronverters) is developed. The voltage references are generated using the dynamic equations of a synchronous machines that includes the mutual inductance, back electromotive force (emf), flux linkages, etc. combined with the droop equations for parallel inverter operation in addition to virtual inertia implementation. A simple PI controller is used to regulate the virtual flux linkage which is then used as reference values for PWM signal generation. The machine parameters, e.g., inertia, friction coefficient, and field and mutual inductances, can be flexibly selected. Furthermore, no magnetic saturation or eddy currents can be considered as the method is implemented virtually. However, increased number of coefficients makes the parameter selection and tuning procedure challenging, which may result in instability or oscillations around the synchronous frequency. Also, the output filter inductance is considered instead of the stator inductance, which is nearly 30 times less than the actual stator inductance of a synchronous machine of the same rating. It is noted that using a higher inductance value closer to a realistic rotor inductance performs more stable operation [93]. Therefore, the authors used a virtual inductance to increase the effective inductance of the filters. Additionally, a new field current controller is proposed using a different method to calculate the reactive power and an anti-windup mechanism for the integrator applied in the controller. Furthermore, virtual output impedance losses are considered in the developed controller to accurately regulate the desired active power. However, the design complication increases, and the designer must have a strong electric machines background. On the other hand, a synchronization unit, e.g., a phase-locked-loop (PLL), needs to be equipped. A self-synchronization without requiring a PLL is developed for synchronverters in [94]. First, a virtual impedance is used during the synchronization process to generate a virtual current with respect to the fed-in voltage error. Then, a PI controller is implemented to zero the change in torque, ΔT . According to the defined switching look-up table, the inverter can synchronize with the grid when P and

Q set-points are set to zero (stand-by) to avoid large transients. In [95], a bounded control structure is applied for field-excitation current and the frequency that ensures an asymptotic stability of the closed-loop system. This updated design also considers measurement errors and sudden disturbances. However, the controller becomes highly nonlinear. Oscillations in active power when two parallel synchronverters are used is studied in [96], and a suppression technique developed. However, weak grid condition is not considered. Also this study as well as the previous synchronverter methodologies do not consider the case where the inverter changes its mode of operation when active and reactive power are being injected to the system.

Implementing the virtual electric machines method may introduces the following summarized drawbacks:

- Virtual electric machine control method requires complex formulations of electromechanical systems and electric machines for a proper voltage and frequency generation, regulation, and synchronization.
- Increased number of virtual machine parameters makes the tuning process challenging, which can degrade the efficiency and performance of the controller or lead to instability.
- The virtual inductances must be selected carefully since the output filter inductance is typically considered as the stator inductance which is much smaller in ratings.

h) *Indirect control:*

In the indirect approach, an inner current control loop is implemented on the d- and q-axes that is responsible for current regulation. This inner loop work in conjunction with an outer loop that controls the output voltage and frequency in grid-forming mode, see Fig. 1.6. The indirect GFM control method is a similar approach to the indirect grid-following inverters control. However, this current controlled voltage source inverter operation introduced by the indirect control methods contradicts with the main concept of grid-forming operation utilizing voltage controlled voltage source inverters. According to the findings, the state-of-the-art GFM indirect control strategies can be listed under two categories, i.e, conventional indirect control and virtual inertia-based indirect control.

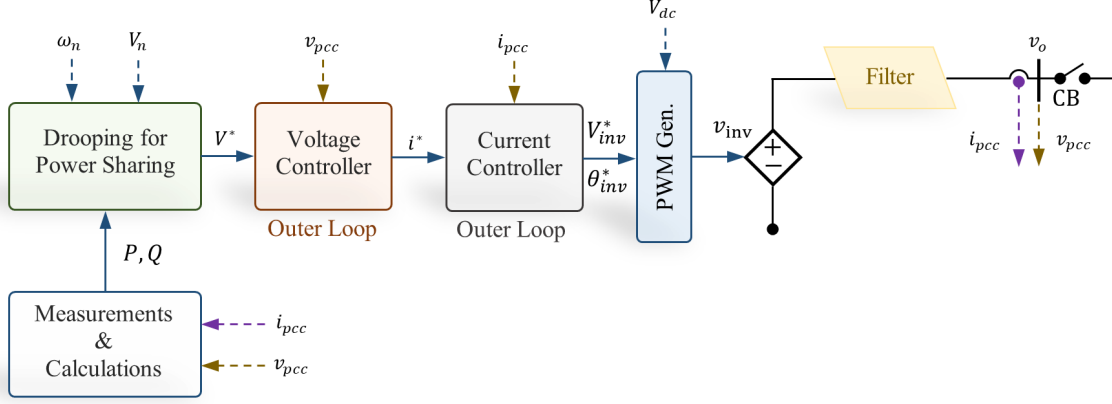


Figure 1.6: Block diagram representation of indirect control strategy using a regulators in series.

The conventional indirect controller consist of a cascaded control loop structure without improving the inertia of the system using virtual inertia techniques. An inner control loop can be used to regulate the current during a change in demand, and saturates or limits the output of the current controller when the inverter current exceeds a certain threshold. An outer loop determines the desired voltage level, and as voltage at the PCC sags or swells due to a change in load or grid conditions, the outer loop can be designed to recover the PCC voltage.

A comprehensive control strategy for voltage-source converters in power grids is proposed using indirect control in [97]. This approach leverages the advantages of both grid-forming, i.e., power-synchronization control (PSC) and grid-following, i.e., vector current control (VCC) controls, addressing the issue of grid stability in the presence of renewable energy sources. It aims to unify the PSC and VCC strategies in a way that the PSC can be equipped with the current control capability. Experiments performed with a focus on effectiveness, robustness and performance of the unified controller across various grid short-circuit ratio (SCR), from lower (weaker grid) to higher (stiffer grid). Also, the results compare the developed controller with the VCC, highlighting their effectiveness in maintaining grid stability. In [98], the stability of grid-forming inverters (GFMI) with a focus on the role of voltage control loop feedforward terms is examined. It is studied that instability may be observed due to the feedforward terms in the voltage loop unless the current control loop

is faster. The authors propose an approach addressing the stability issues caused by feed-forward interactions. This involves detailed mathematical modeling and the introduction of two remedial actions to mitigate the instability issues. The effectiveness of these actions is validated through simulations and experiments. Another GFM indirect controller for power converters in weak grid is developed in [99], replacing the PI-based voltage control loop with virtual admittance concept, to improve grid stability. A PLL is used for the synchronization. The study employs a full-order model that considers the filter, PLL, time delay, and full controller models of the system for the simulation scenarios to validate the effectiveness of the proposed methodology. The analyses are performed in weak-grid conditions, and the controller is tested for grid-support functionality, islanding transition and operation, black-start capabilities, and nonlinear load conditions. The findings demonstrate stable dynamic performance. The authors in [100] focus on addressing the challenges of power and frequency instability in multi-inverter-based microgrid systems using an indirect controller superimposed with droop control. The authors propose a novel power system stabilizer (PSS) using a lead compensator for adjusting the change in angular frequency, $\Delta\omega$, for $P - \omega$ droop to improve the stability of the system. The experimental results and eigenvalue analysis verify that the PSS achieves sufficient damping to the low-frequency oscillation, even at higher droop gains, which are otherwise unstable.

On the other hand, harmonic current filtering and resonance damping in islanded microgrid systems is addressed in [101]. The methodology involves using an indirect control strategy for distributed generation units equipped with inverters employing a load compensator based on the decomposition of output current. The load compensator comprises a virtual-fundamental-impedance loop for enhanced reactive power sharing and a variable-harmonic-impedance loop. This allows it to mitigate harmonic voltage drops across the grid-side inductance of inverters and to dampen harmonic resonance propagation in the microgrid, ensuring improved stability. Next, a virtual impedance-based fault current limiter (VI-FCL) approach that applies the indirect GFM control method superimposed with droop control is developed to mitigate fault currents in AC microgrids dominated by inverters

in [102]. The methodology includes a systematic model of inverter-dominated AC micro-grids, incorporating VI-FCLs for stability analysis. Controller-based protection provides a lower-cost solution for fault mitigation compared to installing expensive hardware protection equipment. Another fault ride through strategy for grid-forming converters is developed in [103]. This strategy addresses the challenges posed by both symmetrical and asymmetrical grid faults while being compliant to the grid codes. The methodology is validated through power-hardware-in-the-loop and experimental analyses under different fault types, and the results are in consistent with the grid codes. Alternatively, transient stability in voltage source converters (VSCs) under large current disturbances is studied in [104], proposing an enhanced P-f droop control scheme. In the enhanced method, q-axis component of the voltage, i.e., $V_q = 0$ during the steady-state where voltage is locked at d-axis in the synchronous reference frame, is feedforwarded to adjust the angular frequency derived from $P - \omega$ droop during the transients using a proportional gain coefficient. The stability analysis of the developed method heavily focuses on the active power vs. power angle dynamics, $P - \delta$, where δ is the angle between the inverter terminal voltage and the grid voltage.

Implementing the virtual electric machines method may introduces the following summarized drawbacks:

- The trend indicates that the developed methodologies primarily aim to mitigate high inrush or fault currents during overload events or grid faults. However, they lack performance results for plug-and-play inverter operation under various modes of operation.
- The indirect controller requires fine-tuning for the controller gains to achieve a faster inner loop operation while regulating the PCC voltage and frequency and avoiding high-frequency oscillations.
- Performing dynamical analysis or model of the system, which necessitates system knowledge, can aid in controller parameter optimization, but it introduces a trade-off with the computational load which makes the direct control structures more attractive.
- A comparative study between the direct and indirect controllers performed in [21] finds that the multi-loop droop control has a tendency to exhibit lower damping and greater

susceptibility to instability in several microgrid conditions.

i) *Virtual inertia-based indirect control:*

Similar to the direct control methods, virtual inertia control is also implemented in indirect control schemes to address the challenges in frequency dynamics due to the transition towards renewable-based energy distributed generation while possessing flexibility in current control.

In [105], the lack of natural inertia and governor damping is addressed using a virtual power plant framework using grid-forming inverters interfaced with distributed energy resources. An online learning-based method for parameter settings of the inverters is developed to adaptively adjust the inertia support, and inverters' parameter configurations are coordinated to develop a synchronous operation. The effectiveness of the method is demonstrated through a case study in the IEEE 34 nodes system, and the proposed method successfully maintains system inertia under various disturbances, maintaining the rate of change of frequency and frequency nadir within expected limits which indicates a stable grid operation. While the paper presents a novel approach, the approach might face challenges when scaled up to larger and more complex grid systems. The intricacies and variabilities in larger grids could impact the effectiveness of the proposed solution. Hence, performance of the online algorithm may vary particularly when grid conditions can be highly variable and unpredictable. Although, it is noted that the parameters are updated periodically, changing the damping coefficient on one unit may cause overloading on the other units. Furthermore, the cost-effectiveness of the proposed solution is a crucial factor for practical adoption, and the authors does not provide the economic aspects of implementing such a system. Another adaptive virtual inertia method is introduced in [79] that addresses the challenges in frequency regulation in AC microgrids due to low inertia. The method involves modifying the inertia moment in real-time based on system conditions using a mathematical model for adaptive inertia, instead of optimizing it. This makes the controller more suitable for large-scale applications. The methodology is tested using hardware-in-the-loop (HIL) real-time simulations in a microgrid model, focusing on different load conditions including a squirrel-cage induction motor and RoCoF limitations. On the other hand, another control strategy emulating

indirect virtual inertia is developed in [106]. Unlike the other methods, this method forms a relationship between the DC-bus voltage and the frequency output of the inverter, leveraging the dynamic behavior of the DC-bus capacitor to mimic inertia to enhance the grid stability even under weak-grid conditions, thereby achieving power-frequency characteristics similar to those of the synchronous generators. However, the main focus of the paper is on the challenge of grid synchronization in weak grid conditions, where traditional Phase-Locked Loop (PLL) methods are less effective. The authors in [25] utilize a virtual inertia control method superimposed on a cascaded controller to examine the impact of current limiting and voltage regulation performance of the cascaded operation on mitigating inrush current effects and enhancing inverter robustness for safe connection of inductive and dynamic loads. The necessity for fine-tuning of the control parameters to maintain a stable operation while inherently mitigating the inrush currents is demonstrated through experimental tests using a multi-inverter-based laboratory-scale hardware setup. The PCC voltage recovery performance is tested for different controller gain parameters. The paper provides detailed insights into the control scheme's PCC voltage recovery performance and its sensitivity to different controller gain settings. However, improper tuning might cause power to flow from one generation unit to another, leading to potential damage of the equipment.

Although results of the above-mentioned methodologies demonstrate improved frequency regulation compared to the conventional indirect controllers, the challenges for the virtual-inertia superimposed indirect controllers can be summarized as:

- Similar to the fundamental indirect control method, complexity of fine-tuning and lack of performance results for plug-and-play inverter operation under various modes of operation still exist.
- Existing literature demonstrating performance of the virtual inertia-based indirect controllers are insufficient. The robustness and performance of the developed method needs comparative and extensive verification to demonstrate the benefits, particularly over the direct virtual inertia controllers, which perform dynamically faster and requires less tuning process.

- Performing dynamical analysis or model of the system, which necessitates system knowledge, can aid in controller parameter optimization, but it introduces a trade-off with the computational load which makes the direct control structures more attractive.

Nonlinear Control Methods

This section discusses different nonlinear control approaches including their state-of-the-art applications in grid-forming inverters. These strategies are virtual oscillator control (VOC), model predictive control (MPC), sliding mode control, and back-stepping control. The nonlinear strategies are developed to enhance stability, dynamic response of the system, and robustness of the inverters.

j) *Virtual oscillator control:*

Virtual oscillator control (VOC) is a time-domain method that emulates the inherent dynamics of weakly nonlinear limit-cycle oscillator circuits for synchronization and control of grid-forming inverters [23, 107]. By leveraging the dynamic characteristics of these circuits, VOC effectively ensures stable, accurate synchronization among various grid-forming inverters, promoting coordinated functioning within microgrids or broader networked power systems [108]. Additionally, VOC aids in the precise regulation of voltage and frequency, contributing significantly to the grid's overall stability and dependability [109]. Inverters controlled with VOC can synchronize with each other autonomously from an arbitrary initial condition [24]. Early investigation in [110] focuses on synchronizing parallel single-phase inverters in a decentralized manner in distributed AC power systems. It introduces a method inspired by the synchronization in networks of coupled oscillators to control the inverters implementing a dead-zone oscillator, which is defined by its piece-wise nonlinearity. This approach ensures synchronization and load-sharing proportional to the inverters' power ratings. Studies are expanded the application from single-phase systems to three-phase systems [111, 112]. However, it is reported that the mathematical modeling of Van der Pol oscillators can be formulated easier compared to dead-zone oscillators [24].

Therefore, the Van der Pol oscillator became an attractive solution as an alternative to

the dead-zone oscillators. The study in [113] revealed its voltage and frequency regulation capabilities and detailed design process, aiming to stabilize arbitrary initial conditions to a synchronized sinusoidal limit cycle. Further analysis highlighted that a proper selection of control parameter configurations of a Van der Pol oscillator, the controller behaves as droop control and offers improved dynamic response speed, attributed to its time-domain implementation [114]. In [115], performance of VOC and droop controllers are compared, and the results demonstrate that VOC shows better performance than the droop controller only when $\Delta\omega$ is higher than a certain threshold. However, droop method outperforms for a smaller change in $\Delta\omega$. For grid-interactive applications, desired active and reactive power setpoints, i.e., P^* and Q^* , respectively, are followed in a hierarchical structure by applying an additional outer loop into the Van der Pol oscillator in [116, 117]. Similar to the indirect controllers, a fast inner-loop current controller is implemented in Van der Pol type VOC application in [118]. The drawback of the Van der Pol oscillator are that the parameters must satisfy a specific condition to achieve the ideal sinusoidal waveform, and the initial conditions influence the system's stability and the speed at which it transitions from the initial state to a steady state [119].

On the other hand, dispatchable VOC (dVOC) concept is introduced for grid-interactive applications [120–122]. Advancements in the dVOC strategy led to implementation of Andronov-Hopf Oscillator (AHO). The AHO control provides a trajectory free of harmonics and more agile dynamic response, enabling the control of power delivery from one or more inverters through high-bandwidth setpoints while ensuring power quality [107, 119]. An AHO control method is superimposed with indirect controller in [123]. A self-synchronization capability for cascaded inverters using AHO-based VOC is developed in [124]. An inrush current mitigation strategy is developed in [125] to suppress the current during inverter connection using an adaptive pre-synchronization technique. Researchers have developed a design framework for a unified virtual oscillator, adaptable for both grid-interactive and islanded modes, by leveraging the VOC's strong synchronization capabilities in [126].

Although nonlinear methods are developed to improve robustness and dynamic response

time of the system, implementation of virtual oscillator control method are challenging due to the reasons listed below.

- The mathematical modeling of VOC techniques are more complex in terms of control algorithm design, compared particularly with traditional droop or virtual-inertia control methods. This complexity makes the system design and implementation more challenging.
- Due to the nonlinear nature of VOC, dynamic analysis of systems becomes more complicated compared with the linear direct control methods. This may lead to improper controller gain parameter selection. Ensuring stability across all operating conditions may require more intricate design and analysis.
- VOC may introduce low-level harmonics into the system due to the nature of its control algorithm, which might require additional filtering or control strategies to mitigate.

k) Sliding mode control:

The Sliding Mode (SM) control is a type of nonlinear control primarily developed for controlling variable structure systems, especially in applications involving variable or uncertain system dynamics. The main principle of SMC is to drive the system's state to a predefined sliding surface (or manifold) and then maintain it on this surface despite any disturbances or uncertainties. Once the system state reaches this sliding surface, the control action switches (or slides) between different states to keep the system's trajectory within a desired performance margin. It has been applied for many power electronics control applications such as DC-DC converters, rectifiers, and inverters. It offers robustness against disturbances and uncertainties, making it suitable for grid-forming inverters operating in dynamic environments [127–129].

The sliding-mode controller presented in [130], utilizes a nonlinear direct power control scheme where droop characteristics of grid-forming inverters are replaced to ensure enhanced stability. An improved sliding-mode direct-voltage control is presented in [131], where the sliding variable is defined with proportional-derivative (PD) dynamics to utilize its inherent active damping properties. In [132], a sliding mode nested-loop strategy is proposed to

manage inrush current scenarios.

Common challenges of implementing sliding-mode control in power electronics applications are listed below.

- Chattering phenomena is the major drawback of sliding-mode control concept. High-frequency oscillatory behavior near the sliding manifold and switching imperfections cause chattering.
- A higher-order sliding-mode control design is essential to reduce the chattering; however, as the order of the mathematical model increases, complexity of the design also increases.

1) Backstepping control:

Several advanced nonlinear backstepping control methods for grid-forming inverters have been recently introduced. These methods involve adaptive tuning of control parameters in response to changes in system dynamics [133–135]. The challenge of maintaining stable operation in systems with a mix of grid-forming and grid-following converters, and synchronous generators are addressed in [133]. The methodology involves nonlinear backstepping control techniques to ensure system stability and effective performance, particularly in the presence of dynamic loads and disturbances. In [134], a sophisticated Kalman filter to enhance state estimation is employed. This strategy aims to reduce the reliance on sensors and handle the complexities of nonlinear and time-varying systems in microgrids, thereby ensuring stability and effective tracking for an inverter operating in grid-forming mode. This technique allows for the bypassing of steps necessary for calculating time-derivatives. By adjusting control parameters in accordance with system disturbances, the backstepping control achieves adaptivity. In [135], a robust and distributed secondary control scheme is proposed. The adaptive nature of the backstepping control is further refined through the use of an extended state observer for disturbance estimation.

The technical challenges of using backstepping control concept for inverters are as follows.

- Kalman filters or state observers may be used for adaptive operation, where an accurate

system modeling is required. For a system with many states, this procedure will be computationally intensive.

- In certain implementations, backstepping control can lead to chattering, a phenomenon where the control signal oscillates rapidly.
- Similarly, the backstepping control structure is more complex compared to the linear direct control strategies. Therefore, the design process is computationally demanding.

In this section, the state-of-the-art control strategies are reviewed, and their disadvantages have been listed. Ensuring a stable system operation can be challenging when different control methodologies are implemented for the inverters in a multi-inverter-based system which may jeopardize the resiliency and robustness of the inverters. In the following subsections, features and services that can be provided by grid-forming inverters to maintain a normal operation under various conditions are discussed.

1.2.2 Synchronization Techniques for GFM Inverters

Synchronization is crucial in scenarios where multiple inverters operate simultaneously within a microgrid. The design complexity for grid-forming inverters escalates, as each unit independently generates voltage and frequency for the system [22, 136, 137]. Traditionally, phase-locked loops (PLLs) are used to synchronize these inverters, requiring them to operate in a grid-following mode, especially when connected to a stiff-grid [138]. However, traditional PLLs are sensitive to issues like voltage imbalance and limited bandwidth. In contrast, direct phase-angle detection methods, which employ mathematical formulas for estimation, offer a faster and more accurate solution without using any regulators in conditions where the grid is unbalanced or distorted [55, 139].

Several centralized synchronization methods for GFM inverters are reported in [140–142], where the inverters obtain synchronization signals via a communication network. A low-bandwidth Ethernet communication channel, independent from the supervisory control, exchanging only phase-angle references to the inverters is developed in [143]. Moreover, a synchronization technique utilizing radio communication is presented in [144], employing

FM modulated signals to align the phase-angle among inverters. However, these methods are dependent on the external data received through a communication link. In case the communication is lost due to disruptions, poor synchronization performance can be observed which may lead to tripping of inverters.

Research on decentralized synchronization methods for grid-forming inverters is limited. This limitation caused mainly by the difficulty in accessing information about microgrid voltage, frequency, and phase angle at the point of common coupling (PCC) for the synchronizing inverter [24, 28]. This challenge exists due to the need for voltage, frequency, and phase-angle adjustments necessary for droop-based power sharing among multiple inverters. In most advanced synchronization techniques inverters are connected to the grid in grid-following mode. A study in [145] introduces a linearized synchronization control system for grid-forming inverters, featuring a soft-start synchronization to mitigate transients. A virtual synchronous generator-based inverter synchronization method, proposed in [146], demonstrates robust stability in weak grid conditions. Virtual oscillator-based synchronization methods, useful in scenarios lacking phase-angle measurements, are explored in [107, 108]. These studies, through small-signal modeling, indicate improved stability with virtual oscillators when the PLL measurements are unreliable. However, highly nonlinear behavior of VOC method possesses design and implementation challenges. A self-synchronizing PLL-less control methodology is proposed in [147] that applies a different virtual electric machine concept. This developed method is known as inducverter, and it is inspired by the dynamics of induction machines. A virtual impedance transfer function adapted from an equivalent induction machine model, representing a lag-lead compensator to generate the three-phase voltage references. However, this method also requires fine-tuning and selection of the control and machine parameters. It should also be noted that islanded or GFM operation are not considered in the test scenarios. Also, analytical direct PLL techniques used in [55, 139] provides an easier solution to implement.

Two novel synchronization techniques, output-sync and controller-sync, are discussed in [20]. The output-sync method involves the incoming grid-forming inverter aligning its voltage and phase angle before connection to the existing system, followed by a circuit

breaker facilitating the connection. Post-connection, the inverter continue its operation in grid-forming mode. Notice that pre- and after-syncing, the inverter operates in GFM mode. On the other hand, the controller-sync method employs dual control paths, running in parallel while only one path is engaged for PWM generation, to automatically synchronize the controller output with the circuit breaker that connects the inverters to the grid. Compared to the output-sync method, controller-sync eliminates the need for separate set of sensors. This controller-sync approach could be further developed for a universal operation mode, allowing an inverter to smoothly transition between different modes using a unified control structure while maintaining synchronization [64, 148]. However, the universal control structure applies an indirect approach when operating in GFM mode. Furthermore, no information and results are provided for the scenario when the inverters change their modes of operation from GFM to GFL when the grid is re-available. Several techniques are proposed in [149–153], where the inverter transitions its mode from GFL to GFM to maintain synchronization after an islanding. A cost mode (an intermediate mode) is used to achieve smooth transients during a switch from GFL to GFM in [149]. A combination of a current and voltage controller where only one is active at a time is proposed in [150, 151]. On the other hand, a current and voltage control are unified to generate the PWM references in [152]. An MPC method featuring an auto-tuning capability, allowing the inverter to adjust the weight factors, for controllers operating in both GFL and GFM modes is developed in [153]. However, a model-predictive approach necessitate a reference model, which can be difficult to establish for microgrids functioning in both GFL and GFM modes. Additionally, these above-mentioned methods typically assume that the inverters operating are linked to a common bus, where the coupling filter inductance is considered as the tie-line if an LCL-type filter is used.

1.2.3 Restoration for GFM Inverters

In a microgrid, the frequency and voltage levels at the PCCs of GFM inverters might deviate from their nominal values depending on the control methodology used, e.g., autonomous

techniques, and grid conditions [55, 154]. However, if the variations in frequency and voltage violates the standards defined by IEEE Std. 1547, the inverters must trip [16]. To ensure power availability, prevent the inverters from tripping, and protect the system, voltage and frequency restoration techniques are developed.

The key point of restoration is to enabling and disabling the developed technique. If the restoration is always enabled, no frequency and voltage variation will be allowed in the system during steady-state which jeopardizes the load-sharing for the decentralized linear controllers. Therefore, various feedback and feedforward paths are implemented in [155–160] the local controller to restore the system frequency and PCC voltages. In [156], the restoration is managed via a low-bandwidth communication system, in which the GFM inverters receive a unidirectional signal from the supervisory control when initiation is necessary. To minimize communication in centralized restoration, state estimation-based supervised method is implemented in [155, 157]. However, delays and risk of having cyber intrusions becomes challenge for [157]. Secondary and tertiary control-based techniques for frequency restoration have been developed in [161, 162].

To overcome the scalability, implementation, and cost concerns, decentralized or near-decentralized restoration techniques are essential. A timer/counter-based restoration technique is developed in [158] to initiate the restoration when a load change is detected. However, under pulse-load events or insufficient timer settings, restoration might not begin or performance can be poor [55, 163]. An adaptive low-pass filter is utilized in [159, 160] for restoration. The restoration is activated based on a change in load. However, load-sharing will be a challenge for an incoming inverters as they will measure the frequency and voltage near their nominal values. One can notice that these strategies do not allow a complete plug-and-play functionality for a GFM inverter. Therefore, an autonomous restoration technique that can allow power-sharing under pulse-load and inverter plug-in events are essential.

Alternatively, a threshold-based completely decentralized restoration control method is outlined in [55, 164]. This method addresses the limitations of timer-based approaches by adaptively adjusting the restoration period based on measured parameters. Thus, the inverter can share the load while operating at the nominal voltage and frequency. Therefore,

this methodology is adopted for the remainder of this dissertation.

1.2.4 Fault Ride-Through for GFM Inverters

GFM control strategies strictly regulate the PCC voltages at the nominal values. In droop and virtual inertia control, a $Q-V$ droop is used for reactive power sharing between inverters to adjust the PCC voltages, and a PI controller is used to follow the reference voltage value. To minimize the voltage variation at the PCC, a smaller droop coefficient, m_Q is preferred. Consequently, large amount of current may be injected during faults or voltage sags due to a large load, particularly inductive and dynamic loads, e.g., an induction motor, when PCC voltage is well regulated and grid voltage sags. This high current flow may trip or damage the inverters or power switches as the semiconductor switches can typically handle up to 40% of the over-current due to thermal limits [23, 26]. Alternatively, the microgrid may require oversizing the inverters, which increases costs and failure in reducing inrush currents. Hence, a current limiting mechanism is critical for safeguarding grid-forming inverters against excessive currents and protecting the equipment.

To mitigate the over-current events within a desired range, methods developed in [165–167] switches the inverter’s mode of operation from GFM to GFL and follows a preset fault current reference, ensuring that the over-current stays within an acceptable limit. Particularly in [167], a PLL is used during the fault. However, performance of the PLLs are not effective when voltage sag happens particularly in weak grids [23, 168].

On the other hand, current limiters are implemented for the current reference signals in indirect control [104, 169, 170]. The idea is to saturate the current at a desired value to limit the output current of the inverter during over-current situations. However, if the control method does not utilize synchronous dq -reference frame, the reference signals become a sinusoidal quantities and can result in distortion if the quantities are limited [23]. This can be overcome by implementing circular current saturator used in [171]; however, nonlinear VOC control is used, which entails the challenges discussed earlier. In [172, 173], fault ride-through strategy for synchronverters are developed. A conventional synchronverter structure

is altered to have a cascaded current reference generator and an inner current controller [23, 173]. As they emulate a voltage source connected to an impedance, these methodologies are inherently injects the fault current into the grid [23]. In [174], a dynamic virtual damping controller is proposed for indirect control method using a saturated virtual admittance to generate the current references and conditionally adjusting the power set-points depending on the measured quantities. However, it is demonstrated that direct control methods outperform the indirect controllers. Also, windup in the integrators can degrade the transient response and may lead to instability [23, 175]. Also, recent studies focused on instability issues caused by an outer control loop due to current limiting [176, 177]. In [176], virtual impedance is implemented to enhance the critical clearing time (CCT). However, this approach doesn't explicitly address the avoidance of instability in scenarios where the fault persists.

Alternatively, by adjusting the direct controllers, two protection stages can be implemented: the first-stage protection using hysteresis-based fault current limiting at the PWM signal generation stage, and second-stage protection that actively maintains synchronism by setting maximum active and reactive power limits [65, 178]. The second adjustment stage only works if measured power exceeds the pre-defined power limits using PI controllers. These stages can be also implemented independently. This method avoids the windup in the integrators since they yield zero during normal operation where the measured power is within the allowed margin. However, PI loops must be fine-tuned to minimize the response time of the controller to effectively mitigate the circulating or fault currents. On the other hand, a virtual impedance technique for is developed for a direct control method to mitigate the inrush currents caused by start of an induction motor [26] in multi-inverter-based islanded microgrids. Also, inrush current mitigation performance of the indirect control method by adjusting the outer-loop gain settings to allow more flexible voltage regulation using the same hardware setup is reported in [25]. However, a permanent voltage drop always exists due to the nature of using virtual impedance techniques. Therefore, a voltage recovery method which meets the grid standards is needed for virtual impedance-based current limiting strategies.

At the best of the author's knowledge, the-state-of-the-art fault ride-through methods

generally focus on mitigating or limiting the fault currents within an allowed margin. However, studies on the impact of a switched connection of an inductive and dynamic loads, where the rotor presents a low impedance, resulting in the starting current escalating to levels that can be five to six times greater than the loads' standard rated current during the start-up, in multi-inverter-based microgrids is insufficient and needs attention. Notice, these inrush currents should not be considered as fault, and happens for a short period, e.g., within a first few electrical cycles. Hence, changes in modes of operation or slow indirect control methods may fail during this period. To fill the gaps identified in the existing research works, the following steps are essential for GFM inverters.

- A completely decentralized and direct inrush current mitigation strategy needs to be developed to protect the converters and the system while meeting the grid requirements and maintaining synchronization.
- This mitigation strategy should have the capability to be incorporated with the existing fault ride-through methodologies to enhance the overall protection of the system.

1.3 Contributions

This section outlines the contributions of this dissertation in developing an autonomous control strategy allowing a unique universal and plug-and-play operation for the GFM inverters, maintaining power during an outage, restoring connection to the utility grid without requiring communication, and protecting the inverters from inrush currents caused by inductive and dynamic loads in a microgrid.

The main concept of grid-forming inverters relies on their operation as voltage-controlled voltage source inverters. This is because the objective is to generate a voltage magnitude and frequency at the inverters' terminals, without regulating the current, whether in a centralized or decentralized manner. Additional to voltage-controlled methods, there are numerous control techniques in the literature, discussed in Section (1.2.1), where grid-following concept is modified and incorporated to operate in GFM mode. This GFL methodologies introduces the flexibility of current-regulation by using an indirect control strategy which violates the

grid-forming concept. Each developed direct and indirect GFM control methods provide operational advantages and disadvantages. However, the performance showcase cycle typically includes a comparison of a newly developed technique with the state-of-the-art version of another technique. This latter technique is likely to be updated later to outperform its new counterpart. On the other hand, the existing baseline comparison of a fundamental direct method with an indirect method includes insufficient test scenarios, typically limited to fault, certain grid and load conditions, or synchronization dynamics, to demonstrate robustness and resiliency of developed techniques. Therefore, this dissertation provides a different perspective for the performance comparison between two well-known decentralized methodologies, i.e., direct and indirect control.

The results of this comparison are used to determine the type of controller that should be used as the foundation for the proposed autonomous controller. First, details of both control strategies are explained. Then, the sensitivity of both controllers under various conditions, including static, inductive and dynamic loads, by adjusting controller gain parameters is demonstrated in an islanded microgrid. This is performed to identify the margin of flexibility in selecting gains and the robustness of the controller to gain selection, and achieved using eigenvalue analysis and further verified through experimental analysis. To begin with, both controllers are tuned to yield the same dynamic performance as the baseline scenario. Subsequently, the controller gains are systematically adjusted, respectively. The comparison extends beyond dynamic analysis, encompassing also a comparison of the steady-state performance between the controllers. Furthermore, the eigenvalue analysis takes into account scenarios where the grid is perceived as inductive and capacitive equivalent circuits at the PCC points. This is based on the reactive power sharing between inverters, where one may inject reactive power while the other one absorbs it.

The comparison continues with inherent inrush current mitigation performance of both controllers at the baseline conditions when an induction motor is connected to the system. To address the challenges caused by the switched connection of an inductive and dynamic loads without a soft-start capabilities, a feedforward inrush current mitigation with voltage restoration technique is proposed for the direct control of GFM inverters. A virtual reactance

inrush current mitigation technique is implemented with the direct method to provide momentary control over inrush caused by the dynamic loads. The PCC voltage is momentarily reduced with respect to the magnitude of PCC currents. The voltage restoration method is developed to address the permanent voltage drop issues in [26] due to the inherent nature applying virtual impedance techniques. The mitigation and recovery performance of the developed mitigation technique is verified experimentally for different virtual reactance and recovery gain parameter values. Furthermore, inrush current mitigation performance of the direct method with the developed strategy and indirect method is experimentally compared for different gain parameter settings.

Inverters operating in GFL and GFM modes typically utilize two distinct control paths, see subsection (1.2.2). Achieving a smooth transition between these modes presents a significant technical challenge. In this dissertation, a unique and decentralized control scheme is developed for the inverters to seamlessly switch between the modes of operation, i.e., GFM and GFL modes, using two sets of synced-parallel control paths while maintaining synchronization. One set generates voltage amplitude and phase-angle references for GFM operation using droop control strategy, while the other set is dedicated to GFL operation and follows the grid voltage level and frequency. Both control paths operate simultaneously; one functions as the active path while the other operates in the background, continuously synchronizing its outputs with the corresponding outputs in the active path. Therefore, power availability can be ensured in a microgrid during utility outages or catastrophic events. The efficacy of the developed controller is experimentally verified using a multi-inverter microgrid setup for different modes of operation. Compared to [20, 55, 164], the novelty of the developed method comes from implementing direct control method (no inner loops) for both GFM and GFL paths. This enhanced control technique simplifies the required tuning process.

The primary innovation of this dissertation is the ability to autonomously detect the utility grid reconnection without the need for communication. This provides a novel decentralized approach to detect the grid's presence, also enabling microgrid interactions within the same region. As this developed algorithm does not require communication or extra external sensors, it can offer a cost-effective solution by eliminating the associated installation

costs for communication infrastructure. Additionally, this algorithm can be effective for scenarios where the existing communication between the inverter and utility or third-party aggregator controllers is disrupted or compromised by a cyberattack. The algorithm detects the reconnection of the grid by measuring the active power and frequency at the PCC. Since the utility is generally a stiff power source (high short-circuit ratio), the frequency is well regulated around the nominal value. A reconnection of the utility will dominate the frequency of the GFM path, leading to a ramping change in active power. The algorithm detects this change at fixed frequency and sends a signal to the controller to change the mode of operation. The efficacy of the novel grid detection algorithm is experimentally verified using a multi-inverter microgrid setup. Compared to [20, 55, 164], this dissertation demonstrates a complete universal operation with the ability to switch from GFM to GFL as needed, all autonomously.

The contribution of this dissertation can be summarized as follows:

- Comprehensive performance and sensitivity comparison between direct and indirect grid-forming control methods under various conditions, including static, inductive and dynamic loads, by adjusting controller gain parameters are provided. The outcome of this comparison entails the selection of the specific controller type to serve as the basis for the proposed autonomous controller.
- A linear and piece-wise linear feedforward inrush current mitigation technique using virtual reactance with fast voltage recovery is proposed for the direct control to limit inrush currents for system protection and prevent overloading due to connection of an inductive and dynamic loads.
- An innovative communication-less grid-reconnection detection algorithm is developed. This algorithm facilitates a decentralized approach for switching from GFM to GFL mode when the grid becomes available again, thereby eliminating challenges such as communication loss or malicious activities.
- An autonomous synced-parallel control tasks concept, implementing a direct control approach for both GFM and GFL paths, is developed. The unique controller enhances

the inverters' functionality, enabling them to operate in both grid-connected and islanded modes, and facilitates a seamless transition between each mode.

1.4 Organization of This Dissertation

The remainder of this dissertation is outlined as follows. Chapter 2 elaborates the comparative analysis on droop-based direct control and its indirect counterpart. The motivation behind this study is to select a base controller for the autonomous controller. Dynamic model of the system is developed for each controller for eigenvalue analysis, and the results are experimentally verified using an islanded multi-inverter microgrid setup.

Chapter 3 compares the performance of direct and indirect control methods under inrush currents caused by switched connection of an inductive and dynamic load, i.e., an induction motor, and provides the details of the developed feedforward inrush current mitigation technique with voltage recovery capability for direct control method. High inrush currents caused by a connection of an induction motor is mitigated by incorporating virtual reactance technique. Experimental results verifies that direct controllers can mitigate inrush currents without requiring an inner current controller.

Chapter 4 proposes a novel autonomous control technique for inverters in microgrids. Details of GFM and GFL paths as well as the main and background paths for seamless transition between the modes are provided. An innovative algorithm that autonomously detects utility grid reconnection without relying on communication is discussed.

Chapter 5 showcases the experimental results of the unique control method. Various test scenarios are implemented to evaluate the controller's efficacy in synchronization and changing the modes of operation based on the grid's availability.

Finally, Chapter 6 concludes this dissertation and suggests possible future research directions.

Chapter 2

Direct vs. Indirect Control Methods

This chapter focuses on the control architecture of direct and indirect controllers in Section (2.1) and (2.2), respectively. For the direct control, droop and virtual inertia control methods are discussed in detail, including their similarities and differences in subsections (2.1.1) and (2.1.2), respectively. In this paper droop control is selected as the base control structure for the GFM control. However, there will be some instances where virtual inertia control will be also utilized for test scenarios. The indirect control method is superimposed with droop control to allow power sharing between the other inverters in the system, and the design details are elaborated.

Following the controller schemes, insights into the dynamic operation of GFM inverters using direct and indirect control methods and performance comparison between them are presented in (2.3). The purpose of this comparison is to identify the sensitivity of each controller to different gain settings, particularly in an islanded microgrid which represents a weak grid. The dynamic performance comparison is performed using eigenvalue analysis. Then, the results are verified using a three-phase 15 kVA 208 V experimental setup using two inverters and one static load. The chapter is concluded with final remarks in Section (2.4), where the value of the analyses are discussed.

2.1 Direct Control

2.1.1 Droop Control

The control block diagram of the direct control scheme is illustrated in Fig. 2.1. This controller utilizes two decoupled paths to generate θ_{inv}^* and V_{inv}^* , which serve as phase-angle and voltage amplitude references, respectively, and are supplied to the PWM generator. The output angle of the inverter can be established and the system frequency can be regulated through either employing an active power-frequency (P- ω) droop coefficient or a virtual-inertia approach to proportionally distribute the total power demand among the inverters. In both direct control schemes, the voltage level is regulated typically using a $Q - V$ droop coefficient. The linear relationship for the droop coefficients can be simply derived from:

$$\begin{cases} m_P = \frac{\Delta\omega}{\Delta P} \\ m_Q = \frac{\Delta V}{\Delta Q} \end{cases} \quad (2.1)$$

where m_P and m_Q are the active power and reactive power droop coefficients. Notice, ($G_\theta(s) = m_P$) if droop control is implemented, and the desired references can be simply calculated from ($\omega_{inv}^* = \omega_n - \Delta\omega = \omega_n - G_\theta(s)\Delta P = \omega_n - m_P\Delta P$), and ($V_{inv}^* = V_n - m_Q\Delta Q$), see Fig. 2.1. Under GFM operation, the equations ($\Delta P = P - P^* = P$) and ($\Delta Q = Q - Q^* = Q$) are commonly observed since the reference active and reactive power values are set to zero, i.e., ($P^* = 0$) and ($Q^* = 0$), respectively. In the direct control architecture, the inverter

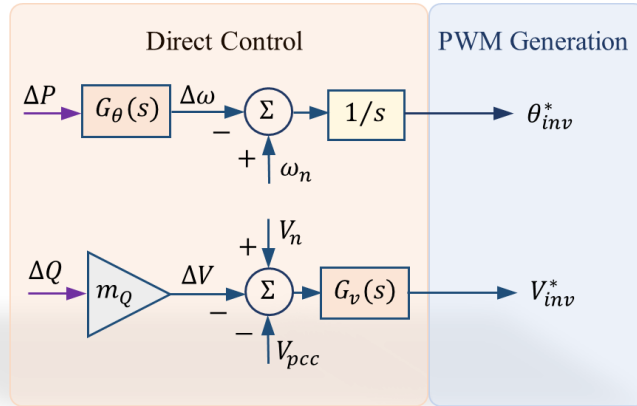


Figure 2.1: The direct control scheme after synchronization.

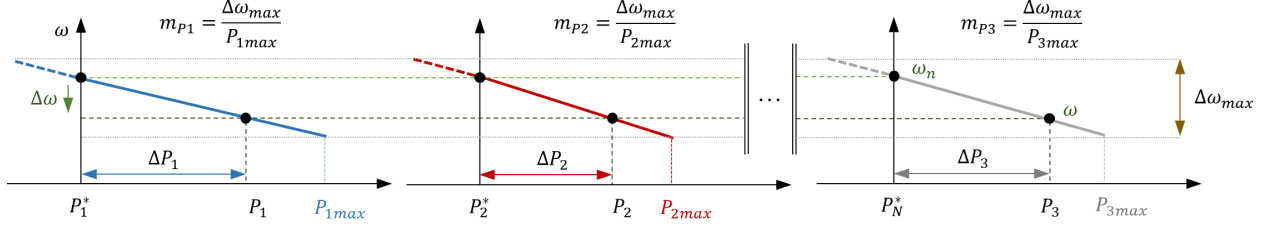


Figure 2.2: A demonstration of load-sharing between N number of inverters in a microgrid with different power ratings using $P - \omega$ droop control method.

terminal voltage is generated using a PI controller, $(G_v(s) = (sK_{Pv} + K_{Iv})/s)$, such that the output voltage, V_{pcc} follows $V_n - m_Q Q$.

Letting the system frequency and the voltage deviate in a droop-based microgrid enables the inverters to share their active and reactive power without any communication. Unless the inverters have different P_{max} ratings, each inverter contributes equally to power sharing since m_P for each inverter becomes identical, as demonstrated in Fig. 2.2. This holds true for variations in the system's frequency when losses are disregarded. This can be mathematically explained as $\Delta P_L = \Delta P_1 + \Delta P_2 + \dots + \Delta P_N$, where ΔP_L is the total load, and P_i , $i \in \{1, 2, \dots, N\}$, is the power injected from each inverter.

2.1.2 Virtual-Inertia Control

In the event of a disturbance in the system, such as a fault, load change, or a modification in the setpoints, an electric generator has the ability to temporarily balance the power discrepancy between supply and demand while stabilizing the frequency using the kinetic energy stored in machine's rotor due to the rotating mass. An inverter can mimic this dynamic behavior of the machines by implementing an inertia constant virtually to the inverter's controllers. This can be analytically derived as follows.

The equation of motion can be expressed as:

$$T_m - T_e = J \frac{d\omega_m}{dt} + D_p \omega_m \quad (3)$$

where, T_m is the mechanical torque generated by the turbine, and T_e is the developed electrical torque, J is the moment of inertia, and D_p is the damping coefficient. This equation

can be approximately written in terms of input and output power, also known as the swing equation:

$$P^* - P = J\omega_n \frac{d\omega}{dt} + D\omega \quad (2.2)$$

where, P^* is a constant at the steady-state condition, ω_n is the nominal frequency, and D is the damping coefficient. Eq 2.2 can be linearized as follows:

$$-\Delta P = J\omega_n \frac{d\Delta\omega}{dt} + D\Delta\omega \quad (2.3)$$

One can assume that the steady-state power makes the nominal frequency, ω_n . Therefore, $\Delta\omega$ is basically generated by any change in $-P$, and the inverter frequency is obtained from adding the nominal frequency to a frequency change, i.e., $\omega = \omega_n + \Delta\omega$. Thus, Eq. 2.3 can be rewritten in the Laplace domain as follows:

$$\Delta\omega = \frac{-\Delta P}{(J\omega_n s + D)} \quad (2.4)$$

Notice that if one assumes $J = 0$, Eq. 2.4 becomes the droop equation, where the droop coefficient $m_p = 1/D$. The damping loop acts like a droop control for power-sharing. The inertia and damping terms behave like a first-order low pass filter with a gain, $K_\omega = -1/D$, and time constant, $\tau_\omega = J\omega_n/D$. Therefore, it inherently adds delay to $\Delta\omega$ response to a change in active power in comparison with the droop control response.

The direct controller block diagram shown in Fig. 2.1 also applies for the virtual-inertia control method. Herein, $G_\theta(s) = 1/(J\omega_n s + D)$ to deviate the frequency if virtual-inertia is used. Therefore, $G_\theta(s)$ can be rewritten as:

$$\begin{cases} G_\theta(s) = m_P & (P - \omega) \text{ droop} \\ G_\theta(s) = \frac{-1}{(J\omega_n s + D)} & \text{Virtual Inertia} \end{cases} \quad (2.5)$$

However, the voltage regulation becomes as same as the droop controller since only inertia of the machines is virtually implemented. If the back emf and virtual flux leakages are considered, then virtual electric machines control method is employed.

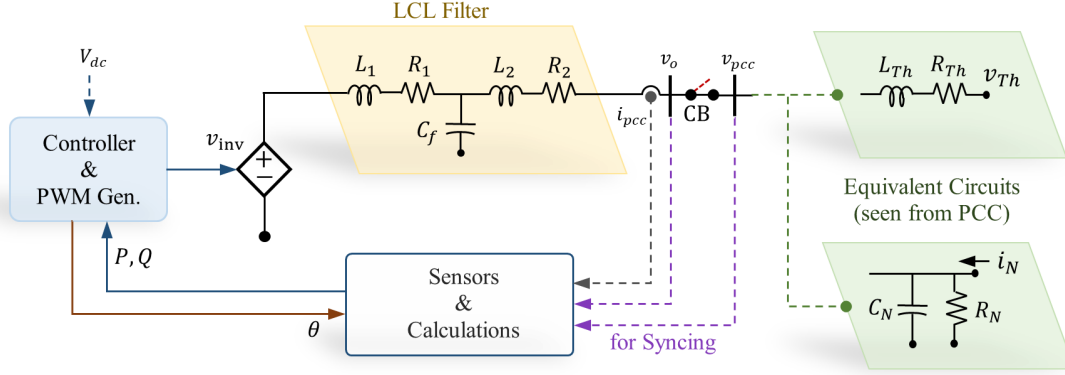


Figure 2.3: Simplified single-line-diagram of a grid-interactive inverter.

2.2 Indirect Control

In this subsection, an inner loop is designed to regulate the PCC current for grid-forming inverters. This concept is adopted from indirect control of grid-following inverters where cascaded loops are regulating the power and line currents. Hence, the indirect GFM and GFL control structures show similarities in design procedures.

The simplified single-line schematic of the system is shown in Fig. 2.3. In this diagram, a voltage-source inverter is connected to the PCC through an LCL filter. A circuit breaker (CB) is used as an interface to interact with or islanded from the grid. The equivalent circuit seen from the PCC is represented as the Thevenin and Norton equivalent circuits to represent the grid as an inductive and capacitive source, respectively, depending on the calculated reactive power.

2.2.1 Controller Scheme for GFL Operation

Considering the simplified schematic in Fig. 2.3, KVL can be applied to each side of the LCL filter in the abc reference frame as follows:

$$\begin{cases} v_{inv} = L_1 \frac{d}{dt} i_1 + R_1 i_1 + v_c \\ v_c = L_2 \frac{d}{dt} i_2 + R_2 i_1 + v_{pcc} \end{cases} \quad (2.6)$$

where, v_{pcc} represents the line-to-neutral voltages at the inverter's output terminals, i_1 and i_2 are the inverter and PCC-side line currents. The inverter-side filter impedance is L_1 and

R_1 , and the PCC-side filter impedance is L_2 and R_2 . Also, the capacitor current can be formulated as $i_c = i_1 - i_2$.

After neglecting the effects of the filter capacitor on the voltage and current fundamental components for to ease the calculation process, considering the PCC current $i_{pcc} = i_1 = i_2$, and lumping the filter impedance as $L_f = L_1 + L_2$ and $R_f = R_1 + R_2$, the system can be represented in dq reference frame using the following expression.

$$v_{dq0}^{inv} = (TR_fT^{-1}i_{dq0}) + (TL_fT^{-1})\frac{d}{dt}i_{dq0} + (TL_f)\frac{d}{dt}T^{-1}i_{dq0} + TT^{-1}v_{dq0}^{pcc} \quad (2.7)$$

where, T , T^{-1} , and $(TI)(dT^{-1}/dt)$, when I is a (3×3) identify matrix, can be respectively written as

$$\left\{ \begin{array}{l} T = \begin{bmatrix} \cos(\theta) & \cos\left(\theta - \frac{2\pi}{3}\right) & \cos\left(\theta - \frac{4\pi}{3}\right) \\ \sin(\theta) & \sin\left(\theta - \frac{2\pi}{3}\right) & \sin\left(\theta - \frac{4\pi}{3}\right) \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix} \\ T^{-1} = \begin{bmatrix} \cos(\theta) & \sin(\theta) & 1 \\ \cos\left(\theta - \frac{2\pi}{3}\right) & \sin\left(\theta - \frac{2\pi}{3}\right) & 1 \\ \cos\left(\theta - \frac{4\pi}{3}\right) & \sin\left(\theta - \frac{4\pi}{3}\right) & 1 \end{bmatrix} \end{array} \right. \quad (2.8)$$

$$(TI)\frac{d}{dt}T^{-1} = \begin{bmatrix} 0 & \omega & 0 \\ -\omega & 0 & 0 \\ 0 & 0 & 0 \end{bmatrix} \quad (2.9)$$

Therefore Eq 2.7 can be simplified as

$$\left\{ \begin{array}{l} v_q^{inv} = L_f \frac{d}{dt}i_q + L_f \omega i_d + R_f i_q + v_q^{pcc} \\ v_d^{inv} = L_f \frac{d}{dt}i_d - L_f \omega i_q + R_f i_d + v_d^{pcc} \end{array} \right. \quad (2.10)$$

where, $L_f \omega i_d$ and $L_f \omega i_q$ are the feedforward cross-coupling terms generated by $(TL_f)(dT^{-1}/dt)$.

Similarly, the instantaneous power, i.e., $p(t) = v_{pcc}^T i_{pcc}$, can also be represented in dq refer-

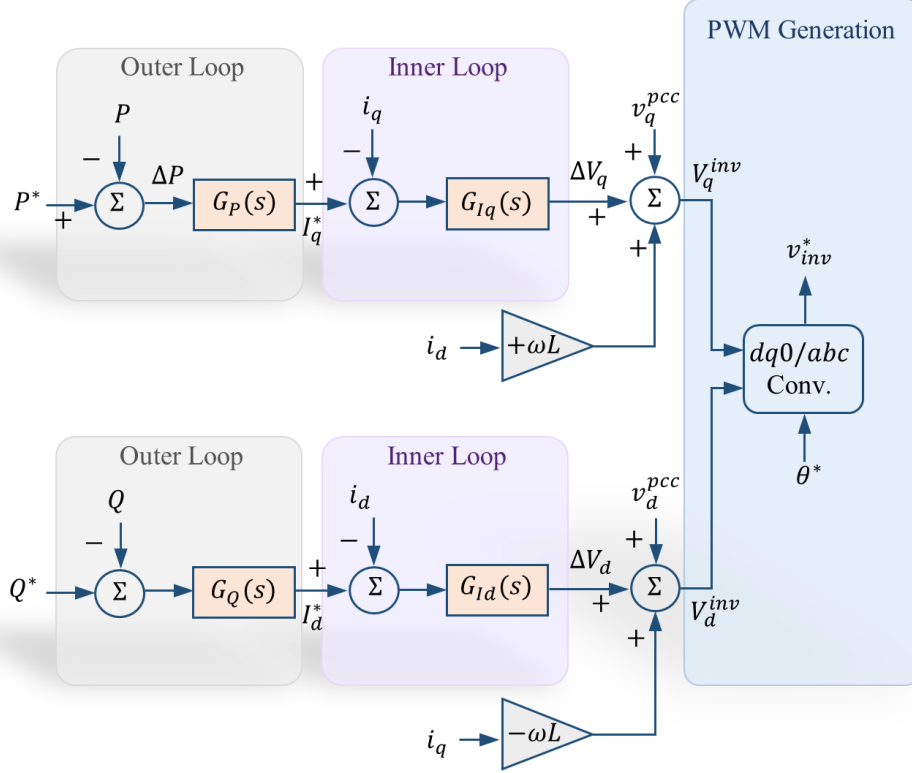


Figure 2.4: The controller block diagram of indirect GFL control scheme.

ence frame from $p(t) = (v_{dq0}^{pcc})^T (T^{-1})^T T^{-1} i_{dq0}^{pcc}$. Thus, the instantaneous power in dq -frame becomes:

$$\begin{cases} p(t) = \frac{3}{2}(v_q i_q + v_d i_d) \\ q(t) = \frac{3}{2}(v_q i_d - v_d i_q) \end{cases} \quad (2.11)$$

When synchronous reference frame is used, where q -axis is locked at a -axis to be consistent with the vector control theory [179, 180], i.e., $v_d = 0$ and $v_q = |v_{pcc}|$, active and reactive power can be decoupled. This independence is mathematically represented as $p(t) = (3v_q i_q)/2$ and $q(t) = (3v_q i_d)/2$. Based on this relationship, P and Q injection can be regulated at their setpoints (desired values) using an outer loop controller while an inner current control loop can be implemented to generate the PWM signal voltage references, V_q^{inv} and V_d^{inv} . The control scheme for grid-following mode of operation is demonstrated in Fig. 2.4. In GFL mode, the measured line-to-neutral voltage angle at the PCC, θ^* , is typically followed using a PLL, e.g., $\theta^* = [\tan^{-1}(v_{ab} + 2v_{bc})/(\sqrt{3}v_{ab})] - (\pi/6)$, where v_{ab} and v_{bc} are the line-to-line voltages, and $(\pi/6)$ is subtracted to calculate the corresponding phase angle.

On the other hand, proportional-integral (PI) controllers can be implemented as the inner and outer loop controllers for power and current regulations. Therefore, the transfer functions, $G_P(s)$, $G_Q(s)$, $G_{Iq}(s)$ and $G_{Id}(s)$ can be written as follows:

$$\begin{cases} G_P(s) = \frac{I_q^*}{\Delta P} = \frac{sK_{PP} + K_{IP}}{s} \\ G_Q(s) = \frac{I_d^*}{\Delta Q} = \frac{sK_{PQ} + K_{IQ}}{s} \\ G_{Iq}(s) = \frac{\Delta V_q}{\Delta I_q} = \frac{sK_{PIq} + K_{IIq}}{s} \\ G_{Id}(s) = \frac{\Delta V_d}{\Delta I_d} = \frac{sK_{PID} + K_{IID}}{s} \end{cases} \quad (2.12)$$

Inverters operating in GFL mode can be programmed to provide grid-supporting features, also known as ancillary services, and device-level self-protection to adaptively enhance the system stability, compensate the harmonics, regulate the system's voltage and frequency, and/or prevent malicious events [3, 8, 10, 14, 15, 17, 18, 149, 181]. More robust and direct controllers, which require less tuning compared to the indirect control method, can also be developed for GFL operation [182, 183].

2.2.2 Controller Scheme for GFM Operation

The single-line diagram of the system, following the synchronization process of an inverter, is depicted in Fig. 2.3. Since the system is same, equations from (2.6) to (2.11) apply for the GFM operation. For comparison studies, Eq 2.10 can be rewritten in s-domain as

$$\begin{cases} v_q^{pcc} = v_q^{inv} - (L_f s i_q + L_f \omega i_d + R_f i_q) \\ v_d^{pcc} = v_d^{inv} - (L_f s i_d - L_f \omega i_q + R_f i_d) \end{cases} \quad (2.13)$$

From Eq. 2.13, it can be seen that the current control loops are capable of reconstructing V_q^{inv} and V_d^{inv} , which are the input reference voltages in dq -frame, using $G_{Iq}(s)$, $G_{Id}(s)$, and the cross-coupling terms, i.e., $L_f \omega i_d$ and $L_f \omega i_q$. Similarly, a PI controller can be implemented to regulate the PCC current by generating a voltage difference between v_{inv} and v_{pcc} , see Fig. 2.5.

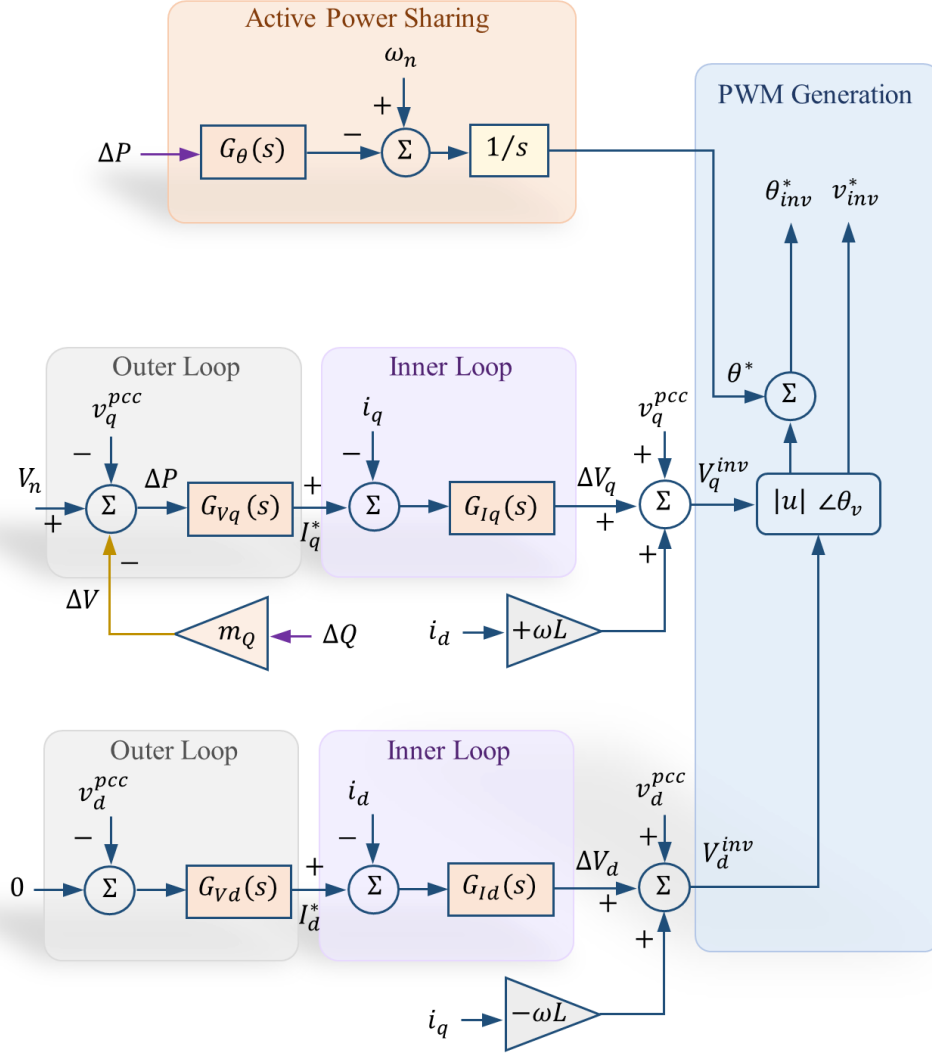


Figure 2.5: The controller block diagram of indirect GFM control scheme.

To allow reactive power sharing between the distributed generation units, a $Q - V$ droop characteristic which enables $\Delta V = m_Q \Delta Q$ is used in the indirect controller. The PCC voltage, v_{pcc} , is regulated at the desired output voltage, $V_n - \Delta V$ by implementing $G_{Vq}(s)$ and $G_{Vd}(s)$ as:

$$\begin{cases} G_{Vq}(s) = \frac{I_q^*}{\Delta P} = \frac{sK_{Pvq} + K_{Ivq}}{s} \\ G_{Vd}(s) = \frac{I_d^*}{\Delta Q} = \frac{sK_{Pvd} + K_{Ivd}}{s} \end{cases} \quad (2.14)$$

Notice that, PCC voltage can be calculated as $v_{pcc}^2 = ((v_q^{pcc})^2 + (v_d^{pcc})^2)/2$ from the measured dq -frame quantities, i.e., v_q^{pcc} and v_d^{pcc} .

For active power sharing in a multi-inverter system, droop control is superimposed with the indirect controller to mimic the behavior of electric machines. Therefore, $G_\theta(s) = m_p$, see Eq 2.5 for droop and Fig. 2.5. The resulting angle of the PWM reference signal is derived from $\theta_{inv}^* = \theta_v + \theta_n - \Delta\theta$, where $\theta_v = \tan^{-1}(V_q^{inv}/V_d^{inv})$ for the direct GFM control method.

2.3 Dynamic Model Development

The dynamic model development for the system depicted in Fig. 2.3 for each modes of operation begins with constructing the signal-flow diagram. Ignoring the control method and the equivalent circuit seen from the PCC in Fig. 2.3, the dynamic model of the system shows similarities as the system can be depicted by a voltage source inverter connected to an LCL filter. In this circuit, considering the state variables i_1 , i_2 , and v_c , and applying Kirchhoff's Current Law (KCL) at the filter capacitor, C , the following first-order differential equations can be derived using Eq. 2.13.

$$\frac{d}{dt} \begin{bmatrix} i_1 \\ i_2 \\ v_c \end{bmatrix} = \begin{bmatrix} -\frac{R_1}{L_1} & 0 & -\frac{1}{L_1} \\ 0 & -\frac{R_2}{L_2} & \frac{1}{L_2} \\ \frac{1}{C} & -\frac{1}{C} & 0 \end{bmatrix} \begin{bmatrix} i_1 \\ i_2 \end{bmatrix} + \begin{bmatrix} v_{inv} \\ v_{pcc} \\ 0 \end{bmatrix} \quad (2.15)$$

The grid can be represented using either Thevenin or Norton equivalent circuits, which symbolize the inductive or capacitive aspects of the grid as perceived by each inverter's PCC. The characteristic of the grid can lead to different dynamic performances, influenced by various system conditions or control parameters. In scenarios where the equivalent circuit is inductive, the voltage at the PCC can be written as follows:

$$v_{pcc} = (L_{Th}s)i_2 + R_{Th}i_2 + v_{Th} \quad (2.16)$$

For the capacitive equivalent circuit, refer to Fig 2.3, the dynamics of v_{pcc} can be determined by applying the KCL as follows:

$$sv_{pcc} = \frac{i_2 + i_N}{C_N} - \frac{v_{pcc}}{R_N C_N} \quad (2.17)$$

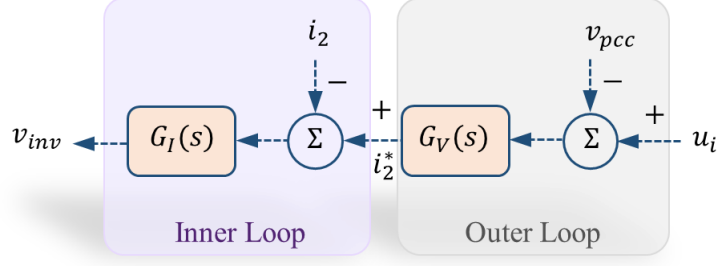


Figure 2.6: Simplified indirect control block diagram for GFM inverters.

Equations from (2.15) to (2.17) can be applied for the direct and indirect methods, shown in Figs 2.1 and 2.5. Thus, the signal flow graphs and corresponding transfer functions for both indirect and direct methods, considering the capacitive and inductive behaviors of rest of the grid, can be developed for eigenvalue analysis using Mason's Rule.

Developed Dynamic Model for Indirect GFM Control Method

In the simplified system shown in Fig 2.6, the transfer function can be obtained through Mason's Rule. In this simplified control diagram, the relationship between the input and output of inner and outer controllers can be expressed as

$$\begin{cases} i_2^* = G_V(s)(u_i - v_{pcc}) \\ v_{inv} = G_I(s)(i_2^* - i_2) \end{cases} \quad (2.18)$$

where, $G_V(s) = (K_{Pv}s + K_{Iv})/s$ and $G_I(s) = (K_{Pi}s + K_{Ii})/s$, as demonstrated in Fig. 2.6, are selected to be PI controllers to match with the type of controller implemented in the experiments.

Assuming the PCC Thevenin equivalent circuit being inductive, the signal flow graph (SFG) is constructed based on Eqs. 2.15, 2.16, and 2.18 as illustrated in Fig 2.7(a). The forward path, loop gains, and the non-touching loop gains are calculated below, respectively.

The forward path gain:

$$F = \frac{G_V G_I}{s^3 L_1 L_2 C_f} \quad (2.19)$$

The loop gains:

$$\left\{ \begin{array}{ll} L1 = -\frac{R_2}{sL_2}, & L2 = -\frac{R_{Th}}{sL_2}, \\ L3 = -\frac{L_{Th}}{L_2}, & L4 = -\frac{G_V G_I R_{Th}}{s^3 L_1 L_2 C_f}, \\ L5 = -\frac{1}{s^2 L_1 C_f}, & L6 = -\frac{R_1}{sL_1}, \\ L7 = -\frac{G_V G_I L_{Th}}{s^2 L_1 L_2 C_f}, & L8 = -\frac{1}{s^2 L_2 C_f}, \\ L9 = -\frac{G_I}{s^3 L_1 L_2 C_f} \end{array} \right. \quad (2.20)$$

Two non-touching loop gains:

$$\left\{ \begin{array}{ll} NL1 = L1 \times L6 = \frac{R_1 R_2}{s^2 L_1 L_2}, & NL2 = L2 \times L6 = \frac{R_1 R_{Th}}{s^2 L_1 L_2}, \\ NL3 = L3 \times L6 = \frac{L_{Th} R_1}{s L_1 L_2}, & NL4 = L1 \times L5 = \frac{R_2}{s^3 L_1 L_2 C_f}, \\ NL5 = L2 \times L5 = \frac{R_{Th}}{s^3 L_1 L_2 C_f}, & NL6 = L3 \times L5 = \frac{L_{Th}}{s^2 L_1 L_2 C_f}, \\ NL7 = L6 \times L8 = \frac{R_1}{s^3 L_1 L_2 C_f} \end{array} \right. \quad (2.21)$$

When the PCC Thevenin equivalent circuit exhibits capacitive characteristics, the signal flow graph can be constructed utilizing equations Eqs. 2.15 and 2.17, as depicted in Fig. 21(b). The forward path, loop, and non-touching loop gains are computed as follows: The forward path gain:

$$F = \frac{G_V G_I}{s^3 L_1 L_2 C_f} \quad (2.22)$$

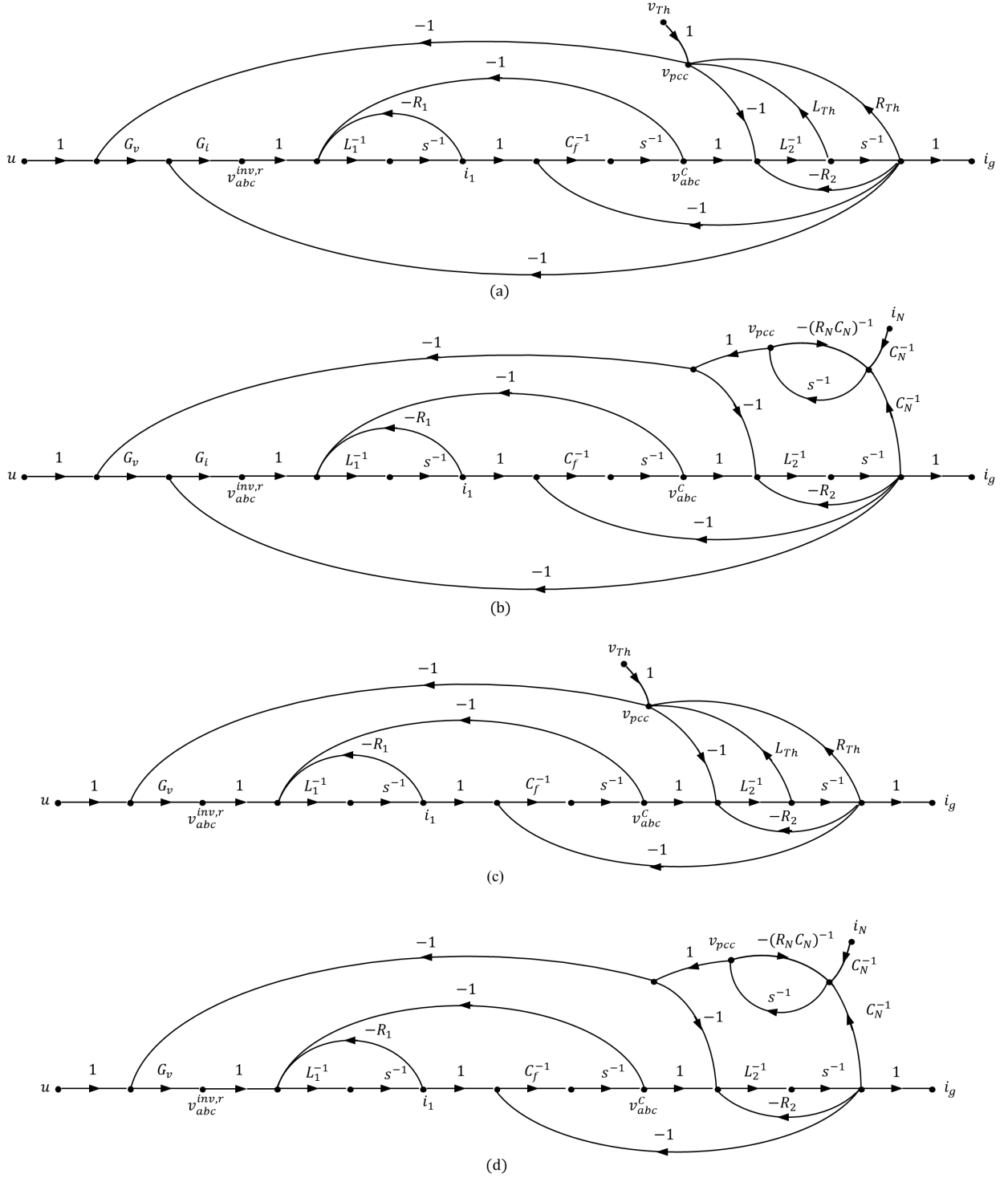


Figure 2.7: Signal flow graph representation for: (a) inductive and (b) capacitive equivalent circuits implementing the indirect method, as well as (c) inductive and (d) capacitive equivalent circuits implementing the direct method, all after syncing [2].

The loop gains:

$$\left\{ \begin{array}{ll} L1 = -\frac{R_2}{sL_2}, & L2 = -\frac{1}{s^2L_2C_N}, \\ L3 = -\frac{1}{sR_NC_N}, & L4 = -\frac{G_VG_I}{s^4L_1L_2C_fC_N}, \\ L5 = -\frac{1}{s^2L_1C_f}, & L6 = -\frac{R_1}{sL_1}, \\ L7 = -\frac{1}{s^2L_2C_f}, & L8 = -\frac{G_I}{s^3L_1L_2C_f} \end{array} \right. \quad (2.23)$$

Two non-touching loop gains:

$$\left\{ \begin{array}{ll} DL1 = L1 \times L6 = \frac{R_1R_2}{s^2L_1L_2}, & DL2 = L2 \times L6 = \frac{R_1}{s^3L_1L_2C_N}, \\ DL3 = L3 \times L6 = \frac{R_1}{s^2L_1R_NC_N}, & DL4 = L6 \times L7 = \frac{R_1}{s^3L_1L_2C_f}, \\ DL5 = L1 \times L3 = \frac{R_2}{s^2L_2R_NC_N}, & DL6 = L3 \times L7 = \frac{1}{s^3R_NL_2C_fC_N}, \\ DL7 = L3 \times L8 = \frac{G_I}{s^5L_1L_2R_NC_fC_N}, & DL8 = L3 \times L5 = \frac{1}{s^3L_1R_NC_fC_N}, \\ DL9 = L1 \times L5 = \frac{R_2}{s^3L_1L_2C_f}, & DL10 = L2 \times L5 = \frac{1}{s^4L_1L_2C_fC_N} \end{array} \right. \quad (2.24)$$

Three non-touching loop gains:

$$\left\{ \begin{array}{l} TL1 = L1 \times L3 \times L6 = -\frac{R_1R_2}{s^3L_1L_2R_NC_N} \\ TL2 = L1 \times L3 \times L5 = -\frac{R_2}{s^4L_1L_2C_fR_NC_N} \end{array} \right. \quad (2.25)$$

Hence, one can apply the Mason's Rule using the following expression.

$$H(s) = \frac{\sum_k F_k \times \Delta_k}{\Delta} \quad (2.26)$$

where, Δ_k represents the complete loop isolated from the k^{th} forward path. Given that there is only one forward path for each scenario, $\Delta_1 = 1$ in the inductive case, and $\Delta_1 = 1 - L3 = (sR_NC_N + 1)/sR_NC_N$ in the capacitive case. By applying the condition provided in Eq. 2.26,

one can deduce $H_{L,Indirect}(s)$ as follows:

$$H_{L,Indirect}(s) = \frac{a_1 s^2 + a_2 s + a_3}{a_4 s^5 + a_5 s^4 + a_6 s^3 + a_7 s^2 + a_8 s + a_9} \quad (2.27)$$

where, $\alpha_1 = K_{Pi}K_{Pv}$, $\alpha_2 = (K_{Pi}K_{Iv} + K_{Ii}K_{Pv})$, $\alpha_3 = K_{Ii}K_{Iv}$, $\alpha_4 = (C_f L_1 L_{Th} + C_f L_1 L_2)$, $\alpha_5 = (C_f L_1 R_{Th} + C_f L_1 R_2 + C_f L_{Th} R_1 + C_f L_2 R_1)$, $\alpha_6 = (L_1 + L_2 + L_{Th} + C_f R_1 R_{Th} + C_f R_1 R_2 + K_{Pi}K_{Pv}L_{Th})$, $\alpha_7 = (R_{Th} + R_1 + R_2 + K_{Pi} + K_{Iv}K_{Pi}L_{Th} + K_{Ii}K_{Pv}L_{Th} + K_{Pi}K_{Pv}R_{Th})$, $\alpha_8 = (K_{Iv}K_{Pi}R_{Th} + K_{Ii}K_{Iv}L_{Th} + K_{Ii}K_{Pv}R_{Th} + K_{Ii})$, and $\alpha_9 = K_{Ii}K_{Iv}R_{Th}$.

Similarly, $H_{C,Indirect}(s)$ can be derived as

$$H_{C,Indirect}(s) = \frac{b_1 s^3 + b_2 s^2 + b_3 s + b_4}{b_5 s^6 + b_6 s^5 + b_7 s^4 + b_8 s^3 + b_9 s^2 + b_{10} s + b_{11}} \quad (2.28)$$

where, $b_1 = K_{Pi}K_{Pv}R_N C_N$, $b_2 = (K_{Pi}K_{Pv} + K_{Pi}K_{Iv}R_N C_N + K_{Ii}K_{Pv}R_N C_N)$, $b_3 = (K_{Pi}K_{Iv} + K_{Ii}K_{Iv}R_N C_N)$, $b_4 = K_{Ii}K_{Iv}$, $b_5 = R_N C_N C_f L_1 L_2$, $b_6 = (R_2 R_N C_N C_f L_1 + R_1 R_N C_N C_f L_2 + C_f L_1 L_2)$, $b_7 = (R_1 R_2 R_N C_N C_f + R_1 C_f L_2 + R_2 C_f L_1 + C_f R_N L_1 + R_N C_N L_1 + R_N C_N L_2)$, $b_8 = (L_1 + L_2 + R_1 + R_1 R_2 C_f + R_N C_N K_{Pi} + R_1 R_N C_f + R_1 R_N C_N + R_2 R_N C_N)$, $b_9 = (K_{Pi}K_{Pv}R_N + R_N C_N K_{Ii} + R_N + R_2 + K_{Pi})$, $b_{10} = (K_{Iv}K_{Pi}R_N + K_{Ii}K_{Pv}R_N + K_{Ii})$, and $b_{11} = K_{Ii}K_{Iv}R_N$.

Thus, the inductive and capacitive circuit models for the indirect control method for grid-forming inverters are derived.

Developed Dynamic Model for Direct GFM Control Method

In the simplified system shown in Fig 2.8, the transfer function can be obtained using the Mason's Rule, similar to the indirect method. In this simplified control diagram, the relationship between the input and output of inner and outer controllers can be expressed as follows:

$$v_{inv} = G_V(s)(u_i - v_{pec}) \quad (2.29)$$

As the system remains the same, the signal flow graph for the inductive case is still constructed based on Eqs. 2.15, and 2.16. Only the applied controller transfer function, given in Eq. 2.29, is different for the direct control method as illustrated in Fig 2.7(c). The forward

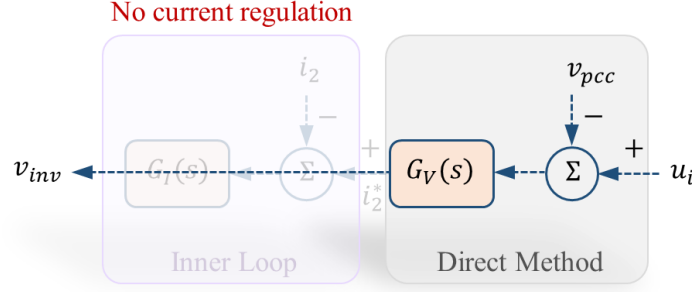


Figure 2.8: Simplified direct control block diagram for GFM inverters.

path, loop gains, and the non-touching loop gains for the simplified direct control scheme can be written as The forward path gain:

$$F = \frac{G_V}{s^3 L_1 L_2 C_f} \quad (2.30)$$

The loop gains:

$$\left\{ \begin{array}{ll} L1 = -\frac{R_2}{sL_2}, & L2 = -\frac{R_{Th}}{sL_2}, \\ L3 = -\frac{L_{Th}}{L_2}, & L4 = -\frac{G_V R_{Th}}{s^3 L_1 L_2 C_f}, \\ L5 = -\frac{1}{s^2 L_1 C_f}, & L6 = -\frac{R_1}{sL_1}, \\ L7 = -\frac{G_V L_{Th}}{s^2 L_1 L_2 C_f}, & L8 = -\frac{1}{s^2 L_2 C_f} \end{array} \right. \quad (2.31)$$

Two non-touching loop gains:

$$\left\{ \begin{array}{ll} NL1 = L1 \times L6 = \frac{R_1 R_2}{s^2 L_1 L_2}, & NL2 = L2 \times L6 = \frac{R_1 R_{Th}}{s^2 L_1 L_2}, \\ NL3 = L3 \times L6 = \frac{L_{Th} R_1}{s L_1 L_2}, & NL4 = L1 \times L5 = \frac{R_2}{s^3 L_1 L_2 C_f}, \\ NL5 = L2 \times L5 = \frac{R_{Th}}{s^3 L_1 L_2 C_f}, & NL6 = L3 \times L5 = \frac{L_{Th}}{s^2 L_1 L_2 C_f}, \\ NL7 = L6 \times L8 = \frac{R_1}{s^3 L_1 L_2 C_f} \end{array} \right. \quad (2.32)$$

One can notice that Eq. 2.21 and 2.32 are the same since the system remains the same.

For the capacitive PCC Thevenin equivalent circuit characteristics, the signal flow graph

can be derived using Eqs. 2.15 and 2.17, as depicted in Fig. 21(d). Thus, the gains can be written as:

$$F = \frac{G_V}{s^3 L_1 L_2 C_f} \quad (2.33)$$

The loop gains:

$$\left\{ \begin{array}{ll} L1 = -\frac{R_2}{s L_2}, & L2 = -\frac{1}{s^2 L_2 C_N}, \\ L3 = -\frac{1}{s R_N C_N}, & L4 = -\frac{G_V}{s^4 L_1 L_2 C_f C_N}, \\ L5 = -\frac{1}{s^2 L_1 C_f}, & L6 = -\frac{R_1}{s L_1}, \\ L7 = -\frac{1}{s^2 L_2 C_f} \end{array} \right. \quad (2.34)$$

Two non-touching loop gains:

$$\left\{ \begin{array}{ll} DL1 = L1 \times L6 = \frac{R_1 R_2}{s^2 L_1 L_2}, & DL2 = L2 \times L6 = \frac{R_1}{s^3 L_1 L_2 C_N}, \\ DL3 = L3 \times L6 = \frac{R_1}{s^2 L_1 R_N C_N}, & DL4 = L6 \times L7 = \frac{R_1}{s^3 L_1 L_2 C_f}, \\ DL5 = L1 \times L3 = \frac{R_2}{s^2 L_2 R_N C_N}, & DL6 = L3 \times L7 = \frac{1}{s^3 R_N L_2 C_f C_N}, \\ DL7 = L3 \times L5 = \frac{1}{s^3 L_1 R_N C_f C_N}, & DL8 = L1 \times L5 = \frac{R_2}{s^3 L_1 L_2 C_f}, \\ DL9 = L2 \times L5 = \frac{1}{s^4 L_1 L_2 C_f C_N} \end{array} \right. \quad (2.35)$$

Three non-touching loop gains:

$$\left\{ \begin{array}{l} TL1 = L1 \times L3 \times L6 = -\frac{R_1 R_2}{s^3 L_1 L_2 R_N C_N} \\ TL2 = L1 \times L3 \times L5 = -\frac{R_2}{s^4 L_1 L_2 C_f R_N C_N} \end{array} \right. \quad (2.36)$$

The same voltage controller used for the direct methods, i.e., droop and virtual-inertia, see Fig. 2.1, is selected for the simplified direct controller. Therefore, $G_V(s)$ can be rewritten as $G_V(s) = \Delta v_{inv}/u = (K_{P_v}s + K_{I_v})/s$. Similar to the indirect control, one can derive the

coefficients of $H_{L,Direct}(s) = i_2/u$ as:

$$H_{L,Direct}(s) = \frac{n_1s + n_2}{n_3s^4 + n_4s^3 + n_5s^2 + n_6s + n_7} \quad (2.37)$$

where, $n_1 = K_{Pv}$, $n_2 = K_{Iv}$, $n_3 = (C_f L_1 L_{Th} + C_f L_1 L_2)$, $n_4 = (C_f L_1 R_{Th} + C_f L_1 R_2 + C_f L_{Th} R_1 + C_f L_2 R_1)$, $n_5 = (L_1 + L_2 + L_{Th} + C_f R_1 R_{Th} + C_f R_1 R_2 + K_{Pv} L_{Th})$, $n_6 = (R_{Th} + R_1 + R_2 + K_{Iv} L_{Th} + K_{Pv} R_{Th})$, and $n_7 = K_{Iv} R_{Th}$.

Then, $H_{C,Direct}(s) = i_2/u$, can be derived as;

$$H_{C,Direct}(s) = \frac{m_1s^2 + m_2s + m_3}{m_4s^5 + m_5s^4 + m_6s^3 + m_7s^2 + m_8s + m_9} \quad (2.38)$$

where, $m_1 = K_{Pv} R_N C_N$, $m_2 = (K_{Iv} R_N C_N + K_{Pv})$, $m_3 = K_{Iv}$, $m_4 = R_N C_N C_f L_1 L_2$, $m_5 = (R_2 R_N C_N C_f L_1 + R_1 R_N C_N C_f L_2 + C_f L_1 L_2)$, $m_6 = (R_1 R_2 R_N C_N C_f + R_1 C_f L_2 + R_2 C_f L_1 + C_f R_1 L_N + R_N C_N L_1 + R_N C_f L_1 + R_N C_N L_2)$, $m_7 = (L_1 + L_2 + R_1 R_2 C_f + R_1 R_N C_f + R_1 R_N C_N + R_2 R_N C_N)$, $m_8 = (K_{Pv} R_N + R_N + R_2)$, and $m_9 = K_{Iv} R_N$. Notice that $i_g = i_2$, see Fig. 2.7.

Derivation of $H_{L,Indirect}(s)$, $H_{C,Indirect}(s)$, $H_{L,Direct}(s)$, and $H_{C,Direct}(s)$ completes the dynamic model development process. These simplified models provide a platform to observe and compare the performance of each controller under different scenarios with simulation studies, provided in the next section.

2.4 Synchronization of GFM Inverters

It is essential to synchronize an incoming inverter with the other power generation units in the system to achieve smooth transitions during connection and avoid trips in the inverter. For the comparison study, the output-sync technique is utilized [20] to synchronize both inverters with each other. The block diagram representation of the output-sync method and its adjustment terms are demonstrated in Fig. 2.9. This method requires sensors on both side of the circuit breaker (CB), see Fig. 2.3. When the CB is open, $P = 0$ and $Q = 0$. Thus, $V^* = V_n$ and $\theta_{inv}^* = \theta_n$, while the rest of the grid might be at a different voltage magnitude

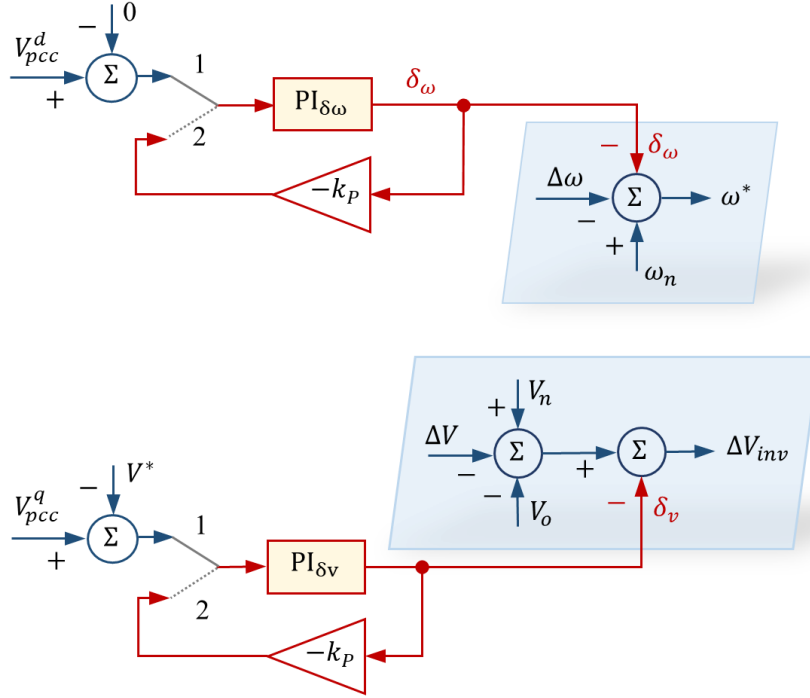


Figure 2.9: The output-sync method for synchronization implemented in direct or indirect control for GFM inverters.

and frequency if a load is connected. To achieve synchronization, the voltage and frequency adjustment terms, i.e., δ_v and δ_ω , respectively, are introduced using two PI-based regulators, $PI_{\delta\omega}$ and $PI_{\delta v}$. This can be mathematically expressed as:

$$\begin{cases} \omega^* = \omega_n - \Delta\omega - \delta_\omega \\ \Delta V_{inv} = V_n - \Delta V - \delta_v \end{cases} \quad (2.39)$$

After the synchronization process is finished, and the circuit breaker (CB) is closed, the adjustment settings are reset to their initial state. This is done by changing the position of the state switches from 1 to 2, as shown in Fig. 2.9.

2.5 Performance Comparison

The controller performance comparison between the direct and indirect methods is carried out in terms of simulation studies using the developed dynamic model for eigenvalue analysis and hardware experiments. First, the microgrid system under study is explained in detail.

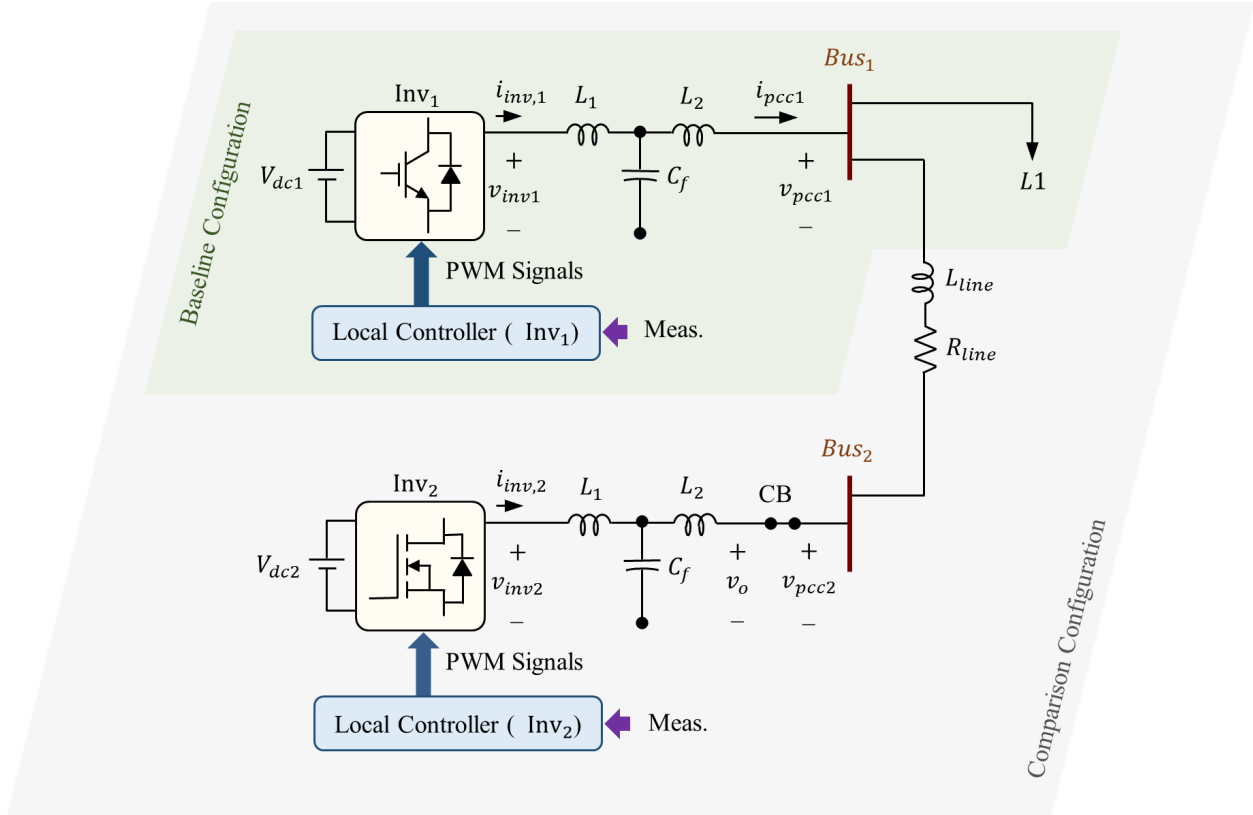


Figure 2.10: A single-line diagram demonstration of the system under study after the inverters have been synchronized, featuring two grid-forming inverters, Inv₁ and Inv₂.

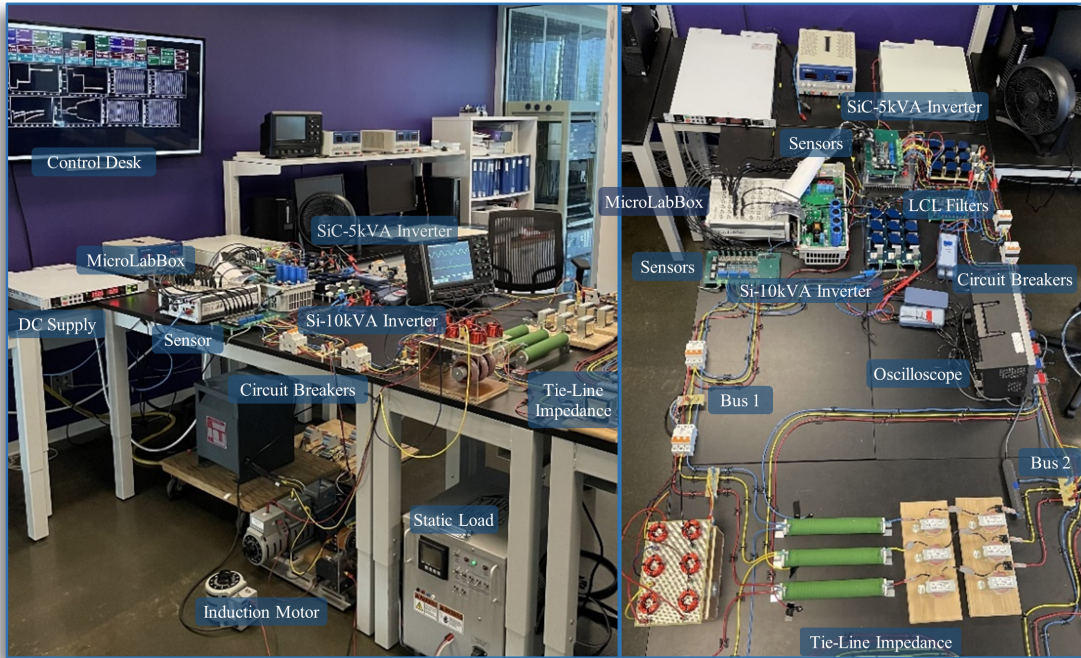


Figure 2.11: The experimental laboratory-scale microgrid test setup, consisting of: (left) a side-view and (right) a bird's-eye view.

Table 2.1: System parameters.

Parameters	Value
Filter inductance (L_1)	1 mH
Filter capacitance (C_f)	5 μ F (Δ)
Filter cap. series resistance (R_{cf})	1.65 Ω
Coupling inductance (L_2)	0.5 mH
Line inductance (L_{line})	5 mH
Line resistance (R_{line})	1 Ω
Nominal frequency (ω_n)	377 rad/s
Nominal voltage (V_n)	208/ $\sqrt{3}$ V
PWM switching frequency (f_{PWM})	5 kHz
DC-bus voltage (V_{dc})	350 V
Droop gain (m_P)	0.005
Droop gain (m_Q)	0.001
Outer loop gains	$K_{Pv_q} = K_{Pv_d} = 1.2$
	$K_{Iv_q} = K_{Iv_d} = 0.2$
Inner loop gains	$K_{Pi_q} = K_{Pi_d} = 5$
	$K_{Ii_q} = K_{Ii_d} = 2$

The experimental setup is depicted in Fig. 2.10, which illustrates a single-line diagram featuring two inverters and one static load. Details of the system and selected controller parameters for the baseline conditions are available in Table 2.1. The inverters were considered to be linked via a tie-line, i.e., R_{line} and L_{line} . The tie-line is emulated using a set of inductors and resistors for the hardware experiments. By using a tie-line, it is indicated that inverters are connected in different buses (not in parallel configuration) and do not share the same bus voltage.

In this setup, as shown in Fig. 2.11, the Si-IGBT inverter is rated for 10 kVA, and SiC-Mosfet inverter is rated for 5 kVA. A 5 kW switching load is used for the test scenarios. Each inverter comes with an LCL filter, sensors for voltage and current measurement, and circuit breakers. The dSPACE 1202 MicroLabBox controllers generates the PWM signals needed for the experiment. Once the inverters are synchronized, the experimental tests begin, concentrating on evaluating the dynamic performance of both direct and indirect

methods. Data collection is conducted through the dSPACE ControlDesk and visualized with MATLAB.

The Benchmarking

As the beginning point, the direct and indirect controllers are tuned using a single inverter, i.e., Inv_1 , to dynamically perform nearly identical. In other words, controller parameters of both techniques are adjusted so that the behavior of Inv_1 , when controlled by the indirect method, closely aligns with its behavior under the direct method during load step changes. This adjustment provides a baseline scenario for sensitivity analysis to observe the effect of each change that will be implemented in the controllers. The controller gain settings at the nearly identical dynamic performance conditions are recorded in Table 2.1. There is no load connection or sharing in the system, $P = 0$, before a 1 kW switched load connection is performed.

Using these gain settings, it is demonstrated in Fig. 2.12 that nearly the same dynamic performance is achieved using direct and indirect controllers, individually. The performance results are shown in Fig. 2.12 for P , ω , and v_{pcc} during connecting and disconnecting a 1kW load to the system. The inertia constant is selected to be nearly zero to achieve droop-like performance to allow more transients due to almost zero-inertia in the system during comparison. Table 2.2 displays various parameters when the load is switched in at $t = 2s$: the maximum percentage change in voltage at the PCC, ΔV_{pcc} , the time period until V_{pcc} recovers to 95% of the nominal voltage denoted as τ_V , the percentage change in frequency, $\Delta\omega$, and the fall-time until the angular frequency reaches 90% of its new steady-state value, denoted as τ_ω . The results indicate that the selected controller gains yield similar dynamic behavior for a 1 kW change in the load. Further analysis can be conducted to determine

Table 2.2: Baseline tuning performance when the load is switched [2].

Controller	ΔV_{pcc}	$\Delta\omega$	τ_V	τ_ω
Indirect	2.30	1.27	510	18.3
Direct	2.48	1.27	590	20.4

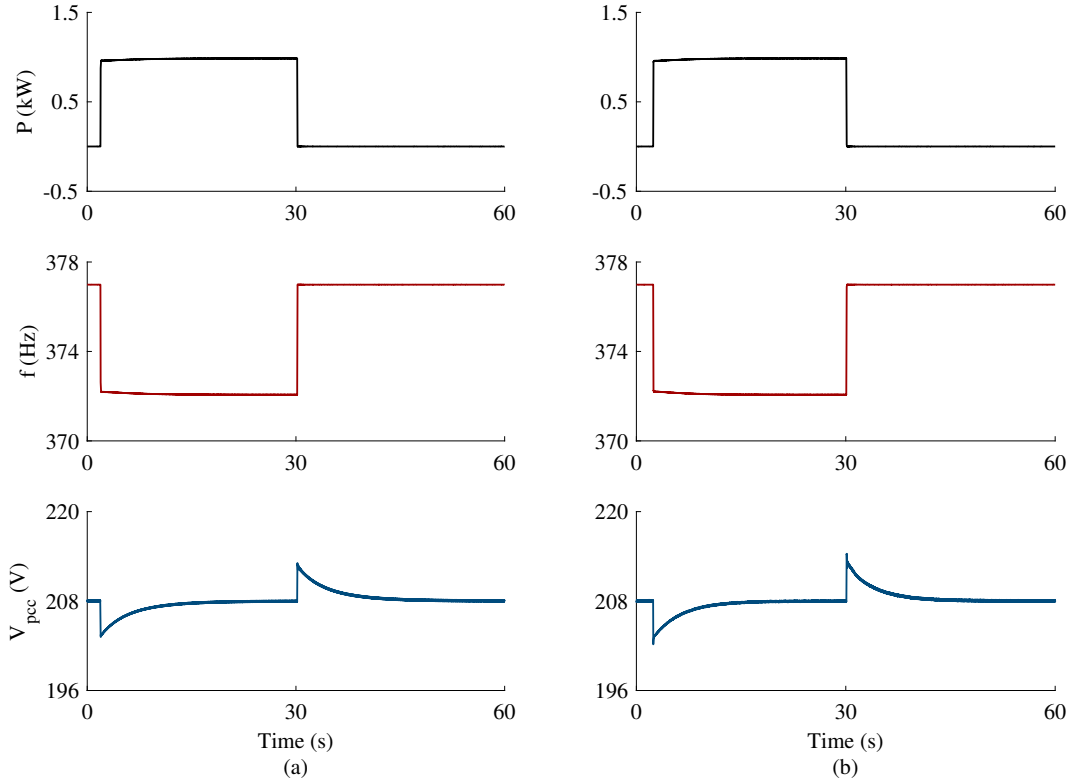


Figure 2.12: Experimental obtained baseline comparison performance of two control methods: (a) the indirect and (b) direct methods [2].

the responsiveness of the controllers to different controller gains and dynamic loads. The subsequent test scenarios involves the comparison configuration demonstrated in Fig. 2.10.

Sensitivity Analysis for Different Controller Gain Settings

Since the controllers are tuned to dynamically perform nearly identical, the following scenarios are applied to identify the sensitivity of direct and indirect controllers to different gain settings. During these scenarios, both inverters are connected to the system, and they are synchronized. Each inverter is equipped with the same grid-forming control method.

The first test of controller gain sensitivity commence by comparing voltage regulation performance of direct and indirect controllers. The indirect controller outer loop (voltage regulator) gain coefficients, i.e., $K_{Pv_q} = K_{Pv_d}$ and $K_{Iv_q} = K_{Iv_d}$, are systematically raised from their initial baseline values, listed in Table 2.1, up to 125%, with each increment being 25%,

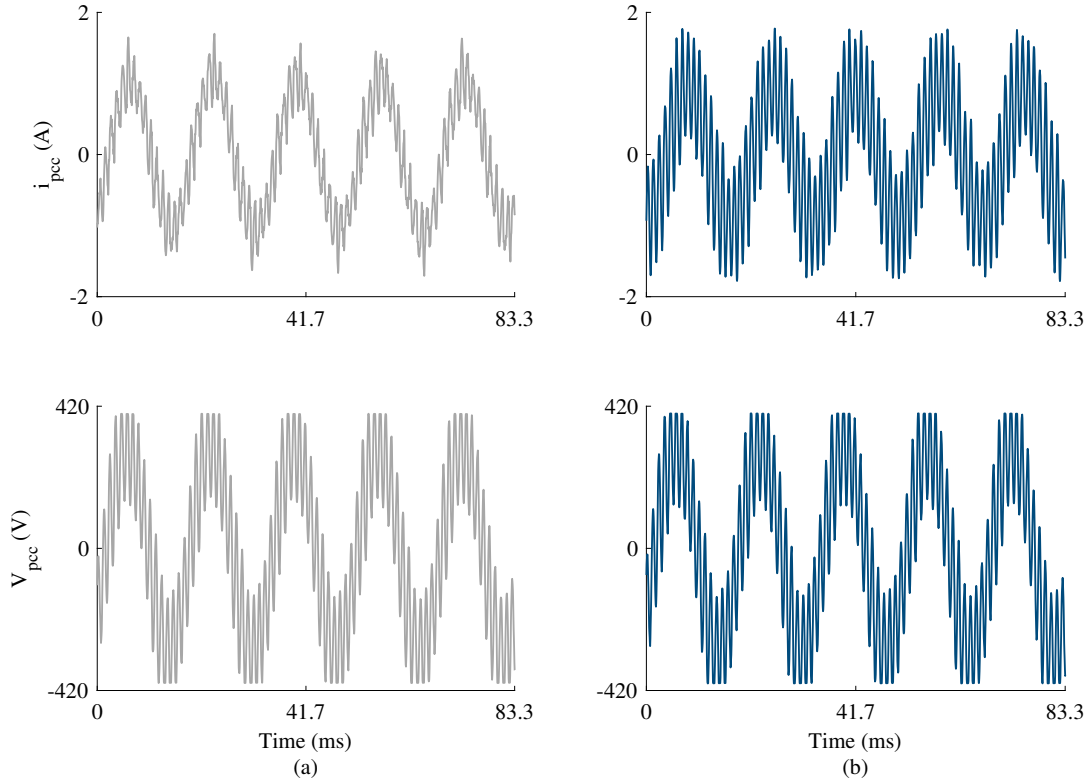


Figure 2.13: Experimental results for i_a and v_{ab} when outer loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].

while the inner loop (current regulator) coefficients of the indirect method are maintained at their baseline values. At the 125% increase from their base values, the steady-state behavior of i_{pcc} , v_{pcc} , P , and Q is shown in Figs. 2.13 and 2.14 for 50 ms (three electrical cycles). The results indicate a high-frequency oscillation in the system with the oscillation frequency of $(2\pi/0.00096 = 6545 \text{ rad/s})$. This oscillation can be elaborated through eigenvalue analysis using the simplified reduced-order model of the indirect control method, $H_{L,Indirect}(s)$ and $H_{C,Indirect}(s)$. One can see that the Q measured at PCC_1 is negative, whereas at PCC_2 , it is positive, as depicted in Fig 2.14(right). This indicates that the load seen from PCC_1 is inductive, absorbing Q , while it is seen as capacitive at PCC_2 , supplying Q . This reactive power distribution is needed between inverters to regulate the PCC voltages. The characteristic equation of the system (denominator of the transfer functions), provided in Eq. 2.27 and Eq. 2.28, the dynamic behavior of the system can be observed.

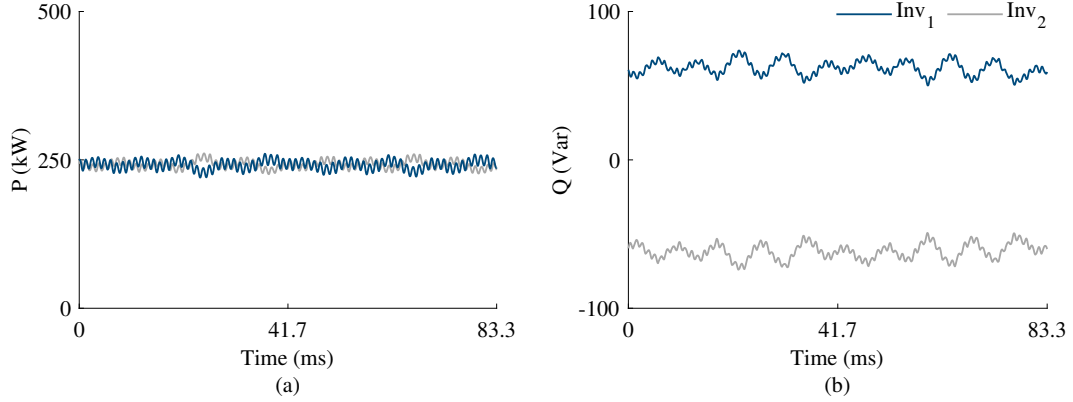


Figure 2.14: Experimental results for P and Q when outer loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].

Considering the capacitive case first (the Norton equivalent circuit), the voltage regulator gain coefficients are varied as $K_{P_v} \rightarrow [0.2, 0.5]$ and $K_{P_i} \rightarrow [0.2, 0.5]$ with 100 samples. When the outer loop coefficients are raised to 125%, the high-frequency poles, λ_3 and λ_4 , approach the stability boundary and become unstable if the gains are further elevated to 150% of their baseline values. An oscillation frequency of 67.3×10^3 rad/s is observed at a 125% increase, as shown in Fig. 2.15. Unlike the high-frequency poles, the low-frequency poles, λ_1 and λ_2 shift towards more stable region as the outer loop gains are increased, see Fig. 2.15. Accuracy of the analysis can be improved if full-order model of the system is used. However, the computational burden and processing time are the major drawbacks of using full-order model.

In the scenario with an inductive Thevenin equivalent circuit, as opposed to the capacitive case, the eigenvalues of $H_{L,Indirect}(s)$ remain stable despite similar increases in both inner and outer loop coefficients. This stability is evident in the results for the inductive scenario shown in Figs 2.16, which depict changes in outer loop gains. The oscillation frequency, as determined by the simplified model, is observed to be $(47.3 \times 10^3$ rad/s). It's important to note that the fifth eigenvalue, λ_5 , is located near -6000 on the real axis and continues to move further left (stable region) as the gains increase.

On the other hand, the controller gains, K_{P_v} and K_{I_v} , of $G_v(s)$ for direct control method, shown in Fig. 2.1, are incrementally adjusted above their baseline values, reaching up to 125%

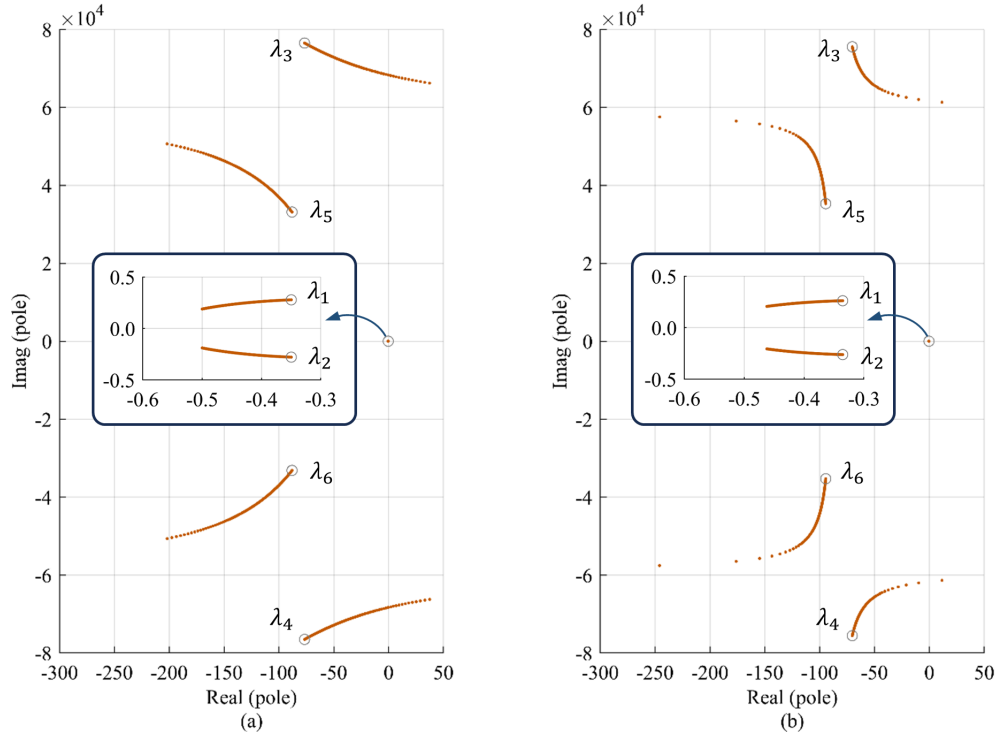


Figure 2.15: Eigenvalue analysis using the capacitive dynamic model when (a) outer and (b) inner loop coefficients of indirect method are increased [2].

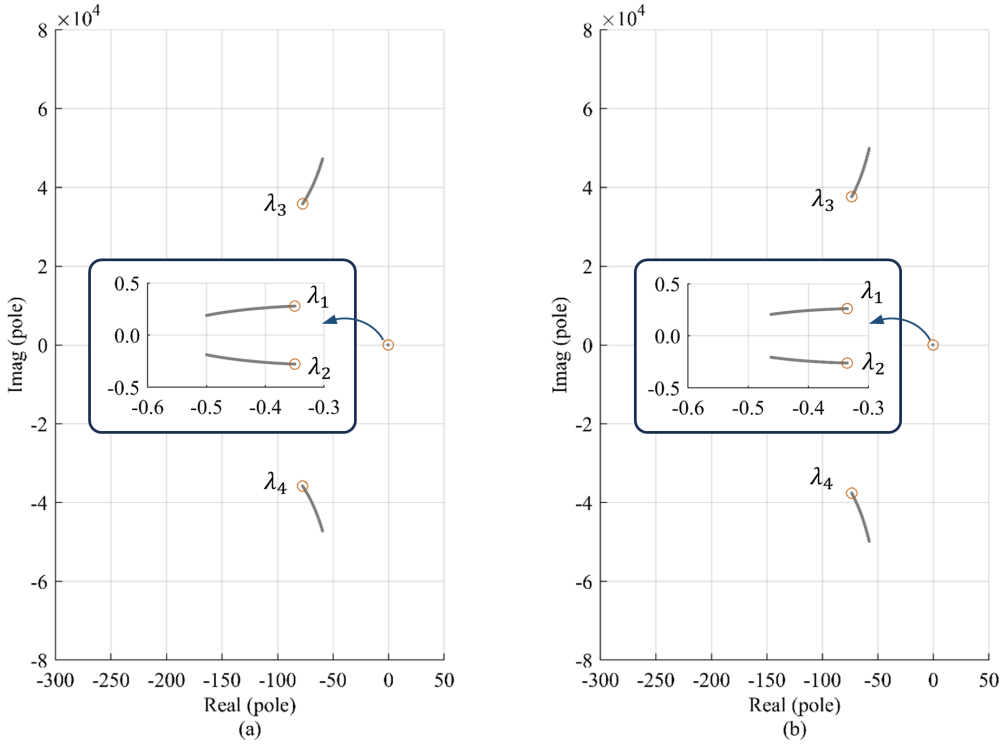


Figure 2.16: Eigenvalue analysis using the inductive dynamic model when (a) outer and (b) inner loop coefficients of indirect method are increased [2].

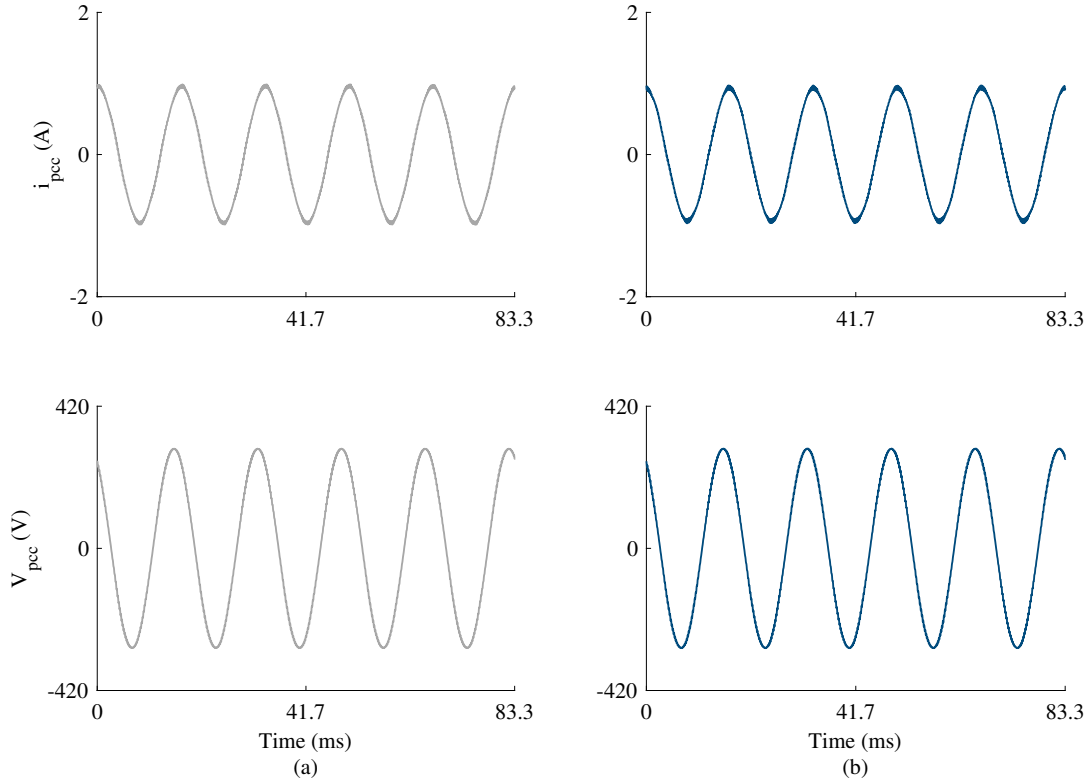


Figure 2.17: Experimental results for i_a and v_{ab} when voltage regulator gains of the direct method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].

in steps of 25%. Figs. 2.17 and 2.18 display the behavior of i_{pcc} , v_{pcc} , P , and Q for 50 ms (three electrical cycles) when K_{P_v} and K_{I_v} are set at 125% of their baseline values. These figures reveal that the direct method does not exhibit high-frequency oscillations at this same rate of adjustment unlike the indirect method illustrated in Figs. 2.13 and 2.14. It's noteworthy that increasing the outer loop coefficients of the indirect controller may greatly enhance the presence of higher-order harmonics and may result in harmonic instability.

Figs. 2.19 depict the dynamic behavior of the system when the direct method is applied to capacitive and inductive equivalent circuits, using the simplified transfer functions $H_{C, \text{Direct}}$ and $H_{L, \text{Direct}}$, respectively. Fig. 2.19(a) demonstrates that increasing K_{P_v} and K_{I_v} to 150% of their baseline values for capacitive case, see to Table 2.1 for baseline conditions, does not significantly impact the high- and low-frequency eigenvalues. Additionally, the low-frequency eigenvalue, λ_1 , shifts towards a more stable region in both capacitive and inductive scenarios.

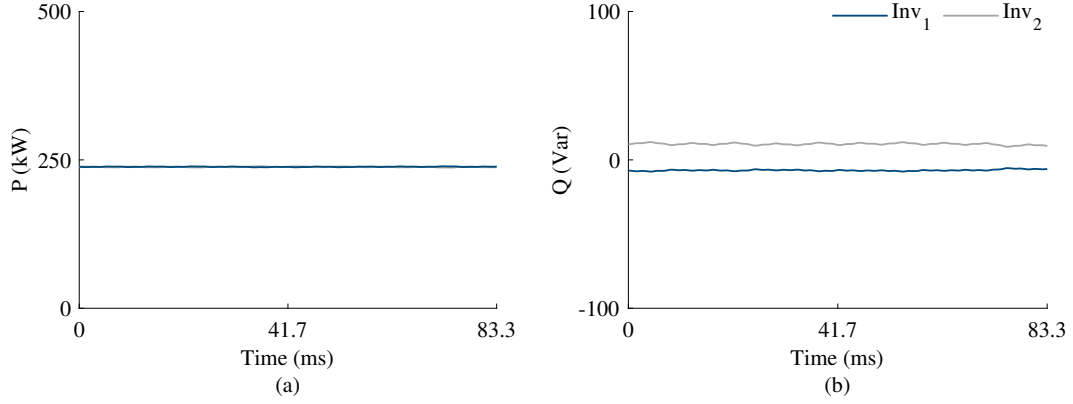


Figure 2.18: Experimental results for P and Q when voltage regulator gains of the direct method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].

The fourth eigenvalue in Fig. 2.19(b) is located near -5978 rad/s and is moving towards a more stable region, similar to the inductive case in the cascaded control.

The impact of varying the inner current control loop coefficients, $K_{P_{i_q}} = K_{P_{i_d}}$ and $K_{I_{i_q}} = K_{I_{i_d}}$, on voltage and current is investigated by incrementally increasing these coefficients of $G_{I_q}(s)$ and $G_{I_d}(s)$, to 125% of their baseline values in 25% steps, while maintaining the voltage loop coefficients at their baseline settings. Findings of Fig. 2.20 indicate that elevating the gains to 125%, which means setting $K_{P_{v_q}} = K_{P_{v_d}} = 11.25$ and $K_{I_{v_q}} = K_{I_{v_d}} = 4.5$

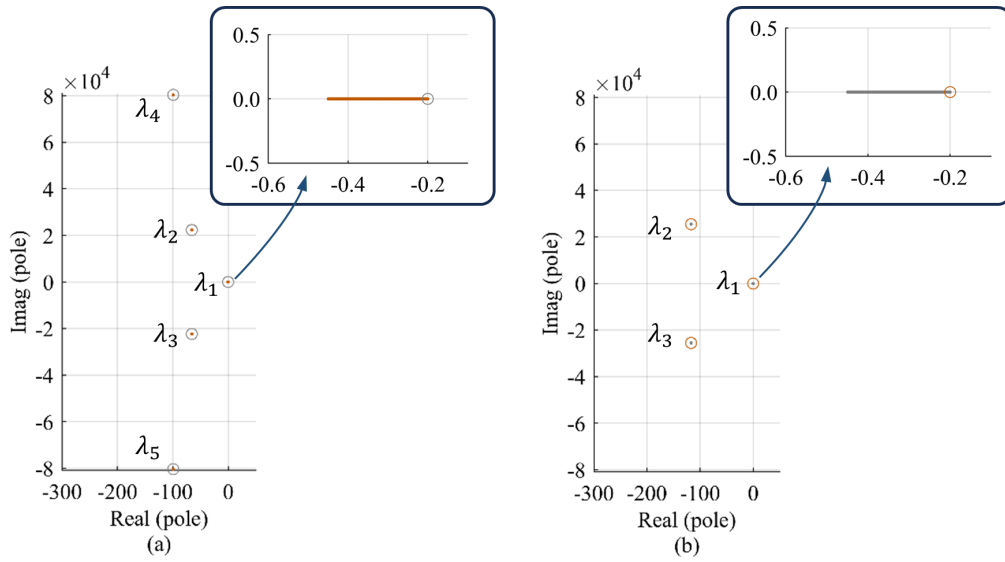


Figure 2.19: Eigenvalue analysis using (a) capacitive and (b) inductive dynamic model when outer loop coefficients of direct method are increased [2].

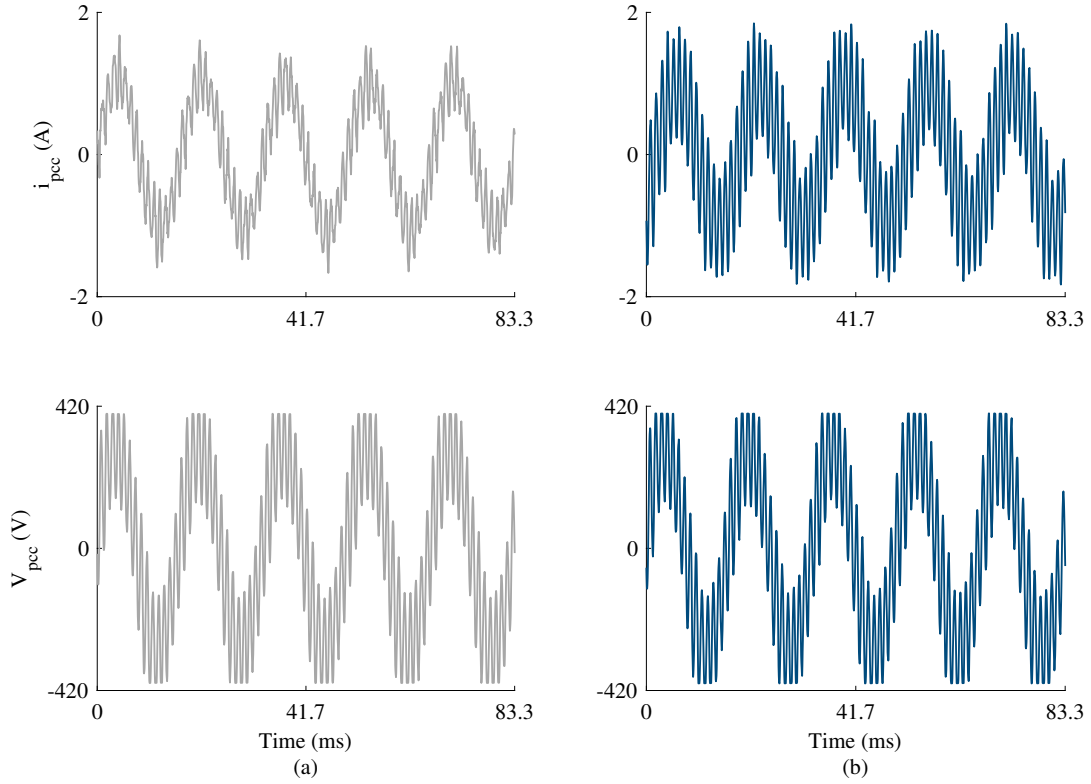


Figure 2.20: Experimental results for i_a and v_{ab} when inner loop gains of indirect method are increased by 125%: for (a) Inv_1 and (b) Inv_2 [2].

in $G_{Iq}(s)$ and $G_{Id}(s)$, leads to high-frequency oscillation of $(2\pi/0.0011) = 5628$ rad/s. However, one can notice that such high-frequency oscillations are not observed when employing the direct method since there is no inner loop controller employed, see Fig. 2.17. Generally, the inner loop is designed to be much faster than the outer loop, but excessively increasing the inner loop coefficients can adversely affect the system's performance.

Fig. 2.15(b) shows the effects of increasing only the inner loop gains, $K_{Pi} \rightarrow [5, 12.5]$ and $K_{Ii} \rightarrow [2, 5]$ with 100 samples for the capacitive Norton equivalent circuit. The high-frequency poles, λ_3 and λ_4 , approach the stability boundary as the inner current control loop coefficients are raised to 125%. They become unstable if the gains are further escalated to 150% of their baseline values, see Table 2.1. An oscillation frequency of 62.3×10^3 rad/s is observed at a 125% increase, as depicted in Fig. 2.15(b).

In contrast to the capacitive scenario, when considering the inductive Thevenin equivalent

circuit, the eigenvalues of $H_{L, \text{ Indirect}}(s)$ maintain stability even with the same level of increase in the inner loop coefficients. This stability is evident in the results for the inductive scenario shown in Figs 2.16(b), which depict changes in inner loop gains. The oscillation frequency recorded from the simplified model is 50.8×10^3 rad/s. Notably, The fifth eigenvalue, λ_5 resides around -6000 on the real axis and continues to move leftward with increased gains, similar to the case in Fig 2.16(b).

Results provided in Figs. 2.13, 2.15, and 2.16 highlight the critical need for precise tuning of parameters in the indirect control approach. For instance, it is necessary for the inner current loop to operate at a significantly higher speed than the outer loop, but excessive increase in the inner loop coefficients can cause high-frequency instability. Likewise, enhancing the coefficients of only the outer voltage control loop, while still maintaining a faster inner loop operation, may lead to the generation of high-frequency harmonics in the current and voltage waveforms at the (PCC). Lowering the gains of the outer loop tends to decelerate voltage regulation. However, overly reducing these coefficients might result in the inverter's inability to effectively regulate voltage, particularly in situations during transients when mode of operation is changed or with connection of inductive and dynamic loads, such as induction motors.

2.6 Insights and Discussions

In the precious sections, two commonly used GFM control methods, i.e., droop and cascaded control methods, are compared through experimental and simulation studies. It must be emphasized that the term "direct" refers to the control strategies where inverter reference PWM signals are generated by a single controller, achieving a voltage-controlled operation. On the other hand, indirect control method indicates that the PWM reference signals are generated indirectly using two or more cascaded control structures, typically to allow current regulation. After comparing direct (droop) control method with indirect (cascaded) control method, the analyses of the outcomes, performed in the previous sections, can be summarized as follows:

- Analyses in the literature typically view the system from the perspective of the inverter terminals as having inductive characteristics. However, in microgrids with multiple inverters, these inverters can exchange reactive power to control their Point of Common Coupling (PCC) voltages, leading to conditions where the system may act as a capacitive equivalent circuit for inverters that are absorbing reactive power. This research has shown that a capacitive system behavior seen from the inverters can increase the system's sensitivity to minor adjustments in controller coefficients, more than with an inductive system equivalent. This issue escalates into a significant challenge as the number of inverters within the system grows.
- Indirect control method requires a diligent tuning process as the controller's maximum operational speed is limited with the bandwidth of the most inner controller. Although the outer loop can be designed to react faster to regulate a desired quantity, a proper regulation cannot be achieved if inner loop coefficients are not selected properly.
- Increased number of controller parameters will make the tuning process more challenging for the indirect control strategies. To identify proper gain coefficients, one may need to perform dynamic analyses such as eigenvalue analysis or bode response of the system, which are recommended to select proper initial controller parameters regardless of the control methodology. As the controller gets more sophisticated, computational burden to calculate proper gain values will be significant.
- Typically, inner loop coefficients are chosen to be at least 10 to 20 times greater than the outer loop coefficients, varying with the application. Increasing the gain coefficients of PI controllers accelerates the regulation of the desired quantity. However, the findings confirmed that the system's high-frequency eigenvalues (also verified by the experimental procedures) could approach the boundary of instability, and even a minor change in the inner loop coefficients of the indirect controller can intensify higher-order harmonics. Likewise, augmenting the outer loop coefficients of the indirect controller substantially increases higher-order harmonics.
- The results showed that implementing a direct GFM control method allows significantly more flexibility for control parameter selection, which ease the tuning process.

The indirect control method performed abnormally for 125% increase in the gain parameters, while a normal operation is maintained even above 400% increase in direct control gains.

2.7 Conclusion

The indirect method utilizes two or three cascaded stages to produce the reference signal sent to the PWM generator, in contrast to the single-stage approach of the direct method. In other words, the reference signals are directly adjusted by the desired inputs, which can be voltage, power, etc., when direct control method is implemented. Upon comparing the performance and sensitivity of these two methods, it has been observed that the direct method generally outperforms the indirect method in various studies. Experimental findings and eigenvalue analysis demonstrate that in the indirect method, increasing the gain parameters of either the inner or outer loop beyond 125% can lead to the appearance of higher-order harmonics. Furthermore, amplifying these parameters beyond a 150% increase might cause system instability. In contrast, similar adjustments in the direct method do not seem to significantly affect the system. Effectiveness of the indirect control method is reliant on accurately choosing controller gains compared to the direct method.

Chapter 3

Inrush Current Mitigation

This chapter discusses the inrush current mitigation performance of the direct and indirect grid-forming inverter control methods. Inductive and dynamic loads, like induction motors (IM), are commonly available in most microgrids. The connection of a large inductive load, such as an induction motor, to a microgrid can result in high inrush currents, especially when voltage regulation at the PCC is strict. In the absence of a soft-start technique, this may cause grid-forming inverters to trip due to overloading. Higher power rated inverters and equipment are not preferred to address this tripping issue and protect the system from being damaged since the system cost may significantly increase. Therefore, a cost-effective solution, i.e., an enhanced control method with a flexible voltage regulation, is essential to reduce inrush currents (nearly five or six times the nominal value during connection) and maintain power availability while protecting the equipment in the system.

The details of the direct and indirect controllers on inrush current mitigation are discussed in Sections (3.1) and (3.2), respectively. Since the indirect control concept inherently have flexibility of current control, a virtual reactance technique is developed for the direct control method to mitigate inrush currents by providing more flexible voltage control without requiring an inner current loop. The developed method also includes a voltage recovery technique to zero the voltage drop caused by the virtual reactance. The effectiveness of the control methods and developed methodology were experimentally evaluated using a laboratory-scale

microgrid setup, powered by multiple inverters and an induction motor in Section (3.3). The study begin with the impact of the basic direct and indirect GFM control methods with baseline settings, where both inverters achieve nearly the same dynamic performance under the same change in the load, on mitigating inrush currents at inverters' PCCs. Then, the efficacy of the developed direct inrush current technique is demonstrated. The findings from these tests are subsequently presented. The statistical results are also provided performance comparison between both control methods. The chapter is concluded with final remarks in Section (3.5).

3.1 Inrush Current Mitigation Using Direct Control

Droop and virtual inertia control methods similarly regulate the inverter voltages at their PCCs as described in Section (2.1), using a PI controller as $G_v(S)$, see Fig. 2.1. This procedure involves determining the desired inverter terminal voltage, represented as V_{inv}^* , from the $Q - V$ droop relationship described in Eq. 2.1. This is done to achieve reactive power-sharing among the inverters. Herein, a smaller m_Q value maintains the PCC voltage more consistent near the nominal value, leading to a strict voltage regulation. However, a level of voltage variation is allowed by the standards defined by IEEE Std. 1547 [16], and this can be leveraged to reduce the PCC voltage during the motor connection, which may result in reduced inrush currents.

Virtual reactance technique is a common method which is mainly used to mitigate the fault currents, discussed in Subsection 1.2.4. However, inrush currents should not be confused with the fault currents, and the PCC voltage must be maintained within the permissible range during operation to avoid disconnection of inverters from the system. To facilitate flexible voltage adjustment, virtual impedance or reactance techniques can be utilized for the direct controller, as shown in Fig. 3.1 such that the output of $G_v(s)$ of the i^{th} inverter can be modified as follows:

$$V_{inv}^* = G_v(V_n - \Delta V - V_{pcc}) - \Delta v_t \quad (3.1)$$

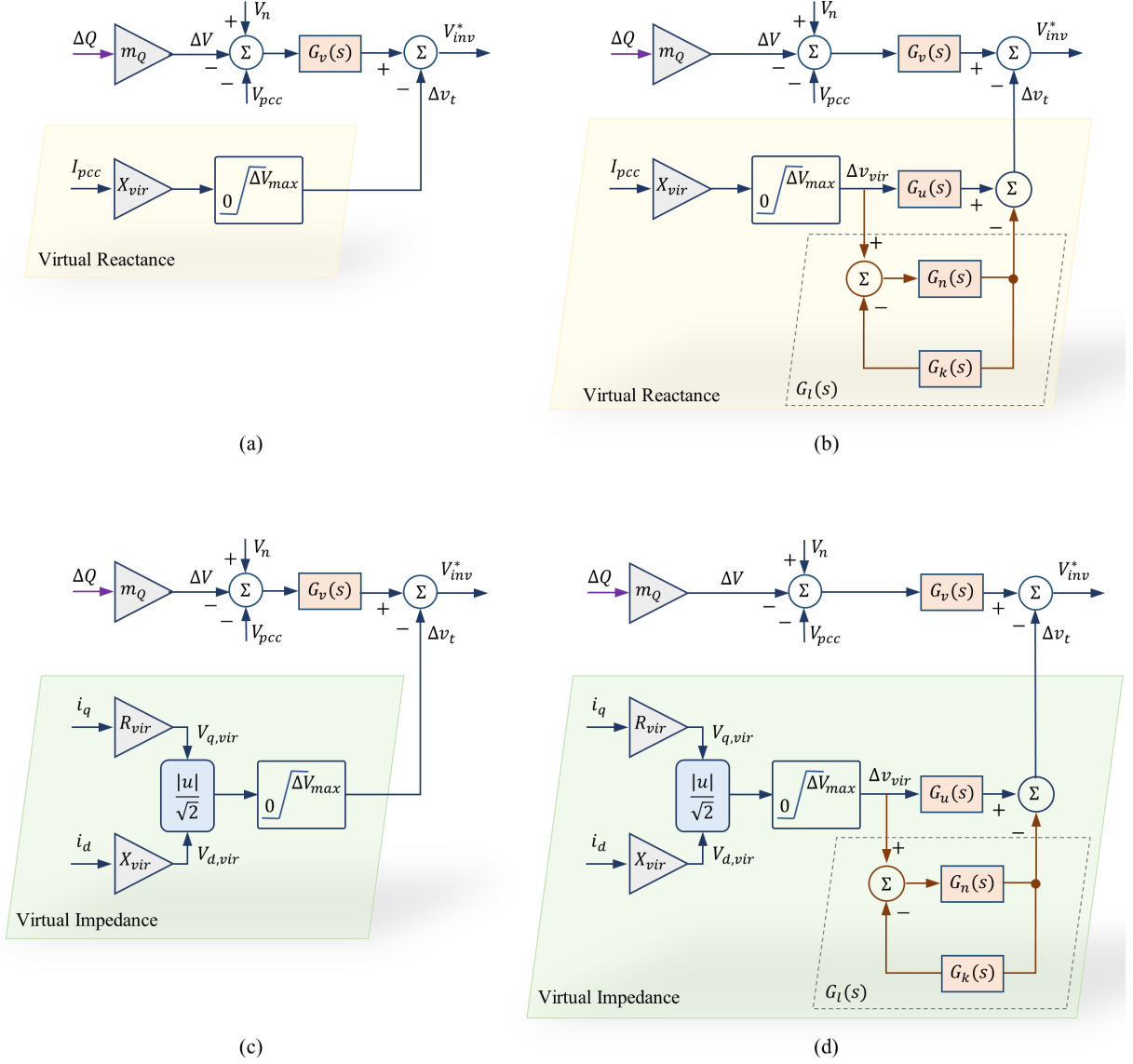


Figure 3.1: Inrush current mitigation concept for direct GFM control method, where (a) virtual reactance (b) with voltage recovery and (c) virtual impedance (d) with voltage recovery techniques are used.

where, Δv_t is a function of the inverter output current, i.e.,

$$\Delta v_t = X_{vir} |I_{pcc}| \quad (3.2)$$

where, $I_{pcc} = \sqrt{(i_q^2 + i_d^2)/2}$ is the magnitude of the current sourced by the inverter when synchronous dq -frame is used, and X_{vir} indicates the virtual reactance, see Fig. 3.1(a). In $Q - V$ droop control, voltage is associated with the reactive power as long as $X \gg R$. Therefore, virtual reactance is selected in abc reference frame to be consistent with the

concept of $Q - V$ operation. If the current is expressed in dq reference frame, Δv_t can be expressed as a function of virtual impedance such that:

$$\Delta v_t = \sqrt{\left(R_{vir} \frac{i_q}{\sqrt{2}}\right)^2 + \left(X_{vir} \frac{i_d}{\sqrt{2}}\right)^2} \quad (3.3)$$

where, $Re(I_{pcc}) = i_q/\sqrt{2}$ and $Im(I_{pcc}) = i_d/\sqrt{2}$ are the real and imaginary parts of PCC current, respectively, R_{vir} is the virtual resistance, and $Z_{vir} = R_{vir} + jX_{vir}$. Inrush current mitigation using virtual impedance is represented in Fig. 3.1(c). However, for simplification and ease of tuning process, only X_{vir} is adopted as given in Eq. 3.2 for the inrush current mitigation technique developed for direct method. The selection of X_{vir} should be manufacturer-defined, and the inverter terminal voltage reference V_{inv}^* must be regulated so fast that the inrush current can be mitigated within the first a few cycles without causing overloading and meeting the requirements of the IEEE Std. 1547.

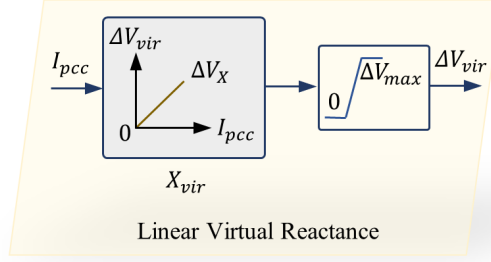
The developed virtual reactance method in Fig. 3.1(a) as well as the virtual impedance method in Fig. 3.1(c) leads to a consistent voltage drop at the PCC when current flows through it. Nevertheless, this voltage drop can be compensated by implementing $G_h(s) = \Delta v_t/\Delta v_{vir}$ as shown in Figs. 3.1(b) and (d). Thus, transfer functions of $G_h(s)$ and $G_l(s)$ can be written as:

$$\begin{cases} G_h(s) = G_u(s) - G_l(s) \\ G_l(s) = \frac{G_n(s)G_k(s)}{1 + G_n(s)G_k(s)} \end{cases} \quad (3.4)$$

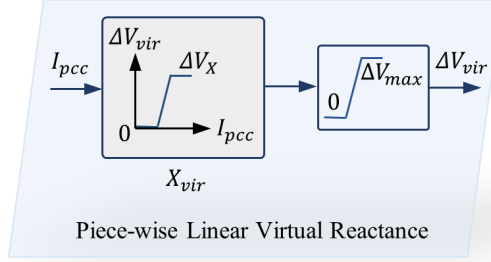
When $G_n(s) = K_{I,vir}/s$ represents an integrator with a gain of k_t , and $G_u(s) = G_k(s) = 1$ represents a unity gain, $G_h(s)$ and $G_l(s)$ can be rewritten as:

$$\begin{cases} G_h(s) = \frac{s}{s + K_{I,vir}} = \frac{\tau_t s}{\tau_t s + 1} \\ G_l(s) = \frac{K_{I,vir}}{s + K_{I,vir}} = \frac{1}{\tau_t s + 1} \end{cases} \quad (3.5)$$

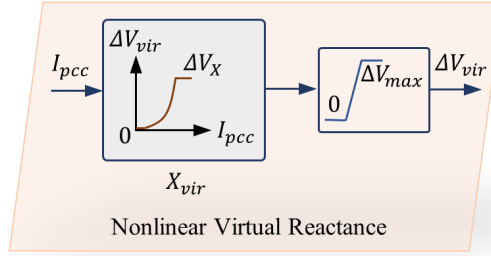
where, $G_h(s)$ becomes a high-pass filter, and $G_l(s)$ becomes a low-pass filter with $\tau = 1/K_{I,vir}$, the time constant of the filters. If the value of $K_{I,vir}$ is set high, it enables a quicker voltage drop recovery. However, sufficient voltage reduction should be provided to restrict the current during the start-up phase of a motor.



(a)



(b)



(c)

Figure 3.2: Different inrush current mitigation implementations; (a) linear, (b) piece-wise linear, and (c) nonlinear virtual reactance techniques.

Mitigation of inrush current can be linear or piece-wise linear, through the use of constant virtual reactance, or nonlinear, by setting it as a function of the inverter's output current. Fig. 3.2 illustrates the linear, piece-wise linear and nonlinear approaches employed in this study. The nonlinear technique can be utilized to achieve less voltage drop at low line currents compared to the linear technique. It should be emphasized that the maximum allowed voltage drop, ΔV_{max} , should be set to 0.5 p.u. based on the IEEE Std. 1547.

3.2 Inrush Current Mitigation Using Indirect Control

The indirect control approach shown in Fig. 2.5 utilizes dual outer loops G_{Vq} and G_{Vd} for PCC voltage regulation. These loops can be tuned for flexible voltage generation while the internal loops, $G_{Iq}(s)$ and $G_{Id}(s)$ can regulate the current. When the load is connected, the voltage drops. Hence, the peak of PCC current can be reduced. To maintain current mitigation during the initial cycles of motor connection, the outer loops can be designed to gradually restore the PCC voltage. Hence, the outputs from the outer voltage controllers gradually establish the reference currents for the inner current controllers. Furthermore, the inner loop can limit current regulation when the controller gains are appropriately selected. It's important to note that opting for lower gain settings increases the rise and fall times, resulting in slower the PWM reference signal regulation, leading to a delayed settling of the PCC current.

3.3 Experimental Analysis

Experimental analyses are conducted to demonstrate the performance and susceptibility of the direct and indirect control methods for the grid-forming inverters during switched inductive and dynamic load events. The same three-phase islanded microgrid hardware setup presented in Fig. 2.11 is used for the experiment, see Table 2.1 for the system parameters. The single-line diagram of the system including the induction motor is presented in Fig. 3.3. In this setup, a three-phase 4-pole 1/3 HP induction machine is used as well as a 5 kW static load.

3.3.1 Performance Analysis at the Baseline Settings

The performance comparison between the basic direct and indirect control methods begins with the baseline controller gain settings, provided in Table 2.1. The induction motor is connected to Bus_1 , where Inv_1 is electrically located closer. Initially, the inverters equally power a 1.5 kW static load as the controller gains of both inverters are set identical. In the

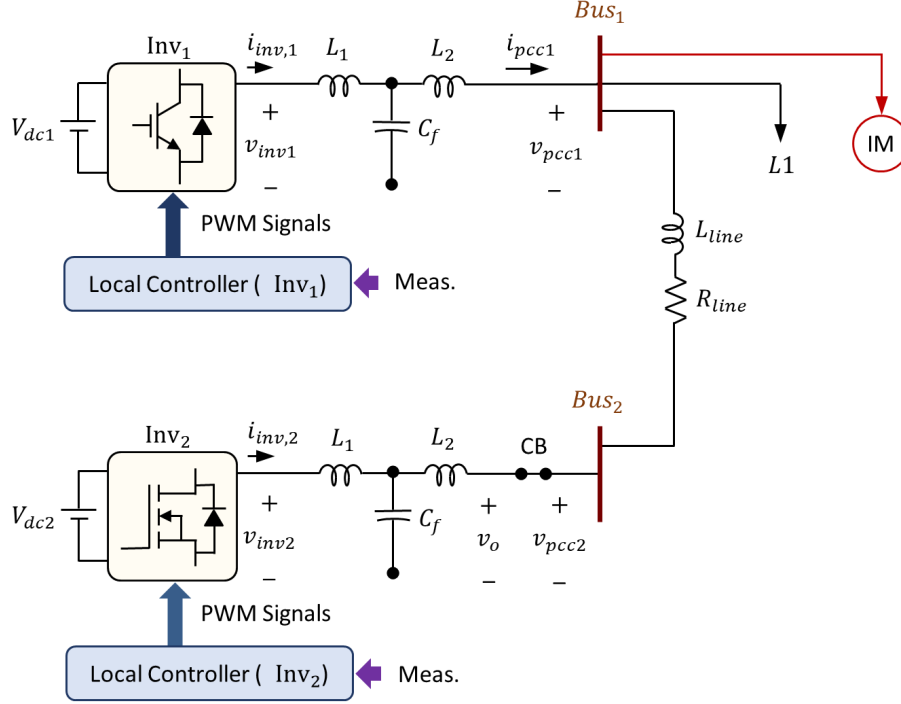


Figure 3.3: A single-line diagram of the system under study with two grid-forming inverters, Inv_1 and Inv_2 , one induction motor, and static load.

baseline scenario, the controller gains are selected such that the inrush current mitigation is disabled for direct and indirect control methods. Since Inv_1 is electrically closer, more severe transients are observed. Hence, Fig. 3.4 displays how the indirect method affects current and voltage waveforms, active and reactive power, and frequency for Inv_1 during the start-up of an induction motor. Upon connecting the motor, a significant inrush current, peaking at 43.1 A, is observed. Notice that this peak surpasses the maximum current rating of Inv_1 , calculated from $I_{max} = \sqrt{2}S_{max}/(3V_n) = 39.25$ A, as depicted in Fig. 3.4(a). If Inv_2 , which is rated for max 19.63 A, was located electrically closest instead of Inv_1 , the inverter may have tripped due to excessive current measured at the PCC.

An abrupt load change may initially lead to a substantial power surge from the inverter that is electrically closer, Inv_1 , at the time the induction motor is connected to Bus_1 , see Fig. 3.4(b). This causes a more phase angle difference between Inv_2 's terminals with respect to the PCC, since the frequency of Inv_1 decreases faster compared to Inv_2 , meaning that $|\Delta\omega_1| > |\Delta\omega_2|$, as illustrated in Fig. 3.4(d). Since $\theta = \int (\omega_n + \Delta\omega) dt$ and $\Delta\omega < 0$, then

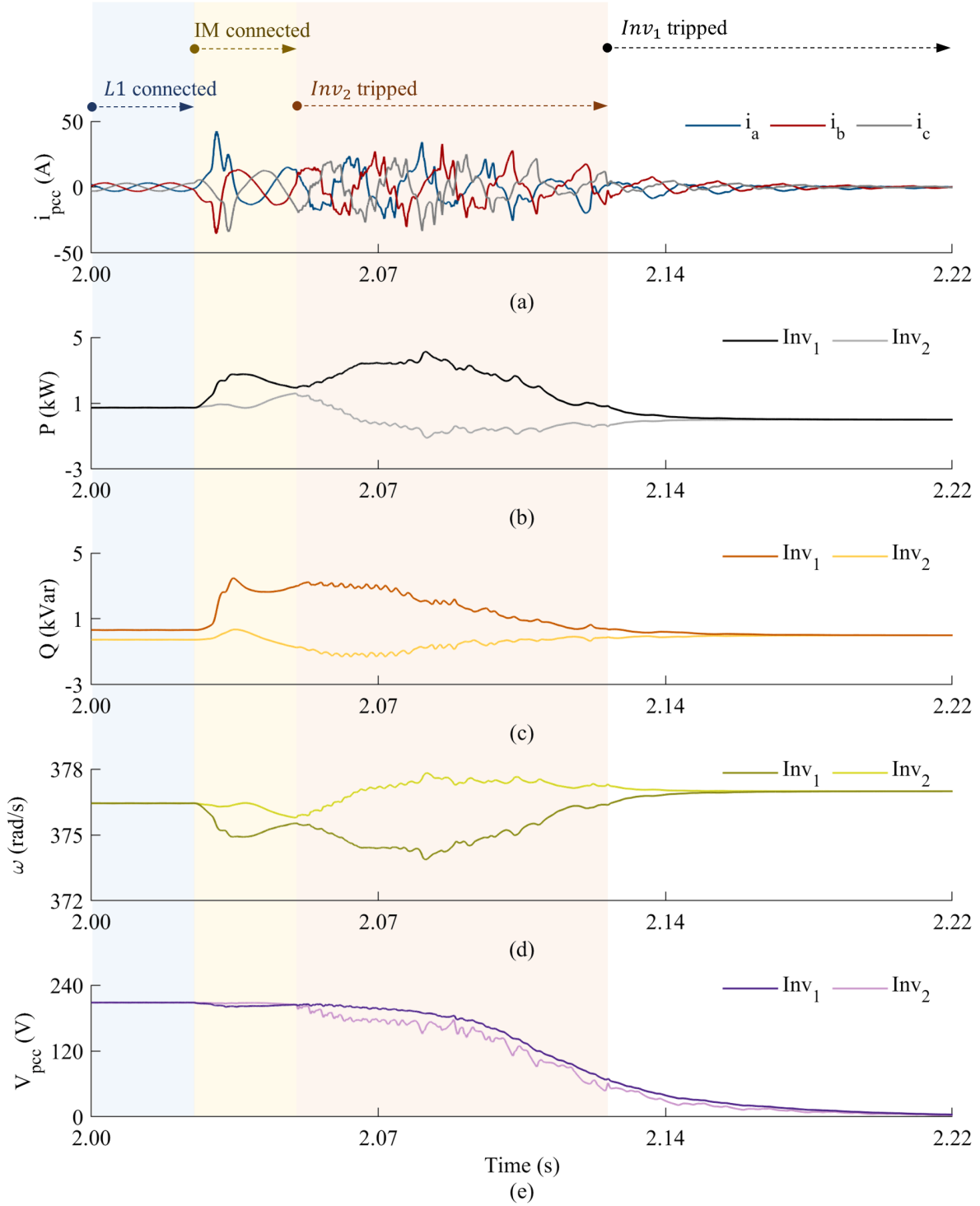


Figure 3.4: Experimental results showcasing the effectiveness of inrush current mitigation implementing indirect control with baseline gain settings; (a) measurement of line current at PCC₁, (b) the active, (c) reactive power supplied by each inverter, (d) the angular frequency generated during transients, and (e) voltage at each PCC.

$\theta_2 > \theta_1$. Then, $\theta_2 - \theta_{pcc1} > \theta_1 - \theta_{pcc1}$. From $P_1 = V_{inv1}V_{pcc1} \sin(\theta_1 - \theta_{pcc1})/X_1$ and $P_2 = V_{inv2}V_{pcc1} \sin(\theta_2 - \theta_{pcc1})/(X_2 + X_{line})$, power flow from P_2 will gradually increase while P_1 reduces. Herein, X_1 and X_2 denote the filter reactances of Inv₁ and Inv₂, respectively.

To enhance understanding and analysis, it's important to clarify the meaning of an inverter trip, which should not be mistaken for disconnection caused by circuit breaker trips. Many inverters come with hardware protection features like desaturation, short-circuit, over-temperature, and overload protection. For example, in scenarios of circulating current or high inrush currents, desaturation protection in gate-drive integrated circuits might halt the generation of the gate-to-source PWM signal due to voltage rise across semiconductor switch terminals, e.g., drain-to-source for SiC MOSFETs, which is crucial for controlling the power switches in power modules. If all gate drivers are deactivated, the inverter would entirely lose control, potentially causing the converter to act as a passive rectifier unless isolation occurs. If some gate-drive ICs remain operational, the inverter's controller might attempt to continue functioning. However, this could lead to abnormal operation or instability.

During the period when IM is connected and both Inv₁ and Inv₂ is connected, reactive power, Q , momentarily becomes positive, $Q_{2,max} = 350$ Var for Inv₂ while $Q_{1,max} = 3.47$ kVar for Inv₁ as shown in Fig. 3.4(c), meaning that Inv₁ and Inv₂ are both providing Q to the load. However, this injection leads to an abrupt change of error signal utilized by the outer loop. This sudden variation in the PCC voltage, coupled with faster gain settings, can cause a swift change in the angle θ_v and so θ_{inv}^* , as shown in Fig. 2.5. Such changes might further result in an increased power flow from Inv₁ and Inv₂. Notice that Inv₂ absorbs active power since $P_{2,min} = -1.1$ kW after it trips and continues an abnormal operation, as shown in Fig. 3.4(b). During this period, Inv₁ maintain a stable operation and feeds the static and dynamic loads while injecting power to Inv₂, providing $P_{1,max} = 4.13$ kW in total. In addition to the trip of Inv₂, connecting the motor could cause distorted current waveforms due to the abrupt and significant reactive power distribution between the inverters, as illustrated in Fig. 3.4(c). This situation might lead to an increase in harmonics, potentially causing the inverter to trip eventually. The voltage response shown in Fig. 3.4(e) demonstrates that Inv₂ loses control over voltage regulation after it trips, and harmonics are observed. Meanwhile,

Inv₁ maintains the voltage regulation at PCC₁. As PCC₂ is connected through the tie-line, i.e., R_{Line} and L_{Line} , as illustrated in Fig. 3.3, the voltage at PCC₂, denoted as v_{pcc2} , can be measured. The abnormal operation of Inv₂, while still connected to PCC₂, results in undesired active and reactive power absorption from Inv₁.

In the direct method, the PWM angle reference, θ_{inv}^* , is independent from the V_{inv}^* , in contrast to the indirect method where a variation in reactive power influences the voltage reference signal, as shown in Figs. 2.1 and 2.5. The affect of direct control method for GFM inverters on current and voltage waveforms, active and reactive power, and frequency for Inv₁ during the start-up of an induction motor is shown in Fig. 3.5. The active power overshoot observed at PCC₁, $P_{1,max} = 1.87$ kW, in Fig. 3.5(b) is significantly reduced compared to Fig. 3.4(b), resulting in the inverters sharing the load more smoothly, as indicated in Fig. 3.5(a). When the angular frequency performance are compared between direct and indirect control methods during connection of the induction motor, one can notice that the changes in $|\Delta\omega_1|$ and $|\Delta\omega_2|$ are smaller in Fig. 3.5(d) compared to Fig. 3.4(d). During the inrush currents when the motor is connected, $Q_{1,max} = 1.83$ kVar for Inv₁, while $Q_{2,max} = -75$ Var only for Inv₁ as shown in Fig. 3.5(c), when the direct method is applied. In contrast to Fig. 3.4(d), reactive power is significantly mitigated when direct method is implemented. Since both inverter maintain a normal operation, no inverter trips are observed, and PCC voltages momentarily dropped during motor connection, and regulated to near nominal value, see Fig. 3.5(e).

3.3.2 Sensitivity Analyses for Inrush Current Mitigation

To slow down the voltage regulation, the outer voltage regulator is slowed down. To achieve this, the controller proportional gain coefficients, $K_{P_{v_q}}$ and $K_{P_{v_d}}$ are reduced, and this procedure is repeated for different gain settings.

Fig. 3.6 illustrates the controller's performance when a motor is connected to Bus₁ for 60 cycles. In this instance, to facilitate a safe motor start, the gain coefficients are reduced by 91.67% to $K_{P_{v_q}} = K_{P_{v_d}} = 0.1$ from their initial baseline values, 1.2, while all other coefficients

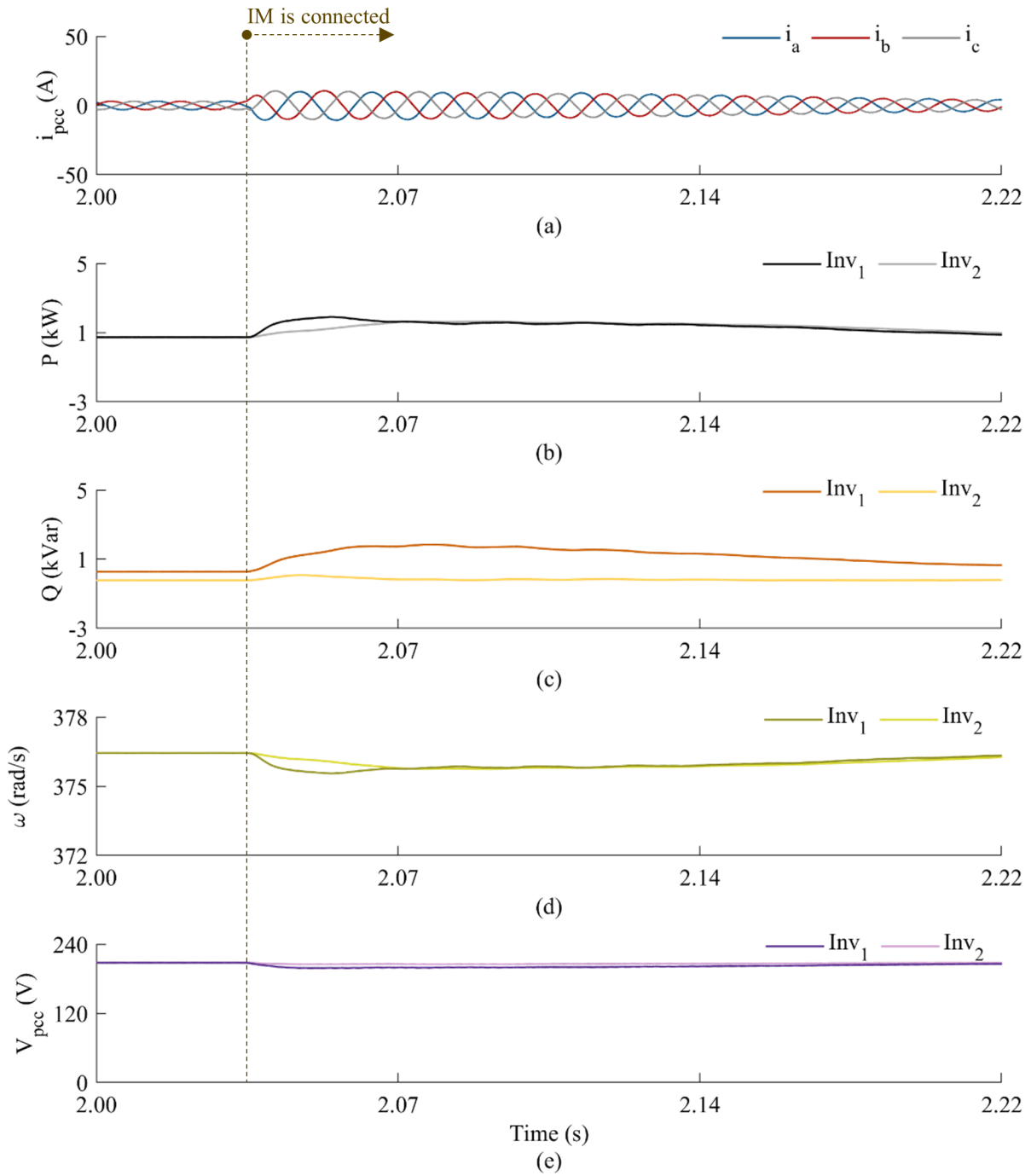


Figure 3.5: Experimental results showcasing the effectiveness of inrush current mitigation implementing direct control with baseline gain settings; (a) measurement of line current at PCC₁, (b) the active, (c) reactive power supplied by each inverter, (d) the angular frequency generated during transients, and (e) voltage at each PCC.

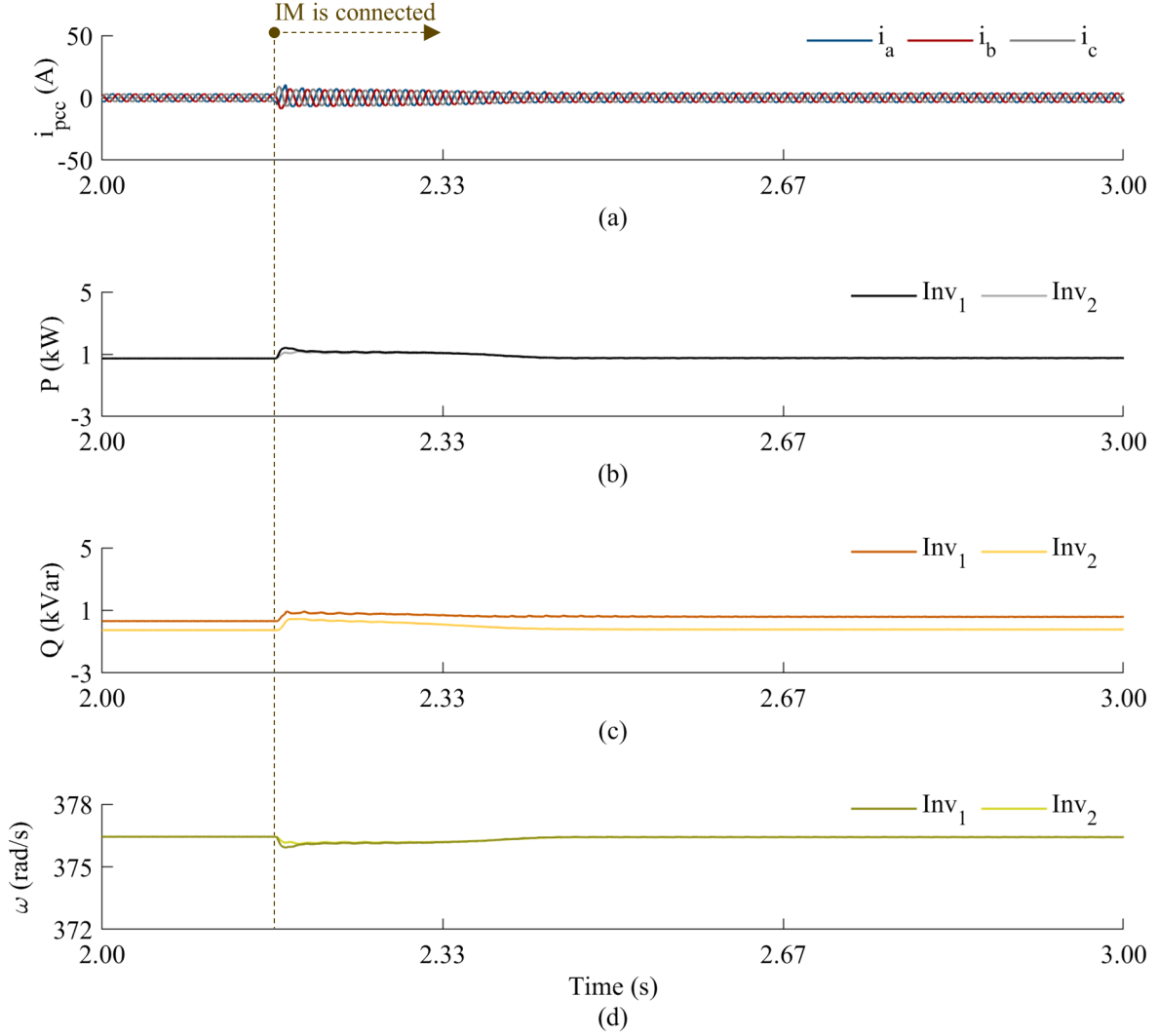


Figure 3.6: Experimental results showcasing the effectiveness of inrush current mitigation implementing indirect control with 91.67% reduced outer loop gain settings; (a) measurement of line current at PCC₁, (b) the active, (c) reactive power supplied by each inverter, and (d) the angular frequency generated during transients.

remain constant. Fig. 3.6(a) demonstrate that the peak transient current peaks at 10.4 A. Herein, the inrush current is limited by allowing the voltage at the PCC to decrease and then recover over an extended period due to the reduction in proportional gains. Compared to the baseline conditions in Figs. 3.4(b) and (c), the active power overshoot observed at PCC₁ as $P_{1,max} = 1.42$ kW for Inv_1 , in Fig. 3.6(b), while $Q_{1,max} = 942$ kVar as shown in Fig. 3.6(c). Concurrently, as depicted in Fig. 3.6(d), the ω remains within the requirements of IEEE Std. 1547 for the duration of the operation.

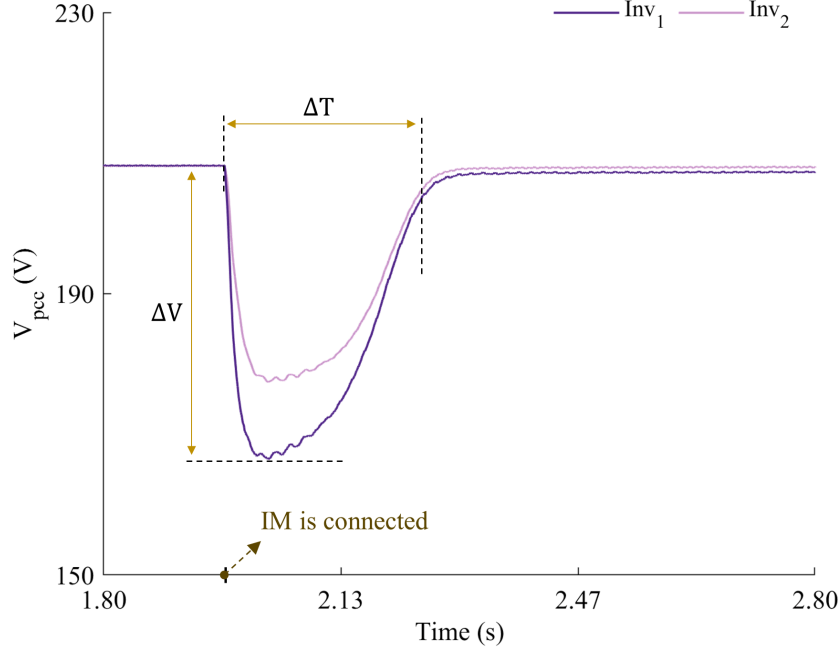


Figure 3.7: Experimental result demonstrating the PCC voltage regulation performance during inrush currents using the indirect method with reduced outer loop gain.

In Fig. 3.7, one can observe flexible voltage regulation performance from Fig. 3.6(b) when the inductive dynamic load is connected. The voltage briefly remains under the continuous operating region limit defined by IEEE Std. 1547, i.e., 183.04 V (0.88 p.u.), and recovers by 189.2 ms, meeting the criteria set by the IEEE standard [16]. Proper voltage regulation is crucial in islanded microgrids to avoid inverter trips caused by inrush currents. Thus, achieving fast voltage recovery and optimizing voltage dips during the connection of inductive and dynamic loads are essential, particularly in multi-inverter-based weak grids. The performance of the indirect controller in terms of voltage regulation and recovery is evaluated for different proportional gain values in the outer voltage control loop, and the statistical results are provided in Table 3.1. On the other hand, performance of the direct inrush current mitigation technique is tested for different virtual impedance, X_{vir} , and integral gain coefficients which determines time constant of the recovery path, k_t . Table 3.2 presents the percentage of voltage drop relative to the nominal voltage, ΔV , and the duration required for the voltage to recover to 95% of its nominal value, Δt , for both direct and indirect control methods.

Table 3.1: Experimentally obtained voltage recovery statistics for indirect method when outer loop gains coefficients are changed.

Indirect Control							
K_{Pv_q}, K_{Pv_d}		0.06	0.17	0.28	0.38	0.49	0.60
Inv ₁	$\Delta V(\%)$	25.38	15.23	11.88	8.66	7.45	6.37
	$\Delta t(\text{ms})$	240.5	188.2	152.7	112.9	67.7	33.3
Inv ₂	$\Delta V(\%)$	20.62	10.33	7.28	5.48	4.92	4.11
	$\Delta t(\text{ms})$	230.09	181.78	145.09	130.38	0	0
K_{Iv_q}, K_{Iv_d}		0.06	0.17	0.28	0.38	0.49	0.60
Inv ₁	$\Delta V(\%)$	20.94	20.51	19.5	19.31	19.28	19.04
	$\Delta t(\text{ms})$	235.66	222.24	212.32	202.53	183.75	175.25
Inv ₂	$\Delta V(\%)$	14.82	14.36	14.04	13.89	13.51	13.12
	$\Delta t(\text{ms})$	234.78	218.74	198.02	186.82	172.27	161.66

Table 3.2: Experimentally obtained voltage recovery statistics for direct method when virtual reactance and voltage recovery coefficients are changed.

Direct Control							
X_{vir}		1.25	2.5	5	7.5	10	12.5
Inv ₁	$\Delta V(\%)$	8.19	11.42	16.6	19.39	22.25	24.84
	$\Delta t(\text{ms})$	106.27	167.39	204.08	222.62	242.74	256.26
Inv ₂	$\Delta V(\%)$	4.23	6.82	10.52	13.67	16.7	19.09
	$\Delta t(\text{ms})$	0	113.7	182.49	209.26	228.51	244.14
$K_{I,vir}$		0	0.25	0.50	0.75	1	1.25
Inv ₁	$\Delta V(\%)$	15.8	15.86	15.94	16.19	15.87	16.2
	$\Delta t(\text{ms})$	212.76	205.98	204.96	203.2	199.46	192.92
Inv ₂	$\Delta V(\%)$	10.59	10.68	10.48	10.46	10.25	10.87
	$\Delta t(\text{ms})$	192.29	186.47	183.28	181.78	176.38	174.42

The results indicate that a higher K_{Pv_q} and K_{Pv_d} lead to stricter voltage regulation but also quicker recovery times. It is noted that changing in K_{Iv_q} and K_{Iv_d} have minimal impact on voltage recovery or regulation. With the implementation of the direct controller and the virtual reactance approach for inrush current mitigation, it is observed that an increase in X_{vir} causes a greater decline in PCC voltage and lengthens Δt . Therefore, an optimal X_{vir} value should be chosen to ensure rapid recovery and minimal voltage drop. Additionally,

Table 3.3: Implemented virtual reactance values for experimental analysis.

Technique (X_{vir})	Value
Linear	5.5
Nonlinear	$k u ^3$

while $K_{I,vir}$ has little effect on voltage regulation, it slightly enhances the recovery time.

3.3.3 Linear vs. Nonlinear Virtual Reactance for Direct Inrush Current Mitigation

The effectiveness of inrush current mitigation through both linear and nonlinear techniques is experimentally evaluated for direct GFM control method. At the outset, a static load of 1 kW is equally distributed across both inverters, $P_1 = P_2 = 500$ W; then, the 1/3 HP induction motor is connected to the system to assess the performance. To compare the base performance of both techniques, the developed voltage recovery feature is disabled. Selected virtual reactance values for linear and nonlinear techniques are provided in Table 3.3, where $0 < k < 1$, and u represents the input, i.e., I_{pcc} . A k near 1 allows more voltage drop to suppress the effect of inrush and fault currents, and $k = 1$ is used for the following test scenarios. Furthermore, the effect of using linear and nonlinear virtual reactance techniques at different virtual inertia settings are experimentally demonstrated.

Fig. 3.8 illustrates the PCC voltages for two inverters, each employing a virtual inertia control at a low inertia setting, yet utilizing linear and nonlinear virtual reactance techniques in two distinct scenarios. Figs. 3.8(a) and (b) display V_{pcc1} and V_{pcc2} , respectively. The minimum recorded line-to-line voltage is nearly 172.1 V ($\approx 0.83 V_{p.u.}$) with the linear technique, and around 167.7 V ($\approx 0.81 V_{p.u.}$) with the nonlinear approach. In accordance with IEEE Std.1547, both V_{pcc1} and V_{pcc2} are categorized within the mandatory operation range. As depicted in Fig. 3.8, the nonlinear mitigation technique facilitates a quicker recovery of the PCC voltage. At $t=2.7$ s, V_{pcc1} reaches 205.1 V under the linear mitigation, compared to 206.6 V with the nonlinear mitigation.

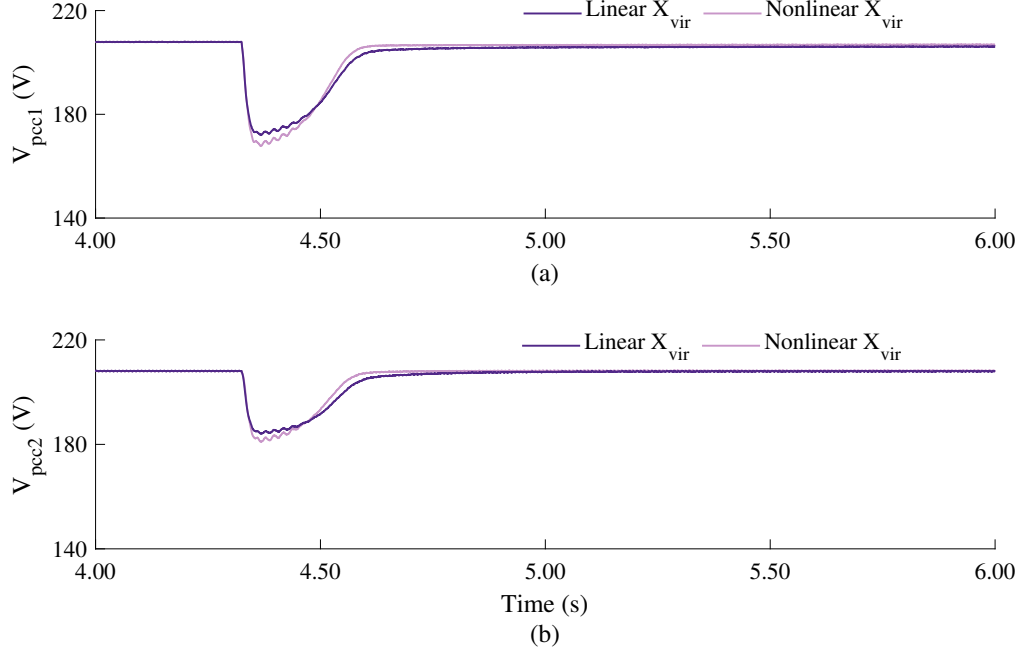


Figure 3.8: Experimentally observed voltage drop at each PCC when $J = 0.0001$ (baseline setting) for all inverters, alongside linear and nonlinear virtual reactance methods.

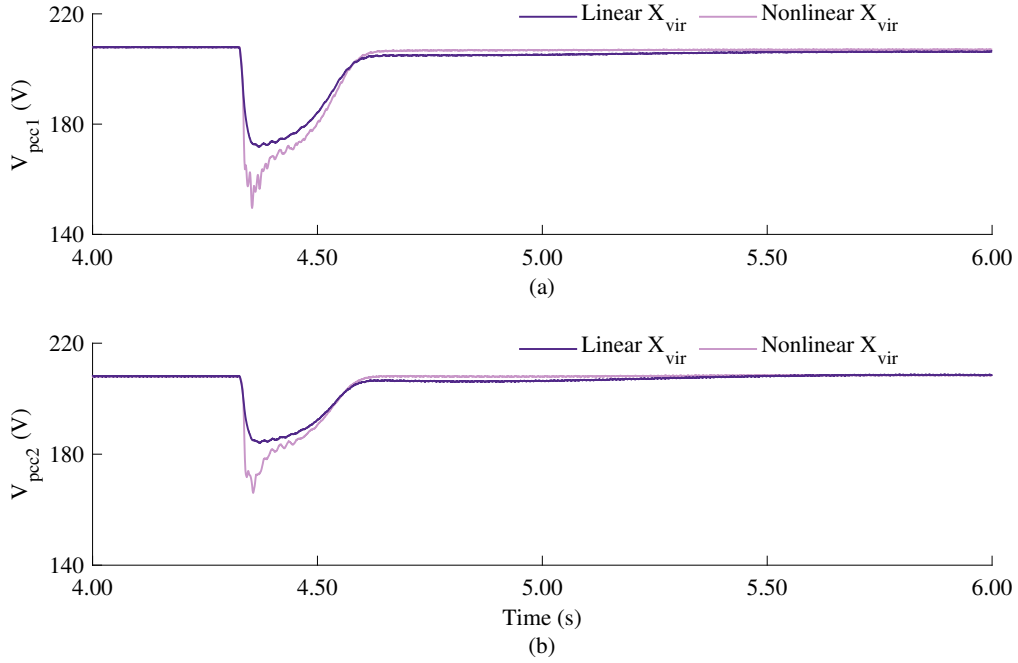


Figure 3.9: Experimentally observed voltage drop at each PCC when $J = 2$ for all inverters in the system, alongside linear and nonlinear virtual reactance methods.

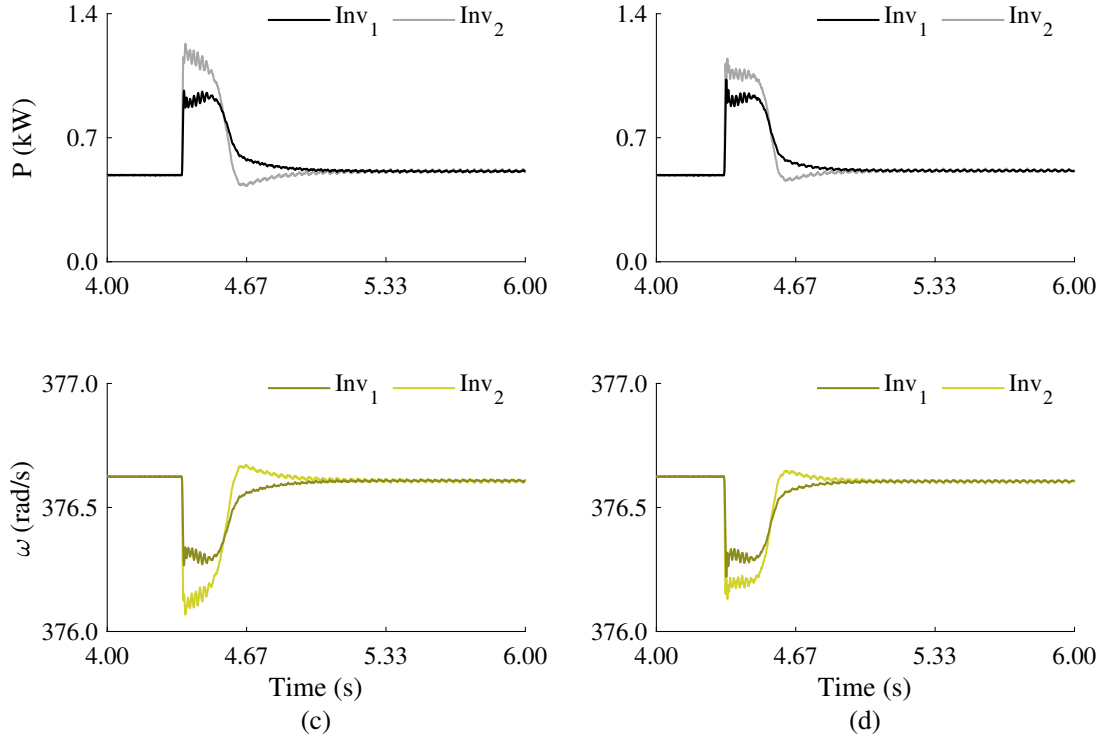


Figure 3.10: Experimental results for P and ω when J is at the baseline setting using; (a) linear and (b) nonlinear virtual reactance techniques.

In Fig. 3.9, the PCC voltages for two inverters, each regulated by the virtual inertia control method applied in two distinct scenarios using linear and nonlinear virtual reactance techniques are displayed. In this experiment, both inverters are set with identical virtual inertia settings, where $J_1 = J_2 = 2$. Given the load's proximity to Inv_1 , the voltage drop at V_{pcc1} exceeds that of V_{pcc2} . Comparing the voltage transients in Figs. 3.8 and 3.9, one can say that the virtual inertia control method in Inv_1 exhibits a more intense transient performance to the induction motor during the start-up.

Figs. 3.10(a) and 3.10(b) illustrate the responses of P and ω for each inverter after connecting the induction motor, employing virtual inertia control when $J = 0.0001$ in conjunction with linear and nonlinear approaches to mitigate inrush currents. Notice that the change in frequency for the electrically closer inverter (Inv_1), $\Delta\omega_1$, is less when nonlinear technique is used while the change is more when linear technique is employed during the transients. Therefore, $\Delta P_{1,\text{nonlinear}} < \Delta P_{1,\text{linear}}$. On the other hand, inrush current miti-

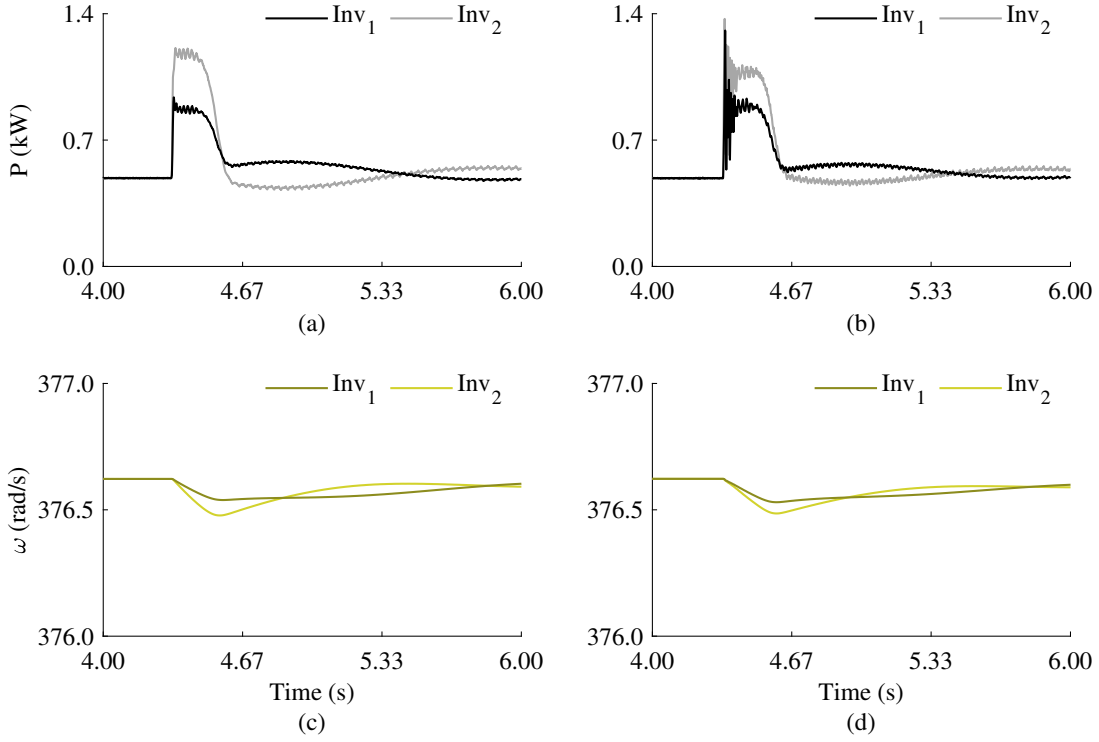


Figure 3.11: Experimental results for P and ω when $J = 2$ using; (a) linear and (b) nonlinear virtual reactance techniques.

gation transient performance at higher virtual inertia setting, i.e., $J = 2$, is demonstrated in Figs. 3.11(a) and 3.11(b) when linear and nonlinear techniques are used. Since virtual inertia controller behaves like a low pass filter, the time constant, τ_ω increases as J increases, resulting in smoother transients for frequency regulation. In baseline settings where $J = 0.0001$, $\tau_\omega = J\omega_n/D = 2\pi(0.0001)/100 = 28.4 \mu s$, whereas, $\tau_\omega = 0.57 s$ with a gain of $K_\omega = -1/D = -1/1326.3 = -754 \times 10^{-6}$. However, selecting large inertia delays the change in controller frequency required for power sharing, which may cause low-frequency oscillations or instability. Furthermore, any high frequency oscillations at V_{pcc} when the voltage dips during motor connection also affects the load current. Therefore, the high frequency oscillation on P_1 and P_2 are also observed when nonlinear technique is used. This interference can also be explained from the imperfection in synchronous $dq0$ reference frame. When the PCC angle calculated from PLL is used for the abc to $dq0$ conversion, V_d becomes zero. However, the inverter output terminal angle generated by the controller for PWM generation

is used for the $dq0$ conversion. Therefore, there is a mismatch between the PCC angle and inverter's output angle, resulting in nonzero V_d component. Therefore, voltage oscillations impose chattering in active power during the transients.

3.4 Analyses of the Outcomes

The insights for the results obtained through experimental analyses are provided as follows:

- Virtual reactance selection criteria used in this work determined by the necessity of voltage reduction at high current levels during inrush currents. Therefore, voltage drops at low PCC currents should be eliminated to avoid unreliable voltage regulation under changing load conditions.
- Nonlinear method provides better voltage regulation at low current levels and recovers faster after the inrush currents. However, high-frequency oscillations present as current increases, particularly at higher inertia settings.
- Therefore, a piece-wise linear virtual reactance shown in Fig. 3.2(b) can be used to eliminate direct voltage regulation at low current levels while achieving more seamless transients during motor connection.
- The results verify that direct control method can still achieve a stable operation during the motor connection unlike the case with the indirect control method, where inverters failed. Therefore, the indirect control method is highly sensitive to a change in the controller parameter.
- Although the implementation of the inner loop is developed for current regulation, it is proven to be ineffective against the inrush currents since the outer loop has greater effect on the mitigation.
- The direct control method, designed to produce voltage without current limitation, can be easily adapted to mitigate high inrush currents without directly restricting the current. This adaptation underscores the potential redundancy of implementing an inner control loop.

3.5 Conclusion

The findings have indicated that the indirect method exhibits greater sensitivity to controller gains in comparison to the direct method when addressing inrush current phenomenon during connection of an inductive and dynamic load. Inadequate tuning might result in power transfer between generation units, which may cause inverter trips or power outages. Although the use of precise models for dynamic analysis can aid in fine-tuning the controller settings, this comes at the cost of increased computational demands. Conversely, relying solely on an inner current controller has been proven to be ineffective, as versatile voltage regulation has been crucial for countering inrush currents, particularly when connecting inductive and dynamic loads to the system. Thus, the direct control method could replace indirect controllers, which restrict inrush and fault currents using the virtual reactance approach. This method offers a simpler and more robust control strategy for Grid-Forming (GFM) inverters in islanded microgrids.

Chapter 4

Autonomous Control for Inverters

This chapter introduces an innovative self-governing control architecture for grid-interactive inverters capable of detecting both the reconnection to the utility grid and islanding events. It outlines how the system determines the proper operational mode, achieving a smooth transition between modes and ensuring uninterrupted system functionality. The control-sync method, proposed in [20, 55], is enhanced and simplified to achieve direct control operation in both GFL and GFM modes to minimize the computational burden and hassles during controller parameter tuning process. Considering the situations where communication between supervisory controllers and inverters is lost or interrupted, a novel fully autonomous grid reconnection detection algorithm is developed. This proposed technique performs transition from grid-forming to grid-following mode of operation without requiring communication.

The motivation for developing this unique and independent controller is discussed in Section (4.1). The effectiveness of employing a dual-path control structure which is the core of the developed controller is illustrated in Section (4.2). The proposed controller and islanded detection techniques are introduced in Section (4.3). Simulation studies are carried out to initially verify the controller's efficacy during changes between the modes in Section (4.5). Next, the novel autonomous grid reconnection detection architecture is presented in Section (4.4). Initial outcomes are analyzed in Section (4.6). Finally, the chapter is ended with conclusion remarks in Section (4.7).

4.1 Concept of Communication-Less Microgrids

Utility power outages due to faults, extreme weather conditions, or natural disasters may isolate a local area from the rest of the grid for unforeseeable period, which can disrupt essential and critical events. Furthermore, increasing number of inverter-based distributed power generation units in the grid can become ineffective when the grid is disconnected due to conventional control strategies implemented in their local controller units, operating mainly in grid-following (GFL) mode. Hybrid inverters tackle this challenge by operating in islanded mode, also known as grid-forming mode. In this mode, they supply local demand in the absence of the utility grid, utilizing external AC generators or energy storage units like batteries. However, the existing inverter technologies require complete isolation from the grid when islanding is detected, and no contribution in load sharing is observed within a local area. Therefore, critical loads and residential demand cannot be met if power generation units are isolated during an outage, especially in the event of a catastrophic occurrence. To address this challenge, a concept of microgrid where inverters in an islanded grid are synchronized to form a clustered grid structure to supply the demand is essential.

In a microgrid, it is necessary to synchronize the voltage waveforms on both sides of the main circuit breaker to reconnect an inverter with the rest of the microgrid. This implies that they must share the same frequency, voltage amplitude, and phase sequence. Otherwise, inverters can trip due to high power transients, as demonstrated in Fig. 4.1 [55]. To synchronize the inverters, many methods have been developed [20, 164, 184–186].

Power generation can exceed the demand in an islanded microgrid. Frequency and voltage measured at PCC rise if the controller is programmed to provide the maximum available power in GFL mode of operation to the islanded branch, while they are well regulated in grid-connected scenario, particularly in residential-scale power generation. Therefore, maintaining generation-demand balance in a divided subdivision in GFL mode is a challenge. In such cases, inverters must trip based on the threshold defined by the grid standards. To prevent undesired inverter trips and regulate the voltage and frequency at their nominal values while injecting power up to their maximum capabilities, inverters must operate in

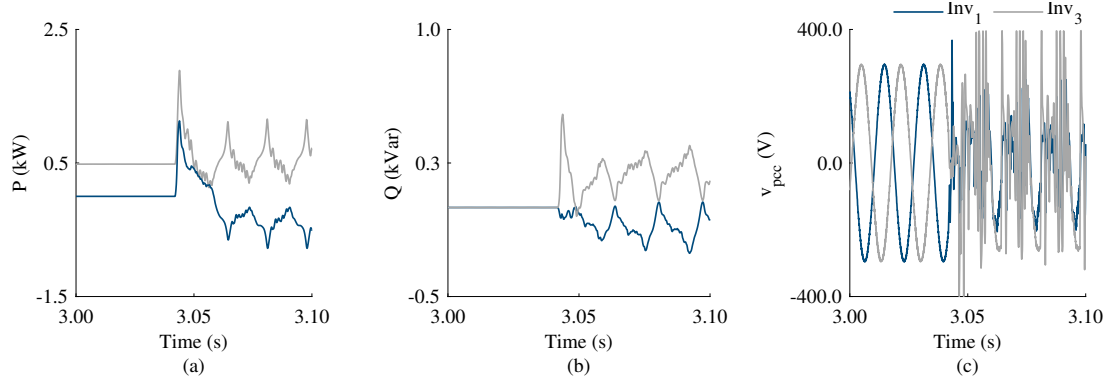


Figure 4.1: Transient performance during inverter connection; (a) voltage, (b) active power, and (c) reactive power when an inverter is not synchronized.

GFM mode. However, transition between GFL and GFM should be smooth to achieve seamless transients after grid is unavailable.

During GFM mode of operation if the utility grid is re-available, microgrid needs to be reconnected with the utility grid. Typically, the management of this synchronization is handled by a synchro-check relay. This relay compares the voltage parameters on both sides of the breaker and closes the breaker once they match. During the breaker closing, the supervisory controller sends signals to the inverters to adjust their mode of operation. The existing inverter control strategies in microgrids commonly require this external information [1]. This dependency can become a challenge if the communication infrastructure is damaged during a disaster. In such cases, inverters cannot perform a transition between modes. Therefore, the concept of communication-less transitions between modes of operations is essential to detect the presence of utility grid after the synchro-check relay is closed. This concept does not exist in the current industrial standards, and there is no literature developing such technique while demonstrating its effectiveness. This challenge becomes the motivation for developing the autonomous grid reconnection detection and seamless transition from GFM to GFL in this dissertation. Considering that communication is available, this unique technique can be used in addition to the existing methodologies that require communication to enhance the reliability of system operation.

4.2 Effectiveness of Synced Parallel Control Concept

The concept of implementing synchronized parallel control paths is versatile and can be effectively implemented in numerous systems that necessitate seamless switching across different operational modes, offering transient enhancements during transitions compared to traditional control methods. Two concurrent control paths, i.e., the active and inactive paths, are incorporated, regulating the desired parameters regardless of the system's mode. The active (main) paths are responsible for generating desired control signals, such as PWM voltage magnitude and frequency for converters, required to uphold the system's target output. Critical control operation is performed using the active path, which directly effects the accuracy of the controller and efficiency of the system. Simultaneously, the inactive paths aim to consistently synchronize their outputs with the active paths to ensure a unified operation and proper transition from inactive to active path. The inactive paths only run in the background without contributing to the active paths' decisions. Multiple active and inactive paths can be employed simultaneously for different control tasks. This synchronized parallel control concept is developed to enhance the robustness, resiliency, and stability of the system under various operating conditions while providing flexibility in selecting control objectives for each path, compared to the traditional methodologies where primary and secondary control objectives are fixed and typically experience operational disturbances or high transients during mode shifts.

To illustrate the effectiveness of the proposed control concept, a dual-path system where one path is active while the other path is inactive, is considered [187]. The block diagram representation of the developed control concept is shown in Fig. 4.2. The outputs of the parallel control paths, i.e., $Y_{c1}(s)$ and $Y_{c2}(s)$, can be written as can be written as [187]:

$$\begin{cases} Y_{c1}(s) = [n(O_1^* - O_1) + (\bar{u}\bar{n})e(s)]G_{c1}(s) \\ Y_{c2}(s) = [\bar{n}(O_2^* - O_2) + (un)e(s)]G_{c2}(s) \end{cases} \quad (4.1)$$

where $e(s)$ represents the discrepancy between the parallel paths, $(n, \bar{n})$ denote the logic switches for transitions between modes of operations, and $(u, \bar{u})$ are the logic switches for enabling synchronization for the inactive path. The truth table for the logic operation is

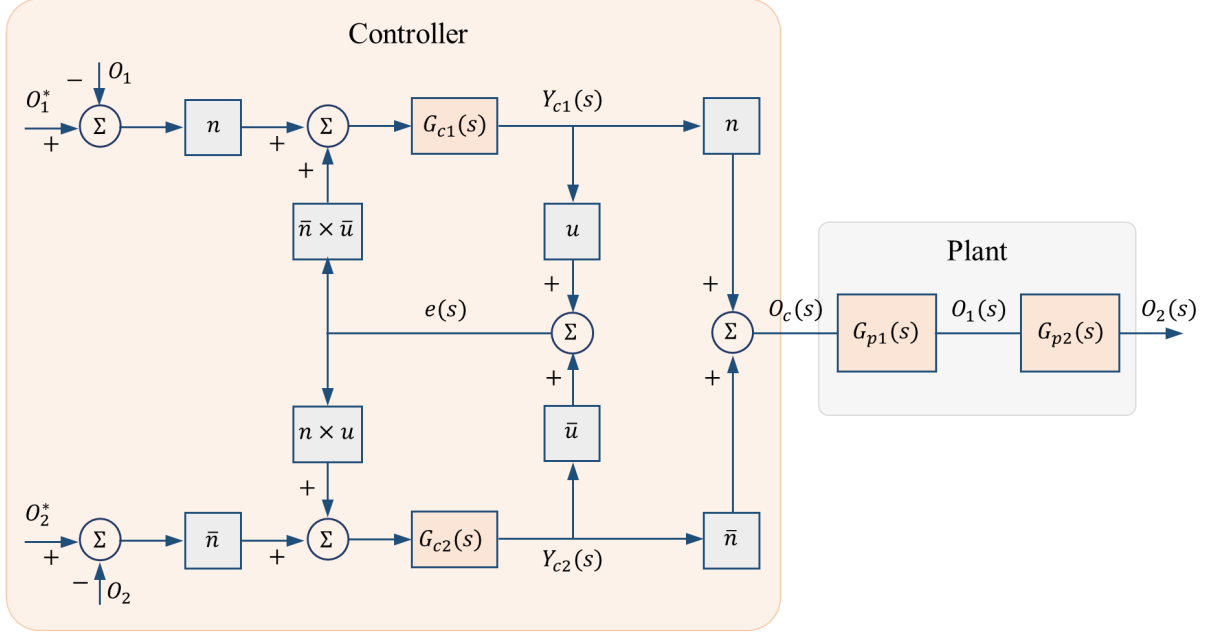


Figure 4.2: Block diagram representation of the developed synced parallel control concept using dual control paths.

provided in Table 4.1. The controller output and error between the paths, $O_c(s)$ and $e(s)$, respectively can be formulated as:

$$\begin{cases} e(s) = (u Y_{c1}(s) + \bar{u} Y_{c2}(s)) \\ O_c(s) = n Y_{c1}(s) + \bar{n} Y_{c2}(s) \end{cases} \quad (4.2)$$

The concept of synced parallel operation can be modified based on the application requirements as long as the error path is implemented for the alignment. For instance, the switching logic, n and $\bar{n}$, used after the feedback errors are optional, and can be included for the applications where the error is necessary to be provided.

The error loop plays a critical role in ensuring alignment between the active and inactive

Table 4.1: Switching states for $(n, \bar{n})$ and $(u, \bar{u})$ over one switching period, $T_p = T_{on} + T_{off}$.

Logic	(State, Period)
n	$(1, T_{on}) , (0, T_{off})$
$\bar{n}$	$(0, T_{on}) , (1, T_{off})$
u	$(1, T_{on}) , (-1, T_{off})$
$\bar{u}$	$(-1, T_{on}) , (1, T_{off})$

path's outputs. This alignment is essential at each point of transition, as it significantly contributes to the overall stability of the system. By maintaining this consistency, the error loop aids in preserving continuous and uninterrupted operation, which is particularly critical in systems where precision and reliability are the key aspects. This mechanism not only enhances performance during regular operations but also provides an added layer of robustness, particularly in scenarios involving rapid or frequent switching between different modes of operations. Consequently, the system's ability to adapt to changing conditions without compromising on efficiency or output quality is greatly improved, underlining the importance of the error loop in complex control environments.

The effectiveness of the concept design using dual parallel paths is demonstrated through a simulation study. The objective is to demonstrate the seamless transition capability of the synced parallel control structure and to elucidate why this strategy is needed when mode of operation changes. For this study, transfer functions of the plants and two PI controllers for the parallel paths are considered to be:

$$\begin{cases} G_{p1}(s) = 2/(s^2 + 5s + 10) \\ G_{p2}(s) = 2/(s + 5) \\ G_{c1}(s) = (3s + 8)/s \\ G_{c2}(s) = (6s + 28)/s \end{cases} \quad (4.3)$$

The transfer functions are selected such that the fourth-order system is sensitive to a change in the reference values. Transitions between modes of operations and logic states are executed within $T_p = 60\text{ s}$ with 50% duty cycle. In the first scenario, the reference values, $O_1^* = 150$ and $O_2^* = 60$, are selected such that $e_{o2} = O_2^* - O_2 = 0$ when $O_1 = O_1^*$. By doing this, no variation is expected at the output of the system during transitions between paths. To disable the synchronization between dual paths and achieve a fixed control strategy, one can set $(u \rightarrow 0, \bar{u} \rightarrow 0)$. Outcomes of dynamic performance comparison for O_1 , O_2 , and error between the parallel paths, e , are shown in Fig. 4.3 when the conventional fixed control approach, see Fig. 4.3(a), and synced parallel control concept, see Fig. 4.3(b), are implemented. The results indicate that oscillations may occur during the transition, even

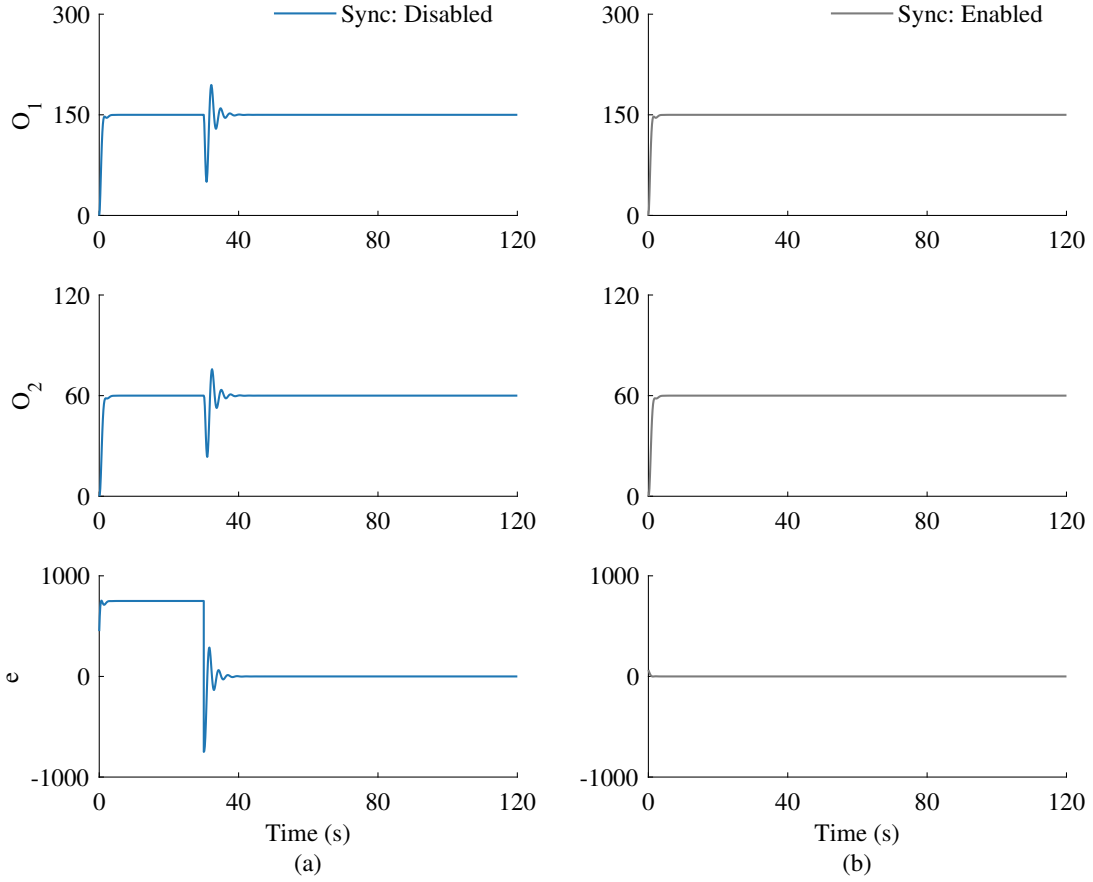


Figure 4.3: Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , and the error between parallel paths e , when input $(n, \bar{n})$ are removed and synchronization is disabled (a) and enabled (b).

though the desired values for O_1 and O_2 are chosen to ensure $(O_1 = O_1^*)$ and $(O_2 = O_2^*)$, irrespective of the active path. This oscillation is due to the fact that $(n = 1)$ and $(\bar{n} = 1)$ at the input to enable both paths operating in parallel all the time. In other words, when n and $\bar{n}$ are bypassed, G_{c1} is the active path, while G_{c2} runs in the background without being synchronized. Notice that any transients observed in Y_{c1} affects O_c , and so O_1 and O_2 . Therefore, the change in O_2 impacts the error received by G_{c2} and consequently Y_{c2} . When the synchronization is disabled, a change in Y_{c1} or Y_{c2} during background operation will cause oscillation for every transition between the paths. However, enabling the synchronization path ensures $(Y_{c1} = Y_{c2})$, which results in $e = 0$. Thus, $(O_1 = O_1^*)$ and $(O_2 = O_2^*)$ are always satisfied. On the other hand, Fig. 4.4 reveals the results when input $(n, \bar{n})$ are implemented in

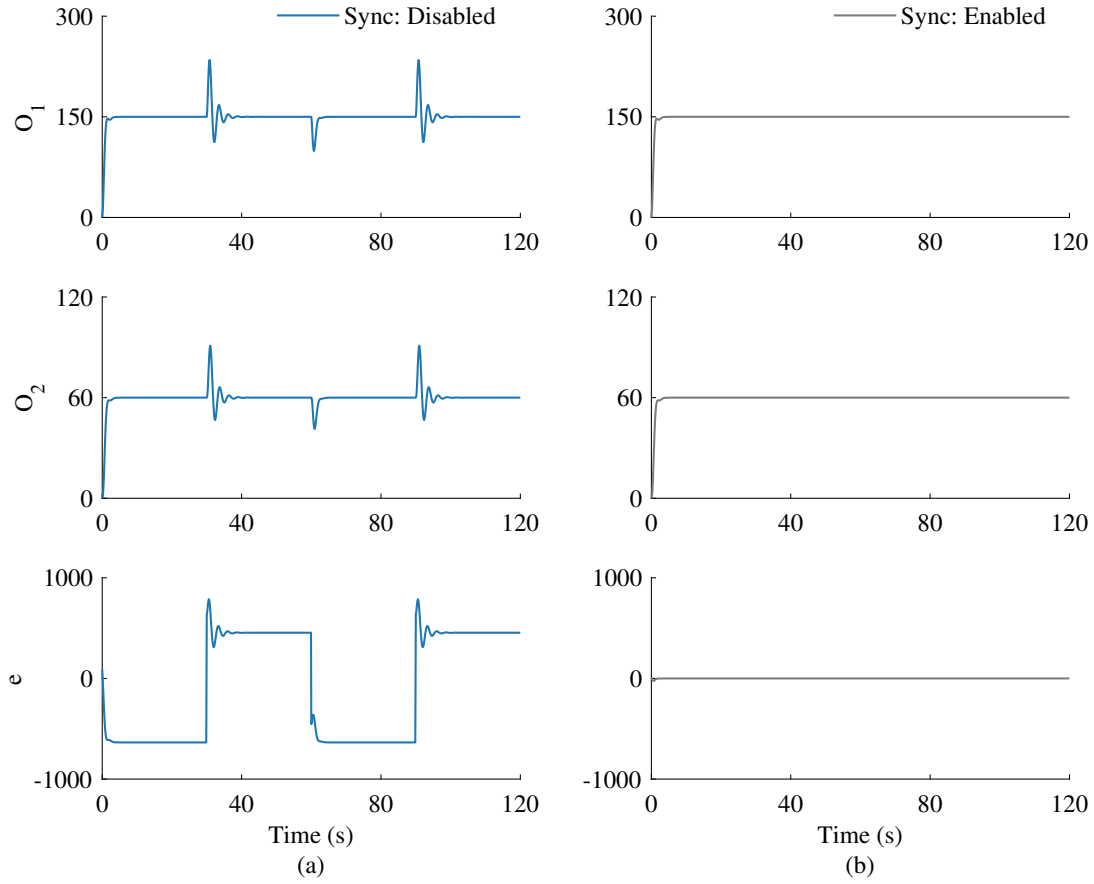


Figure 4.4: Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , and the error between parallel paths e , when input $(n, \bar{n})$ are implemented and synchronization is disabled (a) and enabled (b).

the concept design. In this scenario, for the inactive paths, $(O_1^* - O_1 = 0)$ when $(n = 0, \bar{n} = 1)$ or $(O_2^* - O_2 = 0)$ when $(n = 1, \bar{n} = 0)$ since the input path is disconnected. Therefore, the inactive path controller, G_{c1} when $(n = 0, \bar{n} = 1)$ and G_{c2} when $(n = 1, \bar{n} = 0)$, do not regulate its output as $(O_1^* - O_1 - e = 0)$ and $(O_2^* - O_2 - e = 0)$, respectively.

To further demonstrate the performance of the proposed concept, the transfer function of the plant G_{p2} is changed so that $(e_{o2} = O_2^* - O_2 \neq 0)$ when $(O_1 = O_1^*)$ and vice-versa. The new plant can be written as $(G_{p2} = 2.5/(s + 5))$. In Fig. 4.5, dynamic performance of O_1 and O_2 for the modified plant when path synchronization is enabled and disabled are shown. Additionally, $(G_{c2} = (6s + 10)/s)$ is implemented to see compare the results at different control settings. The rest of the system and simulation parameters remain the same with

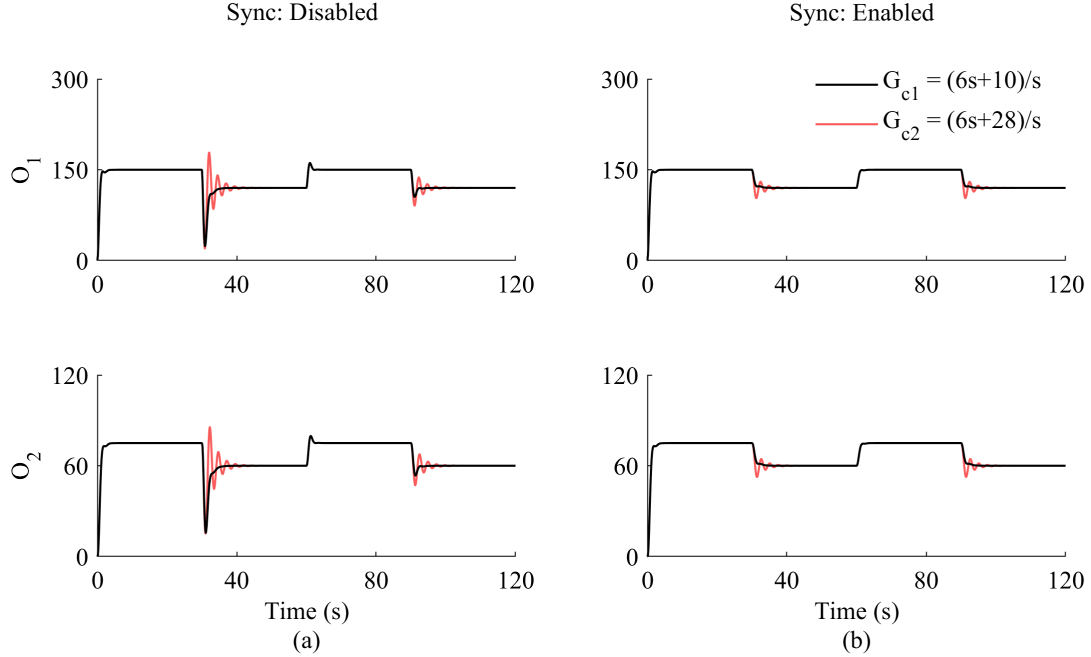


Figure 4.5: Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , for $(G_{p2} = 2.5/(s + 5))$ when input $(n, \bar{n})$ are removed and synchronization is disabled (a) and enabled (b).

the previous scenario.

Notice that increased integrator gain of G_{c2} results in oscillatory behavior for the selected plant. Fig. 4.5(b) and 4.6(b) demonstrate that overshoots are minimized when the synced parallel paths are enabled. In Fig. 4.6, excessive over and undershoots are observed when the synchronization is disabled, while smooth transitions around the reference values are observed when syncing is enabled. In Fig. 4.6(a), (undershoot, overshoot) boundaries can be recorded as $(-4521, 2802)$ for O_1 and $(-2041, 1232)$ for O_2 . This clearly demonstrates that the inactive path controller is insensitive to the error during transitions when synchronization is enabled.

The results reveal that simultaneous synchronization feature enhances the robustness and stability of the system, which are crucial for high precision and uninterrupted system operation, compared to the traditional methodologies, which typically experience operational disturbances or high transients during mode shifts. This concept can substantially elevate the system's overall resilience and adaptability to various system conditions.

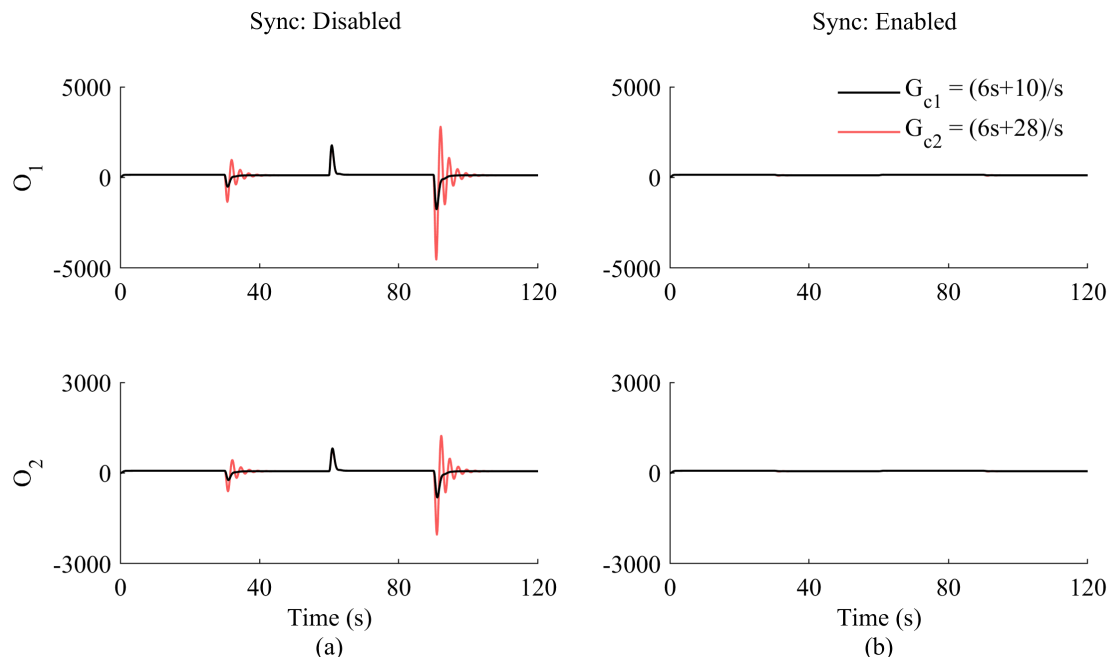


Figure 4.6: Effectiveness of the synced parallel control concept demonstrated by dynamic performance comparison of outputs, O_1 and O_2 , for ($G_{p2} = 2.5/(s+5)$) and synchronization is disabled (a) and enabled (b).

4.3 Proposed Direct Control Scheme

Inverters in microgrids must adapt themselves to different operating conditions depending on availability of the utility grid to achieve a seamless transition while maintaining an uninterrupted operation. Robustness of synced parallel control concept during the transition between different modes is crucial to minimize transients as demonstrated in Section 4.2. Therefore, a unique inverter controller that can change its mode of operation between GFL and GFM by actively synchronizing each set of GFL and GFM control paths for a seamless transition is developed in this dissertation. The block diagram representation of the proposed control method is presented in Fig. 4.7.

At any instant, only a single path is active, while the background path is synchronized with the active path, ensuring matching reference outputs during a transition. The controller features two sets of dual control paths: one set for the PWM angle and the other for voltage reference generation. To mitigate the inrush currents caused by connection of inductive and dynamic loads, a piece-wise linear virtual reactance technique is implemented. The key inno-

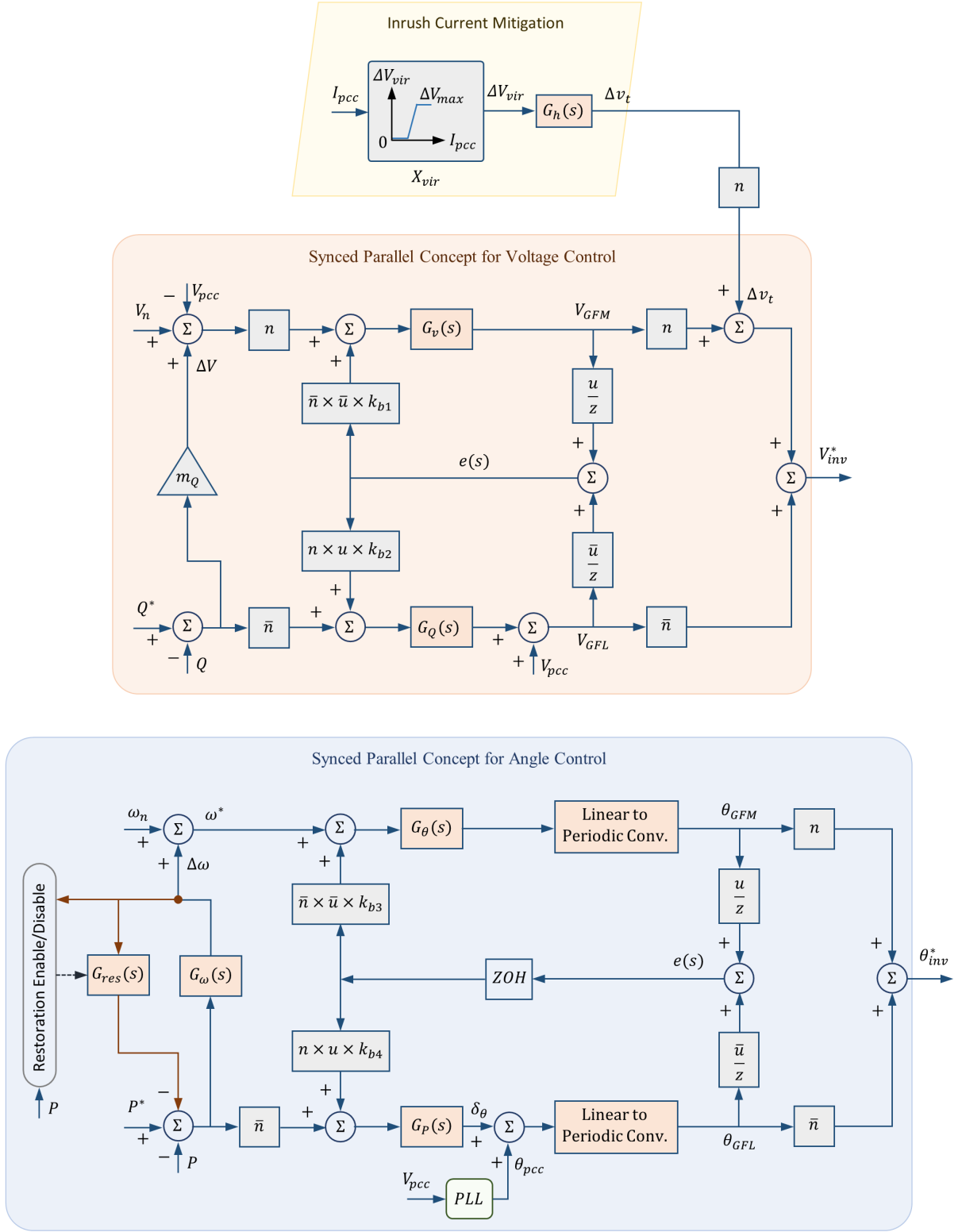


Figure 4.7: Block diagram representation of the proposed unique control method for autonomous and seamless transitions between GFL and GFM modes.

vation in the proposed architecture is its ability to allow an inverter to function independent from any supervisory commands received externally, particularly during an interruption in communication. This complete autonomy between the transitions is realized through the development of a novel communication-less grid reconnection detection algorithm, which is integrated to the unique synced parallel technique. The frequency of the system is restored using the technique developed in [55, 164], which is also required for the grid reconnection detection algorithm. The change between mode of operations is controlled by logic states, $(n, \bar{n})$. On the other hand, $(u, \bar{u})$ ensures synchronization of inactive path with the active path. The details of the developed controller are presented in the following subsections.

4.3.1 Dual Control Paths for GFM and GFL Operations

This section thoroughly explains the proposed controller, designed for both grid-following and grid-forming modes of operations, and outlines the seamless transition mechanisms between each mode. Each path used in a control set is designated for one mode of operation. In other words, two sets of voltage and phase angle references, (θ_{GFL}, V_{GFL}) and (θ_{GFM}, V_{GFM}) are generated by the parallel paths, independent from their operational mode. Notice that only one set of references, i.e., $(\theta_{inv}^* = \theta_{GFL}, V_{inv}^* = V_{GFL})$ or $(\theta_{inv}^* = \theta_{GFM}, V_{inv}^* = V_{GFM})$, is engaged for PWM signal generation, while inactive path operates simultaneously in the background, matching its outputs with the active path reference values. Therefore, the background term begins its operation at the point where the previous active path ended. This operation is anticipated to ensure smooth transients during transitions between modes, as the PWM reference values are regulated seamlessly.

The transfer functions of GFL path control blocks, as shown in Figs. 4.7, can be formulated as:

$$\begin{cases} G_P(s) = \frac{sK_{PP} + K_{IP}}{s} \\ G_Q(s) = \frac{sK_{PQ} + K_{IQ}}{s} \end{cases} \quad (4.4)$$

whereas, the transfer functions of GFM paths can be formulated as:

$$\begin{cases} G_\theta(s) = \frac{1}{s} \\ G_{res}(s) = \frac{nK_r}{s} \\ G_h(s) = \frac{\tau_t s}{\tau_t s + 1} \\ G_V(s) = \frac{sK_{PV} + K_{IV}}{s} \end{cases} \quad (4.5)$$

Depending on virtual inertia or droop control methods, $G_\omega(s)$ can be formulated similar to Eq. 2.5:

$$\begin{cases} G_\omega(s) = m_P & \text{Droop} \\ G_\omega(s) = \frac{1}{(J\omega_n s + D)} & \text{Virtual Inertia} \end{cases}$$

where, $K_{P\theta}$, K_{PP} , K_{PQ} are the proportional gains, $K_{I\theta}$, K_{IP} , K_{IQ} , K_r are the integrator gains, $\tau_t = 1/K_{I, vir}$ is the time constant of the high-pass filter used for inrush current mitigation voltage recovery loop, J is the virtual inertia constant, $\omega_n = 2\pi 60$ is the nominal grid angular frequency, and D is the virtual damping ratio. One can notice that the frequency restoration is always enabled during GFM operation.

Fig. 4.7 shows the block diagram representation of the unique synced-parallel control task structure. Each path is equipped with its own controller G_v and G_θ for voltage and phase-angle regulation in GFM mode, while G_P and G_Q for voltage and phase-angle regulation in GFL mode. Notice that the transition between modes of operations (active path) are executed by the control logic signals $(n, \bar{n})$, whereas transitions between the inactive background terms are performed using the logic signals $(u, \bar{u})$, where logic for each control signal is provided in Table 4.1. In the standardized form shown in Fig. 4.7, active power sharing between generation units is achieved using G_ω , where droop or virtual-inertia control method can be implemented, see Chapter 2.1.1 and 2.1.2 for details. During GFM operation, reactive power is shared based on the variation in frequency. Thus, demand increases, power injection from each inverter unit will proportionally increases, which results in frequency drop. Therefore, the frequency restoration control block, G_{res} , used in [55, 164] is

implemented and necessary for the innovative decentralized grid reconnection technique developed, discussed later in this chapter. ($G_{res}(s) = nK_r/s$), where K_r is the restoration gain for the integrator, and n is the logic signal defined in Table 4.1. The frequency of the system is restored to its nominal value with frequency response of $(\Delta\omega(t) = \Delta\omega(0^+)e^{-(m_P K_r)t})$, where $\Delta\omega(0^+) = m_P[P(0^-) - P(0^+)]$. The recovery time constant can be estimated as $(\tau_{res} < 5/(m_P K_r))$, based on the rule of 5τ , [55, 164].

The GFM angle control block, ($G_\theta = 1/s$), generates the PWM angle required for GFM operation. One may notice that input to G_P represent a non-periodic signal while output is a periodic. To maintain a proper syncing, input to G_θ must be non-periodic while the output is a periodic signal. Therefore, G_θ is located inside the synced-parallel loop. Since an integrator linearly sums its input, the output of G_θ can reach to large number which may cause memory issues and overwriting for selected DSP and control units. Thanks to periodicity of angles, linearly increasing input signal can be transformed to periodic signal, changing from $(0, 2\pi)$, using a linear to periodic conversion unit which facilitates trigonometric identities, as shown in Fig. 4.7. On the other hand, a feedforward direct phase-locked-loop (PLL) is used to calculate the grid angle. This expedites angle the tracking process in GFL mode, and G_P only generates a required angle difference between the voltages at inverter terminals and PCCs to inject desired active power to the system. Furthermore, the background synchronization feedback paths are delayed one sample using (z^{-1}) which helps with initial condition settings when building the control architecture to the DSP controller. A zero-order hold is implemented for the error path, $e(s)$, with a delay of one electrical cycle (16.67 ms) to prevent mismatches in tracking. This is required to maintain the values of the phase angle and ensure synchronization after each cycle, as θ_{GFL} and θ_{GFM} oscillate periodically between 0 and 2π . Thus, a sufficient time is allowed for G_θ to compare the phase-angle measurements in one instance. The outputs of G_θ and G_P are compared in the background and fed to the inactive path to match the angle outputs generated by GFL and GFM paths all the time, i.e., $(\theta_{GFL} = \theta_{GFM})$. Note that ω^* is always connected to the GFM path, regardless of whether the GFM path is active or running in the background. This is to allow an initial reference value such that $(e(s) \rightarrow 0)$ faster, and $(\omega_{GFL} = \omega_{GFM})$ can be achieved sooner since G_θ only

consists of an integrator. If this is not achieved, $e(s)$ can reach high numbers when GFM path becomes the active, and if grid is reconnected and mode of operation needs to change, a large $e(s)$ can violate seamless transition as ($\omega_{GFL} \neq \omega_{GFM}$). The feedback gains k_{b3} and k_{b4} can be used to expedite the synchronization process by forcing G_θ and G_P to yield larger δ_{GFM} and δ_θ , respectively, when $e(s)$ holds a large value.

In contrast, V_{GFL} and V_{GFM} do not exhibit periodic variation, thus eliminating the necessity for a ZOH block. Similar to the angle synchronization, voltage paths are also synced, $V_{GFM} = V_{GFL}$, using $G_v(s)$, see Fig. 4.7, when $(n = 0, \bar{n} = 1)$ and $(u = -1, \bar{u} = 1)$, as given in Table 4.1. When $(n = 1, \bar{n} = 0)$ and $(u = 1, \bar{u} = -1)$, the background term is matched with the reference value of the active path, $V_{GFL} = V_{GFM}$, using $G_Q(s)$, see Fig. 4.7. A $(Q - V)$ droop control, with m_Q being the droop coefficient, is implemented to share reactive power for loads or between inverters to regulate the PCC voltages. The feedforward term, V_{pcc} is necessary to expedite the synchronization process. Similarly, the background synchronization feedback paths are delayed one sample using z^{-1} which helps with initial condition settings when building the control architecture to the DSP controller. The feedback gains k_{b1} and k_{b2} can be used to expedite the synchronization process by forcing G_v and G_Q to yield larger V_{GFM} and δ_v , respectively, when $e(s)$ holds a large value.

Independent from the control states, the change in angle and voltage in GFL mode, $\delta\theta_{GFL}$ and δV_{GFL} , respectively, can be generalized as:

$$\begin{cases} \delta\theta_{GFL} = \bar{n} G_P(s) \Delta P + n u \left(\frac{G_P(s)}{1 + k_{b4} G_P(s)} \right) \delta\theta_{GFM} \\ \delta V_{GFL} = \bar{n} G_Q(s) \Delta Q + n u \left(\frac{G_Q(s)}{1 + k_{b2} G_Q(s)} \right) \delta\theta_{GFM} \end{cases} \quad (4.6)$$

Herein, θ_{pcc} and V_{pcc} are disturbances, and they can be considered as constant. Therefore, they are not included in Eq. (4.6). Similarly, the change in angle and voltage in GFM mode, $\delta\theta_{GFM}$ and δV_{GFM} , respectively, can be generalized as:

$$\begin{cases} \delta\theta_{GFM} = G_\omega G_\theta(s) \Delta P + \bar{n} \bar{u} \left(\frac{G_\theta(s)}{1 + k_{b3} G_\theta(s)} \right) \delta\theta_{GFL} \\ \delta V_{GFM} = n m_Q G_v(s) \Delta Q + \bar{n} \bar{u} \left(\frac{G_v(s)}{1 + k_{b1} G_v(s)} \right) \delta\theta_{GFL} \end{cases} \quad (4.7)$$

,where ($\omega_n = 2\pi f$) is constant. Therefore, it is not considered in Eq. (4.7). It is essential to match the inverter's voltage magnitude, sequence, and angle with the grid's ratings before connecting the inverter to the utility grid.

Control in GFL Mode

In grid-following (GFL) mode, the inverter remains synced with the grid by measuring the phase angle and amplitude of the voltage, θ_{pcc} and V_{pcc} , respectively. The phase angle is measured using direct phase-angle detection method, requiring only sensing two line-to-line voltages [139]. Assume that v_{ab} and v_{bc} are measured line-to-line voltages, the following formulation can be written.

$$\begin{cases} v_{ab} = V_{LL} \cos(\theta_{ab}) \\ v_{bc} = V_{LL} \cos\left(\theta_{ab} - \frac{2\pi}{3}\right) \end{cases} \quad (4.8)$$

where, V_{LL} = is the peak value of the line-to-line voltages, and ($V_{ab} = V_{bc}$) in balanced three-phase systems. V_{bc} can be further expanded as:

$$v_{bc} = -\frac{1}{2}V_{LL} \cos(\theta_{ab}) + \frac{\sqrt{3}}{2}V_{LL} \sin(\theta_{ab}) \quad (4.9)$$

After dividing Eq. (4.9) by v_{ab} in Eq. (4.8), one can write:

$$\frac{v_{bc}}{v_{ab}} = -\frac{1}{2} + \frac{\sqrt{3}}{2} \tan(\theta_{ab}) \quad (4.10)$$

Consequently, the line-to-line angle can be calculated from [188–190]:

$$\theta_{ab} = -\tan\left(\frac{v_{ab} + 2v_{bc}}{\sqrt{3}v_{ab}}\right) \quad (4.11)$$

The line-to-neutral angle can be simply calculated from $\theta_a = \theta_{ab} - (\pi/6)$. Using the analytical direct phase angle detection method results in faster dynamics compared to conventional PLL methods that relies on using closed-loop structures.

The active paths engaged in generating PWM reference angle and voltage signals during GFL operation, along with the inactive background synchronization paths, are illustrated in Fig. 4.8. The PI controller, G_P , evaluates the error between desired P^* and the measured

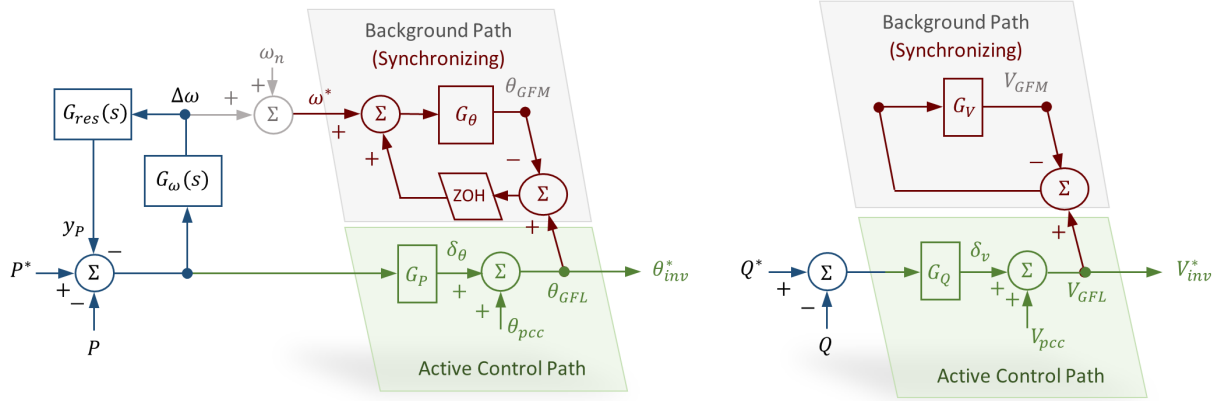


Figure 4.8: Simplified block diagram of the unique synced-parallel control method, highlighting the main paths engaging the reference values and the background paths synchronizing the outputs during GFL operation.

active power P . Then, G_P regulates the active power by adjusting δ_θ such that $(P = P^*)$, i.e., $(e_P = 0)$, where e_P represents the calculated error for G_P . Similarly, the G_Q control block controls the reactive power flow by adjusting δ_v to ensure $(Q = Q^*)$, i.e., $(e_Q = 0)$, where e_Q represents the calculated error for G_Q . If both P and Q values are set to zero, the inverter works in zero-power mode, also known as standby mode, and capable of maintaining a grid-connected state, without any power injection. This can be formulated from:

$$\begin{cases} \theta_{inv}^* = \theta_{pcc} + G_P(s)\Delta P \\ V_{inv}^* = V_{pcc} + G_Q(s)\Delta Q \end{cases} \quad (4.12)$$

In standby mode, $(\theta_{inv}^* = \theta_{pcc})$ and $(V_{inv}^* = V_{pcc})$ since theoretically $(e_P = 0)$ and $(e_Q = 0)$. Consequently, $(\delta_\theta = \delta_v = 0)$.

In grid-following mode of operation, where control states $n, \bar{n}, u, \bar{u}$ shown in Fig. 4.7 are defined as 0, 1, -1, 1, respectively, $(\theta_{inv}^* = \theta_{GFL})$ and $(V_{inv}^* = V_{GFL})$ for the active path can be rewritten from Eq. (4.6) as:

$$\begin{cases} \theta_{inv}^* = \theta_{pcc} + \delta_\theta = \theta_{pcc} + G_P(s)(P^* - P) \\ V_{inv}^* = V_{pcc} + \delta_V = V_{pcc} + G_Q(s)(Q^* - Q) \end{cases} \quad (4.13)$$

The inactive background path (GFM path) outputs can also be written as:

$$\begin{cases} \theta_{GFM} = \left(\frac{k_{b3}G_\theta(s)}{1 + k_{b3}G_\theta(s)} \right) \theta_{GFL} \\ V_{GFM} = \left(\frac{k_{b1}G_v(s)}{1 + k_{b1}G_v(s)} \right) \theta_{GFL} \end{cases} \quad (4.14)$$

It must be noted that θ_{GFM} and V_{GFM} are not engaged to the PWM generator in GFL mode. The above equations can also be verified from Fig. 4.8.

Control in GFM Mode

In grid-forming (GFM) mode, inverters generates and regulates their own voltage and phase angle references, θ_{inv}^* and V_{inv}^* , respectively. Once an inverter changes its mode of operation from GFL to GFM, the active and reactive power setpoints are instantly set to ($P^* = 0$) and ($Q^* = 0$). Note that P^* and Q^* can also be set to a different level. However, this would result in unequal power sharing if inverters are programmed to utilize the same droop coefficients, m_P and m_Q . For instance, when ($P^* > 0, Q^* > 0$), then, ($\Delta P(k+1) < \Delta P(k)$), where k represents number of samples, resulting in less active injection, whereas ($\Delta Q > 0$) increases PCC voltage since ($V^* = V_n + \Delta_v$), consequently causing reactive power absorption. The active paths engaged in generating PWM reference angle and voltage signals during GFM operation, along with the inactive background synchronization paths, are illustrated in Fig. 4.9.

In GFM mode of operation, where control states $\{n, \bar{n}, u, \bar{u}\}$ shown in Fig. 4.7 are defined as $\{1, 0, 1, -1\}$, respectively, ($\theta_{inv}^* = \theta_{GFM}$) and ($V_{inv}^* = V_{GFM}$) for the active path can be rewritten from Eq. (4.7) as:

$$\begin{cases} \theta_{inv}^* = \theta_n + \delta\theta_{GFM} = \omega_n G_\theta(s) + G_{res}(s)G_\omega(s)(P^* - P) \\ V_{inv}^* = V_n + \delta V_{GFM} = V_n + m_q G_v(s)(Q^* - Q) \end{cases} \quad (4.15)$$

The inactive background path (GFL path) outputs can also be written as:

$$\begin{cases} \theta_{GFL} = \left(\frac{k_{b4}G_P(s)}{1 + k_{b4}G_P(s)} \right) \theta_{GFM} \\ V_{GFL} = \left(\frac{k_{b2}G_Q(s)}{1 + k_{b2}G_Q(s)} \right) \theta_{GFM} \end{cases} \quad (4.16)$$

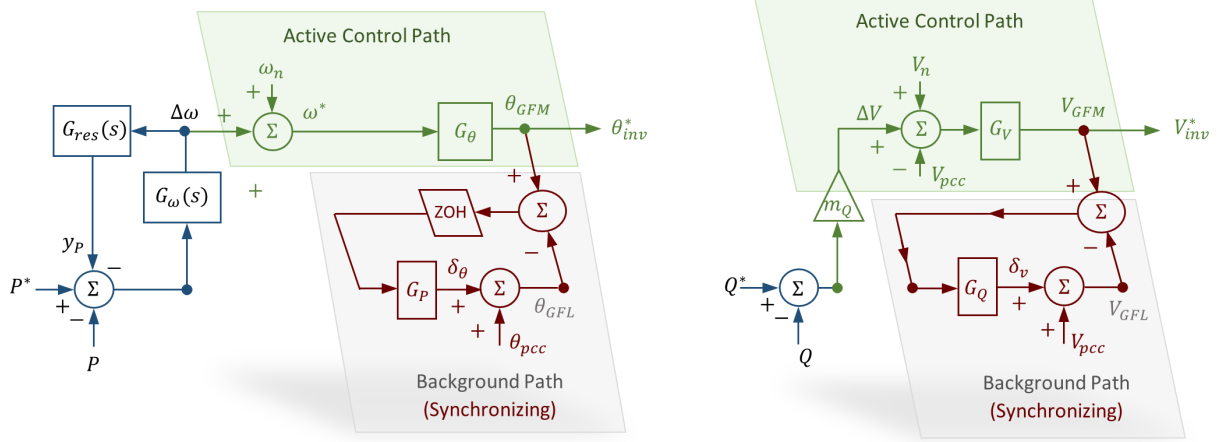


Figure 4.9: Simplified block diagram of the unique synced-parallel control method, highlighting the main paths engaging the reference values and the background paths synchronizing the outputs during GFM operation.

It must be noted that θ_{GFL} and V_{GFL} are not engaged to the PWM generator in GFL mode. The above equations can also be verified from Fig. 4.9.

4.4 Novel Autonomous Grid Reconnection Detection

This section introduces the main contribution of this dissertation, which is autonomous technique for detecting grid reconnection for inverters operating in GFM mode, which does not rely on external sensors or communication signals. Using this method, an inverter in GFM mode can detect grid reconnection through measurements of active power and frequency, and subsequently switch to GFL mode using the unique synced-parallel control scheme. An inverter implementing this decentralized approach with parallel control structure can still maintain their operation in GFM mode, possible when inverter's frequency, phase-angle, and voltage amplitude align with those of the grid at the PCC using a synchro-check relays. Notice that implementing a frequency restoration technique is essential to bring the microgrid frequency to its nominal values, minimizing the difference between the actual utility grid frequency and risk of sudden power surges upon the grid and microgrid connection. Then, a synchro-check relay can reestablish the connection between the grid and the islanded microgrid. However, there may still be slight imperfections in voltage phase-

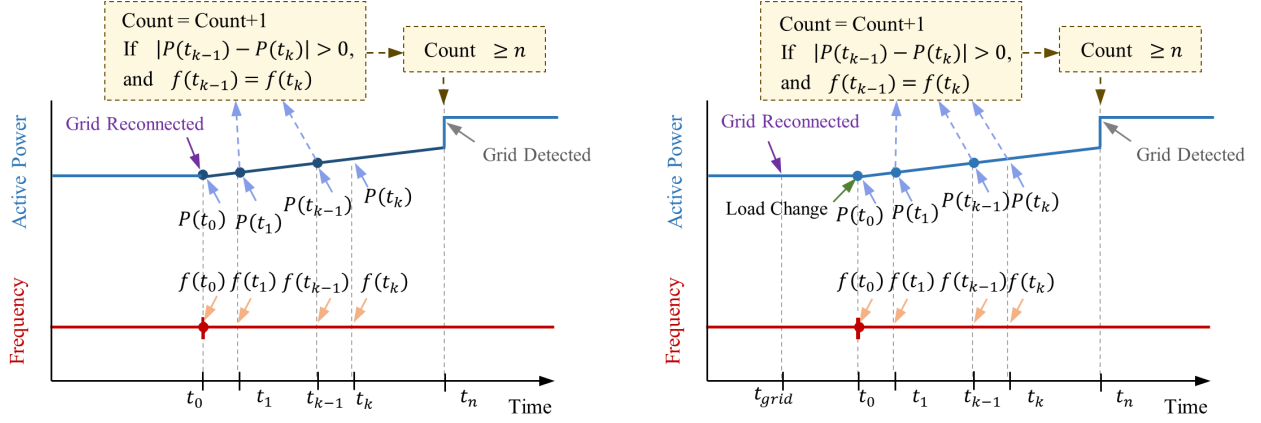


Figure 4.10: Two possible grid-reconnection scenarios for an inverter operating in GFM mode; when active power injection ramps immediately after grid connection (left), or a load is changed (right).

angle and frequency between the grid and the inverters due to non-ideal operation of the system. As a result, a discrepancy in phase-angle between the inverter and the grid emerges, leading to ramping active power injection, which can be described as $\Delta P \propto \sin(\Delta\omega dt)$. In GFM mode when droop or virtual inertia control strategies are implemented, and the utility is unavailable, this increase in power reduces the controller's frequency and amplifies the phase-angle difference between inverter's terminals and the PCC. Intriguingly, with the presence of a stiff grid (utility), the system frequency remains well regulated, holding at the nominal value, despite the inverter's increased active power injection under decentralized control. The grid reconnection detection approach introduced in this dissertation is built upon the idea that a constant frequency is detected while ramping power injection is observed by a GFM inverter in the presence of a stiff grid, as this particular situation clearly violates the droop or virtual inertia operation. Hence, active power and frequency must be measured over two distinct time periods. Upon recognizing a stiff grid, the inverter is able to seamlessly switch to GFL mode with the aid of the developed controller.

In Fig. 4.10, it is illustrated that an instant phase-angle discrepancy may arise between the inverter and the grid when the grid is reconnected, resulting in ramping active power injection, see In Fig. 4.10(left) at $(t = t_0)$. This is one of the situations indicating that a stiff power source (utility grid) is connected the microgrid. Therefore, mode of operation must be

Table 4.2: Conditions of grid reconnection detection.

Conditions	Scenario
$P(t_{k-1}) = P(t_k)$	GFM operation
$ P(t_{k-1}) - P(t_k) > 0 \ \& \ f(t_{k-1}) \neq f(t_k)$	Load change
$ P(t_{k-1}) - P(t_k) > 0 \ \& \ f(t_{k-1}) = f(t_k)$	Grid reconnected

changed to GFL to control the active power injection. In the second condition, it is assumed that the grid reconnection has been performed ideally seamless, where grid and microgrid frequencies perfectly aligned during reconnection at $(t = t_0)$. Thus, the inverters will not detect the grid at that instant, and continue their operation in GFM mode. However, a frequency mismatch between the restored microgrid frequency and the grid frequency may occur during a switched load connection, resulting in continuous increasing power injection, see Fig. 4.10(right). Thus, the proposed grid-reconnection algorithm must be used to change the mode of operation from GFM to GFL.

In Fig. 4.11, flowchart of the developed algorithm for detecting grid reconnection in decentralized concept without requiring communication is illustrated for inverter operating in GFM mode. This method involves discrete-time measurements of the active power, P and frequency, f , to calculate the sampling rate ($t_{sr} = t_k - t_{k-1}$), with t_{k-1} and t_k representing two consecutive sampling instances. Unlike the controller clock, t_{sr} is adjustable through a trigger block, where t_{sr} is the trigger duration. Selection of t_{sr} is crucial to ensure that ($t_{sr} < \Delta t_{res}$), where Δt_{res} is the maximum duration needed to restore frequency in GFM mode upon system load alterations, also referred as τ_{res} . Satisfying ($t_{sr} < \Delta t_{res}$), the inverter can accurately distinguish between grid reconnection and changes in system load. Detection of grid reconnection occurs when an alteration in active power injection is observed, ($|P(t_{k-1}) - P(t_k)| > 0$) while the frequency remains constant around the nominal value, ($f = 60$ Hz), prompting the inverter to transition to GFL mode. The criteria for this detection are detailed in the relationships shown in Table 4.2.

To avoid incorrect activation of the GFL mode flag due to unforeseen transients within the microgrid, several verification processes are needed which along with a counter, incremented

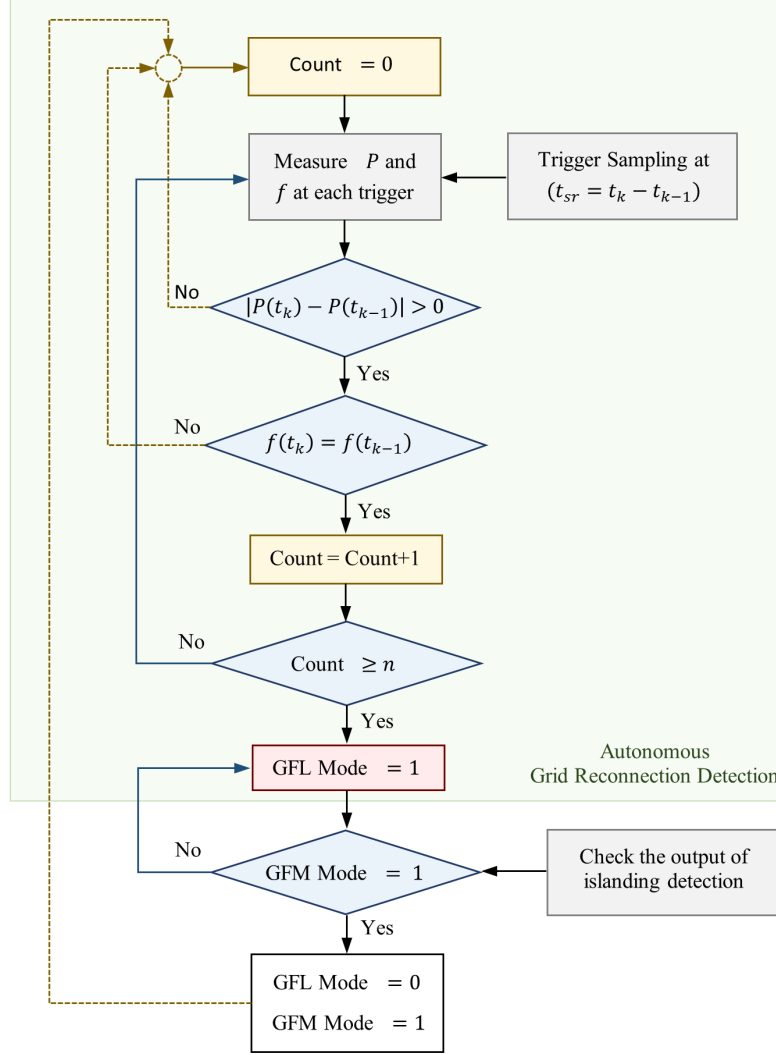


Figure 4.11: Flowchart of the fully autonomous grid-reconnection detection algorithm.

after each check. If the counter reaches a predetermined threshold, n , the grid-reconnection detection algorithm then outputs 1, prompting the inverter to switch from GFM to GFL mode.

4.5 Analytical Verification

In this section, seamless synchronization performance of the developed synced-parallel control architecture is analytically verified for two cases, i.e., transition from GFL to GFM for islanding, and GFL to GFM for grid reconnection scenarios, respectively. These analyses

are performed using the final value theorem. The details are provided below.

4.5.1 Transition from GFL to GFM: Islanding

In the absence of the utility grid, inverters must seamlessly transition from GFL, by applying the control states, $\{n, \bar{n}, u, \bar{u}\}$, as $\{1, 0, 1, -1\}$, respectively, to obtain $(\theta_{inv}^* = \theta_{GFM})$ and $(V_{inv}^* = V_{GFM})$. Considering the instant when transition is performed as t_0 , the initial angle and voltage references can be defined as $(\theta(t_{0-}) = \theta_{GFL}(t_{0-}) = \theta_{PLL} + \delta_\theta(t_{0-}))$ and $(V(t_{0-}) = V_{GFL}(t_{0-}) = V_{pcc} + \delta_v(t_{0-}))$. When the angle and voltage of the main and background paths are aligned, minimum transients are expected during the transition, allowing the local load to be powered without interruption. Considering $(G_\theta(s) = 1/s)$ and $(G_V(s) = (sK_{PV} + K_{IV})/s)$ when $(k_{b1} = k_{b3} = 1)$, then one can use Final Value Theorem for a step change at the input $(\Delta P = 1/s)$ as:

$$\begin{cases} \theta_{GFM}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{1}{s+1} \right) \theta_{GFL} \right] = \theta_{pcc} + \delta_\theta(t_{0-}) \\ V_{GFM}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{K_{PV}s + K_{IV}}{s + K_{PV}s + K_{IV}} \right) V_{GFL} \right] = V_{pcc} + \delta_v(t_{0-}) \end{cases} \quad (4.17)$$

The synchronization at steady-state is still ensured when the gain terms, k_{b1} and k_{b3} , are used to expedite the synchronization process if the controller gains of the background path is selected to be conservative. This can be verified from:

$$\begin{cases} \theta_{GFM}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{k_{b3}}{s + k_{b3}} \right) \theta_{GFL} \right] = \theta_{pcc} + \delta_\theta(t_{0-}) \\ V_{GFM}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{k_{b1}K_{PV}s + k_{b1}K_{IV}}{s + k_{b1}K_{PV}s + k_{b1}K_{IV}} \right) V_{GFL} \right] = V_{pcc} + \delta_v(t_{0-}) \end{cases} \quad (4.18)$$

Hence, $(\theta(t_{0+}) = \theta(t_{0-}))$ and $(V(t_{0+}) = V(t_{0-}))$, ensuring the continuity of angle and voltage references during the transition from GFL to GFM. The inputs to the background controllers, i.e., $(e_\theta = \theta_{GFM} - \theta_{GFL})$ and $(e_v = V_{GFM} - V_{GFL})$, forces the output of the inactive controller to effectively $(\theta_{GFM} \rightarrow \theta_{GFL})$ and $(V_{GFM} \rightarrow V_{GFL})$.

4.5.2 Transition from GFM to GFL: Grid Reconnection

For cases where multiple inverters form an islanded microgrid that is subsequently reconnected to the utility grid, inverters need to transition from GFM to GFL mode for more efficient and reliable operation. This is a challenge in decentralized manner as the utility grid must be distinguished from microgrid. Using the innovative decentralized grid reconnection detection technique, discussed in the following section, the synced parallel controller can identify the utility grid and prepares itself to change its mode of operation. At the moment of transition, t_0 , the initial angle and voltage references are set to $(\theta(t_{0-}) = \theta_{GFM}(t_{0-}) = \theta_n + \delta_\theta(t_{0-}))$ and $(V(t_{0-}) = V_{GFM}(t_{0-}) = V_n + \delta_v(t_{0-}))$. To minimize the transients during this transition, the background and main paths' angle and voltage must align, allowing the local load to be initially supported by the inverters without requiring any coast mode. After applying the transfer functions, characterized by K_{PP} , K_{IP} , K_{PQ} , and K_{IQ} coefficients, the following expression can be formulated:

$$\begin{cases} \theta_{GFL}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{K_{PP}s + K_{IP}}{s + K_{PP}s + K_{IP}} \right) \theta_{GFM} \right] = \theta_n + \delta_\theta(t_{0-}) \\ V_{GFL}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{K_{PQ}s + K_{IQ}}{s + K_{PQ}s + K_{IQ}} \right) V_{GFM} \right] = V_n + \delta_v(t_{0-}) \end{cases} \quad (4.19)$$

Similarly, synchronization is still ensured when the background path gains, i.e., k_{b2} and k_{b4} , are non-zero.

$$\begin{cases} \theta_{GFL}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{k_{b4}K_{PP}s + k_{b4}K_{IP}}{s + k_{b4}K_{PP}s + k_{b4}K_{IP}} \right) \theta_{GFM} \right] = \theta_n + \delta_\theta(t_{0-}) \\ V_{GFL}(t_{0+}) = \lim_{s \rightarrow 0} \left[(s) \left(\frac{1}{s} \right) \left(\frac{k_{b2}K_{PQ}s + k_{b2}K_{IQ}}{s + k_{b2}K_{PQ}s + k_{b2}K_{IQ}} \right) V_{GFM} \right] = V_n + \delta_v(t_{0-}) \end{cases} \quad (4.20)$$

,where $(\theta(t_{0+}) = \theta(t_{0-}))$ and $(V(t_{0+}) = V(t_{0-}))$, the consistency of angle and voltage references is consistently ensured during transitions from GFM to GFL mode. Similarly, this seamless transition is made possible by the operation of the background paths.

4.6 Insights and Discussion

The self-governing control structure presented in this chapter is developed to address various challenges observed in inverter-based microgrids. Therefore, the reasons why the proposed controller is significant for distributed generation units are listed below along with some discussion on controller design.

- Switching the mode of operation from GFM to GFL often relies on communication links, which can be impractical and expensive for larger-scale microgrids. Given the possibility of communication disruptions or interference, the system risks instability without appropriate control measures. The presented innovative decentralized grid-reconnection detection strategy eliminates the need for communication to switch operational modes. This approach offers an adaptive response to fluctuating grid conditions, maintaining stable system frequency and voltage levels at the Point of Common Coupling (PCC).
- The developed control structure also removes the necessity for an intermittent mode, commonly referred to as a coast mode, which is employed to facilitate seamless transitions between modes, thereby simplifying the control processes.
- The synchronized parallel tasks approach can be adapted for different GFM and GFL strategies, allowing for the independent selection of controllers for each mode while synchronizing their outputs.
- The grid-reconnection detection algorithm verifies availability of the grid in various ways such as during connection of the utility grid or a load change when grid-connected. Therefore, room of failure is minimized.
- Incoming inverters may continue their operation in GFL mode although the system is islanded, and the rest of the inverters operate in GFM mode. The developed controller can detect the variations in frequency and seamlessly change their operating mode to GFM during a load change or microgrid interactions.
- The parallel control paths used to generate PWM phase angle and voltage references for GFM and GFL modes are continuously synchronized in the background, enabling

a seamless transition between each mode.

- This configurable control strategy using the logic states offers flexible control solution since n number of tasks can be performed by increasing the number of branches even for the tasks that requires no synchronization such as inrush current mitigation.
- The background paths are proven to match with the active paths during the steady-state using the final value theorem. Therefore, both paths will adjust their outputs to uncertainties in the system by maintaining the synchronization. Unlike the developed control architecture, a traditional control method running in the background may output an outdated PWM reference signals for the changing system conditions, inevitably resulting in high transients when mode of operation changes.
- Only the paths functioning in the background are synchronized with the currently active path. This alignment guarantees a seamless shift between modes by reducing any disturbances that might arise from toggling between the main and secondary control paths.
- The controller requires communication in GFL operation for utility-scale applications to receive active and reactive power setpoints when economic dispatching is applied by the utility supervisory control unit. However, for residential applications, $P^* = P_{\max}$ and $Q^* = 0$, where $P_{\max}$ may represent the maximum power point of solar and wind turbines, or the maximum capacity of the inverter when driven by energy storage units. Therefore, the inverters can operate 100% autonomous.
- Frequency restoration near nominal value is a necessary future for grid reconnection since a large difference in frequency causes desynchronization between grid and micro-grid voltages measured by both sides of the circuit breaker or synchro-check relays, making seamless transition a challenging task.
- The comprehensive control topology not only facilitates plug-and-play flexibility for inverters but also delivers a universal control strategy adaptable across various microgrid configurations.

4.7 Conclusion

This chapter has presented a novel control architecture for microgrid inverters that introduces an always synced parallel control pathways for GFM and GFL control tasks to generate the desired PWM voltage and its angle. Together with the innovative and first-in-class grid reconnection detection technique, the requirement for communication links and external sensors in presence of utility grid has been eliminated. The strategy has been developed to observe a negligible power and voltage transients within the IEEE Std. 1547, during islanding and grid-reconnection scenarios where modes of operations change. A gradual power escalation while the frequency being nearly constant around the nominal value reveals the secret behind the grid-detection algorithm. The overall control topology enables plug-and-play flexibility for the inverters while providing a universal control approach.

Chapter 5

Experimental Verification

This chapter experimentally validates the efficacy and performance of the proposed autonomous controller which operates independently without requiring communication during islanding or grid reconnection events. It must be underlined that the main contribution of this dissertation comes from developing the communication-less grid reconnection detection and seamless synchronization. The experiments are performed using laboratory-scale three-phase multi-inverter-based microgrid hardware setups. This hardware setup can represent an industry or utility which equips the inverters and has full control access to power their local demand.

Details of the developed inverter-based microgrid hardware setup are provided in Section (5.1). The robustness of the innovative and universal controller architecture is extensively tested in Section (5.2) across a range of scenarios, including various load, i.e., static loads and induction motor, and grid conditions, i.e., islanding, grid reconnection, or microgrid connection. Analyses are presented to justify the experimentally obtained outcomes for each scenario. Then, insights are provided in Section (5.3) to highlight the technical contributions of the developed methodology. The chapter is ended in Section (5.4) with closing remarks.

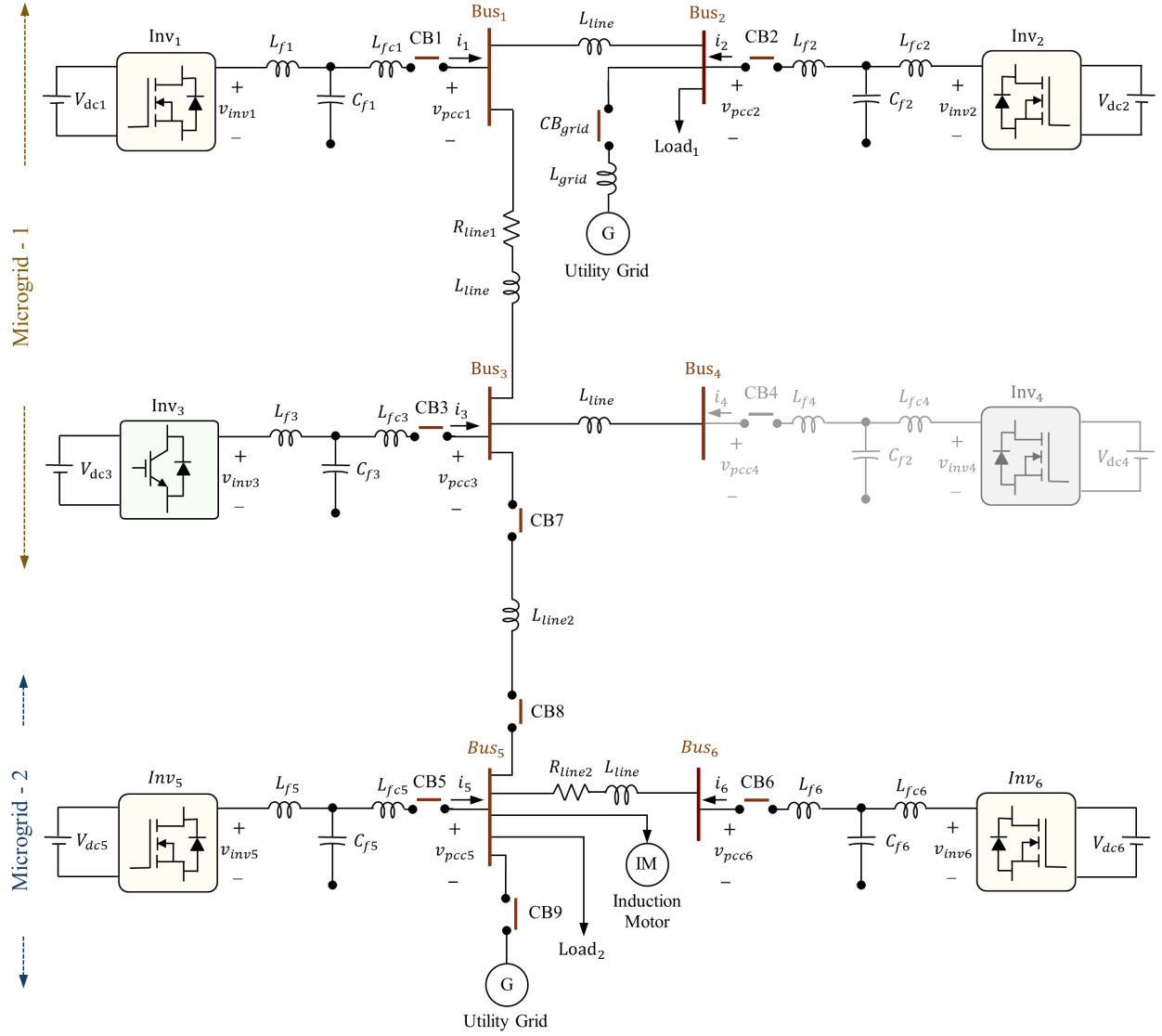


Figure 5.1: Schematic diagram of the dual microgrid multi-inverter hardware testbed.

5.1 System Configuration

This section introduces the block diagram representation and image of the actual laboratory-scale microgrids utilized for the experimental tests. The developed system consists of two individual microgrids, as shown in Fig. 5.1, considering that the owner of the system has the authority to cluster their power structure based on application and demand. The first microgrid, MG_1 , features three inverters, Inv_1 , Inv_2 , and Inv_3 , while the second microgrid, MG_2 , is equipped with only two inverters, Inv_4 and Inv_5 .

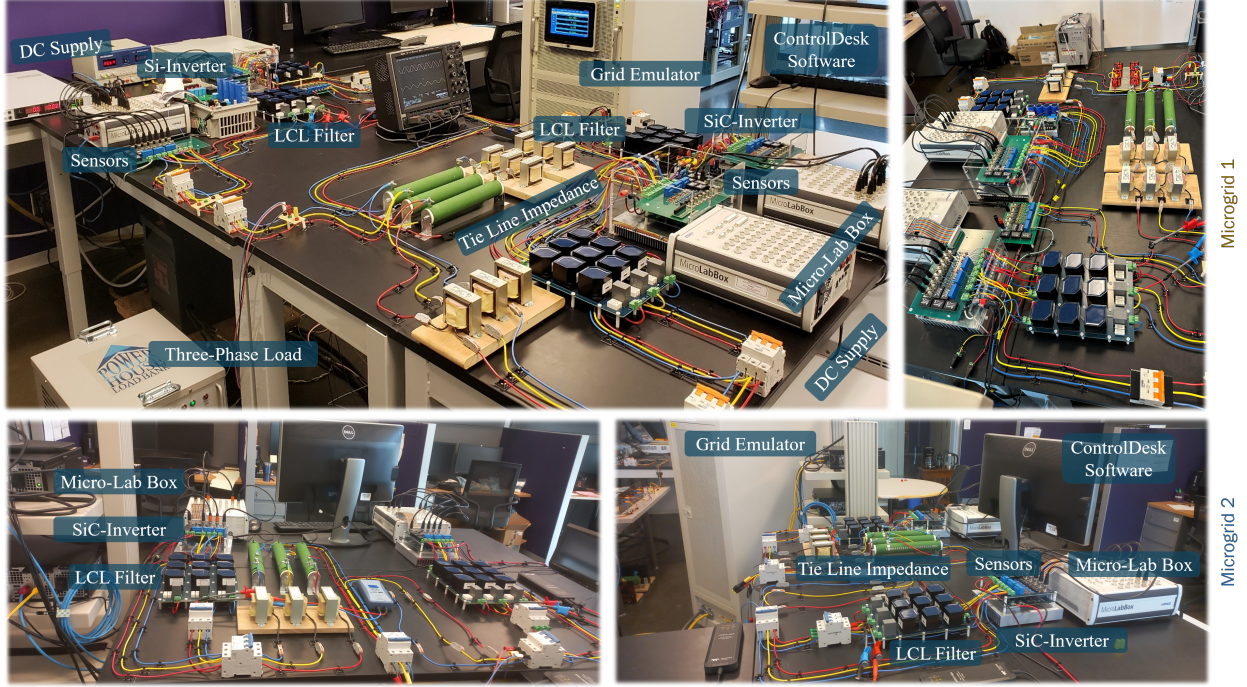


Figure 5.2: Developed microgrid setups used for experimental verification; (top) microgrid 1 and (bottom) microgrid 2.

Each inverter equipped with a sensor board to measure their three-phase line-to-line PCC voltages, v_{pcc} , and line currents, i . An LCL filter set is designed with a resonance frequency of $f_r < (f_{PWM}/2)$, and connected at inverters' output terminals. The filter capacitors, C_f , are connected in delta configuration. Thus, the effective output capacitance becomes three times larger, $C_\Delta = 3C_Y$, compared to the capacitance value in Wye configuration. The PCC-side inductor, L_2 , provides coupling between inverters connected to the same bus, preventing parallel operation of inverters. Outputs of the inverter filters are connected to their corresponding PCCs through a circuit breaker, CB1, CB2, and CB3 for the first microgrid, and CB5 and CB6 for the second.

In the first microgrid show in Fig. 5.1, a switching static load is connected to Bus₂. The tie-line impedances, represented by R_{line} and L_{line} , are used to emulate transmission lines of varying lengths. The utility grid is connected to Bus₂ through, L_{grid} . Furthermore, L_{line} , connects Bus₁ to Bus₂ and Bus₃ to Bus₄. Longer electrical distance is represented by $R_{line,1}$ and L_{line} . Notice that Inv₄ is disconnected from the system as a part of experimental procedure. On the other hand, an identical switching static load and an induction motor are

Table 5.1: System parameters

Parameters	Value
Filter inductance (L_f)	1 mH
Coupling inductance (L_{fc})	0.5 mH
Filter capacitance (C_f)	5 μ F (Δ)
Filter cap. series resistance (R_{cf})	1.65 Ω (Δ)
Line inductances ($L_{line}, L_{line,2}$)	(2.5 mH, 49 μ H)
Line resistances ($R_{line,1}, R_{line,2}$)	(1 Ω , 0.2 Ω)
Nominal frequency (ω_n)	377 rad/s
Nominal line-to-line voltage (V_n)	208 V
PWM switching frequency (f_{PWM})	5 kHz
DC-bus voltage (V_{dc})	350 V

connected at Bus_4 as loads. Both inverters in the second microgrid, Inv_5 and Inv_6 , are connected to each other through $R_{line,2}$ and L_{line} , see Fig. 5.1. All inverters feature the innovative and autonomous control architecture in their local controllers as well as direct phase-angle detection technique to gather the voltage phase-angle and system's frequency [139]. The developed control scheme is responsible for supplying the necessary voltage amplitude and phase-angle to the PWM generation unit. The GFM control structure is compatible with both droop and virtual inertia control methods, see Fig. 2.1.

The developed inverter-based multi-microgrid experimental setup is displayed in Fig. 5.2, including a 10 kVA Silicon-IGBT, five 5 kVA Silicon Carbide (SiC) Mosfet inverters, two 30 kVA grid emulators, two 5 kW switching loads, one three-phase four-pole 1/2 HP induction motor. Operation of only one grid emulator is allowed in the system when both microgrid is synchronized and connected to each other. When they are islanded, each grid emulator can be utilized. The PWM signal generation, analog-to-digital (A/D) and digital-to-analog (D/A) conversions, as well as the controller functions, are using dSPACE MicroLabBox, while the experimental data is gathered using ControlDesk real-time interface. The system and control parameters utilized in these experiments are outlined in Tables 5.1 and 5.2, respectively.

Table 5.2: Controller parameters

Controller	K_p	K_i
Droop (m_P)	0.005	—
Droop (m_Q)	0.001	—
G_v	0.1	5
G_Q	0.005	0.0001
G_θ	—	1
G_P	0.005	0.0001
G_{res}	250	—

5.2 Experimental Analysis

The experimental procedures aim to demonstrate the effectiveness of the self-adapting controller on transitioning between modes of operation across multiple scenarios. These scenarios also include connection and disconnection of both islanded microgrids when they operate in GFM. Each experiment emphasizes the performance of the controller for numerous number of inverters in the system. It is necessary to mention that inverters measure the PCC voltage during startup and detects if there is a voltage source. If this condition satisfies, the inverter starts in GFL mode and connects the system in stand-by mode, i.e., ($P^* = 0$) to achieve seamless synchronization. Effectiveness of the stand-by syncing is well demonstrated in [1, 20, 191]. Therefore, it will not be studied in this dissertation.

5.2.1 Case 1: Grid-Interaction Through Another Microgrid

The first experimental scenario highlights the controller's flexibility in adapting to different systems that operate in random modes of operation. For this scenario, utility grid is initially connected to Bus₂ of MG₁ and Bus₅ of MG₂, and both microgrids are disconnected from each other since CB7 is initially open while CB8 is closed. Thus, the inverters in both microgrids begin their operation in GFL mode. (Load₁ = 2 kW) and (Load₂ = 1 kW) are enabled at Bus₂ of MG₁ and Bus₅ of MG₂, respectively. The initial active power setpoints, P^* , used for the experimental scenario are listed in Table 5.3. It must be underlined that Inv₄ is inactive

$(P_4, Q_4) = (0, 0)$, $v_{inv4} = 0$, and CB4 is always open, see Fig. 5.1. Thus, if $P_{all} > P_{Load}$, where P_{all} represents the total power injected from each inverter in a microgrid, i.e., ($P_{all} = P_1 + P_2 + P_3 + P_4$) for MG₁, ($P_{all} = P_5 + P_6$) for MG₂, and ($P_{all} = P_1 + P_2 + P_3 + P_4 + P_5 + P_6$) when both microgrids are connected to each other, excessive power will be injected to the utility. Otherwise, the utility will contribute to supplying the demand.

The first scenario demonstrates islanding of MG₂ and reconnection of MG₂ to the grid through MG₁. Then, the overall system will be disconnected from the utility and continue powering the system in GFM mode when both microgrids are still synced to each other. Thus, MG₂ will perform communication-less transition between modes twice. The experimental results demonstrating the active power and frequency dynamics in a multi-inverter system is shown in Fig. 5.3. From $0 < t < t_1$, all inverters inject desired active power levels as listed in Table 5.3. During this period, the GFL control path of the synced parallel control strategy is active, while the inactive GFM path is actively synchronized with the main path to achieve $e_v < \varepsilon_v$ and $e_\theta < \varepsilon_\theta$, where e_v and e_θ are the synchronization errors between GFL and GFM path outputs, and $\varepsilon_v \approx 0$ and $\varepsilon_\theta \approx 0$ represent the controller tolerance due to measurement noise, controller or measurement delays, etc.

Islanding Detection

At $(t = t_1)$, the circuit breaker CB9 opens to disconnect MG₂ from the grid. During disconnection, almost no transient in P_1 and P_2 has been observed. The zoomed-in section of Fig. 5.3 along with voltage and current waveforms when MG₂ is islanded is reported in Fig. 5.4, where no distortion is observed at $(t = t_1)$ when the grid is disconnected. Notice that the controllers maintain GFL mode of operation until the islanding is detected by the islanding detection algorithm at $(t = t_{1b})$ [1, 55, 191]. During this period, the local controllers

Table 5.3: Initial power setpoints for GFL operation

P_1^* (kW)	P_2^* (kW)	P_3^* (kW)	P_5^* (kW)	P_6^* (kW)
0.8	1.2	0.6	0.75	0.5

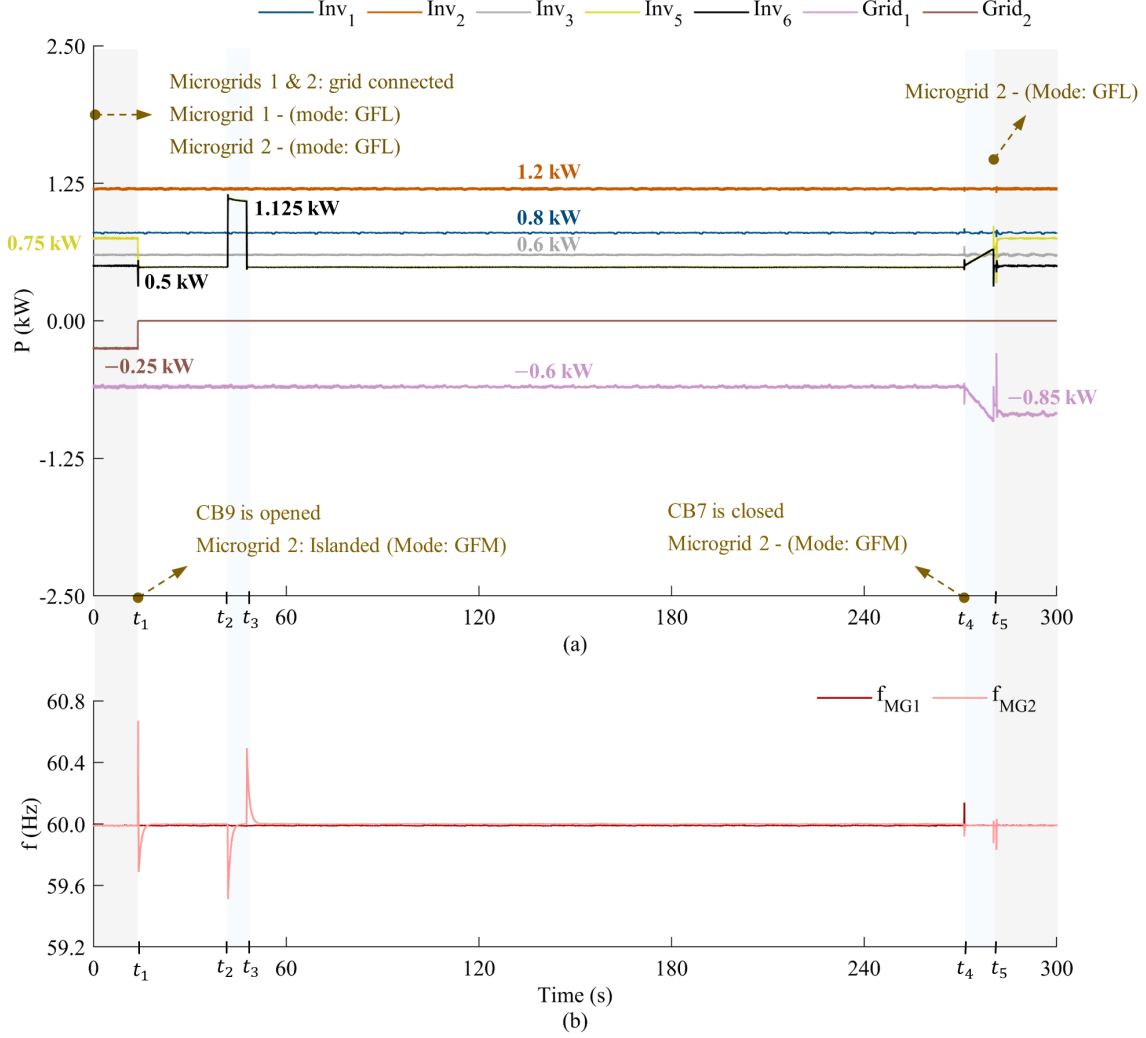


Figure 5.3: Experimental results demonstrating; (a) the active power and (b) frequency of both microgrids, where Inv₅ and Inv₆ change their mode of operation from GFL to GFM after the grid of MG₂ is disconnected at t_1 , and from GFM to GFL after MG₂ is connected to MG₁ at t_2 , and detect the grid at t_3 , while the rest of the inverters operate in GFL mode.

are unable to follow the reference setpoints as Load₂ is the only load in MG₂ and constant at 1 kW, while the PCC voltage is still being regulated by the inverters. Therefore, P_5 and P_6 momentarily drops as shown in Fig. 5.4(a) such that $(P_1 + P_2 = P_{Load2})$, neglecting the loss on line and filters, ($P_{loss} = 0$). Thus, the active power error becomes nonzero since $(e_P = -(P^* - P)e^{-\tau t} + (P^* - P))$, where τ is the growth rate that the error reaches to steady-state. Consequently, the output of PI controller, G_P , see Eq. (4.4), rises as $\int (e_P K_{IP}) dt$, which directly controls the inverter's output angle. Therefore, frequency of the islanded

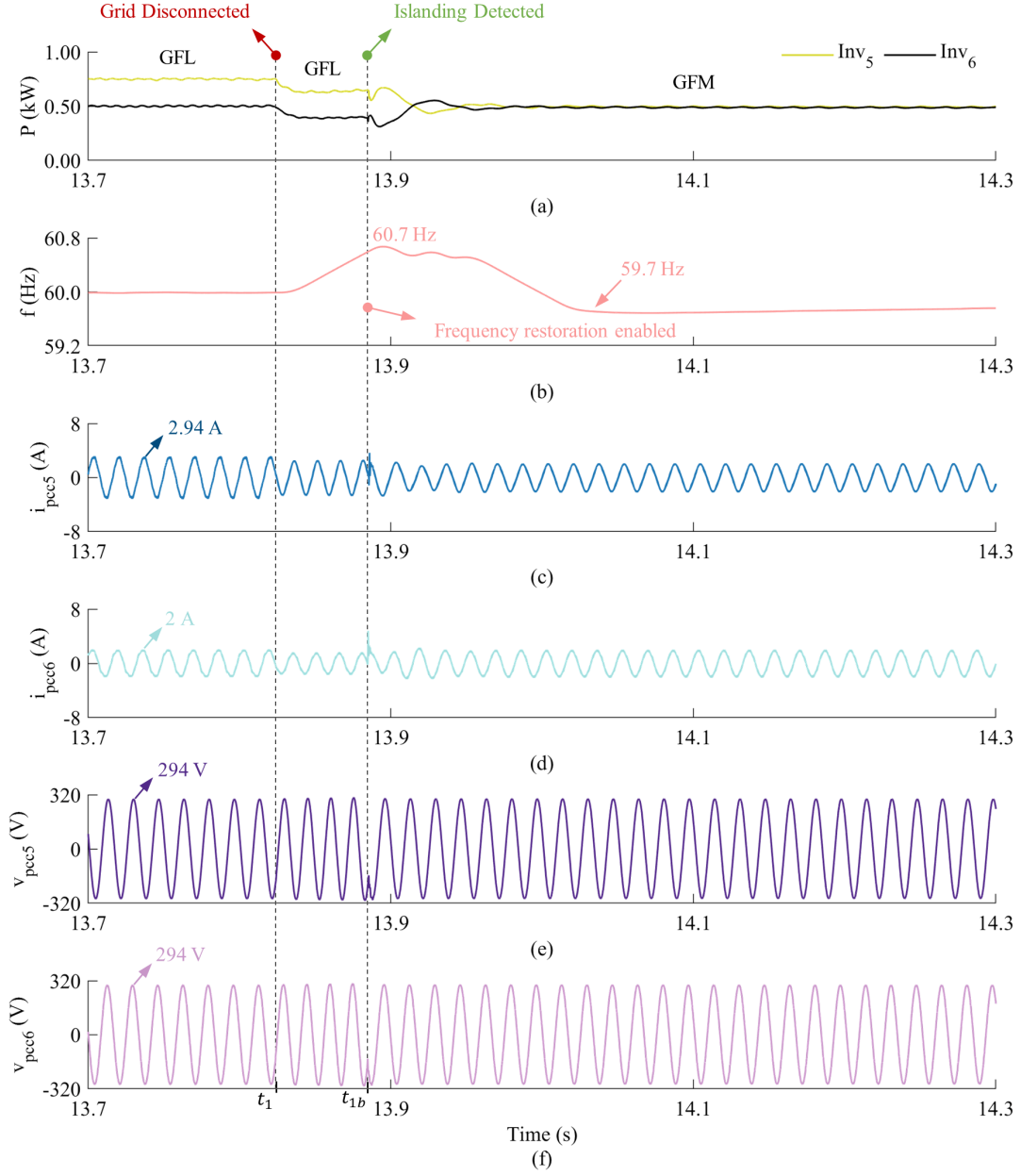


Figure 5.4: Zoomed-in plots of (a) active power, (b) frequency, PCC line currents of (c) Inv_5 and (d) Inv_6 , and PCC line-to-line voltages of (e) Inv_5 and (f) Inv_6 around t_1 when the grid is disconnected and t_{1b} when mode of operation changes from GFL to GFM due to islanding detection.

microgrid, MG_2 , becomes ($f_2 > 60$ Hz), and rises up to 60.7 Hz for this test scenario, see Fig. 5.4(b).

As soon as f_2 reaches the pre-defined frequency thresholds, $(60 - \varepsilon_{f1}) \leq f_2 \leq (60 + \varepsilon_{f2})$, where $(\varepsilon_{f1} = 1$ Hz) and $(\varepsilon_{f2} = 0.6$ Hz), the decision algorithm detects the islanding scenario

and commands to change the mode of operation from GFL to GFM at t_{1b} . During this transition no overshoots or undershoots are observed in PCC line currents as depicted in Fig. 5.4(c) and (d), and line-to-line voltages, see Fig. 5.4(e) and (f), for each inverter. Once the GFM mode is activated, the frequency restoration is enabled, and the frequency of the system is restored to its nominal value with frequency response of $(\Delta\omega(t) = \Delta\omega(0^+)e^{-(m_P K_r)t})$, where $\Delta\omega(0^+) = m_P[P(0^-) - P(0^+)]$. The recovery time constant can be estimated as $(\tau_{res} < 5/(m_P K_r))$, where $(\tau_{res} < 4 \text{ s})$, and actually calculated as $(\tau_{res} = 2.55) \text{ s}$. The selected recovery gain value, K_r , is sufficient to allow inverters to share the load with respect to their capacities and selected droop coefficients. Otherwise, the frequency droop will be manipulated, which can result in unequal or undesired power sharing. During the GFM steady-state, Inv₅ and Inv₆ share the load equally since $(m_{P5} = m_{P6})$.

At (t_{1b}) , a shift is observed in the current and voltage waveforms shown in Fig. 5.4. This happens due to the small deviation (error) between the active and inactive angle paths in synced-parallel control technique. After the grid is disconnected, the active path controller continues to adjust its angle until the mode of operation changes. Since, G_θ is slower than the time it takes for the change in mode of operation, the background term is not perfectly aligning. Fig. 5.5 shows the active and inactive path angles generated by Inv₅ and Inv₆. Notice that θ_{GFL} and θ_{GFM} deviate in Fig. 5.5(a) and (b) for Inv₅ and Inv₆, respectively. This shift between both modes of operation is observed near $(e_\theta = 1.82 \text{ rad})$, and both inverters experience the the same shift as they aligned with each other, see Fig. 5.5(c), resulting in smooth transients once the GFM mode is enabled by the islanding detection algorithm. In GFM, inverters equally share the load. Since $(G_\theta = 1/s)$, it should not be tuned using an integrator gain, which violates $(\theta = \int \omega(t) dt)$. However, the constant k_{b3} , shown in Fig. 4.7, can be set to a higher value such that $(\omega^* + (k_{b3} \bar{n} \bar{u}) = 0)$, which is the error received by G_θ , faster.

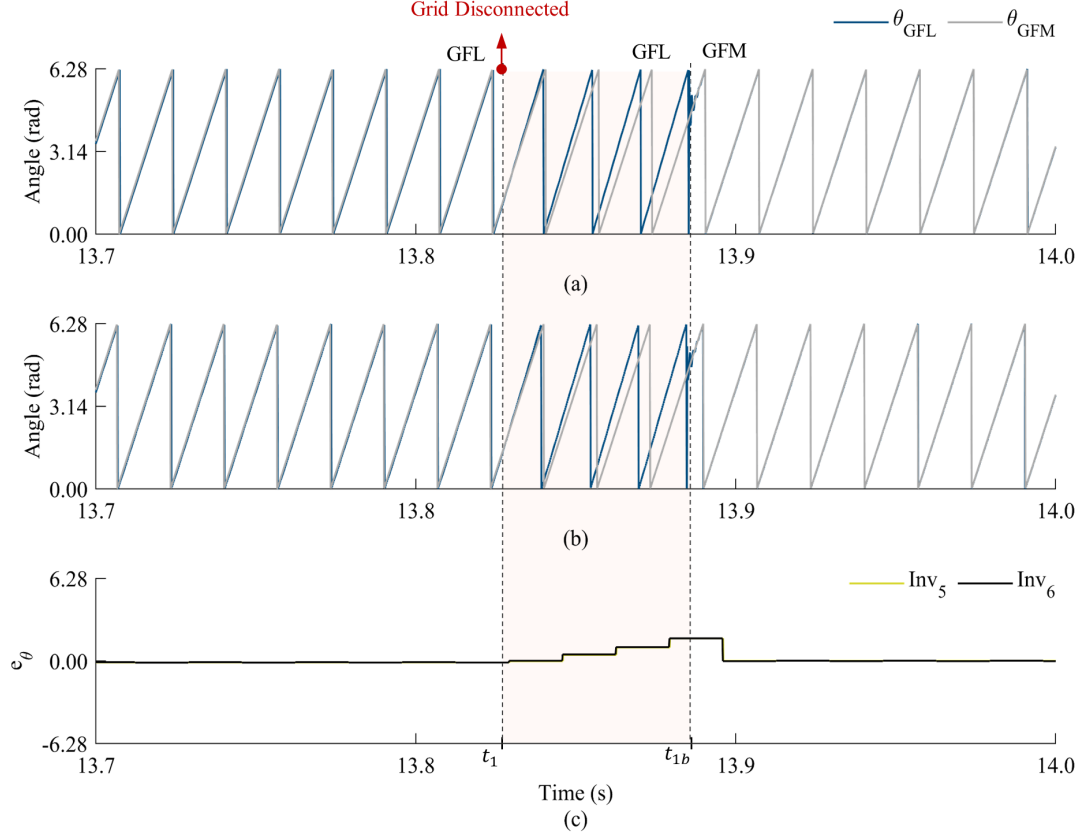


Figure 5.5: Zoomed-in plots of synced parallel angle plots including active and inactive path outputs for (a) Inv₅, (b) Inv₆, and (c) the error in angle, e_θ , demonstrating the angle synchronization dynamics during grid disconnection.

MG₂ Operates in GFM Mode

After the mode of operation is changed to GFM, the load in MG₂ is switched to ($P_{Load2} = 2.25 \text{ kW}$) at ($t = t_2$) and brought back to 1 KW at ($t = t_3$), see Fig. 5.3(a). Notice that the frequency reduces to $\{\omega_k^* = \omega_n + (P_k^* - P_k), k \in 5, 6\}$ as ($P_5 > 500 \text{ W}$) and ($P_6 > 500 \text{ W}$) before the restoration is enabled, where k represents the k^{th} inverter, and ($P^* = 0$) and ($e_P = P_k^* - P_k < 0$) in GFM mode. Then, the frequency is restored at 60 Hz. Changing the load to 1 kW result in an increase in ω_k^* as $\Delta\omega$ will hold a smaller value. The jump in frequency, seen in Fig. 5.3(b), happens since the restoration is disabled after frequency is completely restored, and the new change is added to the restored value. In other words, if restoration technique has not been implemented, the jump in frequency when the load is reduced should not pass 60 Hz. Until ($t = t_4$) is reached, MG₁ and MG₂ operates in GFL

and GFM, respectively.

MG₂ Detects Utility Grid Reconnection

In the system represented in Fig. 5.1, CB7 represents a synchro-check relay which closes only when signals from both sides of the relay are synchronized. Typically, synchro-check relays are equipped with a zero crossings algorithm. However, inverter controllers need to stabilize the voltage and frequency near nominal values to achieve ($v_{Bus,k} - v_{pcc,k} \approx 0$) during operation. This stabilization is necessary in cases where inverters might not receive any signals from the relay due to utility outages or communication disruptions. Satisfying this condition ensures a seamless transition when the switch is closed. When the grid is connected, the frequency is typically strictly regulated at 60 Hz, which can violate the droop operation unless the frequency restoration is enabled or result in ramping power injection or absorption. Therefore, changing the mode of operation is essential once the utility grid is (re)available.

The main contribution of this dissertation, which comes from the novel communication-less grid-reconnection detection algorithm is tested when MG₂ is connected to MG₁ at ($t = t_4$) as shown in Fig. 5.3, considering the utility outage at CB9 persists, see Fig. 5.1. After the synchro-check relay closes, P_5 and P_6 gradually changes while the frequency remains constant. The increase in power can be linked to minor discrepancies in the voltages of MG₁, where the grid is connected, and microgrid on each side of CB7, representing a synchro-check relay, and to the difference between the grid frequency and the restored microgrid frequency ($\omega_{MG1} \neq \omega_{MG2}$), which results in a variation of the phase-angle. It is important to note that the frequency stays constant after the initial transient, due to a stiff grid condition. In Fig. 5.6, PCC line currents and line-to-line voltages of all inverters are plotted during connection of MG₂ to MG₁. The current and voltage waveforms verifies that no significant transients are observed. Since mode of operation for Inv₅ and Inv₆ is currently GFM, and ($P_5 + P_6 = P_{Load2} = 1 \text{ kW}$), any ramp in P_5 and P_6 is fed to the utility grid. As ($|P(t_{k-1}) - P(t_k)| > 0$) and ($f(t_{k-1}) = f(t_k)$), where t_k denotes the sample at the time

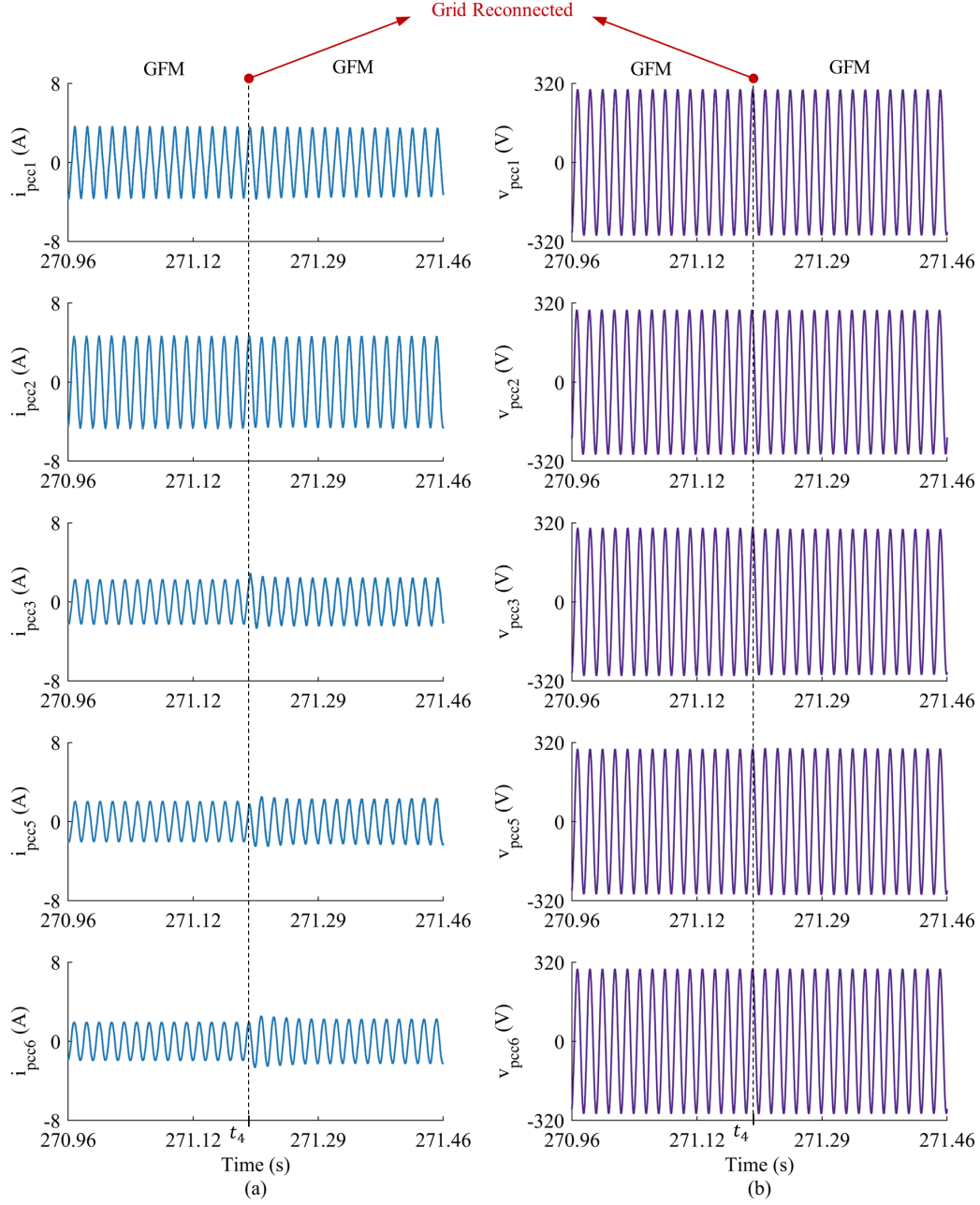


Figure 5.6: Zoomed-in plots of PCC (a) line currents and (b) line-to-line voltages of all inverters in the system around t_4 when MG_2 is connected to MG_1 through CB7, while Inv_5 and Inv_6 still operates in GFM mode.

instant, the algorithm detects the grid. To avoid false detection, a counter-based verification process is developed where ramp in active power while the frequency is constant is counted multiple times before switching the mode of operation.

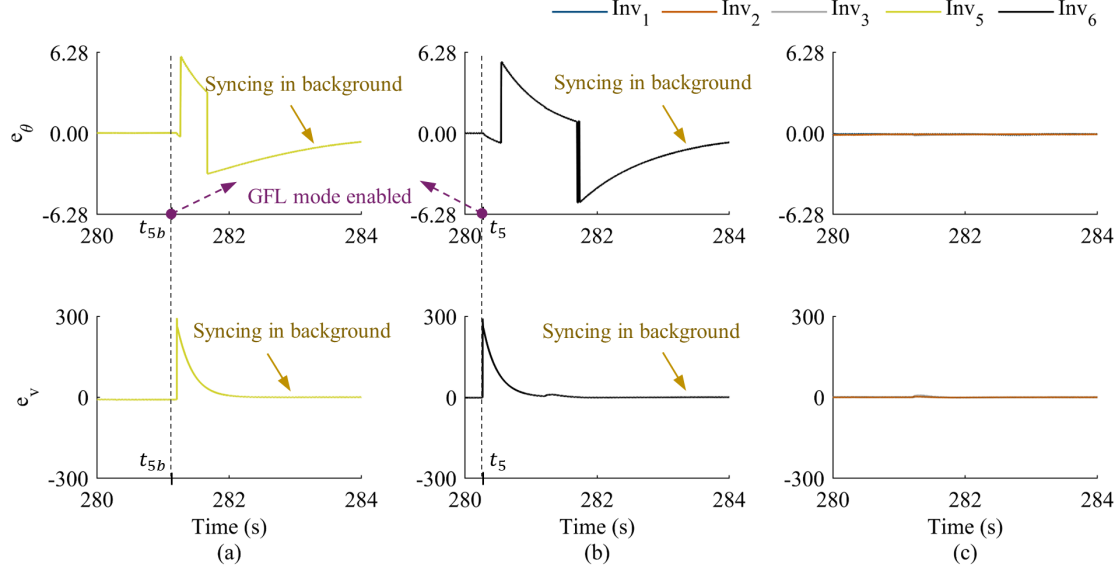


Figure 5.7: Zoomed-in plots of angle and voltage errors for (a) Inv₅, (b) Inv₆, and (c) the rest of the inverters that operate in GFL mode at ($t = t_5$) and ($t = t_{5b}$) during Inv₅ and Inv₆ change their mode of operation from GFM to GFL.

MG₂ Changes the Mode of Operation From GFM to GFL

Fig. 5.7 shows the output of voltage and angle error paths for all inverters during transition from GFM to GFL mode at ($t = t_5$). The active power, frequency, current, and voltage waveforms during grid detection and reconnection is shown in Fig. 5.8. Power may rise due to the discrepancy in frequency between the grid and the restored microgrid ($\omega_{grid} \neq \omega_{MG}$), leading to variations in the angle, along with a minor mismatch in the voltages of the grid and microgrid on either side of the CB or synchro-check relays. The GFM inverter controller is designed to autonomously identify the grid's reconnection without relying on external information. When ($\Delta P > 0$) and ($\varepsilon f_l < f < \varepsilon f_m$), where ($\varepsilon f_l = 59.95$ Hz, $\varepsilon f_m = 60.05$ Hz) are the pre-determined frequency maximum and minimum boundaries and ($\Delta P = P(k) - P(k-1)$), the algorithm verifies the trend by repeating the comparison by counting up to 10 seconds. Since inverters are individually controlled from different local control units, grid-reconnection verification time may vary. Therefore, inverters may change their mode of operation at different instants. First, Inv₆ changes its mode of operation at ($t = t_5$). At this instant, error calculated between the controller GFL and GFM parallel paths

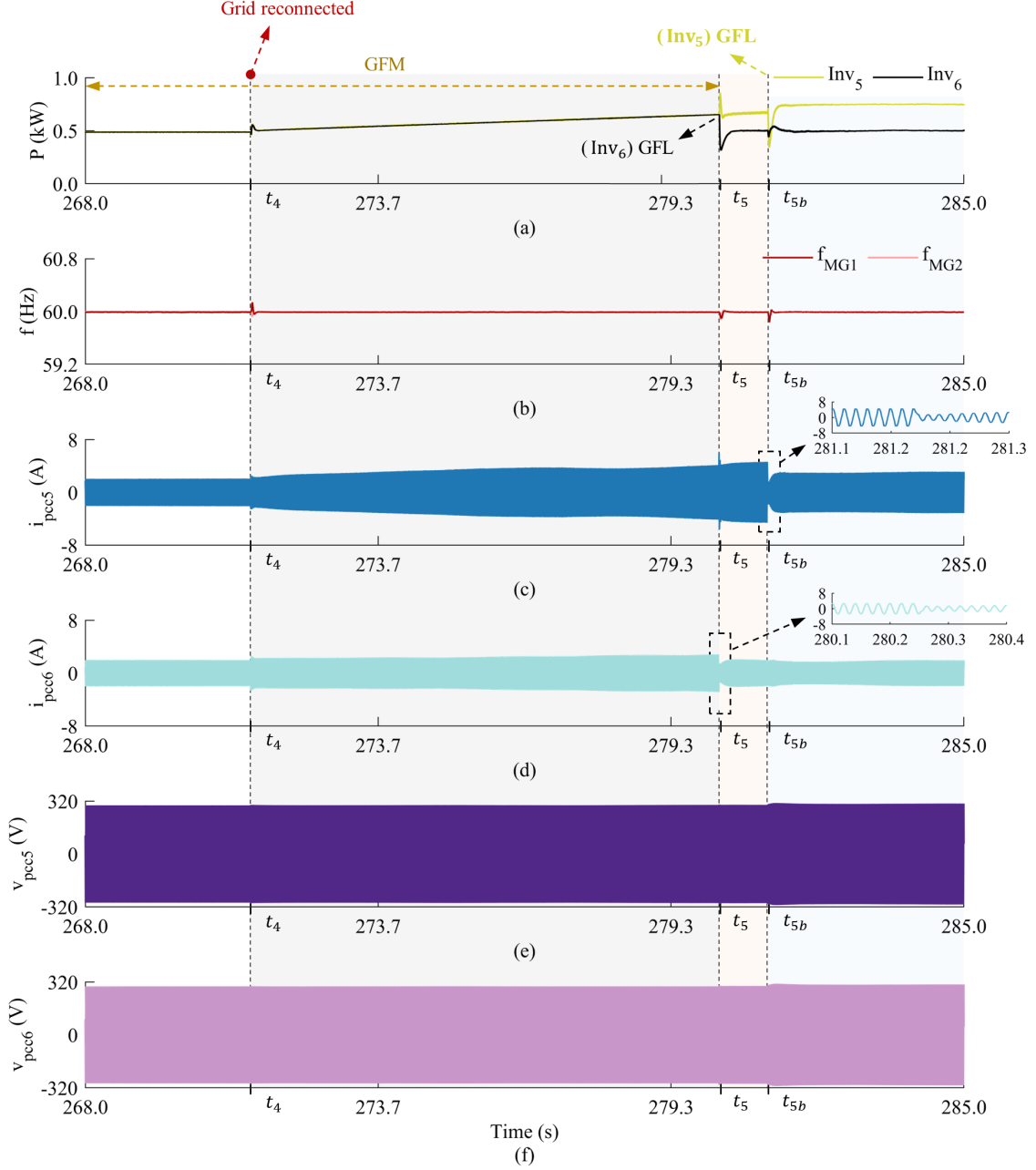


Figure 5.8: Zoomed-in plots of (a) active power, (b) frequency, PCC line currents of (c) Inv₅ and (d) Inv₆, and PCC line-to-line voltages of (e) Inv₅ and (f) Inv₆ during autonomous grid reconnection and mode of operation changes from GFM to GFL.

for angle and voltage are ($e_\theta = 0$) and ($e_v = 0$). After the change in mode of operation, error transients in angle and voltage between the parallel paths are observed. However, this error variation only happens in the background and has no effect on the active control path. Furthermore, the inactive path diminishes the error by actively syncing both paths

in the background. After transitioning to GFL mode, P_5^* and P_6^* is set to their previous setpoints until new setpoint command is received from the utility supervisory control unit. After Inv_6 , Inv_5 changes its mode of operation from GFM to GFL at $(t = t_{5b})$. Since the inverters are controlled using independent controllers, there can be measurements and sensor delays. Therefore, one inverter can detect the change in power sooner than the others. Since MG_1 is always grid-connected and no change in mode of operation is observed, the active and inactive paths of Inv_1 , Inv_2 , and Inv_3 stay synced. Fig. 5.8 reveals that no significant transients are observed during transition from GFM to GFL. The results verifies that smooth transition is achieved using the novel self-governing grid-reconnection detection technique.

5.2.2 Islanding Performance Assessment

Transition Under Mismatched Parallel Paths: Inactive Path Lagging

Adaptive matching between the active and background paths is crucial to perform a seamless transition between the modes of operations. Fig. 5.9 demonstrates the error dynamics of the synced parallel controller for each inverter connected to the system in the presence of mismatches between GFM and GFL angles and voltages. At $(t = t_6)$, CB_{grid} is opened to disconnect the grid from the system. Notice that $(P_{\text{all}} = P_1 + P_2 + P_3 + P_5 + P_6 = P_{\text{Load1}} + P_{\text{Load2}})$, and $(e_\theta \neq 0)$ since P_{all} is constant, output of $[\int (e_P K_{IP} dt) + e_P K_{PP}]$ results in increasing PWM reference angle as well as angle mismatch between the active (GFL) and inactive (GFM) paths for all inverters during $t_7 < t < t_{7b}$. Therefore, the PCC angles must also increase with respect to PWM reference angle to maintain a constant active power injection during $t_6 < t < t_{6b}$. The pulsating variation in e_θ can be ignored the periodic nature of trigonometric identities, i.e., $\sin(\theta) = \sin(\theta - 2\pi)$. Simply, the values at the higher and lower peaks of the pulses result in the same ratings. Considering that θ_{pcc} is close to θ_{inv}^* , Fig. 5.9(a) shows that the PCC angle of each inverter is ahead of the angle generated by the background GFM path by nearly e_θ at $(t = t_{6b})$ when the mode of operation changes from GFL to GFM.

A system frequency ($f > 60$ Hz) at $(t = t_{6b})$ can result in a positive $\Delta\omega$ value, depending

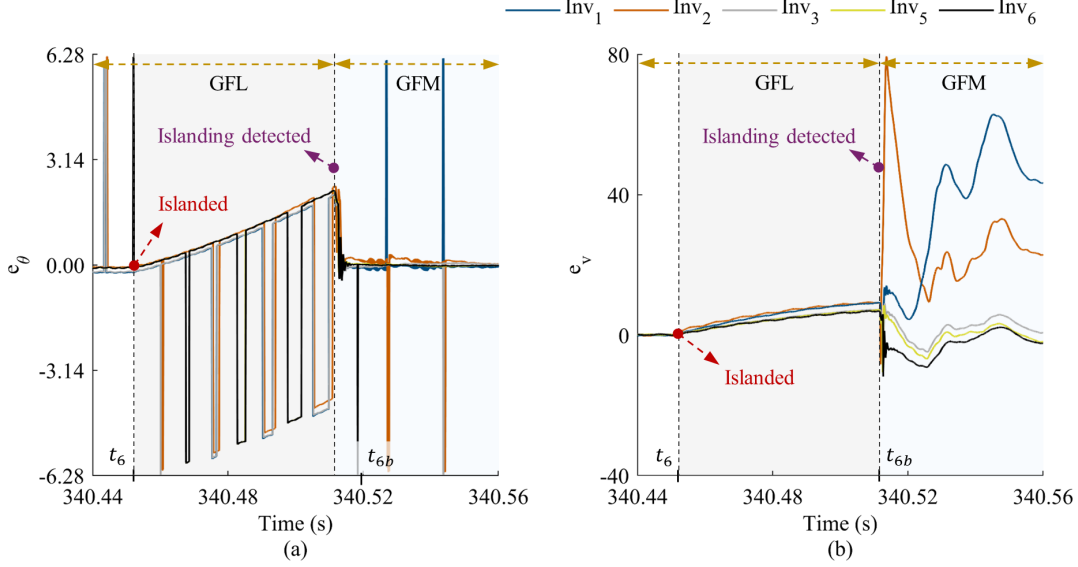


Figure 5.9: Zoomed-in plots of (a) angle and (b) voltage error dynamics for all inverters at $(t = t_6)$ when the grid is disconnected and $(t = t_{6b})$ during islanding detection and changing mode from GFL to GFM for lagging inactive path scenario.

on the droop settings, meaning a power absorption for the inverters since $(\omega^* = \omega_n + \Delta P)$ and $(\Delta P > 0)$. In droop control, the inverter terminal angle is adjusted until the system frequency reaches to steady state. At the steady-state, $(\Delta P = (\omega^* - \omega_n)/m_p)$ yields the active power that needs to be supplied from the source. Therefore, any $(e_\theta \neq 0)$ at $(t = t_{6b})$ represents the phase-shift error with respect to θ_{pcc} . Considering that the background value of θ_{inv}^* at $(t = t_{6b})$ results in $(\theta_{pcc} > \theta_{inv})$, this means that power absorption will be inevitable. From $(P = V_{inv,k} V_{pcc,k} \sin(\theta_k - \theta_{pcc,k})/X_{line,k})$, the inverters will try to absorb active power from PCC, particularly electrically closest inverters, see Fig. 5.10(a). During transients, since $\theta = \int (\omega_n + \Delta\omega) dt$ and $(\Delta\omega < 0)$, then $(\theta_l > \theta_k)$. Then, $(\theta_l - \theta_{pcc,k} > \theta_k - \theta_{pcc,k})$, where k and l represent different inverters. If the background path yields $(\theta_k - \theta_{pcc,k} < 0)$, then $(\theta_l > \theta_k)$. From $(P_k = V_{inv,k} V_{pcc,l} \sin(\theta_k - \theta_{pcc,l})/X_{line,k})$ and $(P_l = V_{inv,l} V_{pcc,l} \sin(\theta_l - \theta_{pcc,l})/X_{line,l})$, the active power dynamics can be estimated as illustrated in Fig. 5.10(a). It is important to highlight that when the stiff utility grid is disconnected, the PCC voltages fluctuate. This situation leads to increased vulnerability in the system, as it can cause inverters to conflict with one another. As soon as the proper mode of operation is enabled, the inactive path synchronizes the outputs, $(\lim_{t \rightarrow \infty} e_\theta(t) = 0)$ and $(\lim_{t \rightarrow \infty} e_v(t) = 0)$. On the other hand,

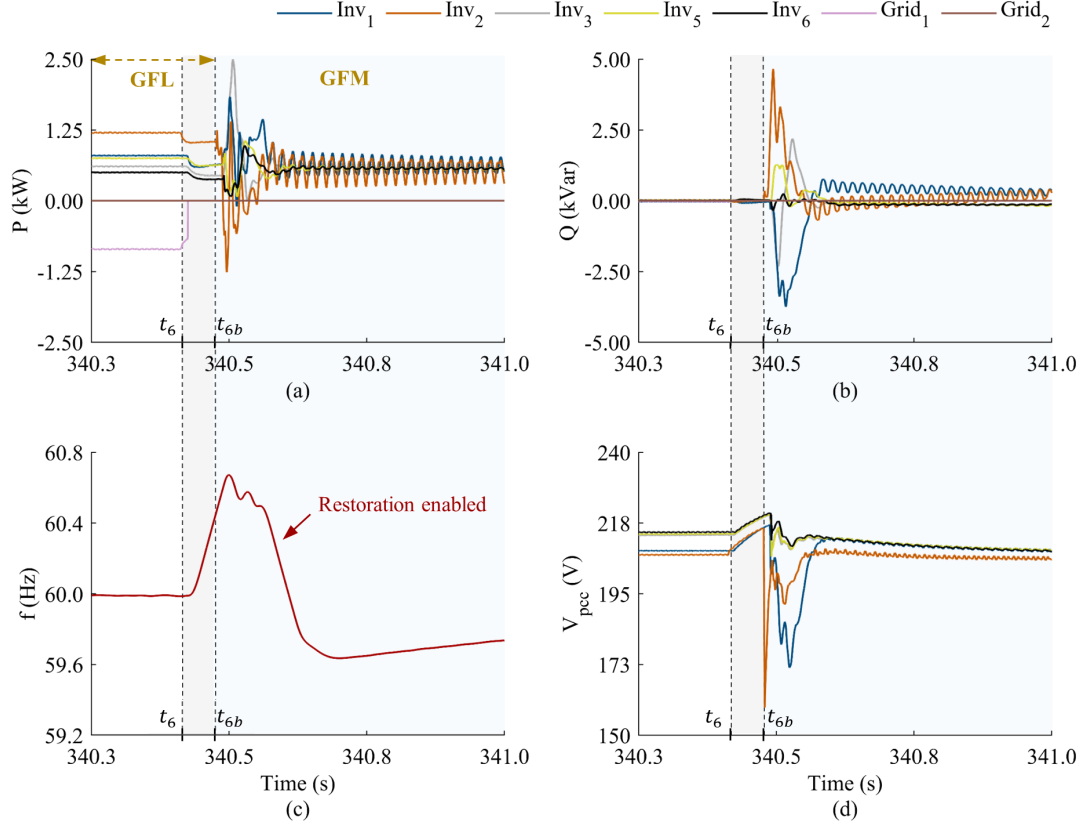


Figure 5.10: Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages in of each inverter in RMS in the system during islanding for lagging inactive path angle.

a sudden change in the PCC angles also cause larger potential differences at ($t = t_{6b}$), which lead to reactive power transients, see Fig. 5.10(b) and (d). Fig. 5.10(c) depicts that the system frequency increases since ($\theta_{pcc} = \int \omega_{pcc}(t) dt$). In a multi-inverter system, these power transients can be shared between inverters and may lead to tripping of inverters due to high current injection from one source to another.

It must be noted that Inv₂ trips due to excessive power absorption. This trip happens due to the protection features that gate-drive circuits of the SiC power modules equip. However, the inverter is still connected unless the CB2 is opened since the protection circuit only tripped a single switch out of the whole module. Therefore, oscillatory behavior and current harmonics are observed. During this time, Inv₂ is operating nonlinearly. The root-mean-square (RMS) values of line-to-line voltages which demonstrate the voltage dynamics during the change in mode of operation can be seen in Fig. 5.10(d). Furthermore, the

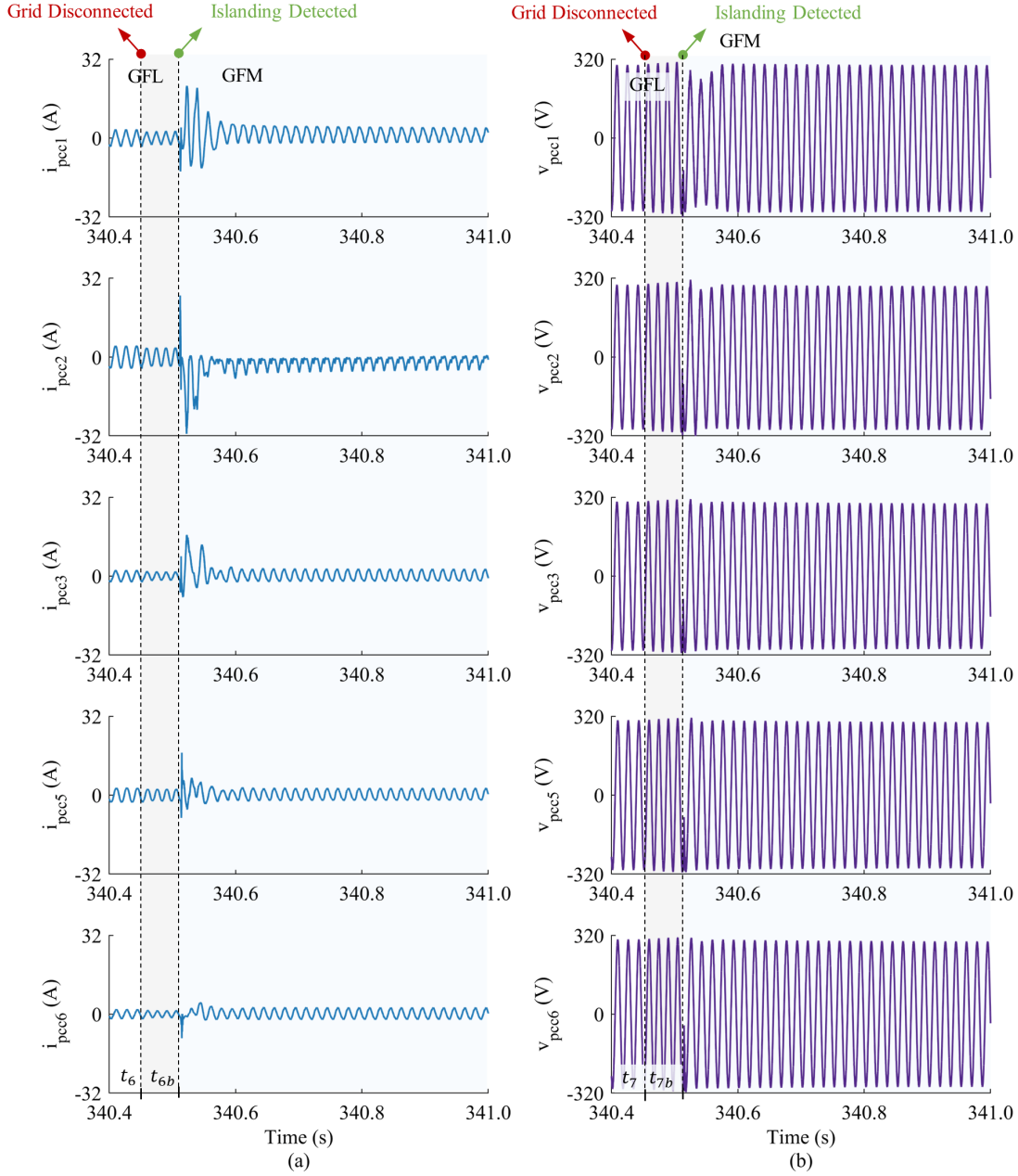


Figure 5.11: Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter in the system during islanding.

PCC line-to-line voltage and line currents of each inverter during the faulty operation is presented in Fig. 5.11. During the transient, Inv₁ exhibits ($I_{pcc1} = 20.8$ A) peak, while Inv₂ reaches ($I_{pcc2} = -31.2$ A) peak. Notice that Inv₁ and Inv₂ is momentarily overloaded since ($I_{max} = 5000/(\sqrt{3} 208) = 19.63$ A), considering $Q = 0$. However, Fig. 5.10(b) reveals that Inv₁ injects 4.67 kVar while Inv₂ absorbs 3.73 kVar, which exceeds the current limits of each

Table 5.4: Selected active power setpoints for GFL operation at increased capacity.

P_1^* (kW)	P_2^* (kW)	P_3^* (kW)	P_5^* (kW)	P_6^* (kW)
0.8	1.2	1	1	0.5

inverter and may damage the equipment if the over-current persists and CB1 and CB2 do not trip.

Transition Under Mismatched Parallel Paths: Inactive Path Leading

This scenario showcases the islanding transient performance of the developed controller when the background path angle is leading the active path angle compared to the previous mismatched scenario during islanding. Different than the previous case, active power setpoint for Inv₃ and Inv₅ are selected to be higher as ($P_3 = P_5 = 1$ kW), see Table 5.4. This change increases the total active power generation capacity to ($P_{all} = 4.5$ kW) when both MG₁ and MG₂ are connected to each other, ($P_{all} \gg P_{Load1} + P_{Load2}$) since $P_{Load1} = 1$ kW and $P_{Load2} = 1.5$ kW. Therefore, ($P_{grid} = 2$ kW) during ($t < t_1$), and P_{grid} will be applied to the system at the instant, ($t = t_1$). This large difference between the demand and generation is expected to result in voltage swells at each PCC and an increase in the system's frequency after islanding. Therefore, significant transients are often anticipated if the inverter outputs are not adequately adjusted or synchronized according to the PCC conditions, regardless of the control methodology used during the transition phase, as depicted in Fig. 5.10 and 5.11.

Fig. 5.12 shows the error dynamics of all inverters when two microgrids are connected while the utility grid is disconnected at ($t = t_1$). At ($t = t_1$), CB_{grid} is opened to disconnect the grid from the system. Similar to the case where the active path angle is leading the inactive path angle, ($P_{all} = P_1 + P_2 + P_3 + P_5 + P_6 = P_{Load1} + P_{Load2}$), and ($e_\theta \neq 0$) since P_{all} is constant, resulting in increased PWM reference angle as well as the PCC angles to maintain a constant active power injection during $t_1 < t < t_{1b}$. Before ($t = t_{1b}$), $P_1 = 410$ W, $P_2 = 782$ W, $P_3 = 572$ W, $P_5 = 751$ W, and $P_6 = 272$ W. Notice that $P_{all} > P_{Load1} + P_{Load2}$. This inequality happens due to the increase in PCC voltages as shown in Fig. 5.12(b) and Fig. 5.13(d), while the total load is fixed. As the inactive voltage path follows the active

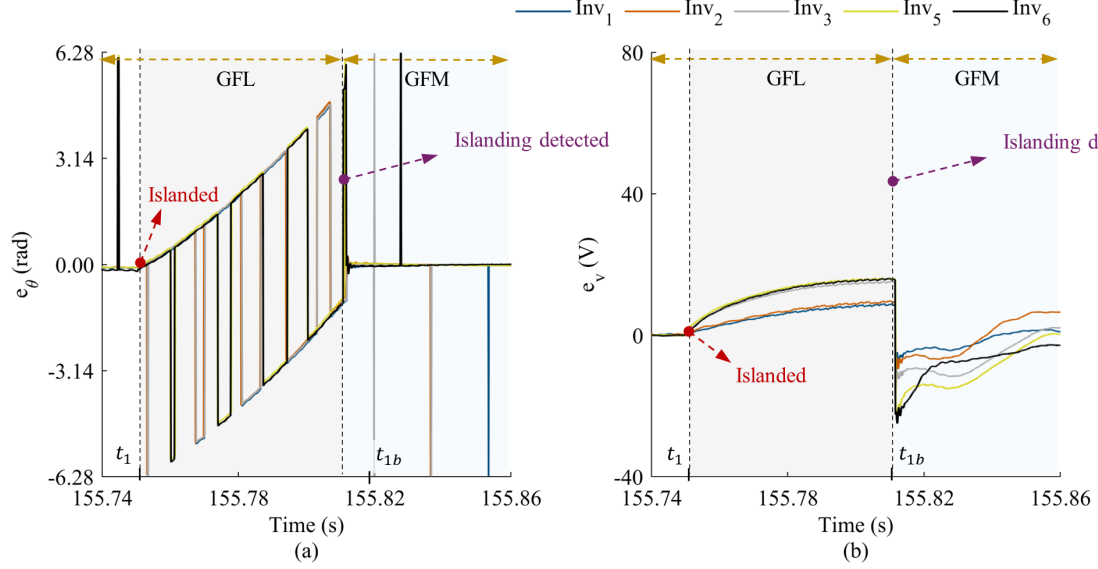


Figure 5.12: Zoomed-in plots of (a) angle and (b) voltage error dynamics for all inverters at $(t = t_1)$ when the grid is disconnected and $(t = t_{1b})$ during islanding detection and changing mode from GFL to GFM for leading inactive path scenario.

path, e_v stabilizes, see Fig. 5.12(b). The pulsating variation in e_θ can be ignored due to the periodic nature of trigonometric identities, i.e., $\sin(\theta) = \sin(\theta - 2\pi)$. Considering that θ_{pcc} is close to θ_{inv}^* , the PCC angle of each inverter lags the angle generated by the background GFM path since $(e_\theta = \theta_{GFL} - \theta_{GFM} < 0)$ at $(t = t_{1b})$ when the mode of operation changes from GFL to GFM, see Fig. 5.12(a). Again, from $(P = V_{inv,k} V_{pcc,k} \sin(\theta_k - \theta_{pcc,k}) / X_{line,k})$, the inverters will begin the transient phase with an angle reference that results in active power injection to the PCC. However, Inv₂ and Inv₅ are the closest generation units to the loads in the system. Therefore, these inverters react the load imbalances and suppress the excessive power in the system, see Fig. 5.13(a).

5.2.3 Grid Reconnection of Combined Microgrids

The performance of the novel autonomous grid reconnection is evaluated under larger-scale microgrid and operating conditions. The MG₁ and MG₂ are connected to each other, and both microgrids operate in GFM mode since the overall combined microgrid is islanded. The ratings of the loads are $P_{Load1} = 2$ kW and $P_{Load2} = 1.5$ kW, with each inverter sharing approximately 700 W equally until there is a change in the mode of operation, assuming

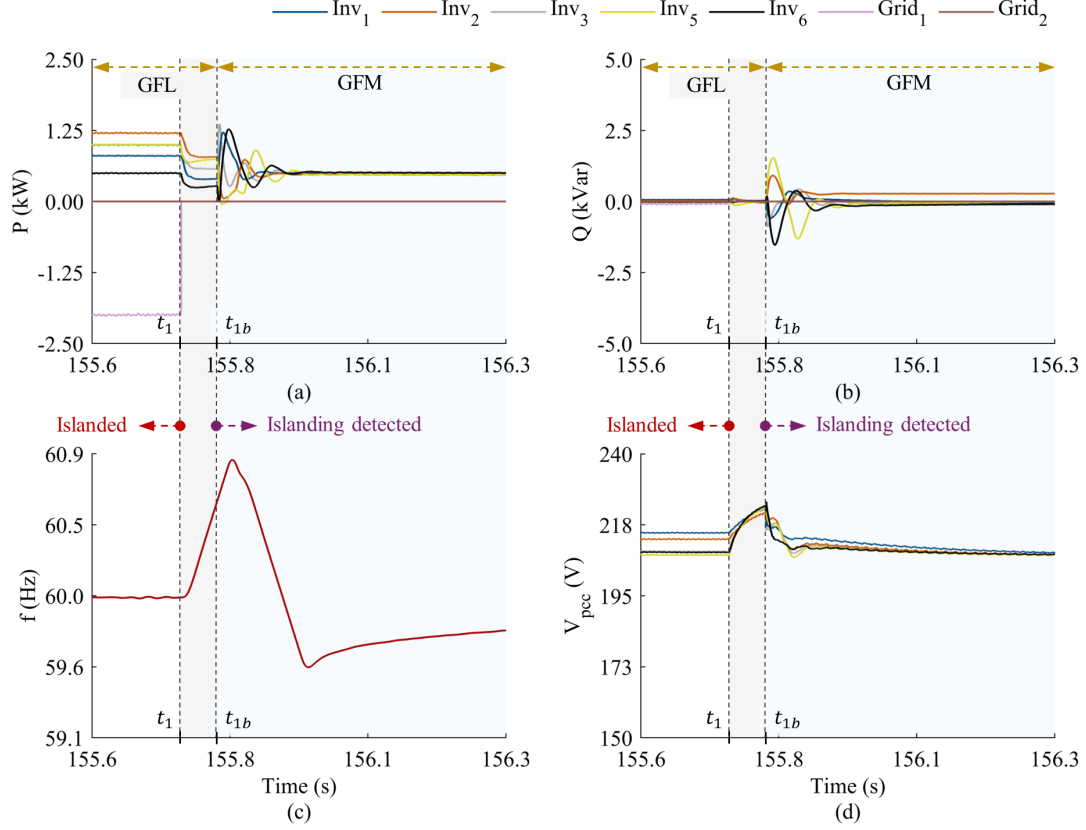


Figure 5.13: Zoomed-in plots of (a) active power, (b) reactive power, (c) system frequency, and (d) PCC voltages in of each inverter in RMS in the system during islanding for leading inactive path angle.

losses and measurement errors are negligible.

In Fig. 5.14, active power and frequency waveforms for all inverters during grid detection and reconnection is shown. For this case, the overall microgrid is connected to the grid at MG_2 at $(t = t_1)$ when the voltages are synchronized at each side of the circuit breaker. Notice that the stiff grid regulates the frequency at 60 Hz while ramping change in active power is detected by the developed algorithm. To avoid a false grid detection at $(t = t_1)$ due to the sudden rise in active power, the developed method calculates the change in active power, ΔP , by comparing the $\Delta P = P(k) - P(k-1)$. When $(\Delta P > 0)$ and $(\varepsilon f_l < f < \varepsilon f_m)$, the algorithm verifies the trend by repeating the comparison by counting up to 10 seconds. Since inverters are individually controlled from different local control units, grid-reconnection verification time may vary. Therefore, inverters may change their mode of operation at different instants. For instance, In Fig. 5.14(a) shows that Inv_3 switches its mode to GFL

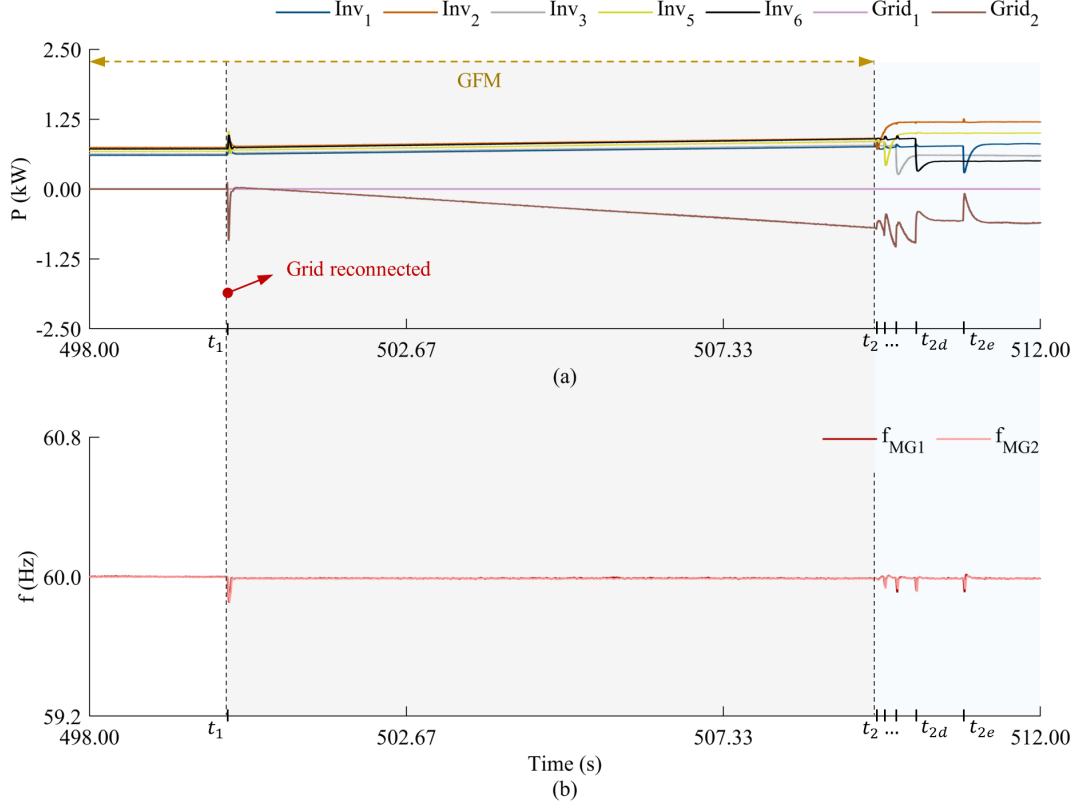


Figure 5.14: Grid reconnection performance of the islanded microgrid when all inverters operate in GFM before the transition; (a) active power and (b) system frequency.

at ($t = t_2$), while Inv_5 at ($t = t_{2b}$), Inv_1 at ($t = t_{2c}$), Inv_5 at ($t = t_{2d}$), and Inv_2 at ($t = t_{2e}$) completes the transition phase. In case the power does not ramp and inverter maintain the GFM operation, the grid can be detected by a sudden change in load. This would cause a slight mismatch, ($\omega_{grid} \neq \omega_{MG}$). Then, an increasing or reducing power can be observed, and the countdown begins [1]. Furthermore, the change in power can also be reducing instead of increasing. However, $\Delta_P = P(k) - P(k - 1)$ is still valid. To demonstrate the transients during the transition from GFM to GFL, PCC current and line-to-line voltages are plotted in Fig. 5.15. The current and voltage responses verify that a seamless transition is achieved.

The PWM phase-angle and voltage magnitude error statistics for all inverters at the instant when the transition is executed from GFM to GFL are provided in Table 5.5. In the table, phase-angle error represents the difference between the active GFM PWM angle refer-

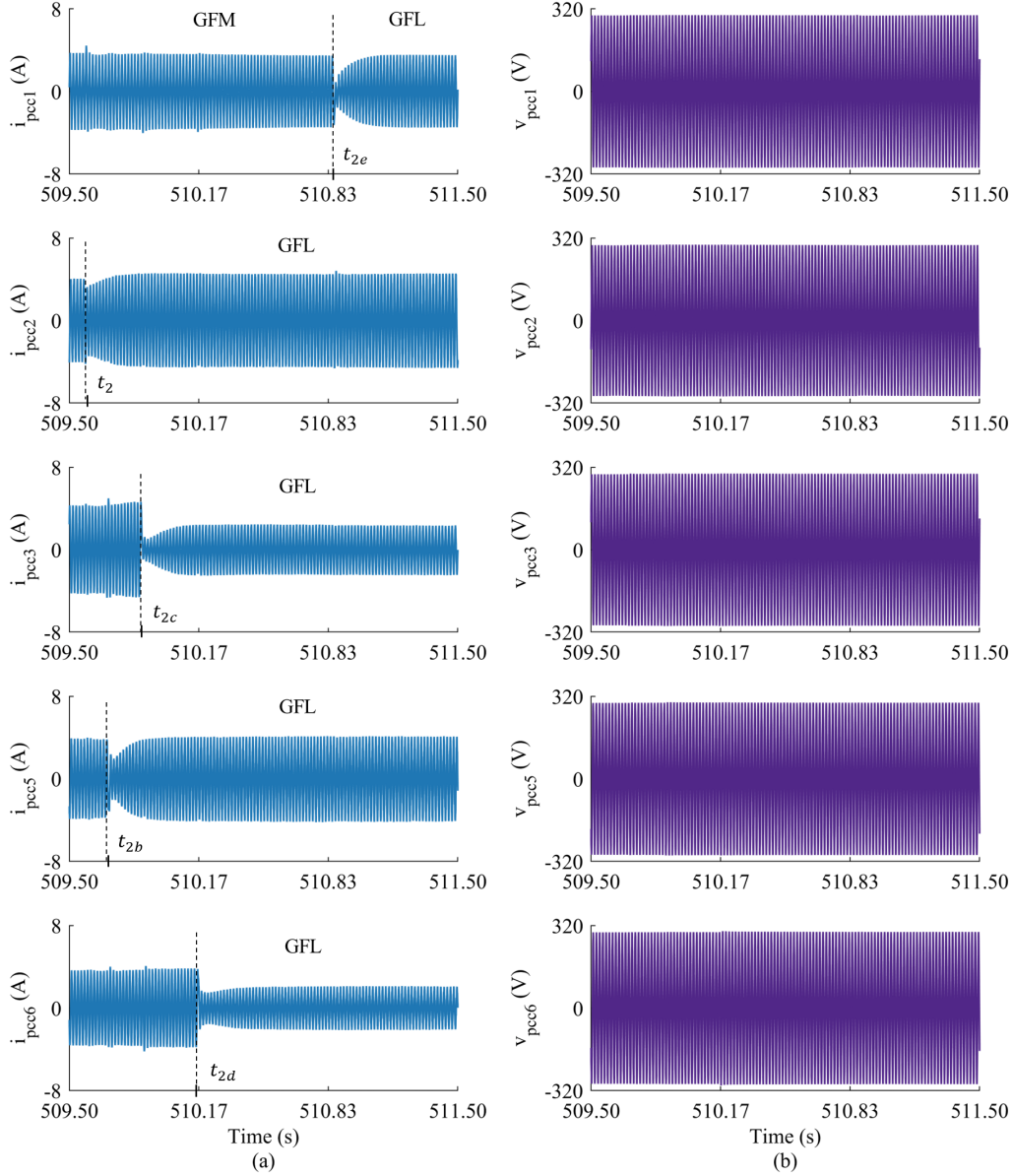


Figure 5.15: Grid reconnection performance of the islanded microgrid when all inverters are initially operate in GFM mode; (a) PCC line currents and (b) PCC line-to-line voltages during the transition.

ence path and the background GFL angle reference path. Similarly, percent error in voltage magnitudes between the active GFM and background GFL paths are reported. Table 5.5 indicates that the errors between the active and inactive paths for both angle and voltage are negligible, verifying that the communication-less grid reconnection technique can effectively maintain synchronization between parallel paths, thus enabling a smooth transition.

Table 5.5: Error statistics for generated PWM reference angle and voltage magnitude when mode of operation changes from GFM to GFL during grid reconnection.

e_θ (rad)	e_v (%)
0.01337	0.24237
0.01441	0.30962
0.02693	2.58091
0.02914	1.57686
0.02270	0.74018

5.2.4 Interconnecting Microgrids in GFM Mode

So far, the novel parallel synced controller's performance has been evaluated in utility grid islanding scenarios, where inverters operate in GFL mode, and during grid reconnection. However, islanding events between microgrids, especially when all inverters are in GFM mode, is possible and needs performance verification. Additionally, microgrids under the same facility's management can interact to augment generation capacity as needed. It's important to note that in inverter-based microgrids, the system frequency may fluctuate during such interactions, since inverters in GFM mode establish the system's voltage and frequency. Therefore, the reconnection performance of interconnected microgrids should be documented and analyzed to thoroughly validate the effectiveness of the developed control architecture.

In the following test scenario, MG_1 and MG_2 initially connected to each other, and all inverters operate in GFL mode since the utility grid is connected through Bus_2 of MG_1 , see Fig. 5.1. The active power setpoints are the same as reported in Table 5.4, while the load settings are ($P_{Load1} = 1$ kW) and ($P_{Load2} = 1.5$ kW). The active power and frequency waveforms of the experimental procedure is shown in Fig. 5.16. At ($t = t_1$), the utility grid is disconnected by opening CB_{grid} . From ($t_1 < t < t_2$), inverters switch their mode of operation from GFL to GFM and share the load equally, ($P_k = 500$ W), where ($k \in 1, 2, 3, 5, 6$), since m_p and m_q settings are identical for each inverter. The microgrids are disconnected from each other at ($t = t_2$) by opening CB_7 , see Fig. 5.1. From the inverter point of view, this is

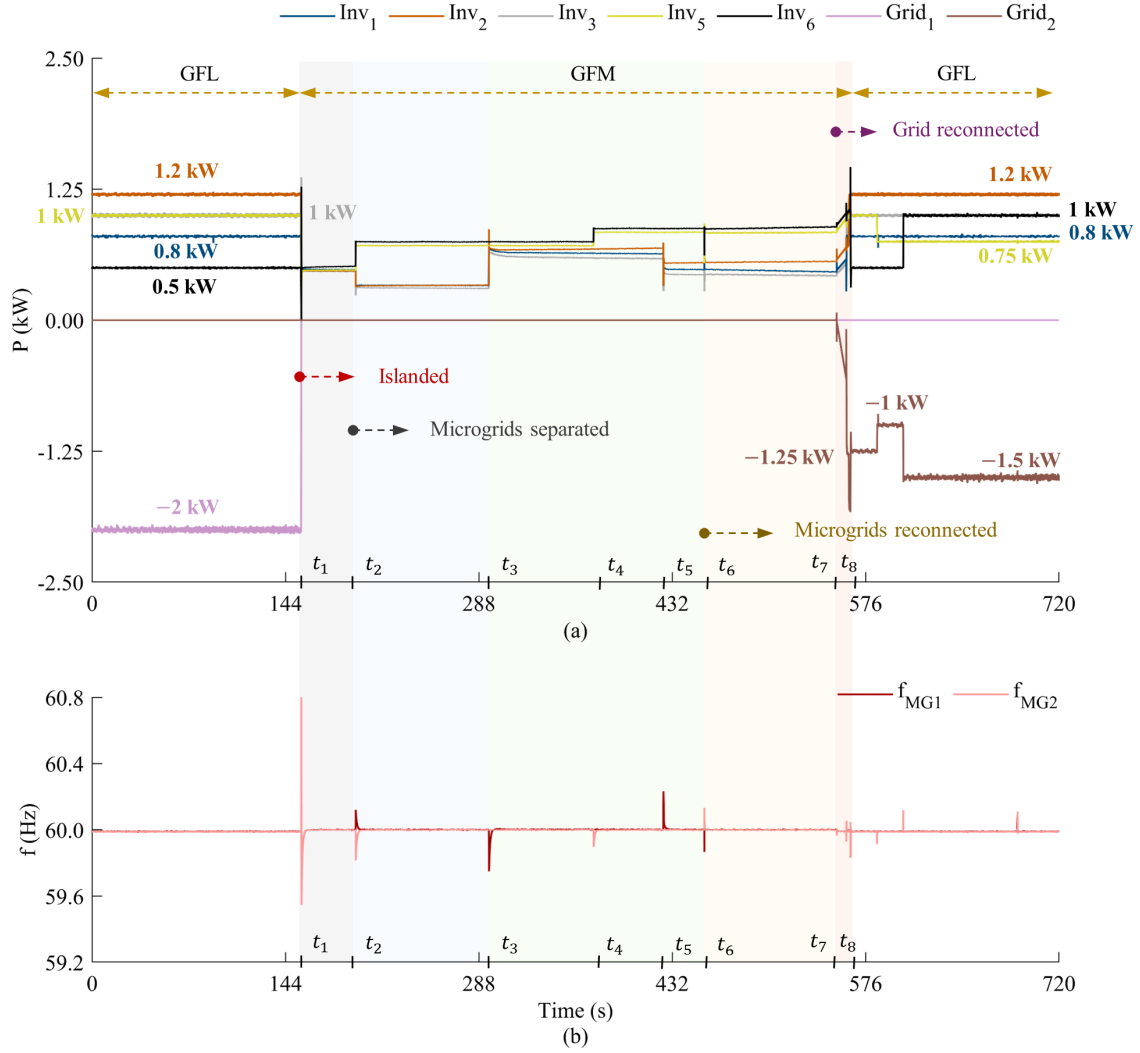


Figure 5.16: Experimental results demonstrating; (a) the active power and (b) frequency of both microgrids, where the grid is disconnected at t_1 , MG₁ and MG₂ are separated at t_2 , MG₁ and MG₂ are reconnected in GFM mode at t_5 , and utility grid is reconnected at t_6 , and inverters detect the grid reconnection and changes their mode from GFL to GFM using the proposed autonomous technique after t_8 .

perceived as a step change in load since Load₁ and Load₂ are disconnected from MG₂ and MG₁, respectively. The P , Q , f , and V_{pcc} transients are provided in Fig. 5.17 for performance demonstration. During the disconnection, PCC voltages are still regulated around the nominal values. Therefore, the load continues to consume power, and the consumed power is equally shared between each inverter in the same microgrid during the steady-state. This relationship can be derived from $(\Delta P = \Delta \omega / m_p)$, where $(\Delta \omega = \omega^* - \omega_n)$. Since the system

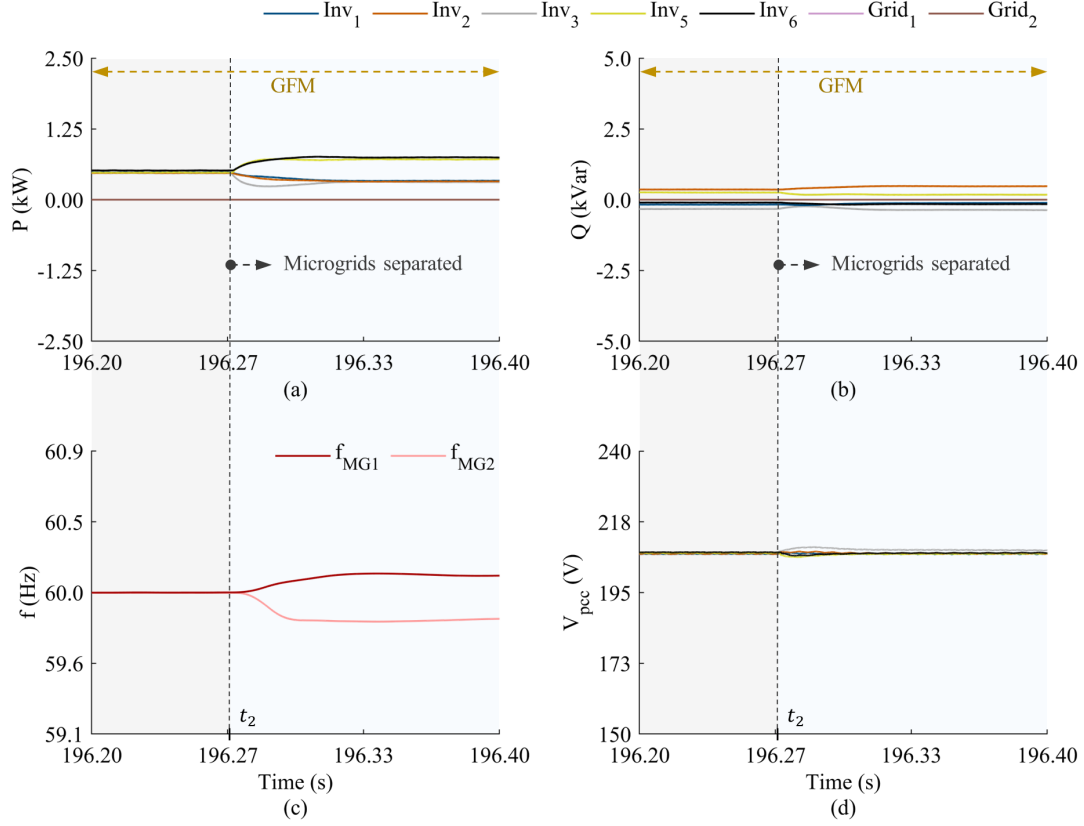


Figure 5.17: Experimental results demonstrating zoomed-in sections of; (a) the active power, (b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter during the separation of both microgrids operating in GFM mode at t_2 .

frequency is the same for each inverter, variations in frequency due to load changes dictate the amount of power an inverter needs to supply, relative to its m_p setting. As long as the droop coefficients m_p and m_q are properly selected, no significant transients are expected on active and reactive power sharing, see Fig. 5.17(a) and (b).

Notice that the frequency is restored at 60 Hz before the disconnection as shown in Fig. 5.17(c). From ($t_2 < t < t_3$), inverters at MG₁ share 1 kW load equally around ($P_k = 333$ W), where ($k \in 1, 2, 3$), and inverters at MG₂ share 1.5 kW load equally around ($P_k = 750$ W), where ($k \in 5, 6$) as reported in Fig. 5.16. This results in load reduction at MG₁. From ($\Delta\omega = m_p\Delta P$) and ($\Delta P = P^* - P$), where ($P^* = 0$) in GFM mode, see Eq. (2.1), the system frequency, ($f = \omega/(2\pi)$), increases when ($P(n+1) - P(n) < 0$), with n represents the sample in discrete-time operation. Since the frequency was restored, ($f > 60$ Hz) is recorded for MG₁ after t_2 in Fig. 5.17(c). If the frequency restoration is disabled, ($f < 60$

Hz) would be recorded for any power delivered from inverters to the load since ($f > 60$ Hz) corresponds to power absorption for our controller design while ($f = 60$ Hz) is the standby operation at nominal frequency and voltage during GFM operation. However, G_{res} , shown in Fig. 4.7, zeros $\Delta\omega$ by virtually forcing ($\Delta P = 0$) when frequency restoration is enabled. Therefore, if ($f > 60$ Hz), this results in reduced power injection from the inverter. On the other hand, ($P(n+1) - P(n) > 0$) for Inv₅ and Inv₆ at MG₂. Thus, ($f < 60$ Hz) after t_2 , see Fig. 5.17(c).

The PCC voltages may momentarily drop as shown in Fig. 5.17(d) at the Bus₂ and Bus₅, where the loads are connected since Inv₂ and Inv₅ that are electrically the closest to Load₁ and Load₂, respectively. Therefore, Inv₂ and Inv₅ is injecting ($Q_2 = 362$ Var) and ($Q_2 = 252$ Var), respectively to rise the PCC voltage before t_2 , see Fig. 5.17(b). The injected reactive power is absorbed by Inv₁, Inv₃, and Inv₅ as ($Q_1 = -174$ Var), ($Q_2 = -324$ Var), and ($Q_5 = -99.5$ Var), respectively. may momentarily vary due to a sudden change in load. The resultant (16 Var) can be counted for filter power consumption and tie-line losses. In Fig. 5.17(d), a sudden load increase at MG₂ results in an 1.312 V voltage undershoot at Bus₅ during the transient after microgrids are disconnected at t_2 . The PI voltage controller, G_v , regulates the inverter voltage back to ($V_n + \Delta V - V_{pcc}$), where ($\Delta V = m_q \Delta Q$) and ($\Delta Q = Q^* - Q$). During GFM operation, ($Q^* = 0$). Similarly, 1.082 V reduction is observed at the PCC of Inv₆ due to a sudden load increase. For Inv₂, the a sudden load reduction momentarily increased the V_{pcc2} by 0.604 V as well as 0.224 V at V_{pcc1} . The largest momentary PCC voltage rise is observed for Inv₃ as 2.215 V. This is because of the change in tie-line after microgrids are separated. Notice, Inv₃ at MG₁ is connected to the longest tie-line. Therefore, the effective impedance seen from Inv₃'s terminals are ($Z_{eff3} = R_{line1} + j\omega(L_{f3} + L_{c3} + L_{line})$) whereas it was the closest inverter to Load₂ after Inv₅.

After the microgrids are separated, P_{load1} at MG₁ is changed from 1 kW to 2 kW at ($t = t_3$). Then, P_{load2} at MG₂ is changed from 1.5 kW to 1.75 kW ($t = t_4$). After that, P_{load1} at MG₁ is again changed from 2 kW to 1.5 kW at ($t = t_5$). Following the load changes, MG₁ and MG₂ are reconnected with each other at ($t = t_6$) when both microgrids operate in GFM mode. Fig. 5.18(a) shows that the power sharing is unequal although all inverters are

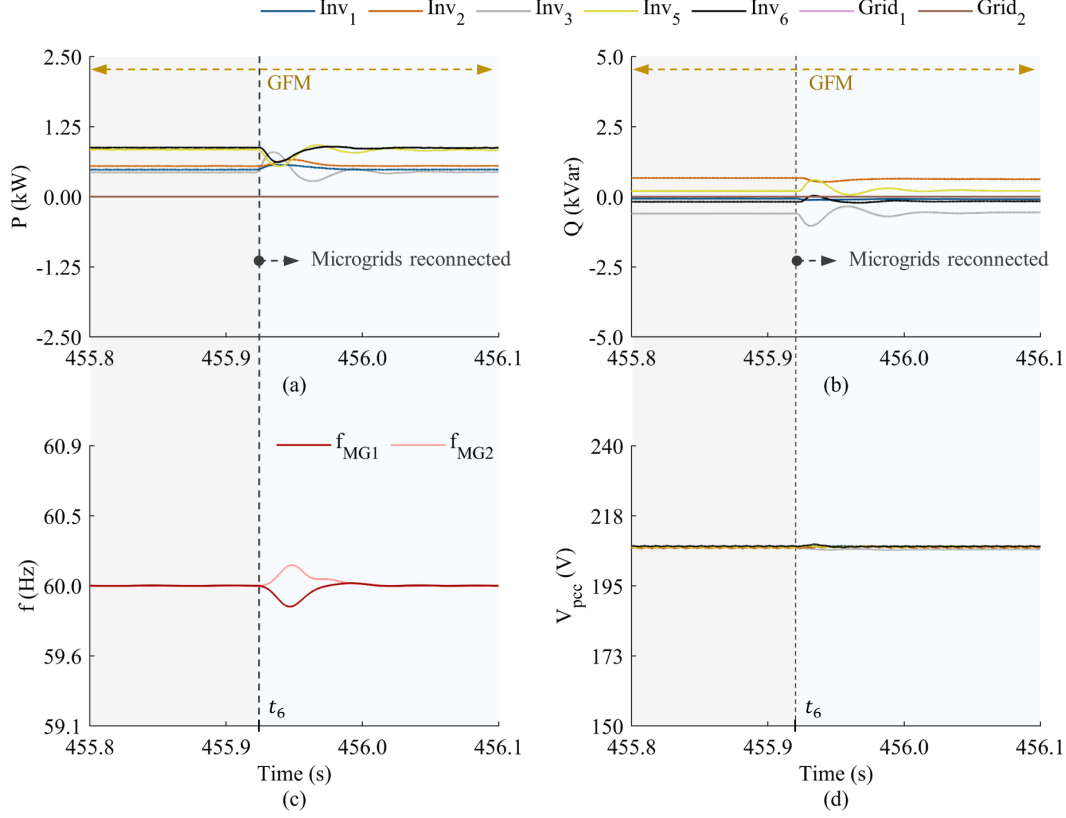


Figure 5.18: Experimental results demonstrating zoomed-in sections of; (a) the active power, (b) reactive power, (c) system frequency, and (d) PCC voltages of each inverter during reconnection of both microgrids when they operate in GFM mode at t_6 .

synced together. This is expected since frequency of both microgrids are restored at 60 Hz at $(t_6(0^-))$. Due to the imperfection (violation of zero-crossing detection) when manually closing the circuit breaker, a small frequency oscillation is observed as depicted in Fig. 5.18(c). Since P and f are related using the $(P - f)$ droop characteristic, P_5 and P_6 oscillate with respect to the frequency. Once the frequency reaches the steady-state, the power sharing remains the same as long as $(P_5 + P_6 = P_{load2})$. Thus, the inverters do not detect any change in load. After t_6 , Q_3 and Q_5 momentarily oscillates as shown in Fig. 5.18(b) since they are electrically located closer with total of 1 mH coupling inductance and $(L_{line2} = 49 \mu\text{H})$ between them. However, a seamless voltage transients are observed in Fig. 5.18(d) despite the oscillation in reactive power.

The experimental tests are concluded with final scenario where the utility grid is reconnected at Bus₂ of MG₂ while each microgrid is operating in GFM mode at $(t = t_7)$. In

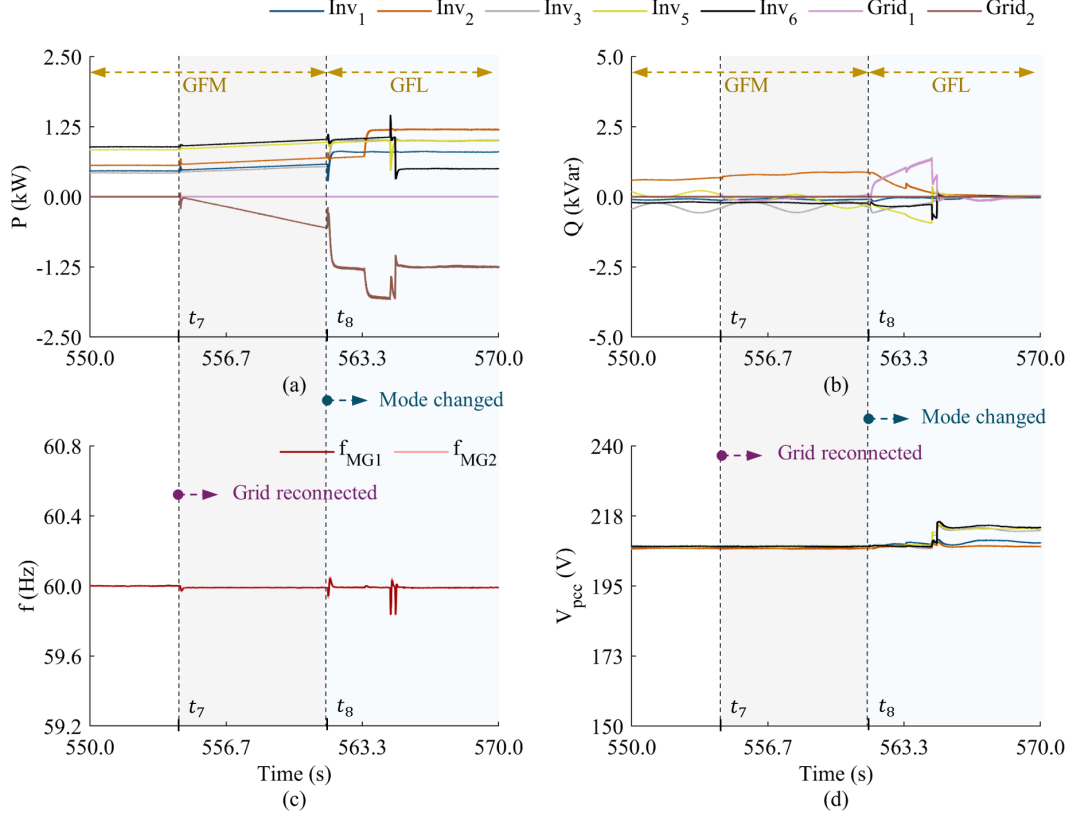


Figure 5.19: Grid reconnection performance of the islanded and interconnected microgrid scenario when all inverters operate in GFM before the transition; (a) active power and (b) system frequency.

Fig. 5.19, active power, reactive power, system frequency, and line-to-line PCC voltages in RMS are demonstrated. Power rises due to the inequality in frequency between the grid and the restored microgrid ($\omega_{grid} \neq \omega_{MG}$), leading to variations in the angle, along with a negligible voltage mismatch of the grid and microgrid on either side of the CB. This rise is detected when the frequency remains constant near 60 Hz, see Fig. 5.19(c). After 10 seconds at ($t = t_8$), Inv₁, Inv₃, Inv₂, Inv₆, and Inv₅ completes transition from GFM to GFL, respectively, and continues in grid-following mode. During the transitions, PCC voltages may slightly rise, as shown in Fig. 5.19(d), which lead Q_2 to reduce while Inv₅ and Inv₆ absorb more reactive power from the grid, see Fig. 5.19(b). Once inverter operate in GFL, they follow ($Q^* = 0$).

Table 5.6 indicates that the errors between the active and inactive paths for both angle and voltage are negligible, verifying that the communication-less grid reconnection technique

Table 5.6: Error statistics for generated PWM reference angle and voltage magnitude when mode of operation changes from GFM to GFL during grid reconnection for interconnecting microgrid case.

e_θ (rad)	e_v (%)
0.00495	0.09131
0.01510	0.07332
0.01261	1.20236
0.04396	3.37095
0.03882	1.93460

can effectively maintain synchronization between parallel paths, thus enabling a smooth transition.

5.3 Insights and Discussions

Islanded and grid reconnection experimental verification procedures verify that, inverters in microgrids have the potential to operate as voltage sources, crucial for frequency and voltage regulation. When connected to a utility grid, they typically synchronize with the grid voltage and its frequency, a mode known as grid-following, and function as current source inverters. There is extensive literature on islanding detection methods, with many already integrated into commercial inverters from the manufacturers such as ABB, Enphase, and SunnyBoy. Conventionally, microgrid inverters require communication with the main circuit breaker, e.g., a synchro-check relay, to perform a change in its operation mode. The contribution of the developed control architecture to the state-of-the-art technology can be listed as follows:

- The autonomous reconnection detection method presented here uniquely eliminates this need for communication, distinguishing it as a key component in decentralized control strategies.
- It enables inverters in GFM mode to autonomously switch to GFL mode following grid reconnection.
- If some inverters continue operating in GFM mode when utility grid is connected,

a change in mode of operation can still be executed due to a frequency mismatch between the inverter, particularly with droop or virtual inertia controllers, and grid. For instance, a load change may trigger this process. Thus, switching to GFL mode becomes necessary in these instances to manage power effectively.

- Despite power fluctuations, the utility grid maintains a stable and strict frequency regulation, which serves as an indicator for inverters to recognize grid connectivity.
- The experimental findings confirm the proposed controller's capability to manage this autonomous mode shift effectively.
- GFM and GFL control methods may yield different PWM control signal outputs. In addition to the distinctive grid-reconnection detection algorithm, implementing synced-parallel control structure matches the output of both methods while one path actively generates the reference signals, and the other one runs in the background.
- Once the background path is enabled, it initiates its operation from the point where the preceding active path reached.
- Furthermore, implementation of the synced-parallel control structure removes the redundancy of an interconnection mode, commonly referred to as a coast mode, which enables seamless switching between different modes of operation.
- The results demonstrated that if alignment is not satisfied, inverters can trip, particularly during islanding detection.
- Application of the developed synced-parallel control structure equipped with the innovative decentralized grid-reconnection detection algorithm provides an self-governing and plug-and-play operation while providing smartness for inverters.
- The developed controller becomes crucial to enable increase number of inverters in microgrids, particularly considering a multi-inverter-based zero-inertia systems where any measurement or controller delay may cause abnormal operation.

5.4 Conclusion

This chapter has introduced a self-governing control architecture for inverters in microgrids, facilitating autonomous transitions between operational modes. The architecture has allowed for islanding and grid-reconnection detection within 0.06 s and 10 s, respectively, while the duration can be programmable. This novel control method has ensured that inverters maintain operation during utility grid disconnections and disrupted or manipulated supervisory controller communication. The control strategy, incorporating synced-parallel control paths for generating PWM reference signals with specified voltage magnitude and phase angle, has been experimentally validated to provide seamless transitions between GFM and GFL modes of operations. The efficacy of the innovative grid detection algorithm has been tested and proven to perform communication-less grid reconnection without using external sensors. Experimental findings have verified the effectiveness of this control scheme in synchronizing inverters with the rest of the system and equally distributing the load during transitions from GFL to GFM mode. In this chapter, the feasibility of direct grid reconnection to the microgrid using a synchro-check relay without communication, allowing the microgrid frequency to align with the nominal value after microgrid frequency is restored by the controller, has been demonstrated. This promising autonomous control architecture provides plug-and-play flexibility and a solution for integrating more distributed energy resources at the distribution level while opening new directions for future research, particularly in enhancing stability in inverter-dominated power grids through adaptive control capabilities.

Chapter 6

Conclusion and Prospects

This chapter provides a comprehensive synthesis of the dissertation's core content, spotlighting the significant contributions of the research undertaken. It is structured into two distinct sections to facilitate a clear understanding of the key findings and insights derived throughout the study.

First, Section 6.1 serves as the foundation of this chapter, where a concise overview of the dissertation is laid out. Here, research objectives, methodologies employed, and key findings are summarized, providing a consolidated overview that highlights the essence and scope of the study. Following that, Section 6.2 is dedicated to inspire the researchers for possible enhancements or contributions based on the outcomes and groundwork laid by this research. It pinpoints areas where further investigation could yield significant advancements. This section not only highlights the potential for extending the research presented in this dissertation but also suggests new avenues and methodologies that could be explored to build upon the existing knowledge. The aim is to inspire subsequent research efforts that can lead and revolutionize autonomous, robust, and resilient control architectures for distributed generation units under various and uncertain system conditions.

6.1 Conclusion Remarks

As the modern power grid infrastructure is expected to have more clustered-grid structure, also referred as microgrids, necessity for GFM inverters in the grid are inevitable in the future. Therefore, developing a robust control structure for multi-inverter microgrids that can ensure stable operation under different grid conditions is highly popular research interest. In Chapter 1, the fundamental control concepts, i.e., grid-following (GFL) and grid-forming (GFM), for inverters have been defined, and their capabilities and drawbacks have been briefly introduced. Following the concept definitions, a comprehensive literature review has been included to identify the state-of-the-art control methodologies developed for GFM mode of operation. This review has categorized the control strategies under three main sections, i.e., centralized, decentralized (autonomous), and nonlinear control.

The outcomes of the centralized control strategy has emphasized that efficient system operation is achievable with a supervisory controller unit, capable of monitoring the overall system status, including sensor readings, when paired with an economic power dispatch algorithm. However, there are several trade-offs, such as adaptability and cost concerns, especially as the number of inverters in the system increases. Moreover, delays, communication disruptions, and accessing data network may compromise the robustness of the inverter controllers, increasing their vulnerability to cyberattacks. Such attacks could lead to inverter failures or equipment damage. To avoid the need for communication links, decentralized control approaches have been recommended.

Decentralized GFM control methods enable inverters to function autonomously, facilitating plug-and-play operation. These methods allow for operation without the need for a communication network, thereby reducing system costs and enhancing adaptability for generation units that are geographically distant from the system. Consequently, decentralized approaches enable the integration of an increased number of inverters into the system. However, operating multiple GFM inverters simultaneously can lead to instability due to inadequate synchronization, due to inverters' zero-inertia nature and decentralized power distribution. This issue is particularly challenging when an inverter is required to func-

tion in both GFL and GFM modes, necessitating seamless transitions between these modes. Therefore, it is crucial to develop a proper control architecture to ensure seamless operation across different modes while maintaining synchronization under various load and grid conditions.

The literature review has showed that nonlinear methods can provide fast control operation. However, controller design procedure and dynamic system modeling become more complicated. This complication makes proper controller parameter selection a challenge. Also, nonlinear control techniques typically require a proper filter design to eliminate high and low frequency oscillations, making them less popular alternative comparing with the other decentralized methods. Following the literature review, Chapter 1 has been concluded with proposed contribution of this dissertation.

In Chapter 2, the control concept of direct and indirect controllers have been discussed in detail and compared with each other for performance showcase. The direct control provides a voltage-controlled operation while generating PWM signal references with a single controller stage, whereas the indirect control structure enables a current-controlled operation and generates the reference PWM signals through two or more cascaded stages. When evaluating both methods in terms of performance and sensitivity, the direct method is generally found to be superior according to various studies performed in Chapter 2. Through experimental research and eigenvalue analysis, it has been noted that in the indirect method has significantly less flexibility in gain parameter selection since higher-order harmonics have been introduced compared to the direct control method, making the direct controller more robust and resilient since it has minimal impact on the system's stability. Increasing the gains of indirect controller further may lead to system instability. Therefore, it has been concluded that the success of the indirect control method significantly depends on the precise selection of controller gains, unlike in the direct method.

Chapter 3 has discussed the mitigation of inrush currents through direct and indirect grid-forming inverter control methods, emphasizing the challenges posed by inductive and dynamic loads, such as induction motors, within microgrids. It has highlighted that the connection of large inductive loads can lead to high inrush currents, potentially causing

grid-forming inverters to trip when they are switched connected to the system. A flexible voltage regulation in the controllers has been used as a solution for reducing inrush currents and ensuring equipment protection. This has been achieved by proposing virtual reactance-based inrush current mitigation technique for the direct control method, while outer loop of the indirect controller is slowed down to allow momentary voltage drop. The study has proved that while both direct and indirect control methods can mitigate inrush currents, the direct method, with its virtual reactance approach, offers a more effective and simpler solution for managing inrush currents in islanded microgrid scenarios. The outcomes have demonstrated the potential of flexible voltage regulation using the virtual reactance inrush current mitigation technique for direct control method to enhance the reliability and efficiency of microgrid operations, particularly when integrating inductive and dynamic loads.

Chapter 4 has introduced a cutting-edge control architecture using always synchronized parallel control paths for inverters, designed to autonomously detect grid reconnection and islanding events while changing its mode of operation seamlessly without requiring communication links or a transition mode. The controller consists of dual control sets, one for voltage and one for angle generation, consisting of main and background paths running in parallel to generate GFM and GFL signals. The main path provides reference voltage and angle to the PWM generator, while the inactive path runs in the background to achieve continuous synchronization between the outputs of each path. The proposed control-sync method has been simplified for both GFL and GFM modes to reduce computational demands and streamline the tuning of controller parameters. Additionally, an innovative first-in-class fully decentralized grid reconnection detection algorithm, eliminates the need for communication links and external sensors, making it a perfect solution when communication signal is lost or falsified when the utility grid is connected to the microgrid. This complete control architecture not only adheres to IEEE Std. 1547 by minimizing power and voltage transients during operational mode changes but also showcases a plug-and-play flexibility, offering a universal control approach for microgrid inverters.

Chapter 5 has unveiled the experimental performance of the novel autonomous control architecture for microgrid inverters, designed to enable automatic switching between

different operational states. The controller has proven to detect islanding and grid reconnection events within 0.06 seconds and 10 seconds, respectively, with adjustable detection durations. This innovative approach ensures continuous inverter operation and power availability during utility grid disconnections, compromised or interrupted supervisory control communications, and catastrophic events. Experimental validation has confirmed the system's ability to smoothly synchronize inverters and evenly distribute loads during mode transitions. Furthermore, the chapter has demonstrated the direct grid reconnection capability to the microgrid through typically a synchro-check relay, achieving nominal frequency alignment after restoration, all without the need for communication. This advanced control solution supports the incorporation of more distributed energy resources and opening the door for further research into improving stability within inverter-dominated power systems via adaptive control techniques.

6.2 Suggestions for Future Work

The developed controller emerges new opportunities for more in-depth research. The proposed next steps for future investigations can be listed as follows:

- This advanced control solution facilitates the expanded implementation of distributed energy generation, providing an opportunity for further research into improving stability within inverter-dominated power systems via adaptive control techniques.
- The concept of synchronized parallel tasks can be applied to various GFM and GFL methodologies, offering the flexibility to choose different controllers for each mode and ensuring their outputs are aligned. The concept can be guided with data-driven machine-learning methodologies to achieve optimal tracking performance and transition conditions.
- Additional to the inverter operation, this developed synced-parallel control approach can be used for power converters in many other applications, such as DC-DC converters and rectifiers, where seamless control is needed. Particularly synchronizing variables operating at high frequency makes the tracking a challenging task for the conventional

control methods for adaptive control applications, where the developed controller can provide a solution.

- The developed control structure can be featured with harmonics compensation and fault protection or tolerance algorithms to provide ancillary services for inverters operating in a multi-inverter-based microgrids. Each task can be incorporated with the developed controller individually and activated using the logic states while the other tasks runs in the background. This way the PWM reference signals can maintain synchronization and transition from one feature to another once the task is completed. A data-driven methodology can be implemented for optimized performance.
- The performance of the multi-inverter microgrids can be tested in ring connected distribution systems, where circulating currents can be observed in GFM operating mode. For such cases, a circulating current mitigation method can be developed.
- Loading conditions in single-phase residential applications can result in unbalanced three-phase generation in microgrids powered by GFM inverters if each phase of the three-phase is loaded unequally. Further analysis and experimentation is essential to observe the sensitivity and performance of the GFM controllers in unbalanced conditions, particularly in islanded microgrids. A phase-balancing task may be implemented to achieve a balanced operation restored at the nominal values.
- The developed inrush current mitigation technique implements a fixed virtual reactance value selected based on the experimental setup. However, this technique can be enhanced to adaptively update the virtual reactance parameter based on the system conditions. This adaptation can be achieved using analytical or optimization-based approaches.

Bibliography

- [1] F. Sadeque, M. Gursoy, and B. Mirafzal, “Grid-forming inverters in a microgrid: Maintaining power during an outage and restoring connection to the utility grid without communication,” *IEEE Trans. Ind. Electron.*, pp. 1–10, 2024.
- [2] M. Gursoy and B. Mirafzal, “Direct vs. indirect control schemes for grid-forming inverters—unveiling a performance comparison in a microgrid,” *IEEE Access*, vol. 11, pp. 75023–75036, 2023.
- [3] B. Mirafzal and A. Adib, “On grid-interactive smart inverters: Features and advancements,” *IEEE Access*, vol. 8, pp. 160526–160536, 2020.
- [4] G. Li, J. Yang, F. Wu, X. Zhu, S. Ke, and Y. Li, “A market framework for a 100% renewable energy penetration spot market,” *IEEE Trans. Sustain. Energy*, vol. 14, no. 3, pp. 1569–1584, 2023.
- [5] J. Qi, A. Hahn, X. Lu, J. Wang, and C.-C. Liu, “Cybersecurity for distributed energy resources and smart inverters,” *IET Cyber-Physical Syst.: Theory & Appl.*, vol. 1, no. 1, pp. 28–39, 2016.
- [6] C. Fu, M. Guo, J. Wang, L. Lan, M. Ma, and D. Han, “A review of energy transition paths for germany and other countries,” in *2022 Power System and Green Energy Conference (PSGEC)*, pp. 236–240, 2022.
- [7] M. Gursoy and B. Mirafzal, “On self-security of grid-interactive smart inverters,” in *2021 IEEE Kansas Power and Energy Conference (KPEC)*, pp. 1–6, 2021.
- [8] T. Hossen, M. Gursoy, and B. Mirafzal, “Self-protective inverters against malicious setpoints using analytical reference models,” *IEEE J. Emerg. Sel. Top. Ind. Electron.*, vol. 3, no. 4, pp. 871–877, 2022.

- [9] N. Mohammed, M. H. Ravanji, W. Zhou, and B. Bahrani, “Enhanced frequency control for power-synchronized pll-less grid-following inverters,” *IEEE Open J. Ind. Electron. Soc.*, vol. 4, pp. 189–204, 2023.
- [10] A. Adib, J. Lamb, and B. Mirafzal, “Ancillary services via vsis in microgrids with maximum dc-bus voltage utilization,” *IEEE Trans. Ind. Appl.*, vol. 55, no. 1, pp. 648–658, 2019.
- [11] J. Lamb and B. Mirafzal, “Grid-interactive cascaded h-bridge multilevel converter pq plane operating region analysis,” *IEEE Trans. Ind. Appl.*, vol. 53, no. 6, pp. 5744–5752, 2017.
- [12] Q. Liu, T. Caldognetto, and S. Buso, “Review and comparison of grid-tied inverter controllers in microgrids,” *IEEE Trans. Power Electron.*, vol. 35, no. 7, pp. 7624–7639, 2020.
- [13] M. Abujubbeh, *Sensitivity based planning and operation of modern distribution systems*. PhD thesis, Kansas State University, 2023.
- [14] A. Adib, B. Mirafzal, X. Wang, and F. Blaabjerg, “On stability of voltage source inverters in weak grids,” *IEEE Access*, vol. 6, pp. 4427–4439, 2018.
- [15] A. Adib and B. Mirafzal, “Virtual inductance for stable operation of grid-interactive voltage source inverters,” *IEEE Trans. Ind. Electron.*, vol. 66, no. 8, pp. 6002–6011, 2019.
- [16] “Ieee standard for interconnection and interoperability of distributed energy resources with associated electric power systems interfaces,” *IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003)*, pp. 1–138, 2018.
- [17] T. Hossen and B. Mirafzal, “Hidden modes of instability for inverters in weak grids,” *IEEE Trans. Ind. Appl.*, vol. 59, no. 4, pp. 4505–4515, 2023.

- [18] T. Hossen, G. Amariuca, and B. Mirafzal, “Integrating an analytical risk factor into a neural network framework for self-protective inverters,” *IEEE J. Emerg. Sel. Top. Power Electron.*, pp. 1–1, 2023.
- [19] M. H. Ravanji, W. Zhou, N. Mohammed, and B. Bahrani, “Comparative analysis of the power output capabilities of grid-following and grid-forming inverters considering static, dynamic, and thermal limitations,” *IEEE Trans. Power Syst.*, vol. 39, no. 2, pp. 2693–2705, 2024.
- [20] D. Sharma, F. Sadeque, and B. Mirafzal, “Synchronization of inverters in grid forming mode,” *IEEE Access*, vol. 10, pp. 41341–41351, 2022.
- [21] W. Du, Z. Chen, K. P. Schneider, R. H. Lasseter, S. Pushpak Nandanoori, F. K. Tuffner, and S. Kundu, “A comparative study of two widely used grid-forming droop controls on microgrid small-signal stability,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 8, no. 2, pp. 963–975, 2020.
- [22] F. Sadeque, D. Sharma, and B. Mirafzal, “Multiple grid-forming inverters in black-start: The challenges,” in *2021 IEEE 22nd Workshop on Control and Modelling of Power Electronics (COMPEL)*, pp. 1–6, 2021.
- [23] D. B. Rathnayake, M. Akrami, C. Phurailatpam, S. P. Me, S. Hadavi, G. Jayasinghe, S. Zabihi, and B. Bahrani, “Grid forming inverter modeling, control, and applications,” *IEEE Access*, vol. 9, pp. 114781–114807, 2021.
- [24] R. Rosso, X. Wang, M. Liserre, X. Lu, and S. Engelken, “Grid-forming converters: Control approaches, grid-synchronization, and future trends—a review,” *IEEE Open J. Ind. Appl.*, vol. 2, pp. 93–109, 2021.
- [25] M. Gursoy and B. Mirafzal, “Dynamic load inrush current mitigation in islanded microgrids powered by grid-forming inverters,” in *2022 1st IEEE International Conference on Industrial Electronics: Developments and Applications (ICIDEA)*, pp. 73–77, 2022.

- [26] M. Gursoy and B. Mirafzal, “Inrush current mitigation for grid-forming inverters in islanded microgrids,” in *2022 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 1–7, 2022.
- [27] A. Elnady, A. A. A. Ismail, M. AlShabi, and A. Noureldin, “A comprehensive review of centralized current/power control schemes for parallel inverters and ac microgrids,” *IEEE Access*, vol. 10, pp. 125061–125085, 2022.
- [28] F. Sadeque, M. Gursoy, and B. Mirafzal, “Survey of control methods for grid-forming inverters – advancements from 2020 to 2023,” in *2023 IEEE Kansas Power and Energy Conference (KPEC)*, pp. 1–6, 2023.
- [29] A. Singhal, T. L. Vu, and W. Du, “Consensus control for coordinating grid-forming and grid-following inverters in microgrids,” *IEEE Trans. Smart Grid.*, vol. 13, no. 5, pp. 4123–4133, 2022.
- [30] B. Zhou, J. Zou, C. Y. Chung, H. Wang, N. Liu, N. Voropai, and D. Xu, “Multi-microgrid energy management systems: Architecture, communication, and scheduling strategies,” *J. Mod. Power Syst. Clean Energy.*, vol. 9, no. 3, pp. 463–476, 2021.
- [31] Y. Khayat, Q. Shafiee, R. Heydari, M. Naderi, T. Dragičević, J. W. Simpson-Porco, F. Dörfler, M. Fathi, F. Blaabjerg, J. M. Guerrero, and H. Bevrani, “On the secondary control architectures of ac microgrids: An overview,” *IEEE Trans. Power Electron.*, vol. 35, no. 6, pp. 6482–6500, 2020.
- [32] I. Serban, S. Céspedes, C. Marinescu, C. A. Azurdia-Meza, J. S. Gómez, and D. S. Hueichapan, “Communication requirements in microgrids: A practical survey,” *IEEE Access*, vol. 8, pp. 47694–47712, 2020.
- [33] H. Zou, S. Mao, Y. Wang, F. Zhang, X. Chen, and L. Cheng, “A survey of energy management in interconnected multi-microgrids,” *IEEE Access*, vol. 7, pp. 72158–72169, 2019.

- [34] N. L. Díaz, A. C. Luna, J. C. Vasquez, and J. M. Guerrero, “Centralized control architecture for coordination of distributed renewable generation and energy storage in islanded ac microgrids,” *IEEE Transactions on Power Electronics*, vol. 32, no. 7, pp. 5202–5213, 2017.
- [35] H. Han, X. Hou, J. Yang, J. Wu, M. Su, and J. M. Guerrero, “Review of power sharing control strategies for islanding operation of ac microgrids,” *IEEE Trans. Smart Grid.*, vol. 7, no. 1, pp. 200–215, 2016.
- [36] D. E. Olivares, A. Mehrizi-Sani, A. H. Etemadi, C. A. Cañizares, R. Iravani, M. Kazerani, A. H. Hajimiragha, O. Gomis-Bellmunt, M. Saeedifard, R. Palma-Behnke, G. A. Jiménez-Estévez, and N. D. Hatziargyriou, “Trends in microgrid control,” *IEEE Trans. Smart Grid.*, vol. 5, no. 4, pp. 1905–1919, 2014.
- [37] T. Caldognetto and P. Tenti, “Microgrids operation based on master–slave cooperative control,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 2, no. 4, pp. 1081–1088, 2014.
- [38] A. Bidram, B. Poudel, L. Damodaran, R. Fierro, and J. M. Guerrero, “Resilient and cybersecure distributed control of inverter-based islanded microgrids,” *IEEE Trans. Ind. Inf.*, vol. 16, no. 6, pp. 3881–3894, 2020.
- [39] P. P. Vergara, J. M. Rey, H. R. Shaker, J. M. Guerrero, B. N. Jørgensen, and L. C. P. da Silva, “Distributed strategy for optimal dispatch of unbalanced three-phase islanded microgrids,” *IEEE Trans. Smart Grid.*, vol. 10, no. 3, pp. 3210–3225, 2019.
- [40] L. Che, X. Zhang, M. Shahidehpour, A. Alabdulwahab, and A. Abusorrah, “Optimal interconnection planning of community microgrids with renewable energy sources,” *IEEE Trans. Smart Grid.*, vol. 8, no. 3, pp. 1054–1063, 2017.
- [41] K. Rahbar, C. C. Chai, and R. Zhang, “Energy cooperation optimization in microgrids with renewable energy integration,” *IEEE Trans. Smart Grid.*, vol. 9, no. 2, pp. 1482–1493, 2018.

- [42] T. Lu, Z. Wang, Q. Ai, and W.-J. Lee, “Interactive model for energy management of clustered microgrids,” *IEEE Trans. Ind. Appl.*, vol. 53, no. 3, pp. 1739–1750, 2017.
- [43] A. Parisio, C. Wiezorek, T. Kyntäjä, J. Elo, K. Strunz, and K. H. Johansson, “Cooperative mpc-based energy management for networked microgrids,” *IEEE Trans. Smart Grid.*, vol. 8, no. 6, pp. 3066–3074, 2017.
- [44] M. B. Delghavi and A. Yazdani, “Sliding-mode control of ac voltages and currents of dispatchable distributed energy resources in master-slave-organized inverter-based microgrids,” *IEEE Trans. Smart Grid.*, vol. 10, no. 1, pp. 980–991, 2019.
- [45] A. Mortezaei, M. G. Simões, M. Savaghebi, J. M. Guerrero, and A. Al-Durra, “Cooperative control of multi-master–slave islanded microgrid with power quality enhancement based on conservative power theory,” *IEEE Trans. Smart Grid.*, vol. 9, no. 4, pp. 2964–2975, 2018.
- [46] N. Cai and J. Mitra, “A multi-level control architecture for master-slave organized microgrids with power electronic interfaces,” *Electric Power Syst. Research*, vol. 109, pp. 8–19, 2014.
- [47] M. Borrega, L. Marroyo, R. González, J. Balda, and J. L. Agorreta, “Modeling and control of a master–slave pv inverter with n-paralleled inverters and three-phase three-limb inductors,” *IEEE Trans. Power Electron.*, vol. 28, no. 6, pp. 2842–2855, 2013.
- [48] N. Hur and K. Nam, “A robust load-sharing control scheme for parallel-connected multisystems,” *IEEE Trans. Ind. Electron.*, vol. 47, no. 4, pp. 871–879, 2000.
- [49] H. Wang and J. Huang, “Incentivizing energy trading for interconnected microgrids,” *IEEE Trans. Smart Grid.*, vol. 9, no. 4, pp. 2647–2657, 2018.
- [50] H. K. Morales-Paredes, J. P. Bonaldo, and J. A. Pomilio, “Centralized control center implementation for synergistic operation of distributed multifunctional single-phase grid-tie inverters in a microgrid,” *IEEE Trans. Ind. Electron.*, vol. 65, no. 10, pp. 8018–8029, 2018.

- [51] S. S. Madani, C. Kammer, and A. Karimi, “Data-driven distributed combined primary and secondary control in microgrids,” *IEEE Trans. Control Syst. Technol.*, vol. 29, no. 3, pp. 1340–1347, 2021.
- [52] Q. Shafiee, V. Nasirian, J. C. Vasquez, J. M. Guerrero, and A. Davoudi, “A multi-functional fully distributed control framework for ac microgrids,” *IEEE Trans. Smart Grid.*, vol. 9, no. 4, pp. 3247–3258, 2018.
- [53] Z. Li, C. Zang, P. Zeng, H. Yu, and S. Li, “Fully distributed hierarchical control of parallel grid-supporting inverters in islanded ac microgrids,” *IEEE Trans. Ind. Inf.*, vol. 14, no. 2, pp. 679–690, 2018.
- [54] T. Heins, M. Joševski, S. Karthik Gurumurthy, and A. Monti, “Centralized model predictive control for transient frequency control in islanded inverter-based microgrids,” *IEEE Trans. Power Syst.*, vol. 38, no. 3, pp. 2641–2652, 2023.
- [55] F. Sadeque, *Restoration and universal operation of grid-forming inverters*. PhD thesis, Kansas State University, 2022.
- [56] W. Du, F. K. Tuffner, K. P. Schneider, R. H. Lasseter, J. Xie, Z. Chen, and B. Bhattarai, “Modeling of grid-forming and grid-following inverters for dynamic simulation of large-scale distribution systems,” *IEEE Trans. Power Deliv.*, vol. 36, no. 4, pp. 2035–2045, 2021.
- [57] Q.-C. Zhong and Y. Zeng, “Universal droop control of inverters with different types of output impedance,” *IEEE Access*, vol. 4, pp. 702–712, 2016.
- [58] W. Deng, N. Dai, K.-W. Lao, and J. M. Guerrero, “A virtual-impedance droop control for accurate active power control and reactive power sharing using capacitive-coupling inverters,” *IEEE Trans. Ind. Appl.*, vol. 56, no. 6, pp. 6722–6733, 2020.
- [59] W. Du, R. H. Lasseter, and A. S. Khalsa, “Survivability of autonomous microgrid during overload events,” *IEEE Trans. Smart Grid.*, vol. 10, no. 4, pp. 3515–3524, 2019.

- [60] N. Pogaku, M. Prodanovic, and T. C. Green, “Modeling, analysis and testing of autonomous operation of an inverter-based microgrid,” *IEEE Trans. Power Electron.*, vol. 22, no. 2, pp. 613–625, 2007.
- [61] A. Milczarek, M. Malinowski, and J. M. Guerrero, “Reactive power management in islanded microgrid—proportional power sharing in hierarchical droop control,” *IEEE Trans. Smart Grid.*, vol. 6, no. 4, pp. 1631–1638, 2015.
- [62] F. Sadeque, D. Sharma, and B. Mirafzal, “Power-sharing between grid-forming and grid-following inverters,” in *2021 IEEE 22nd Workshop on Control and Modelling of Power Electronics (COMPEL)*, pp. 1–5, 2021.
- [63] F. Sadeque and F. Fateh, “On control schemes for grid-forming inverters,” in *2022 IEEE Kansas Power and Energy Conference (KPEC)*, pp. 1–6, 2022.
- [64] F. Sadeque, D. Sharma, and B. Mirafzal, “Seamless grid-following to grid-forming transition of inverters supplying a microgrid,” in *2023 IEEE Applied Power Electronics Conference and Exposition (APEC)*, pp. 594–599, 2023.
- [65] W. Du and S. M. Mohiuddin, “A two-stage current limiting control strategy for improved low-voltage ride-through capability of direct-droop-controlled, grid-forming inverters,” in *2023 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 2886–2890, 2023.
- [66] R. A. Jabr, “Economic operation of droop-controlled ac microgrids,” *IEEE Trans. Power Syst.*, vol. 37, no. 4, pp. 3119–3128, 2022.
- [67] H. Safamehr, I. Izadi, and J. Ghaisari, “Robust $v - i$ droop control of grid-forming inverters in the presence of feeder impedance variations and nonlinear loads,” *IEEE Trans. Ind. Electron.*, vol. 71, no. 1, pp. 504–512, 2024.
- [68] J. Hu, J. Zhu, D. G. Dorrell, and J. M. Guerrero, “Virtual flux droop method—a new control strategy of inverters in microgrids,” *IEEE Trans. Power Electron.*, vol. 29, no. 9, pp. 4704–4711, 2014.

- [69] J. Erdocia, A. Urtasun, and L. Marroyo, “Power angle–frequency droop control to enhance transient stability of grid-forming inverters under voltage dips,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 11, no. 4, pp. 3751–3764, 2023.
- [70] S. Khanabdal, M. Banejad, F. Blaabjerg, and N. Hosseinzadeh, “Adaptive virtual flux droop control based on virtual impedance in islanded ac microgrids,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 10, no. 1, pp. 1095–1107, 2022.
- [71] J. Liu, Y. Miura, and T. Ise, “Comparison of dynamic characteristics between virtual synchronous generator and droop control in inverter-based distributed generators,” *IEEE Trans. Power Electron.*, vol. 31, no. 5, pp. 3600–3611, 2016.
- [72] Q. Lin, H. Uno, K. Ogawa, Y. Kanekiyo, T. Shijo, J. Arai, T. Matsuda, D. Yamashita, and K. Otani, “Field demonstration of parallel operation of virtual synchronous controlled grid-forming inverters and a diesel synchronous generator in a microgrid,” *IEEE Access*, vol. 10, pp. 39095–39107, 2022.
- [73] J. Fang, P. Lin, H. Li, Y. Yang, and Y. Tang, “An improved virtual inertia control for three-phase voltage source converters connected to a weak grid,” *IEEE Trans. Power Electron.*, vol. 34, no. 9, pp. 8660–8670, 2019.
- [74] C. Li, Y. Yang, Y. Cao, L. Wang, and F. Blaabjerg, “Frequency and voltage stability analysis of grid-forming virtual synchronous generator attached to weak grid,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 10, no. 3, pp. 2662–2671, 2022.
- [75] J. Pahasa, P. Potejana, and I. Ngamroo, “Mpc-based virtual energy storage system using pv and air conditioner to emulate virtual inertia and frequency regulation of the low-inertia microgrid,” *IEEE Access*, vol. 10, pp. 133708–133719, 2022.
- [76] N. Sockeel, J. Gafford, B. Papari, and M. Mazzola, “Virtual inertia emulator-based model predictive control for grid frequency regulation considering high penetration of inverter-based energy storage system,” *IEEE Trans. Sustain. Energy*, vol. 11, no. 4, pp. 2932–2939, 2020.

- [77] M. H. Khooban, “An optimal non-integer model predictive virtual inertia control in inverter-based modern ac power grids-based v2g technology,” *IEEE Trans. Energy Convers.*, vol. 36, no. 2, pp. 1336–1346, 2021.
- [78] D. B. Rathnayake, S. P. Me, R. Razzaghi, and B. Bahrani, “ H_∞ -based control design for grid-forming inverters with enhanced damping and virtual inertia,” *IEEE Trans. Energy Convers.*, vol. 11, no. 2, pp. 2311–2325, 2023.
- [79] X. Hou, Y. Sun, X. Zhang, J. Lu, P. Wang, and J. M. Guerrero, “Improvement of frequency regulation in vsg-based ac microgrid via adaptive virtual inertia,” *IEEE Trans. Power Electron.*, vol. 35, no. 2, pp. 1589–1602, 2020.
- [80] D. Sun, H. Liu, S. Gao, L. Wu, P. Song, and X. Wang, “Comparison of different virtual inertia control methods for inverter-based generators,” *J. Mod. Power Syst. Clean Energy.*, vol. 8, no. 4, pp. 768–777, 2020.
- [81] M. Chen, D. Zhou, and F. Blaabjerg, “Enhanced transient angle stability control of grid-forming converter based on virtual synchronous generator,” *IEEE Trans. Ind. Electron.*, vol. 69, no. 9, pp. 9133–9144, 2022.
- [82] M. Li, W. Huang, N. Tai, L. Yang, D. Duan, and Z. Ma, “A dual-adaptivity inertia control strategy for virtual synchronous generator,” *IEEE Trans. Power Syst.*, vol. 35, no. 1, pp. 594–604, 2020.
- [83] J. Liu, Y. Miura, H. Bevrani, and T. Ise, “A unified modeling method of virtual synchronous generator for multi-operation-mode analyses,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 2, pp. 2394–2409, 2021.
- [84] J. Jongudomkarn, J. Liu, and T. Ise, “Virtual synchronous generator control with reliable fault ride-through ability: A solution based on finite-set model predictive control,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 8, no. 4, pp. 3811–3824, 2020.
- [85] M. Ren, T. Li, K. Shi, P. Xu, and Y. Sun, “Coordinated control strategy of virtual

- synchronous generator based on adaptive moment of inertia and virtual impedance,” *IEEE J. Emerg. Sel. Top. Circuits Syst.*, vol. 11, no. 1, pp. 99–110, 2021.
- [86] M. Zavala Tinajero, F. Ornelas-Tellez, and N. Garcia-Barriga, “Optimal control of an inverter-based virtual synchronous generator with inertial response,” *IEEE Latin America Transactions*, vol. 20, no. 5, pp. 780–786, 2022.
- [87] Q. Xu, T. Dragicevic, L. Xie, and F. Blaabjerg, “Artificial intelligence-based control design for reliable virtual synchronous generators,” *IEEE Trans. Power Electron.*, vol. 36, no. 8, pp. 9453–9464, 2021.
- [88] Y. Li, W. Gao, S. Huang, R. Wang, W. Yan, V. Gevorgian, and D. W. Gao, “Data-driven optimal control strategy for virtual synchronous generator via deep reinforcement learning approach,” *J. Mod. Power Syst. Clean Energy.*, vol. 9, no. 4, pp. 919–929, 2021.
- [89] P. Liu, Y. Bi, and C. Liu, “Data-based intelligent frequency control of vsg via adaptive virtual inertia emulation,” *IEEE Syst. J.*, vol. 16, no. 3, pp. 3917–3926, 2022.
- [90] Q.-C. Zhong, “Virtual synchronous machines: A unified interface for grid integration,” *IEEE Power Electron. Mag.*, vol. 3, no. 4, pp. 18–27, 2016.
- [91] H.-P. Beck and R. Hesse, “Virtual synchronous machine,” in *2007 9th International Conference on Electrical Power Quality and Utilisation*, pp. 1–6, 2007.
- [92] Q.-C. Zhong and G. Weiss, “Synchronverters: Inverters that mimic synchronous generators,” *IEEE Trans. Ind. Electron.*, vol. 58, no. 4, pp. 1259–1267, 2011.
- [93] V. Natarajan and G. Weiss, “Synchronverters with better stability due to virtual inductors, virtual capacitors, and anti-windup,” *IEEE Trans. Ind. Electron.*, vol. 64, no. 7, pp. 5994–6004, 2017.
- [94] Q.-C. Zhong, P.-L. Nguyen, Z. Ma, and W. Sheng, “Self-synchronized synchronverters:

- Inverters without a dedicated synchronization unit,” *IEEE Trans. Power Electron.*, vol. 29, no. 2, pp. 617–630, 2014.
- [95] Q.-C. Zhong, G. C. Konstantopoulos, B. Ren, and M. Krstic, “Improved synchronverters with bounded frequency and voltage for smart grid integration,” *IEEE Trans. Smart Grid.*, vol. 9, no. 2, pp. 786–796, 2018.
- [96] Z. Shuai, W. Huang, Z. J. Shen, A. Luo, and Z. Tian, “Active power oscillation and suppression techniques between two parallel synchronverters during load fluctuations,” *IEEE Trans. Power Electron.*, vol. 35, no. 4, pp. 4127–4142, 2020.
- [97] L. Harnefors, J. Kukkola, M. Routimo, M. Hinkkanen, and X. Wang, “A universal controller for grid-connected voltage-source converters,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 5, pp. 5761–5770, 2021.
- [98] M. H. Ravanji, D. B. Rathnayake, M. Z. Mansour, and B. Bahrani, “Impact of voltage-loop feedforward terms on the stability of grid-forming inverters and remedial actions,” *IEEE Trans. Energy Convers.*, vol. 38, no. 3, pp. 1554–1565, 2023.
- [99] J. D. V. Leon, A. Tarraso, J. I. Candela, J. Rocabert, and P. Rodriguez, “Grid-forming controller based on virtual admittance for power converters working in weak grids,” *IEEE J. Emerg. Sel. Top. Ind. Electron.*, vol. 4, no. 3, pp. 791–801, 2023.
- [100] A. Firdaus and S. Mishra, “Mitigation of power and frequency instability to improve load sharing among distributed inverters in microgrid systems,” *IEEE Syst. J.*, vol. 14, no. 1, pp. 1024–1033, 2020.
- [101] X. Wang, F. Blaabjerg, and Z. Chen, “Autonomous control of inverter-interfaced distributed generation units for harmonic current filtering and resonance damping in an islanded microgrid,” *IEEE Trans. Ind. Appl.*, vol. 50, no. 1, pp. 452–461, 2014.
- [102] X. Lu, J. Wang, J. M. Guerrero, and D. Zhao, “Virtual-impedance-based fault current limiters for inverter dominated ac microgrids,” *IEEE Trans. Smart Grid.*, vol. 9, no. 3, pp. 1599–1612, 2018.

- [103] R. Rosso, S. Engelken, and M. Liserre, “On the implementation of an frt strategy for grid-forming converters under symmetrical and asymmetrical grid faults,” *IEEE Transactions on Industry Applications*, vol. 57, no. 5, pp. 4385–4397, 2021.
- [104] L. Huang, H. Xin, Z. Wang, L. Zhang, K. Wu, and J. Hu, “Transient stability analysis and control design of droop-controlled voltage source converters considering current limitation,” *IEEE Trans. Smart Grid.*, vol. 10, no. 1, pp. 578–591, 2019.
- [105] Q. Hu, R. Han, X. Quan, Z. Wu, C. Tang, W. Li, and W. Wang, “Grid-forming inverter enabled virtual power plants with inertia support capability,” *IEEE Trans. Smart Grid.*, vol. 13, no. 5, pp. 4134–4143, 2022.
- [106] L. Huang, H. Xin, Z. Wang, K. Wu, H. Wang, J. Hu, and C. Lu, “A virtual synchronous control for voltage-source converters utilizing dynamics of dc-link capacitor to realize self-synchronization,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 5, no. 4, pp. 1565–1577, 2017.
- [107] M. Lu, “Virtual oscillator grid-forming inverters: State of the art, modeling, and stability,” *IEEE Trans. Power Electron.*, vol. 37, no. 10, pp. 11579–11591, 2022.
- [108] L. Kong, Y. Xue, L. Qiao, and F. Wang, “Enhanced synchronization stability of grid-forming inverters with passivity-based virtual oscillator control,” *IEEE Trans. Power Electron.*, vol. 37, no. 12, pp. 14141–14156, 2022.
- [109] M. Lu, S. Dhople, and B. Johnson, “Benchmarking nonlinear oscillators for grid-forming inverter control,” *IEEE Trans. Power Electron.*, vol. 37, no. 9, pp. 10250–10266, 2022.
- [110] B. B. Johnson, S. V. Dhople, A. O. Hamadeh, and P. T. Krein, “Synchronization of parallel single-phase inverters with virtual oscillator control,” *IEEE Trans. Power Electron.*, vol. 29, no. 11, pp. 6124–6138, 2014.

- [111] B. B. Johnson, S. V. Dhople, J. L. Cale, A. O. Hamadeh, and P. T. Krein, “Oscillator-based inverter control for islanded three-phase microgrids,” *IEEE J. Photovolt.*, vol. 4, no. 1, pp. 387–395, 2014.
- [112] E. R. M. Leyba, D. F. Opila, and C. Keith Kintzley, “Three phase dead-zone oscillator control under unbalanced load conditions,” in *2019 IEEE Electric Ship Technologies Symposium (ESTS)*, pp. 134–140, 2019.
- [113] B. B. Johnson, M. Sinha, N. G. Ainsworth, F. Dörfler, and S. V. Dhople, “Synthesizing virtual oscillators to control islanded inverters,” *IEEE Trans. Power Electron.*, vol. 31, no. 8, pp. 6002–6015, 2016.
- [114] M. Sinha, F. Dörfler, B. B. Johnson, and S. V. Dhople, “Uncovering droop control laws embedded within the nonlinear dynamics of van der pol oscillators,” *IEEE Trans. Control Netw. Syst.*, vol. 4, no. 2, pp. 347–358, 2017.
- [115] Z. Shi, J. Li, H. I. Nurdin, and J. E. Fletcher, “Comparison of virtual oscillator and droop controlled islanded three-phase microgrids,” *IEEE Trans. Energy Convers.*, vol. 34, no. 4, pp. 1769–1780, 2019.
- [116] D. Raisz, T. T. Thai, and A. Monti, “Power control of virtual oscillator controlled inverters in grid-connected mode,” *IEEE Trans. Power Electron.*, vol. 34, no. 6, pp. 5916–5926, 2019.
- [117] M. A. Awal, H. Yu, H. Tu, S. M. Lukic, and I. Husain, “Hierarchical control for virtual oscillator based grid-connected and islanded microgrids,” *IEEE Trans. Power Electron.*, vol. 35, no. 1, pp. 988–1001, 2020.
- [118] M. Lu, G.-S. Seo, M. Sinha, F. Rodriguez, S. Dhople, and B. Johnson, “Adaptation of commercial current-controlled inverters for operation with virtual oscillator control,” in *2019 IEEE Applied Power Electronics Conference and Exposition (APEC)*, pp. 3427–3432, 2019.

- [119] M. Li, Y. Gui, Y. Guan, J. Matas, J. M. Guerrero, and J. C. Vasquez, “Inverter parallelization for an islanded microgrid using the hopf oscillator controller approach with self-synchronization capabilities,” *IEEE Trans. Ind. Electron.*, vol. 68, no. 11, pp. 10879–10889, 2021.
- [120] M. Lu, R. Mallik, B. Johnson, and S. Dhople, “Dispatchable virtual-oscillator-controlled inverters with current-limiting and mppt capabilities,” in *2021 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 3316–3323, 2021.
- [121] M. Colombino, D. Groß, J.-S. Brouillon, and F. Dörfler, “Global phase and magnitude synchronization of coupled oscillators with application to the control of grid-forming power inverters,” *IEEE Trans. Autom. Control.*, vol. 64, no. 11, pp. 4496–4511, 2019.
- [122] G.-S. Seo, M. Colombino, I. Subotic, B. Johnson, D. Groß, and F. Dörfler, “Dispatchable virtual oscillator control for decentralized inverter-dominated power systems: Analysis and experiments,” in *2019 IEEE Applied Power Electronics Conference and Exposition (APEC)*, pp. 561–566, 2019.
- [123] J. Li, M. Ali, J. E. Fletcher, and H. I. Nurdin, “Modeling and analysis of multiple inverters with dual-loop-based virtual oscillator control,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 10, no. 4, pp. 3963–3974, 2022.
- [124] M. Lu, S. Dutta, and B. Johnson, “Self-synchronizing cascaded inverters with virtual oscillator control,” *IEEE Trans. Power Electron.*, vol. 37, no. 6, pp. 6424–6436, 2022.
- [125] M. Lu, “An inrush current limiting strategy for virtual-oscillator-controlled grid-forming inverters,” *IEEE Trans. Energy Convers.*, vol. 38, no. 3, pp. 1501–1510, 2023.
- [126] M. A. Awal and I. Husain, “Unified virtual oscillator control for grid-forming and grid-following converters,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 4, pp. 4573–4586, 2021.
- [127] A. M. Osman and F. Alsokhiry, “Sliding mode control for grid integration of wind

- power system based on direct drive pmsg,” *IEEE Access*, vol. 10, pp. 26567–26579, 2022.
- [128] M. Gursoy, G. Zhuo, A. G. Lozowski, and X. Wang, “Photovoltaic energy conversion systems with sliding mode control,” *Energies*, vol. 14, no. 19, 2021.
- [129] M. Gursoy, A. G. Lozowski, and X. Wang, “Power Electronics Sliding Mode Control Design for Photovoltaic Energy Conversion Systems,” vol. Volume 6: Energy of *ASME International Mechanical Engineering Congress and Exposition*, p. V006T06A007, 11 2019.
- [130] C. Alfaro, R. Guzman, L. G. de Vicuña, H. Komurcugil, and H. Martín, “Distributed direct power sliding-mode control for islanded ac microgrids,” *IEEE Trans. Ind. Electron.*, vol. 69, no. 10, pp. 9700–9710, 2022.
- [131] C. Lascu, “Sliding-mode direct-voltage control of voltage-source converters with lc filters for pulsed power loads,” *IEEE Trans. Ind. Electron.*, vol. 68, no. 12, pp. 11642–11650, 2021.
- [132] Z. Li, C. Zang, P. Zeng, H. Yu, S. Li, and J. Bian, “Control of a grid-forming inverter based on sliding-mode and mixed h_2/h_∞ control,” *IEEE Trans. Ind. Electron.*, vol. 64, no. 5, pp. 3862–3872, 2017.
- [133] L. Karunaratne, N. R. Chaudhuri, A. Yogarathnam, and M. Yue, “Nonlinear backstepping control of grid-forming converters in presence of grid-following converters and synchronous generators,” *IEEE Trans. Power Syst.*, vol. 39, no. 1, pp. 1948–1964, 2024.
- [134] N. Vafamand, M. M. Arefi, and A. Anvari-Moghaddam, “Advanced kalman filter-based backstepping control of ac microgrids: A command filter approach,” *IEEE Syst. J.*, vol. 17, no. 1, pp. 1060–1070, 2023.
- [135] S. K. Panda and B. Subudhi, “An extended state observer based adaptive backstepping controller for microgrid,” *IEEE Trans. Smart Grid.*, vol. 15, no. 1, pp. 171–178, 2024.

- [136] J. Yu, Y. Qi, H. Deng, X. Liu, and Y. Tang, “Evaluating small-signal synchronization stability of grid-forming converter: A geometrical approach,” *IEEE Trans. Ind. Electron.*, vol. 69, no. 9, pp. 9087–9098, 2022.
- [137] A. Adib, F. Fateh, and B. Mirafzal, “A stabilizer for inverters operating in grid-feeding, grid-supporting and grid-forming modes,” in *2019 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 2239–2244, 2019.
- [138] M. S. Reza, F. Sadeque, M. M. Hossain, A. M. Y. M. Ghias, and V. G. Agelidis, “Three-phase pll for grid-connected power converters under both amplitude and phase unbalanced conditions,” *IEEE Trans. Ind. Electron.*, vol. 66, no. 11, pp. 8881–8891, 2019.
- [139] F. Sadeque, J. Benzaquen, A. Adib, and B. Mirafzal, “Direct phase-angle detection for three-phase inverters in asymmetrical power grids,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 1, pp. 520–528, 2021.
- [140] Y. Qi, H. Deng, J. Fang, and Y. Tang, “Synchronization stability analysis of grid-forming inverter: A black box methodology,” *IEEE Trans. Ind. Electron.*, vol. 69, no. 12, pp. 13069–13078, 2022.
- [141] S. Sahoo, Y. Yang, and F. Blaabjerg, “Resilient synchronization strategy for ac microgrids under cyber attacks,” *IEEE Trans. Power Electron.*, vol. 36, no. 1, pp. 73–77, 2021.
- [142] Y. Li, Y. Gu, and T. C. Green, “Revisiting grid-forming and grid-following inverters: A duality theory,” *IEEE Trans. Power Syst.*, vol. 37, no. 6, pp. 4541–4554, 2022.
- [143] M. Litwin, D. Zieliński, and K. Gopakumar, “Remote micro-grid synchronization without measurements at the point of common coupling,” *IEEE Access*, vol. 8, pp. 212753–212764, 2020.

- [144] I. Patrao, R. González-Medina, S. Marzal, G. Garcerá, and E. Figueres, “Synchronization of power inverters in islanded microgrids using an fm-modulated signal,” *IEEE Trans. Smart Grid.*, vol. 8, no. 1, pp. 503–510, 2017.
- [145] O. Atmaca and M. Karabacak, “Frequency, phase, and magnitude difference locked-loop based linear synchronization scheme for islanded inverters and microgrids,” *IEEE Access*, vol. 11, pp. 61748–61772, 2023.
- [146] M. N. Ambia, K. Meng, W. Xiao, A. Al-Durra, and Z. Y. Dong, “Interactive grid synchronization-based virtual synchronous generator control scheme on weak grid integration,” *IEEE Trans. Smart Grid.*, vol. 13, no. 5, pp. 4057–4071, 2022.
- [147] M. Ashabani, F. D. Freijedo, S. Golestan, and J. M. Guerrero, “Inducverters: Pll-less converters with auto-synchronization and emulated inertia capability,” *IEEE Trans. Smart Grid.*, vol. 7, no. 3, pp. 1660–1674, 2016.
- [148] F. Sadeque and B. Mirafzal, “A universal controller for grid-forming inverters in micro-grid during islanding for low transient current,” in *2022 1st IEEE International Conference on Industrial Electronics: Developments & Applications (ICIDeA)*, pp. 62–67, 2022.
- [149] D. S. Ochs, B. Mirafzal, and P. Sotoodeh, “A method of seamless transitions between grid-tied and stand-alone modes of operation for utility-interactive three-phase inverters,” *IEEE Trans. Ind. Appl.*, vol. 50, no. 3, pp. 1934–1941, 2014.
- [150] T.-V. Tran, T.-W. Chun, H.-H. Lee, H.-G. Kim, and E.-C. Nho, “Pll-based seamless transfer control between grid-connected and islanding modes in grid-connected inverters,” *IEEE Trans. Power Electron.*, vol. 29, no. 10, pp. 5218–5228, 2014.
- [151] M. N. Arafat, A. Elrayyah, and Y. Sozer, “An effective smooth transition control strategy using droop-based synchronization for parallel inverters,” *IEEE Trans. Ind. Appl.*, vol. 51, no. 3, pp. 2443–2454, 2015.

- [152] M. Kwon, S. Park, C.-y. Oh, J. Lee, and S. Choi, “Unified control scheme of grid-connected inverters for autonomous and smooth transfer to stand-alone mode,” *IEEE Trans. Power Electron.*, vol. 37, no. 1, pp. 416–425, 2022.
- [153] S. Sajadian and R. Ahmadi, “Model predictive control of dual-mode operations z-source inverter: Islanded and grid-connected,” *IEEE Trans. Power Electron.*, vol. 33, no. 5, pp. 4488–4497, 2018.
- [154] H. Mahmood, D. Michaelson, and J. Jiang, “Reactive power sharing in islanded microgrids using adaptive voltage droop control,” *IEEE Trans. Smart Grid.*, vol. 6, no. 6, pp. 3052–3060, 2015.
- [155] Y. Khayat, M. Naderi, Q. Shafiee, Y. Batmani, M. Fathi, J. M. Guerrero, and H. Bevrani, “Decentralized optimal frequency control in autonomous microgrids,” *IEEE Trans. Power Syst.*, vol. 34, no. 3, pp. 2345–2353, 2019.
- [156] B. Liu, T. Wu, Z. Liu, and J. Liu, “A small-ac-signal injection-based decentralized secondary frequency control for droop-controlled islanded microgrids,” *IEEE Trans. Power Electron.*, vol. 35, no. 11, pp. 11634–11651, 2020.
- [157] W. Gu, G. Lou, W. Tan, and X. Yuan, “A nonlinear state estimator-based decentralized secondary voltage control scheme for autonomous microgrids,” *IEEE Trans. Power Syst.*, vol. 32, no. 6, pp. 4794–4804, 2017.
- [158] J. M. Rey, P. Martí, M. Velasco, J. Miret, and M. Castilla, “Secondary switched control with no communications for islanded microgrids,” *IEEE Trans. Ind. Electron.*, vol. 64, no. 11, pp. 8534–8545, 2017.
- [159] Y. Han, H. Li, L. Xu, X. Zhao, and J. M. Guerrero, “Analysis of washout filter-based power sharing strategy—an equivalent secondary controller for islanded microgrid without lbc lines,” *IEEE Trans. Smart Grid.*, vol. 9, no. 5, pp. 4061–4076, 2018.
- [160] M. Yazdanian and A. Mehrizi-Sani, “Washout filter-based power sharing,” *IEEE Trans. Smart Grid.*, vol. 7, no. 2, pp. 967–968, 2016.

- [161] K. Ahmed, M. Seyedmahmoudian, S. Mekhilef, N. M. Mubarak, and A. Stojcevski, “A review on primary and secondary controls of inverter-interfaced microgrid,” *J. Mod. Power Syst. Clean Energy.*, vol. 9, no. 5, pp. 969–985, 2021.
- [162] K. Feng and C. Liu, “Distributed hierarchical control for fast frequency restoration in vsg-controlled islanded microgrids,” *IEEE Open J. Ind. Electron. Soc.*, vol. 3, pp. 496–506, 2022.
- [163] A. K. Sahoo, K. Mahmud, M. Crittenden, J. Ravishankar, S. Padmanaban, and F. Blaabjerg, “Communication-less primary and secondary control in inverter-interfaced ac microgrid: An overview,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 5, pp. 5164–5182, 2021.
- [164] F. Sadeque and B. Mirafzal, “Frequency restoration of grid-forming inverters in pulse load and plug-in events,” *IEEE J. Emerg. Sel. Top. Ind. Electron.*, vol. 4, no. 2, pp. 580–588, 2023.
- [165] K. O. Oureilidis and C. S. Demoulias, “A fault clearing method in converter-dominated microgrids with conventional protection means,” *IEEE Trans. Power Electron.*, vol. 31, no. 6, pp. 4628–4640, 2016.
- [166] X. Lin, Y. Zheng, Z. Liang, and Y. Kang, “The suppression of voltage overshoot and oscillation during the fast recovery process from load short-circuit fault for three-phase stand-alone inverter,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 1, pp. 858–871, 2021.
- [167] K. Shi, W. Song, P. Xu, R. Liu, Z. Fang, and Y. Ji, “Low-voltage ride-through control strategy for a virtual synchronous generator based on smooth switching,” *IEEE Access*, vol. 6, pp. 2703–2711, 2018.
- [168] M. Zarif Mansour, S. P. Me, S. Hadavi, B. Badrzadeh, A. Karimi, and B. Bahrani, “Nonlinear transient stability analysis of phased-locked loop-based grid-following

- voltage-source converters using lyapunov's direct method," *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 10, no. 3, pp. 2699–2709, 2022.
- [169] A. Gkountaras, S. Dieckerhoff, and T. Sezi, "Evaluation of current limiting methods for grid forming inverters in medium voltage microgrids," in *2015 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 1223–1230, 2015.
- [170] N. Bottrell and T. C. Green, "Comparison of current-limiting strategies during fault ride-through of inverters to prevent latch-up and wind-up," *IEEE Trans. Power Electron.*, vol. 29, no. 7, pp. 3786–3797, 2014.
- [171] M. A. Awal and I. Husain, "Transient stability assessment for current-constrained and current-unconstrained fault ride through in virtual oscillator-controlled converters," *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 9, no. 6, pp. 6935–6946, 2021.
- [172] Z. Shuai, W. Huang, C. Shen, J. Ge, and Z. J. Shen, "Characteristics and restraining method of fast transient inrush fault currents in synchronverters," *IEEE Trans. Ind. Electron.*, vol. 64, no. 9, pp. 7487–7497, 2017.
- [173] T. Zheng, L. Chen, Y. Guo, and S. Mei, "Comprehensive control strategy of virtual synchronous generator under unbalanced voltage conditions," *IET Gen., Transm. & Distrib.*, vol. 12, no. 7, pp. 1621–1630, 2018.
- [174] M. G. Taul, X. Wang, P. Davari, and F. Blaabjerg, "Current limiting control with enhanced dynamics of grid-forming converters during fault conditions," *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 8, no. 2, pp. 1062–1073, 2020.
- [175] A. D. Paquette and D. M. Divan, "Virtual impedance current limiting for inverters in microgrids with synchronous generators," *IEEE Trans. Ind. Appl.*, vol. 51, no. 2, pp. 1630–1638, 2015.
- [176] T. Qoria, F. Gruson, F. Colas, G. Denis, T. Prevost, and X. Guillaud, "Critical clearing time determination and enhancement of grid-forming converters embedding virtual

- impedance as current limitation algorithm,” *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 8, no. 2, pp. 1050–1061, 2020.
- [177] J. Chen, F. Prystupczuk, and T. O’Donnell, “Use of voltage limits for current limitations in grid-forming converters,” *CSEE Journal of Power and Energy Systems*, vol. 6, no. 2, pp. 259–269, 2020.
- [178] W. Du, Q. Nguyen, Y. Liu, and S. M. Mohiuddin, “A current limiting control strategy for single-loop droop-controlled grid-forming inverters under balanced and unbalanced faults,” in *2022 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 1–7, 2022.
- [179] D. G. Holmes and T. A. Lipo, *Pulse Width Modulation for Power Converters: Principles and Practice*. Hoboken, NJ, USA: Wiley, 2003.
- [180] B. Mirafzal, *Power Electronics in Energy Conversion Systems*. New York, NY, USA: McGraw-Hill, 2022.
- [181] A. Adib, F. Fateh, and B. Mirafzal, “Smart inverter stability enhancement in weak grids using adaptive virtual-inductance,” *IEEE Trans. Ind. Appl.*, vol. 57, no. 1, pp. 814–823, 2021.
- [182] M. Gursoy, F. Sadeque, F. Fateh, and B. Mirafzal, “Direct control methods for grid-forming and grid-following inverters,” in *2023 IEEE Energy Conversion Congress and Exposition (ECCE)*, pp. 1081–1088, 2023.
- [183] M. Gursoy and F. Fateh, “A model-reference adaptive direct-power control scheme for grid-interactive inverters,” in *2021 IEEE 22nd Workshop on Control and Modelling of Power Electronics (COMPEL)*, pp. 1–5, 2021.
- [184] M. Ramezani, S. Li, F. Musavi, and S. Golestan, “Seamless transition of synchronous inverters using synchronizing virtual torque and flux linkage,” *IEEE Trans. Ind. Electron.*, vol. 67, no. 1, pp. 319–328, 2020.

- [185] K.-Y. Lo and Y.-M. Chen, “Design of a seamless grid-connected inverter for microgrid applications,” *IEEE Trans. Smart Grid.*, vol. 11, no. 1, pp. 194–202, 2020.
- [186] C.-T. Lee, R.-P. Jiang, and P.-T. Cheng, “A grid synchronization method for droop-controlled distributed energy resource converters,” *IEEE Trans. Ind. Appl.*, vol. 49, no. 2, pp. 954–962, 2013.
- [187] B. Mirafzal and F. Fateh, “Synced parallel control paths for multi-task system operation,” *arXiv*, 2023.
- [188] J. Benzaquen, F. Fateh, and B. Mirafzal, “On the dynamic performance of variable-frequency ac–dc converters,” *IEEE Trans. Transp. Electrification*, vol. 6, no. 2, pp. 530–539, 2020.
- [189] J. Benzaquen and B. Mirafzal, “Seamless dynamics for wild-frequency active rectifiers in more electric aircraft,” *IEEE Trans. Ind. Electron.*, vol. 67, no. 9, pp. 7135–7145, 2020.
- [190] J. Benzaquen, M. B. Shadmand, and B. Mirafzal, “Ultrafast rectifier for variable-frequency applications,” *IEEE Access*, vol. 7, pp. 9903–9911, 2019.
- [191] F. Sadeque, M. Gursoy, D. Sharma, and B. Mirafzal, “Autonomous control of inverters in microgrid,” *IEEE Trans. Ind. Appl.*, pp. 1–10, 2024.

Appendix A

Experimental Setup Development

In this Appendix section, details of the developed microgrid hardware are provided. The experimental testbed consists of two different multi-inverter microgrids that can interact with each other using circuit breakers, as demonstrated in Fig. 5.1. The following procedures will outline the breakdown of the components used in the experimental setup.

In Fig. A.1, a set of inverters is shown, including the local control unit (dSPACE MicroLabBox 1202), a custom-made sensor board for current and voltage measurements, and a custom-made LCL filter designed to obtain the fundamental component from the inverters' output voltage by attenuating any undesired harmonics in the system. The PWM signals

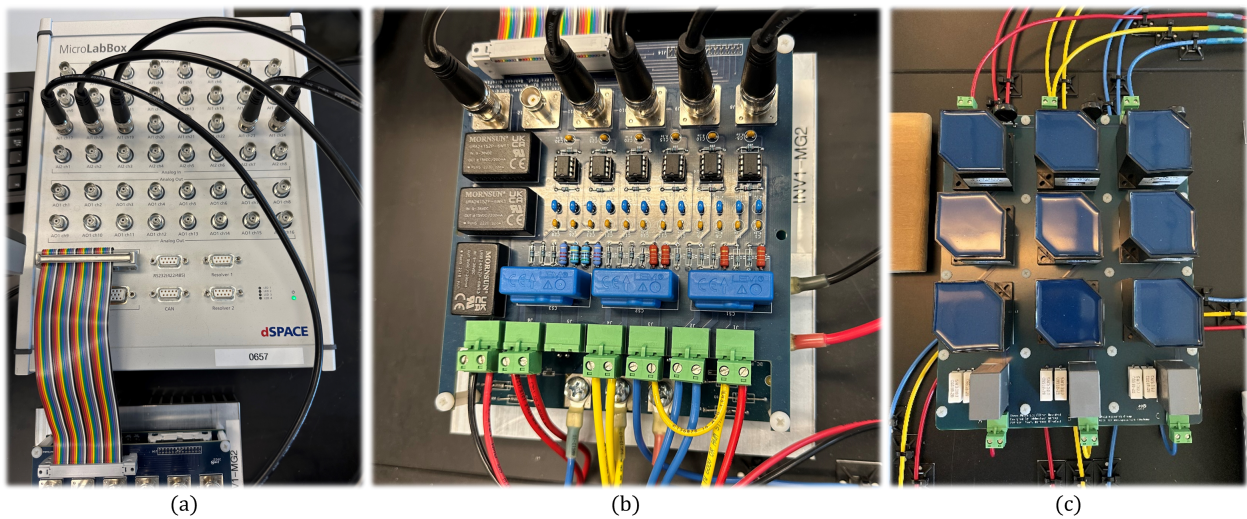


Figure A.1: A set of inverter; (a) local control unit, (b) sensor board, and (c) LCL filter.

generated by the controller are sent to the inverter using a ribbon cable, and the measured signals are transmitted to the local controller using BNC cables, as shown in Fig. A.1(a). The first microgrid setup uses two different types of semiconductor technology for the inverters. Three of the inverters are SiC-based, utilizing the CREE Wolfspeed CGD15FB45P1 power board with gate drivers and the 1.2 kV Wolfspeed CCS020M12CM2 three-phase SiC power module. Only one inverter in the setup is IGBT-based, equipped with a three-phase 10 kVA power module.

Signals necessary for closed-loop control operation are gathered using the sensor board, attached to inverter's power board. To achieve a noise-immune sensor functionality, differential operational amplifiers are employed on the sensor board, as shown in Fig. A.1(b), where the outputs are filtered out using first-order RC low-pass filter with ($R = 100\ \Omega$) and ($C = 0.1\ \mu F$). This yields the filter time constant as ($\tau_{LCL} = 20\ \mu s$). To sense the line currents, LEM LAH 25-NP hall-effect current transducers are used, see Fig. A.1(b).

The LCL filter in the setup, rated for 15 A, is designed to have a resonance frequency of 2.32 kHz based on the parameters listed in Table 5.1. The filter capacitors are arranged in a delta configuration to increase the effective capacitance of the filter. Damping during resonance is facilitated by resistors serially connected to the capacitors, see Fig. A.1(c). Metal Oxide Varistors (MOVs) are connected between each inverter output line-to-line voltages for over-voltage protection. The print-circuit-board (PCB) designs for both the sensor and LCL filter boards are shown in Fig. A.2.

The inverters are individually powered by Magna-Power SL600-10 DC supplies to provide a reliable and stable power source, as shown in Fig. A.3(a). These variable DC supplies have ratings of (0-600 V) for voltage and (0-10 A) for current, enabling a maximum power output of 6 kW. For safety, setting a specific current limit for each supply is recommended. On the output side, a three-phase 30 kVA NHR 9410 regenerative grid emulator is utilized for grid-interactive operations, as depicted in Fig. A.3(b). This four-quadrant grid emulator has the capability to both inject and absorb active and reactive power, with adjustable voltage and frequency settings.

There are two types of loads, i.e., static and inductive/dynamic loads, used for the

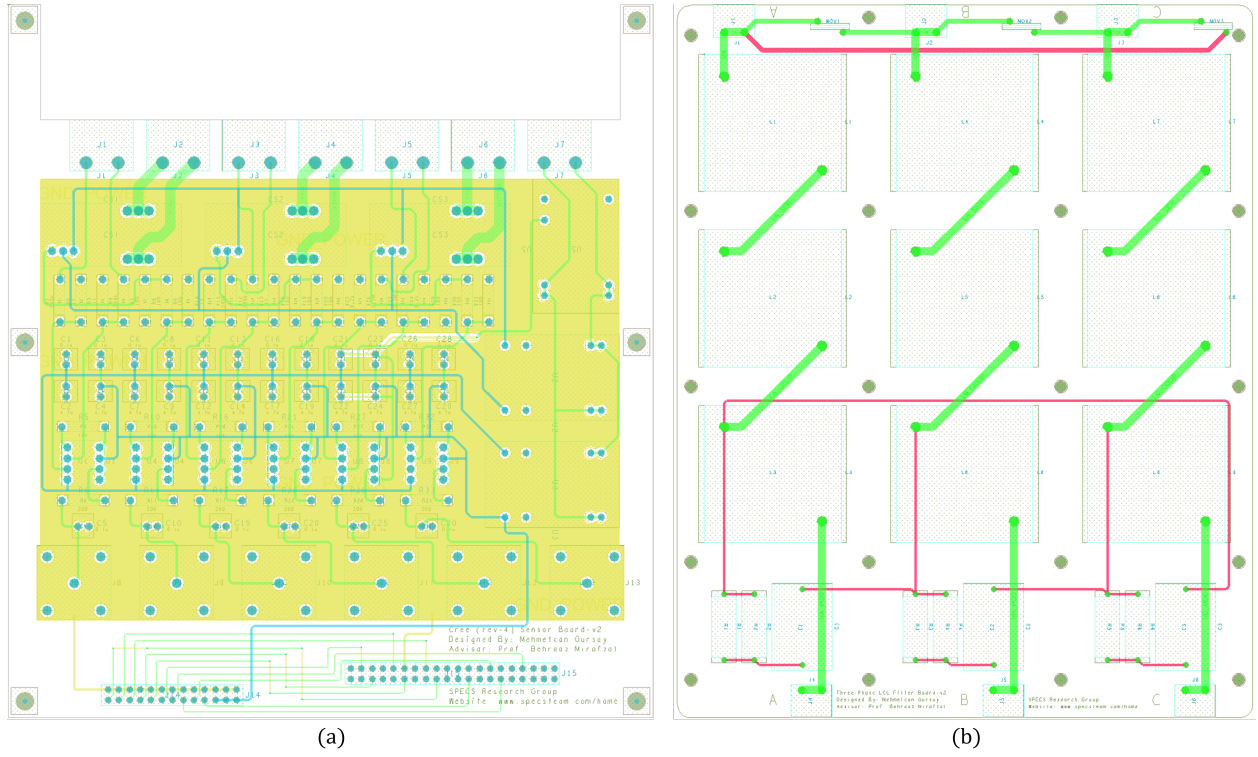


Figure A.2: PCB schematics for; (a) sensor board and (b) LCL filter.

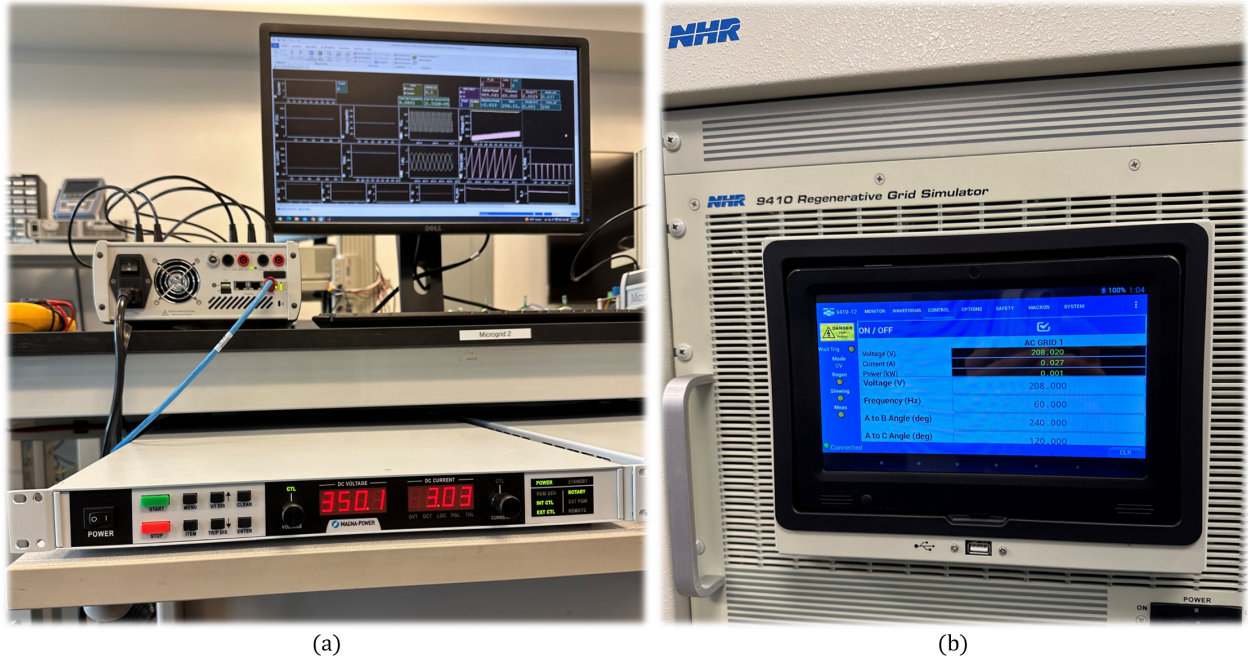


Figure A.3: DC and AC sources used in the testbed; (a) DC supply and (b) grid emulator.

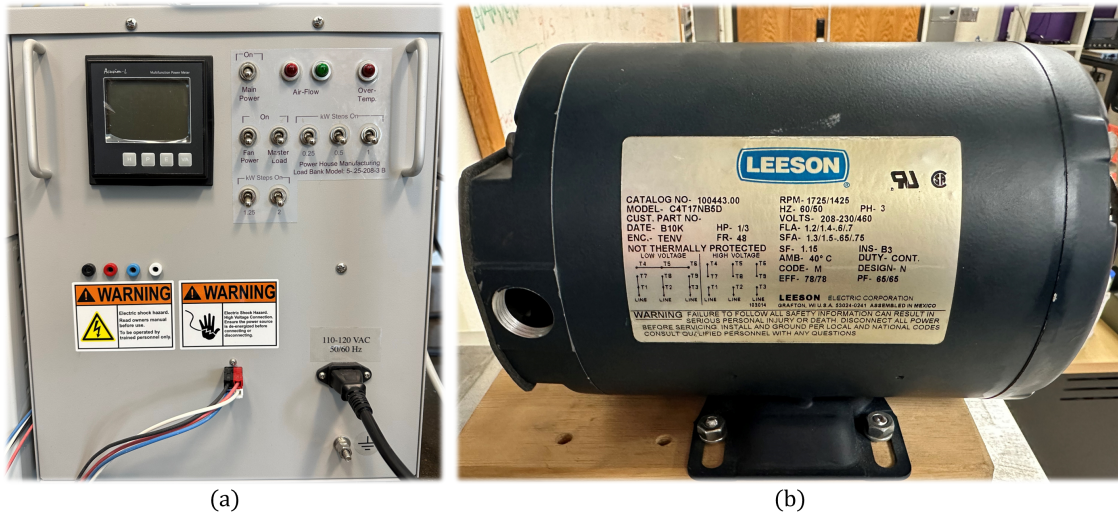


Figure A.4: Static vs. inductive and dynamic load; (a) resistive load bank and (b) an induction motor as load.

experimental validation. A resistive load bank capable of handling up to 5 kW is used for the static load, see Fig. A.4(a), whereas a three-phase, 208 V, 1/3 HP, and 4-pole induction motor is utilized as the inductive and dynamic load, illustrated in Fig. A.4(b). Circuit breakers facilitate the connection and disconnection between the inverters and the utility grid, and are also utilized to link or isolate microgrids. Moreover, an induction machine is connected to the system through these circuit breakers, shown in Fig. A.5(a). The tie-line impedances between each inverter are modeled by a series connection of a resistors and inductors for each phase, see Fig. A.5(b).

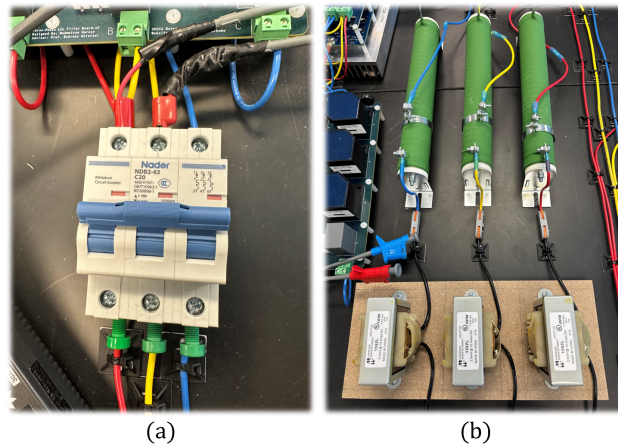


Figure A.5: Circuit breaker and tie-lines used in the setup.

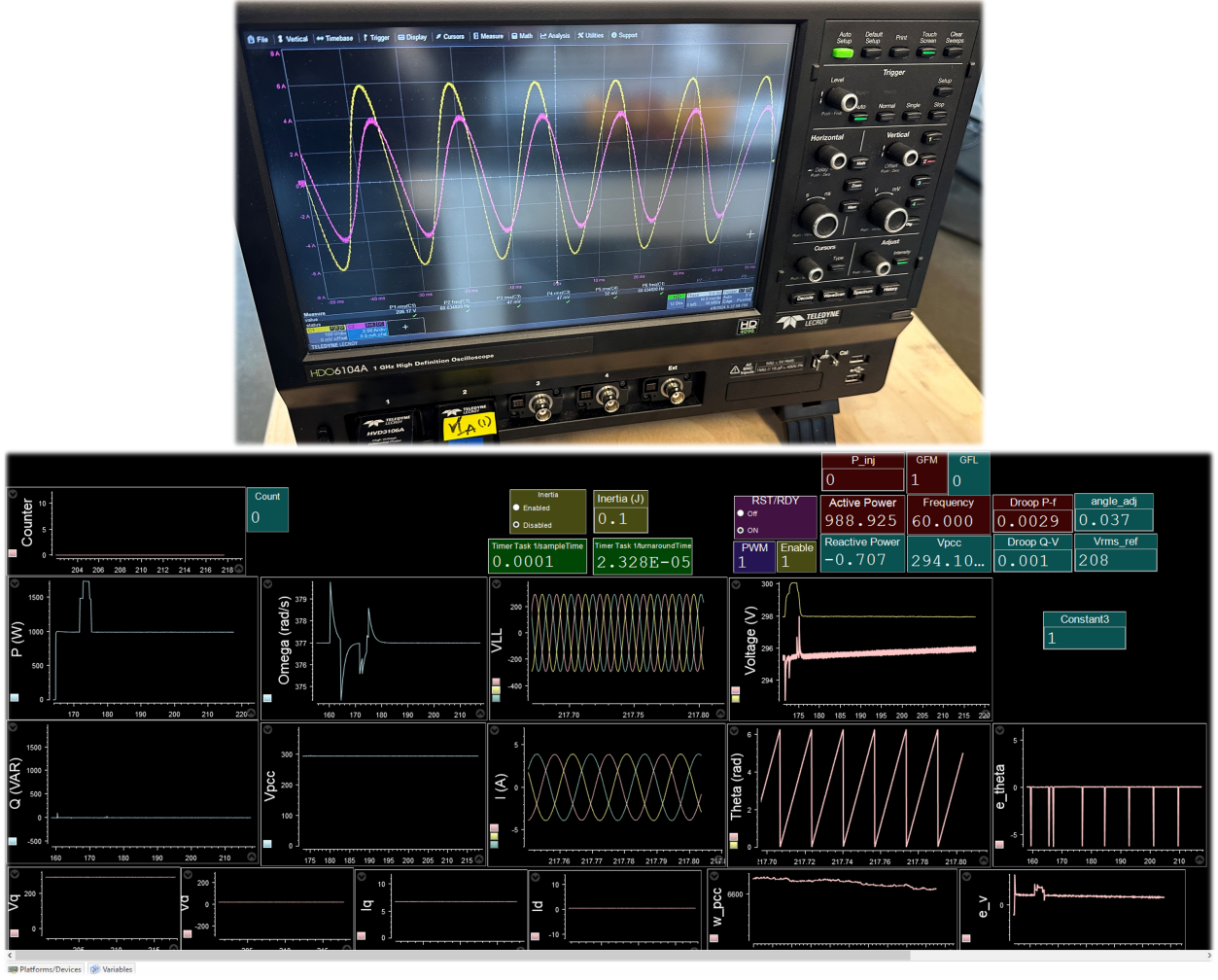


Figure A.6: Monitoring and data acquisition using; (top) oscilloscope and (bottom) ControlDesk software.

To monitor current and voltage waveforms during operation, a Teledyne LeCroy HD4096 oscilloscope equipped with HVD3106A 120 MHz high voltage differential probes and Teledyne CP030 current probes is used, demonstrated in Fig. A.6(top). For real-time adjustments in the local controller and data recording, the ControlDesk human-machine interface is utilized, see Fig. A.6(bottom), allowing for instantaneous changes to the control parameters.