

DER Utilization for Voltage-Sag Mitigation by Applying Different Network Partitioning Techniques

by

Ahmed Mohamed Abdel Rahman Mustafa

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Examining Committee Membership

The following served on the Examining Committee for this thesis. The decision of the Examining Committee is by majority vote.

External Examiner:	Dr. Medhat M. Morcos Professor Department of Electrical and Computer Engineering Kansas State University
Supervisor:	Dr. Magdy Salama Professor Department of Electrical and Computer Engineering University of Waterloo
Internal Member:	Dr. Mehrdad Kazerani Professor Department of Electrical and Computer Engineering University of Waterloo
Internal Member:	Dr. Kankar Bhattacharya Professor Department of Electrical and Computer Engineering University of Waterloo
Internal-external Member:	Dr. Bissan Ghaddar Adjunct Associate Professor Department of Management Sciences University of Waterloo

Author's Declaration

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abstract

Power quality (PQ) has been gaining increased attention in relation to Active Distribution Systems (ADSs), especially with regard to voltage-related PQ problems (i.e., voltage variation events). Voltage variation events, whether short- or long-term, can cause serious consequences, such as process interruptions, failure of computer-controlled and sensitive equipment, and data loss. One common form of short-term voltage magnitude variations is voltage-sag events, which may be caused by fault conditions, load condition variations, the starting of large motors, or the inrush current of transformers. Voltage-sag events caused by a motor-starting current or a transformer-inrush current are more localized than voltage-sags caused by faults. However, voltage-sag caused by faults propagates in the system such that system-level voltage-sag mitigation is required.

Thanks to the high penetration rate of both Renewable Energy Sources (RESs) and Battery Energy Storage Systems (BESSs), an increased number of inverter-based Distributed Energy Resources (DERs) exist in the ADSs. These inverter-based DERs have fast controllability and thus can be utilized to mitigate this type of voltage-sag event while achieving their main objective of supplying energy to the system. Therefore, the active management of RESs and BESSs can swiftly alleviate the voltage-sag problem. Existing DERs in the system can be considered controllable power resources with adjustable active/reactive power signals, so active and reactive power management of inverter-based DREs is proposed in this research for performing system-level voltage-sag mitigation in ADSs. The proposed voltage control framework is based on two parallel and complementing actions. The first is injecting active and reactive powers to restore the system's voltage close to the $0.9 p.u.$, and the second action involves the identification and isolation of the voltage-sag origin (i.e., faults).

This thesis has four main parts that achieve the two actions required in order to mitigate voltage-sags. The first part of the thesis develops a voltage-sag origin identification methodology to identify the fault origin and detect whether the fault is upstream or downstream from the system's point of common coupling (PCC). This developed technique is assumed to run in the background and is initiated by the voltage-sag event. The technique is fast, efficient, and cost-effective, based on the application of voltage and current estimation techniques in conjunction with Tellegen's theorem for identifying and detecting the exact location of the voltage-sag origin in ADSs.

At the same time the developed identification sub-routine is running, a voltage-sag mitigation sub-routine is also running to achieve the first action of the proposed framework. In the second part, a novel system level-based voltage-sag mitigation algorithm is proposed for solving voltage-sag problems in ADSs. The algorithm is based on partitioning the system into virtual mitigation zones to mitigate the voltage-sag as quickly and optimally as possible. Information regarding the voltage-sag origin will help mitigate voltage-sags that could not be overcome via the available DERs' capacity. Therefore, if the fault is within the system boundary (i.e., downstream from the PCC), the voltage-sag origin should be isolated, which is achieved by the second action running in the background. If the voltage-sag mitigation requirements (i.e., injection of active and reactive powers) are beyond the DERs' capabilities, parts of the system can face unintentional islanding. To

prevent this unintentional islanding, the planning of intentional islanding will isolate the voltage-sag origin from the system and hence improve supply continuity and system reliability. Intentional islanding of this kind can be achieved via partitioning the system into clusters of survivable microgrids. The partitioning approach will not only isolate the faulted zone that caused the voltage-sag event, but will also ensure that the constructed microgrids are survivable in terms of supply adequacy and microgrid stability.

In the third part, a framework based on small-signal stability is proposed to construct survivable microgrids according to a stability-constrained partitioning scheme. The partitioning of the system into survivable self-adequate microgrids during prolonged voltage-sag events can isolate the voltage-sag root cause. Thus, by isolating the voltage-sag origin from the rest of the system, voltage-sag mitigation is accomplished. Moreover, this partitioning scheme is valuable to the DSOs and it leads to voltage-sag mitigation without adding any resources to the system.

Finally, in the fourth part, a recovery algorithm for post-voltage-sag mitigation is proposed. The recovery algorithm is based on reconnecting the neighbouring microgrids. These microgrids should have the ability to seamlessly reconnect when necessary. To facilitate the implementation of the proposed recovery algorithm, a smooth reconnection method between two microgrids is a key feature that should be adopted by the microgrid control scheme. Moreover, survivable microgrids must be synchronized before reconnection. These synchronization conditions are: same voltage magnitude, same frequency, and same phase angle at the terminal buses of the two microgrids. The effectiveness of the synchronization algorithm is proven by multiple case studies, and the microgrids are successfully returned to synchronization and connected together to form one microgrid.

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December 2020

Dedication

To my beloved father, Mohamed

To my beloved mother, Mona

To my beloved wife, Mona

To my beloved brothers and sisters, Rana, Ramy, Hany, Khloud,

To my lovely angels, Rahaf, Mohamed, Malek and Talya

Thank you for your support, love, and encouragement

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Nomenclature

Acronyms

AD	Adjoint System
ADS	Active Distribution System
AMI	Advanced Metering Infrastructure
ANN	Artificial Neural Network
ASM	Active System Management
BESS	Battery Energy Storage System
CC	Central Coordinator
CL	Candidate Line
CU	Central Unit
DC	Distributed Coordinator
DER	Distributed Energy Resource
DFT	Discrete Fourier Transform
dq	Direct-quadrature
DSO	Distribution System Operator
DVR	Dynamic Voltage Restorer
EII	Electrical Influence Intensity
FACTS	Flexible Alternating Current Transmission System
FI	Fault Identification
GAMS	General Algebraic Modeling System
HV	High Voltage
ICT	Information and Communication Infrastructures
IDVR	Interline-DVR
IEC	Intelligent Electronic Controller
IED	Intelligent Electronic Device
MAS	Multi-Agent System
MG	Microgrid
OC	Open Circuit
OLTC	On-load Tap Changer
PCC	Point of Common Coupling

PF	Power Flow
PI	Proportional-Integral
PMU	Phasor measurement unit
PQ	Power Quality
PWM	Pulse Width Modulation
RES	Renewable Energy Source
SC	Strength of Connectivity
SCPS	Stability-Constrained Partitioning Scheme
SE	State Estimation
SI	Stability Index
SLG	Single Line-to-Ground
SMES	Superconducting Magnetic Energy Storage
SSS	Small-Signal Stability
STATCOM	Static Synchronous Compensator
UPQC	Unified Power Quality Conditioner
ZC	Zone Coordinator
ZCI	Zone Capability Index

Sets:

bat	Set of buses associated with batteries
f_{oc}	Set of the open-circuited branches
f_{sc}	Set of the short-circuited buses
i	Set of system buses
K	Set of mitigation zones
N	Set of system buses inside the mitigation zone
p	Set of port branches
RES	Set of buses associated with renewable energy sources
t	Set of intermediate branches

Parameters:

A_{ij}	Weighted adjacent matrix
B	Susceptance of branch
Br	Total number of branches
C	Capacitance

Com_i	The community to which node i belongs
Cap	Ratio of available resources capacity to total loading inside the mitigation zone
D_i	Degree of node i
E_{ij}	Weighted value of the edge between nodes i and j
F	Multi-Objective Function
F_1	Objective Function for minimizing power injection variations
F_2	Objective Function for minimizing voltage deviations
G	Conductance of branch
I	Branch current
K	Gain of PI controller
L	Inductance
m_p	Droop gain of the active power
M	Total number of edges in the network
n_q	Droop gain of the reactive power
PO	Input/output Port
P_{RES}	Active power of a RES, MW
P_{bat}	Active power of a battery, MW
P_{bat}^{max}	Maximum active power of a battery, MW
Q_{RES}	Reactive power of a RES, Mvar
Q	Modularity index
r	Resistance
SC_{ij}^{VP}	Strength of connectivity between node i and node j based on active power-voltage magnitude sensitivity
SC_{ij}^{VQ}	Strength of connectivity between node i and node j based on reactive power-voltage magnitude sensitivity
S_{ij}^{VP}	Voltage sensitivity coefficient at node i for active power injection at node j
S_{ij}^{VQ}	Voltage sensitivity coefficient at node i for reactive power injection at node j
S_{RES}^{max}	The maximum apparent power of a RES, MVA
T_{diff}	The right-hand side of the difference form
th	Threshold value
$ V $	Average value of bus voltage magnitudes inside mitigation zone
VD	Branch voltage drop

W_{est}	Weights for voltage and current estimation
Y	Admittance
Z	Zone
θ	Angle
λ	Eigenvalue
ω	Angular frequency

Variables:

V	Voltage magnitude, V
W_1	Weighting factor assigned to the first objective function
W_2	Weighting factor assigned to the second objective function
θ	Voltage angle
ΔP_{bat}	Active power injection from a battery, MW
ΔQ_{bat}	Reactive power injection from a battery, MW
ΔQ_{RES}	Active power injection from a RES, Mvar

Chapter 1

Introduction

1.1 Preface

One of the most significant operational challenges of our time is the transformation to energy networks that are based on Renewable Energy Sources (RESs) and Battery Energy Storage Systems (BESSs). This transformation has forced Distribution System Operators (DSOs) to change their usual passive control approaches to Active System Management (ASM) approaches [1]. A major challenge within Active Distribution Systems (ADSs) is voltage-related Power Quality (PQ) problems (i.e., voltage variation events). These can take the form of short-term voltage magnitude variations such as voltage-sag events, which are caused mainly by electrical faults, the on/off switching of heavy loads (e.g., large motors), and load condition variations.

Thanks to the high integration rate of RESs and BESSs, an increased number of inverter-based Distributed Energy Resources (DERs) exist in ADSs. The projected growth of the installed capacity globally for different technologies is illustrated in Figure 1.1. As shown, RESs (e.g., mainly solar and wind) are currently more popular with developers and investors [2]. Figure 1.2 presents the annual US BESSs deployments from 2012 to 2021, as reported by US Energy Storage Monitor publications [3]. From these figures, it is clear that an intelligent grid with an ASM scheme is indispensable for allowing for the proper coordination of power system operation, which facilitates the implementation of different voltage variation mitigation techniques. The use of communication systems and real-time control for DERs (i.e., RESs and BESSs) facilitates this transformation of energy networks [4].

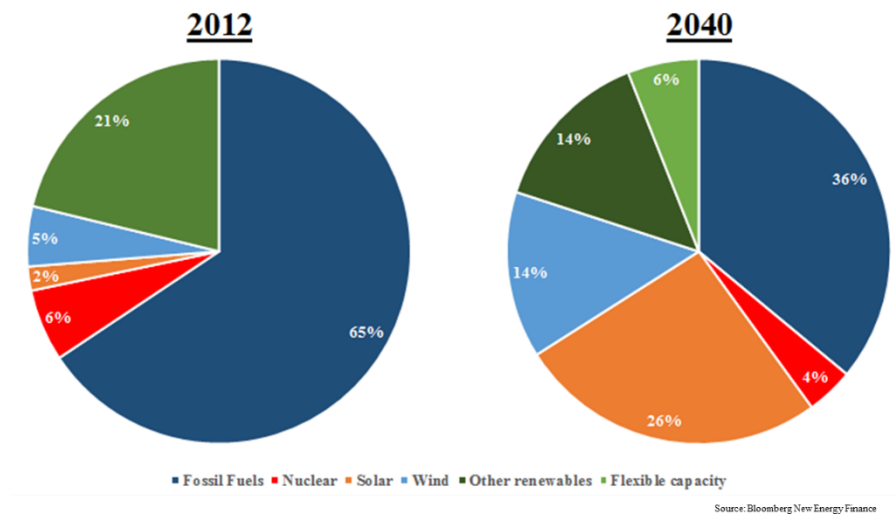


Figure 1-1 Annual capacity additions

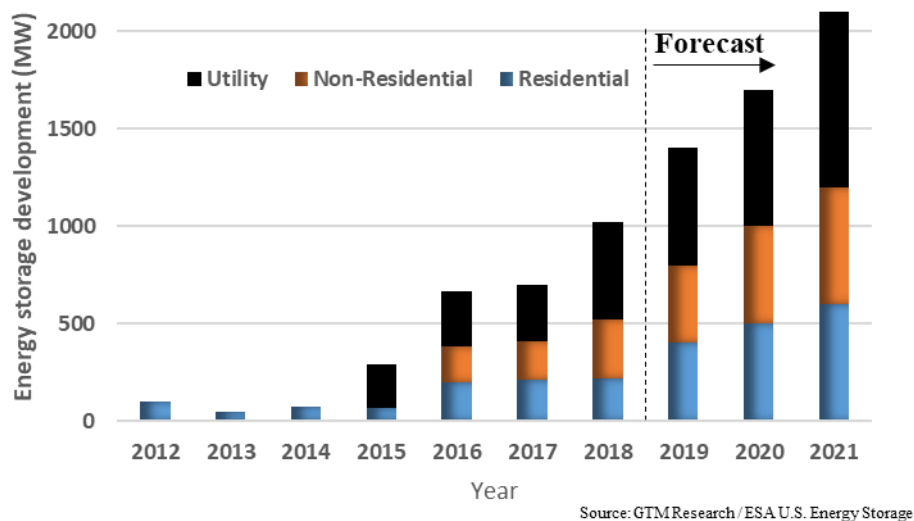


Figure 1-2 Annual US energy storage development (MW), 2012-2021

1.2 Research Motivation

Different types of voltage-related PQ problems can occur in ADSs. Some common examples of these problems are: 1) short-term voltage magnitude variation, 2) long-term voltage magnitude variation, and 3) voltage imbalance. Short-term voltage magnitude variations, known as voltage-sag events, are usually caused by electrical faults in power system networks, the on/off switching of large loads, and the switching on of a large motor. The existence of these types of voltage-related PQ problems is considered an early warning for upcoming critical problems in the system.

The expected high penetration rate of RESs and BESSs in ADSs prompts the need for new techniques to control ADS operation by DSOs. Utilizing traditional voltage variation mitigation techniques (e.g., installing a DVR at the Point of Common Coupling [PCC]) can be one possible solution to deal with the problem at the local level. However, the existence of DERs in the system yields extra opportunities that can be utilized to improve the voltage quality at the system level. Therefore, the participation of DERs in ASM schemes has motivated the development of voltage variation mitigation techniques and promoted the idea of self-healing grids.

1.3 Research Objectives

Based on the above discussion, ASM schemes that take into account the high penetration rates of RESs and BESSs are necessary to deal with voltage variation problems in ADSs. A proposed framework will be introduced based on two complementing parallel actions. The first action deals with the optimal active and reactive power management of DERs deployed in the system to mitigate the voltage variation problem. Since the output power of RESs is highly dependent on weather conditions (which can change during the day), their abilities to mitigate voltage variations vary considerably. The second action is the identification and isolation of the voltage-sag origin (i.e., faults). Identifying the voltage-sag origin (i.e., upstream or downstream from the PCC of the system) is a critical step in preventing the propagation of a voltage variation event in the system. The idea of a self-healing system is adapted in the proposed framework to improve both supply continuity and system reliability.

In this work, different network partitioning techniques are introduced to facilitate the implementation of the proposed framework. A study of system-level voltage variation mitigation techniques is also presented. The research objectives of the study can be summarized as follows:

1. Proposing a voltage-sag origin identification algorithm in ADSs. The proposed algorithm is a fast, efficient, and cost-effective approach based on the application of voltage and current estimation techniques and Tellegen's theorem to identify and detect the exact location of the voltage-sag origin in ADSs.
2. Proposing a system-level voltage-sag mitigation algorithm by using DERs. The proposed algorithm aims to optimize the utilization of existing ADS assets (i.e., DERs) to mitigate voltage-sag without the need to reinforce the system with new equipment.
3. Proposing a voltage-sag mitigation algorithm using eigenvalue analysis to obtain a Stability-Constrained Partitioning Scheme (SCPS). This partitioning scheme will be used by the DSOs

to isolate the portion of the network that contains the source of the voltage-sag, enabling the mitigation to be done without the need for any additional resources.

4. Proposing a recovery algorithm for post-voltage-sag mitigation. This algorithm is based on proposing a reconnection technique for islanded microgrids constructed according to the SCPS.

1.4 Thesis Outline

The thesis outline is structured as follows. Chapter 2 provides a background and literature survey on the previous work achieved in the area of voltage variation mitigation. Chapter 3 presents a voltage-sag origin identification algorithm in ADSs. Chapter 4 gives a detailed description of the system-level algorithm proposed for mitigating voltage-sags in distribution systems. In Chapter 5, a voltage-sag mitigation algorithm based on a SCPS is introduced. Chapter 6 proposes a recovery algorithm for post-voltage-sag mitigation. Finally, the conclusion and future plans are presented in Chapter 7.

Chapter 2

Background and Literature Survey

2.1 Introduction

Distribution networks are currently facing numerous challenges, such as limited expansion space, incremental increases in load demands, ageing infrastructure, and environmental issues. Coping with these challenges requires planning and updating conventional distribution systems into ADSs. In general, ADSs should accommodate a diverse variety of DERs, along with devices that are attached to intelligent technologies that can integrate and accept more complexity into the system operation. ADSs should therefore be intelligent and modernizing grids that have the ability to fit with bi-directional power flow and information exchange between different resources. However, the infrastructure and technologies of conventional distribution systems limit the adoption of active management in distribution systems [5].

Controlling the ADS voltage is one of the most important goals for DSOs [6]. The available capacity of variable power generation sources (e.g., RESs and BESSs) offers an excellent opportunity to deal with voltage variation issues. In contrast, the considerable penetration level of RESs can pose a severe threat to the permissible limits of ADS voltage. Therefore, DSOs may apply an ASM strategy in order to operate the ADS assets appropriately.

A variety of voltage control approaches have been investigated to mitigate the violation of voltage permissible limits in systems, as will be discussed later. Partitioning the whole system into loosely coupled active/reactive power control communities is a subject undergoing intense study for voltage regulation. Hence, a detailed literature review for network partitioning approaches will be presented in this chapter. After that, a literature review of how to apply ASM schemes to ADS is provided. These ASM schemes will maximize the usage of the capability of existing network assets (i.e., DERs) to actively manage voltage constraints. Moreover, these schemes will facilitate the integration of larger volumes of RES without considering the need for expensive network reinforcements.

At the same time, the ASM schemes will optimally utilize the flexible operation of DERs based on; 1) the reactive power capability of RESs, 2) real and reactive power control of BESSs, and 3) generation curtailment techniques. Approaches for ASM schemes in ADSs can be classified based on various aspects, so this study will present the spectrum (i.e., from centralized to decentralized) of ASM schemes in detail. ADSs are able to operate in islanded or grid-connected modes (i.e., microgrids). However, the

survivability of these microgrids is questionable and stability studies should have been incorporated. Finally, this chapter presents a literature review of the stability evaluation of microgrids.

2.2 Voltage Variation Problems

ADSs are widely considered the next generation of electric power distribution systems for sustainable and secure energy development. As an essential part and a significant element of the power system infrastructure, ADSs should be awarded preference towards evolving future smart grids. This is because most end-users and low carbon technologies (e.g., RESs, heat pumps, and BESSs) exist in these networks. As mentioned previously, the penetration level of different energy resources is rapidly increasing in the global market's power systems, with ambitious countries targeting the expansion of their renewable energy generation. Furthermore, rising oil and gas rates have not only ensured but speeded up the demand for RESs, thus introducing considerable challenges to both DSOs and transmission system operators.

One of the main issues faced by DSOs is voltage variation problems caused by reverse power flow [7]. An additional issue is maintaining voltage profiles within particular limits, as desired by the typical supply standards quality. Long-term voltage magnitude variations (e.g., over and under-voltage) may show up in the ADSs for different reasons. For example, the intermittent nature of RESs, such as solar resources and wind farms, comes from the stochastic of solar radiation and wind speed. Another example is when the load demand peaks and RES outputs have not occurred simultaneously during high RES generation and low load conditions. A change in the RMS voltage value beyond the standard voltage value is defined as short-term voltage magnitude variations (e.g., sag, swell, or interruption).

The IEEE Std. 1159,3.1.73 defines voltage-sag as “*a sudden decrease in voltage magnitude for a time greater than 0.5 cycles of the power frequency but less than or equal to 1 minute*”. Voltage-sag events in power systems occur for several reasons, as provided by Bolin [8]. One of these is electrical faults, which can critically affect a power plant's operation and are of crucial concern. According to the type of fault (e.g., symmetrical or unsymmetrical), voltage-sag depths can have the same value in each phase or unequal values, respectively. Symmetrical voltage-sags are caused by induction motors starting as each phase draws more or less the same in-rush current. In this scenario, the induction motor characteristics and the network's strength at the connection node of the motor are affecting the voltage-sag depth. Another source for voltage-sags is transformer energizing, which often occurs due to the over-fluxing of the transformer core.

In most situations, a three-phase balance is optimal for a power grid. Nevertheless, single-phase loads, single-phase DERs, asymmetrical three-phase devices and equipment, unbalanced faults, and numerous other reasons can lead to power system imbalances and badly affect the PQ. For a balanced three-phase power network, the three-phase voltages should be equal in magnitude and be in a 120° phase shift.

Voltage unbalance level is another crucial PQ index for ADSs. The reasons for voltage imbalances can be separated into two groups, namely typical reasons and abnormal reasons [9]. Typical reasons for voltage imbalances are uneven load allocations among the three phases, random load behaviours, and three-phase transformer banks connected in a wye-open delta. Abnormal reasons cover fault events in the system and single-phase operation of motors. Thus, an acceptable voltage imbalance level is desired to deliver adequate electricity to the end-users.

The mitigation of voltage-sags can be done with a number of available methods using custom power devices; such as Static Synchronous Compensator (STATCOM), Superconducting Magnetic Energy Storage (SMES), Dynamic Voltage Restorer (DVR), and Unified Power Quality Conditioner (UPFC). In the main, DVR is more efficient and capable of proposing direct solutions for re-establishing the voltage profile quality at its load-side terminals if the voltage profile quality at its source-side terminals is disturbed. Figure 2.1 shows a categorization of DVR topologies [10].

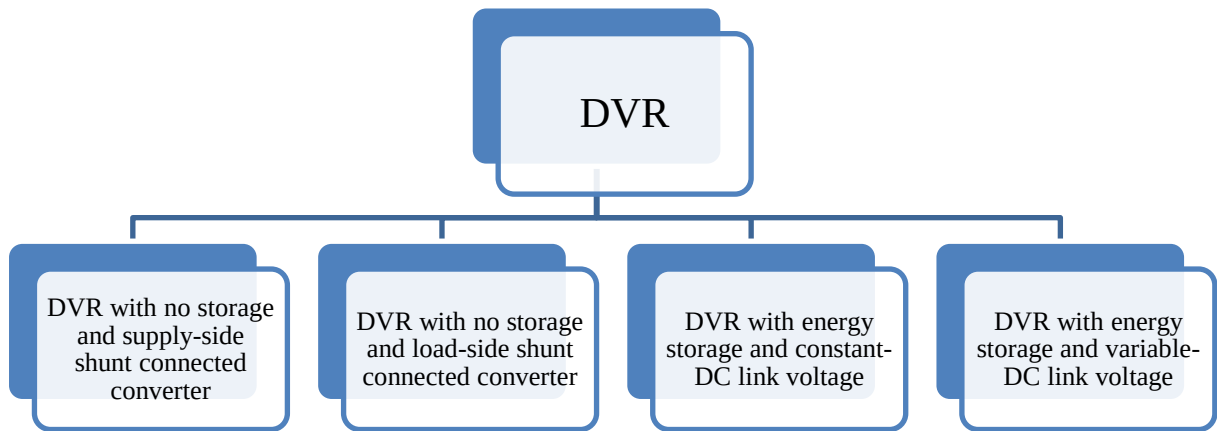


Figure 2-1 Different DVR topologies

Generally, the SMES is utilized to mitigate voltage fluctuations due to its high power density, fast response speed, long lifetime, and lower amounts of environmental pollution [11]. However, the

SMES-based power devices such as DVR were not as cost-effective as those operated with traditional BESS due to the expensive capital costs of the SMESs [12].

Thus, a SMES/battery hybrid energy storage is used for mitigating both long- and short-term voltage variations [13]. This hybrid concept has many advantages in reducing costs and enhancing voltage support capability compared to a SMES-based system. In addition, reducing the required battery power rating is another advantage for the SMES/battery hybrid unit. Moreover, the hybrid unit's battery life is expected to be improved more than a battery-only system because of the decrease in the peak discharge power and battery power cycling. Although the energy source at the DC bus has a high cost, a minimum rating of DVR is granted due to the injected in-phase voltage with the voltage at the PCC [14].

For a self-charging DVR, a significant amount of active power is required from the DC-link capacitor to compensate for the voltage phase jump. Therefore, this technique will lead to a shorter voltage-sag support time and demand a larger capacitor. On the other hand, a new control strategy to improve the voltage-sag mitigation time while compensating for the voltage phase jump is presented in [15]. This strategy aims to regulate the active power contribution to the lowest possible option. Integrating an ultra-capacitor with DVR will give active power capability to the system to mitigate deeper sags [16].

A novel coordinated control algorithm for distributed BESSs to achieve a more stable and reliable operation is given in [17]. The traditional “master-slave” concept is utilized in [17] to coordinate several BESSs in the aggregation manner. However, this algorithm will lead to the early ageing of the master battery during the project and will bring in an undesired replacement cost. Therefore, the return of the capital cost is not justified. Inspired by Flexible Alternating Current Transmission System (FACTS) equipment, the Interline-DVR (IDVR) was introduced in [18] as an economical solution for mitigating voltage-sag events in multi-feeder distribution systems. This new configuration increases the mitigation capacity of the IDVR at high power factors. Moreover, it improves the mitigation performance in order to compensate for profound voltage-sag events at moderate power factors.

In [19], a UPQC is used to mitigate voltage-sags as well as study the UPQC allocation impact on distribution systems. The authors base their study on determining the load voltage required with respect to phase-angle shifting. In [20], a new control algorithm with a synchronous reference frame-based power angle control method is presented, while in [21] a novel UPQC configuration that improves the PQ in the installed area is proposed. This configuration is different from the typical UPQC, in that the UPQC usually contains a single device capable of improving the PQ at the local level only. However, a further investigation is needed to provide the optimal rating and location of a UPQC in the system.

STATCOM is also used to mitigate voltage-sags and swells. STATCOM could be implemented with just a DC capacitor [22] or with a BESS. The BESS provides additional capacity for DSTATCOM to be utilized in load balancing, reactive power compensation, and harmonic current elimination [23]. Furthermore, the reference currents are obtained by the controller for VSC in the DSTATCOM based on SRF theory with the carrier-based Pulse Width Modulation (PWM) technique. However, these direct solutions deal with the problem at the local level only and re-establish the voltage profile quality at its PCC.

To the best of the authors' knowledge, few methods provide solutions for voltage-sag problems at the system level. Most of these methods are based on the use of innovative handling of customer power devices.

2.3 Network Partitioning Approaches

Information, technological, and social systems can regularly be depicted as complex networks. They are described as a group of interconnected nodes merging both randomness and organization [24]. The idealistic size of large systems like mobile phone networks and social network services is now counted in millions of nodes and more. Given their large size, these system sizes seek new algorithms to obtain global information based on their topology. A scheme that divides the system into communities or partitions is presented in [25], with the partitions representing groups of strongly coupled nodes.

Some of the active/reactive power combined control algorithms deal with the power networks in bulk [26, 27]. However, this approach requires an extensive computational burden and the complexity such a burden causes when applied in large systems. It is worth mentioning that, due to the modern nature of ADSs, some voltage control algorithms are based on partitioning the network into communities (i.e., zones). These algorithms offer a promising path to mitigate voltage-related PQ problems in ADSs with a feasible computational burden [28, 29].

Power network partitioning has been extensively investigated using a variety of approaches. The spectral clustering method has been applied for network partitioning in [30]. The method requires a pre-defined number of clusters for obtaining the partitioning scheme. Line power flows and admittances could be considered as weight indices in partitioning. In [31], the spectral clustering succeeded in reducing the convergence time without compromising the solution accuracy for partitioning the power system under study. Optimal partitioning is utilized to obtain optimal AC power flow while neglecting the power system's geographical topology.

In [32], electrical distance plays an important role in partitioning the electrical network, with the K-means clustering algorithm being applied as a primary tool. While neglecting the network's topology under study, the operational constraints such as the energy policy and ownership are considered the major aspects in obtaining an optimal partitioning algorithm in [33].

More recently, complex network theory has attracted the attention of researchers to look closer at networked systems. In [34], a divisive method for detecting sub-networks is introduced; however, this method does not apply to larger networks. Therefore, a hierarchical agglomeration is proposed in [35]. A genetic algorithm is utilized in [36] to identify the groups that contain nodes with a dense relationship but a sparse relationship between groups. By optimizing two objective functions, the optimal number of sub-networks can be obtained automatically. In order to have both accuracy and complexity, a method to detect sub-network based on the anti-triangle centrality is proposed in [36].

The methods for network partitioning utilized in complex networks can be applied to the power networks. In [37], a novel method is introduced for detecting sub-networks that define a new similarity index. This index is considered a major tool for examining the effect of bridging nodes on cascading failures in power networks. The penetration of RESs in ADS causes a steady-state overvoltage problem. Thus, to mitigate this overvoltage problem, a network partitioning algorithm based on the improved modularity for voltage control is presented in [38].

From the brief literature survey above, we can say network partitioning algorithms in complex systems offer great potential to be utilized with ADSs. However, there is still a research gap in mitigating voltage-sag at the system level. Existing solutions deal with the problem at the local level only and re-establish the voltage profile quality at its PCC. Thus, to achieve a system-level solution for voltage-sag problems, more mitigation devices should be installed in the system. Another approach presented in [39] focuses on mitigating voltage-sag events based on reactive power support only. Due to the high R/X ratio in distribution systems, as shown in [40], both active and reactive power requirements from DERs should be considered for voltage-sag mitigation.

2.4 Active Distribution System Management

Active distribution systems indicate the direction of gaining benefits from the flexibility services presented by DERs for ASM in addition to distribution automation. The deployment of Intelligent Electronic Devices (IED), Advanced Metering Infrastructures (AMI), and advanced Information and Communication Infrastructures (ICT) will improve distribution automation through the facilitation of those modern functionalities. In the case of low voltage distribution networks, the ASM application is

achieved by integrating active elements (e.g., RESs and BESSs) along with advanced ICT infrastructures.

Amid these radical and innovative changes considered for the system operation, the ASM will authorize functionalities and features of disturbance management, asset management, and congestion management. The active elements impose instrumental importance on the ASM, since they persist in attempting active participation in network operation from a technical and economic perspective.

The different controllable resources existing in ADSs can be controlled in various ways (e.g., separately or coordinately) by using different control approaches (i.e., the decision-making algorithm). A typical control process is shared between all of these approaches: collecting information of the network states from monitoring and then obtaining the control decisions followed by the control actions. On the other hand, control approaches are entirely dissimilar and should be categorized based on different aspects.

From the perspective of the corresponding network model's requirements, control approaches can be classified into model-based and model-free [41]. From the perspective of dealing with uncertainties such as unpredictable renewable generation, data dropping, and data distortion issues, control approaches can be classified into stochastic and robust. The first technique considers the uncertain variables based on the probability density function, whereas the second guarantees that the solution works for all instances within the range of uncertain variables. Furthermore, from a more practical viewpoint of implementation, the control approach's network coverage is one of the foremost vital angles, especially for DSOs. Based on this guideline, the spectrum of ADS management schemes can be classified into three control approaches, namely centralized, semi-coordinated, and decentralized, as shown in Figure 2.2.

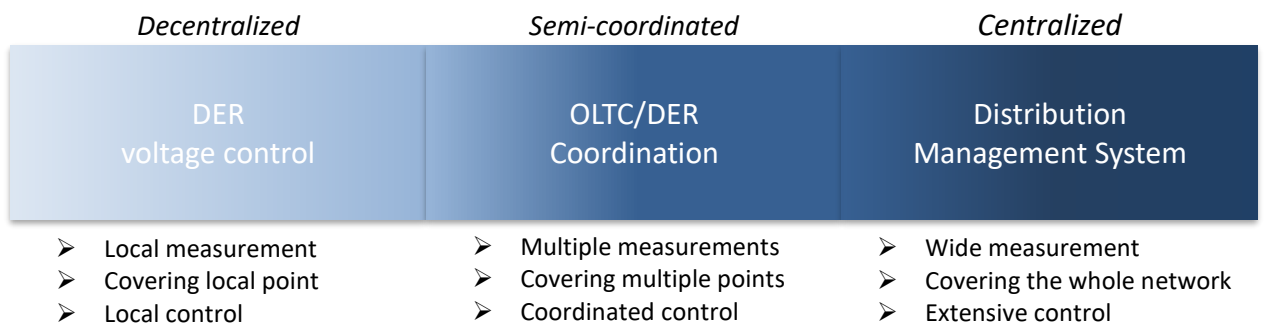


Figure 2-2 Spectrum of ADS management schemes

2.4.1.1 Centralized Control

Centralized control involves the whole network and requires a high standard of coordination among the different network elements, such as generators, transformers, RES units, storage units, and switches. During the control scheme, the whole network states are measured and then delivered to the control center to obtain the control settings. Later on, these settings are sent back to the controllable equipment to perform the control actions. The comprehensive perceptibility and optimal control settings usually make the execution of centralized control approaches the best among the three categories when considering the voltage behavior and network loadings. In contrast, this type of control approach mainly depends on remote monitoring and the corresponding communication infrastructure [42]. Monitoring the whole network could lead to high investment costs and reliability issues in light of the potential data dropping and distortion issues related to the communication system (e.g., due to lack of metering infrastructure or privacy matters). Centralized approaches have been implemented in a considerable number of ADS management applications.

2.4.1.2 Semi-Coordinated Control

In contrast to centralized control approaches, which require the entire observability and coordination of the controllable network resources, semi-coordinated control approaches deal with only part of the network and exclusively coordinate and control RES units and On-Load Tap Changer (OLTCs). Within the context of this method, only twofold (pinch points) are monitored, such as the RES unit coupling point and the secondary OLTCs. The recorded measurements are sent to a control center for determining control decisions for RES units and OLTCs, whereas RES coupling point measurements can be sent to OLTCs. Thus, the OLTCs can obtain coordinated control actions in cases where RES units are locally controlled.

Overall, the approaches that rely on a control center can result in preferable performance, while cost-effective and robust solutions can be achieved from the second approach. Furthermore, compared to centralized approaches, semi-coordinated strategies demand much less observability of the network and a much lower cost. However, the trade-off is that the performance will be worse.

2.4.1.3 Decentralized Control

The decentralized control approaches gather the data only in a single point and obtain the settings locally, depending on the site's measurements. The central processor then takes control of decisions regarding the whole network. In the decentralized control approach, the states at the coupling point of

the controllable elements are measured and delivered to the local controller. Following the setting's determination, they return to the controllable elements directly to execute control actions.

Note that limited monitoring and a lack of communication infrastructure are considered advantages in decentralized approaches. However, the local controller has to be placed at a controllable resource. This approach is motivated by the pursuit of real-time (nearly instantaneous) control that can divide the goals between multiple controllers as every controller takes care of a smaller section of goals. In addition, the solution of the sub-problems will not seek global information, unlike the solution of centralized control. Hence, decentralized approaches are cost-effective solutions, especially for networks with restricted access to communications.

Furthermore, not depending on communication results in a more robust approach, as communication issues can be avoided. A relatively simple control strategy is thus achieved with limited available information and controllable elements. However, this will lead to a worse overall performance regarding the optimization algorithm compared with the previous two control approaches. In the main, due to their simple and low-cost nature, decentralized approaches are preferable options compared to the implementation of more complex centralized techniques. For that reason, utilizing the active and reactive power capabilities of the available DERs in a decentralized control strategy is the focus for developing the ASM schemes in this thesis

2.5 Voltage Coordination Management

The DSOs mainly focus on the security, reliability, and efficiency of the electricity grid. Thus, a considerable number of ASM schemes have been presented in the literature to manage network constraints while considering the existence of different network resources. ADS management aims to actively manage voltage-related PQ limits, thermal limits, and fault level constraints in this context. The present work focuses on voltage variation mitigation in ADSs that lead to massive investments from DSOs to reinforce the existing network. The high penetration level of DER units installed in ADSs can cause reverse power flow, increasing the probability of voltage variation problems, as shown in Figure 2.3. This figure shows that the percentage of network nodes with operational constraint violations increases with more renewables connected to the system under study. On the other hand, voltage-sag and voltage imbalance are common power problems that can cause severe consequences in the network. This section presents the various ASM schemes found in the literature that utilize controllable resources in the network to manage voltage constraints.

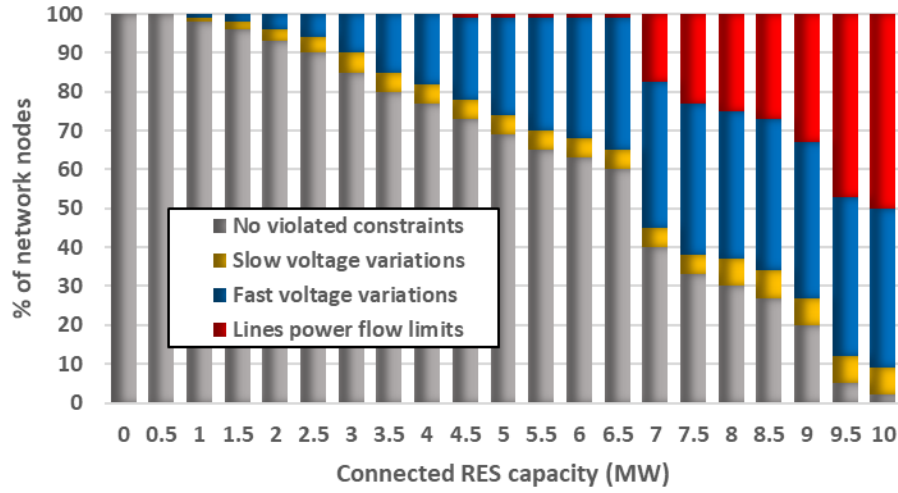


Figure 2-3 Number of network nodes with operational constraints violation vs connected RES capacity [43]

As mentioned above, voltage regulation is one of the most crucial control functionalities in ADSs. It is used in High Voltage (HV) transmission networks to build the control concept based on reactive power management. However, a similar assumption does not apply to distribution systems. Figure 2.4 shows the requirements of active and reactive power in demand to regulate the voltage magnitude of a specific bus in the system under study by 2% as a function of the network lines' R/X ratio [44]. Note that as the R/X ratio increases, the requirements of active and reactive powers should be considered for voltage regulation. Hence, voltage control approaches in ADSs must depend on both active and reactive power output regulation.

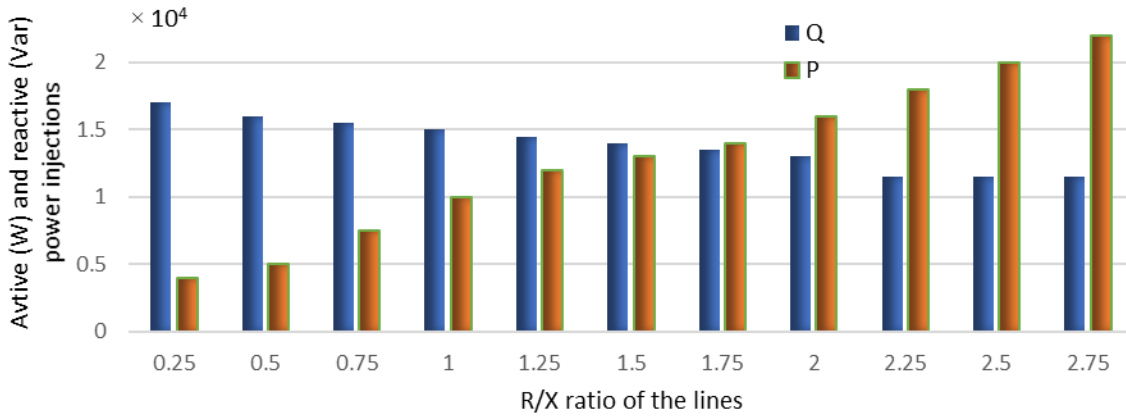


Figure 2-4 Active and reactive power requirements vs different R/X ratio of the lines [44]

The voltage management strategies can be divided into two main categories: autonomous (i.e., local) and communication-based. A deeper classification of the communication-based category can be determined according to the type of information being exchanged among the participating resources,

such as centralized, decentralized, and distributed. In addition, a hybrid combination between the two categories is also applicable.

In autonomous control, the local controllers are referred to as Intelligent Electronic Controllers (IECs), as shown in Figure 2.5. These local controllers need measurements at the PCC only, without the requirements of any other remote measurements in the network. This strategy can respond quickly to RES unit variability and any other short-term voltage variations. Moreover, local controllers are not affected by communication failures. In contrast, without any coordination between resources, they do not achieve the full potential of the available DERs, which can cause a globally non-optimal control solution [45].

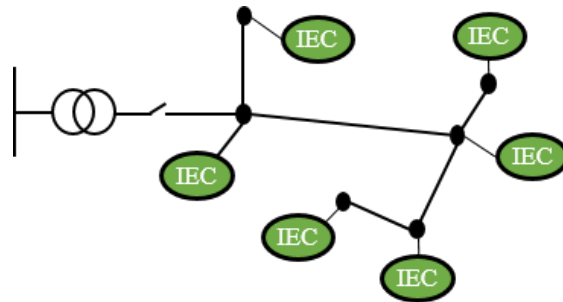


Figure 2-5 Local control scheme

In centralized control, the strategy relies on one Central Coordinator (CC), which collects all the required measurements from the grid by utilizing remote terminal units and smart meters that retrieve the solution to the control problem. After that, these meters communicate the settings (set-points for DERs) back to the IECs [46], as shown in Figure 2.6. It should be noted that any control action can only be initiated by the CC.

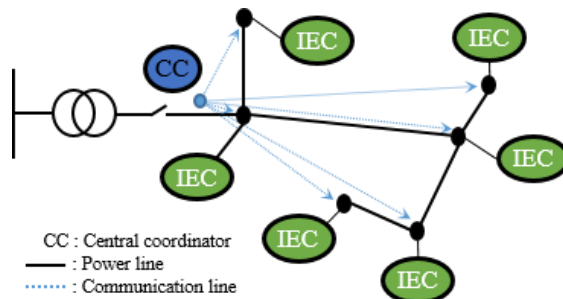


Figure 2-6 Centralized control scheme

In distributed control, the IECs are not remotely dispatched. Rather, all the IECs collaborate to achieve a combined decision with respect to the tasks set by the grid operator or end-user [47], as shown in Figure 2-7. Each IEC seeks to communicate only with neighbour nodes. Therefore, global information of the network (i.e., the state of all nodes) is not needed to obtain the control goal. The

target of the Distributed Coordinator (DC) is to attain a self-organized power network. In this way, the network will have the capability to adapt effectively to any situation that might appear when applying only local interactions and securing “plug and play” capability.

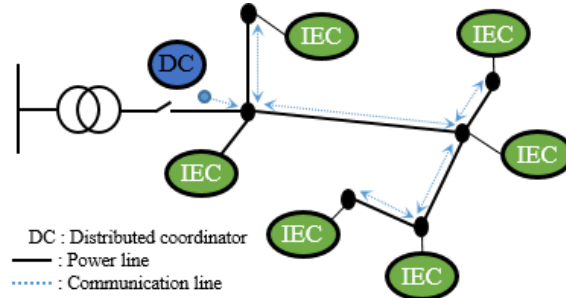


Figure 2-7 Distributed control scheme

An intermediate level between distributed control and centralized control is defined as decentralized control. This indicates that the strategy is partly centralized and partly distributed with respect to decisions, computations, or command/information signals, as shown in Figure 2.8. A straightforward example of decentralized control is partitioning the network into zones [48]. Each partition (e.g., zone) is provided by its own controller (i.e., Zone Coordinator [ZC]) that performs in the same manner compared with the central coordinator in its zone. The ZCs are authorized to be coupled in order to accomplish a specific goal, similar to distributed control.

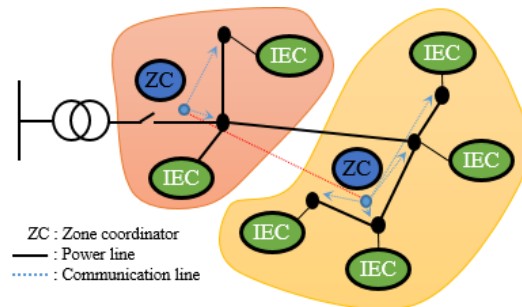


Figure 2-8 Decentralized control scheme

A decentralized scheme can present effective, flexible, and robust control of the ADS. Furthermore, it can overcome the limited communication situations and is much less influenced by failures in the communication lines. All these qualities give decentralized schemes a high priority to be utilized in ASM schemes.

2.6 Stability Evaluation of Microgrids

A group of DERs, such as RESs and BESSs that operate locally as a single controllable unit, is defined as a microgrid. Based on its size and functionalities, a microgrid can have multiple possible

configurations. In this way, two different operation modes can exist, such as grid-connected mode and islanded mode. Figure 2-9 shows a general microgrid configuration. As shown, the PCC breaker determines the operation mode of the microgrids. Commonly, a microgrid consists of several different components, such as RESs, loads, and ESSs. As well, there is a communication infrastructure between switches, metering devices, DERs' primary control, and secondary control units.

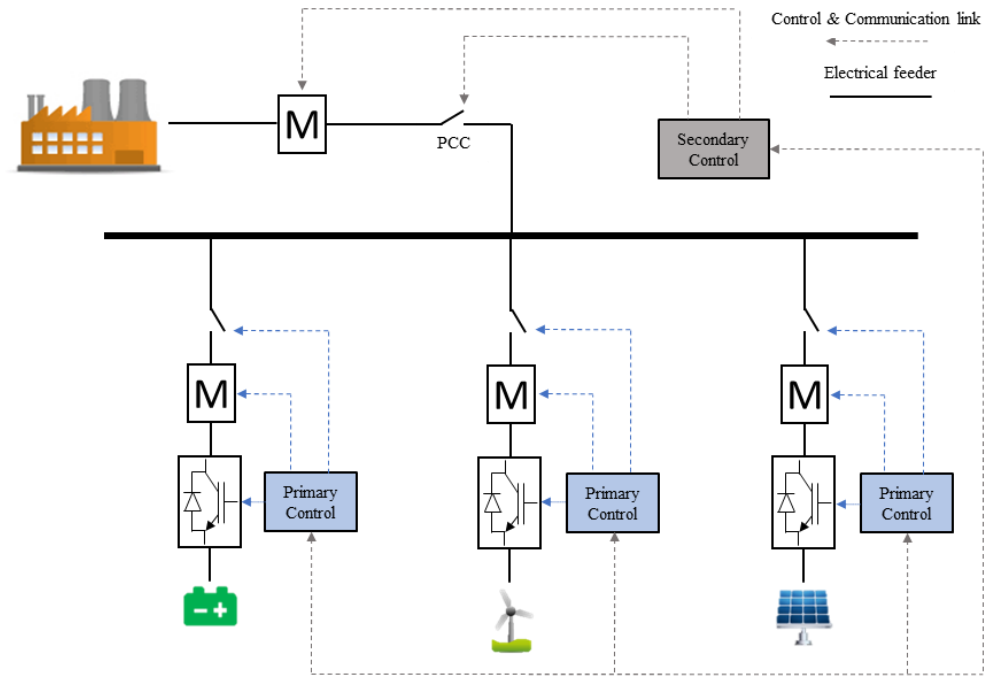


Figure 2-9 Typical layout of an MG

The microgrid control system contains three core functions: 1) keeping the frequency, currents, and voltages within required standards; 2) maintaining the balance between power generation and loads; and 3) transitioning between different modes of operation. As shown in Figure 2-9, the control system of microgrids includes primary and secondary control.

Increasing the penetration of DERs or exchanging conventional generators with inverter-based DERs enables the transition from traditional power systems into a number of smaller power networks named MGs. These MGs are characterized by low equivalent system inertia. Thus, these MGs are more sensitive to stability problems. In the case of a minor disturbance, such as load switching and output power of DERs, deviation might lead to significant frequency and voltage fluctuations or system instability [49]. Therefore, grid-connected MGs face a stability problem that mainly depends on the individual component's stability (e.g., a specific DER or a group of local loads) and their impact on the system [50].

As IEEE Standard 1547 allows the power systems to operate in islanded operation [51], islanded MGs are considered an essential part of ADSs. Thus, the system frequency and voltage are not specified by the utility any longer, and several DERs will play a significant role in keeping these variables within acceptable ranges. As discussed in [52], the microgrid has systemic differences and unique intrinsic features. Islanded mode operation is, therefore, more stimulating than conventional power systems, fronting specific system adequacy and stability problems [53].

Many researchers have studied the stability issues in MGs in the past [54]. To that end, Small-Signal Stability (SSS) analysis of networks, including several interconnected synchronous generators, have been adapted in MG studies. Various approaches are used in [55, 56], such as eigenvalue, frequency response, and gain-phase margin criterion. Other techniques, like reduced-order, dynamic phasors, and matrix pencil to assess the dynamic stability of inverter-based order, rotating direct-quadrature (dq) frame and harmonic linearization, are reviewed in [57]. Similarly, [58] discusses several SSS analysis schemes regarding voltage and transient stabilities for islanded and grid-connected MGs.

Generally, a microgrid is formulated in an eigenvalue-oriented technique through a combination of state-space equations. It is then required to formulate the equivalent overall state matrix for an MG and determine its eigenvalues [59]. This approach is considered by [60, 61] to examine the SSS of an MG with DERs. References [60, 62, 63] look at renewable sources with internal dynamics in SSS analyses, while [64] neglects the converters and filters internal dynamics to achieve a reduced-order technique. In addition, [65-67] studies MG stability while considering the effect of energy storage systems, constant power and induction motor loads, ramp rates of DERs, the uncertainty of renewable resources, communication delays, and resonance in inverters.

2.7 Summary

This chapter first considered the high penetration level of distributed energy resources, with various voltage variation problems being presented and discussed in detail. After that, several network partitioning methods were reviewed. With the background knowledge of the DERs' flexibility in ADSs, the spectrum of network management was presented, along with a detailed overview of centralized to decentralized classifications.

In conclusion, it can be seen that active and reactive power-combined control schemes are becoming an essential issue in the voltage-sag mitigation research field. However, the algorithms that treat the power network as bulk suffer from time-consuming computations. Implementing these algorithms with large systems is challenging and, in many cases, impractical. According to the previously surveyed

literature and because of the intermittent nature of the RESs, a system-level voltage control algorithm relying on different network partitioning techniques was proposed as an effective solution to mitigate the voltage variations in the networks. More research work in the area of voltage management schemes is required to resolve all the voltage variation problems associated with ADSs.

Chapter 3

Detecting and Locating Voltage-Sag Origins in Active Distribution Systems

3.1 Introduction

The fast and accurate detection of voltage-sag in the distribution systems is an essential tool, as it would allow DSOs to perform fast voltage-sag mitigation, system recovery, and restoration. As faults are one of the major causes of voltage-sag events, accurate fault identification in the system can help expedite the healing process. However, with the trend toward adopting more inverter-based DERs in the system, traditional fault-detection schemes have become inappropriate, as they rely on excessive fault currents. Identifying the fault origin and detecting whether the fault is upstream or downstream from the PCC of the system is a crucial piece of information for preventing the propagation of the voltage-sag event throughout the system.

In general, fault detection is composed of two parts: 1) determining the inception time of the fault, and 2) determining the geographical location of the fault. In this thesis, the detection of the inception of the fault is determined by detecting the voltage-sag event, which is a direct effect of the fault, while the geographical location of the fault is determined by the proposed method in this chapter.

In this chapter, we develop a fast, efficient, and cost-effective voltage-sag origin (i.e., geographical location of the fault) identification methodology based on the voltage and current estimation in the system and Tellegen's theorem. The developed technique is assumed to run as a background routine and is initiated by the voltage-sag event (i.e., the fault inception time). The chapter's structure is presented as follows: section 3.2 discusses a survey about different techniques to detect faults in the system (i.e., the fault inception time). More details about locating faults in the system (i.e., the fault's geographical location) are presented in section 3.3. Details about the proposed voltage-sag methodology are illustrated in section 3.4. Finally, a case study is performed in section 4.5 to evaluate the effectiveness of the proposed methodology.

3.2 Fault Detection Techniques in Active Distribution Systems

In order to maintain the stability of the system, fault inception time detection techniques should detect the fault in a fast, efficient, and cost-effective manner. Several different fault detection techniques have been reported in the literature that consist of mainly data-driven and model-based methods in distribution systems [68]. Model-based approaches deal with the recognition of how the system components work comprehensively.

In [69], a fault detection technique is proposed according to the phase difference of the node voltage and feeder current of the positive sequence fault component. In [70], the voltage magnitude is used to determine the relay operating time-based on a communication-less method, whereas in [71], for both islanded and grid-connected modes of operation, a fault detection method with a communication-assisted is presented. The strategy is to use overcurrent and undervoltage relays to detect the fault. However, backup protection is required in the situation of a failure in the communication links. The authors in [72] utilize the sequence Thevenin equivalents of the sources to detect the faulted section along with the 3-ph voltage and current phasor data at the local bus of the DER unit. This method records the voltage and current data by fitting data from digital fault recorders. However, the technique needs fault contribution from the DERs affected by the calculation errors and the current transformer saturation.

In [70] and [71], the slow response noted during fault detection emerges as a drawback, while in [73], the inverter output current is used as a local variable to measure transient monitoring function. However, the length of the moving window for the current waveform affects the performance of the algorithm. A longer window length improves accuracy but reduces the speed and time response.

Data-driven methods depend on discovering the relationship between the input and output state variables. In [74], a fault identification method based on wavelet transform and decision tree to retrieve and preprocess the current signal measurements is applied. In this approach, selecting the right wavelets for a particular mode is usually challenging. Another data mining-based differential protection method that extracts differential features using the Discrete Fourier Transform (DFT) is presented in [75], where a decision tree to examine the fault type is built based on these features. The researchers employ data-oriented methods (e.g., neural network [76], support vector machine [77], adaptive neuro-fuzzy logic with Artificial Neural Network (ANN)-based methods [78]) to detect the fault based on the input from measuring or transforming features, after which the decision is concluded for the status of the system.

Fault-detection techniques based on Phasor measurement units (PMUs) are also getting more attention from researchers. The following studies illustrate the possibility of detecting the faults for distribution systems based on PMU. In [79], high-precision synchronized data are acquired by the deployment of PMUs, motivated to preserve the equilibrium between communication latency and deployment costs. The ratio between the current and the fault component of the voltage is calculated based on the phasor information collected by both of the PMUs installed at the lines' end in [80], called the integrated impedance angle. However, PMUs are required to be installed at every bus in that method, which is neither efficient nor cost-effective. It is worth mentioning that State Estimation (SE) is commonly utilized in PMU-based fault detection techniques. In [81], a single line-to-ground (SLG) fault is detected by a hybrid SE, while in [81], according to modified SE and PMU data, the correct fault location is diagnosed by calculating residual indexes. The synchrophasor-based parallel SE with every state estimator described by a various structure are discussed in [82]. In another SE algorithm, simulated PMUs are used to extract the real-time data of the distribution system [83]. However, convergence rate and computational complexity problems are major drawbacks in these SE-based algorithms.

3.3 Techniques to Locate Faults in Active Distribution Systems

Once the fault incident (i.e., fault inception time) is detected, another critical step to maintain the system's stability is locating the geographical position of the fault in the system [84]. According to [85], this can be accomplished using a variety of techniques. Figure 3-1 shows a summary of the techniques that have the potential to locate a fault in the system [86]. In [87], a phasor-based method depends on a frequency component and line parameters for locating the system's fault, while a time-domain-based method depends on transient components of signals and distributed line parameters. Furthermore, the travelling wave theory is adapted in the phasor-based method to detect the fault location according to multiple synchronized measurement units. However, synchronization errors may affect the performance of that method if synchronization signals are lost. On the other hand, expert systems, neural networks, or fuzzy logic are the main engines for locating system faults using the time domain-based method.

In [88], the researchers employ the Gaussian Markov approach to measure the phasor angle for different buses in the system to estimate the fault location, while the authors in [89] propose a fault location technique based on the source impedances that inspect the system's lines from one or two ends to locate the fault. In [90], the proposed technique depends on voltage-sag measurements to determine

the location of a fault caused by a short circuit fault, switching on/off of a large capacitor, or turning on a large load. Another method based on State Estimation is proposed in [91] to determine the fault's exact location based on a mathematical method. Specifically, State Estimation is used to determine each bus's voltage in the system based on studying the fault current from the main source only. It is worth noting here that the power system's size is a critical factor affecting the accuracy in most of these proposed techniques.

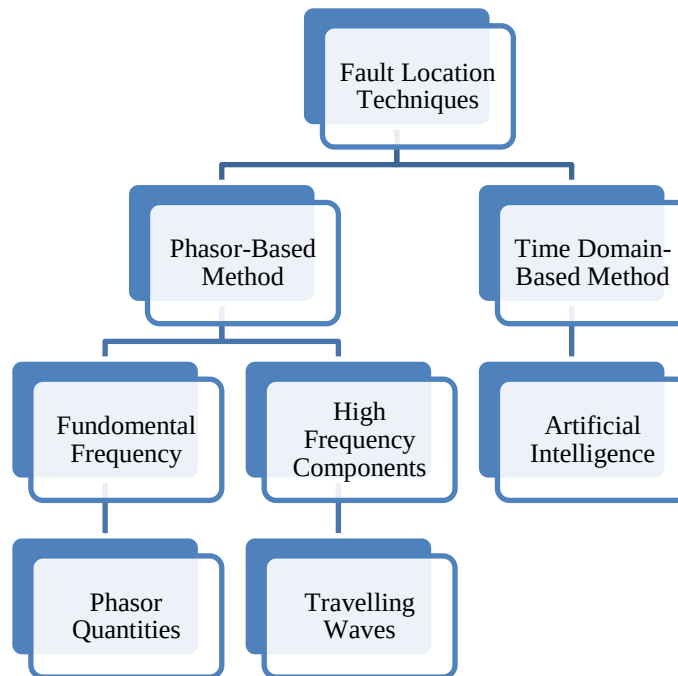


Figure 3-1 Fault location techniques

Impedance-based techniques have also been studied by researchers due to their relatively low implementation cost and high accuracy [74]. These methods utilize measured voltages and currents to calculate the impedance to the fault, and then use the line's per-unit length parameters to transform the impedance into distance [92]. In [93], synchronized measurements from the main grid and DER units are employed. As the synchronization angle may have an error angle that is considered unknown, an iterative load flow algorithm is used to calculate the error.

3.4 Proposed Voltage-Sag Origin Identification Methodology

One of the leading causes of voltage-sag events is a fault in the electrical systems. Therefore, an efficient, quick, cost-effective, and accurate Fault Identification (FI) method is needed as an essential step for mitigating voltage-sags in distribution systems. The proposed FI methodology has three stages. First, the entire distribution system is divided into several zones using the proposed network

partitioning scheme. Then the faulted zone is detected using the measurements from the available PMUs installed in the system. In this way, a smaller search area for the fault's exact location is required based on the partitioned zone's prior knowledge. Finally, the exact location of the fault is identified inside the faulted zone. The proposed FI algorithm has the following assumptions:

- The entire system is divided into several zones using the proposed network partitioning concept, as explained in the next section.
- The bus with the minimum voltage inside the faulted zone is assumed to be the fault location.

Figure 3-2 illustrates a flowchart of the proposed FI algorithm. In the algorithm, the PMUs are installed at all the branching nodes in the system and all the end nodes in the system to monitor the current and voltage phasors online. For each phase of those zones, the proposed FI algorithm is executed at the same time. First, the faulted two-port system (i.e., zone) is detected. The faulted two-port systems are detected based on threshold values chosen from empirical observations. Then, in that faulted zone, the exact faulted branch is identified based on estimating the line currents and the complete voltage profile of the zone. The adjoint system is created offline and stored in the database, as it is constant in nature. More details about the proposed algorithm are provided in the following sections.

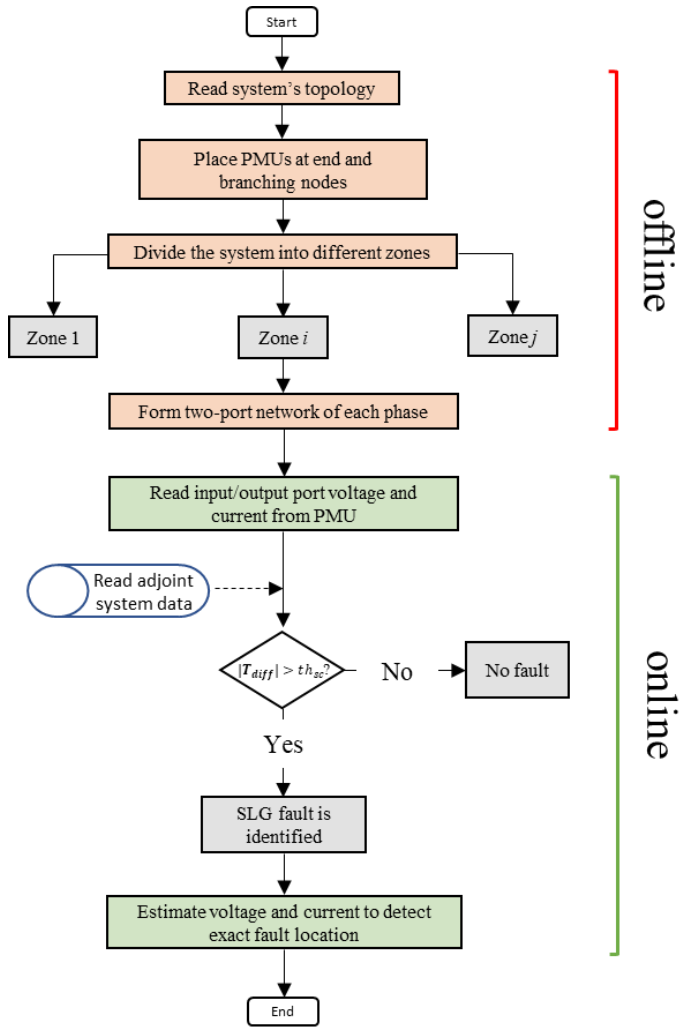


Figure 3-2 Flowchart of proposed FI algorithm

3.4.1 Observability-based Network Partitioning technique

The initial stage of the proposed FI algorithm is to define the virtual boundaries of the divided zones in the original system. This network partitioning technique is introduced in the proposed FI algorithm and differs from other network partitioning techniques that will be discussed later. Network connectivity and PMU location are the keys to forming the zones. For the given sample system in Figure 3-3, three types of nodes (i.e., buses) are identified, as follows:

- 1) An end node is any node connected to only one branch.
- 2) A branching node is the start node of a lateral.
- 3) An intermediate node is any other node not defined in 1 and 2.

Table 3-1 shows the type of each node in the sample system.

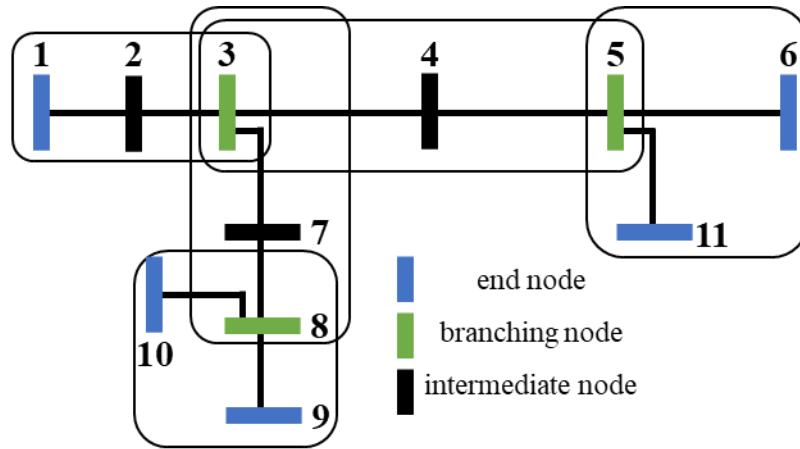


Figure 3-3 Sample system with virtual boundaries of zones

Table 3-1
TYPE OF NODES IN SAMPLE SYSTEM

# of Node	Type
1, 6, 9, 10, 11	end node
3, 5, 8	branching node
2, 4, 7	intermediate node

In the proposed FI algorithm, there is a set of rules that should be followed to formulate the boundary for each zone. These rules are:

- 1) The PMUs are installed at each branching bus in the system and all the system's end buses.
- 2) All DERs in the system report their power generation to a central unit located at the substation bus.
- 3) The PMUs placement strategy does not depend on the number of DERs existing in the system or their location.
- 4) For buses adjacent to any PMU-bus, the voltage and current phasors are obtained through the known information from the PMU-bus and distribution line parameters. Thus, for any lateral with just two nodes (e.g., laterals 5-6, 5-11, 8-9, and 8-10), it is sufficient to identify the fault by using one PMU at the extreme end of these laterals.

According to the previous node's definition and set of rules, the boundary of each zone is determined by following the next steps:

- 1) Identify the primary feeder branching from the source (e.g., for the system in Figure 3-3, the primary feeder is: 1-2-3-4-5-6).

- 2) Identify end and branching nodes in the system (e.g., end and branching nodes are: 1, 3, 5, 6, 8, 9, 10, and 11).
- 3) Determine the first end node (e.g., 1), then search for the first branching node (e.g., 3) to formulate the first zone.
- 4) Search for the next end/branching node (e.g., 5) in the primary feeder to formulate one more zone.
- 5) Repeat step 4 until all the primary feeder nodes are included in zones, satisfying Rule 4.
- 6) For each branching node in the primary feeder (e.g., 3, 5), repeat the steps (i.e., step 4 and step 5) until all the sub-feeders nodes are included in the zones.

3.4.2 Identification of Faulted Zone Based on Tellegen's Theorem

3.4.2.1 Tellegen's Theorem and Adjoint Networks

In general terms, Tellegen's theorem [94] is based mainly on Kirchhoff's laws and the network's topology. Moreover, this theorem is applicable to all electrical systems that follow Kirchhoff's laws; these systems can be linear/nonlinear, active/passive, or time-variant/time-invariant. According to Tellegen's theorem, the complex voltages are related to the complex current passing through all network elements, as follows [94]:

$$\sum_{i=1}^{br} VD_i I_i = 0 \quad (3-1)$$

where VD_i is the branch voltage drop, I_i is the branch current, and br is the total number of branches in the network.

Tellegen's theorem is considered valid for voltages and currents related to the original system and another adjoint system if they have the same topology. Given an electric system N containing two-port elements, its adjoint system N' has the same system topology; however, it is not required to have similar elements installed in the same branches. Thus, (3-1) can be modified as follows:

$$\sum_{i=1}^{br} VD_i I'_i = 0, \quad \sum_{i=1}^{br} VD'_i I_i = 0 \quad (3-2)$$

where VD'_i and I'_i are the branch voltage drop and the branch current of the adjoint system N' , respectively. Moreover, the adjoint system is formed by exponential, sinusoidal, random, and periodic excitation with different initial conditions. All the branches within the system are categorized into two types, as follows:

- 1) Input and output port branches (p) are connected to the nodes on the zone boundary.
- 2) An intermediate branch (t) is every other branch that is not defined in 1.

Therefore, (3-2) is separated as follows:

$$\sum_t VD_t I'_t + \sum_p VD_p I'_p = 0, \quad t \in (b - p) \quad (3-3)$$

$$\sum_t VD'_t I_t + \sum_p VD'_p I_p = 0, \quad t \in (b - p) \quad (3-4)$$

where the indices t and p are the intermediate and port branches of the system, respectively. For example, if there is a two-port network, p will equal two. From (3-3) (3-4), the difference form of Tellegen's theorem is defined as follows [95]:

$$\sum_t (VD_t I'_t - VD'_t I_t) = - \sum_p (VD_p I'_p - VD'_p I_p) \quad (3-5)$$

3.4.2.2 Terminology

Figure 3-4 shows a sample distribution system integrated with DERs. According to the network partitioning scheme in section 3.4.1, the system is divided into three zones (Z_1, Z_2 , and Z_3), as shown in Figure 3-5. Each zone is represented by three two-port networks corresponding to the three phases, and the PMU is installed based on the previous network partitioning scheme. An agent is assigned to each zone to collect the measurements from the PMUs. Then, all the agents communicate with the central unit to share their data in order to detect the voltage-sag origin using the fault identification algorithm in [96]. Each PMU is responsible for extracting the P and Q data flow in the upstream and downstream feeders, measuring the voltage magnitude at the PCC, and communicating these measurements back to the central unit through the zone agent. However, the central unit is in charge of knowing the impedance of each line and the system topology, and calculating the complete voltage profile and branch currents for the faulted zone.

Figure 3-6 (a) shows the details of a two-part system representing zone 1 (Z_1), with two PMUs located at the input PO_1 and output PO_2 ports of Z_1 . Between nodes N_1 and N_2 is a distribution line z_{12} . For Z_1 , the branch currents in phase A for t intermediate branches are expressed as $I_{B_a} = [I_{B_1^a}, I_{B_2^a}, \dots, I_{B_t^a}]$, and the branch voltage drops in phase A for n intermediate nodes are expressed as $VD_{B_a} = [V_{N_1^a} - V_{N_2^a}, V_{N_2^a} - V_{N_3^a}, \dots, V_{N_{(n-1)}^a} - V_{N_n^a}]$.

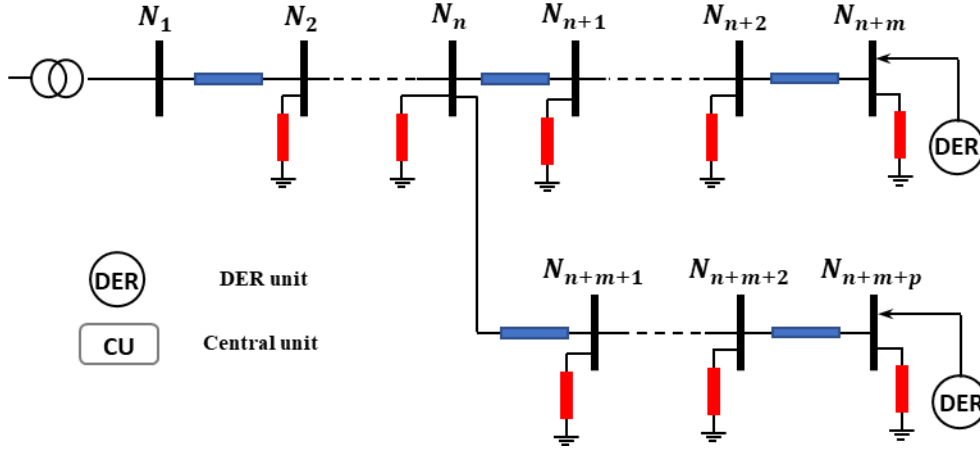


Figure 3-4 Sample radial system

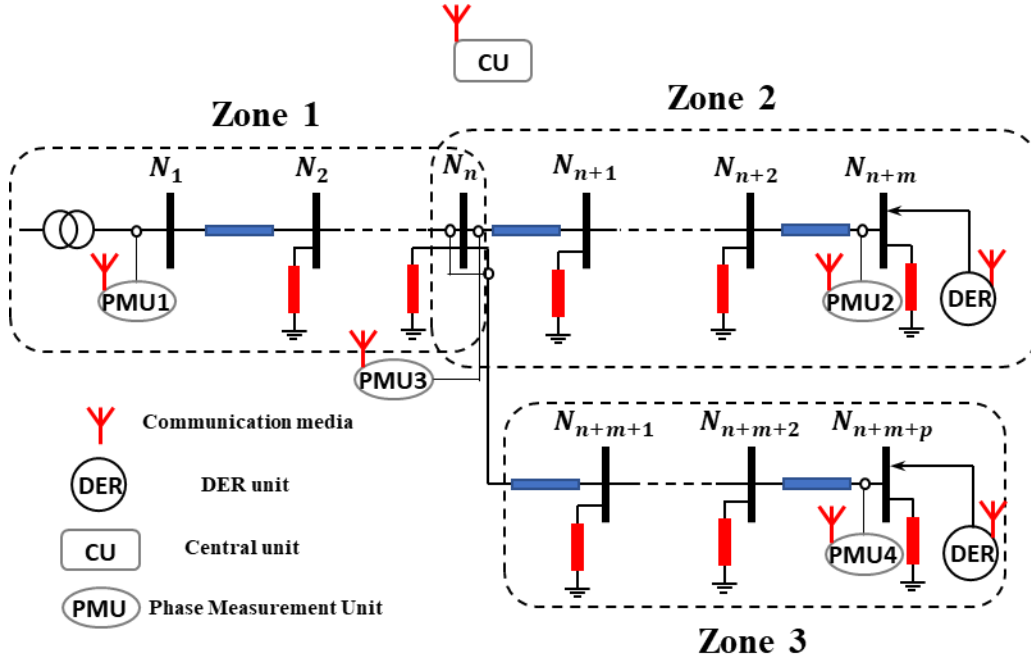


Figure 3-5 Partitioning scheme with PMUs of sample radial system

To create an adjoint system for Z_1 , called AD_{1Z_1} , excitation sources are installed at P_1 and P_2 of the system, as shown in Figure 3-6 (b). It should be noted that the adjoint system has the same t internal branches and n internal nodes as the original system. Therefore, branch currents and voltage drops for AD_{1Z_1} are denoted as $I'_{B_a} = [I'_{B_1^a}, I'_{B_2^a}, \dots, I'_{B_t^a}]$ and $VD'_{B_a} = [V'_{N_1^a} - V'_{N_2^a}, V'_{N_2^a} - V'_{N_3^a}, \dots, V'_{N_{(n-1)}^a} - V'_{N_n^a}]$, respectively. According to Tellegen's theorem, the difference form is defined as [96]:

$$\sum (VD_{B_a} \odot I'_{B_a} - VD'_{B_a} \odot I_{B_a}) = -((VD_{p1_a} I'_{p1_a} - VD'_{p1_a} I_{p1_a}) + (VD_{p2_a} I'_{p2_a} - VD'_{p2_a} I_{p2_a})) \quad (3-6)$$

where $\odot$ is the element-wise multiplication, VD_{p1_a} , I_{p1_a} and VD_{p2_a} , I_{p2_a} are the voltages and currents at PO_1 and PO_2 of the original system measured by PMUs, respectively, while VD'_{p1_a} , I'_{p1_a} and VD'_{p2_a} , I'_{p2_a} are the PO_1 and PO_2 voltages and currents of the adjoint system, respectively. The right-hand side of (3-6) is denoted as T_{diff} .

Further, it should be noted that both the adjoint system and the original system have the same topology, but the element with each adjoint system has arbitrary characteristics. One condition is considered for choosing the excitation sources of the adjoint system at input and output ports, as shown in (3-7), such that the determinate of the PO_1 and PO_2 voltages of the original system and adjoint system cannot equal zero.

$$\begin{vmatrix} V_{p1_a} & V_{p2_a} \\ V'_{p1_a} & V'_{p2_a} \end{vmatrix} \neq 0 \quad (3-7)$$

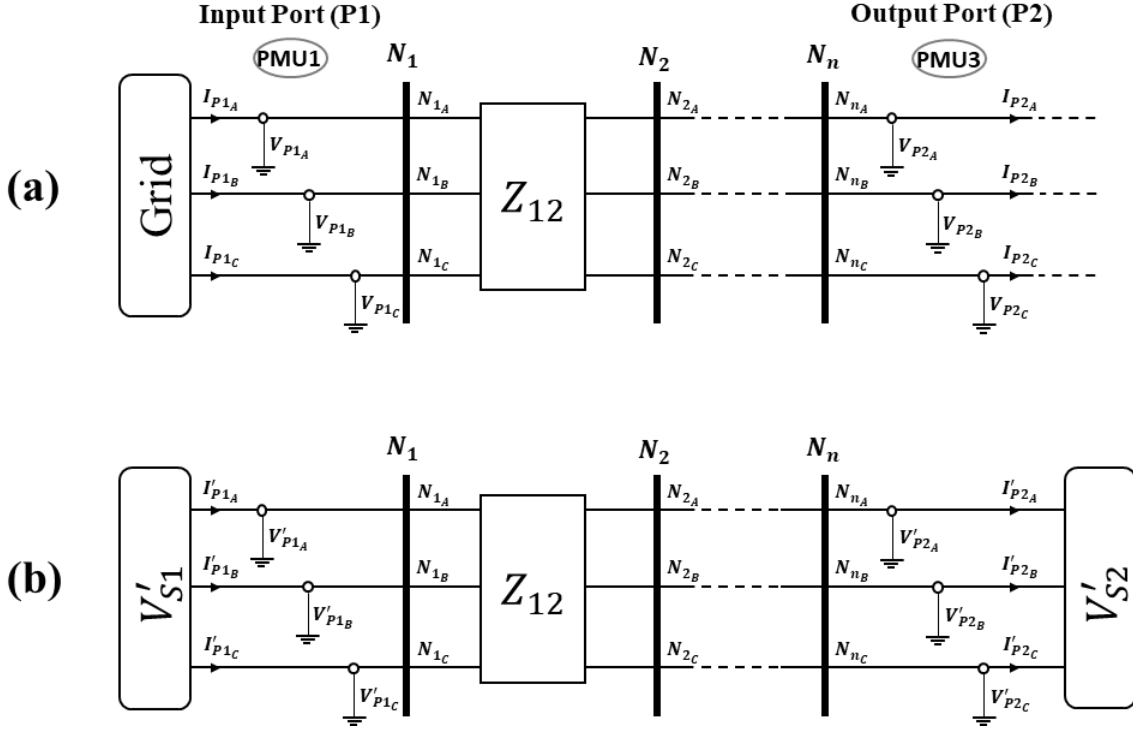


Figure 3-6 Actual circuit and its adjoint system in three-phase representation: (a) Zone 1 (Z_1) and (b) Adjoint system 1 (AD_{1Z_1})

Assuming an SLG fault is detected in phase A, zone 1 of the original system, (3-6) gets modified as follows:

In the case of an SLG fault, the set of the short-circuited buses is represented by f_{SC} , such that:

$$\sum_{t \in f_{SC}} V_{D_{Nt_a}} I'_{t_a} = 0 \quad (3-8)$$

while (3-6) can be rewritten as:

$$-\sum_{t \in f_{SC}} (V'_{N(n-1)_a} - V'_{Nn_a}) I_{t_a} + \sum_{t \in b-f_{SC}} ((V_{N(n-1)_a} - V_{Nn_a}) I'_{t_a} - (V'_{N(n-1)_a} - V'_{Nn_a}) I_{t_a}) = T_{diff} \quad (3-9)$$

However, before the instant of the fault, $(V_{N(n-1)_a} - V_{Nn_a}) I'_{t_a}$ equals $(V'_{N(n-1)_a} - V'_{Nn_a}) I_{t_a}$ for the healthy branches ($t \in b - f_{SC}$). Then, the final form of (3-6) that used to detect the faulted zone is as follows:

$$-\sum_{t \in f_{SC}} (V'_{N(n-1)_a} - V'_{Nn_a}) I_{t_a} = T_{diff} \quad (3-10)$$

The same calculations are repeated for each of the phases (i.e., A, B, and C) of all the zones (i.e., $Z1, Z2, \text{ and } Z3$) of the original system. All of the faulted zones are then detected for any SLG fault, if one exists. Based on pre-specified thresholds, the faulted zone is identified by calculating the difference form of Tellegen's theorem. These threshold values are determined according to empirical observations from [96], and the thresholds are not system-dependent. In the case of an SLG fault, if the T_{diff} magnitude ($|T_{diff}|$) is increased above threshold (i.e., $th_{sc} = 10$ times of the pre-fault value), the magnitude of that zone is identified as a faulted zone because of the existence of an SLG fault. Once the faulted zone (i.e., two-port network) is identified, the search for the exact fault location is initiated in that faulted zone, as will be shown in the following section.

3.4.3 Detection of Exact Location of Voltage-Sag Origin

The voltage and current estimation technique in [97] is utilized to detect the exact location of the faulted bus within the faulted MG. For a distribution feeder with a number of DERs connected inside zone i , as shown in Figure 3-7, the voltage and current estimation are determined as follows:

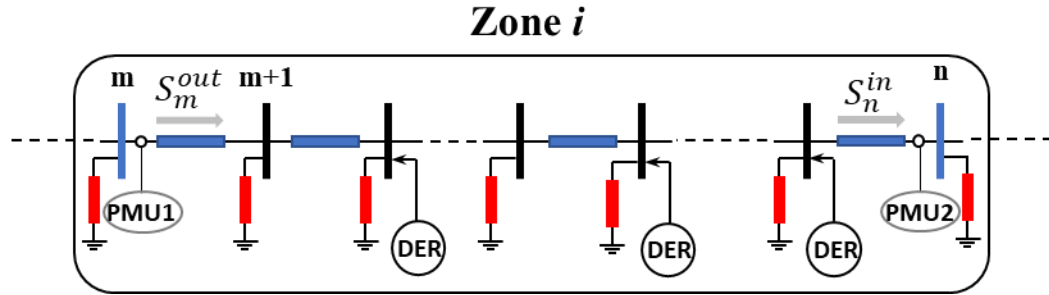


Figure 3-7 Sample distribution feeder

The magnitude of bus m voltage (i.e., $V_{abc,m}$) and the P and Q flows toward the downstream bus of each phase are measured by the PMU at bus m (e.g., PMU1). Based on the PMU1 measurement and the information about the DERs powers, the sum of the total downstream loads (S_f) to bus m is calculated for each of the three phases in (3-11):

$$S_f = S_m^{out} + S_{DER} \quad (3-11)$$

where S_m^{out} is the measured downstream power flow by the PMU at bus m , and S_{DER} is the total power injected by all the DERs between the two PMUs. This DER power is measured by the DER's meter, and the measured value is sent to the central unit. The PMU1's measurements are sent to the central

unit as well. The S_f is assumed to be shared equally among all the buses downstream to PMU1, as shown in (3-12):

$$S_{m+1}^L = S_{m+2}^L = \dots = S_n^L = S_f / (n - m) \quad (3-12)$$

where S_{m+1}^L , S_{m+2}^L , and S_n^L are the estimated power of each load, and the number of buses downstream from PMU1 is $n - m$. The central unit calculates the feeder power flows by using each load's estimated power and the system topology. As a first estimation, the central unit calculates the feeder currents and voltage profile using (3-13) and (3-14). The voltage angle of bus m is considered the reference bus (i.e., angle of phase (a) equals zero), such that:

$$I_{a,ij} = (S_{a,ij}/V_{a,i})^*, \quad I_{b,ij} = (S_{b,ij}/V_{b,i})^*, \quad I_{c,ij} = (S_{c,ij}/V_{c,i})^* \quad (3-13)$$

$$\begin{aligned} V_{a,j} &= V_{a,i} - I_{a,ij}Z_{aa,ij} - I_{b,ij}Z_{ab,ij} - I_{c,ij}Z_{ac,ij} \\ V_{b,j} &= V_{b,i} - I_{b,ij}Z_{bb,ij} - I_{a,ij}Z_{ba,ij} - I_{c,ij}Z_{bc,ij} \\ V_{c,j} &= V_{c,i} - I_{c,ij}Z_{cc,ij} - I_{a,ij}Z_{ca,ij} - I_{b,ij}Z_{cb,ij} \end{aligned} \quad (3-14)$$

where $V_{abc,i}$, and $V_{abc,j}$ are the 3-ph voltages at bus i and bus j , respectively, and $I_{abc,ij}$ and $S_{abc,ij}$ are the 3-ph current and power flow from bus i to bus j , respectively. Similarly, the voltage magnitude of bus n and the P and Q flows from the upstream bus are measured by the PMU at bus n (e.g., PMU2). The PMU2 measurements are sent to the central unit, and the measured power ($S_{n,in}$) is assumed to equal each load upstream to PMU2, as shown in (3-15).

$$S_m^L = S_{m+1}^L = \dots = S_n^L = S_{n,in} \quad (3-15)$$

The central unit then calculates the feeder currents and voltage profile using (3-13) and (3-14) as a second estimation. Here, the voltage angle of bus n is considered the reference bus (i.e., angle of phase (a) equals zero). To update all the voltages' and currents' angles based on the last estimation, the central unit subtracts the voltage angle of bus m from the first estimation from each voltage or current angles in the last estimation. Hence, the bus m voltage is ensured to be the reference angle for the two estimations. To estimate the most accurate voltage profile, the central unit performs a weighted average of both estimations, as in (3-16).

$$V_{i,est}^{abc} = V_{i,est(1)}^{abc} \times W_{est(1)} + V_{i,est(2)}^{abc} \times W_{est(2)} \quad (3-16)$$

where $V_{i,est}^{abc}$ is the updated estimated voltage at bus i for each phase, $V_{i,est(1)}^{abc}$ is the estimated voltage value at bus i from the first estimation, $V_{i,est(2)}^{abc}$ is the estimated voltage value at bus i from the second estimation, and $W_{est(1)}$ and $W_{est(2)}$ are weights that can be described as in (3-17) and (3-18):

$$W_{est(1)} = \left(\frac{n-i}{n-m} \right) \quad (3-17)$$

$$W_{est(2)} = \left(\frac{i-m}{n-m} \right) \quad (3-18)$$

The central unit also uses the weighted average to estimate the feeder currents accurately, as in (3-19):

$$I_{i,est}^{abc} = I_{i,est(1)}^{abc} \times W_{est(1)} + I_{i,est(2)}^{abc} \times W_{est(2)} \quad (3-19)$$

where $I_{i,est}^{abc}$ is the updated value for estimated feeder current flowing to the bus for each phase, $I_{i,est(1)}^{abc}$ is the estimated branch current flowing to bus i from the first estimation, and $I_{i,est(2)}^{abc}$ is the estimated feeder current flowing to bus i from the second estimation. Generally, for a feeder with a number of laterals such as the feeder from bus m to bus n inside zone i , as shown in Figure 3-8, the central unit performs the same estimation with the modification to (3-11) as shown in (3-20):

$$S_f = S_m^{out2} + S_{DER} + \sum S_n^{out} \quad (3-20)$$

where S_m^{out2} is the measured downstream power flow into bus n , and $\sum S_n^{out}$ is the total downstream power flow to bus n . Similarly, (3-15) is modified, as shown in (3-21). However, if a DER is installed at a specific bus, the DER's power should be considered by measured power by PMU2, as shown in (3-22). Finally, the line currents and the complete voltage profile of the feeder are estimated accurately, and the bus with the minimum voltage is considered the faulted bus:

$$S_m^L = S_{m+1}^L = \dots = S_n^L = S_n^{in} - \sum S_n^{out} \quad (3-21)$$

$$S_m^L = S_{m+1}^L = \dots = S_n^L = S_n^{in} + S_{DER} - \sum S_n^{out} \quad (3-22)$$

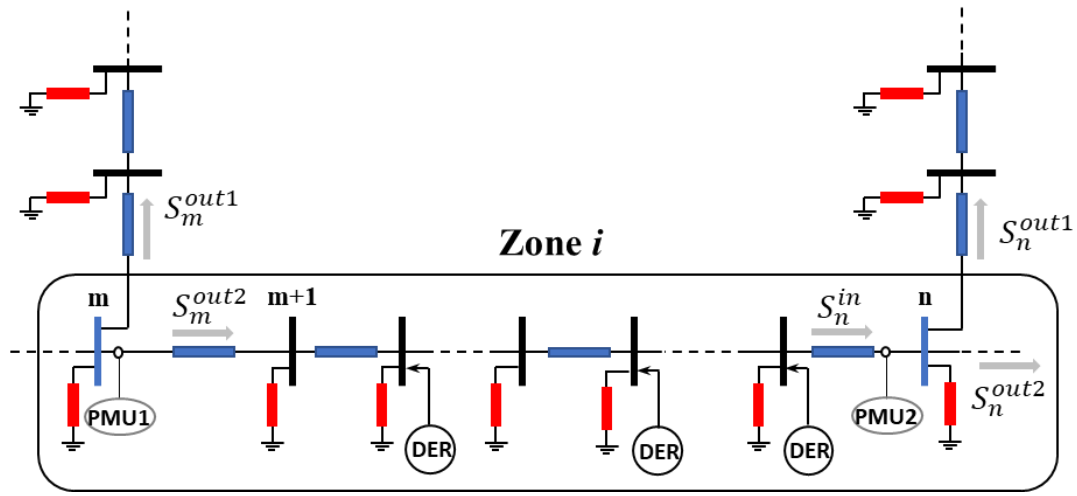


Figure 3-8 Sample distribution feeder with a number of laterals

3.5 Case Study

A modified three-phase balanced 12.66 kV IEEE 33-bus distribution network, with DERs at buses 6, 10, 14, 25, and 28, is selected as the system for the case study. The topology of the network with candidate DER locations is shown in Figure 3-9. The specific parameters for the DERs are listed in Table 3-2.

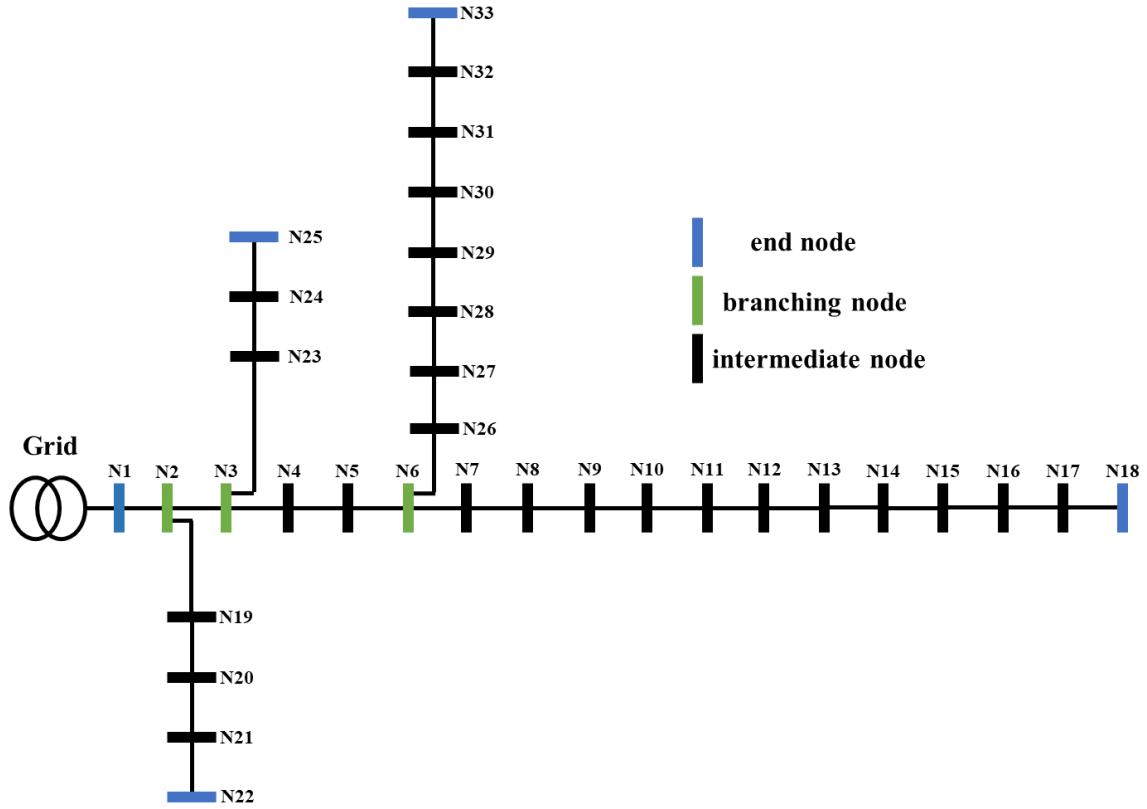


Figure 3-9 Layout for IEEE-33 bus system

Table 3-2 CAPACITY AND LOCATION OF DERS		
DER	Location	Unit Capacity (kVA)
PV	6, 10, 25	300
wind	14, 28	400

As shown in Figure 3-10, the IEEE-33 bus system is partitioned into seven zones (i.e., $Z_1, Z_2, \dots, Z_7$). Thus, for each zone, there are three two-port systems corresponding to the 3-ph's. To create the adjoint system AD_{1Z_1} , a 3-ph sinusoidal excitation that has a magnitude of 12.66 kV and 6.33 kV is connected to P_1 and P_2 of the zones, respectively. However, if a zone consists of only one branch, the measured data from one PMU will be sufficient to detect any fault that occurs. According to the observability-based network partitioning technique in section 3.4.1, the PMU locations are determined. It should be noted that the proposed network partitioning scheme succeeded in reducing the number of both PMUs and zones. Thus, there is a reduction in both the hardware and communication burdens to determine the faulted zone and detect the exact location of the faulted node.

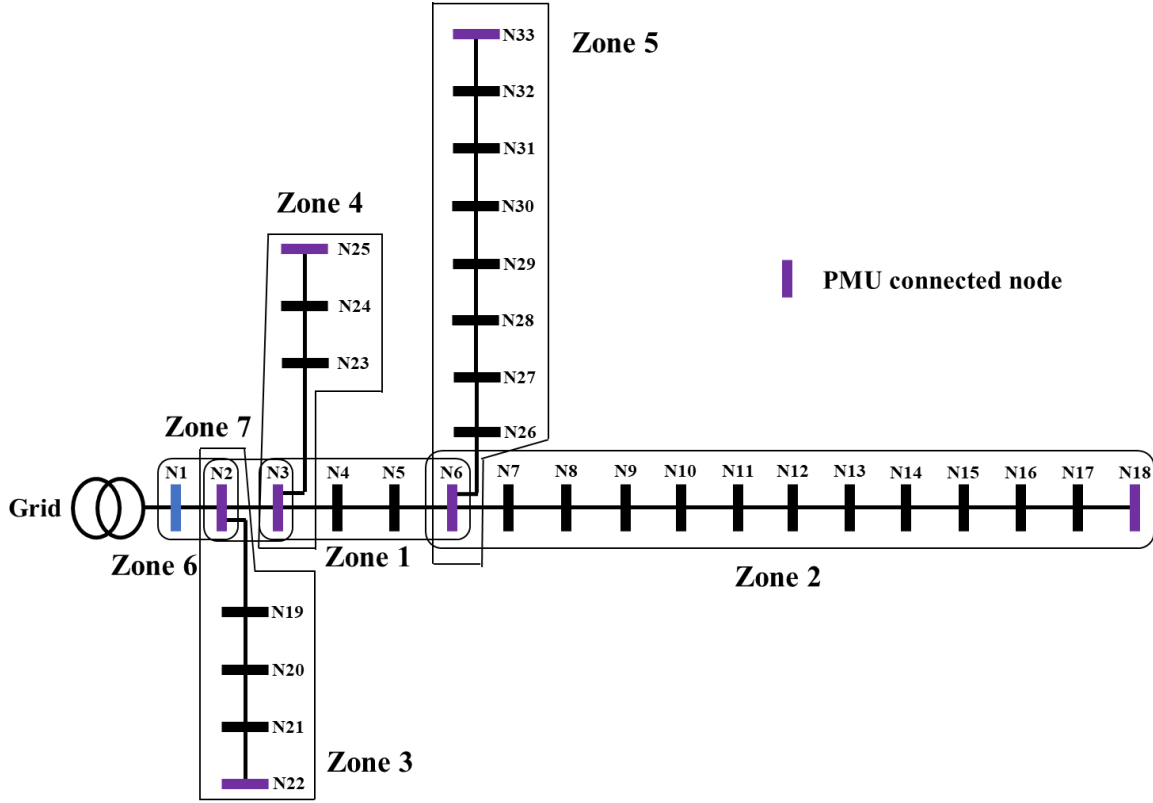


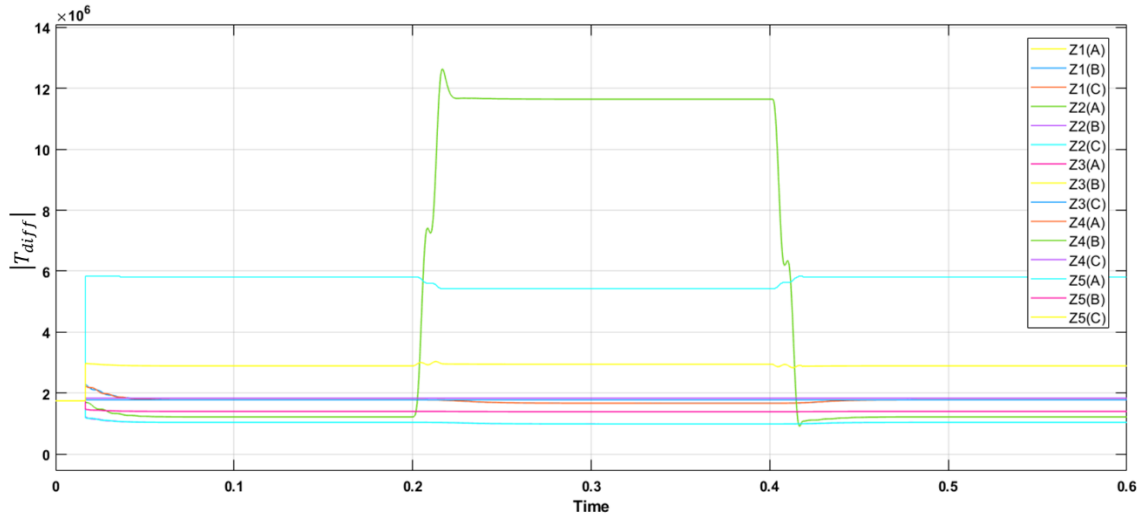
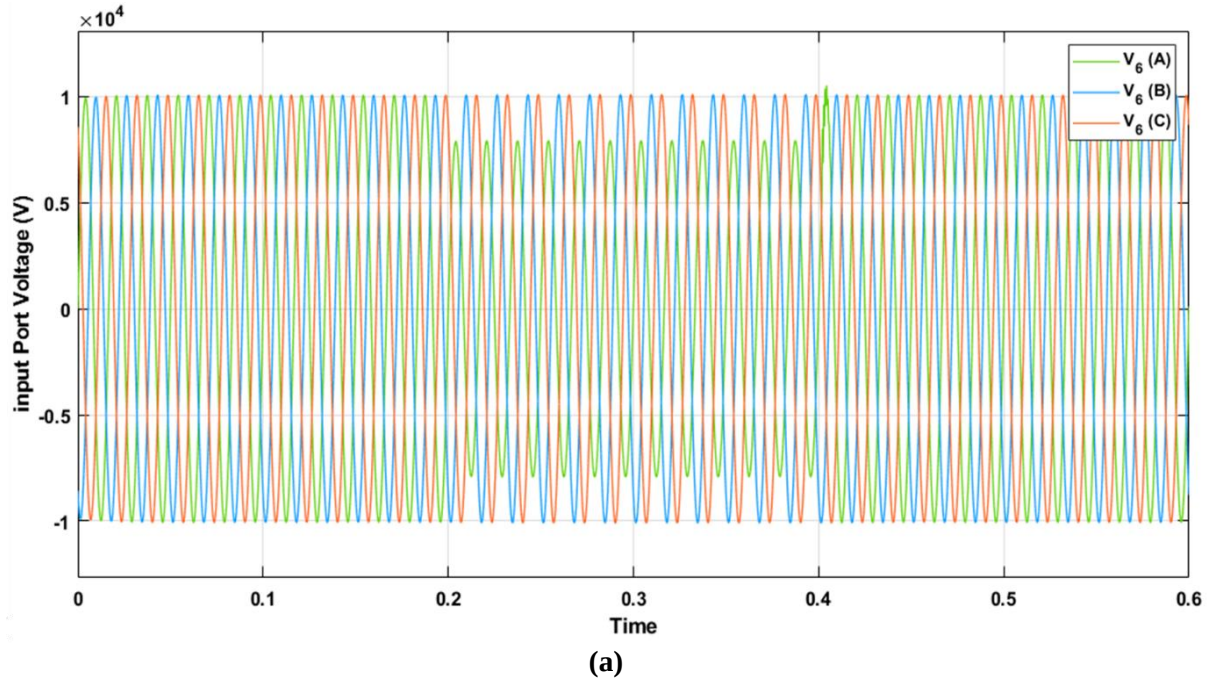
Figure 3-10 Network partitioning scheme based on proposed algorithm

The following two sections illustrate the proposed algorithm's effectiveness in identifying and detecting an SLG fault in the distribution system. This SLG fault is considered to be the voltage-sag origin in the system.

3.5.1 Single-Line to Ground (SLG) Fault

To prove the effectiveness of detecting an SC fault (e.g., single line to a ground fault) by the proposed algorithm, a high impedance fault is created at phase A of bus 8 (i.e., $N8_A$). As shown in Figure 3-11 (a), the SC fault is created at $t = 0.2$ s, and the input port voltage of phase A is decayed. Once the SC fault begins, the T_{diff} magnitude ($|T_{diff}|$) of all the zones, calculated from (3-10), will fluctuate until they reach a steady-state, as shown in Figure 3-11 (b). To identify the faulted zone, the zone with a magnitude reaching a threshold value (th_{sc}) for a short-circuit fault (i.e., 10 times the pre-fault value [96]) is identified as the faulted zone, as shown in Figure 3-11 (c). The fault flag related to that particular phase in the second zone is turned on at $t = 0.211$ s. Based on the results in Figure 3-11, phase A in Zone 2 is identified as the faulted zone.

Similarly, in the second stage, the proposed FI algorithm detects the exact location of the faulted node in the faulted zone. The complete line currents and voltage profile of the faulted zone are estimated accurately by using (3-13) and (3-14). Hence, the node with the minimum voltage is considered the faulted node [98], as shown in Table 3-3. It can be inferred from Table 3-3 that branch $N8_A$ is the faulted node, so another flag associated with the faulted node is turned on to detect the exact location of the fault. From this, we can see that the proposed FI algorithm succeeded in detecting the faulted zone and identifying the exact location of the faulted node in approximate 0.66 *cycles*, compared to 1.2 *cycles* in [96].



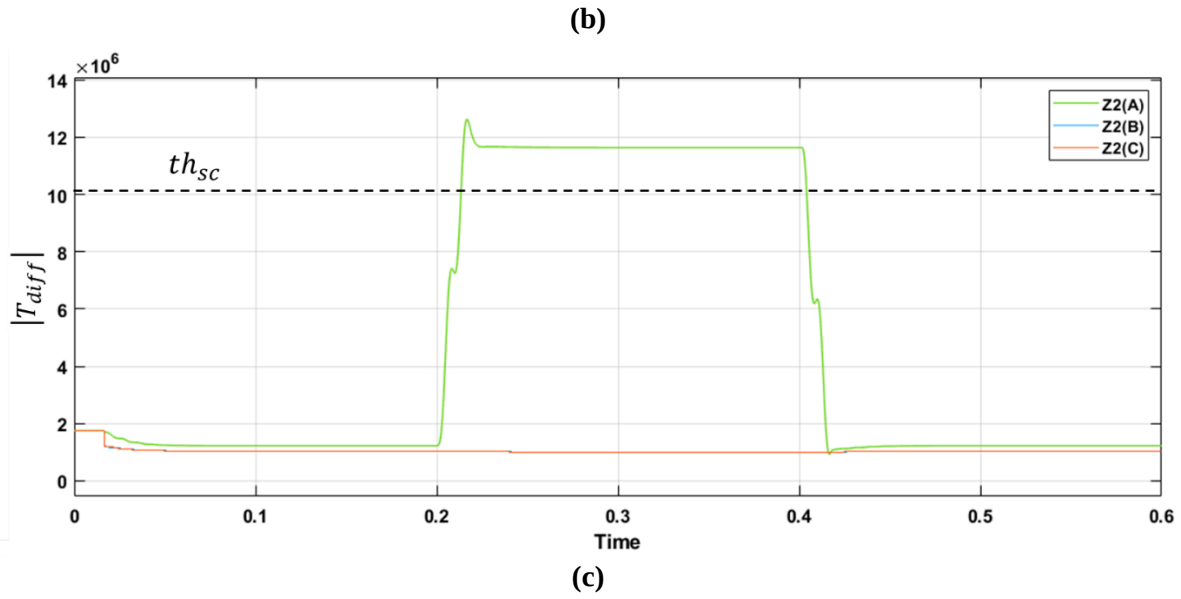


Figure 3-11 High impedance fault type in Z2

Table 3-3
VOLTAGE PROFILE OF PHASE A IN ZONE 2

# of node	Node	Voltage (A)
1	N_6	0.722
2	N_7	0.69
3	N_8	0.6
4	N_9	0.617
5	N_{10}	0.625
6	N_{11}	0.626
7	N_{12}	0.627
8	N_{13}	0.63
9	N_{14}	0.633
10	N_{15}	0.632
11	N_{16}	0.631
12	N_{17}	0.63
13	N_{18}	0.629

3.5.2 Comparative Assessment

The proposed FI algorithm succeeded in detecting and protecting the system from the SLG fault. Moreover, the proposed algorithm demonstrated a fast response and high accuracy in identifying the fault node inside the faulted zone. A detailed comparative assessment is presented in Table 3-4 to summarize the effectiveness of the proposed FI algorithm. As can be seen, the algorithm was able to detect the voltage-sag origin with much fewer PMUs than in [96] or [80], which leads to a reduction in the cost. It can also be observed from Table 3-4 that the algorithm achieved a fast voltage-sag origin

detection compared to [96] and [80]. Hence, it can be concluded from the previous comparative assessment that the proposed FI algorithm is simple, fast, cost-effective, and accurate in identifying the voltage-sag origin by utilizing relatively few PMUs in the system.

Table 3-4
COMPARATIVE ASSESSMENT OF PROPOSED FI ALGORITHM

Method	Test system	DER locations	# of PMUs	PMU Locations	Fault detection time
Proposed FI	IEEE 33-bus system	6, 10, 14, 28	7	2, 3, 6, 18, 22, 25, 33	11 <i>ms</i> for SLG
[96]			10	1, 3, 6, 10, 14, 18, 22, 25, 28, 33	20 <i>ms</i> for SLG
[80]			33	All buses	40.3 <i>ms</i> for SLG

3.6 Conclusion

This chapter developed a fault-locating algorithm for voltage-sag origin identification in ADSs. The scheme proposes the integration of an intra-zone fault location sub-routine that utilizes a voltage and current estimation technique with a fault zone identification sub-routine based on Tellegen's theorem. A network partitioning technique was also presented in this chapter, as network connectivity is the key to forming the zones. Compared to the existing voltage-sag identification techniques in the literature, the proposed scheme can swiftly and efficiently detect the exact voltage-sag origin with minimum units allocated. To evaluate the proposed methodology's effectiveness in identifying and detecting the faults in the system, a modified IEEE 33-bus system was considered for the case studies. Fast and accurate voltage-sag origin (i.e., fault) identification was achieved in less than 11 *ms* with 100% accuracy. The proposed scheme is also cost-effective, as it depends only on the measurements from the available PMUs in the system.

Furthermore, while the developed voltage-sag identification sub-routine is running (i.e., as discussed in this chapter), a voltage-sag mitigation sub-routine runs to calculate the optimal active and reactive power injections from the DERs deployed in the system in order to mitigate the voltage-sag. This voltage-sag mitigation via injection of DERs' will be proposed and discussed in detail in the next chapter. The fast identification of voltage-sag origin in the system is an excellent advantage in the healing process and system restoration during a voltage-sag event.

Chapter 4

System Level-Based Voltage-Sag Mitigation Using DERs via Different Network Partitioning Techniques

4.1 Introduction

Distributed energy resources are mostly interfaced via inverters into the network. Therefore, the availability of inverter-based DERs in ADSs is fast-growing, along with the deployment of these resources. Revised grid codes will permit the inverter-based DERs to provide ancillary services by controlling their active and reactive output power and considering their high energy density [99]. One crucial ancillary service that DERs can provide to the system is voltage-sag mitigation. This chapter proposes a voltage-sag mitigation sub-routine based on the active and reactive power management of inverter-based DERs. The proposed algorithm takes into consideration the available volt-ampere capacity in these inverter-based DERs to boost the voltage profile as close as possible to 0.9 p.u. . Moreover, the proposed sag-mitigation framework is unique in that it mitigates the voltage-sag from a system-level perspective while optimizing the injections through a novel system partitioning technique based on a network sensitivity index. The index ranks the mitigation zones according to their potential in successful voltage-sag mitigation.

The structure of this chapter is presented as follows. The details of the problem formulation are demonstrated in section 4.2, while section 4.3 provides an in-depth analysis of the proposed network partitioning approaches. The mitigation zone optimization control formulation is then presented in section 4.4, with section 4.5 providing further details of the formulation. In section 4.6, the tools used in this study are explained. Finally, a case study is performed in section 4.7 to prove the effectiveness of the proposed voltage control algorithm.

4.2 Problem Formulation

In the present work, a partition-based voltage control algorithm for solving voltage-sag problems is developed. This algorithm is based on partitioning the system into mitigation zones by considering the participation of DERs. The DERs are motivated by incentives from DSOs to provide voltage support during voltage-sag periods. The proposed algorithm takes advantage of the available capacity in DERs to supply ancillary services associated with the voltage control in ADSs, which can reduce the investment of voltage regulating equipment and guarantee the profitability of DERs. Each group of

DERs is considered in one partition with its controller agent. All of the partitions (i.e., mitigation zones) communicate with each other through communication media to share the required injections from DERs within their zones. The advantage of the proposed algorithm is utilizing the DERs, which are already existing in the system without the need to install any new hardware, is illustrated in Figure 4-1.

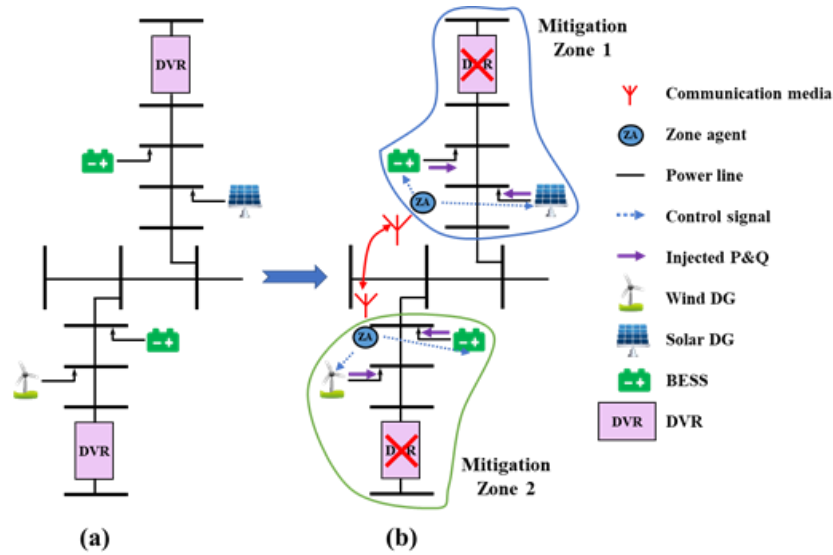


Figure 4-1 Main idea of proposed algorithm: (a) traditional voltage-sag mitigation by using DVR, (b) proposed system-level voltage-sag mitigation

The proposed voltage-restoring framework can be divided into three components, as shown in Figure 4-2. The first of these is the detection component, where node voltages are monitored or estimated through power flow calculations to detect voltage-sag problems in order to trigger the mitigation algorithm. The second component divides the network into prioritized partitioning mitigation zones. This component identifies the optimal partitioning scheme for the given network, following the Zone Capability Index (ZCI) values, which are calculated to prioritize all mitigation zones. The partitioning is executed offline and is triggered by changes in the network's topology.

Finally, the third component involves solving a multi-objective optimization algorithm within each mitigation zone in sequential order according to the prioritization obtained from the ZCI. The algorithm mounted in each zone finds the required changes in active and reactive power injections from DERs while achieving two objectives: 1) minimizing the total amount of the active/reactive power changes, and 2) minimizing the voltage magnitude differences of all buses within each mitigation zone. A short, high-level pseudo-code for the proposed algorithm is presented in Figure 4-3.

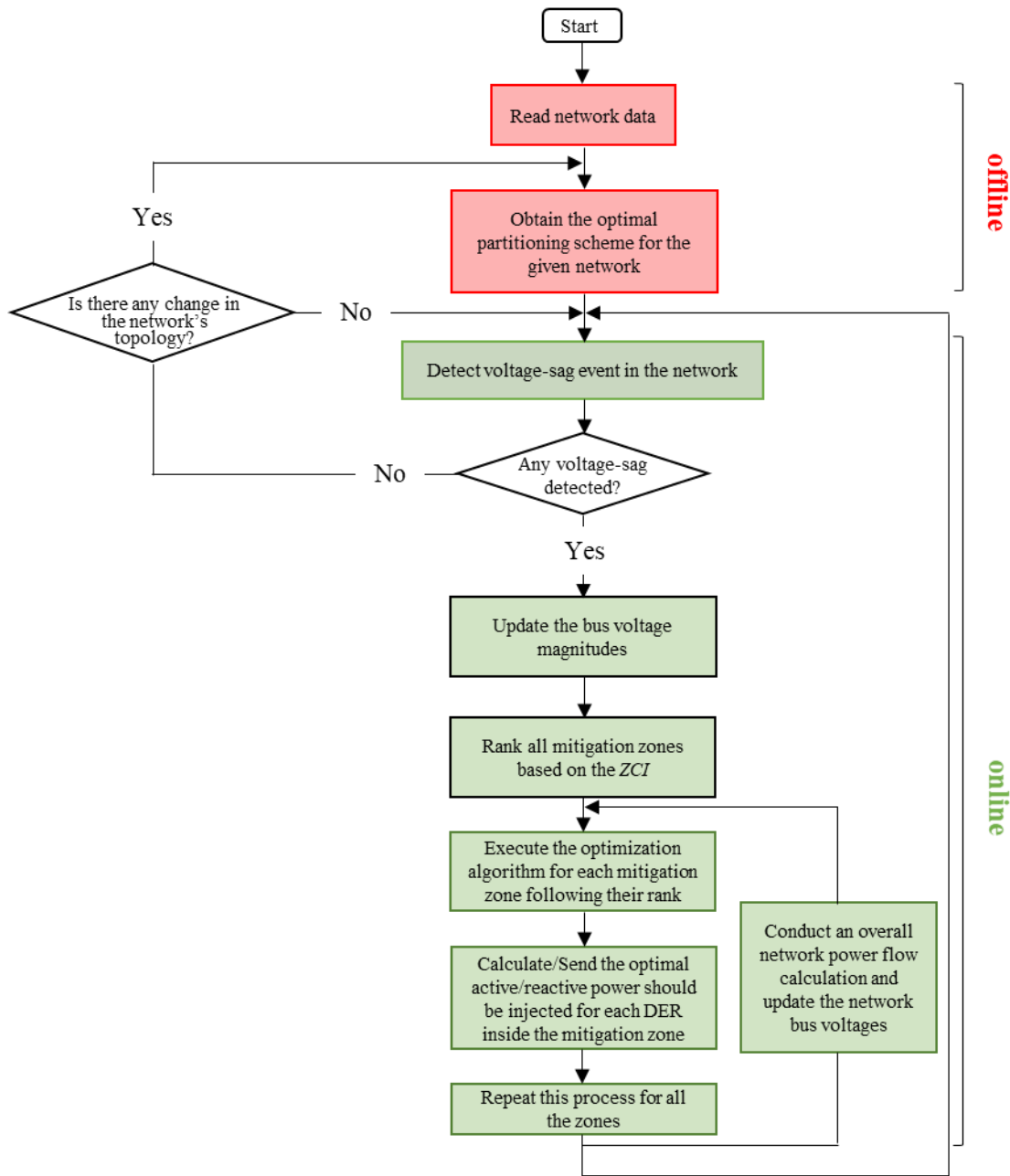


Figure 4-2 Flowchart of partition-based voltage control algorithm

Algorithm System Level-Based Voltage-Sag Mitigation

- 1: **procedure** offline
- 2: **read** network data
- 3: **initiate the** modularity concept algorithm
- 4: **end procedure**
- 5: **procedure** online
- 6: **if** voltage-sag event is detected
- 7: load mitigation zones boundaries
- 8: **end if**

- 9: rank all mitigation zones based on the ZCI
 - 10: execute the optimization algorithm for each mitigation zone following their rank
 - 11: calculate/send the optimal scheduling for each DER
 - 12: **end procedure**
-

Figure 4-3 General structure of proposed algorithm

4.3 Network Partitioning Techniques

The increasing penetration of the various DERs causes a mandatory opportunity to solve voltage-sag problems in ADSs. Some approaches, such as the Fit & Forget approach, consider the passive use of available resources without a control strategy, but these approaches are expensive and time-consuming. To get the most out of the DERs integrated into the network while satisfying the voltage constraints, it is crucial to apply more active control on these energy resources. A variety of control algorithms are found in the literature, ranging from centralized to decentralized control approaches. These algorithms mainly focus on utilizing the ability of inverters to regulate the active and reactive output power. Hence, they are highly reliant on the relations between the bus voltage and the active and reactive output power of the resource plant.

Some of the active/reactive power combined control algorithms mentioned in the literature deal with the power networks as a whole. However, this method is time-consuming in computation in addition to the difficulty of applying them to existing large systems. It is worth mentioning that, due to the modern nature of ADSs, some voltage control algorithms are based on partitioning the network into mitigation zones. These algorithms will be a promising trend in order to mitigate voltage-related PQ problems across the ADSs.

As sensitivity analysis is often applied to figure out the relations between variables, the present work will focus on finding the incremental change in voltage concerning the DER active ΔP and reactive ΔQ power injections. Voltage sensitivity coefficients are obtained based on this analysis. The sensitivity coefficients will be very helpful for the DSOs to deal with voltage-related PQ problems through a control algorithm. While the control algorithm aims to determine the optimal set-points of active and reactive power injections from DERs, its effectiveness will strongly depend upon the accuracy of the calculated voltage sensitivity coefficients.

A large number of energy resources (e.g., RESs and BESSs) allocated in ADSs poses challenging management issues to DSOs due to the intermittent nature of the RESs. It is inefficient to control all available resources in a centralized fashion, and optimizing the system in bulk for real-time operation is not possible unless some approximations are made. Accordingly, it is more practical to gather nodes

with a high coupling degree and manage them as a mitigation zone. In this approach, the system is divided into a number of manageable zones that are formed based on structural characteristics (e.g., coupling degrees among different nodes) for achieving the desired voltage-sag mitigation. It is worth mentioning that the nodes in the same sub-section have a high coupling degree if compared to other system nodes.

In this chapter, two different network partitioning techniques are presented, namely the network partitioning based on the modularity concept and the minimum power flow concept. These two techniques have two different perspectives in studying the strength of connectivity between the nodes. The network partitioning scheme based on the modularity concept studies the strength of connectivity between different nodes in the network according to a voltage sensitivity analysis. On the other hand, the network partitioning scheme based on the minimum power flow studies the strength of connectivity between different nodes in the network with respect to energy balance (i.e., self-adequate clusters). The suitability of each of these network partitioning techniques for voltage-sag mitigation is investigated later in this chapter.

4.3.1 Electrical Influence Intensity

In general, from the network structural point of view, an adjacent matrix is commonly used to represent undirected and unweighted networks. A network with n vertices is represented by an $n \times n$ binary-weighted adjacent matrix A_{ij} , with its elements defined as:

$$A_{ij} = \begin{cases} 1 & \text{if } i \text{ and } j \text{ are connected,} \\ 0 & \text{otherwise.} \end{cases} \quad (4-1)$$

where A_{ij} is the weighted adjacent matrix and can be simply represented by zero or 1.

However, as has long been appreciated, most of the practical networks are fundamentally weighted networks, as their edges have different strengths. Thus, to ignore them is to throw out many useful data that could help to understand these systems preferable. Although ADSs can be considered as a sort of complex network, the previous straightforward representation is not convenient. This is because power flows on the distribution feeders are not the same, as different DERs are usually distributed across the whole network. Consequently, ADSs should be analyzed as weighted rather than unweighted networks.

In the proposed algorithm, the weighted adjacent matrix (A_{ij}) of an ADS is described by the Electrical Influence Intensity (EII). Moreover, the A_{ij} will represent the electrical connection between any two nodes in the network. The elements of the A_{ij} matrix are expressed as:

$$A_{ij} = \begin{cases} E_{ij} & \text{if } i \text{ and } j \text{ are connected,} \\ 0 & \text{otherwise} \end{cases} \quad (4-2)$$

where E_{ij} illustrates the edge's weighted value between nodes i and j . Moreover, $E_{ij} = 0$, in case of no edge, connects the two nodes. The proposed EII comprehensively reflects the strength of connectivity between nodes to ensure that the structural characteristics are appropriately represented.

There are two main steps to calculate the E_{ij} index. The first step is to determine the reactive power-voltage ($Q - V$) and the active power-voltage ($P - V$) sensitivity matrix. The following sensitivity matrix represents the relationships between the voltages (i.e., incremental change in voltage magnitude ΔV and incremental change in phase angle $\Delta\delta$) and the changes in the power injections (i.e., active ΔP and reactive power ΔQ), as follows:

$$\begin{bmatrix} \Delta\delta \\ \Delta V \end{bmatrix}_{2N \times 1} = \begin{bmatrix} S_{\delta P} & S_{\delta Q} \\ S_{VP} & S_{VQ} \end{bmatrix}_{2N \times 2N} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}_{2N \times 1} \quad (4-3)$$

where $S_{\delta P}$ and $S_{\delta Q}$ describe the voltage angle sensitivity for ΔP and ΔQ , respectively; S_{VP} and S_{VQ} describe the voltage magnitude sensitivity for ΔP and ΔQ , respectively; and S_{VP} and S_{VQ} are $N \times N$ matrices.

The second step, analogous to the definition of electrical distance in [100], calculates the Strength of Connectivity (SC) between two nodes. A popular definition for the electrical distance between bus i and bus j is the equivalent impedance Z_{ij} , which considers the lines' impedance and connects i and j as follows [101]:

$$Z_{ij} = z_{ii} + z_{jj} - z_{ij} - z_{ji} \quad (4-4)$$

where Z_{ij} is the equivalent impedance of the circuit whose ends are nodes i and j , and z_{ij} is the i th, j th element of the impedance matrix.

The SC is defined in the proposed algorithm according to the ($P - V$) sensitivity matrix. Therefore, the strength of connectivity based on $P - V$ sensitivity matrix SC_{ij}^{VP} is calculated as:

$$SC_{ij}^{VP} = \begin{cases} S_{VP}^{ii} + S_{VP}^{jj} - S_{VP}^{ij} - S_{VP}^{ji} & \forall i \neq j \\ 0 & \text{otherwise.} \end{cases} \quad (4-5)$$

If the connection between node i and node j is tight, their mutual active power-voltage sensitivities will have almost the same value and their SC_{ij}^{VP} will be small. Similarly, the strength of connectivity based on $Q - V$ sensitivity matrix SC_{ij}^{VQ} is calculated as:

$$SC_{ij}^{VQ} = \begin{cases} S_{VQ}^{ii} + S_{VQ}^{jj} - S_{VQ}^{ij} - S_{VQ}^{ji} & \forall i \neq j \\ 0 & otherwise. \end{cases} \quad (4-6)$$

Finally, to illustrate the strength of connectivity between two nodes properly, an average weight formula will be used to illustrate the average strength of connectivity between any two nodes. Considering that SC_{ij}^{VP} is out of proportion to SC_{ij}^{VQ} , this average value may be calculated as:

$$SC_{ij} = \frac{\sqrt{(SC_{ij}^{VP})^2 + (SC_{ij}^{VQ})^2}}{2} \quad (4-7)$$

Based on the above discussion, the E_{ij} index may be expressed as:

$$E_{ij} = 1 - \frac{SC_{ij}}{\max_{g,h \in N} SC_{gh}} \quad (4-8)$$

where SC_{gh} is the total strength of connectivity between any two nodes in the network. After that, the E_{ij} index is utilized to obtain the weighted adjacent matrix. This matrix will be considered as the input parameter to obtain the network partition scheme based on the modularity concept, as will be discussed in the following section.

4.3.2 Modularity-based Network Partitioning Technique

There are several methods for detecting sub-networks in complex networks. A popular and widely used method is the Newman fast algorithm, which is based on the modularity concept [102]. Newman introduced the modularity index Q to judge the quality of the network partitioning. However, unlike other community detection methods, this method can reach the optimal number of communities (i.e., mitigation zones) without previous knowledge of the number of clusters, so predetermining the number of clusters in a dataset is not required. A large modularity index implies that the nodes are densely connected within the same community.

On the other hand, nodes that are in different communities have scattered connections with each other, in which case the larger the modularity index, the more efficient the partitioning. It should be noted that the Q index of a partitioning scheme is a scalar value between -1 and 1.

The modularity index Q is defined as follows [103]:

$$Q = \frac{1}{2m} \sum_i \sum_j \left[A_{ij} - \frac{D_i D_j}{2m} \right] \delta(Com_i, Com_j) \quad (4-9)$$

$$D_i = \sum_j A_{ij} \quad (4-10)$$

$$m = \frac{1}{2} \sum_i \sum_j A_{ij} \quad (4-11)$$

where $D_i(D_j)$ is the degree of node $i(j)$. It is expressed as the total edges' weights connected to node $i(j)$, as shown in (4-10), while m is the total edges' weights in the network, as shown in (4-11). Furthermore, $\delta(i, j)$ is the Kronecker delta and $Com_i(Com_j)$ represents the community to which node $i(j)$ belongs. In cases where node i and node j are in the same community, $\delta(Com_i, Com_j) = 1$; otherwise, $\delta(Com_i, Com_j) = 0$. According to the modularity concept, the optimal partitioning, the associated modularity indices, and the mitigation zone boundaries are obtained. A pseudo-code for the steps of the modularity concept is shown in Figure 4-4.

Algorithm Modularity Concept

```

1: read network data
2: procedure weighted adjacent matrix
3:   for  $i = 1$  to  $N_{Bus}$  do
4:     for  $j = 1$  to  $N_{Bus}$  do
5:       calculate  $S_{VP}^{ij}$  and  $S_{VQ}^{ij}$  as in (4-3)
6:     end for
7:   end for
8:   calculate the strength of connectivity  $SC_{ij}$  according to (4-7)
9:   calculate the electrical influence intensity  $E_{ij}$  according to (4-8)
10: end procedure
11: procedure modularity index
12:   calculate modularity index according to (4-9)
13: end procedure
14: return mitigation zones boundaries (at which modularity index is maximized)

```

Figure 4-4 Modularity concept structure

The former stage discussed the modularity concept and how the modularity index is considered the strength of the connectivity factor. A high value of Q means a high strength of connectivity between

nodes within the same mitigation zone, however opposite with respect to the other zones. Therefore, optimal partitioning can be achieved by seeking the partitioning results with the maximum Q .

4.3.3 Minimum Power Flow (PF)-based Network Partitioning Technique

In the method described in [104], the weakly loaded lines with minimum flows are selected as Candidate Lines (CL). Thus, the boundary buses for self-adequate clusters are candidate lines' buses. At these virtual boundaries, the effect of injections from the DERs located within the cluster has vanished, leaving the nodes within these clusters strongly coupled with the energy balance criteria. The selected candidate line's loading should not surpass a pre-specified threshold, demarcated as a percentage of the line's rated value and calculated from the deterministic PF as:

$$threshold = \frac{P_{operating\ scenario}}{P_{deterministic}} \quad (4-12)$$

The voltage control algorithm can be implemented within these boundaries to optimize the injections from DERs to mitigate the voltage-sag problems. The latter stage identifies how the voltage-sag mitigation algorithm is implemented in each mitigation zone.

4.4 Mitigation Zone Optimization Control

As discussed in the previous section, the ADS is partitioned into several mitigation zones in the proposed algorithm's first stage. In each mitigation zone, the buses have a more robust electrical connection from the strength of connectivity perspective. The network partitioning algorithms described above are used to divide the system into D optimal mitigation zones. The zones are denoted as $(Z_1, Z_2, \dots, Z_K, \dots, Z_D)$, and there is no overlap among them. Due to the light coupling among these zones, the optimal voltage mitigation algorithm is applied independently in a sequential order set by the prioritization algorithm. As mentioned earlier, the optimal voltage mitigation algorithm has a multi-objective function applied within the mitigation zone. The proposed DERs' injection control to mitigate the voltage-sag adopts double-layer control architecture (as demonstrated in detail in the following sub-sections) by considering a general mitigation zone, Z_K , as an example.

4.4.1 Unified Mitigation

Conventional centralized system optimization is based on managing the system as a whole. This management concept can be considered a particular case of the portioning concept, with the network partitioned into one zone or unified priority for all zones. Therefore, all of the network components –

including DER units – are treated as one mitigation zone. The optimal active and reactive power injections are determined by applying the optimization algorithm presented later to the one zone. This optimization algorithm will solve the system all at once and determine all the injections at all nodes according to the system's current state.

4.4.2 Sequential Mitigation

A novel management concept is introduced based on the sequential optimization approach. The optimization algorithm is executed in each zone of the available mitigation zones following a pre-defined sequence that is based on zone-prioritization and uses the Zone Capability Index (ZCI). This prioritization layer is implemented directly after the network partitioning is completed. A novel *ZCI* is introduced as the main engine for this step and is calculated, as shown in (4-13):

$$ZCI_K = \frac{|V|_K \times Cap_K}{N_K} \quad (4-13)$$

where $|V|_K$ represents the average value of bus voltage magnitudes inside mitigation zone K , and Cap_K represents the ratio of available resources capacity to total loading inside the mitigation zone K . The number of buses inside the mitigation zone is described by N_K . The *ZCI* arranges all the mitigation zones from the highest value (i.e., the most successful voltage-sag mitigation) to the lowest, based on the previous three factors. In this way, all of the mitigation zones are sorted in descending order according to their potential in successful voltage-sag mitigation.

This arranging process will create a priority list for the mitigation zones in the network. The priority list determines the sequential order to execute the optimization algorithm in the available mitigation zones. Thus, the mitigation zone with the highest *ZCI* will be selected as the first mitigation zone to conduct the mitigation algorithm to optimize the injections. It is worth noting that, when optimizing injections inside a zone, the current system's state is considered after the application of the previous zones' mitigation attempts.

4.4.3 Mitigation Zone Active/Reactive Power Control

In the second layer, a multi-objective function is used in the optimization algorithm. The optimal voltage control algorithm in each mitigation zone is formulated in the General Algebraic Modeling System (GAMS) as a non-linear programming problem. The problem is solved by the MINOS solver, which performs a linearly constrained Lagrangian method. In order to reach the optimal scheduling of DERs within a mitigation zone, operating conditions should be assumed for these DERs.

As mentioned earlier, power electronics-based RESs are controlled to operate with a unity power factor. However, due to these sources' low efficiency, the active power generated by RES inverters is less than their actual power ratings. In addition, inverters can be controlled to operate with a power factor different from one. Thus, the remaining capacity of RESs generation may be used to produce reactive power.

As shown in Figure 4.1, when the RES inverter generates active power P_3 , it has a maximum reactive power capability Q_3 to mitigate the voltage variation problem, which will not lead to a reduction in RES active power. The cap of Q that can be injected or absorbed by the RES inverter relies on the actual P generated by the RES source and the inverter-rated power.

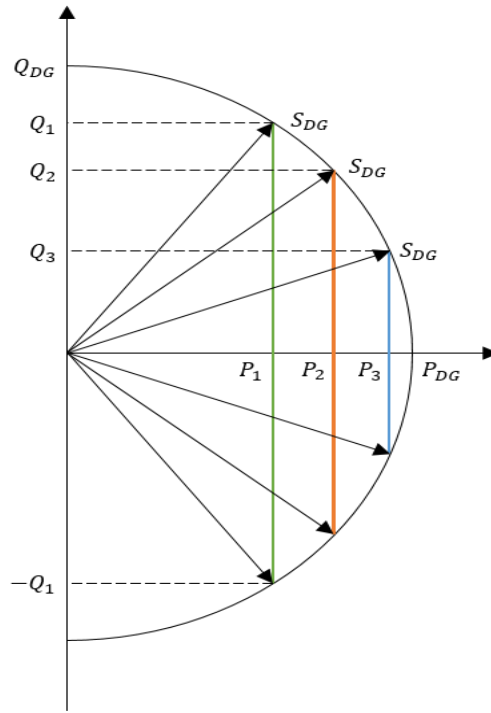


Figure 4-5 Limits in reactive power output of RES inverter

4.5 Mitigation Zone Optimization Model

A multi-objective model is developed to optimize injections from DERs. This model will be mounted in each zone and will be executed according to a pre-defined sequence. Equations (4-14), (4-15) and (4-16) show the multi-objective function of the proposed algorithm. The constraints considered in this model are power balance constraints, as expressed in Eqs. (4-17), (4-18), (4-19) and (4-20), as well as in the capacity limits of RESs and BESSs (4-21).

4.5.1 Objective Function

$$F_1 = \sum_{bat=1}^{N_{bat}} (\Delta P_{bat} + \Delta Q_{bat}) + \sum_{RES=1}^{N_{RES}} \Delta Q_{RES} \quad (4-14)$$

$$F_2 = \sum_{N=1}^{N_Z} (V_{ref} - V_N)^2 \quad (4-15)$$

$$\min F = w_1 \times F_1 + w_2 \times F_2 \quad (4-16)$$

where F_1 and F_2 are the first and second normalized objective functions, respectively; N_{bat} is the total number of batteries in the mitigation zone; ΔP_{bat} and ΔQ_{bat} are the active and reactive power injected from a battery, respectively; N_{RES} is the total number of RESs in the mitigation zone; ΔQ_{RES} is the reactive power injected from a RES; V_{ref} is the voltage reference value; V_N is the voltage magnitude of node N inside the mitigation zone; N_Z is the total number of buses included in the mitigation zone; and w_1 and w_2 are the weighting factor assigned to the first and second objective functions, respectively. The weighting factors will also depend on the priority assigned to each objective function by the system operator and the system operator's experience. It should be noted that during normal operation, RESs are operating in a constant active power control mode with zero output reactive power (i.e., unity power factor) [105]. With this being said, at any time, the RESs are already injecting their allowed active power, and are not capable of injecting more active power. However, to inject more active power, the input power coming from the RES (i.e., wind speed or solar irradiance) must be increased. Therefore, the proposed framework assumes that RESs can not contribute to the increase in active power injections. In summary, renewable resources are assumed to inject their maximum achievable active power P at any time to maximize their profit. Therefore, they can not contribute to the power change request ΔP . Once the voltage-sag event is detected, a new output reactive power reference (ΔQ_{RES}) is optimized based on the available volt-ampere from the RES's inverter.

4.5.2 Power Balance Constraints

The following power balance constraints are considered for the full network, including the updated ΔP and ΔQ changes in the resources within the mitigation zone under control.

$$P_{G_i} + P_{DER_i} - P_{Li} = V_i \sum_{j=1}^{N_{Bus}} V_j (G_{ij} \cos(\theta_{ij}) + B_{ij} \sin(\theta_{ij})), \quad \forall i \in N_{Bus} \quad (4-17)$$

$$Q_{G_i} + Q_{DER_i} - Q_{Li} = V_i \sum_{j=1}^{N_{Bus}} V_j (G_{ij} \sin(\theta_{ij}) - B_{ij} \cos(\theta_{ij})), \quad \forall i \in N_{Bus} \quad (4-18)$$

where

$$P_{DER_i} = \sum_{i=1} P_{RES_i} + (P_{bat_i} + \Delta P_{bat_i}) \quad (4-19)$$

$$Q_{DER_i} = \sum_{i=1} (Q_{RES_i} + \Delta Q_{RES_i}) + (Q_{bat_i} + \Delta Q_{bat_i}) \quad (4-20)$$

and where P_{G_i} and Q_{G_i} are the active and reactive power generated by the grid, respectively. Moreover, P_{DER_i} and Q_{DER_i} are the total active and reactive power injected by DERs with the mitigation zone, respectively, as explained in Eqs. (4-16)-(4-17); V_i and V_j are the voltage magnitude of the node i and node j , respectively; G_{ij} and B_{ij} are the conductance and susceptance of branches consisting of nodes i and j , respectively; θ_{ij} is the phase difference between node i and node j ; and N_{Bus} is the total number of buses in the network.

4.5.3 RES and Battery Capacity Limits

The following capacity limits are applied to all DERs in the network:

$$\text{sqrt}(P_{RES}^2 + (Q_{RES} + \Delta Q_{RES})^2) \leq S_{RES}^{max} \quad (4-21)$$

$$\text{sqrt}((P_{bat} + \Delta P_{bat})^2 + (Q_{bat} + \Delta Q_{bat})^2) \leq S_{bat}^{max} \quad (4-22)$$

where S_{RES}^{max} and S_{bat}^{max} are the installed capacity of both the RES inverter and BESS inverter, respectively. It should be noticed that the injected power is needed for a short duration (according to the standards, voltage sag duration is within 1 min). Thus, the energy supplied by the BESS is negligible concerning the SOC of the battery.

The following constraint is added to ensure that the required injections from DERs are always positive.

$$\Delta P_{bat} \times \Delta Q_{bat} \times \Delta Q_{RES} \geq 0 \quad (4-23)$$

After the optimal algorithm for the mitigation zone Z_K is executed, a power flow calculation is performed for the entire network. The power flow solution updates the voltage profile, and this mechanism will coordinate the efforts of all the mitigation zones in the network. The updated voltage at the buses of other mitigation zones will be obtained and considered while executing their optimization algorithm process. All of the partitioned zones are examined to ensure that all bus voltages are regulated to the required reference level or until all the DERs units are exerted and no more capacity is available for voltage support.

4.6 Tools Used in the Proposed Study

In this study, a multi-agent system (MAS) framework is assumed to be available for facilitating the voltage control algorithm, as shown in Figure 4-6. Each mitigation zone is represented by an agent (for optimal energy dispatch) as well as a DSO agent. Each agent has the ability to adjust the power generation/consumption of any energy resource (i.e., DER) within its own mitigation zone while supplying the load demand. The coordination among agents plays an essential role, where each agent can update its local information and exchange data with neighbouring zones.

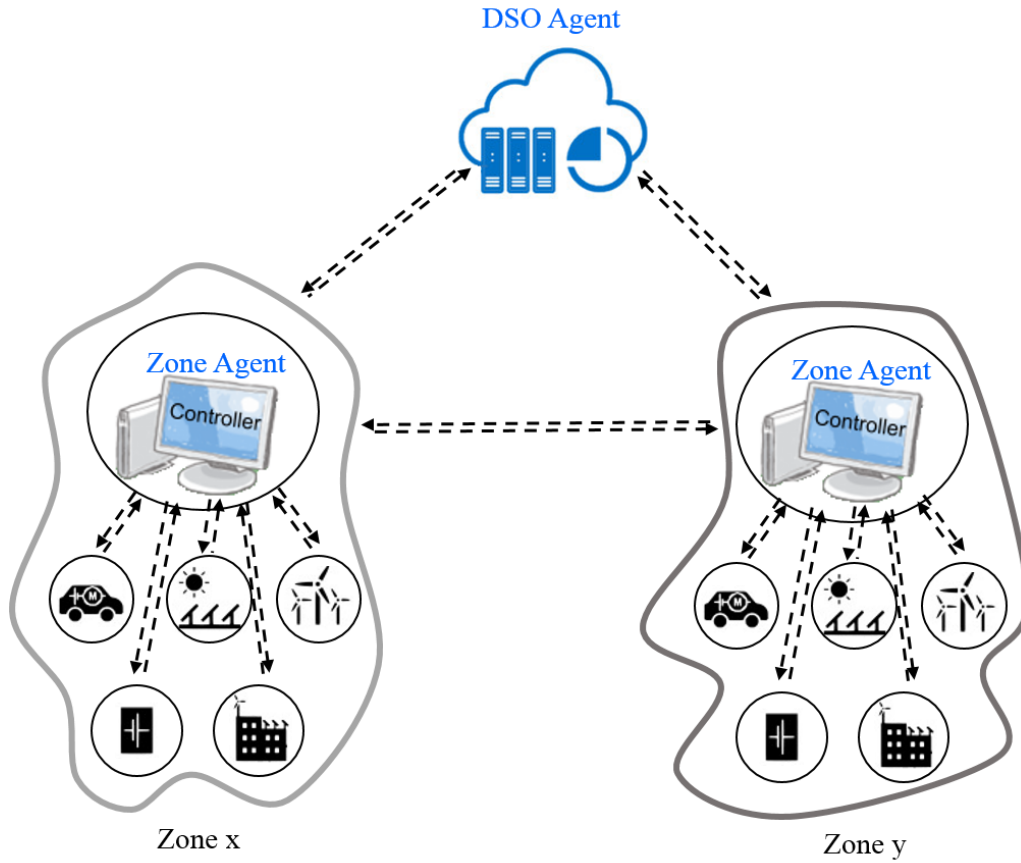


Figure 4-6 Architecture of multi-agent system

By employing the MATLAB environment as the master platform, different models (e.g., GAMS, OpenDSS) have been integrated to achieve this mitigation sub-routine's goals. A high-level pseudo-code for the proposed algorithm is presented in Figure 4-7.

Algorithm System Level-based Voltage-Sag Mitigation

- 1: **procedure** offline
- 2: **read** network data
- 3: **initiate** the modularity concept algorithm
- 4: **end procedure**
- 5: **procedure** online
- 6: **if** voltage-sag event is detected
- 7: load mitigation zones boundaries
- 8: **end if**
- 9: rank all mitigation zones based on the ZCI
- 10: execute the optimization algorithm for each mitigation zone following their rank
- 11: calculate/send the optimal scheduling for each DER
- 12: **end procedure**

Figure 4-7 General structure of proposed voltage-sag mitigation algorithm

4.7 Case Studies

A modified three-phase balanced 12.66 kV IEEE 33-bus distribution network with DERs at some candidate buses is considered in order to demonstrate the effectiveness of the proposed voltage control approach. The topology of the ADS under study and detailed DER connected locations are shown in Figure 4-8. There are 32 load nodes with a total nominal load of $3.715\text{MW} + j2.3\text{MVar}$ in the network. Each DER unit is integrated into the network through a power electronic interface (i.e., inverter). For the practical system, the total installed capacity of PV units is about 0.8 MVA, the total installed capacity of wind units is about 1.2 MVA, and the total installed capacity of battery units is about 1.2 MVA distributed across the entire network. The specific parameters for the capacity and location of DER units are listed in Table 4-1. The information and parameters of the network (i.e., the line impedance and load demand of each bus) are shown in Table 4.1 and Table 4.2, respectively.

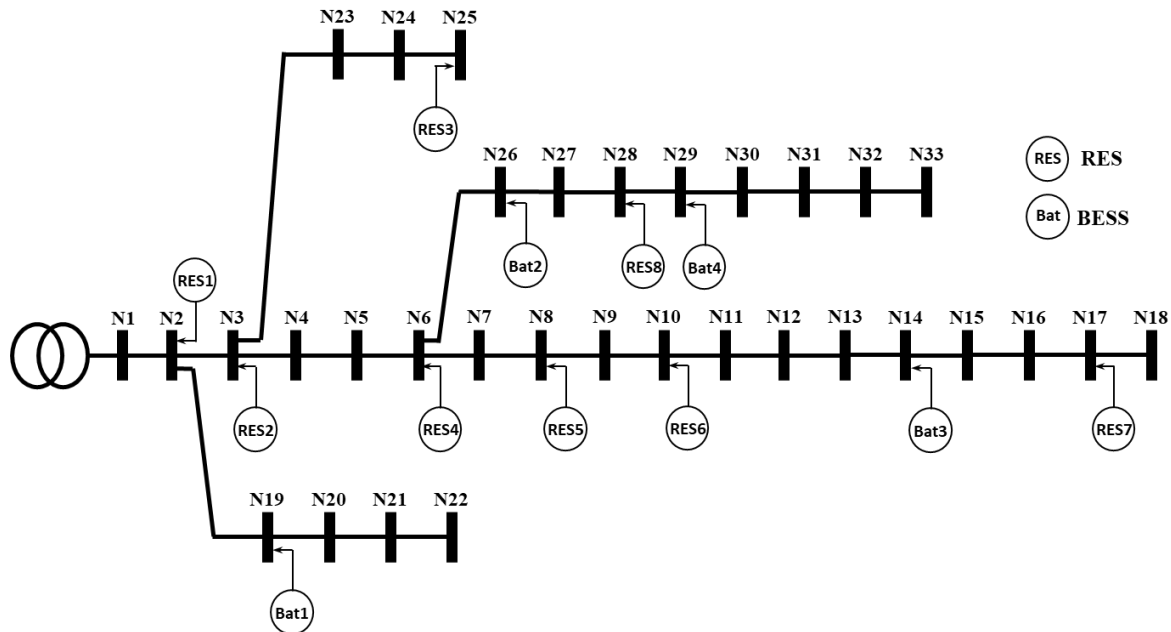


Figure 4-8 Topology of ADS under study

Table 4-1
CAPACITY AND LOCATION OF DER UNITS

DER	Location	Unit Capacity (kVA)
Wind	3, 10, 17, 25	300
PV	2, 6, 8, 28	200
Battery	14, 19, 26, 29	300

4.7.1 Network Partitioning Results

The aforementioned two partitioning algorithms are applied to the system under study to define the mitigation zones.

4.7.1.1 Partitioning Based on Modularity Concept

Before applying the modularity concept to the modified IEEE 33-bus distribution network, E_{ij} is calculated by using (4-8). The results for the E_{ij} calculation, according to (4-8), are shown in Table 4-2. Afterward, the modularity index Q , calculated from (4-9), is determined for all the possible number of mitigation zones, as shown in Figure 4-9. As evident in Figure 4-9, the modularity index reaches its maximum value (i.e., equal to 0.678) when the number of mitigation zones is equal to six. This is considered to be the optimal partitioning layout based on the connectivity strength of the network under study. Accordingly, the IEEE 33-bus is partitioned into six mitigation zones, as shown in Figure 4-10.

Table 4-2
DATA FOR EII RESULTS

From Bus	To Bus	E_{ij}	From Bus	To Bus	E_{ij}
1	2	0.9944	16	17	0.8817
2	3	0.9694	17	18	0.9491
3	4	0.9773	2	19	0.9878
4	5	0.9763	19	20	0.8916
5	6	0.9384	20	21	0.9664
6	7	0.9637	21	22	0.9376
7	8	0.9580	3	23	0.9701
8	9	0.9287	23	24	0.9372
9	10	0.9284	24	25	0.9379
10	11	0.9884	6	26	0.9873
11	12	0.9780	26	27	0.9821
12	13	0.8956	27	28	0.9199
13	14	0.9500	28	29	0.9395
14	15	0.9560	29	30	0.9678
15	16	0.9489	30	31	0.9227

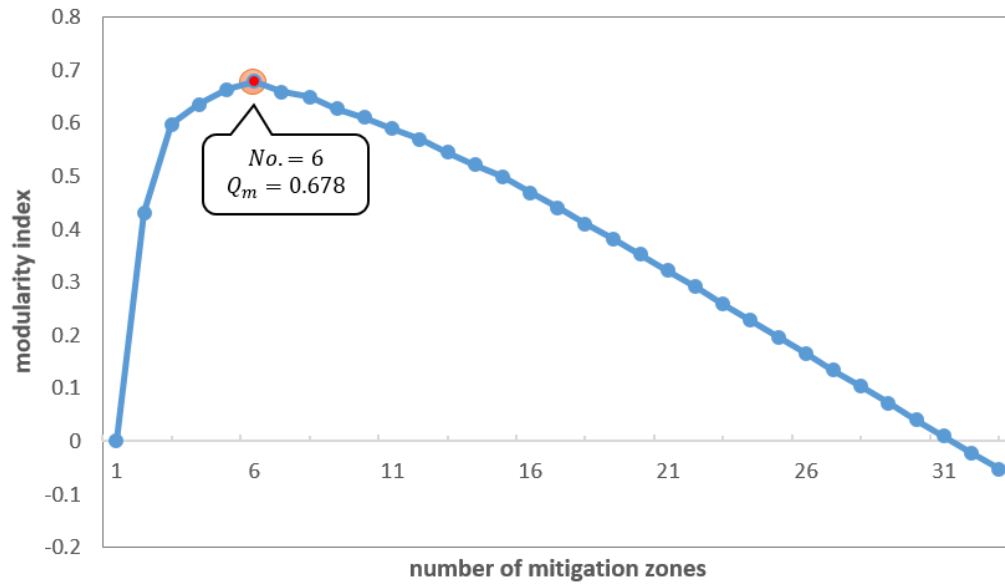


Figure 4-9 Modularity index Q vs number of mitigation zones

Table 4-3
MODULARITY INDEX VALUES

No. of mitigation zones	Q	No. of mitigation zones	Q	No. of mitigation zones	Q
1	0	12	0.569	23	0.259
2	0.431	13	0.545	24	0.228
3	0.598	14	0.522	25	0.197
4	0.635	15	0.499	26	0.166
5	0.664	16	0.469	27	0.134
6	0.678	17	0.44	28	0.103
7	0.659	18	0.41	29	0.072
8	0.649	19	0.382	30	0.041
9	0.627	20	0.352	31	0.010
10	0.611	21	0.322	32	-0.021
11	0.59	22	0.291	33	-0.053

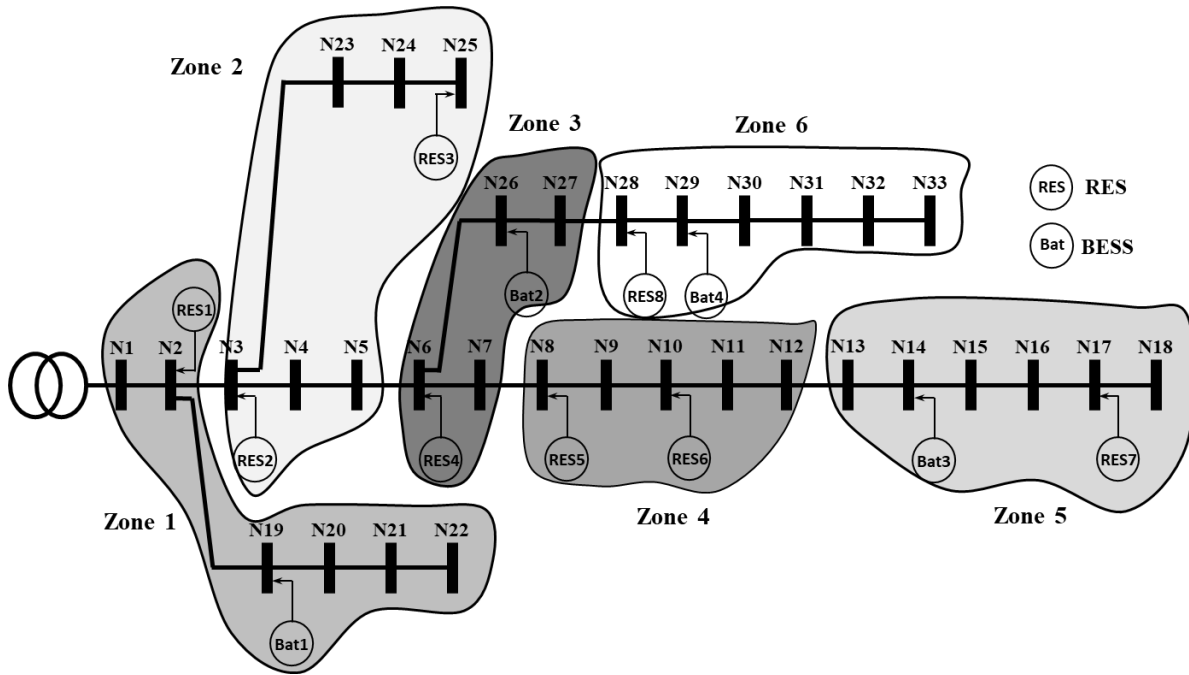


Figure 4-10 Mitigation zone boundaries of a network under the modularity concept

The obtained mitigation zones are then ranked according to the ZCI that is calculated using (4-13) and shown in Table 4-4. This priority list of the necessary mitigation zones mimics the effect of the DER's injection on the voltage profile of the network.

Table 4-4
MITIGATION ZONES RANKING BASED ON ZCI

Mitigation Zone	Buses	ZCI	Rank	Optimization Computation Time (s)
Z_1	1, 2, 19, 20, 21, 22	0.1927	3	0.34
Z_2	3, 4, 5, 23, 24, 25	0.0721	5	0.33
Z_3	6, 7, 26, 27	0.2844	1	0.25
Z_4	8, 9, 10, 11, 12	0.1992	2	0.28
Z_5	13, 14, 15, 16, 17, 18	0.1881	4	0.44
Z_6	28, 29, 30, 31, 32, 33	0.06353	6	0.34
Total optimization problem time=1.98 s				

The mitigation zone with the darkest colour shades represents the highest ZCI value, and vice-versa. It should be mentioned here that these boundaries are fictitious (that is, system lines stay intact) and none of the boundary lines are disconnected.

4.7.1.2 Network Partitioning Based on Minimum PF Concept

Based on the minimum power flow calculations for the IEEE system under study, the obtained mitigation zone boundaries, as per the discussion in section 4.3.3, are shown in Figure 4-11. To ensure self-adequacy, a certain threshold, calculated by (4-12), should not be exceeded by the loading of selected CLs, which in this work is considered 30% of the rated value of each line. The rated values of the lines are calculated according to a deterministic power flow algorithm based on data presented in [106]. Note that the threshold is set according to operator preferences and is considered an input to the network partitioning algorithm.

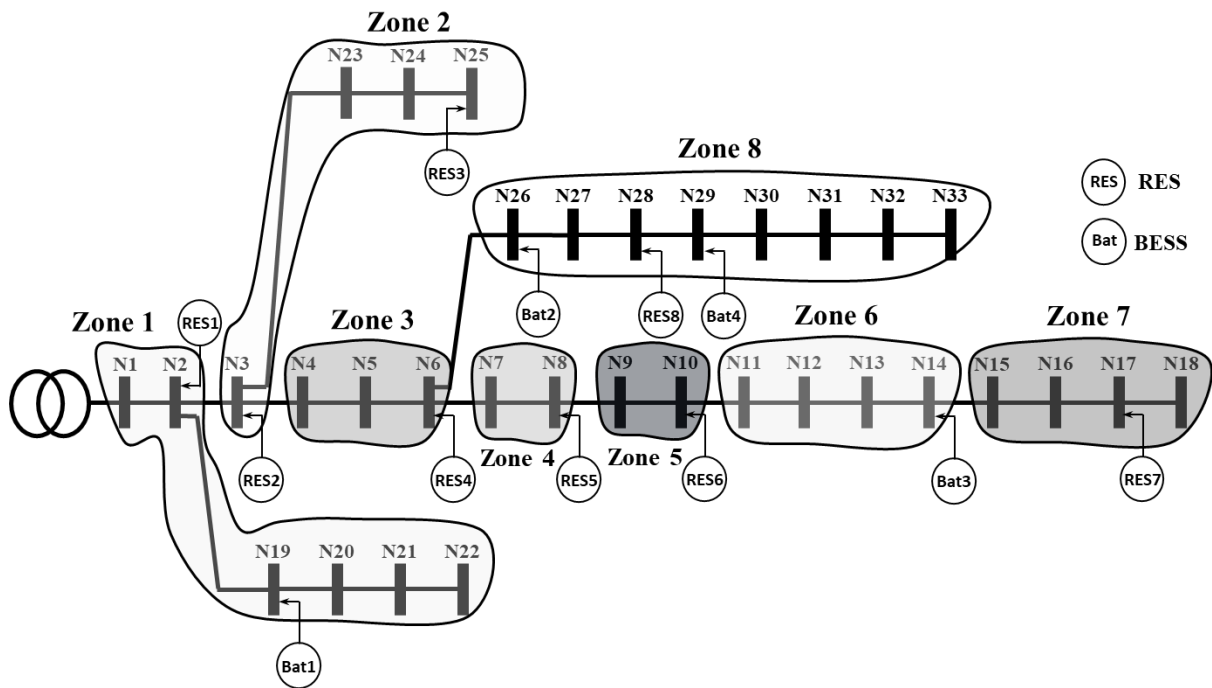


Figure 4-11 Mitigation zone boundaries of network under minimum power flow concept

4.7.2 Zone-based Mitigation Results

Short-circuit faults and large motor-starting are considered as main sources of voltage-sag events. The depth of these events varies for different nodes based on the fault's origin (e.g., transmission system, local, or remote distribution feeders) [107]. Network topology also affects voltage-sag propagation.

To assess the proposed algorithm's effectiveness in mitigating voltage-sag events, disturbances in remote feeders and large motor-starting are considered as the primary sources for these events. A three-phase fault is assumed to occur at a remote distribution feeder; it then propagates as a voltage-sag event

at the ADS under study. The impact of the mentioned fault on the network is reflected as a voltage-sag of 0.147 p.u. magnitude (i.e., voltage magnitude = 0.753 p.u.). This voltage-sag is simulated at bus 1 in the network. All interfacing inverters used with RESs are controlled in constant active power mode. Afterward, voltage-sag mitigation is performed through solving the zone-based optimization model for the ones obtained from various partitioning techniques and ranked according to their ZCI.

4.7.2.1 Modularity Concept

The prioritized sequence of mitigation zones is: $(Z_3, Z_4, Z_1, Z_5, Z_2, Z_6)$, so the proposed coordinated zonal voltage-sag mitigation algorithm starts with mitigation-zone Z_3 . Subsequently, the voltage at nodes in other mitigation zones is updated for further implementation of the voltage-sag mitigation algorithm. All the mitigation zones communicate with each other through zonal agents, which are responsible for all the DER units inside their assigned mitigation zone. Once the system-level voltage-sag mitigation algorithm is initiated, the total injected ΔP and ΔQ are calculated based on the optimization model in section 4.5, as presented in Table 4-5.

Table 4-5
INJECTED ΔP AND ΔQ INTO SYSTEM

	Modularity		min PF		Centralized	
	ΔP (p.u.)	ΔQ (p.u.)	ΔP (p.u.)	ΔQ (p.u.)	ΔP (p.u.)	ΔQ (p.u.)
RES1 (Z1)	0	0.173	0	0.173	0	0.015
RES2 (Z2)	0	0	0	0.18	0	0.18
RES3 (Z2)	0	0	0	0.18	0	0.18
RES4 (Z3)	0	0.173	0	0.173	0	0.173
RES5 (Z4)	0	0.173	0	0.173	0	0.173
RES6 (Z4)	0	0.18	0	0.18	0	0.18
RES7 (Z5)	0	0.174	0	0.18	0	0
RES8 (Z6)	0	0	0	0	0	0.173
Bat1 (Z1)	0.202	0.222	0.205	0.219	0	0
Bat2 (Z3)	0.200	0.223	0	0	0.244	0.174
Bat3 (Z5)	0.3	0	0.226	0.197	0.138	0.1
Bat4 (Z6)	0.089	0	0.193	0.137	0.235	0.186
Total	0.791	1.319	0.624	1.792	0.617	1.534
Base is 1 MVA						

It should be noted that not all the DERs existing in the system are utilized for voltage-sag mitigation. In addition, several RESs did not change their schedule. As shown in Table 4-5, the proposed algorithm succeeded in mitigating the voltage-sag by injecting 1,319 kVar reactive power and 791 kW active power in total. The system's voltage profiles for different scenarios (e.g., normal operation, the system under voltage-sag event, and system under the proposed partition-based voltage control algorithm) are shown in Figure 4-12.

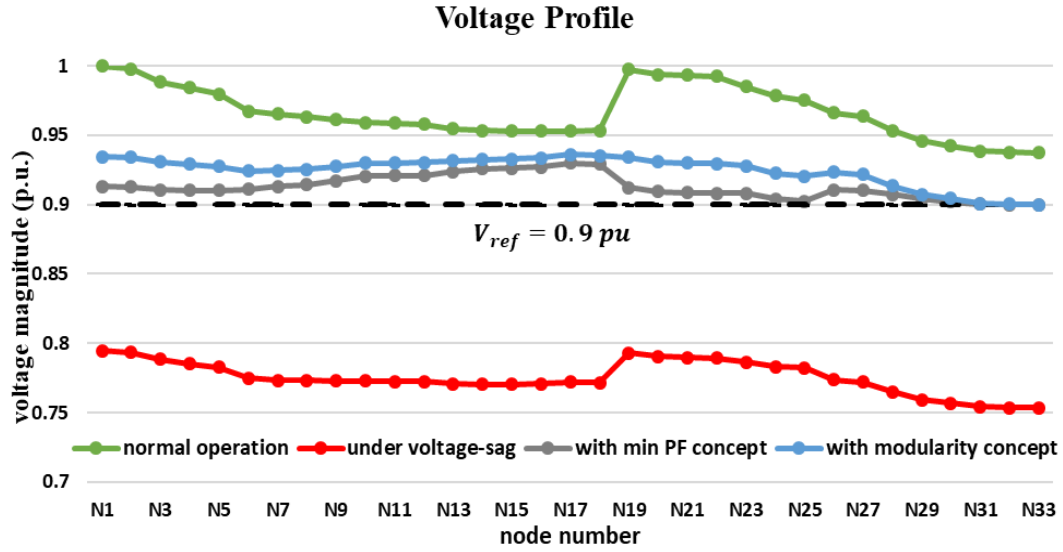


Figure 4-12 Voltage profile of system under different scenarios

4.7.2.2 Minimum PF Concept

The prioritized sequence of mitigation zones based on the ZCI is: $(Z_5, Z_7, Z_3, Z_4, Z_6, Z_1, Z_2, Z_8)$. The total ΔP and ΔQ to mitigate the voltage-sag are given in Table 4-5. Although the voltage-sag problem is solved at the system level, this approach requires more injections from the DERs compared to the modularity concept approach. The node voltage profile of the same three cases using the minimum PF concept is shown in Figure 4-12.

4.7.3 Proving the Effectiveness of the Proposed Algorithm

In order to prove the effectiveness of the proposed algorithm, a detailed comparison is made between the simulation results obtained from the proposed algorithm and those obtained from a non-partition based (i.e., centralized) approach. The total ΔP and ΔQ to mitigate the same voltage-sag using this approach is presented in Table 4-5. The total ΔP is 617 kW (compared to 791 kW), and the total ΔQ is 1534 kVar (compared to 1319 kVar). The non-partition algorithm required more injections for solving the same voltage-sag problem. Furthermore, the non-partition algorithm executes an optimization model considering all the DER units, which increases the computational burden and delays the control action.

To realize this centralized strategy, a more complex and expensive communication system is needed to facilitate communication among all the system nodes [38]. The extensive communication adds increased control action latency. Owing to the fact that the proposed partition-based algorithm executes

the optimization model within mitigation zones, the required computational burden and execution time are much shorter. When dealing with voltage-sag mitigation, the action time is crucial.

It is worth mentioning that the power injections obtained from a mitigation algorithm are the set points of P and Q for the DERs' inverters. Another remarkable effectiveness of the proposed voltage control algorithm is that local inverters are utilized to regulate each mitigation zone's voltage, while inverters inside other mitigation zones are not affected. As well, a complex and time-critical problem is split into individual small sub-problems, which are simple and can be swiftly optimized. The number of communication links between the system's nodes needed to realize this approach is limited compared to the centralized control even while achieving the voltage regulation tasks.

The proposed algorithm is applied to the PG&E 69-bus system [104]. The optimal partitioning layout is obtained based on the modularity concept. Accordingly, the PG&E 69-bus system is partitioned into nine mitigation zones, as shown in Figure 4-13. The obtained mitigation zones are then ranked according to the ZCI, as shown in Table 4-6. The optimization problem is solved in 2.334 s for all the mitigation zones following the prioritized sequence. Note that although the system size is doubled from the 33-bus system to the 69-bus system, the computational time for the optimization problem is increased by only 16.7%. This is because the algorithm for network partitioning is run offline and therefore does not affect the computational time of the proposed mitigation algorithm.

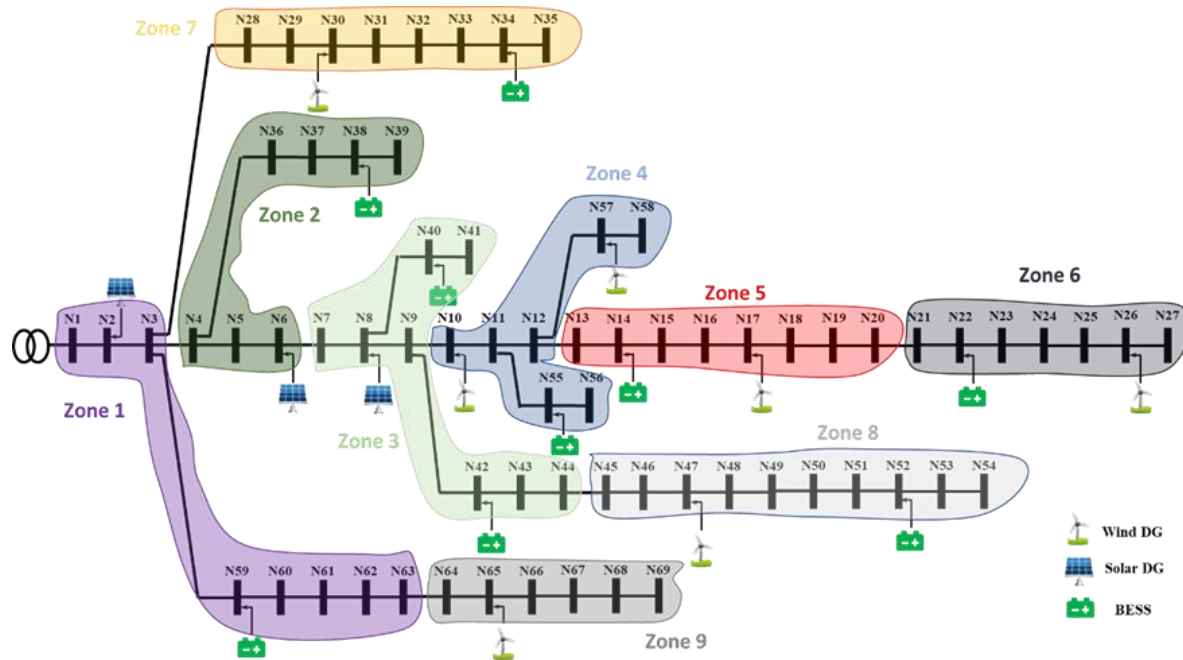


Figure 4-13 Mitigation zone boundaries of PG&E 69-bus system under modularity concept

Table 4-6
RANKING OF MITIGATION ZONES FOR PG&E 69-BUS SYSTEM

Mitigation Zone	Buses	ZCI	Rank	Optimization Computation Time (s)
Z_1	1-3, 59-63	0.211	1	0.181
Z_2	4-6, 36-39	0.024	8	0.181
Z_3	7-9, 40-44	0.111	5	0.187
Z_4	10-12, 55-58	0.075	7	0.488
Z_5	13 - 20	0.103	6	0.587
Z_6	21 - 27	0.118	4	0.179
Z_7	28 – 35	0.202	2	0.169
Z_8	45 – 54	0.005	9	0.184
Z_9	64 - 69	0.146	3	0.178
Total optimization problem time=2.334 s				

In another case study, the proposed algorithm is applied to a modified IEEE 123-bus system. The optimal partitioning layout is obtained based on the modularity concept. Accordingly, the IEEE 123-bus system is partitioned into ten mitigation zones, as shown in Figure 4-14. The obtained mitigation zones are then ranked according to the ZCI, as shown in Table 4-7. The optimization problem is solved in 2.617 s for all mitigation zones following the prioritized sequence. In this case, the system size is almost quadrupled from a 33-bus to a 123-bus system, but the computation time for the optimization problem is increased by only 30.85%.

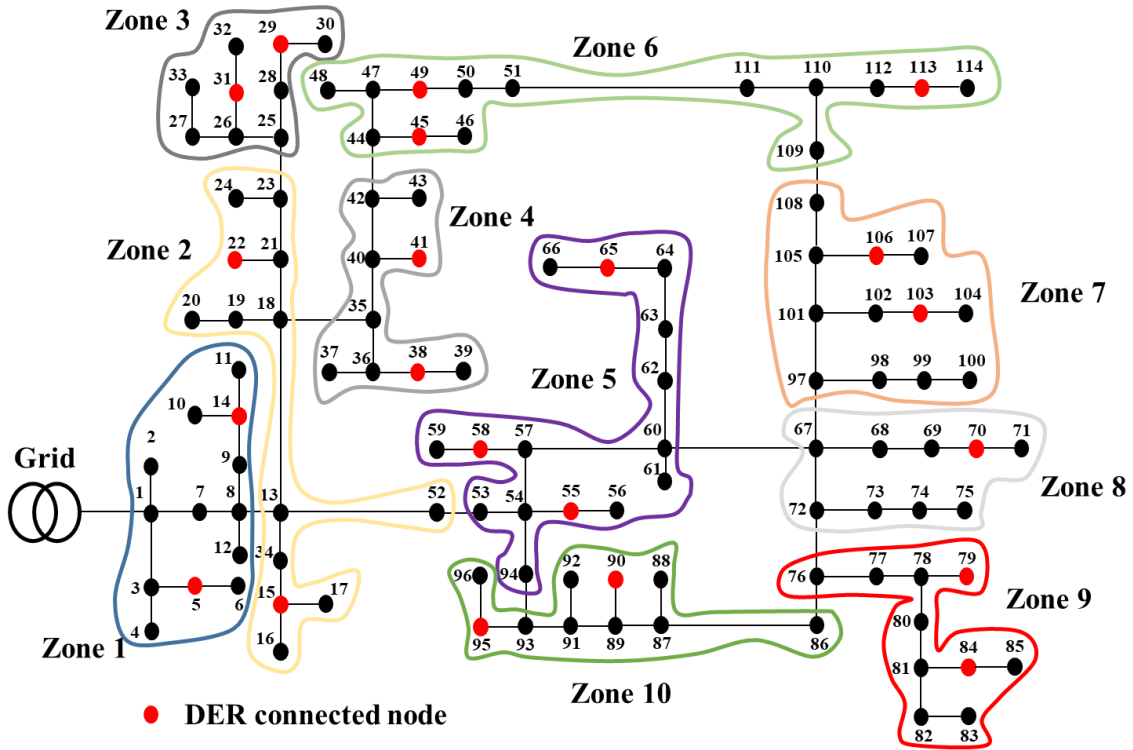


Figure 4-14 Mitigation zone boundaries of IEEE 123-bus system under modularity concept

Table 4-7
RANKING OF MITIGATION ZONES FOR IEEE 123-BUS SYSTEM

Mitigation Zone	Buses	ZCI	Rank	Optimization Computation Time (s)
Z_1	1-12, 14	0.087	4	0.194
Z_2	13, 15-24, 34, 52	0.079	8	0.246
Z_3	25-33	0.167	2	0.198
Z_4	35-43	0.168	1	0.192
Z_5	53-66, 94	0.067	10	0.258
Z_6	44-51, 109-114	0.080	7	0.463
Z_7	97-108	0.081	6	0.345
Z_8	67-75	0.068	9	0.295
Z_9	76-85	0.081	5	0.231
Z_{10}	86-96	0.116	3	0.195
Total optimization problem time=2.617 s				

The graph of the computational time versus the number of buses is shown in Figure 4-15. A curve fitting is used to extrapolate the trend. It is clear from the figure that the proposed algorithm can be used for larger systems without any difficulty.

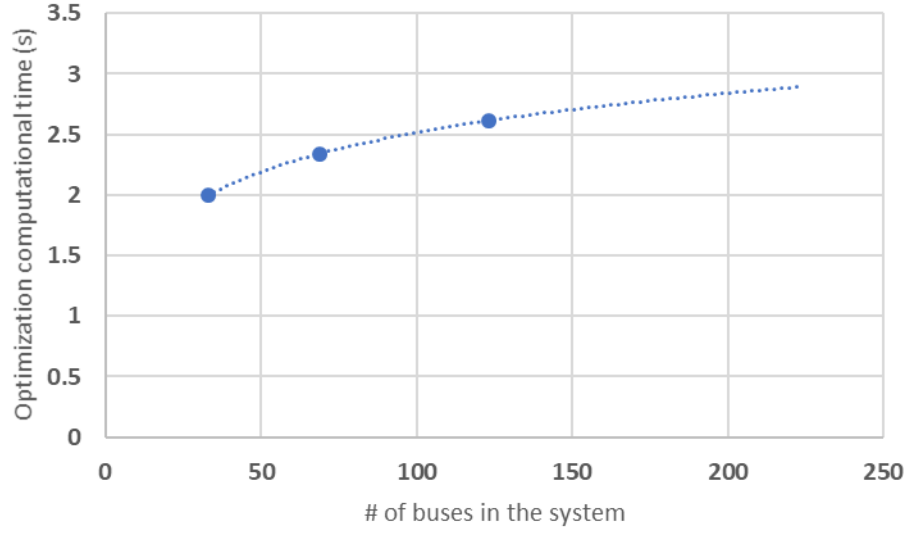


Figure 4-15 Optimization computational time vs number of buses

In summary, the proposed partition-based algorithm mitigated the voltage-sag problem with a minimum number of energy injections and avoided unnecessary usage of available resources. Moreover, in the case of practical ADSs that include a considerable number of buses, the centralized approach is expected to have a slow response, so it is challenging to mitigate the voltage-sag problem within the intended period (i.e., less than 1 min).

4.7.4 Proof of Concept Using the System's Dynamic Model

The IEEE 33-bus system is modelled using MATLAB/SIMULINK to simulate the system's dynamics when reference injections from the optimization algorithm are broadcasted. All inverter-based DERs are modelled using the block diagram shown in Figure 4-16. DERs are assumed to be controlled in the PQ-mode with reference power injections. Any changes in injections (i.e., ΔP and ΔQ) are added to the setting values $P_{setting}$ and $Q_{setting}$ dispatched from the DSOs to establish the reference values for the controllers. Under normal operating conditions, the changes in injections are zeros unless values are sent through agents to the DER. Thus, considering the random occurrence of voltage-sag, each DER will be able to follow its active/reactive power reference seamlessly to control its injected active/reactive power in real-time.

A voltage-sag event is assumed to start at $t = 1$ s, and the system is assumed to return to normal operations at $t = 4$ s. The optimization problem, formulated in (15-20), is solved in less than two seconds for all the mitigation zones following the prioritized sequence. Moreover, while the optimization problem is solving, the injection changes are distributed to zone agents and are assumed

to be available to all DERs following the prioritized sequence. Figure 4-17 shows the timeline of the proposed voltage-sag mitigation algorithm and the required injection from each mitigation zone.

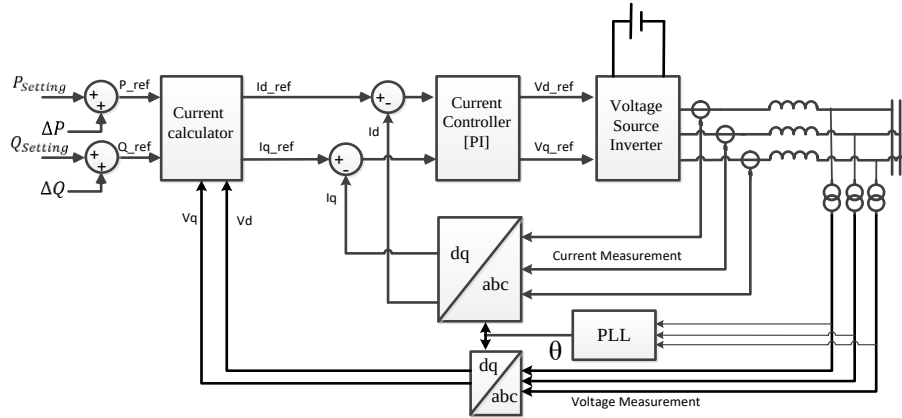


Figure 4-16 Inverter-based DER dynamic model

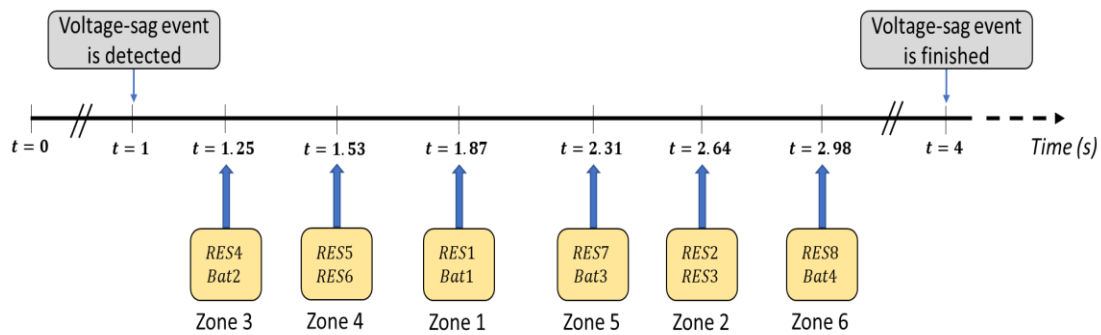
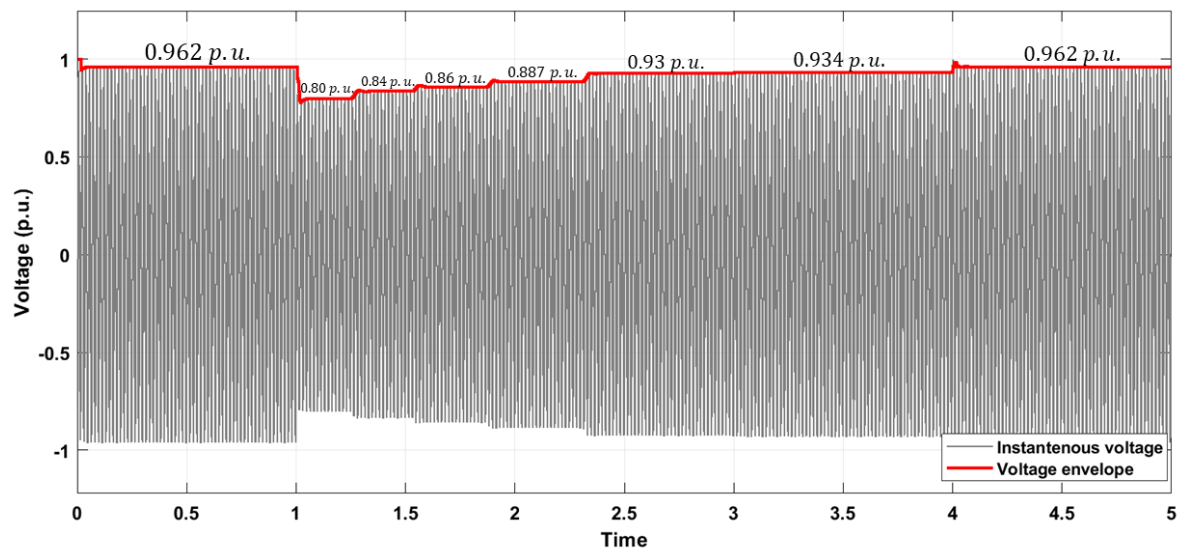
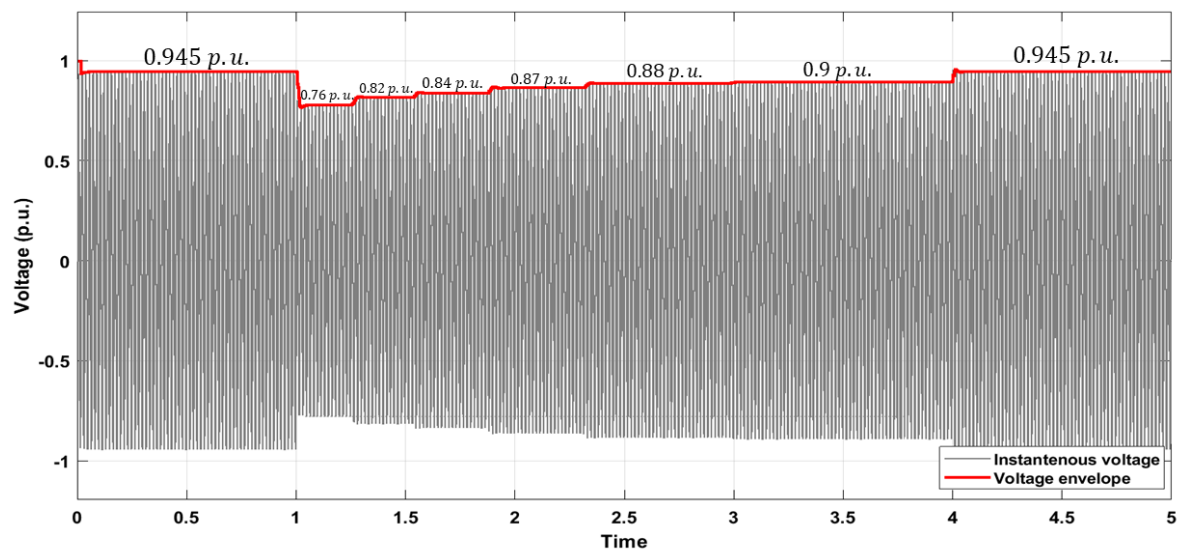


Figure 4-17 Timeline of proposed voltage-sag mitigation algorithm

The voltage profile at bus-33 and bus-18 are shown in Figure 4-18 for the simulation time horizon. In addition, the required power injections from RES6 and Bat1 are illustrated in Figure 4-19, for the simulation time horizon.

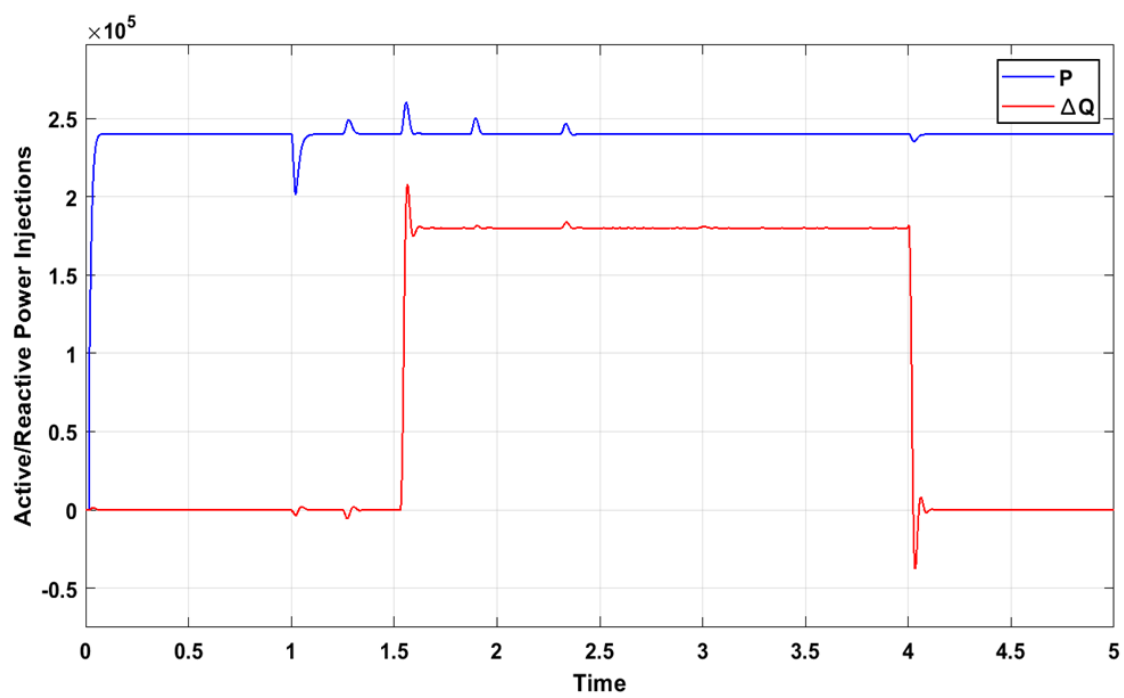


(a) V_{N18}

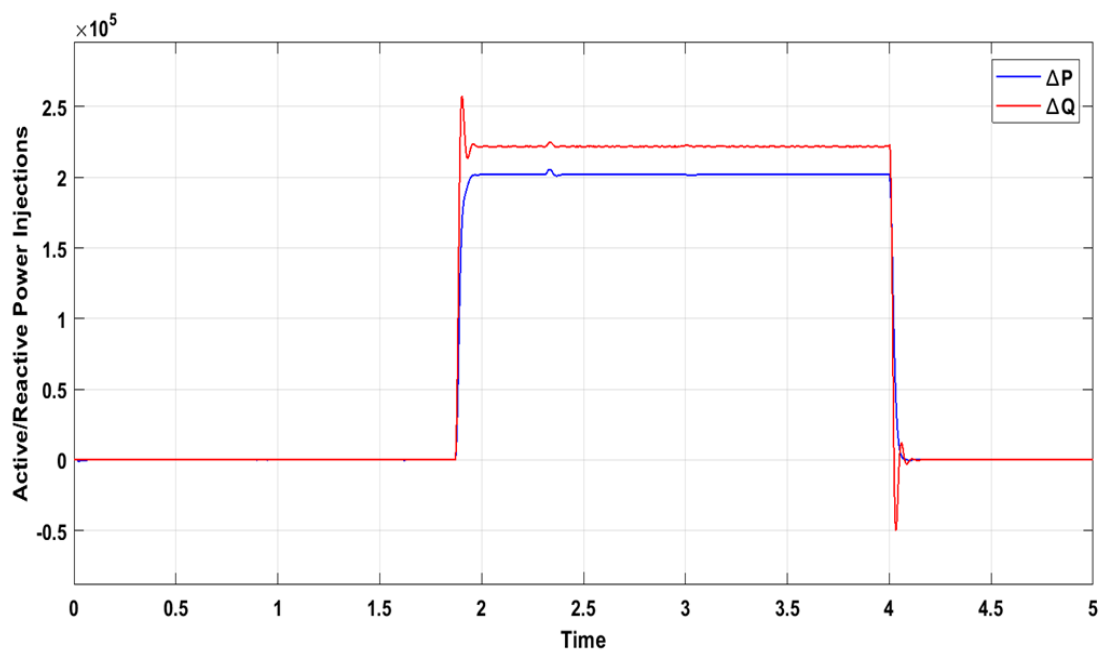


(b) V_{N33}

Figure 4-18 Voltage profile at (a) bus-18 and (b) bus-33



(a) RES6



(b) Bat1

Figure 4-19 Active/reactive power injections from (a) RES6 and (b) Bat1

4.7.5 Comparison with Benchmark Voltage-sag Mitigation Scheme

The partition-based and centralized approaches are executed at the system level and are based on utilizing the available kVA capacity from the DERs' inverters. On the other hand, integrating a DVR that is dedicated only to solving the voltage-sag problems at the point of connection is considered as a local solution for the problem. For benchmark comparison, a DVR is installed at bus 33, which experiences the lowest voltage in the system. The optimization model is solved with one source (i.e., DVR), while an injection of 1248 kVA is required to boost the voltage at bus-33 to 0.9 p.u. The investment cost of the DVR is given as 500 US\$/kVA [108]. Consequently, the system level mitigation through installed DERs can save approximately 624,225 US\$ for the system under study.

Figure 4-20 presents the regulated voltage profiles under the two management schemes, namely the proposed system-level partition- and non-partition-based algorithms, and the DVR benchmark scheme. As shown in the figure, the benchmark scheme failed to mitigate the voltage-sag event for the system under study, as the mitigation is executed locally.

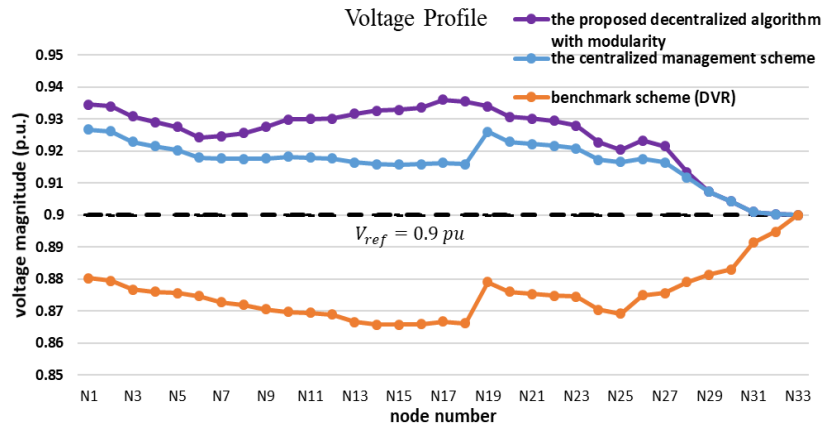


Figure 4-20 Voltage magnitude profile under two different control algorithms

According to the aforementioned discussion, both of the system-level schemes have successfully solved the voltage-sag problem for the system under study. However, the obtained results reveal that the proposed partition-based algorithm is the most effective solution for mitigating voltage-sags.

4.8 Conclusion

The growing deployment of DERs in distribution systems offers considerable kVA capacity that can be utilized to improve system performance. Further, the utilization of already existing kVA capacity will achieve several techno-economic benefits for both system operators and DER owners. This chapter considered the contribution of DERs to the efforts of voltage-sag mitigation, working from the premise

that the algorithms have to be fast and accurate. In order to speed up the optimization process and reach accurate mitigation of voltage-sag event, a novel network partitioning technique was proposed. The network is partitioned according to a voltage sensitivity study, with the system being divided into smaller mitigation zones for zonal voltage control. A novel ZCI based on the available kVA capacity in DERs and average voltage magnitude in each zone was also proposed to prioritize the available mitigation zones. For each mitigation zone, an active/reactive power-voltage zonal control scheme was introduced to mitigate the voltage-sag problem based on the presented optimization problem.

This chapter presented two more network partitioning techniques: the modularity index concept and the minimum PF concept. These two techniques differ from the first technique introduced in Chapter 3. A detailed discussion was presented for the optimization problem executed in each zone following the priority sequence to achieve the overall goal. Eventually, the proposed algorithm's effectiveness was evaluated by applying the algorithm to several standard distribution systems to ensure the success and speed of the algorithm. The results indicate that the zone-based algorithm has successfully and optimally mitigated the voltage-sag problem. The proposed algorithm is kept generic and can be applied to different ADSs. It worth mentioning that the system partitioning is virtual and used to run the optimization technique while the physical system stays intact. However, the physical partitioning of the system may be used as another tool to mitigate voltage-sags beyond this approach's capability.

The information on voltage-sag origin (Chapter 3) will help mitigate voltage-sags that could not be overcome via the capacity of available DERs. Thus, the mitigation sub-routine proposed in this chapter will be successful if the fault is upstream from the system's PCC and the voltage-sag depth is within the mitigation technique's capability. However, if the fault is within the system boundary (i.e., downstream from the PCC), the voltage-sag origin should be isolated, which can be achieved based on the information found by the second action running in the background. Hence, if the voltage-sag mitigation requirements (i.e., injection of active and reactive powers) are beyond the DERs' capability (i.e., voltage-sag is partially mitigated), some parts of the system will face unintentional islanding. To avoid this unintentional islanding, the planning of intentional islanding is discussed in the next chapter. Specifically, a voltage-sag mitigation algorithm is proposed based on a new network partitioning technique denoted as a stability-constrained partitioning scheme.

Chapter 5

Voltage-Sag Mitigation by Stability-Constrained Partitioning Scheme

5.1 Introduction

Microgrids have the ability to function in islanded or grid-connected modes of operation. The increased penetration of inverter-based DERs in the system promotes the concept of self-governing and self-adequate microgrids. Many research works have proposed the intentional islanding of microgrids during emergencies to improve supply continuity [51]. However, the survivability of these microgrids in terms of supply adequacy and stability is questionable, and stability studies should have been incorporated.

In this chapter, a stability-constrained partitioning scheme is proposed based on small-signal stability to ensure the microgrids' survivability when physically partitioned. Moreover, a sensitivity analysis of active and reactive power droop gains is utilized to establish a novel index for microgrid marginal stability. This intentional islanding will be achieved by partitioning the system into clusters of survivable microgrids, thus isolating the faulted zone that caused the voltage-sag event. By isolating the voltage-sag origin from the rest of the system, voltage-sag mitigation is accomplished, as will be discussed in this chapter.

The structure of this chapter is arranged as follows. Details on the proposed stability-constrained partitioning scheme are presented in section 5.2. The next section 5.3 provides the stability analysis and power flow algorithm for the microgrids. Finally, a case study is performed in section 5.4 to evaluate the effectiveness of the proposed voltage-sag mitigation algorithm.

5.2 Stability-Constrained Partitioning Scheme

This section presents a framework for partitioning the system into survivable microgrids based on Small-Signal Stability (SSS). The proposed framework examines the eigenvalues of the constructed microgrids to establish a Stability-Constrained Partitioning Scheme (SCPS). This partitioning scheme is valuable for DSOs to ensure the continuity of service during emergencies by partitioning the system into survival and self-adequate microgrids and then isolating the affected portion of the network. The approach would help to isolate the voltage-sag origin and thus mitigate a severe voltage-sag problem that lasts more than a previously specified critical time duration, as will be explained later.

In our study, the system is assumed grid-connected and is running in a stable normal-operation mode. This assumption is valid up to the instant before the occurrence of voltage-sag. According to IEEE 1547-2018 [109], all the DERs in the system should remain intact within the system up to a previously specified critical time duration (e.g., ten seconds from the voltage-sag instant for voltage-sags up to 50%). Beyond this critical time duration, the DERs start to feed the fault in the system, and it must be disconnected from the system. Therefore, to avoid islanding the DERs and thus disconnecting the resources from the system, the system will be partitioned into clusters of survivable microgrids. The microgrid that contains the origin of the voltage-sag (i.e., the fault) will not be survivable, but this will be addressed in the upcoming chapter. A stability-constrained partitioning scheme is proposed to divide the system into a number of stable MGs. The general procedures of the proposed framework are presented in Figure 5-1.

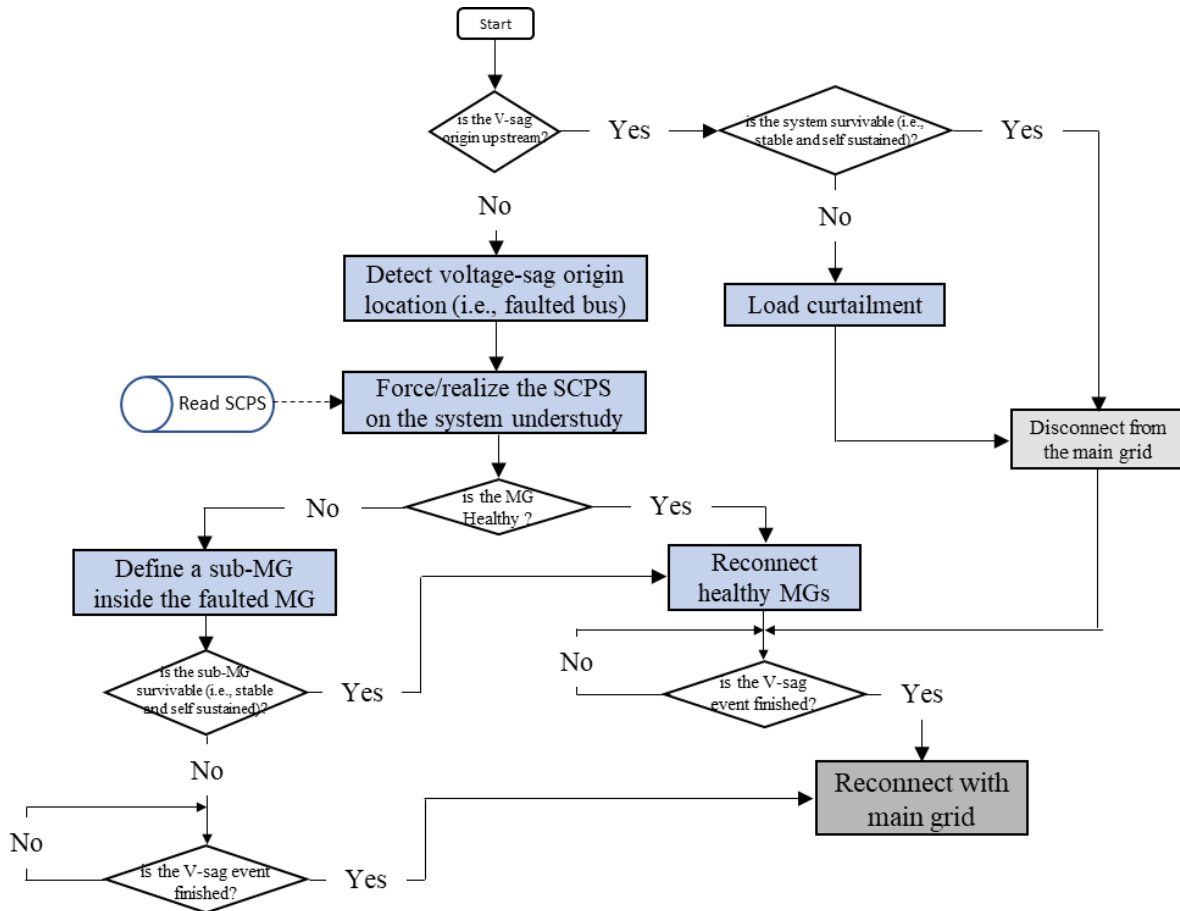


Figure 5-1 Flowchart of proposed mitigation scheme

In the beginning, the MGs' borders are defined based on the minimum power flow partitioning scheme proposed in [104] to ensure the self-adequacy of the constructed microgrids. However, a

stability study based on the investigation of the system's eigenvalues is utilized to examine the stability of each of the candidate MGs. From these steps, the stability-constrained partitioning scheme is obtained and will be available for the DSO. The key result from this study is the critical droop gains resulting in the MG's instability. These droop gain values will be denoted as $m_{th,i}$, where i is the number of the DER. The numerical value of m_{th} for various DERs will differ, as will be shown later in the case study. A novel index for MG stability is defined, referred to as the marginal stability index (SI). It can be expressed as:

$$SI = \frac{m_{th,i} - m_{min}}{m_{max} - m_{min}} \times 100 \quad (5-1)$$

where SI is a unique index for the MG and is not affected by the rating of a specific DER, and m_{max} and m_{min} are the maximum and minimum allowable droop gain values, respectively. When operating with m_{th} , the MG's frequency will deviate from the nominal frequency by $\Delta f = m_{th} \times P_G$. This index determines the highest acceptable frequency deviation of the MG from the nominal frequency before it becomes unstable. A larger SI indicates a more stable MG against frequency deviation.

A later stage deals with the voltage-sag event when it lasts more than the allowable time for DERs to be intact (i.e., critical time $t_{critical}$) or when the voltage-sag mitigation requirements (i.e., injection of active and reactive powers) are beyond the DERs' capability. The proposed algorithm in this chapter is intended to initiate the physical partitioning of the system. This intentional islanding will be achieved by partitioning the system into clusters of survivable microgrids (i.e., SCPS). The SCPS is formulated in the background (i.e., offline) and stored in the database. Therefore, at any time, it is assumed that the system operator knows the stability-constrained borders and the SI for each MG.

The objective of the partitioning is to isolate the voltage-sag origin from the rest of the system in order to improve supply continuity and system reliability. Moreover, based on the information about the location of the voltage-sag origin (i.e., Chapter 3), the status of all switches is updated to isolate the faulted part. The faulted bus number is then communicated to all the agents of the MGs formed according to the SCPS. If the faulted bus lies within the MG's boundary, a flag will be set to 0 to indicate a "Faulted MG" status. Otherwise, the flag will be set to 1 to indicate a "Healthy MG" status.

The boundary switches are now accountable for actions. If the boundary switch is located at the boundary of a faulted MG, it opens; otherwise, it stays connected. These simple actions will disconnect the "Faulted MG" from the healthy ones. To isolate the affected part within the faulted MG and keep supplying the load as possible, a restoration sub-routine is developed to be run in case the MG's flag

indicated a faulty status. This restoration sub-routine is initiated within each faulted MG and accomplished by following the four steps below:

- 1) Identify the DG buses from the database, e.g., for the system in Figure 5-2, DG connected buses are {2, 9, and 11}, and the voltage-sag origin (i.e., faulted bus) is {4}.
- 2) Identify the shortest path connecting DG buses to faulted bus for each DG by using Dijkstra's shortest-path algorithm [110], e.g., path {2-3-4}, path {9-8-7-3-4}, and path {11-5-4}.
- 3) Open the branch associated with the faulted bus if that branch is in one of the paths in Step 2, e.g., branch {3-4} and {5-4}.
- 4) Create new healthy sub-microgrids from the rest of the system, e.g., sub-MG1, sub-MG2.
- 5) Check the survivability of the created sub-microgrids.

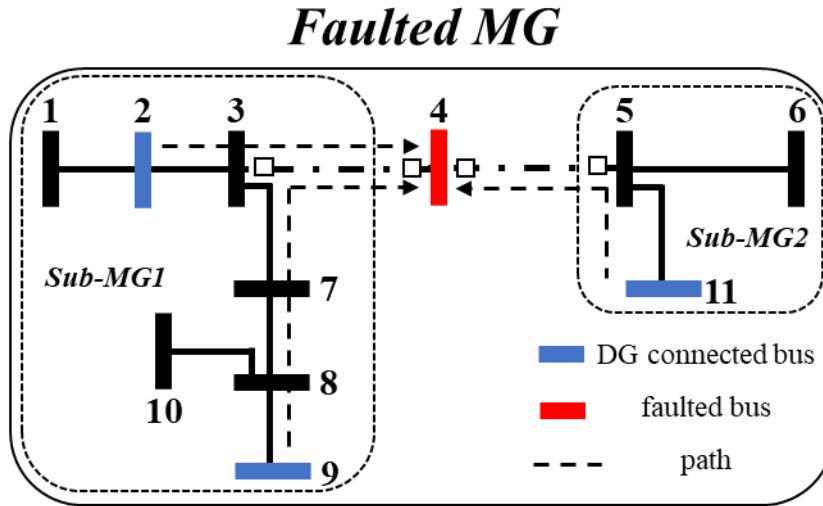


Figure 5-2 Sample case for restoration sub-routine

The healthy MGs stay intact, while the faulted MG is identified and the healthy part of it is isolated (referred to as sub-MGs). A healthy flag is introduced to determine the status of each MG. For example, the healthy flag for every healthy MG will equal one.

A Multi-Agent System (MAS) is proposed to execute the control actions required to isolate the voltage sag-origin. Each MG is assigned an agent located on the terminal bus of the MG. The agent represents the MG and executes a variety of functions, such as supervisory control of all DERs within the MG's boundaries, communication with neighbouring MG agents, control of MG isolation switches, and two-way communication with the PMUs within the MG's boundaries. Moreover, each MG's agent has access to the following information with its MG: bus voltage, current in the feeder, droop gain value for DERs, and MG topology. If there are several healthy neighbouring islanded microgrids, a

reconnection sub-routine is initiated to reconnect these microgrids together. Details of the MG reconnection routine is explained in the next chapter.

Given the dependency of the proposed framework on the communication between agents, the communication delays should be considered in the study. According to [111], the communication delay depends on several reasons, such as discrete Fourier transform, data concentration, the amount of data transmitted, type of communication link, transducer delays, processing time, propagation delay, and data rate. Associated delays in the proposed framework are presented in Figure 5-3. It is worth mentioning that the delay of the voltage-sag identification algorithm presented in Chapter 3 is less than 11 ms , and that the information about the voltage-sag origin is assumed to be available before the pre-specified critical time ($t_{critical}$). Therefore, the overall delay in the proposed framework is about 300 ms from the localization of the fault to the receipt of the control signals.

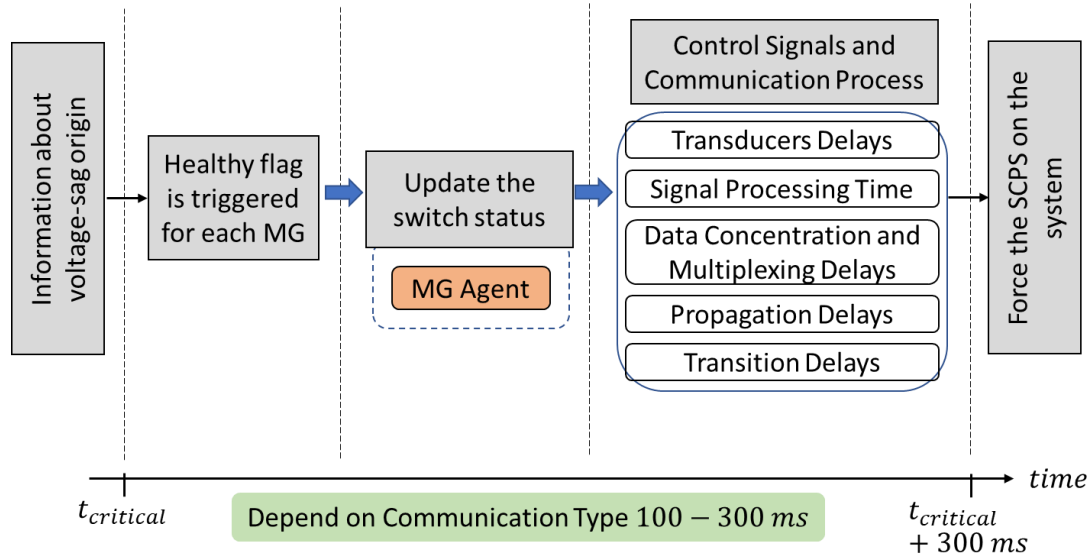


Figure 5-3 Associated delays to proposed voltage-sag mitigation framework

To summarize, the proposed voltage-sag mitigation algorithm based on the SCPS is accomplished by following these five steps:

- 1) Recall the FI algorithm (presented in Chapter 3) to locate the voltage-sag origin (i.e., faulted bus).
- 2) Identify the faulted MG in the system according to the healthy flag of each MG.
- 3) Update each switch's status and force the SCPS on the system (the faulted MG is now isolated from the rest of the system).

- 4) Within the faulted MG, initiate the restoration sub-routine to isolate the faulted part from the healthy part(s) of the faulted MG (i.e., sub-MG).
- 5) Initiate the recovery algorithm for post-voltage-sag mitigation (as will be presented in Chapter 6).

5.3 Stability Analysis and Power Flow Algorithm for MGs

The proposed voltage-sag mitigation framework for voltage-sags lasting more than ten seconds or exceeding the available DERs' capabilities depends on converting the affected system into a number of survivable MGs. In order to establish the survivable MGs, their borders need to be defined based on self-adequacy and stability. Therefore, an operational planning tool is developed to establish the stability-constrained partitioning scheme discussed in the previous section. For each MG, all DERs are assumed to be using droop control for P and Q to share the demand between inverters. Small-signal stability models are used to study the stability of the MG, which requires an operating point, and a power flow algorithm for islanded microgrids is used to calculate the operating conditions for each MG (i.e., the voltage at each bus and current in each line) according to the chosen droop gain value for each DER. The small-signal stability analysis can be studied for all of the MGs individually, and the eigenvalues can be defined by developing the state-space models for the different MGs' components (e.g., inverters, network, and dynamic loads).

5.3.1 Stability Analysis for Microgrids

In [112], modelling is used as a tool to study MG stability, and a comprehensive approach is introduced to model an inverter-based MG. The outer power loop depends on the droop control of each DER inverter for sharing the fundamental P and Q with other DERs. Internal inverter controls include both voltage and current controllers, which are responsible for damping the output LC filter and blocking high-frequency disturbances to avert any resonance with the system. The various components of individual inverters (i.e., the three controllers, output LC filter, and coupling inductor on a Synchronous Reference Frame [SRF]) are considered when formulating the Small-Signal State-Space Model (SSM). The power controller of that inverter determines the rotation frequency of the SRF. A common SRF is arbitrarily determined according to one of the DER inverters' frames.

By using these simple transformation techniques, all of the DER inverters in the system are transferred to the chosen SRF. It is inadequate to formulate the SSM of the network with state-less impedance models while considering full-order DER inverter models that contain high-frequency modes. However, a dynamic SSM of the network can be modelled on the common SRF. In this way, a

complete SSM of the MG can be modelled in order to calculate the eigenvalues (i.e., modes) for studying the MG's stability.

Active power-sharing in the droop control mode of operation is achieved by relating the droop characteristics to the frequency of the DER output voltage at the PCC, as follows:

$$\omega_o = \omega^* - m_p P_G \quad (5-2)$$

where ω_o represents the angular frequency of the DER output voltage, ω^* represents the reference value of the frequency, m_p is defined as the droop gain of the active power, and P_G is the 3-ph injected active power from the DER. According to (5-2), negative feedback is provided by the droop characteristic to ensure that all the DERs are synchronized and generating voltages with the same angular frequency that follows the system angular frequency at a steady-state [112]. In contrast, by controlling the DER output voltage magnitude, the Q sharing among the different DERs in the MG is accomplished. This droop control is achieved in a dq frame that rotates with the angular speed ω . Similarly, reactive power-sharing in the droop control mode of operation is achieved by relating the droop characteristics to the magnitude of the DER output voltage at the PCC, as follows:

$$v_{od} = V^* - n_q Q_G, \quad v_{oq} = 0 \quad (5-3)$$

where v_{od} and v_{oq} are the d – axis and q – axis components of the DER output voltage, respectively; V^* represents the reference value of output voltage in the d – axis; n_q is defined as the droop gain of the reactive power; and Q_G is the output 3-ph reactive power from the DER. According to (5-3), the inverter's SSM only considers the output voltage magnitude in the d – axis component of the SRF, and q – axis component of the output voltage equals zero.

The voltage and frequency standards determine the droop gain values for the DER unit (m_{pi}, n_{qi}), as follows:

$$m_{pi} = \frac{\omega_{max} - \omega_{min}}{P_{Gi,max}} \quad (5-4)$$

$$n_{qi} = \frac{|V_i|_{max} - |V_i|_{min}}{Q_{Gi,max}} \quad (5-5)$$

where ω_{max} and ω_{min} are the maximum and minimum frequency standards, respectively; $|V_i|_{max}$ and $|V_i|_{min}$ are the maximum and minimum voltage magnitude standards, respectively; and $P_{Gi,max}$ and $Q_{Gi,max}$ represent the DER inverter rating of active and reactive power, respectively. The minimum

and maximum standard values of the frequency and voltage magnitude are chosen according to the allowable voltage and frequency regulation [112]. To achieve the proportional sharing of active and reactive powers, the $P - \omega$ and $Q - V$ droop gain values in DERs, respectively, are calculated as:

$$m_{p1} \cdot P_{G1,max} = m_{p2} \cdot P_{G2,max} = \dots = m_{pi} \cdot P_{Gi,max} \quad (5-6)$$

$$n_{q1} \cdot Q_{G1,max} = n_{q2} \cdot Q_{G2,max} = \dots = n_{qi} \cdot Q_{Gi,max} \quad (5-7)$$

The control structure of a droop-controlled DER comprises different components, as shown in Figure 5-4. The power circuit of the DER inverter consists of 1) the DC source of the DER, 2) the interfacing inverter, and 3) the output LC filter in order to block the switching harmonics formed by the DER unit.

Three nested control loops are considered for each DER controller. The outermost control loop is responsible for achieving the proportional power-sharing between the different DERs. First, the required power-sharing functionality is determined by the power-sharing control loop. According to the droop gain equations illustrated in (5-2) and (5-3), the reference value of the frequency and voltage magnitude of the fundamental output voltage at the PCC are generated. The voltage and current control loops are responsible for realizing this reference voltage waveform at the PCC.

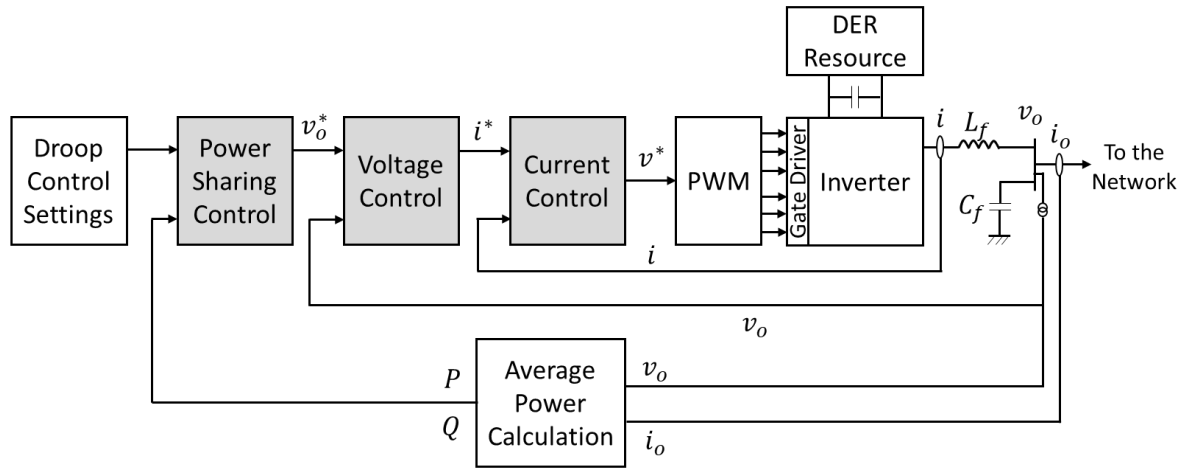


Figure 5-4 Control structure of droop-controlled DER

Specifically, the voltage across the LC filter capacitor is controlled by the middle control loop (i.e., the voltage controller) by obtaining the LC filter's reference signal inductor current, and the LC filter inductor current is controlled by the innermost control loop (i.e., current controller) by obtaining the reference output voltage of the inverter.

The inverter output voltage rotates synchronously with angular speed ω in Park's dq frame. The following equations express the output current and voltage dynamics:

$$\frac{di_d}{dt} = \frac{-r_f}{L_f} i_d + \omega i_q + \frac{1}{L_f} (v_d - v_{od}) \quad (5-8)$$

$$\frac{di_q}{dt} = \frac{-r_f}{L_f} i_q - \omega i_d + \frac{1}{L_f} (v_q - v_{oq}) \quad (5-9)$$

$$\frac{dv_{od}}{dt} = \omega v_{oq} + \frac{1}{C_f} (i_d - i_{od}) \quad (5-10)$$

$$\frac{dv_{oq}}{dt} = -\omega v_{od} + \frac{1}{C_f} (i_q - i_{oq}) \quad (5-11)$$

where v_d , v_q , i_d and i_q are the voltages and currents of the inverter in the d – axis and q – axis; v_{od} , v_{oq} , i_{od} and i_{oq} are the output voltages and currents of the DER in the d – axis and q – axis, and r_f , L_f and C_f are the per-phase resistance, inductance, and capacitance of the LC filter, respectively.

The instantaneous injected active (p) and reactive (q) power components are given by:

$$p = v_{od} i_{od} + v_{oq} i_{oq} \quad (5-12)$$

$$q = v_{od} i_{oq} - v_{oq} i_{od} \quad (5-13)$$

The instantaneous components of the active and reactive powers flow in the low-pass filter in order to obtain the fundamental component of the average real P and reactive Q powers, as follows:

$$P = \frac{\omega_c}{s + \omega_c} p \quad (5-14)$$

$$Q = \frac{\omega_c}{s + \omega_c} q \quad (5-15)$$

where ω_c is the cut-off frequency of the low-pass filter.

Based on the obtained P and Q power components, the droop gain equations illustrated in (5-2) and (5-3) are considered for the fundamental output voltage and frequency of the DER. Inverter output voltage control is implemented to provide close voltage regulation. The controller adapts standard Proportional-Integral (PI) regulators to obtain the reference current vector through the decoupling and feed-forward control loops. The following equations express the voltage controller's dynamics:

$$i_d^* = K_{pv}(v_{od}^* - v_{od}) + K_{iv} \int (v_{od}^* - v_{od}) dt - \omega^* C_f v_{oq} + i_{od} \quad (5-16)$$

$$i_q^* = K_{pv}(v_{oq}^* - v_{oq}) + K_{iv} \int (v_{oq}^* - v_{oq})dt + \omega^* C_f v_{od} + i_{oq} \quad (5-17)$$

where K_{pv} and K_{iv} are the proportional and integral gains of the voltage control loop, respectively.

The voltage across the filter inductor is shaped by the current controller to guarantee the minimum current error. A regular PI current regulator is employed for current regulation through the decoupling and feed-forward control loops. The following equations express the current controller's dynamics:

$$v_d^* = K_{pi}(i_d^* - i_d) + K_{ii} \int (i_d^* - i_d)dt - \omega^* L_f i_q + v_{od} \quad (5-18)$$

$$v_q^* = K_{pi}(i_q^* - i_q) + K_{ii} \int (i_q^* - i_q)dt + \omega^* L_f i_d + v_{oq} \quad (5-19)$$

where K_{pi} and K_{ii} are the proportional and integral gains of the current control loop, respectively.

Equivalent differential equations express the time-domain models of the network and the load elements. Through this small-signal modelling of an MG, the homogeneous form of an MG can be expressed as follows:

$$\Delta \dot{x}_{MG} = A_{MG} \Delta x_{MG} \quad (5-20)$$

where x_{MG} refers to a vector containing all the state variables of the DERs, lines, and dynamic loads within the MG, all defined in the dq frame. From (5-20), the eigenvalues of the MG (denoted by λ) can be calculated as the roots of:

$$\det(\lambda I - A_{MG}) = 0 \quad (5-21)$$

where $\det(\cdot)$ refers to the determinate function and I represents the identity matrix of order A_{MG} .

At this stage, the active power droop coefficients of m_p can be increased from 0.05% *droop* to 1% *droop* around the operating point of m_{p_o} in very small steps for every DER to perform a sensitivity analysis. Similarly, the reactive power droop coefficients of n_q can be increased from 0.5% *droop* to 8% *droop* around the operating point of n_{q_o} in very small steps for every DER [112]. Based on the SI, defined in (5-1), the stability margin of each MG is defined to ensure the survivability of that MG, as shown in Figure 5-5.

Moreover, the SCPS is formulated in the background (i.e., offline) and stored in the database. According to the geographical location of voltage-sag origin (i.e., fault) in the system, all the switches'

statuses are updated to isolate the faulted microgrid from the rest of the system based on the restoration sub-routine. Moreover, all the healthy neighbour MGs should stay intact.

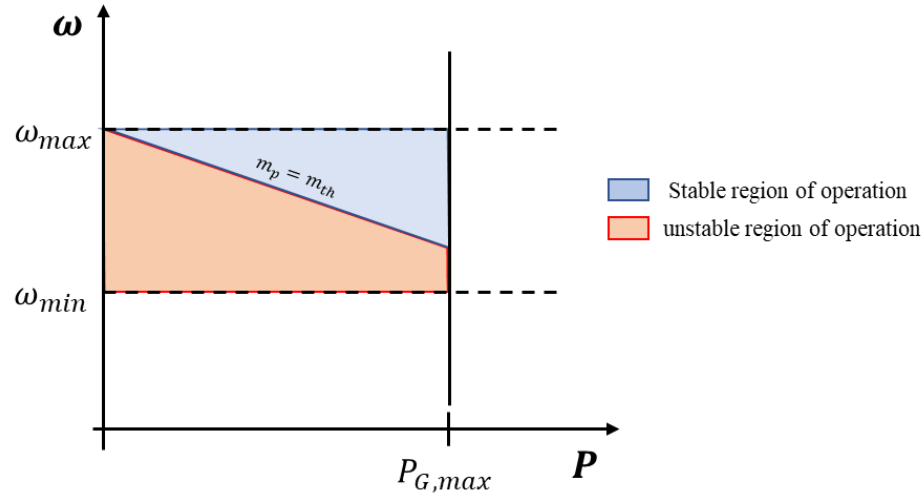


Figure 5-5 Stability margin based on SI

5.3.2 Power Flow (PF) Algorithm for Islanded Microgrids

As the droop values change to study the stability of the system, the operating point will also change. Hence, a power flow solution for the system is required to define the new operating point. A set of power flow equations is used to model droop-controlled MGs' overall steady-state behaviour [113]. Apart from traditional PF algorithms, PF formulation for droop-controlled MGs has different characteristics. First, droop-controlled DER units generate power according to the DER droop gain characteristics illustrated in (5-2) and (5-3). It should be noted that prior to solving the PF equations, the generated power cannot be pre-specified. Thus, for a DER operating with droop control, the 3-ph injected active and reactive power are expressed in the following PF equations:

$$P_G = \frac{1}{m_p} (\omega^* - \omega) \quad (5-22)$$

$$Q_G = \frac{1}{n_p} (|V|^* - |V|) \quad (5-23)$$

Second, no slack bus is able to keep the system frequency constant in a droop-controlled MG. Therefore, the SS frequency of the system is not previously specified, and frequency is considered as one of the PF variables. Finally, the unique philosophy of a droop-controlled microgrid operation can be reflected in the set of PF equations as follows. For each droop bus i , there are two mismatch equations:

$$\frac{1}{m_{pi}}(\omega^* - \omega) - P_{Li} = \sum_{j=1} (|V_i||V_j||Y_{ij}| \cos(\theta_{ij} + \delta_j - \delta_i)) \quad (5-24)$$

$$\frac{1}{n_{qi}}(|V_i|^* - |V_i|) - Q_{Li} = \sum_{j=1} (|V_i||V_j||Y_{ij}| \sin(\theta_{ij} + \delta_j - \delta_i)) \quad (5-25)$$

where P_{Li} and Q_{Li} are the load active and reactive power at bus i , respectively; Y_{ij} and θ_{ij} are the admittance magnitude and angle, respectively; and δ_i is the voltage angle at bus i .

The changes in system voltage and frequency caused by changes in the P_L and Q_L requirements should be modelled accurately. The load characteristics of voltage dependency are illustrated based on a static load model, as follows:

$$P_L = P_o \left(\frac{|V|}{|V_o|} \right)^\alpha \quad (5-26)$$

$$Q_L = Q_o \left(\frac{|V|}{|V_o|} \right)^\beta \quad (5-27)$$

where P_o and Q_o are the nominal operating point of active and reactive powers at the rated voltage V_o , respectively, and α and β are the active and reactive power exponents. For constant impedance, constant current, and constant power models, the α and β are equal to twos, ones, and zeros, respectively. For residential, industrial, and commercial loads, the values of α and β are given in [114].

5.4 Case Study

The proposed voltage-sag mitigation algorithm is tested and validated on the IEEE 33-bus distribution network. This section uses the small signal stability analysis presented in section 5.3 to assess the marginal stability of the system under study and the survivable MGs. To this end, the proposed SI is utilized to express the marginal stability of each MG based on the sensitivity analysis of the m_p and n_q . The stability constrained partitioning scheme is then forced on the system to isolate the voltage-sag origin from the system.

5.4.1 System Under Study

A modified three-phase balanced 12.66 kV IEEE 33-bus distribution network with DERs at some candidate buses is selected to prove the effectiveness of the proposed mitigation framework. The topology of the system with candidate DER locations is shown in Figure 5-6. The specific parameters

for the DERs are listed in Table 5-1. These DERs are controlled via droop-control in the islanded mode of operation to share the real and reactive powers in their MG.

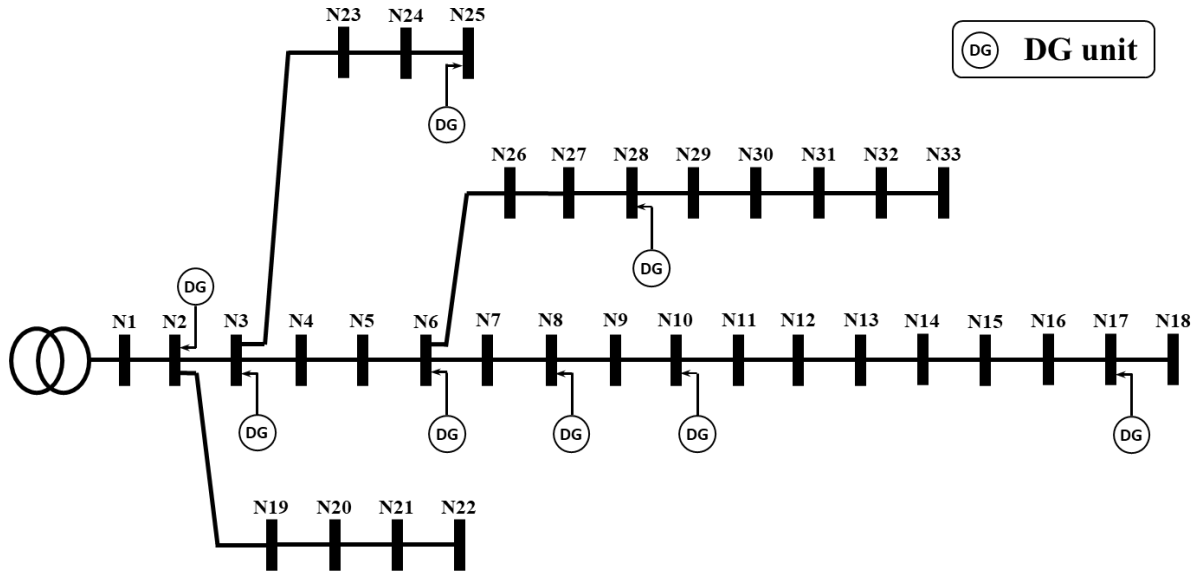


Figure 5-6 Topology of system under study

Table 5-1
CAPACITY AND LOCATION OF DERs

DER	Location	Unit Capacity (kVA)
RES	2, 6, 28, 17	600
RES	3, 10	800
RES	8, 25	400

In this case study, the installed DERs have different ratings. Hence, the m_p and n_q of each DER are selected according to (4-4) and (4-5) so that the fundamental powers are shared proportionally to their ratings. The initial frequency droop, at the $P_{G,max}$, is 0.5% and the initial voltage droop, at the $Q_{G,max}$ is 4%. As various types of DERs can exist in different scenarios, the system operators determine the droop gains and sharing ratios based on economic interest [115].

5.4.2 Stability Constrained Partitioning Scheme

The fault location that initiated the voltage-sag is determined to be upstream or downstream from the system under study, as explained in Chapter 3. If the fault is upstream, the whole system needs to disconnect and isolate itself, if survivable. However, if the fault is downstream, the system should be partitioned based on the framework presented in this chapter. Thus, two scenarios are considered to examine the small-signal stability of the system under study. The first scenario shows the system's

operating stability margin as bulk when the voltage-sag origin is upstream. In the second scenario, the operating stability margin is studied for all MGs within SCPS when the voltage-sag origin is downstream.

Based on the fault identification method presented in Chapter 3, the faulted MG is identified. The exact faulted bus or branch is then detected inside the faulted MG to allow for microgrid restoration. The different system parameters used in the case studies are given in Table 5-2. Based on the power flow algorithm outlined in section 5.3.2, the steady-state operating points have been obtained for each operating scenario.

Table 5-2
SYSTEM PARAMETERS

Inverter Parameters							
Par.	f_s	L_f	C_f	r_f	L_c	r_{L_c}	w_c
Value	8 KHz	3 mH	3 μF	0.03 Ω	1 mH	0.03 Ω	31.41
Par.	m_p	n_q	K_{pv}	K_{iv}	K_{pc}	K_{ic}	F
Value	$8e - 7$	$1.3e - 5$	0.9	1000	20	$1e4$	0.75

5.4.2.1 Scenario 1

In the first scenario, the system under study is disconnected from the grid as one MG. The trajectory of the two-pairs of complex eigenvalues as a function of the m_p (i.e., $0.05\% < m_p < 1\%$) is shown in Figure 5-7. These eigenvalues are calculated according to (5-21). Note that as the m_p is increased, the eigenvalues move towards the stable region. Therefore, the system under study will have a high SI and can successfully disconnect from the main grid to prevent the propagation of the voltage-sag event into the system.

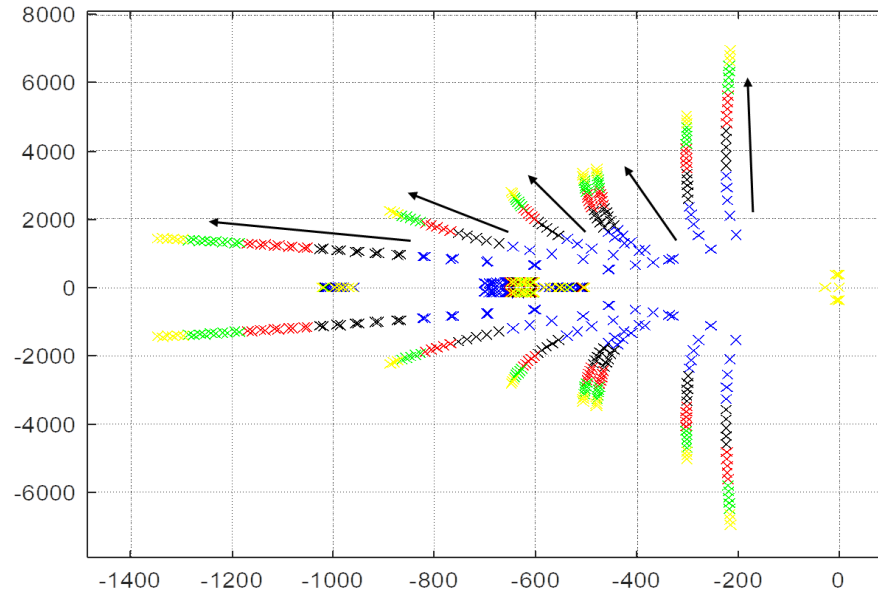


Figure 5-7 Eigenvalue spectrum of system under study as a function of m_p

When the n_q is increased (i.e., $0.5\% < n_q < 8\%$), the eigenvalues move towards the stable region, as shown in Figure 5-8. Thus, the stability constrained partitioning scheme for this scenario is determined as the whole system under stud, and the system is disconnected as a survivable MG to be isolated from the voltage-sag origin.

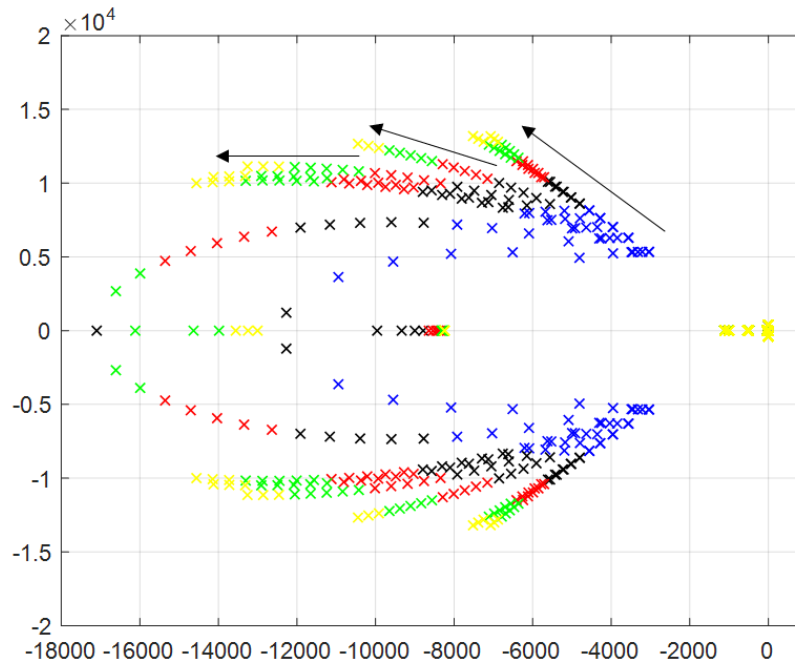


Figure 5-8 Eigenvalue spectrum of system under study as a function of n_q

5.4.2.2 Scenario 2

The second scenario shows the results of the proposed algorithm when the voltage-sag origin is detected within the boundaries of the system under study. To ensure the self-adequacy of the constructed MGs, the minimum power flow partitioning scheme in [104] was used. The obtained MGs' boundaries are shown in Figure 5-9. A certain threshold should not be exceeded by the loading of the selected boundary lines, which in that paper was considered 5% of the rated value of each line. The lines' rated values are calculated according to a deterministic power flow algorithm based on data presented in [106]). Note that this threshold is adjustable and can be set according to the operator's preferences. These microgrids are thus self-adequate; however, their stability needs to be investigated. A complete SSM of each MG components was obtained using the approach outlined in section 5.3.1.

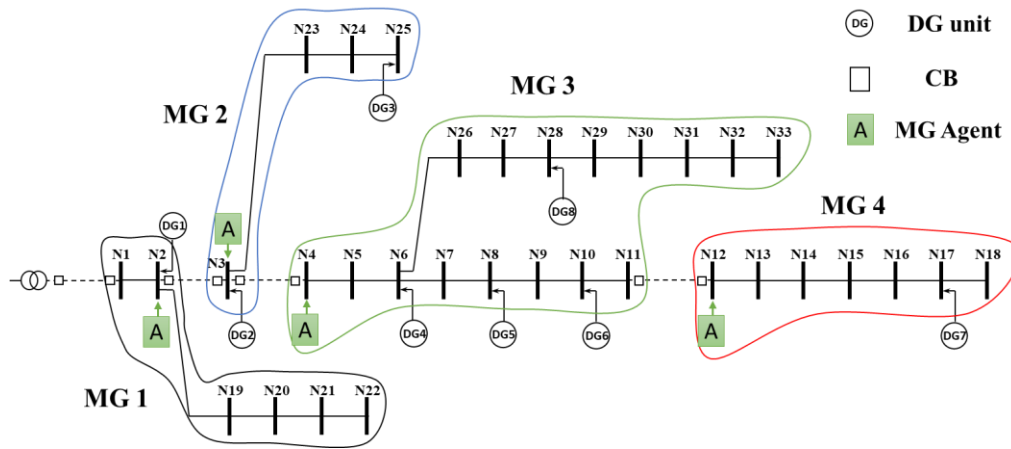
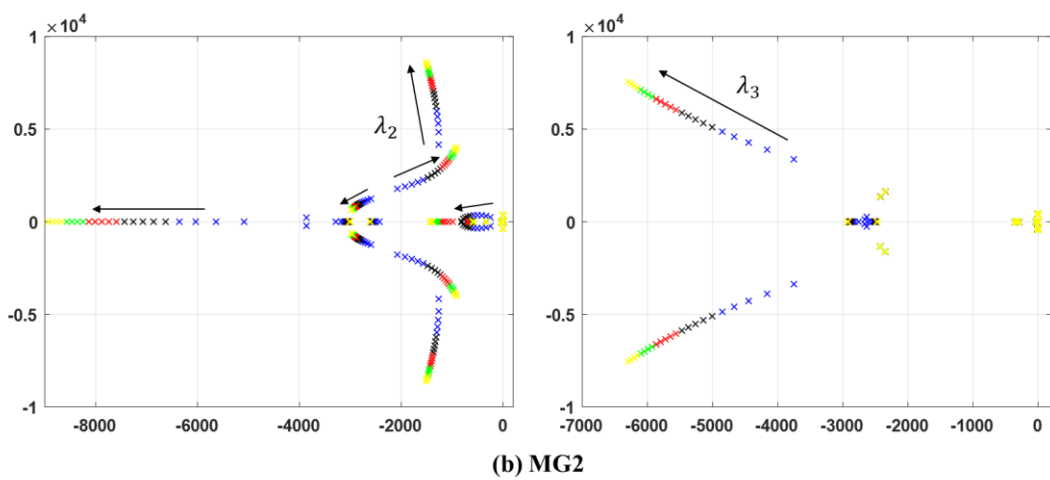
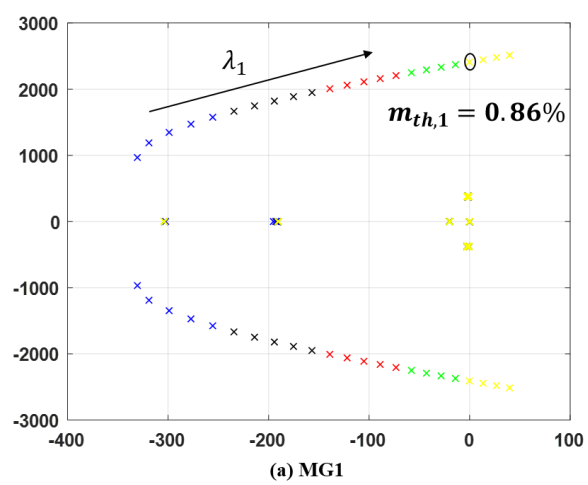


Figure 5-9 MGs boundaries of system under study

Figure 5-10 shows the trajectory of the two-pairs of complex eigenvalues as a function of the m_p , where $0.05\% < m_p < 1\%$ for each MG. Figure 5-11 shows the trajectory of the two pairs of complete conjugate eigenvalues as a function of the n_q , where $0.5\% < n_q < 8\%$ for each MG. The eigenvalues marked with λ_i represent the sensitivity of those eigenvalues to the P and Q part of the power controller of DG_i . Figure 5-10 (a) shows that as m_p is increased, eigenvalues λ_1 moves towards the unstable region, making the MG1 more oscillatory and leading to instability at the end. Note that as the m_p is increased in MG2 and MG3, the eigenvalues are still in a stable region, as shown in Figure 5-10 (b) and Figure 5-10 (c), respectively. For MG4, as the m_p is increased, eigenvalues λ_7 move towards the unstable region. On the other hand, compared to the m_p , the operating stability margin is less sensitive to the n_q [112], as shown in Figure 5-11.



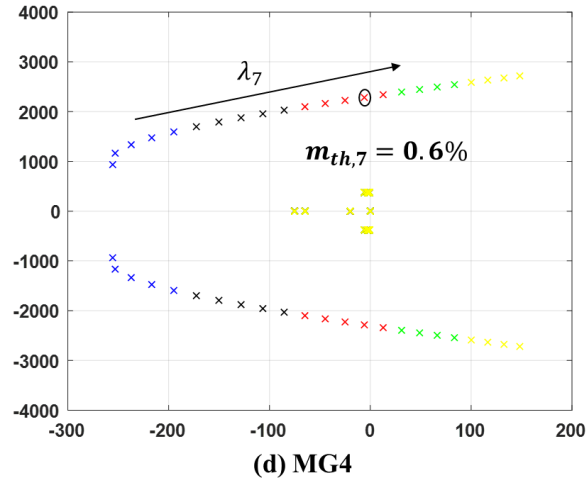
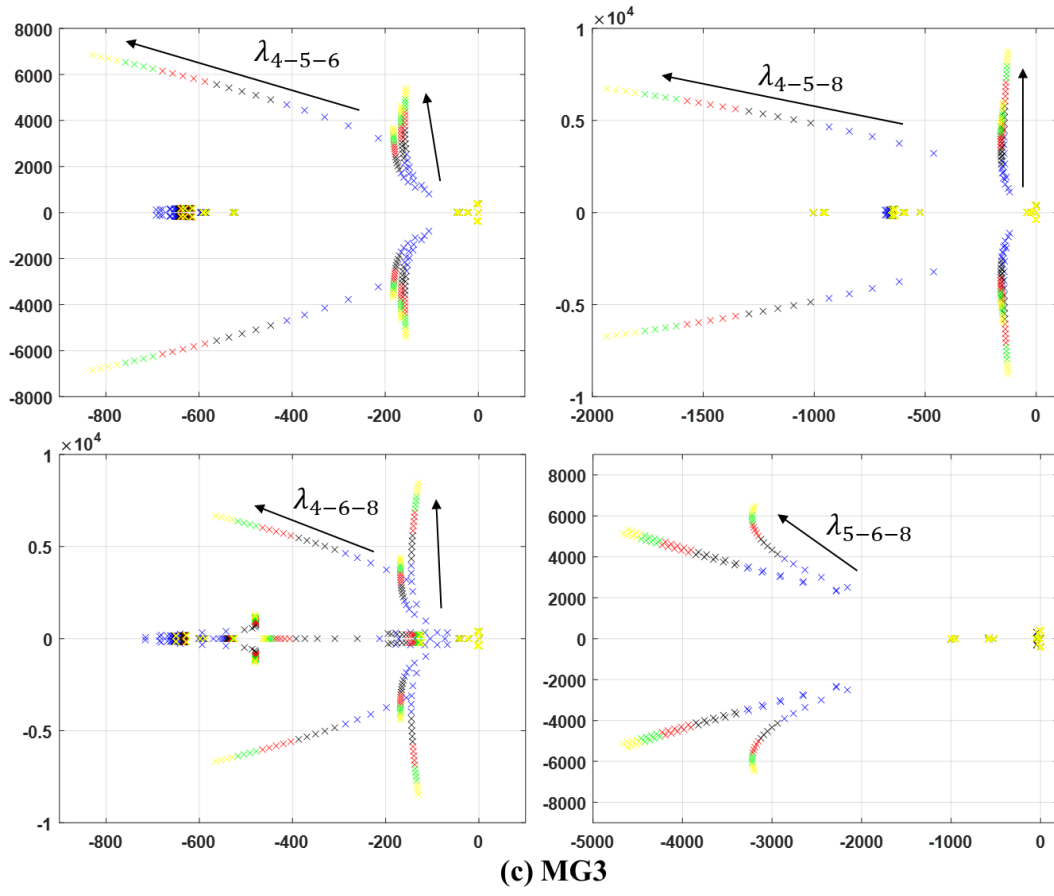
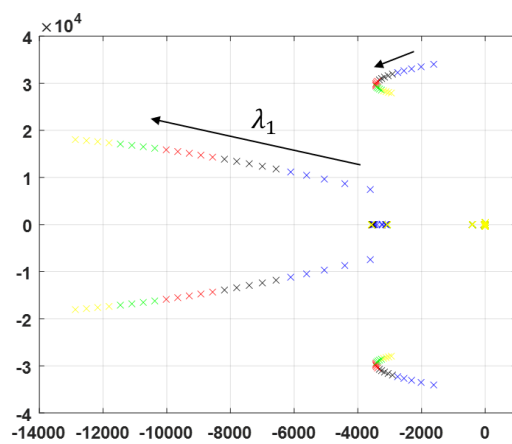
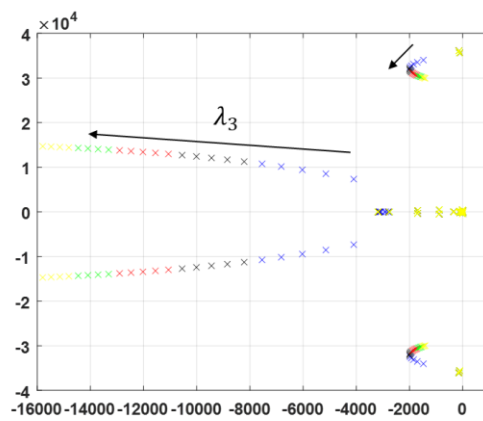
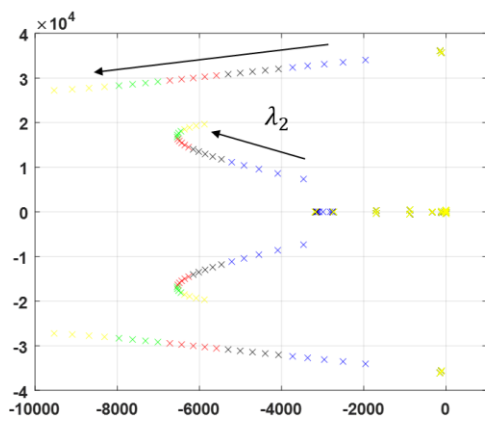


Figure 5-10 Eigenvalue spectrum of each microgrid as a function of m_p : (a) MG1, (b) MG2, (c) MG3, and (d) MG4



(a) MG1



(b) MG2

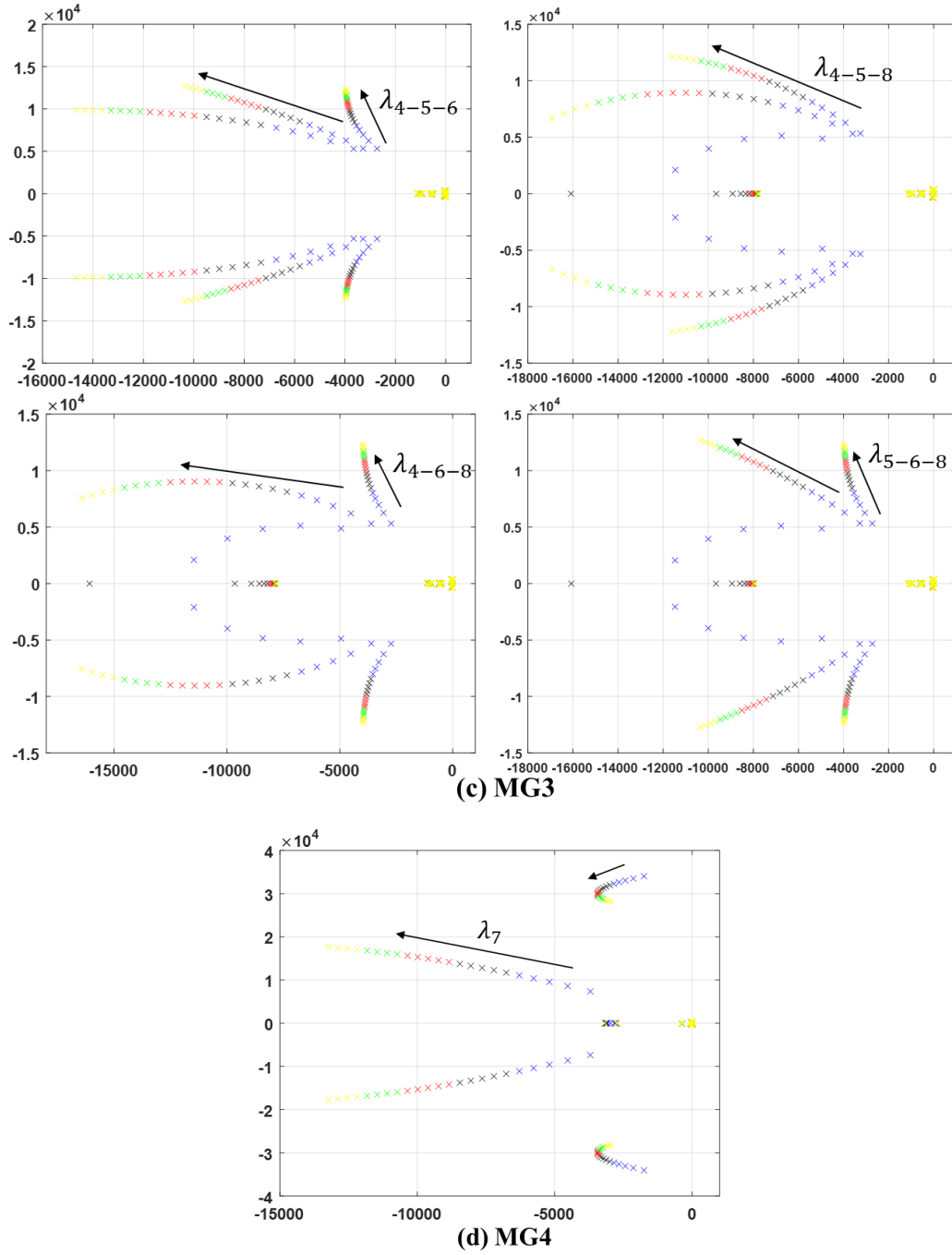


Figure 5-11 Eigenvalue spectrum of each microgrid as a function of n_q : (a) MG1, (b) MG2, (c) MG3, and (d) MG4

Based on the results in Figure 5-10, the SI is calculated according to (5-1), as shown in Table 5-3, and all the microgrids are ranked according to the SI. It should be noted that MG2 and MG3 are the most stable microgrids in the system. Moreover, the MGs with high SI are deemed the host MGs, as will be discussed in the next chapter. On the other hand, at the threshold droop gain values (m_{th}) for

MG1 and MG4, eigenvalues enter the unstable region, making the microgrid more oscillatory. This leads to instability in the end.

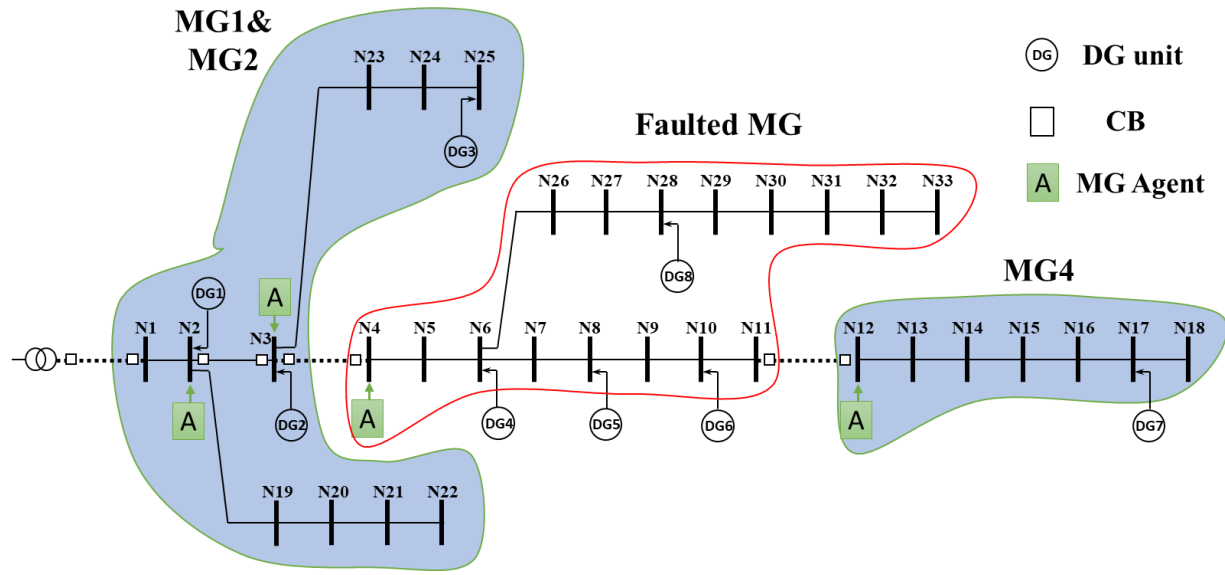
Table 5-3
STABILITY INDEX (SI)

Stability Index				
MG #	1	2	3	4
SI (%)	85.2	100	100	57.9

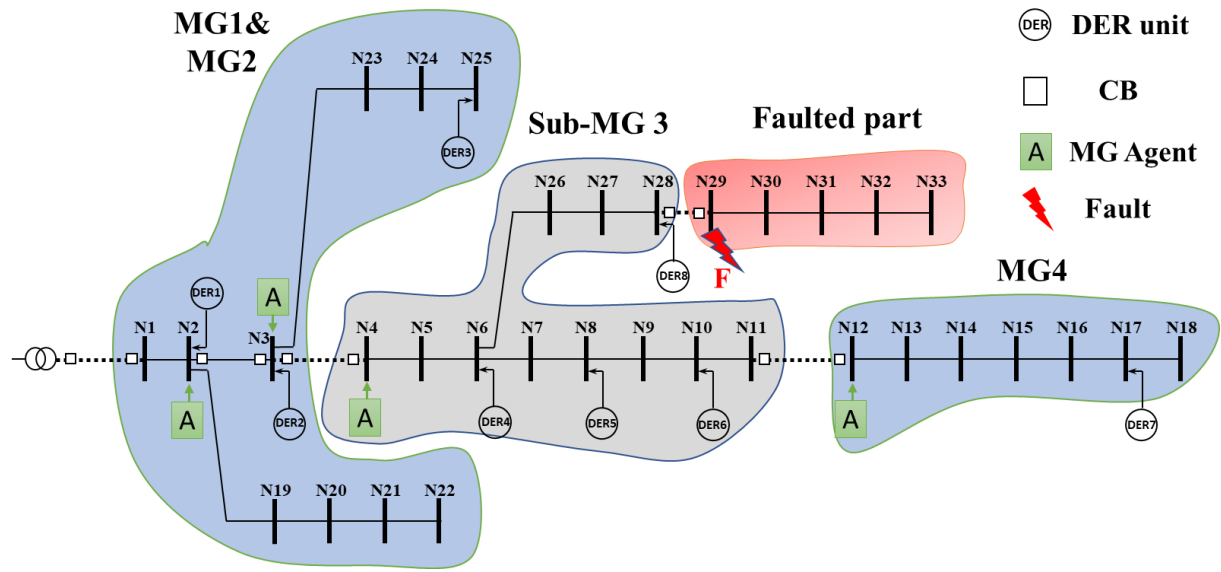
The proposed algorithm ensures that the microgrids with defined boundaries are survivable, self-adequate, and stable. In addition, the algorithm defines the operating marginal stability based on the SI.

To complete the picture of the proposed framework, this part explains how the framework will deal with the faulted microgrid (i.e., the microgrid that has the fault within its boundaries). The algorithm presented in Chapter 3 locates the fault within a particular zone. These zones are defined based on the optimal allocation of the PMUs. The faulted zone will then be matched with the boundaries defined in this chapter (i.e., SCPS) to identify the microgrid that aligns with the fault location (i.e., faulted MG). Once the faulted microgrid is detected, it is isolated from the system. Then the exact fault location (i.e., faulted bus) within the faulted microgrid is detected, and the healthy part of the microgrid is isolated (i.e., referred to as sub-MG) according to the restoration sub-routine.

For the system under study, the fault was assumed to be within MG3, and the fault locating algorithm was successful in locating the faulted bus (i.e., bus 29). The corresponding status of the health flag determines all the healthy microgrids in the system. For instance, $Flag_{MG1} = 1$, $Flag_{MG2} = 1$, $Flag_{MG3} = 0$, and $Flag_{MG4} = 1$ corresponds to a fault in MG3. According to the pre-defined operating marginal stability, the MG agents ensure that all the healthy and stable neighbour microgrids remain intact and that only the faulted microgrid is isolated from the system, as shown in Figure 5-12 (a). Moreover, only the faulted part within the faulted microgrid is isolated based on the restoration sub-routine, and a new sub-MG (e.g., sub-MG3) is created upstream to the faulted bus, as shown in Figure 5-12 (b). Because no DGs are installed downstream from the faulted bus, all the buses downstream from the faulted bus are included in the faulted part. By isolating the voltage-sag origin from the rest of the system, the voltage-sag mitigation is accomplished.



(a)



(b)

Figure 5-12 Post-fault layout of system under study

In the end, the survivable sub-MG3 (i.e., Stable and self-adequate) should have the ability to seamlessly reconnect to the neighbouring healthy microgrids for enhancing supply continuity and system stability, as will be shown in the next chapter.

5.5 Conclusion

This chapter proposed a voltage-sag mitigation framework based on isolating the voltage-sag origin via the intentional partitioning of the system. In order to ensure the survivability of the created microgrids, stability constrained partitioning scheme was developed based on a small-signal stability study. This network partitioning technique (i.e., SCPS) is the fourth technique introduced in this work and differs from the other techniques introduced in Chapter 3 and Chapter 4. An investigation of self-adequate microgrid eigenvalues was used to construct these survivable microgrids. Through a sensitivity analysis of active and reactive power droop gains, a novel marginal stability index was defined for each MG. This index was then used to define the stability margin for each MG and identify the host MG in the case of reconnection of two neighbouring MGs, as will be discussed in detail in the next chapter. The effectiveness of the proposed framework was illustrated via several case studies. The case studies show that the partitioning of the system into survivable self-adequate microgrids during prolonged sags can isolate the voltage-sag origin and enhance supply continuity. Thus, by isolating the voltage-sag origin from the rest of the system, voltage-sag mitigation is accomplished. To complement the voltage-sag mitigation framework's objective, a recovery algorithm for post-voltage-sag mitigation is proposed in the next chapter.

The objective of this recovery algorithm is to reconnect all the healthy parts of the system together to improve the stability and reliability of the system. However, the reconnection must follow a resynchronization process, which is developed in the next chapter.

Chapter 6

Recovery Algorithm for Post-Voltage-Sag Mitigation

6.1 Introduction

One critical feature that microgrids bring to distribution systems is resilience and self-healing. The resilience depends on the microgrid's ability to island from the main grid under certain conditions and formulate a survivable grid that supplies its own load. These microgrids should have the ability to seamlessly reconnect to neighbours when possible, if this would result in a network with enhanced stability. To facilitate the implementation of the proposed recovery algorithm, a smooth reconnection algorithm is developed to allow for the reconnection of two neighbour microgrids. This reconnection algorithm represents a key feature that should be adopted by the microgrid's control scheme. Furthermore, it should be mandated that the microgrids be synchronized prior to reconnection. The conditions for synchronization are the same voltage magnitude, frequency, and phase angle.

The objective of this chapter is to introduce a recovery algorithm for post-voltage-sag mitigation. The algorithm is based on proposing a reconnection algorithm for islanded microgrids constructed according to the stability constrained portioning scheme presented in Chapter 5. The structure of this chapter is presented as follows. Details on the basics for microgrid reconnection are presented in section 6.2. The formulation of the reconnection technique is presented in section 6.3. Finally, a case study is performed in section 6.4 to evaluate the effectiveness of the proposed recovery algorithm for post-voltage-sag mitigation.

6.2 Basics for Microgrid Reconnection

In this section, the reconnection technique is illustrated, assuming the reconnection of two neighbour microgrids. Figure 6-1 shows a schematic layout of two microgrids with multiple DGs and loads. The host microgrid (e.g., MG_i) is connected to its neighbour microgrid (e.g., MG_j) through a static switch or a circuit breaker. The synchronization check relay receives the terminal bus voltage of both microgrids and calculates the information of the reconnection requirements (i.e., ω_{MG}^* , V_{diff} and θ_{diff}). The relay then sends this information to the DER controller to initiate the reconnection process between the two microgrids, as will be discussed later. The operating state of the microgrid is determined by that static switch. When the static switch opens, the MG is disconnected from the host microgrid, and once the switch closes, the two microgrids are reconnected.

There are several events that usually trigger microgrid islanding, such as scheduled maintenance, blackouts, and disturbances. During islanded mode, the MG operates parallel with the main grid and supports the MG's loads by local DERs. Because the voltage and frequency will fluctuate due to differences between supply and demand, synchronization between microgrids and the main grid is lost. Once the event passes and normal conditions are restored, the microgrid will attempt to reconnect with the host microgrid via the static switch. If voltages on both terminal buses of the two microgrids have a similar frequency, voltage magnitude, and phase angle at the instant of reconnection, a smooth reconnection process occurs. Otherwise, severe consequences may result, such as system oscillation, overvoltage, equipment damage, and excessive inrush current. For example, a synchronous machine's shaft may break due to the excessive torsional effort from oscillation and transient power [116].

The voltage difference between the terminal buses of the two microgrids directly affects the voltage across the static switch (SS), as shown in Figure 6-1, and can be calculated as follows:

$$|V_{diff}| = \sqrt{|V_A|^2 + |V_B|^2 - 2|V_A||V_B|\cos(\theta_{diff})} \quad (6-1)$$

where V_A and V_B are the voltage magnitude at terminal-bus A and terminal-bus B, respectively, and θ_{diff} is the corresponding phase angle difference.

Generally, voltage magnitude at the terminal bus of the microgrid (e.g., MG_j) should be regulated to match the terminal bus voltage of the host microgrid (e.g., MG_i). In this way, the V_{diff} is typically determined by θ_{diff} at the instant of reconnection. Based on (6-1), if the two-terminal buses voltages are entirely out of phase, maximum voltage across the static switch is expected to equal $2 p.u.$

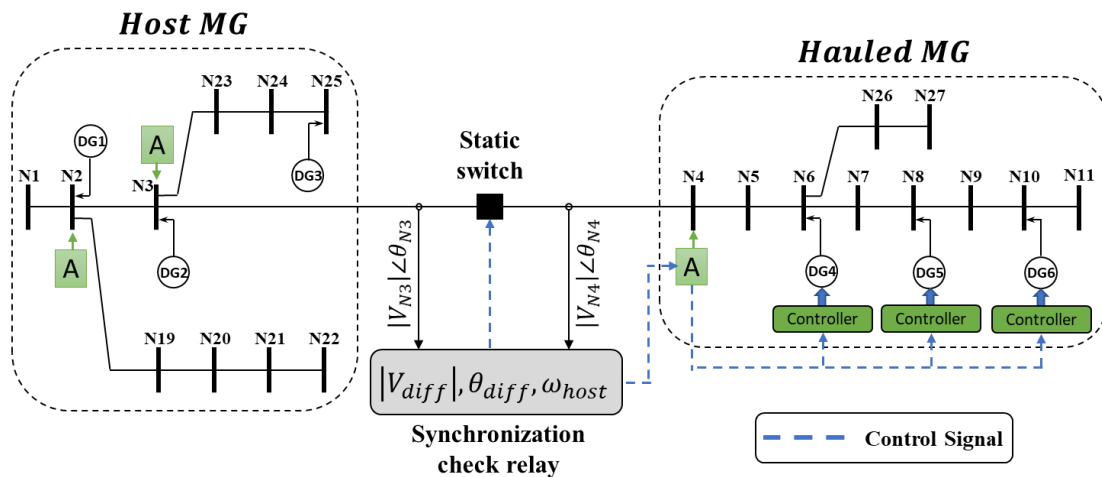


Figure 6-1 Schematic layout of two microgrids in typical distribution system

According to the IEEE 1547 standard [117], the reconnection of two neighbours MGs must follow strict requirements, such as frequency difference, voltage magnitude difference, and phase angle difference, as illustrated in Table 6-1.

Table 6-1
MICROGRID RECONNECTION REQUIREMENTS [117]

Average capacity of DERs (KVA)	Frequency diff. (Hz)	Voltage magnitude diff. (%)	Phase angle diff. (degree)
0 - 500	0.3	10	20
500 - 1500	0.2	5	15
1500 - 10000	0.1	3	10

As noted in Table 6-1, the higher the average rating of DERs, the lower the tolerances. For example, the difference in frequency tolerance drops from 0.2 Hz to 0.1 Hz as the average DER rating changes from 0.5 ~ 1.5 MVA to 1.5 ~ 10 MVA. Figure 6-2 shows the tolerances for an MG with an average DER rating of 1.5 ~ 10 MVA.

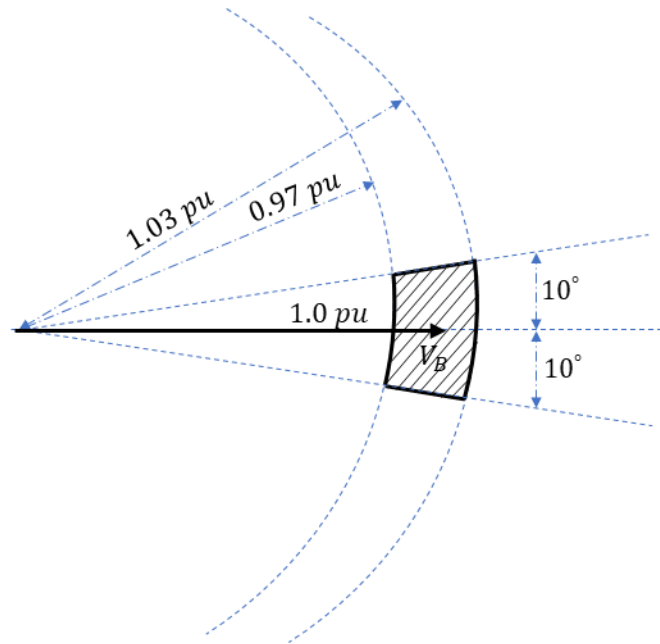


Figure 6-2 Requirements for microgrid reconnection

6.3 Proposed Reconnection Technique

This section presents an MG reconnection technique that utilizes the existing $P - \omega$ and $Q - V$ droop controls and their restoration controls for all the DERs in the system. This technique modifies the DERs'

operating frequencies and phase angles by the frequency restoration of the $P - \omega$ droop control and the DERs' output voltage magnitudes by the voltage restoration of $Q - V$ droop control.

Figure 6-3 shows the stages of the reconnection technique, along with the control signals. As can be seen, there are two main stages during the islanded mode of operation for the microgrid: the initial stage and the transition stage. The initial stage starts once the voltage-sag origin is isolated and the SCPS is forced on the system (i.e., $t_{critical} + 300\text{ ms}$), as discussed in Chapter 5. The time window of the initial stage is determined based on the time needs of the microgrid to reach a new steady-state of operation. The transition stage is then initiated to start the reconnection technique for reconnecting that microgrid with the host microgrid. Once the reconnection technique achieves the reconnection requirements, the synchronization check relay sends a signal to close the SS.

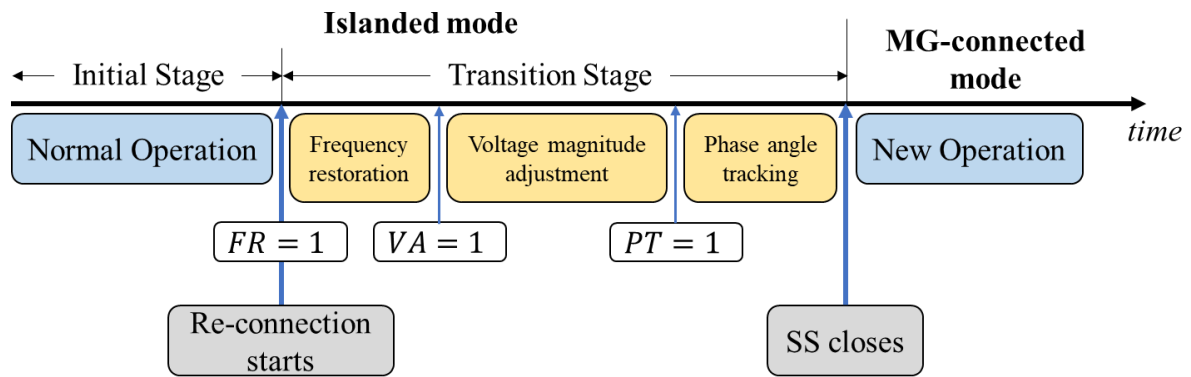


Figure 6-3 Operation modes during reconnection process

The detailed control block diagram for each DER in the proposed reconnection technique is presented in Figure 6-4. The controller has three main parts; the frequency restoration controller, the voltage magnitude adjustment controller, and the phase angle tracking controller. Moreover, there are three main inputs to the controller denoted as; the host MG frequency ω_{MG} , V_{diff} , and θ_{diff} . Once the transition stage is finished, and all the reconnection requirements are satisfied, a synchronization checker sends a signal to close the SS. This reconnection technique addresses the reconnection process of two microgrids with droop-controlled DERs. The proposed method regulates the P and Q output powers of the DERs to achieve the reconnecting of the two microgrids. The details about the proposed reconnection technique will be explained in the following sections.

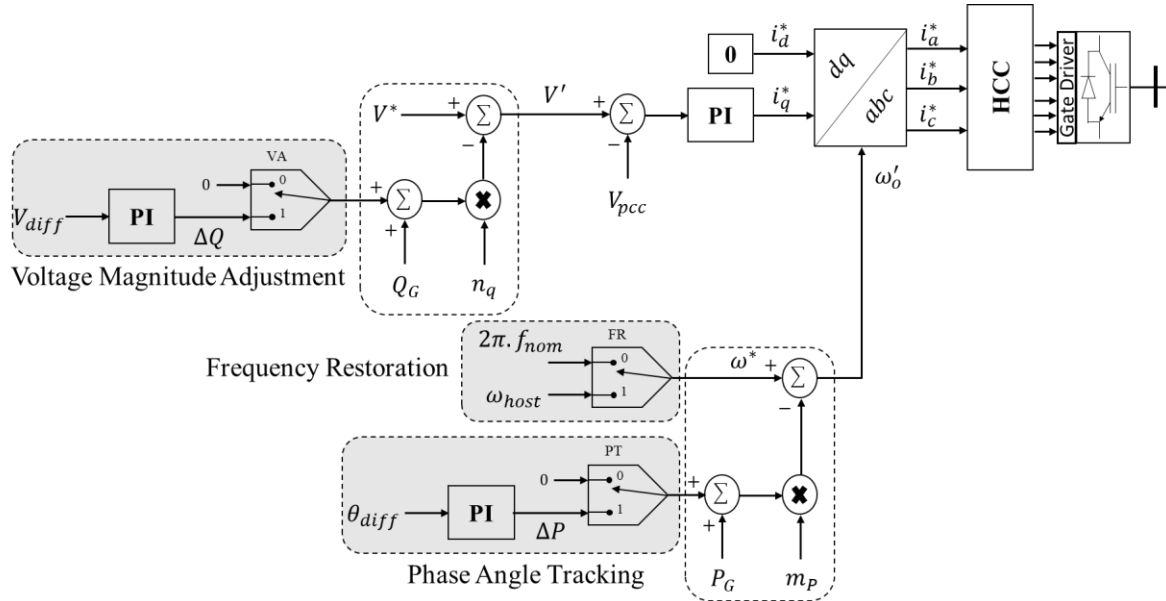


Figure 6-4 Control block diagram of the proposed reconnection method

6.3.1 Frequency Restoration and Phase Angle Tracking

A block diagram for the frequency restoration technique of the $P - \omega$ droop control is shown in Figure 6-5. For the islanded mode of operation, the nominal frequency ω_o is set at $2\pi \cdot f_{nom} \text{ rad/s}$. Once the frequency restoration is commanded by the MG's agent, the $P - \omega$ droop control is redefined as:

$$\omega_o = (\omega^* - m_p \Delta P) - m_p P \quad (6-2)$$

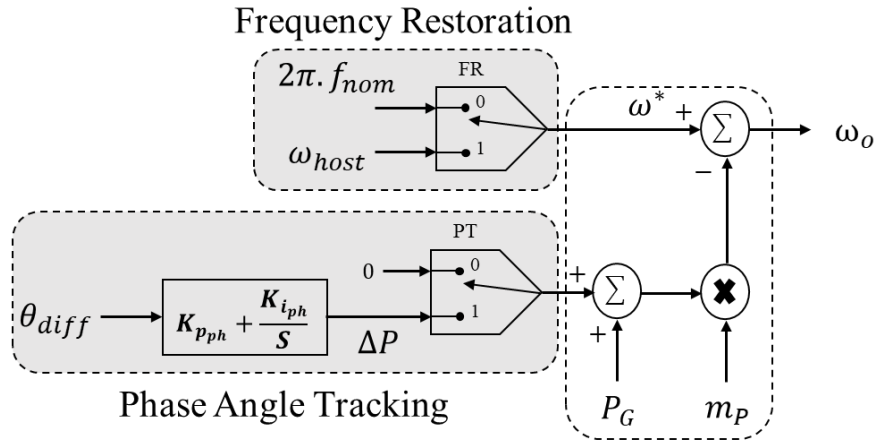


Figure 6-5 Frequency restoration and phase angle tracking controller

where ΔP is the output of the phase angle tracking control block. The three operating scenarios for the $P - \omega$ control are illustrated in Table 6-2.

Table 6-2
OPERATING SCENARIOS FOR THE $P - \omega$ CONTROL

Scenario	ω^*	ΔP
Normal operation	$2\pi f_{nom}$	zero
Frequency restoration	ω_{host}	zero
Phase angle tracking	ω_{host}	$\Delta P = K_{ph}\theta_{diff} + K_{Ih} \int \theta_{diff}$

As in Figure 6-6, the MG operating frequency is restored to the host MG frequency based on the orange droop line, while the DER produces the same active power.

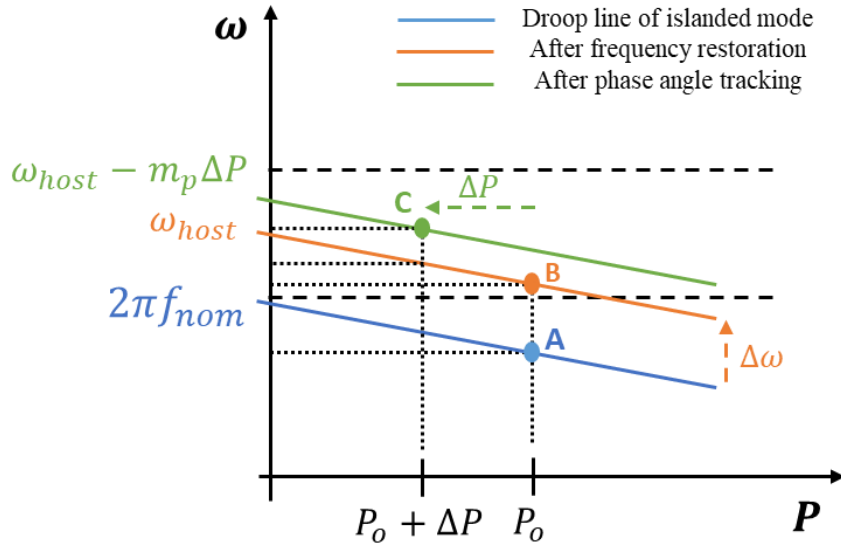


Figure 6-6 Proposed shifting of droop-control for frequency restoration and phase angle tracking

For phase angle tracking, a PI controller is used to regulate the phase angle difference θ_{diff} , and the output ΔP shifts the operating frequency to nullify the phase angle difference between the two microgrids. This modification changes the operating frequency and phase angle of the DER's output voltage. In the end, the PI controller settles into a zero θ_{diff} , which means that the two terminal bus voltages are synchronized in both frequency and phase angle.

Once the frequency reference value is modified, the DER will adjust its P output so that its frequency can follow the new reference value. It should be noted that the adjustment of the P reference value is in proportion to the active power capability of the DER, as in (6-3). Thus, the same frequency change is sensed for all the DERs, as follows:

$$m_{p_1} P_{G_1} = m_{p_2} P_{G_2} = \dots = m_{p_i} P_{G_i} \quad (6-3)$$

6.3.2 Voltage Magnitude Adjustment

The block diagram of the voltage magnitude adjustment controller of the $Q - V$ droop control is shown in Figure 6-7. Once the voltage magnitude adjustment is commanded by the MG's agent, the $Q - V$ droop control is redefined as:

$$V_o = (V^* - n_q \Delta Q) - n_q Q_G \quad (6-4)$$

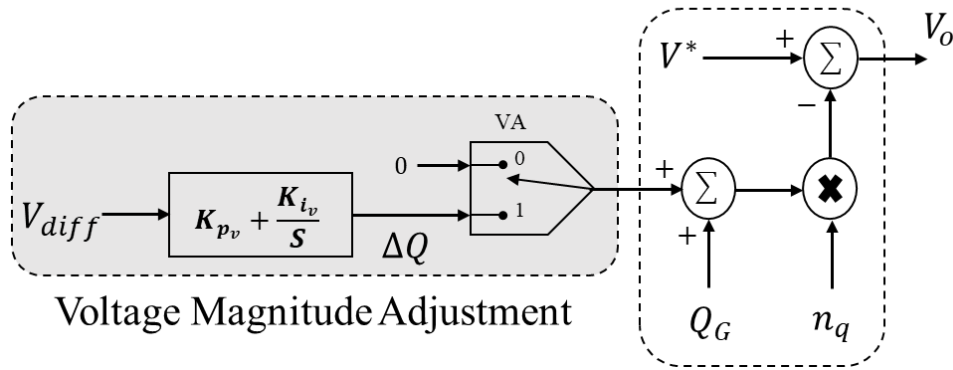


Figure 6-7 Voltage magnitude adjustment controller

where ΔQ comes from the control block of the voltage magnitude adjustment. The two operating scenarios for the $Q - V$ control are shown in Table 6-3.

Table 6-3
OPERATING SCENARIOS FOR THE $Q - V$ CONTROL

Scenario	V^*	ΔQ
Normal operation	V_{nom}	zero
Voltage Magnitude Adjustment	V_{nom}	$\Delta Q = K_{pV} V_{diff} + K_{IV} \int V_{diff}$

As illustrated in Figure 6-8, a PI controller is used to regulate the voltage magnitude difference V_{diff} , and the output ΔQ shifts the operating point. This shift leads the DERs' output voltage magnitude towards the magnitude adjustment of V_{diff} equals to zero, which means that both of the terminal bus voltages are synchronized in voltage magnitudes. It is worth mentioning that all of the DERs use the same PI controller parameters in their controller to achieve proportional active/reactive power-sharing during the transition stage.

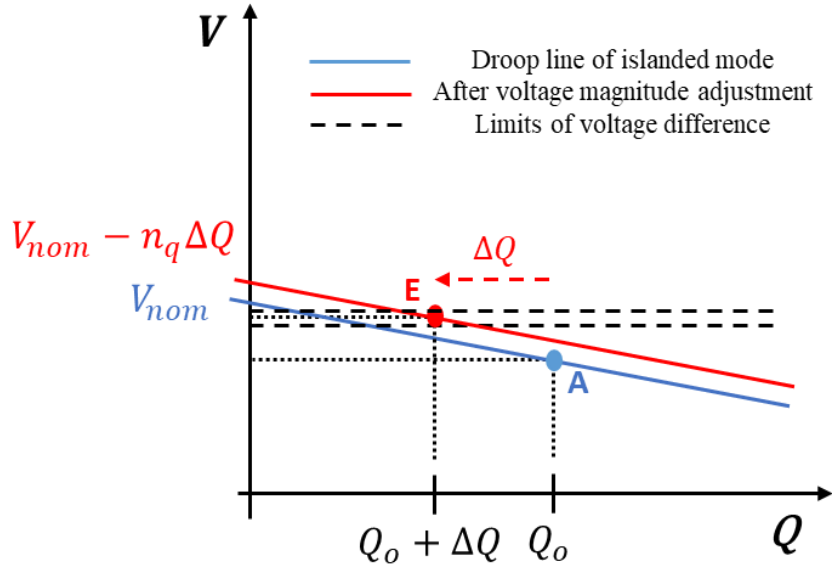


Figure 6-8 Proposed shifting droop-control for voltage magnitude adjustment

Once the voltage reference value is modified, the DER will adjust its Q output so that the MG's terminal voltage can track the new reference value. The adjustment of the Q reference value is in proportion to the reactive power capability of the DER, as in (6-5):

$$n_{q_1} Q_{G_1} = n_{q_2} Q_{G_2} = \dots = n_{q_i} Q_{G_i} \quad (6-5)$$

6.4 Case Study

In this section, the proposed recovery algorithm is considered for the survivable self-adequate microgrids, based on the stability constrained partitioning scheme from Chapter 5. These microgrids should have the ability to seamlessly reconnect when necessary. Thus, the proposed algorithm's objective is to ensure that the reconnection technique of two neighbours' healthy MGs can meet the reconnection requirements in section 6.2.

6.4.1 System Under Study

A modified three-phase balanced 12.66 kV IEEE 33-bus distribution network with DERs at some candidate buses is considered to ensure the proposed mitigation framework's effectiveness. The topology of the network with candidate DER locations is shown in Figure 6-9. The specific parameters for the DERs are listed in Table 6-4. These DERs are controlled to share the active and reactive powers in their respective MGs.

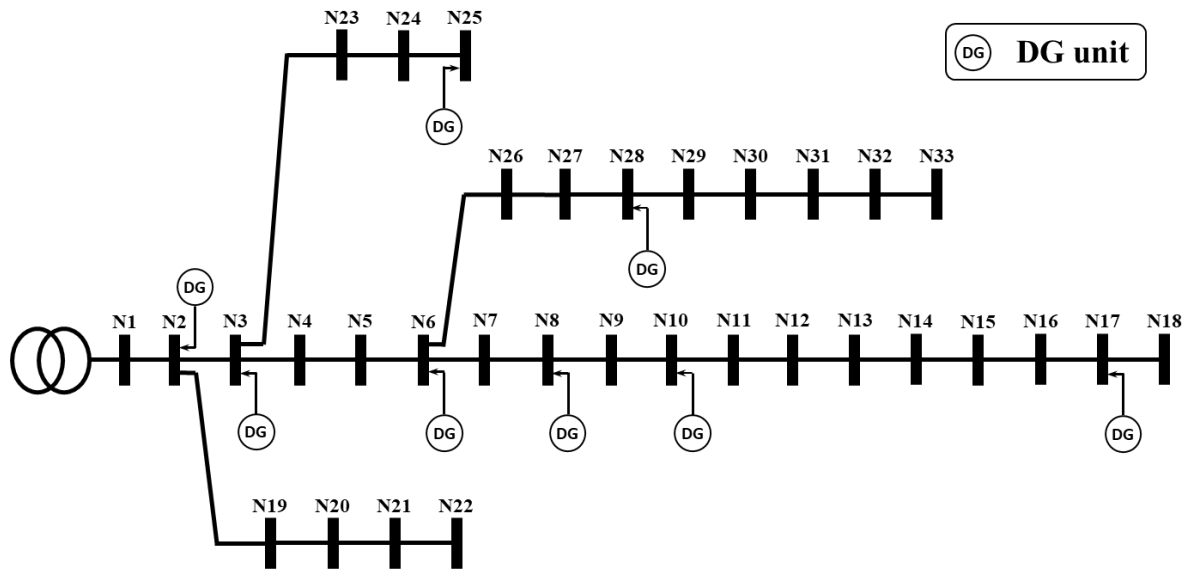


Figure 6-9 Topology of system under study

Table 6-4
CAPACITY AND LOCATION OF DERs

DER	MG #	Location	Unit Capacity (kVA)	Marginal Stability from SI
RES	1	2	600	$0.05\% < m_p < 0.86\%$
RES	2	3	800	$0.05\% < m_p < 1\%$
RES	2	25	400	$0.05\% < m_p < 1\%$
RES	3	6	600	$0.05\% < m_p < 1\%$
RES	3	8	400	$0.05\% < m_p < 1\%$
RES	3	10	800	$0.05\% < m_p < 1\%$
RES	3	28	600	$0.05\% < m_p < 1\%$
RES	4	17	600	$0.05\% < m_p < 0.6\%$

6.4.2 Reconnection Operation of Survivable MGs

According to the SCPS forced on the system in Chapter 5, all the healthy MGs are reconnected based on the MG reconnection technique proposed in section 6.3. In this study, the geographical location of the voltage-sag origin (i.e., fault) is detected within MG3. Therefore, the MAS will take control action to isolate the voltage-sag origin (e.g., faulted part) from the system, as shown in Figure 6-10. The MAS then has the objective to reconnect sub-MG3 and MG4 with the healthy part of the system. The requirements (e.g., frequency difference, voltage magnitude difference, and phase angle difference) for the reconnection process of the case study are presented in Table 6-5.

Table 6-5
MICROGRID RECONNECTION REQUIREMENTS

The average capacity of DERs (KVA)	Frequency diff. (Hz)	Voltage magnitude diff. (V)	Phase angle diff. (degree)
2400	0.1	219	10

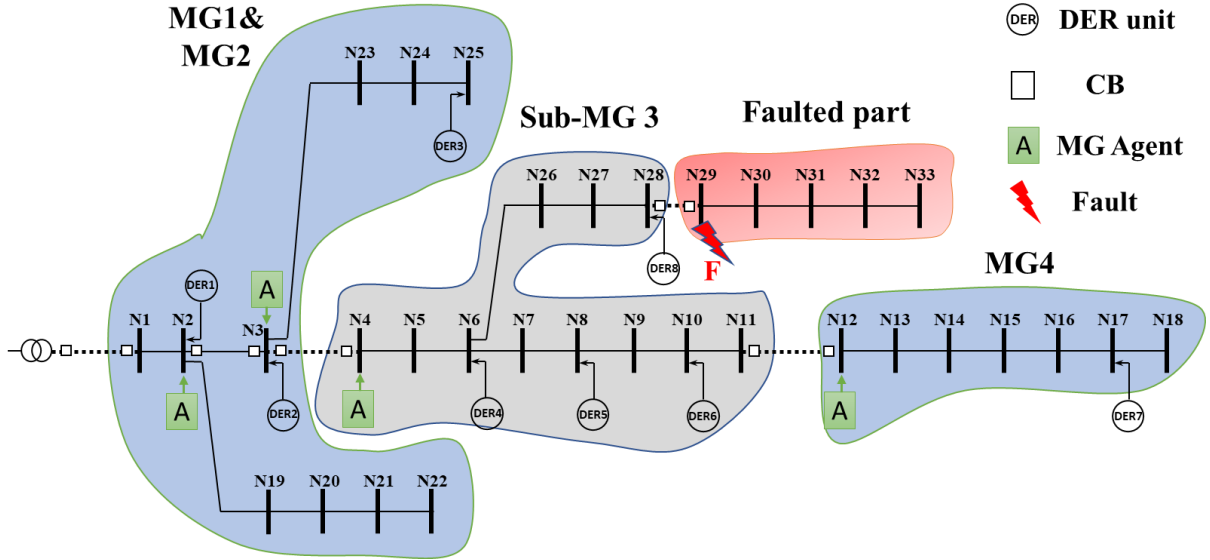


Figure 6-10 Post-fault layout of system under study

First, the proposed recovery algorithm's success and speed to achieve the reconnection requirements for sub-MG3 are tested. The parameters used in this case study are listed in Table 6-6. Initially, the frequency of sub-MG3 reaches a steady state at 59.5 Hz and the voltage at bus-4 reaches a steady state at $0.928 p.u.$, while the frequency of MG1 and MG2 (i.e., host MG) is 59.76 Hz and voltage at bus-3 is about $0.99 p.u.$ In this case study, the simulation time is assumed to start after the SCPS is forced on the system, at which point all the corresponding SSs are opened to isolate the voltage-sag origin. Hence, $t = 0$ corresponds to $t_{critical} + 300 ms$ (i.e., defined in Chapter 5 as the instant of isolating the voltage-sag origin from the system). This steady-state is assumed to be reached at $t = 1.0 s$. Then, the transition stage starts at $t = 1.0 s$ in order to reconnect sub-MG3 with the host MG. Simulation results for reconnecting sub-MG3 with the host MG are presented in Figure 6-11 and Figure 6-12.

Table 6-6 RELATED PARAMETERS OF CONTROLLERS IN SIMULATION RESULTS	
Controllers Parameters	
Phase angle tracking	$K_{i_{ph}} = 5000, K_{p_{ph}} = -1$
Voltage magnitude adjustment	$K_{i_v} = -0.1, K_{p_v} = 1.5$

Figure 6-11 shows the frequency and voltage magnitudes at bus-3 (i.e., the terminal bus of the host MG) and bus-4 (i.e., the terminal bus of the sub-MG3), respectively. According to the SCPS in Chapter 5, the survivability of sub-MG3 is ensured. Due to the droop control operation, a frequency difference exists between the two MGs. Therefore, the frequency restoration is initiated by the MAS at $t = 1.0$ s. As the frequency restoration is achieved, sub-MG3 frequency is restored close to the host frequency.

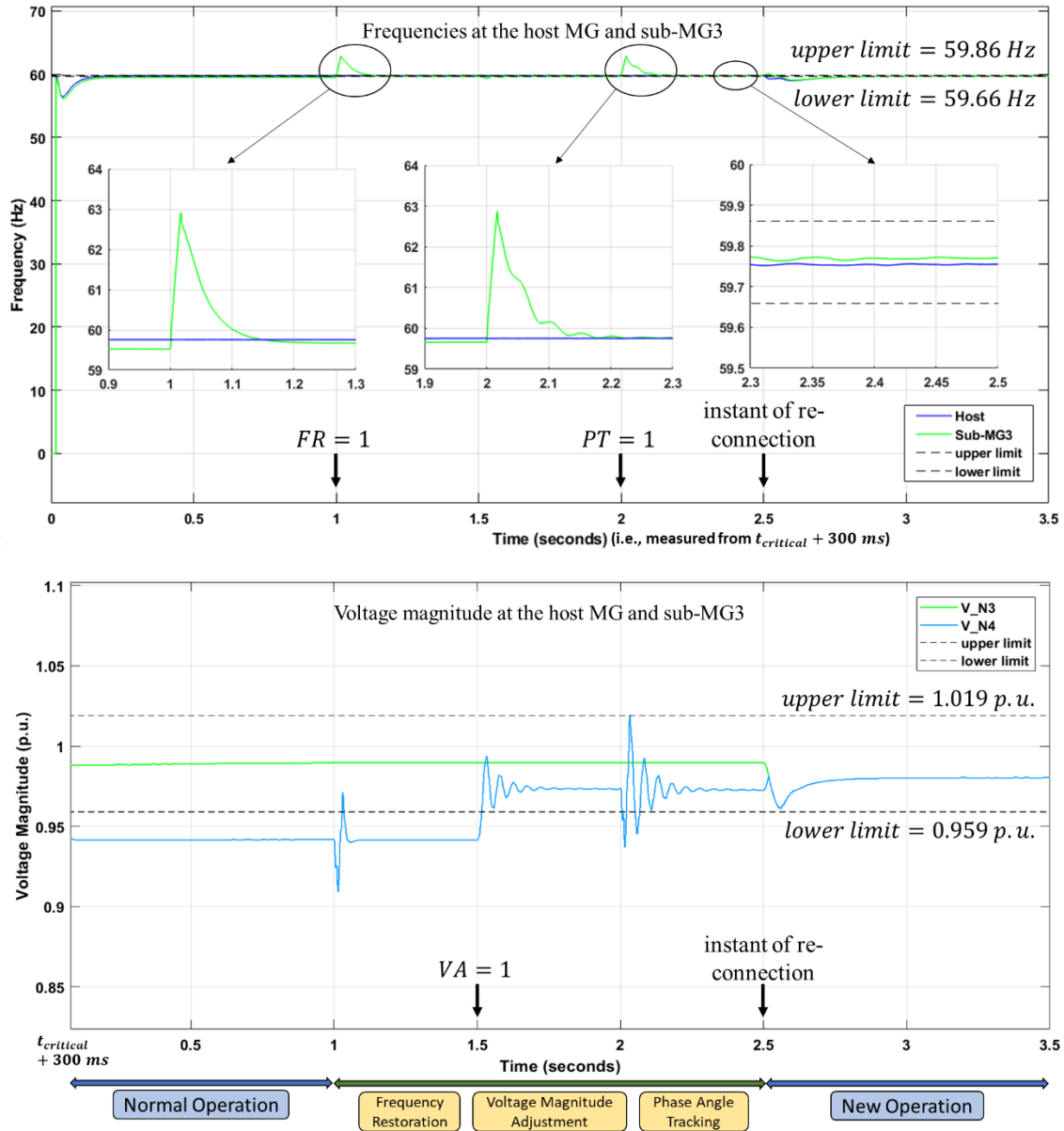


Figure 6-11 Frequency and voltage on both sides of SS

As shown in Figure 6-12, the phase angle difference does not vary and the voltage magnitude adjustment is activated by the MAS at $t = 1.5$ s. The voltage magnitude at bus-4 thus increases to

match the host voltage magnitude at bus-3. At $t = 2.0$ s, the MAS begins the phase angle tracking. At this point, the sub-MG3 operating frequency starts to speed up in order to match the bus-4 voltage phase angle with the host voltage phase angle at bus-3. When the transition stage is completed, the synchronization checker sends a signal to close the SS, and the two MGs are allowed to reconnect at $t = 2.5$ s. The proposed reconnection method verifies that the operation of droop control DERs can be transferred from islanded mode to reconnect mode smoothly.

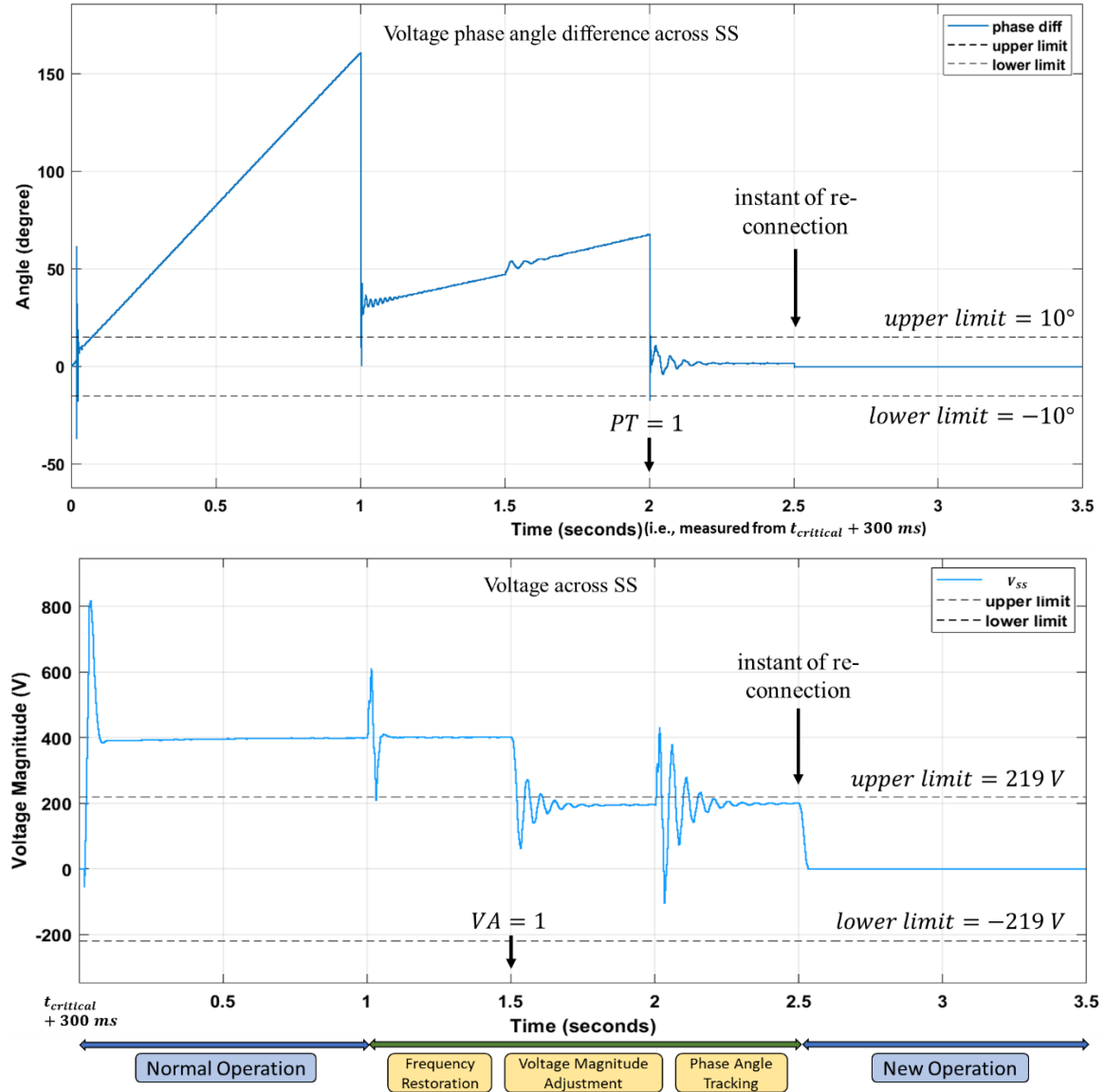


Figure 6-12 Voltage and phase angle difference across SS

In the next phase, the proposed recovery algorithm's success and speed to achieve the reconnection requirements for MG4 are tested, as shown in Figure 6-13. This phase starts after the reconnection

phase between the host MG and sub-MG3 is successfully accomplished, and the new host MG (i.e., MG1, MG2, and sub-MG3) reaches a new steady-state. According to the SCPS, the survivability of MG4 is constrained by the threshold droop gain value (i.e., $m_{th} = 0.6\%$). Therefore, the DSO must choose the initial operating droop gain value to be within the stability margin of MG4, based on Table 6-4.

The same parameters listed in Table 6-6 are used in this phase. Initially, the frequency of MG4 reaches a steady state at 59.75 Hz and the voltage at bus-12 reaches a steady state at 0.98 p.u., while the frequency of the new host MG is 59.89 Hz and the voltage at bus-11 is about 0.93 p.u. The transition stage starts at $t = 1.0$ s. Simulation results for reconnecting MG4 with the new host MG are presented in Figure 6-14 and Figure 6-15. When the transition stage is completed, the synchronization checker sends a signal to close the SS, and the two MGs are allowed to reconnect at $t = 2.5$ s. According to the results in Figure 6-14, the reconnection technique succeeded in maintaining the survivability of MG4 and operated within the stability margin. Figure 6-16 shows that all three operating points (i.e., A, B, and C) are located within the stability region of operation.

The synchronization algorithm's effectiveness was proven by reconnecting both sub-MG3 and MG4 to the healthy part of the system. Thus, all the survivable microgrids were successfully returned to synchronization and connected together to form one survivable microgrid. After the voltage-sag event is finished, the system starts another reconnection process with the main grid to return to normal operation.

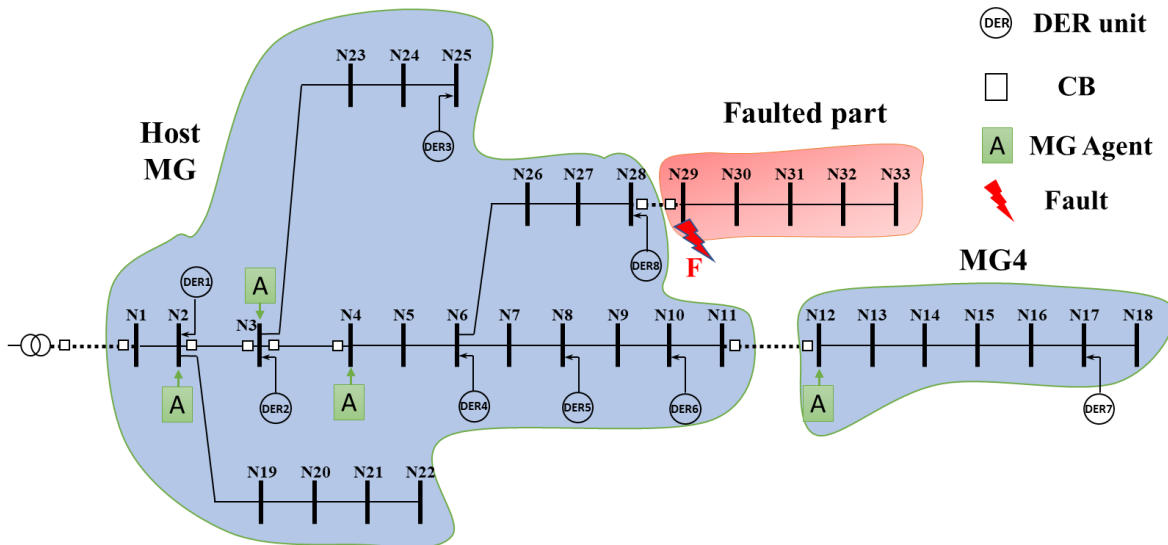


Figure 6-13 Second stage layout of system under study

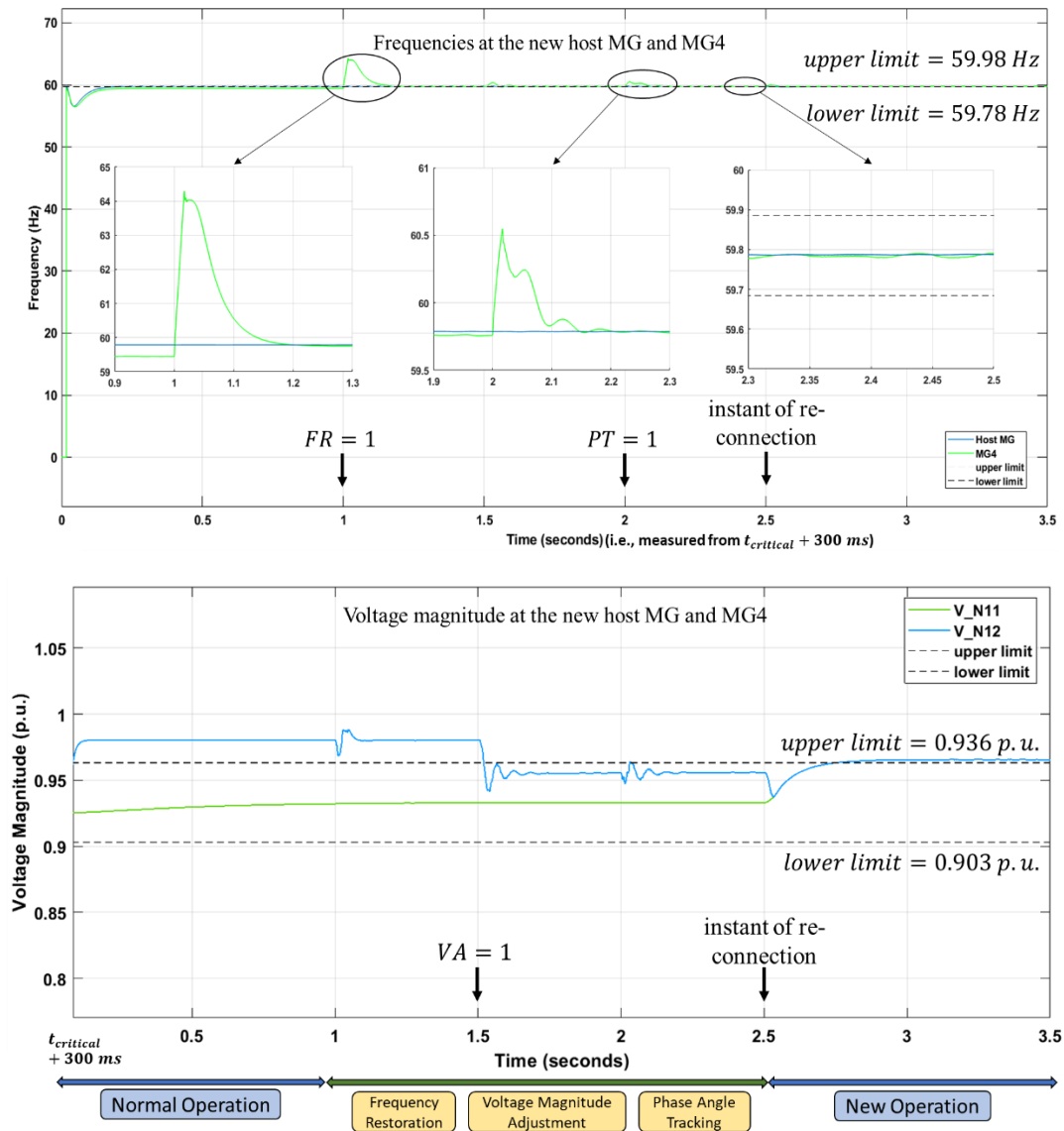


Figure 6-14 Frequency and voltage on both sides of SS

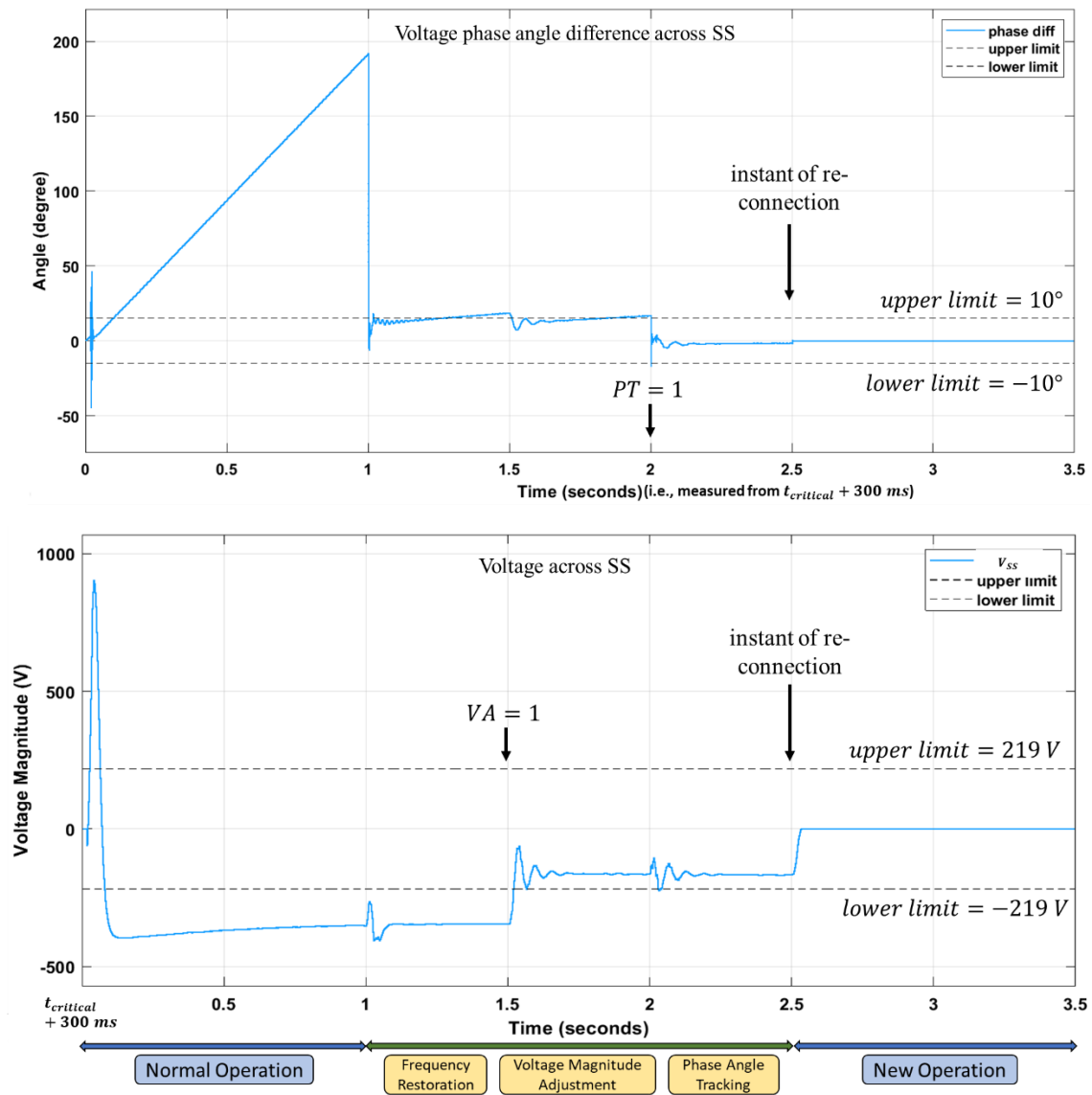


Figure 6-15 Voltage and phase angle difference across SS

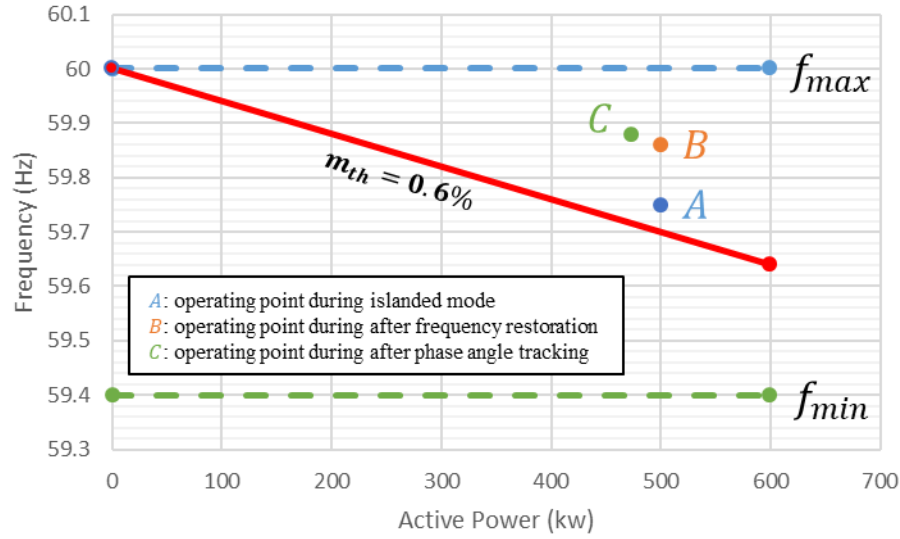


Figure 6-16 Stable region of operation for MG4

6.5 Conclusion

A recovery algorithm for post-voltage-sag mitigation was proposed based on a developed reconnection algorithm for neighbouring microgrids with multiple droop-based DERs. Using the reconnection technique, all DERs act cooperatively to regulate the microgrid's frequency and voltage in order to closely track those of the host microgrid. The host microgrid is the more stable one, based on the stability index defined in Chapter 5. The microgrid's resilience is enhanced by the proposed reconnection method, eliminating the possibility of out-of-phase reclosing. A fast and deterministic reconnection process is achieved by relying on PMU measurements for frequency and phase angle tracking. Moreover, all the system's healthy parts are connected together while isolated from the voltage-sag origin. The effectiveness of the reconnection algorithm was proven by several case studies, and the microgrids were successfully restored to synchronization and connected together to form one survivable microgrid.

Chapter 7

Conclusions and Future Plan

7.1 Conclusions

The main objective of this thesis is mitigating voltage-sag problems based on two complementing parallel actions. The initial action involved injecting active and reactive powers from the available capacity of DERs in ADSs to restore the system's voltage close to the 0.9 p.u. , while the second action involved the identification and isolation of the voltage-sag cause (i.e., faults). The work also introduced appropriate strategies for the active management of ADSs. Active management is performed by optimally determining the operation set-points (i.e., optimal active and reactive output power of DERs) for voltage variation mitigation. Four different network partitioning techniques were introduced in the study as well, namely: observability-based network partitioning technique, modularity-based network partitioning technique, minimum PF-based network partitioning technique, and stability constrained partitioning scheme. Overall, the thesis included four main parts that achieved the two actions required in order to mitigate voltage-sag events. The contributions of this thesis are summarized as follows:

- Develop a system-level solution for voltage-sag problems using the already existing DERs instead of installing DVRs.
- Utilize the fast response of inverter-based DERs while taking into consideration the available volt-ampere capacity in the DER inverters to boost the voltage profile during sag events.
- Instead of dealing with the power network as bulk, the proposed algorithm is based on partitioning the system into a number of mitigation zones. Thus, the problem is split into individual relatively simple sub-problems that can be optimized quickly with a less computational burden.
- Defining the borders of MGs based on the stability constrained partitioning scheme.
- Defining a stability index to select the host MG in case of MG2MG connection.
- Proposing a new method for re-connecting two islanded MGs.

The first part of the thesis developed a voltage-sag origin identification methodology to identify the fault origin and detect whether the fault is upstream or downstream from the system's point of common coupling (PCC). A detailed analysis of this methodology was discussed in Chapter 3. A fast, efficient,

and cost-effective voltage-sag identification methodology based on the voltage and current estimation in the system and Tellegen's theorem was then proposed. The developed technique is assumed to run in the background and forms an essential step in the voltage-variation mitigation framework, which was the primary goal of this thesis. Fast identification of voltage-sag origin in the system provides an excellent advantage in the healing process and system restoration during the voltage-sag event. At the same time that the developed identification sub-routine is running, a voltage-sag mitigation sub-routine is likewise running to achieve the first action of the proposed framework.

In the second part of this thesis, a novel system level-based voltage-sags mitigation algorithm in ADSs was proposed. A detailed analysis of this algorithm was discussed in Chapter 4. The proposed algorithm features a unified network partitioning approach for identifying boundaries of mitigation zones that are considered the system's electrical connection based on a proposed electrical influence intensity index. Furthermore, a novel ZCI was utilized here to consider the installed DER effects on the partitioning scheme by giving different priorities for mitigation zones. A number of different size systems were studied in Chapter 4 to assess the applicability of the proposed algorithm. Information about the voltage-sag origin helps in mitigating voltage-sags that could not be overcome via the available DERs' capacity, so the mitigation sub-routine effort will be successful if the fault is upstream from the system's PCC. However, if the fault is within the system boundary, the voltage-sag origin should be isolated, which was achieved by the second action running in the background. Therefore, if the voltage-sag mitigation requirements are beyond the DERs' capability, parts of the system can face unintentional islanding. To prevent unintentional islanding, the planning of intentional islanding was considered in the subsequent part of the thesis.

In the third part of this thesis, a voltage-sag mitigation algorithm using eigenvalue analysis to obtain a stability-constrained partitioning scheme was proposed. The scheme ensures the microgrids' survivability when the intentional physical partition is forced on the system. A detailed analysis of this algorithm was discussed in Chapter 5. As well, a sensitivity analysis of active and reactive power droop gains was utilized to establish a novel index for microgrid marginal stability. The partitioning of the system into survivable self-adequate microgrids during prolonged sags can isolate the voltage-sag origin. Thus, by isolating the voltage-sag origin from the rest of the system, voltage-sag mitigation is accomplished. The stability-constrained partitioning scheme is valuable to the DSOs. Based on the findings of this research, voltage-sag mitigation can be done without the need for any additional resources.

The last part of this thesis proposed a recovery algorithm for post-voltage-sag mitigation. A detailed analysis of this algorithm was discussed in Chapter 6. The algorithm is based on the proposed reconnection method for neighbouring microgrids with multiple droop-based DERs. A case study was presented to demonstrate the effectiveness of the proposed reconnection method when two healthy neighbour microgrids are ready for connection. The simulation results show the smooth reconnection between any two healthy neighbour microgrids, and the possibility of out-of-phase reclosing is eliminated. A fast and deterministic reconnection process is achieved by relying on PMU measurements for frequency and phase angle tracking. Moreover, the effectiveness of the synchronization algorithm was proven by multiple case studies, with all the healthy microgrids successfully returned to synchronization and isolated from the voltage-sag origin at the end.

7.2 Future Plan

As a future extension to the proposed voltage variation mitigation framework, the system under study will be modelled in the draft menu of a real simulator computer-aided design (RSCAD), after which the proposed algorithms will be executed on real-time power system simulation tool (RTDS). The real-time operation has a distinct benefit, as physical devices (e.g., control devices and power electronics devices) can be connected to the simulated system in a closed-loop. Thus, the interaction between the system and control and power devices can be studied in exacting detail during system transients.

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Appendix A

See Table A. 1 and Table A. 2.

Table A. 1
LINE IMPEDANCE FOR THE IEEE 33-BUS SYSTEM

From	To	Line Resistance (Ω)	Line Reactance (Ω)
1	2	0.0922	0.047
2	3	0.493	0.2511
3	4	0.366	0.1864
4	5	0.3811	0.1941
5	6	0.819	0.707
6	7	0.1872	0.6188
7	8	0.7114	0.2351
8	9	1.03	0.74
9	10	1.044	0.74
10	11	0.1966	0.065
11	12	0.3744	0.1238
12	13	1.468	1.155
13	14	0.5416	0.7129
14	15	0.591	0.526
15	16	0.7463	0.545
16	17	1.289	1.721
17	18	0.732	0.574
2	19	0.164	0.1565
19	20	1.5042	1.3554
20	21	0.4095	0.4784
21	22	0.7089	0.9373
3	23	0.4512	0.3083
23	24	0.898	0.7091
24	25	0.896	0.7011
6	26	0.203	0.1034
26	27	0.2842	0.1447
27	28	1.059	0.9337
28	29	0.8042	0.7006
29	30	0.5075	0.2585
30	31	0.9744	0.963
31	32	0.3105	0.3619
32	33	0.341	0.5302

Table A. 2
BUS DATA OF THE IEEE 33-BUS SYSTEM

Bus No.	Load ($KW + jKVar$)	DER Capacity (KVA)
1	0	0
2	$100 + j60$	200
3	$90 + j40$	300
4	$120 + j80$	0
5	$60 + j30$	0
6	$60 + j20$	200
7	$200 + j100$	0
8	$200 + j100$	200
9	$60 + j20$	0
10	$60 + j20$	300
11	$45 + j30$	0
12	$60 + j35$	0
13	$60 + j35$	0
14	$120 + j80$	300
15	$60 + j10$	0
16	$60 + j20$	0
17	$60 + j20$	300
18	$90 + j40$	0
19	$90 + j40$	300
20	$90 + j40$	0
21	$90 + j40$	0
22	$90 + j40$	0
23	$90 + j50$	0
24	$420 + j200$	0
25	$420 + j200$	300
26	$60 + j25$	300
27	$60 + j25$	0
28	$60 + j20$	200
29	$120 + j70$	300
30	$200 + j600$	0
31	$150 + j70$	0
32	$210 + j100$	0
33	$60 + j40$	0