Reliability Assessment Tools for Future Power Distribution Systems

by

Alberto Escalera Blasco

in partial fulfilment of the requirements for the Doctorate Degree in

Electrical Engineering, Electronics and Automation

University Carlos III de Madrid

Supervisors:

Dr. Edgardo D. Castronuovo
Dr. Milan Prodanović

MAY 2019

To all the important people in my life

Acknowledgements

I would like to thank all the people that has contributed in one way or another to the development of this thesis.

I would like to express my sincere gratitude to my supervisors Milan and Edgardo for their support, guidance and recommendations. A special appreciation goes to Milan for offering me the research opportunity that has led to this thesis. Also thanks to Barry Hayes for his support and guidance at the initial stage.

Thanks to all my colleagues in IMDEA Energy, in particular to my colleagues in the Electrical System Unit, for all the moments and support.

I appreciate all the funding that have significantly contributed to the development of this research, specially to IMDEA Energy, Fundacion Iberdrola under SinCortes project, Spanish Ministry of Economy via RESmart project and Regional Community of Madrid with PRICAM project.

Last but not least, thanks to all the people that is part of my life —specially my family, love and friends —for their unconditional encourage. I hope to give you back all my best.

My most sincere thanks.

Published and Submitted Contents

The following published and submitted contents have been included in this thesis:

- A. Escalera, B. Hayes, and M. Prodanović, "A survey of reliability assessment techniques for modern distribution networks," Renewable and Sustainable Energy Reviews, vol. 91, pp. 344-357, Aug 2018. DOI: 10.1016/j.rser.2018.02.031.
  - This publication is partially included in Chapter 2.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 2, just before the Introduction section.
- A. Escalera, M. Prodanović, E. D. Castronuovo, and J. C. Mazuera, "A comparison of the renewable distributed generation models used in reliability assessment," in 2018 IEEE PES International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), June 2018, pp. 1-6. DOI: 10.1109/PMAPS.2018.8440432.
  - This publication is included in Chapter 3.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 3, just before the Introduction section.
- A. Escalera, M. Prodanović, and E. D. Castronuovo, "Analytical methodology for reliability assessment of distribution networks with energy storage in islanded and emergency-tie restoration modes," International Journal of Electrical Power & Energy Systems, vol. 107, pp. 735-744, 2019. DOI: 10.1016/j.ijepes.2018.12.027.
  - This publication is included in Chapter 4.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 4, just before the Introduction section.
- A. Escalera, M. Prodanović, and E. D. Castronuovo, "An analysis of the energy storage for improving the reliability of distribution networks," in 2018 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Oct 2018, pp. 1-6. DOI: 10.1109/ISGTEurope.2018.8571768.
  - This publication is included in Chapter 5.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 5, just before the Introduction section.

- A. Escalera, E. D. Castronuovo, M. Prodanović and J. Roldán-Perez, “Reliability assessment of distribution networks with optimal restoration based on distributed generation, energy storage and demand management,” submitted.
  - This submitted material is included in Chapter 6.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 6, just before the Introduction section.
- A. Escalera, M. Prodanović, E. D. Castronuovo and J. Roldán-Perez,“Contribution of active network management technologies to distribution system reliability,” submitted.
  - This submitted material is included in Chapter 7.
  - The material from this reference included in the thesis is not marked by using typographic notes. An explicit citation to this reference has been included in Chapter 7, just before the Introduction section.

The first author of all these contents is the author of this thesis.

Other Contributions

This section describes other research contributions obtained by the author during the elaboration of this thesis.

Conference papers, indexed proceedings:

- A. Escalera, B. Hayes, and M. Prodanović, "Reliability assessment of active distribution networks considering distributed energy resources and operational limits," in CIRED Workshop 2016, June 2016, pp. 1-4.
- B. Hayes, A. Escalera, and M. Prodanović, "Event-triggered topology identification for state estimation in active distribution networks," in 2016 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Oct 2016, pp. 1-6.
- A. Escalera, B. Hayes, and M. Prodanović, "Analytical method to assess the impact of distributed generation and energy storage on reliability of supply," in CIRED, vol. 2017, no. 1, pp. 2092-2096, Oct 2017.
- A. Escalera, M. Prodanović, E. D. Castronuovo, and R. Segovia, "Reliability evaluation of grid-connected microgrids with high penetration of renewable distributed energy resources," in CIRED Workshop 2018, June 2018, pp.1-4.
- A. Escalera, M. Prodanović, and E. D. Castronuovo, "Economic evaluation of energy storage used for reliability improvement in distribution networks," accepted in CIRED Conference 2019, June 2019.

Conference papers, non-indexed proceedings:

- A. Escalera, B. Hayes, M. Prodanović, "Impacto de la integración de recursos energéticos distribuidos en la mejora de la continuidad del suministro eléctrico de las Smart Grids," III Congreso Smart Grids, Madrid 2016.
- A. Escalera, M. Prodanović, E. D. Castronuovo, "Impact of wind generation and energy storage on the supply reliability of distribution networks," WindFarms 2017 Conference, Madrid, May 2017.
- J. Roldán, A. Escalera, A. Rodríguez-Cabero, M. Prodanović, "Desafíos de la planificación y control de redes eléctricas de distribución con alta penetración de renovables," IV Congreso Smart Grids, Madrid, November 2017.

Research Grants:

The project SinCortes, proposed by the author of this thesis, was granted by Fundacion Iberdrola under the Research Grants Programme 2018-2019 Energy and Environment.

Abstract

Reliability of distribution networks is one of the fundamental parameters considered during power systems planning as it is used as a measure of continuity of supply delivered to consumers. Increased presence of renewable distributed generation, energy storage and other network management solutions is changing distribution systems by converting them to active distribution networks, as they have been commonly referred to in recent years. Operational properties of all these technological and management solutions can be harnessed to enhance the reliability of distribution networks.

The objective of this thesis is to develop new analytical tools for the reliability assessment of active distribution networks including renewable distributed generation, energy storage, demand management and power-electronics devices. The proposed tools should allow an accurate and efficient evaluation of the previously mentioned technologies in reliability assessment studies.

To achieve this objective, a detailed literature review in the field is performed first. The state-of-the-art with respect to the reliability assessment techniques is established and main research challenges identified.

A novel analytical tool is proposed to assess the contribution of energy storage to reliability as the existing methodologies in this field lack accuracy or computational efficiency. By using the proposed tool, the computational times required for energy storage evaluation are significantly reduced and accurate results obtained. Then, a new methodology for the selection of adequate energy storage technology for reliability improvement applications is introduced. Based on the obtained reliability indices and cost-benefit results, recommendations for the technology and size of energy storage are provided demonstrating the applicability of the proposed methodology.

In addition to energy storage, other network management solutions like dispatchable loads and power electronics devices are also modelled in reliability assessment. The optimal coordination of all these solutions is included in the evaluation, since this aspect has not been previously addressed by the existing tools. The obtained results indicate the network management solutions and their optimal coordination have a significant impact on reliability and, therefore, have to be taken into consideration during reliability assessment.

The principal advantage of the developed tools is that they allow more accurate reliability evaluation of active distribution networks because the existing techniques and models cannot be used to assess these technologies and their operational properties. Moreover, the computational efficiency of the tools allows a faster evaluation of different scenarios that are typically analysed during the planning stage. All these properties facilitate the task of network planners to design distribution networks with any preset reliability levels leading to decreased economic costs caused by power interruptions and reduced investments.

Resumen

La fiabilidad de las redes de distribución es un parámetro fundamental en la planificación de los sistemas eléctricos, ya que influye en el nivel de continuidad de suministro eléctrico de los consumidores. En la actualidad los sistemas de distribución eléctrica están experimentado un crecimiento sin precedentes en la penetración de generadores distribuidos de origen renovable, almacenamiento de energía y tecnologías para la operación eficiente del sistema, dando lugar a redes de distribución activas. Todas estas tecnologías pueden contribuir a mejorar la fiabilidad de las redes de distribución, siendo necesario evaluar su efecto.

El objetivo de esta tesis consiste en desarrollar nuevas herramientas analíticas capaces de evaluar la fiabilidad de redes de distribución activas con generadores distribuidos renovables, almacenamiento de energía, gestión activa de la demanda y dispositivos de electrónica de potencia. Estas herramientas deben permitir una evaluación precisa y eficiente de dichas tecnologías en los estudios de fiabilidad.

Para conseguir este objetivo, en primer lugar se lleva a cabo una revisión literaria de la temática, con el fin de determinar el estado del arte de las técnicas empleadas en la evaluación de la fiabilidad e identificar los principales retos de investigación.

En segundo lugar, se propone una nueva herramienta para evaluar la contribución del almacenamiento de energía sobre la fiabilidad de las redes de distribución. Las metodologías existentes bien carecen de la precisión suficiente o bien necesitan de largos tiempos de computación, mientras que la herramienta propuesta permite reducir significativamente los tiempos de cálculo a la vez que proporcionada resultados precisos. Posteriormente, se presenta una metodología para seleccionar el sistema de almacenamiento más apropiado para mejorar la fiabilidad. Los resultados de fiabilidad y coste-beneficio proporcionados por dicha metodología permiten ayudar a seleccionar el tamaño y la tecnología de almacenamiento más apropiados.

Además del almacenamiento de energía, se proponen nuevas herramientas para modelar soluciones empleadas en la gestión de redes activas, tales como cargas gestionables y dispositivos de electrónica de potencia. La coordinación óptima de todas estas soluciones es incluida en la evaluación de la fiabilidad, ya que dicho aspecto no ha sido evaluado por las herramientas existentes. Los resultados obtenidos ponen de manifiesto que las soluciones modeladas permiten mejorar significativamente la fiabilidad y, por ello, tienen que ser consideradas en los estudios de fiabilidad.

La principal ventaja de las herramientas desarrolladas reside en que permiten una evaluación más precisa de la fiabilidad de redes activas de distribución. Además, permiten realizar una evaluación más rápida y, por consiguiente, analizar un mayor número de escenarios en menos tiempo. Todas estas propiedades facilitan la tarea del planificador de red y le permiten diseñar redes activas de distribución con un nivel adecuado de fiabilidad, menores costes por interrupciones e inversiones más efectivas.

Contents

List of Figures

List of Tables

List of Acronyms

AC	Altern Current
ADN	Active Distribution Network
ANM	Active Network Management
CB	Circuit Breaker
CPT	Capacity Probabilistic Table
DG	Distributed Generator
DR	Demand Response
ENS	Energy Not Supplied
ESS	Energy Storage System
EU	European
FOR	Forced Outage Rate
IC	Interruption Cost
ICT	Information and Communication Technologies
IEAR	Interrupted Energy Assessment Rate
IEEE	Institute of Electrical and Electronics Engineers
IS	Isolator
LP	Load Point
LV	Low Voltage
MCS	Monte Carlo Simulation

MV	Medium Voltage
NOP	Normally-Open Point
OLTC	On-load Tap Changer
PV	Photovoltaic
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
SCR	Storage Capacity Ratio
SMCS	Sequential Monte Carlo Simulation
SOC	State-of-charge
SOP	Soft-Open Point
SPR	Storage Power Ratio
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home

Nomenclature

The symbols in Chapters 4 and 7 of this document are included here to facilitate the readability of the chapter. The rest of the symbols are described the first time they appear in the document.

Indices:

cr	Index of restoration-states of distributed generators and energy storage systems
g	Index of distributed generators in a downstream area
h	Index of time-steps in a representative time-interval
i	Index of load points
j	Index of failures in network components
lpi	Index of load points in a downstream area
rs	Index of representative time-intervals of renewable generation and demand
s	Index of the energy storage systems
t	Index of time-steps in the restoration-evaluation time
tie	Index of the emergency-ties of limited transfer capacity in a downstream area
ts	Index of time-steps with generation shortage
e	Index of soft-open points
g	Index of conventional distributed generators
gcp	Index of primary substations

gr	Index of renewable distributed generators (variable resource)
y	Index of buses

Sets and numbers:

N_{cr}	Number of restoration-states in a downstream area
N_g	Set of distributed generators in a downstream area
$N_{h,rs}$	Number of time-steps in the representative time-interval rs
N_i	Number of load points in a network
N_j	Number of failures in network components
N_{lpi}	Set of load points in a downstream area
N_{rs}	Number of representative time-intervals of a year
N_s	Set of energy storage systems in a downstream area
N_{tie}	Set of emergency-ties of limited transfer capacity in a downstream area
Sp	Set of energy storage systems with higher priority of use
D	Set of loads with demand management
E	Set of soft-open points
G	Set of conventional distributed generators
GC	Set of adjustable renewable distributed generators
GCP	Set of substations
GN	Set of on-off renewable generators
L	Set of lines
ND	Set of loads without demand management
NT	Set of lines without on-load tap changer transformers
SC	Set of soft-open points connections
TT	Set of lines with on-load tap changer transformers

Parameters:

α_g^{cr}	State of distributed generator g (up=1,down=0)
α_s^{cr}	State of energy storage system s (up=1,down=0)
$\Delta t(t)$	Duration of time-step t
ηc_s	Charge efficiency of energy storage system s
ηd_s	Discharge efficiency of energy storage system s
λ_j	Annual average rate of failure j
C_s	Capacity of energy storage system s
FOR_g	Forced outage rate of distributed generator g
FOR_s	Forced outage rate of energy storage system s
La_i	Annual average demand of load point i
$La_{i,j}$	Average demand of load point i during failure j
p_{cr}	Probability of restoration-state cr
p_h	Probability of time-step h in a representative time-interval
p_{rs}	Annual probability of representative time-interval rs
$\overline{Pc}_s$	Maximum charge power of energy storage system s
$\overline{Pd}_s$	Maximum discharge power of energy storage system s
$P_g^{h,rs}$	Power generated by distributed generator g
$P_{lpi}^{h,rs}$	Power demanded by load point lpi
$P_{tie}^{h,rs}$	Transfer capacity of emergency-tie tie
r_j	Average repair time of failure j
st_g	Maximum starting times of all the distributed generators used in the restoration
st_s	Maximum starting times of all the energy storage systems used in the restoration
t_{tie}	Switching time of the tie switches in a downstream area

tsi_j	Time to identify and isolate failure j
tsr_j	Time to restore the supply in areas upstream of failure j
$\underline{SOC}_s$	Minimum state-of-charge limit of energy storage system s
$\overline{SOC}_s$	Maximum state-of-charge limit of energy storage system s
α, β, γ	Cost function coefficients for power supply
β^h	Excessive cost of interrupted demand in loads without demand management
β^I, γ^I	Cost coefficients of interrupted demand
ν_{gr}^c	Availability of renewable resources (between 0 and 1) for cluster c
τ_{iy}^{min}, τ_{iy}^{max}	Tapping lower and upper limits
ϕ_{iy}	On-load tap changer transformer angle
a_e, b_e, c_e	Coefficients of the losses function of a soft-open point
bs_{iy}	Branch charging susceptance in line iy
c_e^{sop}	Operational cost of soft-open points
g_i^s, b_i^s	Shunt conductance and susceptance at bus i
g_{iy}, b_{iy}	Conductance and susceptance in line iy
P_g^{min}, P_g^{max}	Active power limits of conventional distributed generators
P_i^c, Q_i^c	Demand in the buses for cluster c
Q_g^{min}, Q_g^{max}	Reactive power limits of conventional distributed generators
Q_{gr}^{min}, Q_{gr}^{max}	Reactive power limits of renewable distributed generators
S_{ei}^{max}	Capacity of soft-open point terminal ei
S_{gcp}^{max}	Apparent power limit of substation gcp
S_{gr}^{max}	Capacity of renewable distributed generators
S_{iy}^{max}	Apparent power limit on line ij
V_i^{min}, V_i^{max}	Voltage magnitude lower and upper limits

Variables:

λ_i	Failure rate of load point i
$\lambda_{i,j}$	Failure rate of load point i caused by failure j
ENS_i	Annual energy-not-supplied to load point i
ENS_i^*	Energy-not-supplied to load point i considering the fluctuations of demand during failures
$ENS_{i,j}^R$	Energy-not-supplied to load point i during failure j (excluding switching time)
$p_{h,rs}$	Annual probability of time-step h in representative time-interval rs
Pc_s	Charging power of energy storage system s
Pd_s	Discharging power of energy storage system s
Pdm	Maximum power that can be discharged from all the energy storage systems
$Pg^{cr,h,rs}$	Aggregated power generation in a downstream area
$Pl^{h,rs}$	Aggregated power demand in a downstream area
r_i	Outage duration of load point i
$r_{i,j}$	Outage duration of load point i caused by failure j
$r_{i,j}^D$	Interruption duration of load point i in an area downstream of failure j
$r_{i,j}^R$	Interruption duration of load point i in an area downstream of failure j (excluding switching time)
$r_{i,j,cr,rs,h}^R$	Interruption duration (excluding switching time) caused by failure j registered at time-step h of representative time-segment rs and restoration-state of devices cr
rc_s	Ratio of power available to charge energy storage system s
rd_s	Ratio of power required to be discharged from energy storage system s
SOC_s	State-of-charge of energy storage system s
SOC^M	Maximum available state-of-charge

$sr_{i,j,cr,rs,h}$	Last time-step interrupted at failure j registered at time-step h of representative time-segment rs and restoration-state of devices cr
tsw_j	Switching time of an area downstream of failure j
U_i	Annual unavailability of load point i
δ_{gr}	Binary variable for on-off renewable distributed generators
$\sigma_{i,c}$	Ratio of load curtailment at bus i and cluster c
τ_{iy}	Tap magnitude for on-load tap changer transformers
I_{ei}^{sop}	Current injection magnitude of soft-open point e to bus i.
P_{ei}^{sop}, Q_{ei}^{sop}	Power injection of soft-open point e to bus i
P_g, Q_g	Power in conventional distributed generators
P_{gcp}, Q_{gcp}	Power in the substations
P_{gr}, Q_{gr}	Power in intermittent renewable distributed generators
P_{iy}^{line}, Q_{iy}^{line}	Power flow in line from i to y
$Ploss_{ei}^{sop}$	Soft-open point losses in the side of bus i
S_e^{sop}	Apparent power in the soft-open point
V_i, θ_i	Voltage magnitude and angle at bus i

Chapter 1

Introduction

1.1 Motivation

Electricity power supply is frequently considered as a fundamental human right and a large number of daily activities rely on its availability. In this context, the power system infrastructure plays a key role in delivering end users continuous electrical energy in the most efficient way [1].

The power system infrastructure includes critical components. Malfunction or damage to transformers, power lines, substations or protection devices may result in power interruptions, causing high economic impacts to end users and electricity companies [2]. Therefore, the component failures have to be accounted for when planning power systems with the preset levels of reliability, assuming here reliability as the capacity of the system to provide continuous, uninterrupted power supply [3]. Appropriate levels of continuity must be guaranteed during the power systems planning and specific methodologies for reliability assessment are applied for this purpose [3, 4].

Power systems are commonly divided in three functional areas: generation, transmission and distribution. Historically, efforts have been more focused on evaluating the reliability of generation and transmission systems due to the critical consequences in the case of their failure [5]. However, distribution networks represent a large part of the power system infrastructure and are responsible for most of the customer interruptions [5]. Therefore, evaluating the reliability of these networks is of significant importance.

In conventional distribution systems, network redundancy (e.g. parallel power lines or transformers) is one of the main practices to guarantee reliability. It means that if a network component fails, alternative equipment will be used to deliver the power and mitigate interruptions. However, redundancy-based practices have several drawbacks such as high investment cost or possible technical difficulties for their implementation. In addition, these practices are contradictory with a more efficient use of the assets, philosophy that the Smart Grids pursue [6].

Nowadays, power systems, in general, and distribution systems, in particular, are in a process of transformation to improve their sustainability, efficiency and reliability. This comes as a result of current policies that promote an increased integration of renewable generation and implementation of the Smart Grid concept. In this context, distribution systems have significant potential for renewable power integration. Accordingly, distributed generators have been widely installed and a substantial increase has also been foreseen for the years to come [7]. However, renewable distributed generation from wind and solar resources is variable and a massive integration of these resources in the system challenges the security of supply. To mitigate this effect, distribution networks are evolving from passive to active systems known as Active Distribution Networks (ADNs) [8]. As shown in Fig. 1.1, ADNs assume sophisticated monitoring and control systems as well as advanced solutions like energy storage, demand management, electric vehicles and device automation. All these elements, in addition to their contribution to sustainability and efficiency, offer new opportunities for reliability improvement [9]. The level of this improvement needs to be evaluated and considered in the planning of future distribution systems.

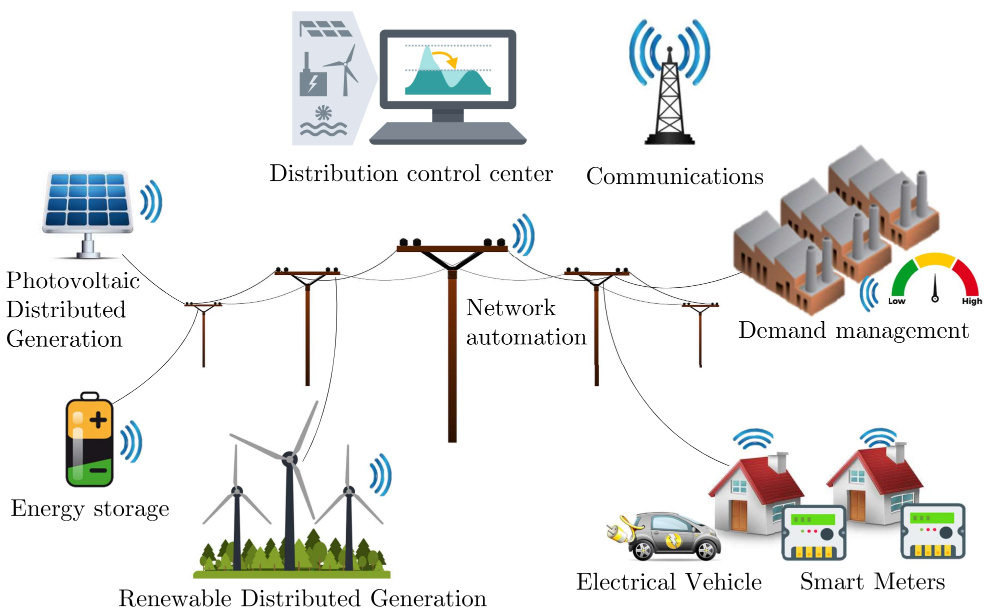


Figure 1.1: Example of Active Distribution Network with advanced operation, control and communication technologies

However, the reliability evaluation of ADNs needs to address increased complexity, such as uncertainty of renewable generation, operation of energy storage and optimal management of controllable network solutions. Commonly used methodologies for the reliability assessment of conventional distribution networks do not have capabilities to address these new challenges, as it has been recently pointed out by the European Platform for Smart Grids ETIP SNET [6]. Therefore, new methodologies are needed for the reliability assessment of ADNs.

1.2 Objectives

The principal objective of this thesis is to develop a set of new tools for reliability assessment of Active Distribution Networks (or ADNs) in order to enable the planning of the networks with desired levels of reliability. The ADNs under evaluation include the following technologies: conventional and renewable distributed generation, energy storage, demand management and power-electronics converters. The proposed tools must be firstly validated and then applied to study the reliability of ADNs operating in different network configurations and scenarios.

In order to achieve the principal objective, the following specific objectives are set:

1. To review the existing methodologies for reliability assessment of ADNs. The existing methodologies should be discussed, and the main research challenges in the field identified.

2. To develop new analytical tools for evaluation and selection of energy storage in reliability studies. The aim of these tools is to:

    (a) Reduce the computation times required for energy storage evaluation in reliability studies and guarantee accuracy of results.

    (b) Support the selection of energy storage in order to improve the reliability of distribution networks. The size and technology of energy storage should be selected according to technical and economic criteria.

3. To develop new tools for reliability assessment of ADNs combining distributed generation, energy storage, demand management and power-electronic devices. All these solutions have advanced control capabilities that should be modelled to obtain accurate reliability results, including their optimal operation during outages.

4. To implement the above-mentioned tools in such a way that different distribution network topologies could be evaluated (networks restored either by islanded operation or by reconnection to other non-interrupted network areas).

5. To validate the proposed tools and to analyse the reliability of ADNs by identifying and quantifying the specific reliability improvements provided by each ADN

technology. Both test and real distribution systems should be used for this purpose.

One should note that none of these methodologies and analyses has been addressed before in the literature, although their development is important for an effective reliability assessment of ADNs.

1.3 Thesis Structure

This thesis is comprised of eight chapters, with additional information provided in the Appendices. All the chapters, except Introduction (Chapter 1) and Conclusions (Chapter 8), are organised in the same format as the published or submitted articles during the elaboration of the thesis. Therefore, each of these chapters has their own abstract, introduction, methodology, results and conclusions.

In Chapter 1, the motivation, objectives and structure of the thesis are presented.

Chapter 2 reviews the methodologies proposed in the literature for reliability assessment of ADNs. First, the reliability benefits provided by different solutions used in ADNs are introduced. These solutions include distributed generation, energy storage, microgrids, demand response, automation of protection devices and electrical vehicles. Afterwards, the methodologies proposed for each of the mentioned solutions in the literature are critically discussed, determining their requirements, advantages and limitations. Finally, main research trends and needs are identified.

In Chapter 3, the existing distributed generation models used for reliability assessment are critically compared. First, different models are discussed and classified according to the approach applied for addressing the variability of renewable resources. Then, accuracy of results and computational times are used to compare the modelling approaches. Finally, recommendations for appropriate model selection are provided.

Chapter 4 presents an analytical technique developed for energy storage evaluation in reliability studies. The energy storage is used to support variability of renewable generation during outages. First, the proposed model for energy storage and the analytical formulation for reliability assessment are described. Then, the technique is validated and its computational efficiency demonstrated. Moreover, the contribution of energy storage to reliability is evaluated for different distribution network topologies.

In Chapter 5, a methodology for energy storage selection in reliability studies is introduced. The technical and economical calculation steps are described. In addition, the reliability and cost-benefit results obtained for a distribution system are used to illustrate the methodology application to energy storage selection.

Chapter 6 proposes a methodology for the reliability evaluation of ADNs with distributed generation, energy storage and demand management. These three resources are coordinated to minimise the effect of interruptions, while the corresponding impact on reliability is calculated. The improved evaluation is demonstrated for two distribution systems.

In Chapter 7, a novel methodology to evaluate the impact of active network management technologies on reliability is explained. Control capabilities of distributed generation, on-load tap changer transformers, demand management and power-electronic-based solutions are all evaluated. The contribution of these technologies to reliability is demonstrated in two distribution networks with different topologies.

Finally, Chapter 8 draws the conclusions, highlights the contributions and reflects on possible future extensions of the work.

Chapter 2

Literature Review: Reliability Assessment of Active Distribution Networks

Reliability assessment tools are of crucial importance for planning power distribution systems. In recent years there has been an increased deployment of renewable energy, distributed generation, energy storage, electric vehicle, protection device automation and demand response schemes in the distribution system, leading to the creation of the term *Active Distribution Networks* (ADNs). All these technologies contribute in their own way to the network reliability. The objective of this chapter is to provide a critical literature review of the reliability assessment techniques used for the evaluation of distribution networks, emphasising the importance of an increased penetration of distributed energy resources and a more widespread application of control, protection and communication technologies. A detailed analysis and a comparison between different techniques used for the reliability assessment will be provided for each technology. Most of the content of this chapter has been already published in [10].

2.1 Introduction

Conventional solutions for providing an adequate level of reliability in distribution networks are based on the design of meshed grids (components in parallel, alternative feeders to restore the supply, etc.), the enhancement of asset maintenance, the application of more reliable components and the installation of additional protection devices. The evolution of distribution networks towards more active and sustainable systems creates a new set of opportunities for further improvement of network reliability [6, 9]. For example, both conventional and renewable Distributed Generators (DGs) can supply power to network areas interrupted by faults. Energy storage technologies can be used to mitigate the fluctuations of renewable generation and extend their contribution to the supply restoration. Automation of the protection devices can be used to reduce the time response necessary for the network reconfigurations in presence of faults. Also, the application of demand response techniques can help decrease the peak demand selectively and preserve the security of supply under emergency conditions. The impact of all these options on distribution network reliability has to be properly addressed in order to support appropriate planning decisions [4]. Different techniques have been proposed and applied for this purpose. A critical review of these techniques will help identify the most suitable ones for any given network scenario as well as their main limitations.

Several publications have addressed the state-of-the-art in reliability assessment techniques applied to distribution networks. The most relevant probabilistic methods applied to reliability evaluation of power systems from 1964 to 1999 were presented in [11, 12, 13, 14, 15, 16], and some of them addressed distribution networks. EPRI white paper in [17] introduced definitions, concepts, practices and regulatory issues with respect to reliability in distribution networks, and a dedicated chapter addressed the principal techniques and the software used for reliability assessment. In year 2000, a review of the reliability evaluation techniques for power systems was published in [5]. In this paper, it was explained the need of new techniques for addressing the competitive nature of modern distribution systems along with the additional modelling requirements for distributed generation. In [18], the reliability assessment techniques for distribution networks were classified by methodology, reliability indices used and inclusion of Distributed Generators (DGs). The models and algorithms applied to reliability evaluation of power systems with wind generation were found in [19], while a review of the Markov models proposed for the evaluation of renewable distributed generation in reliability studies was included in [20]. Although some of those reviews assessed the reliability impacts of conventional and renewable DGs on distribution networks, a critical and complete comparison of the applied methodologies has not been found in the existing scientific literature. Moreover, techniques for reliability assessment of ADNs with energy storage, microgrids, electric vehicle, demand response and protection devices have not been adequately addressed.

This chapter provides a literature review of the most relevant techniques used for reliability assessment of ADNs. The principles and the methodologies proposed for the reliability evaluation of the above-mentioned technologies will be firstly introduced and then critically reviewed. The properties and shortcomings of the proposed methodologies will be specifically discussed. The objectives of this chapter are:

1. To establish the state-of-the-art in reliability assessment of ADNs and present a useful survey for researchers and practitioners in the field.

2. To find the appropriate reliability assessment techniques for ADNs with specific

requirements and technologies and support their modelling.

3. To identify gaps in the literature and suggest opportunities for future research in the field.

The chapter is organised as follows. Section 2.2 introduces the approaches for the reliability assessment of conventional distribution networks. In Section 2.3, how the new technologies in ADNs can further improve the reliability of the distribution system is described. Section 2.4 provides a critical analysis of the techniques proposed for the reliability evaluation of ADNs with DGs, energy storage, microgrids, electric vehicle, demand response, protection devices automation and communication technologies. Finally, concluding remarks including the main findings and opportunities for future research are summarized in Section 2.5.

2.2 Reliability Evaluation in Conventional Distribution Networks

The aim of reliability assessment techniques is to estimate the impact of interruptions on customers, and probabilistic techniques are commonly used for this purpose. Fig. 2.1 shows the main inputs and outputs of a reliability assessment technique. System topology and fault statistics of network components are the input data used by the technique, while the output results are the reliability indices [21]. These indices represent the metrics used during the network planning for quantifying the impact of interruptions. They provide technical and economic information related to the reliability of individual loads and network areas as, for example, the number of interruptions and their duration, the energy-not-supplied and the cost of the energy-not-supplied. Additional information on the definition of indices and their calculation can be found in [21] and in Appendix A.

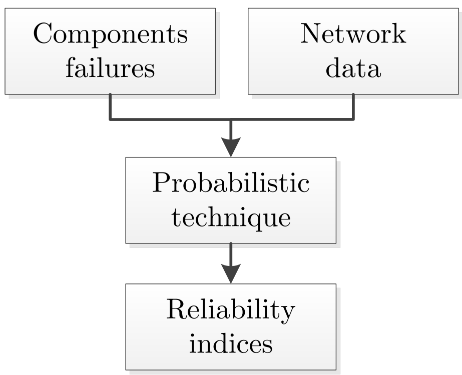


Figure 2.1: Inputs and outputs in a traditional technique for reliability assessment

Two probabilistic approaches can be used in reliability assessment techniques: analytical and simulation [3]. The most relevant characteristics of both approaches are summarized and compared in Table 2.1. Analytical techniques (also called deterministic) incorporate mathematical expressions to evaluate the reliability. They use average values of failure statistics as input data and calculate average values of reliability indices. On the contrary, simulation techniques (commonly know as Monte Carlo Simulation, MCS) sample stochastic failures of network components and other uncertainties inherent to the problem. These techniques use probability distribution of failure statistics as input and compute probability distributions of reliability indices, providing more detailed information than average values. In contrast, a large number of simulations are required to obtain the reliability indices, leading to computational times longer than analytical approach. According to these characteristics, the choice of the approach that is to be used depends on the specific requirements of the analysis [16].

Table 2.1: Comparison of the analytical and MCS approaches

Parameter	Analytical	Simulation
Calculation	Mathematical formulas	Repetitive samples
Input data	Average values	Distribution functions
Results	Average values	Distribution functions
Computational time	Low	High

Once the probabilistic approach is selected, the distribution system is modelled. Reliability models are used for different network components like power lines, transformers, substations or protection devices. These models represent the possible states that a device can have and Markov models are commonly applied. Two-states Markov models are typically used: the up state representing the normal operational conditions and the down state the component failures [22]. In addition, customer loads have to be modelled too and the average values of annual load are commonly assumed [3].

Once the system is modelled, the interruptions caused by component failures are typically evaluated by performing the following steps [22]:

1. The operation of the protection devices during the fault is simulated. The fault isolation and any possible actions during the network reconfiguration are represented.

2. The loads interrupted as a result of the fault are identified. Several network areas with different interruption levels can be found.

3. If possible, supply restoration actions are applied and their capability to supply the interrupted demand is evaluated.

4. The interruptions caused by the fault are determined for each load point.

5. Finally, the evaluation is repeated for all the network failures considered and the reliability indices computed.

With the development of ADNs, new technical solutions are added to distribution systems [9]. The impact of these new functionalities on distribution system reliability need to be assessed by applying new methods.

2.3 Opportunities for Reliability Improvement in Active Distribution Networks

2.3.1 Distributed Generation

Installed DGs can be used to improve reliability of distribution systems [23]. Under fault conditions in a distribution network, the power supply to some areas of the network can be interrupted and the DGs installed in these areas can be used then to restore the interrupted supply.

Fig. 2.2 shows the two modes in which DGs can be operated to restore the supply and improve reliability. The islanded mode (Fig. 2.2, up) is applied in areas isolated from the primary substation under fault conditions. In this case, the DGs located within isolated areas are used to provide energy that is not supplied by the primary substation, assuming the network is equipped to operate in this mode. The emergency-tie mode (Fig. 2.2, down) refers to networks with interrupted areas that can be reconnected to adjacent feeders by closing tie switches (also known as Normally-Open Points, abbreviated as NOPs), but the adjacent feeders have insufficient transfer capacity to restore all the supply. In such a case, the DGs can be used to increase that transfer capacity.

2.3.2 Energy Storage

A significant part of the DGs will use variable renewable sources exposed to fluctuations like wind and solar. Capability of these variable DGs to restore the interrupted supply can be extended by using energy storage. Fig. 2.3 shows an example of network failure in which energy storage is charged at periods of generation exceed (between time-steps $t3$ and $t4$ in the figure) and discharged at periods of insufficient generation (between $t4$ and $t5$). Consequently, reliability of distribution networks can be improved by using energy storage.

2.3.3 Demand Response

Another way to improve network reliability is to take advantage of demand response actions. It can be used to reduce the load under fault conditions by disconnecting or shifting less critical loads. Demand response actions can be combined with DGs to adjust the generation and the demand during the supply restoration as shown in Fig. 2.3 between time-steps $t2$ and $t3$.

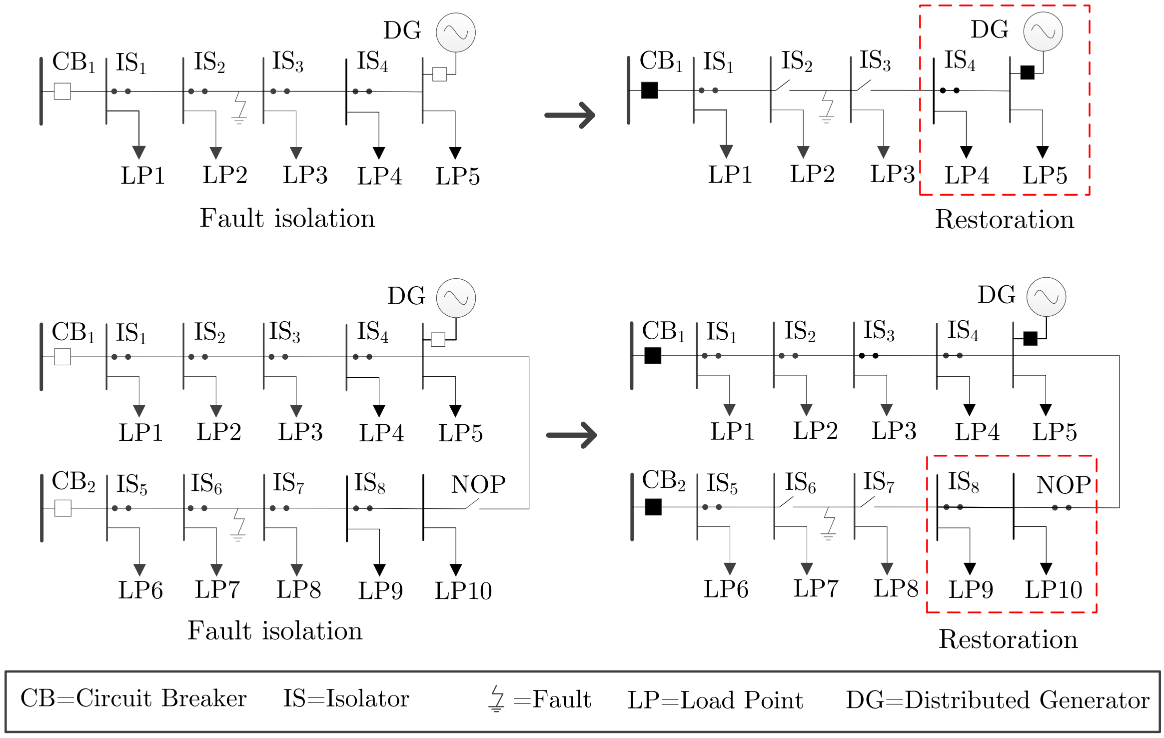


Figure 2.2: DG operating modes for network reliability improvement: islanded mode (up) and emergency-tie mode (down)

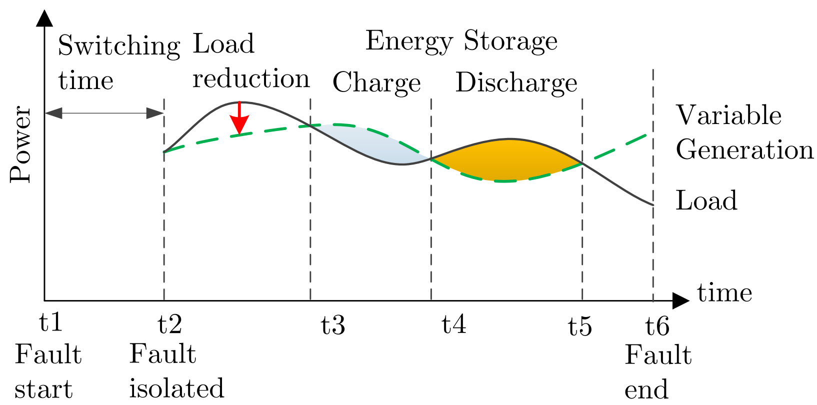


Figure 2.3: Contribution of energy storage and demand response to enhance the network reliability

2.3.4 Electric Vehicles

Electric vehicles introduce several options for reliability improvement under fault conditions:

- Reduce the demand, actuating similar to demand response.

- Supply the energy stored in the batteries of the electrical vehicle, operating similar to energy storage. In this option, the electrical vehicle can improve reliability in vehicle-to-grid and vehicle-to-home modes.

2.3.5 Automation of Protection Devices

The number and the duration of interruptions can be significantly reduced by implementing advanced control of protection devices. Identifying fault locations, applying fault isolation and remotely controlling restoration process are some examples of possible actions to improve reliability provided by protection automation. A dynamic and selective control of customers restored (or not restored) during faults is also another improvement of automated protection devices.

2.3.6 Microgrids

In the case of a fault in the distribution network, microgrids can disconnect from the main distribution system and operate isolated in intentional islanding in order to guarantee their reliability. Diverse resources in the microgrid like DGs, energy storage and demand response can be used to supply the local demand. Once the fault has been solved, the microgrid can be reconnected to the distribution system.

2.4 Reliability Evaluation Techniques for Active Distribution Networks

This section provides a review and discussion of the most relevant techniques used for the reliability evaluation of ADNs. It is assumed such networks can include conventional and renewable DGs, energy storage, microgrids, electric vehicles, demand response actions, automation of protection devices and information and communication systems.

2.4.1 Distributed Generation

The techniques for reliability assessment need to be capable of quantifying the contribution of DGs to network reliability. This means the capacity of DGs to restore the interrupted supply have to be evaluated, including the following properties:

- availability of the DGs exposed to failures,
- operating mode of the DGs (islanded or emergency-tie as described in Section 2.3.1),
- energy source (dispatchable or non-dispatchable).

Availability of the DGs

The DGs failures limit the generator availability to restore the supply. These failures have to be taken into account in reliability assessment and probabilistic models are used to represent their stochastic nature. Markov models are typically used to represent DGs in reliability studies and several variants can be used [3]. A simple solution is to use the two-state Markov model shown in Fig. 2.4 left, which is defined by the up and down states and the transitions between them. Another option is to include additional derated states in the model that represent different levels of power in the DGs as depicted in Fig. 2.4 right.

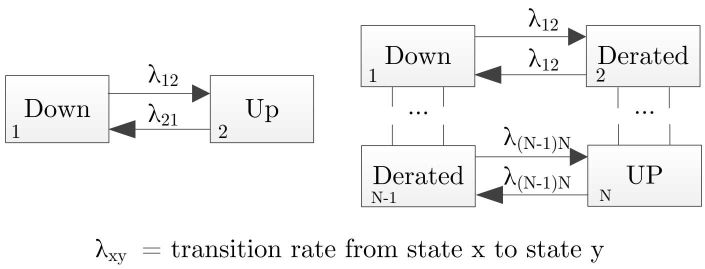


Figure 2.4: Two-states Markov model (left) and example of N-states Markov model with derated states (right)

In the case of dispatchable DGs, the generation power of each state in the Markov model is known and constant. However, the generation for non-dispatchable DGs like wind and solar is conditioned by the availability of the variable resources and, therefore, it needs to be determined. A review of the reliability models proposed for different types of renewable DGs is given in [20]. Nevertheless, the adequateness of these models is conditioned by the technique used to assess reliability. A more detailed discussion of the models used to assess the variability of renewable generation is given in the following sections.

An additional consideration is that the integration of renewable generation depends on the application of power electronics technology. Therefore, the reliability of power electronics devices has to be included in the reliability assessment. Reliability models for inverters used in photovoltaic generators have been proposed in [24] and [25].

Islanded operation

At present the regulation does not permit the intentional islanding operation in distribution networks in most countries. One of the limitations is the requirement for appropriate control, protection and communication technologies that guarantees the successful operation of DGs in islanded mode. Developments in the field make the islanding operation promising when it comes to improvement of distribution network reliability. Consequently, numerous techniques have been proposed in recent years to assess reliability of distribution networks equipped for islanded operation as shown in Table 2.2. These techniques model the principles of islanded operation affecting reliability, such as the actuation of protection devices, the adequacy assessment of load and generation and the modelling of generation and load.

Configuration time of the isolated area:

Before an isolated area switches to the islanded mode, some time is required to isolate the fault and connect the alternative generation sources. This time is given by the operation of the protection devices (defined as switching time) and the start of the DGs involved. As Fig. 2.3 shows, during this time an interruption of supply is produced and its impact on reliability has to be quantified by the reliability assessment techniques. Therefore, the protection devices and the DGs involved in the islanding process are identified and the procedure for the island forming simulated.

A set of analytical expressions is presented in [26, 27] to quantify the impact of the protection devices operation in islanded operation. The expressions assess a large number of operational cases of protection devices. Nevertheless, a more accurate evaluation is proposed in [28] to differentiate between the opening and closing times of all sectionalizers involved in the restoration process.

The definition of the starting time of the DGs depends on the generator technology and its operating mode at the moment of the fault. The earliest techniques proposed to assess the reliability impact of dispatchable DGs [29, 30] already included equations for quantifying the effect of the starting time in the interruption duration. In general, most reliability assessment techniques proposed consider the starting times of DGs. However, what is commonly neglected in the calculation of the starting times is the operation status of the DGs at the moment of the fault. This effect was evaluated in [31] by identifying the probability the generators will be in operation or in standby mode at the moment when the fault occurs.

Adequacy assessment of the isolated area:

Once the isolated area has been configured for the islanded operation, the capacity of the DGs to supply the demand interrupted by the fault is evaluated. An adequacy assessment of generation and load in the island is performed for this purpose. This is a fundamental requirement for all methodologies used in reliability assessment of distribution networks that consider restoration in islanded operation.

The adequacy assessment helps to determine if there are generation shortages that make restoration infeasible. Based on these generation shortages, different criteria can be applied to determine when the supply is restored. A first criterion results in no load being restored if there is a generation shortage at any moment of the adequacy evaluation period. A second criterion is to restore the supply in those time intervals that have sufficient generation to supply the load and guarantee the non-occurrence of repetitive interruptions in restored customers [32, 33]. An alternative option for increasing the load restoration is the application of load-shedding actions under conditions of limited generation in the island [26, 28, 34] (more details in Section 2.4.4). Another option is to minimise the interrupted load during the failure time.

Generation and load models:

The models used to represent generation and load are another important factor to be considered in the adequacy assessment. For dispatchable DGs, a constant power of generation is assigned to the states in the reliability model [29, 31, 35, 36]. However, the existing environmental and market principles suggest that in future a significant part of DGs integrated will be from renewable intermittent sources such as solar and wind. These variable resources reduce the ability of generation to meet the demand in islanded mode and, therefore, affect the reliability. In addition, the demand is also variable and the restoration of supply is influenced by the chronological dependence of variable generation and load. Hence, existing techniques for reliability evaluation need to be extended to address this variability effect. To overcome this challenge, Monte Carlo Simulation approach is frequently used [37, 38, 39, 40, 41, 42] because it provides more flexibility and accuracy than analytical approaches for modelling the variability.

Although Monte Carlo Simulation is the most commonly used approach to assess the reliability in presence of renewable non-dispatchable DGs, its high computation times explain the interest in looking for alternative analytical techniques. Because analytical techniques do not consider the stochastic behaviour of faults occurrence, they require more attention in modelling the variability and time-dependency of renewable generation and load [43]. As a result, several specific probabilistic models of generation and load have been proposed in recent years for their use in the analytical approach as shown in Table 2.2. In this table, the type of model proposed and the probabilistic approach used are specified, and more details are given in the following paragraphs.

Table 2.2: Comparison of techniques for reliability assessment considering DGs in islanded operation

Ref.	DG type[a]	Technique	Generation and load models	Restoration strategy [b]
[29], [30], [31]	D	Analytical	-	(1)
[37], [38], [39]	D, ND	SMCS	Markov (3 states), average load	(1)
[41]	D, ND	MCS	Probabilistic outage table	(1)
[40], [42]	D, ND	SMCS	Hourly profiles of a year	(2)/(1)
[44]	D, ND	Analytical	Levels of a typical day	(1)
[26], [45], [46]	D, ND	Analytical	Probabilistic outage table	(2)/(1)/(1)
[32], [33], [47]	D, ND	Analytical	Representative segments of a year	(3)/(3)/(1)

[a] D=Dispatchable; ND=Non-dispatchable

[b] For each reference: (1) All load in the island has to be restored; (2) Load shedding is also applied; (3) Non repetitive interruptions are caused.

In [37, 38, 39] the average load in the isolated area is determined during failures, while a three states Markov model (up, down and derated) that combines the availabilities of the generator and the renewable resource is used for wind DGs. Using these models of load and generation, the restoration is applied if the minimum power of the renewable generation is higher than the demand. Another option is to use probabilistic tables consisted of a set of power levels and their respective probabilities (capacity probabilistic tables), both for demand and variable generation [26, 41, 45, 46]. For each power level of generation and load in these tables, the adequacy is evaluated in order to determine the restoration capacity of DGs. Simulation techniques sample the level of load and generation stochastically and the analytical techniques calculate the probability of adequacy. The main inconvenience of the probabilistic tables is the use of a discrete number of power levels and the impossibility of considering the time dependent fluctuations of load and generation over the fault duration. Clustering techniques have been used in [28, 45] to determine an appropriate number of levels of renewable generation and demand, but these clusters also neglect fluctuations of generation and demand during failures. It is demonstrated that neglecting these fluctuations leads to a strong overestimation of the DG capacity to meet the load of the island [33]. For a more accurate reliability evaluation, new developments are sought to take into consideration the time-dependent fluctuations of load and generation during failures.

Hourly profiles of load and generation represent another type of model that considers fluctuations of renewable generation and demand. They can be used in Monte Carlo Simulation techniques for accurate evaluation [40, 42], although intensive computational resources are required. In the case of analytical techniques, using hourly models of variable generation and load also represents a solution for considering power fluctuations, but it involves an increased complexity of the analytical formulation. Instead of using a whole year of load and renewable generation data, the hourly data of the year are divided into a set of representative periods like, for example, typical days [44]. In [47] hourly representative models of generation and load were established to analytically compute the reliability indices. In [32] the hourly probability of successful restoration by DGs was calculated considering the variability of generation and load in the island. The accuracy of these hourly-based methods was verified by using the results from the Monte Carlo Simulation, in spite of not modelling the full variability of load and generation as yearly profiles do.

Markov models are also a feasible alternative to evaluate the fluctuations of renewable generation and load during the islanded operation [33], although the complexity of the model can increase significantly with the number of power levels and the transitions between them. Another option that can be investigated consists of obtaining a set of scenarios able to represent the fluctuations of generation and demand during faults.

Other effects in islanded operation:

It is not a common practice to evaluate network constraints in the adequacy assessment because they are typically assumed to be considered in other planning stages. Yet a massive integration of renewable DGs can contribute to violation of operational limits. Therefore, a realistic reliability evaluation should consider network constraints. Some of the existing techniques for reliability assessment integrate power flow calculations for this purpose [40, 48]. Considering network constraints in simulation techniques implies a large number of power flows to be calculated that increases the computation time significantly. Alternative simplified power flow formulations were recommended in order to decrease the computational time [49].

Based on the information provided by power flow calculations, corrective actions are applied in case of a network constraint violation. Load disconnection or generation curtailment are typical solutions to preserve the operational limits in reliability assessment techniques. An alternative to be investigated is the modelling of corrective actions based on active network management schemes in ADNs [50].

Another aspect not considered in previous publications is the dynamic effect of frequency and voltage deviations. It affects the feasibility of the islanded operation and their inclusion in the reliability assessment guarantees more accurate results. In [51], a methodology is proposed to include the islanding dynamics effects in the reliability evaluation.

Emergency-tie operation

In emergency-tie operating mode, DGs improve the reliability of distribution systems by supplying power together with adjacent feeders that have an insufficient transfer capacity to restore the full load [23]. In order to estimate the corresponding reliability impact, it is necessary to quantify the transfer capacity between feeders in presence of DGs.

There have been less research results round for the reliability evaluation of the emergency-tie mode than for the islanded mode, probably because the restoration from alternative feeders in distribution networks is designed to avoid transfer restrictions even in absence of DGs. However, these power transfer restrictions can occur in the network, especially with the increase of the demand in existing networks. In these circumstances, DGs can be an effective alternative to line repowering for guaranteeing reliability [52, 53].

Hence, some publications perform power flow calculations to calculate the transfer capacity of distribution networks with DGs and avoid network constraints violation [48, 54], as shown in Table 2.3. The techniques based on power flow calculations require more computational resources and their application in simulation techniques may be unacceptable or excessively long. A simplified procedure to determine the transfer capacity without power flow calculations represents a computationally efficient alternative even though the accuracy can be compromised. In [55] an analytical procedure is used to calculate the transfer capacity according to a set of load levels in the network (low, medium and high). Then, the analytical procedure is integrated inside of Monte Carlo Simulation to reduce the computational time. Other non power-flow based techniques calculate the joint probability of demand and generation to determine the contribution of DGs in emergency-tie mode [56]. A set of levels of generation, load and transitions between them are used to quantify this joint probability, although the time dependent fluctuations of load and generation during the outage are not included in the calculation. An alternative to overcome this limitation is to use a reduced set of representative scenarios for load and generation. The transfer capacity can be then deduced from these scenarios and the contribution of DGs to the reliability assessed.

Table 2.3: Comparison of techniques for reliability assessment considering DGs in emergency-tie operation

Ref.	Technique	Network constraints	Power flow	Transfer capacity calculation
[48], [54]	Analytical	Loading and voltage	Yes	Transfer produced if DGs alleviate network constraints
[55]	MCS + Analytical	Loading	No	Transfer capacity determined from the load level (high, medium, low)
[56]	Analytical	Loading	No	Lines capacity and joint probability of DGs and load

2.4.2 Energy Storage Systems

In addition to their primary roles like load shifting, congestion alleviation, frequency control, voltage control and electricity trading, energy storage can also contribute to improve the reliability of distribution networks. Under fault conditions, energy storage can be used to mitigate the variability of renewable generation and contribute to restore the interrupted supply in the network. This is a more attractive solution in economic terms than the implementation of energy storage as a stand-alone network application uncoupled from renewable generation [57].

An increased research work has been reported in recent years to assess the impact of energy storage on distribution network reliability. The proposed works are shown and compared in Table 2.4, including the main criteria used for the comparison and discussion along this section. Modelling the time-dependent performance, the availability and the restoration strategy are the main properties for energy storage evaluation in reliability studies.

Table 2.4: Comparison of techniques for reliability assessment considering energy storage

Ref.	Technique	Reliability Model	Purpose	Technology
[42], [57]	SMCS	Fully reliable	Restore supply in isolated areas with DGs/without DGs	Generic
[58], [59]	SMCS	Fully reliable	Improve reliability and economy operation in combination with renewable DGs	Generic
[60]	SMCS	Fully reliable	Reduce the peak demand at moments of higher interruption probability	Generic
[61]	SMCS	Fully reliable	Optimal energy storage allocation for reliability improvement	Battery
[62]	Analytical	Fully reliable (SOC levels)	Mitigate fluctuations of autonomous systems with wind and solar generation	Battery
[63]	Hybrid	Distribution function	Mitigate the fluctuations of renewable DGs in microgrids	Battery
[64]	Analytical	Markov model	Minimize energy-not-supplied and interruption costs in autonomous systems	Battery
[65]	Analytical MCS	Markov model	Mobile batteries to support the restoration of the interrupted supply	Battery

Time-dependent performance of energy storage

One of the most relevant tasks for reliability assessment with energy storage is to simulate its charge and discharge performance during the fault period. The charge takes place at generation excess conditions and the discharge under generation shortage conditions. The chronological evolution of generation and load has to be considered as shown in Fig. 2.3. Sequential Monte Carlo Simulation (SMCS) is typically used for including the chronological evolution in reliability assessment. The evolution of the state-of-charge (SOC) with the charge and discharge processes needs to be calculated and is commonly determined by Equation (2.1). The capacity and the power limits of the energy storage system are also respected in the calculation as shown in (2.2)-(2.3).

$$SOC(t+1) = SOC(t) + \frac{\Delta t}{C}\left(Pc(t)\eta c - \frac{Pd(t)}{\eta d}\right) \tag{2.1}$$

$$\underline{SOC} \leq SOC(t) \leq \overline{SOC} \tag{2.2}$$

$$(\underline{Pc}, \underline{Pd}) \leq (Pc(t), Pd(t)) \leq (\overline{Pc}, \overline{Pd}) \tag{2.3}$$

where Δt is the duration of time step t, C is the capacity of the energy storage, $Pc(t)$ and $Pd(t)$ are the charge and discharge powers, ηc and ηd are the efficiencies to charge and discharge, $\underline{SOC}$ and $\overline{SOC}$ are the minimum and the maximum of SOC, $\underline{Pc}$ and $\underline{Pd}$ are the minimum powers to charge and discharge, and $\overline{Pc}$, $\overline{Pd}$ are the maximum powers to charge and discharge the energy storage.

Reliability assessment techniques reported in [42, 57, 58, 59, 60, 61] consider the time evolution of SOC during faults. They use SMCS approach to sample load and renewable generation hourly profiles, and then to determine the energy storage performance. This method represents a simple and effective way for energy storage assessment in reliability studies, but it requires high computational times. As alternative analytical techniques have been proposed for the reliability assessment of energy storage in combination with renewable DGs [62, 64]. The principal objective is to take advantage of their superior computational efficiency. Specific probabilistic models are required for the calculation of the SOC evolution in analytical techniques and simplifications are commonly applied. In [62, 66] a probabilistic battery state model formed of multiple states of charge and their associated probabilities is used. However, the number of SOC states is limited and the chronological SOC evolution is not considered. This SOC evolution should be considered in future analytical techniques addresing energy storage.

The SOC of the energy storage when the faults occur (designed here as initial SOC) affects to the reliability improvement provided by energy storage. A typical and simple criterion in the reliability assessment assumes the energy storage fully charged when the fault is registered [57, 58, 61]. A more realistic alternative is to consider a certain SOC level [64, 65]. The initial SOC can be established by the distribution network operator in order to guarantee specific reliability requirements. However, there is uncertainty related to the SOC at the moment when the fault occurs. To consider this uncertainty, in [62] the initial SOC and its probability are modelled by means of several SOC states. Another option not explored is to sample the initial SOC when Monte Carlo Simulation approaches is used. Cumulative distribution function or a set of scenarios with their probability can also be sampled.

Reliability models

An additional characteristic of energy storage to be included in the reliability assessment is the component failures of storage. A common assumption in reliability assessment techniques is to consider the performance of energy storage fully reliable without any failure (see Table 2.4). However, the components of the energy storage are exposed to failures and their impact on reliability needs to be quantified. A simple solution is to adopt the traditional two-state Markov model used for conventional components in distribution networks. Another option is to apply a cumulative distribution function of the battery availability [63]. However, failures of different components of the energy storage system are not distinguished. In [64] a multistate Markov model considering the failures of the battery, the controller and the inverter is used. Also, it is recommendable to distinguish between the availability of different energy storage technologies and their components.

Reliability impact of restoration strategies

The stored energy can be used to improve reliability under different strategies: to supply power as long as possible when a fault occurs [57, 58], to reduce the demand at peak periods when there is a higher fault probability [60] and to mitigate the fluctuations of hybrid systems consisting of variable generation (wind and solar) and energy storage [62, 64]. In addition, the control of energy storage systems installed in the distribution network can be coordinated to improve the reliability of bulk supply power systems [59].

Mobile energy storage systems are an alternative solution to restore the interrupted supply. A methodology to assess their impact on reliability is proposed in [65]. The time required for the operation of the mobile storage is taken into account when calculating the interruption duration.

The existing restoration strategies for reliability assessment do not consider an optimal use of energy stored over the outage duration. However, under normal operating conditions, energy storage operation is optimised to maximise the integration of renewable generation [60] or the energy purchasing cost [58]. Therefore, the optimal use of the energy storage in the restoration strategies provides more realistic results of energy storage contribution to reliability. The power to charge and discharge at different time-intervals can be optimized with an aim to minimise the energy not supplied or the interruption costs. At the same time, the system requirements will be satisfied. For example, in [64] a hybrid system consisting of wind generation, solar photovoltaic and energy storage is operated to minimise the power interrupted in the distribution system.

Impact on reliability of energy storage location, size and technology

Location and size of energy storage are a design criteria with a relevant impact on distribution network reliability. These parameters are considered during the planning of distribution networks as well as the reliability assessment. In [61, 67] methodologies for optimal location and size of energy storage were proposed to maximize reliability improvements. The optimal planning of battery systems was also addressed in [68] considering the provided reliability benefits.

Also, a variety of different energy storage technologies are available [69]. Their specific functional details have to be considered by the reliability assessment techniques. Charge and discharge powers, capacity, efficiency, ramps to charge/discharge and reliability of the components depends on the technology. Consequently, these features influence the performance of the energy storage and the network reliability. An accurate comparison of energy storage technologies during the planning stage requires a detailed modelling of their specific properties for the reliability assessment and more research is necessary in future. Generic energy storage systems or batteries are normally considered in the reliability assessment (see Table 2.4). In [61], different types of battery technologies (lead acid, pressed air, sodium sulfur, redox) are compared in the reliability assessment. The lifetime of electrochemical batteries depends on their use and this effect needs to be included in the reliability assessment.

2.4.3 Microgrids

In addition to power systems, microgrids are an example of novel technological solutions introduced, among other reasons, with the aim of improving the reliability. The microgrids discussed in this section refer to subsystems of distribution networks that include distributed energy resources like DGs and/or energy storage, and can be isolated from the rest of the network in case of supply interruption [70]. Therefore, two modes of operation are possible in a microgrid: connected to the network in normal operating conditions, or isolated from the network under fault conditions. In the first mode, or grid-connected mode, the distributed resources within the microgrid are managed to optimize the operating costs, while in the islanded mode the aim is to restore the supply by using the local energy resources.

Reliability is a fundamental parameter for the design of microgrids. A number of methodologies address the microgrid planning and take into account their level of reliability [71, 72, 73], representing islanded operation a potential solution for the reliability improvement of microgrids. The conventional techniques for the reliability assessment can be applied to load points outside a microgrid, but new methods to assess microgrids and their islanded operation are required.

The particular characteristics of microgrids make appropriate the definition of new indices for quantifying their reliability. Microgrids are not always regulated by the policies of the distribution network and new indices as those proposed in [74] can be more valuable for evaluating the reliability of the customers connected to a microgrid.

Operating modes and technologies used in adequacy assessment

The principles for reliability evaluation of microgrids in islanded mode are similar to those described in Section 2.4.1 for distribution networks with DGs and intentional islanded operation. The adequacy of generation and load is the basic principle for the reliability assessment of microgrids. The performance of distributed energy resources and the microgrid operation practices have to be considered in the adequacy assessment.

The principal techniques for reliability assessment of microgrids are shown in Table 2.5. As this table shows, typically both dispatchable and non-dispatchable DGs are analysed to restore the supply. Moreover, load shedding actions of non-critical loads are implemented in order to achieve the adequacy in the case of generation shortage [26, 75, 76], apart from other demand response actions described in Section 2.4.4. Energy storage can also be integrated to mitigate the variability of generation and load [63, 74, 77, 78]. Other resources like electric vehicles are considered in [78].

When faults occur in the distribution system, microgrids are typically operated in islanded mode to enhance the reliability of the customers connected to them (see Table 2.5). Another option is the use of microgrids to provide additional power to the distribution network under faults conditions, option defined here as emergency-tie mode. This last option means that the power excess of the microgrids can be supplied to the distribution network and enhance its reliability. In such a case, microgrids can be modelled as virtual power plants that can be represented by equivalent generators or loads depending on the operation conditions. The reliability improvement provided by this operating mode has been studied in [79, 80, 81].

Table 2.5 also shows that both analytical [26, 75, 80] and simulation techniques [74, 76, 77, 78, 79] have been used for the reliability evaluation of microgrids. Nevertheless, Monte Carlo Simulation is typically used in the presence of energy storage and time-dependent demand response actions because of the modelling advantage this approach provides in assessing the chronological performance compared to the analytical. Also, reliability has been evaluated for both low and medium voltage operated microgrids as summarised in Table 2.5.

Table 2.5: Comparison of techniques for reliability assessment considering microgrids

Ref.	Technique	Operating mode	Resources	Voltage level
[26], [75]	Analytical	Isolated	DGs, load-shedding	MV
[80]	Analytical	Isolated and emergency-tie	DGs, load-shedding, energy storage	LV
[79]	MCS	Isolated and emergency-tie	DGs, load-shedding	MV
[74], [77]	MCS	Isolated	DGs, load-shedding, energy storage	LV/MV
[78]	SMCS	Isolated	DGs, energy storage, electric vehicle	MV
[63]	Hybrid MCS-analytical	Isolated	DGs, energy storage, load-shedding	LV

Protection devices and microgrids operation

The previously mentioned techniques for reliability assessment of microgrids do not consider specifically the impact of protection devices on microgrid reliability. New protection devices and protection schemes help to increase the reliability of microgrids [82], however, their incorrect operation may compromise it. The complex operating conditions in microgrids (typical for their islanded operation), variability of renewable generation and bidirectional power flows require different settings of protection devices. As a result, the probability of undesired activation of protection devices increases. In [83] the impact of malfunctioning of protection devices is evaluated by using a model that correlates voltage/current with the outage rate of components. The uncertainty of the protection settings caused by the changing operating conditions is assessed in [84], while the probability of triggering incorrectly the protection devices is considered in [85].

Frequency and voltage limits of microgrids in islanded operation represent only some of the parameters frequently ignored during a reliability assessment. This means that primary and secondary controls in microgrids, in charge of avoiding the frequency and voltage violations, are not included in the reliability assessment. In [86] the performance of primary and secondary controls of microgrids is modelled and its effect on reliability assessed.

2.4.4 Demand Response

Demand response is a well-known way of incentivising end-use customers to change their energy consumption habits and to reduce their electricity use at times of high market prices, high network loading or emergency conditions [87]. Corrective demand response actions after a network fault represent an useful option for reliability improvement, allowing selective disconnection of certain type of loads or shifting their use over time.

Evaluation of the impact of demand response on reliability requires additional steps when compared to the conventional reliability assessment [88]. Several techniques have been proposed to deal with specific properties of demand response, as Table 2.6 summarizes. It provides a comparative analysis of how different reliability assessment techniques address the specific characteristics of demand response.

Table 2.6: Comparison of techniques for reliability assessment considering demand response

Ref.	Technique	Operating mode	Instrument	Criteria	ICT impact
[89]	Analytical	Emergency-tie	Incentive payments	Min interruption cost	No
[90]	SMCS	Emergency-tie	Incentive payments	Disconnect/shift less critical load	No
[91], [92]	Analytical, SMCS	Emergency-tie	Incentive payments	Min interruption cost and payback incentives	Yes
[93]	SMCS	Islanded	Electricity price	Max incomes of supplier, Min payments to customers	No
[94]	SMCS	Islanded	Incentive payments	Min interruption cost	Yes

Reliability indices for demand response

The first consideration to evaluate the impact of demand response on reliability is to distinguish between interruptions caused by intentional demand management and by component failures. In this respect, the impact of interruptions caused by demand response is less significant (loads interrupted are the less critical ones) and the interruptions are known in advance. Therefore, new reliability indices that differentiate between interruptions caused by demand response actions are required. In [88] a new set of indices is proposed for this purpose.

Demand response capacity

The capacity of demand response actions to shift or disconnect certain type of loads needs to be evaluated and integrated in the reliability assessment procedure. This capacity is defined by the number of responsive appliances and loads, the moment when can be applied and the demand reduction it can provide [89]. As the demand response capacity is linked to the time-dependent evolution of load, the reliability assessment needs to model these chronological patterns of demand. That is the reason why profiles are commonly used to model the load in the reliability assessment. In addition, SMCS is the approach frequently used to assess the reliability [90, 92, 93, 94], although other analytical techniques based on the reduction scenarios techniques were also proposed [89, 91].

Demand response instruments

Implementation of demand response capacity relies on the attractiveness of the proposed incentives and on the willingness of the customer to change its electricity use. Basically, there are two available classes of instruments to build up this capacity: incentive payments for load interruption and changes in the price of electricity [87].

Incentive payment instruments are used to disconnect loads of customers under fault conditions or violations of network constraints. A selective disconnection of loads can help to mitigate the impact of the load interrupted. Attractive incentive payment instruments commonly pursue the minimisation of the total interruption cost and they are considered in the methodologies for reliability assessment as shown in Table 2.6. Criticality of the load is another criterion for demand response applications, being the less critical loads interrupted first [90, 95].

Price-based instruments provide time-varying rates to incentivise customers to use less electricity at high-price time intervals. As a result, load can be decreased selectively and shifted over time. Time-of-use pricing is, therefore, a price-based instrument that can be used under failure conditions to improve the reliability. In [93] the reliability evaluation of a time-of-use tariff is evaluated by considering different criteria to calculate the tariff: minimisation of the customers payment or maximisation of the supplier revenues. Implementing differentiated reliability services is an alternative for an effective demand response application. Adapted pricing schemes based on the outage costs, reliability indices or customers priority can be applied to customers in distribution networks offering them different levels of reliability [96]. However, it is important to mention that the reliability assessment methodologies that evaluate the impact of price based instruments are less in number than for incentive payment instruments. This fact is depicted in Table 2.6 and the possible cause is the incentive-based instruments are directly applied to mitigate the impact of network faults.

The effectiveness of both types of instruments to improve reliability is somewhat uncertain. The willingness of customers to implement the programs for demand management depends on probabilistic factors that need to be included in the reliability assessment techniques [97]. In [94] the willingness of customers to participate in demand response is determined from their historical profitability levels, the human behaviour and incentives applied.

Demand response application in different network modes

Under fault conditions in the distribution network, the instruments for demand response can be applied to improve the reliability of the network in both emergency-tie and islanded modes. In emergency-tie mode, the operational limits of the alternative feeders used to restore the supply can be violated, making the supply restoration infeasible. By implementing appropriate actions, the demand can be decreased and the network constraints alleviated. The reliability improvement achieved by this type of application is evaluated in [89, 90, 92].

The application of demand response in islanded mode helps achieve the adequacy of load and generation in the isolated area. It reduces the demand in the island that needs to be supplied by the distributed energy resources. The corresponding impact on reliability is evaluated in [93, 94].

In both network modes, the operational performance of protection devices needs to be modelled. The modelling should include the interruption of supply during the time required to operate the protection devices since during this time demand response actions can take place. The shifting or intentional interruption of the load leads to an improvement in the reliability [89].

Communication and control technologies for demand response

A successful implementation of demand response relies on the network integration of Information and Communication Technologies (ICT) as well as control systems. ICT technologies are crucial for the information exchange between the agents involved, while automatic control technologies permit the direct actuation on the loads. However, the elements of these technologies are exposed to failures and it is necessary to model them in the reliability assessment procedure. Table 2.6 shows the reliability assessment methodologies that consider the effect of ICT and control devices required for the demand control implementation [91, 92, 94]. A two-state Markov model is typically used for modelling the operational state of these devices.

2.4.5 Electric Vehicles

Electric vehicles can also be used to improve the reliability of distribution networks by offering their services to the system operator under fault conditions. One option to improve the reliability is to interrupt the vehicle charging without penalty if there is insufficient supply capacity [98]. As a result, the demand is selectively reduced and the contribution to reliability can be quantified by using the techniques and principles described for demand response in Section 2.4.4.

Another service that electric vehicles can offer is to supply additional energy back to the grid in vehicle-to-grid mode (V2G) or to the customers in vehicle-to-home mode (V2H) [99]. The contribution of V2G to distribution network reliability is evaluated in [99, 100] for parking lots and in [99] for V2H mode. In both operating modes the contribution can be evaluated in a similar way that it is done for energy storage [100] and, hence, the principles described in Section 2.4.2 for energy storage are applicable. However, some specific details of electrical vehicles need to be included in the reliability assessment. Their probabilistic capacity and availability to inject power back to the grid have to be modelled taking into account uncertainties like the charge and discharge operation and the number of vehicles. In [100] a set of possible scenarios are selected for considering uncertainties of parking lots, while the energy that each parking lot can supply is determined from an optimisation problem which maximises the reward for the electrical vehicle users. In [99] the reversible power is calculated for both V2H and V2G modes and for centralised parking lots or decentralised individual users. In these discussed references, MCS is used to properly assess the uncertainty of the parameters.

Another important aspect to be considered in the reliability assessment is the strategy used by the operator for discharging the stored energy in electric vehicles. Interruption cost or load priority are typical strategies for supply restoration. The interruption cost of a distribution network with electric vehicles connected is evaluated in [101, 102]. For those customers with equal priority, new strategies based on a fair distribution of the resources represent an interesting option [100].

2.4.6 Automation of Protection Devices

Protection devices are fundamental to isolate and restore the supply interrupted by faults. Automatic protection devices and protection schemes can reduce the number and duration of the interruptions and improve the reliability [103]. In addition to that, these technologies allow an efficient network reconfiguration for the supply restoration by distributed energy resources and the application of demand response actions.

Automatic protection devices

A deployment of automatic reclosers and telecontrolled switches in distribution networks represents a clear improvement over the application of conventional manually-operated protection devices. They significantly can reduce the actuation time after a fault. This is the case of automatic reclosers and telecontrolled switches, which allow autonomous service restoration after a fault and a fast actuation on tripped switches. The performance of these automated protection devices needs to be reflected in the techniques for reliability assessment of distribution networks and recommendations for their modelling are given in [104]. A comparison of the techniques proposed for considering these devices in reliability assessment is shown in Table 2.7. The reliability impact of automatic reclosers is assessed in [105] by using an analytical methodology based on the state enumeration techniques and minimal cut set theory. Improvements in the reliability of distribution networks introduced by automatic switches were assessed in [106].

Techniques for the reliability evaluation of telecontrolled switches are proposed in [27, 107], where the switches are used for the network reconfiguration prior to application of intentional islanding operation. It is normally assumed that telecontrolled switches are reliable, however, they are also exposed to malfunctioning and communication problems. In [108] an extension to the reliability assessment techniques for telecontrolled switches was performed and the effects of their malfunctioning included.

Table 2.7: Comparison of techniques for reliability assessment considering automatic protection devices

Ref.	Technique	Protection device	ICT impact	DG restoration
[105]	Analytical	Automatic recloser	No	No
[106]	MCS	Automatic switches	No	No
[27], [107]	Analytical	Telecontrolled	Yes	Yes
[108]	-	Telecontrolled (malfunctioning)	Yes	No

Automatic protection schemes

Automatic protection devices in distribution network are usually operated according to a specific strategy for fault detection, isolation and reconfiguration. Protection automation schemes are used for the operation of these devices.

Different automation schemes provide different levels of reliability. Identifying the most appropriate scheme represents a challenge for the distribution system planning [109]. Therefore, techniques need to address the impact of the automation schemes on distribution system reliability and some methodologies were proposed in [109, 110, 111] to deal with this purpose.

In addition to fast detection and isolation of the fault, automated distribution networks can count on alternative restoration routes through different feeders and resources. A methodology for reliability evaluation of automation schemes that allows restoration by distributed energy resources in islanded operation was proposed in [82].

The implementation of automation schemes assumes the installation of new equipment that is prone to failure as well. The reliability impact of these components must be included in the overall reliability assessment [110, 112]. Some of the previous techniques [107, 108] (see Table 2.7) include the effect of failures in telecontrol communication infrastructure. The following section discusses some of the methodologies proposed for the overall assessment of the communication system.

2.4.7 Information and Communication Technologies

Most of the modern network technologies deployed in ADNs depend on ICT for their correct operation [113]. It is important to bear in mind that the ICT can also fail and the reliability of distribution networks can be compromised. Traditional reliability assessment techniques for distribution systems include only the physical electricity network for energy supply but not the communication network. Thus, it is necessary to combine the reliability assessments for both types of networks in order to obtain more realistic reliability assessments. A survey of some of the latest studies and findings in the literature about the impact of communication imperfections on power system reliability can be found in [114].

2.5 Concluding Remarks

Distribution networks are experiencing a modernisation process converting them into ADNs. ADNs should facilitate the integration of solutions like DGs, energy storage, microgrids, demand response, electric vehicle and automated protection devices. These solutions open up new opportunities to improve the reliability. In this chapter, a literature review of the existing techniques used for the reliability assessment of ADNs has been presented. The modelling requirements and the properties of the proposed methodologies in the field were compared and critically reviewed. The review provides the state-of-the-art in the topic and the necessary details for the implementation of the reliability assessment techniques.

From a general point of view, the literature review discovered intensive research efforts conducted towards modelling the features, complexities and uncertainties necessary for the reliability assessment of ADNs. In this sense, the publications have paid significant attention to the stochastic nature of aspects like the variability of load and renewable generation, the performance of energy storage, the estimation of demand response capacity and the opportunities introduced by electric vehicles.

Research in the field has also focused on the operational aspects of ADNs. Intentional islanding and microgrids have been identified as promising options for reliability improvement. The key criterion for their evaluation is to conduct an adequacy evaluation of generation and load in the isolated areas. Consequently, all those factors that impact the adequacy have to be considered in the assessment.

Another operational aspect affecting the reliability of ADNs is the strategy implemented to restore the supply, this is, how the technologies evaluated are used under fault conditions to reduce the impact of interruptions. The techniques for reliability assessment need to model realistic restoration strategies for accurate assessment.

The approach typically used in literature for reliability assessment is Monte Carlo Simulation. The stochastic nature of this approach allows the complexities and uncertainties of ADNs to be accurately addressed. However, an alternative research trend based on analytical techniques has been identified, promoted by their reduced computational times compared to simulation. The research work in this trend has been mainly focused on DGs, while some simplified models have been proposed for energy storage. New modelling work in the analytical techniques should take into consideration the complexities, the assumptions and the results accuracy.

This chapter also reveals specific findings for each of the technologies studied. Islanded operation of DGs is the technological solution with more techniques proposed for reliability evaluation, mainly due to its promising capacity to restore the supply in areas isolated by faults. In the case of DGs operated in emergency-tie mode, the techniques implemented for reliability assessment focus on quantifying the increase on transfer capacity provided by the generation. The capability of energy storage to mitigate the fluctuations of renewable generation during faults has been modelled and the corresponding impact on reliability evaluated. Behaviour factors (customers willingness, journey habits), environmental conditions and financial instruments (incentive payments, tariffs, vehicle-to-grid, vehicle-to-home) have been considered to evaluate the impact of demand response and electric vehicles on reliability. The field of protection device automation and its contribution to reliability has been focused on the modelling of the operation of new devices and schemes under fault conditions. The literature review also distinguishes the importance of the development of new reliability assessment techniques including the performance of the information and control systems used in ADNs.

Evaluation requirements and new opportunities for further research in the field have been identified: development of computationally-efficient techniques alternative to Monte Carlo Simulation, implementation of more advanced restoration strategies within the reliability assessment techniques, modelling of specific features of energy storage technologies, proposal of new tools for an integrated reliability evaluation of ADNs, and development of techniques for evaluating the impact of other solutions in ADNs like flexible AC transmission systems or power-electronics devices on reliability.

In particular, the following topics are addressed in this thesis:

- Different models of renewable DGs have been proposed for reliability assessment in the literature, however, a critical comparison of their properties including their performance and accuracy of results is missing. Such comparison is useful for the selection of the most appropriate models for the evaluation and is provided in Chapter 3.

- There is a lack of analytical techniques for a proper assessment of the impact of energy storage on distribution network reliability, including appropriate energy storage modelling and evaluation of islanded and emergency-tie modes. To cover this gap, a new analytical technique is proposed in Chapter 4.

- Selecting appropriate energy storage solutions to improve reliability is a complex issue affected by several parameters and there is still a room for an improvement. This problem is studied in Chapter 5 taking into account technical and economic parameters.

- Optimal restoration strategies are commonly neglected in the reliability assessment of ADNs. In presence of renewable DGs, energy storage and demand management, all these solutions should be optimally coordinated to improve reliability and this is analysed in Chapter 6.

- There are novel solutions for the operation of ADNs and their impact on reliability has not been evaluated. This is the case of active network management solutions and power-electronics devices. A novel methodology for their evaluation is presented in Chapter 7.

Chapter 3

Comparison of Distributed Generation Models for Reliability Assessment

Increased levels of deployment of renewable distributed generation create new opportunities for reliability improvement of distribution networks. Variability of renewable resources has been identified as one of the main challenges for reliability assessment and several modelling approaches have been proposed in the literature to address this issue. However, the selection of an appropriate modelling approach is not a straightforward task. In this chapter, the models of renewable distributed generation that are used for reliability assessment of distribution networks are discussed and critically compared. The proposed models have been classified into three groups —capacity probabilistic table, hourly profiles and time-segments —according to the approach applied for the representation of chronological variability of demand and generation. Then, one representative model from each group has been implemented and applied to a test distribution network. The results obtained for reliability indices and computational times were used to compare the three modelling approaches. Finally, the recommendations for an appropriate selection of renewable generation model for reliability assessment studies are provided. Most of the content of this chapter has been already published in [115].

3.1 Introduction

The expected massive integration of Distributed Generators (DGs) to distribution systems and the implementation of Active Distribution Networks (or ADNs) will create new opportunities for reliability improvement. As stated in Chapter 2, the DGs can be used to supply energy in the network areas interrupted by faults, either by supporting restoration from adjacent feeders with insufficient capacity to restore all the demand (emergency-tie mode) or by operating in islanded mode [23, 55]. In both operating modes, a significant part of these DGs is expected to use renewable sources, like wind and solar, that are exposed to fluctuations and uncertainty. This variability needs to be considered in the reliability assessment methods.

The techniques for reliability assessment require appropriate stochastic models to address the variability of renewable generation. In [26, 45, 46] the wind and solar generation were modelled by a set of representative power levels with their respective annual probability, forming a table commonly designed as Capacity Probalistic Table (CPT). A similar approach was proposed in [41] but probabilities of generation and load adequacy were used instead of probabilities of power generation. However, the CPT model evaluated a limited number of power levels and each level was assumed to be constant over the fault duration. Detailed models of renewable generation and its variability during faults were presented in [37, 40]. In these cases, hourly profiles of generation and load over a period of one year were applied for the accurate evaluation of the time-changing powers, while Monte Carlo Simulation (MCS) approach was used for addressing this model. However, MCS demands an intensive use of computational resources [26] and, as a result, alternative analytical techniques have been proposed because of their computational efficiency [32, 33, 47]. In these articles, power variability is evaluated for each hour of the fault duration and the probability of successful restoration analytically computed. Therefore, the detailed discussion of these techniques provides useful information for the selection of renewable generation models. In addition to that, the quantitative information like result accuracy and performance sets the distinguishing criteria for the particular selection, but its comparison is missed in the literature.

In this chapter, the models of renewable DGs used in reliability assessment of distribution networks are compared. Firstly, the models for renewable DGs are discussed with an emphasis on the variability modelling of renewable generation. Then, the results of reliability indices and computational times obtained for different DG models are compared when applied to the distribution system Bus 6 of Roy Billinton, and the advantages and limitations of these models demonstrated. The main contributions of this chapter are in:

1. Providing a critical comparison between the principal modelling approaches for renewable DGs used in reliability assessment.

2. Presenting useful guidelines for an adequate model selection.

The chapter is organised as follows. In Section 3.2 the requirements for modelling DGs in reliability assessment studies are presented. Section 3.3 focuses on describing the approaches used for addressing the variability of renewable resources. In Section 3.4, a case study is presented in order to compare the performances of different modelling approaches. Finally, conclusions are drawn in Section 3.5.

3.2 Distributed Generation Modelling in Reliability Assessment

Adequate models of DGs are needed for evaluating their impact on distribution network reliability. The models have to represent those properties of DGs that affect reliability, such as failures of the generators, availability of resources used to produce power and time to start the generators. These properties are discussed in this section, but before going forward it is important to mention that these properties can be exposed to uncertainty and, therefore, the DG models used for reliability assessment are probabilistic models.

As it was described previously, DGs can help to restore the supply in areas of the distribution network interrupted by failures of network components. However, the DGs are also elements exposed to failures and, if a DG fails at the same time that another network component, its capability to restore the supply cannot be fully used. Therefore, the failures of DGs are required to be modelled for an appropriate reliability assessment. Note that probability of failures in network components and DGs use to be low, thus the probability of simultaneous occurence of both failure types is expected to be even much lower [3].

The availability of DGs to failures is commonly modelled by using Markov models. For conventional DGs with controllable power as those based on fossil fuels, a two-state Markov system is typically used for modelling the availability of single generators [35]. The down state represents the null generation under fault conditions and the up state the rated power of the generator. The model of a generator can be combined to represent the availability of a power plant integrated by several generators, each of them exposed to failures. This is typically represented by using the CPT model, which consists of a simple array of the possible capacity levels and their corresponding probabilities [3]. Table 3.1 shows an example of the CPT for a dispatchable power plant that consists of two generation groups of 5 and 10 MW.

Table 3.1: An example of Capacity Probabilistic Table for a dispatchable power plant

Level	Capacity (MW)	Probability
1	0	0.02
2	5	0.04
3	10	0.06
4	15	0.88

The starting time is another parameter that has to be included in DG models. It is conditioned by the technology of the generator and its operating state at the moment of the fault (up or down [31]). Thermal generators will require longer starting times while diesel and power-electronics-interfaced generators will need shorter starting times.

The availability of the resource that fuels the DGs is also taken into account in the models as an influential parameter. In conventional DGs fuelled by storable resources like fossil fuels, the resource is assumed fully available and the maximum power output considered in the DG model is the generator capacity. However, in those DGs based on variable renewable resources like wind and solar, different power levels are supplied according to the variability of the renewable resource, and this variability has to be modelled for reliability assessment.

3.3 Renewable Distributed Generation Models for Reliability Assessment

In the case of renewable generation, the probabilistic models of DGs combine the availability of the renewable resource with the availability of the generator against failures. Modelling the variability and fluctuations of renewable generation is one of the main challenges of the DG models. The objective of this section is to discuss the proposed solutions in the literature to deal with this challenge, classifying them into three groups according to the procedure used. Moreover, examples of DG models are illustrated by using renewable generation data from [116].

3.3.1 Capacity Probabilistic Table

Renewable DGs can be modelled for reliability studies by using values of power levels and their annual probability. Because of the high variability of renewable resources, a large number of probabilistic levels can be obtained. Evaluation of all these levels is not straightforward and there are several available techniques to reduce their number. A modelling solution is to make the CPT of the renewable DGs, formed by a set of representative powers with annual probabilities [26, 45, 46]. In this way, the traditional concept of CPT model is extended to incorporate the availability of renewable generation in addition to the probability of generator failure. A generic example of the CPT for wind and solar DGs is shown in Table 3.2 (the generation power ratio is given in relative values with respect to the generator capacity). The CPT model for renewable DGs can be used by both analytical [26, 46] and simulation techniques [41], although the calculation procedure is different depending on the approach.

In the CPT model, the representative levels of renewable power are obtained from grouping the multiple generation levels over time. Different methods can be applied for implementing the aggregation. One possible and simple option is to use the annual generation duration curve as data source [46]. Fig. 3.1 shows an example of this curve, where the power output is divided in segments (marked between horizontal dashed lines in the figure) and the probability of each segment calculated. However, this modelling neglects the chronological evolution of the renewable resources in the reliability calculation.

Table 3.2: An example of CPT model for wind (left) and solar (right) DGs

Level	Power ratio	Probability
1	0	0.222
2	0.04	0.194
3	0.16	0.194
4	0.3	0.194
5	0.56	0.194

Level	Power ratio	Probability
1	0	0.216
2	0	0.196
3	0.01	0.196
4	0.12	0.196
5	0.44	0.196

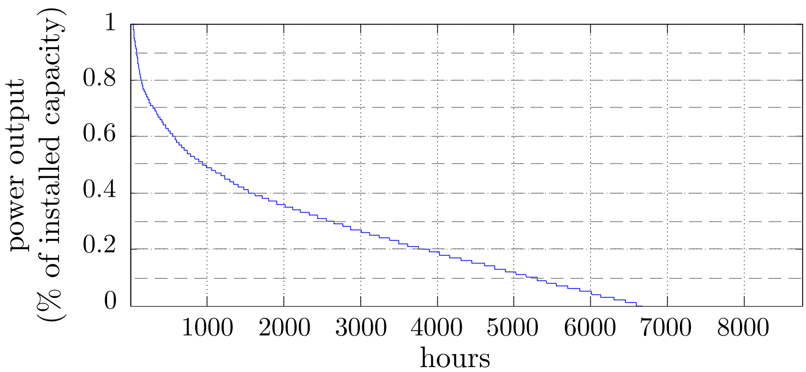


Figure 3.1: An example of annual wind generation duration curve (continuous line) and levels of power (dashed lines) for the CPT model

An alternative is to create the CPT from multi-state Markov models of renewable resources [117]. An example is shown in Fig. 3.2 for wind speed. The annual variability of the renewable resource is represented probabilistically through a set of representative states and the transitions rates between them. Then, the power output of the generator is calculated for each state of renewable resource by applying the corresponding power output formulas as, for example, those given in Equation (3.1) for the case of wind power [118]. Finally, the probability of the representative states is determined to create the CPT for the renewable generation [3]. The unavailability caused by the failures of the generators is also included in the multi-state Markov model.

$$P_t = \begin{cases} 0 & \text{if } 0 \leq v < v_{ci} \\ (A + Bv + Cv^2)P_r & \text{if } v_{ci} \leq v < v_r \\ P_r & \text{if } v_r \leq v \leq v_{co} \\ 0 & \text{if } v \geq v_{co} \end{cases} \tag{3.1}$$

where P_t and P_r are the output and rated powers for the wind turbine generator, v is the wind speed, v_{ci}, v_r and v_{co} are the cut-in wind speed, the rated wind speed and the cut-out wind speed respectively, and A, B and C are parameters calculated as in [118].

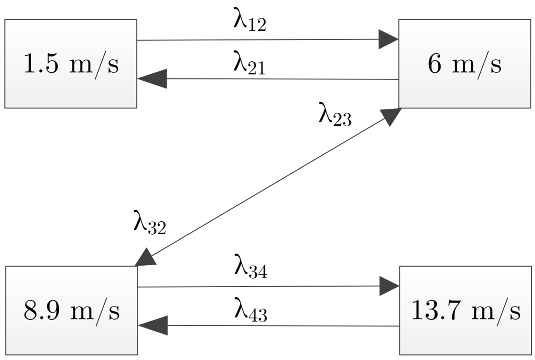


Figure 3.2: Four-state Markov Model for wind speed

However, the multi-state Markov models do not consider the time-dependent evolution between different renewable resources and also between the demand. Clustering techniques like k-means can be applied to model this time-dependency between magnitudes [119]. Profiles of different renewable resources and different types of demand over one or several years can be grouped into representative clusters, where each cluster contains an average profile value and an annual probability. Examples of clustering application for reliability studies are presented in [28, 45].

The CPT for different generation units can be combined to create the probabilistic model of the complete generation plant. Another possible option is to develop a new CPT that contains the probabilities of adequacy for every generation-demand combination [26, 41]. This new CPT is obtained by combining the CPTs of generation and demand in order to determine the adequacy of both magnitudes. Instead of using power values, the resulting CPT use probabilities of the supply adequacy for each level in the table.

3.3.2 Profiles of Generation and Load

The CPT model considers a discrete number of generation powers over a year and assumes them as constant values during the fault duration. These simplifications have two limitations for renewable DG modelling: first, the discrete levels cannot address the entire range of renewable power values; second, the fluctuations of generation during the fault are not evaluated.

To overcome these limitations, probabilistic models are needed to evaluate the fluctuations of renewable generation as well as their chronological correlation with load. A more accurate solution than CPT uses hourly profiles of years to allow a precise evaluation of generation variability and fluctuations [40, 42]. Fig. 3.3 shows an example of wind generation under a stochastic fault occurred between hours 302 and 311 of the year.

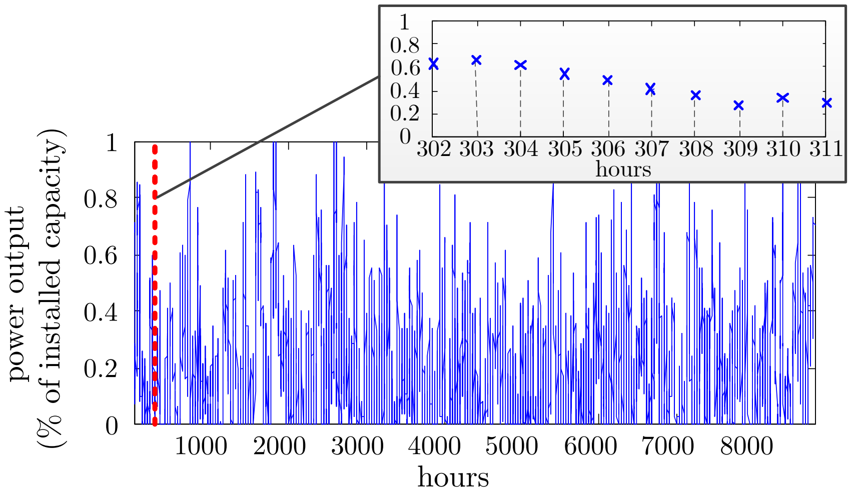


Figure 3.3: Hourly profile of wind generation over a year. Detail of a generation fault registered at hour 302.

The model based on annual profiles can be combined with the model of the failures in a DG, resulting in a model that can be represented as a 3 states Markov model [37, 38]. In addition to the up state of fixed rated power and the down state with null generation, the third state includes the variability of the renewable generation.

Modelling renewable generation by using hourly profiles over a year requires the use of MCS methods. The application of this model assesses accurately the variability of the renewable generation over time but requires increased computational times and memory for data storage.

3.3.3 Simplified Hourly-Models for Analytical Approach

Analytical approach represents a computationally-efficient alternative to MCS. However, it requires specific models of renewable DGs to address the time-dependent fluctuations of generation and its evolution with demand. Hourly profiles of one year are not compatible with analytical approach and simplifications are necessary in order to evaluate hourly variability.

One of the renewable generation models proposed for analytical techniques is presented in [47]. The concept is similar to the probability of adequacy computed in [26] but in this case hourly probabilities are used instead of annual ones. The hourly models are able to represent power output correlations with other generators and load. Moreover, they can be used to determine the hourly probability of generation and load adequacy.

Another modelling option is to divide a year into several time-segments, for example, one day per month of the year [32]. Each segment is assumed to be formed by probability distribution functions that represent the renewable resources for every hour (other time steps can also be used). In this way, the hourly fluctuations of renewable resources can be represented over the time-segments.

3.4 Case Study: Model Comparison

The most representative models of renewable DGs discussed in Section 3.3 were implemented and applied to assess the reliability of a distribution network. The results provided by each model were compared in order to identify the differences in reliability indices, their computational requirements and, ultimately, their appropriateness for the reliability assessment of distribution networks.

The three reliability assessment techniques in Table 3.3 were prepared for their implementation and comparison. The table indicates the approach (analytical or MCS) and the model of renewable generation used by each technique. Each model represents a different way of addressing the variability of renewable generation according to the three classifications discussed in Section 3.3. In each technique the variability of the load was modelled in the same way as the variability of the renewable generation.

Table 3.3: Techniques implemented for the DG model comparison

Technique name	Approach	Generation and load models	Model reference
CPT	MCS	CPT	[26]
Profiles	MCS	Hourly profiles of a year	[40]
Segments	Analytical	Hourly segments	[32]

Profiles and Segments techniques consider fluctuations of generation and demand during the failures. Their strategies for restoration of supply avoid repetitive interruptions in restored customers as in [32]. The time-segments used in Segments technique were a hourly typical day for each month of a year. The CPT model can be used by analytical and simulation techniques. However, in this analysis the MCS approach was selected for a more accurate comparison with Profiles technique.

In order to effectively compare the results of the three techniques, the following considerations were applied to MCS. First, exponential distribution was used for modelling the failure rate of the components and average values were considered for the repair time. Second, an accuracy coefficient of 2 % was used as the stop criteria for the simulation [120]. In addition, to mitigate the uncertainty of this coefficient, the MCS was repeated 10 times for every analysis. Thus, the results for CPT and Profiles techniques show the averaged values over these 10 simulations.

3.4.1 Description of the Test Network

The techniques implemented were applied to assess the reliability of Bus 6 in Roy Billinton Test System [121], a MV distribution network that allows testing the impact of DGs on reliability (more information of this network is given in Appendix B). The DGs in Fig. 3.4 were added to the original network, assuming to be equipped for the islanded operation under fault conditions. Four levels of generation penetration (defined by parameter *pl*) were evaluated for DGs, representing a total capacity equal to 0.25, 0.5, 0.75 and 1 times the annual peak load in the network. The capacity of the NOP in Fig. 3.4 was assumed to be sufficient to restore the supply interrupted in feeders F1 and F2. Therefore, the contribution of DGs to reliability occurred at feeders F3 and F4 and in particular at feeder F4 with larger size and number of component failures. For this reason, the reliability indices shown in this section correspond to feeder F4. SAIDI (in hours of interruptions per customer and year) and ENS (in MWh/year) were the reliability indices used in the comparison (definition of these indices can be consulted in Appendix A). These indices were selected because they allow for quantifying the restoration of supply by DGs in terms of duration and energy. The differences between the indices computed for the three techniques are expressed in %, taking the Profiles technique as a reference since it is considered the model of the three ones evaluated that assess the variability of renewable generation more accurately.

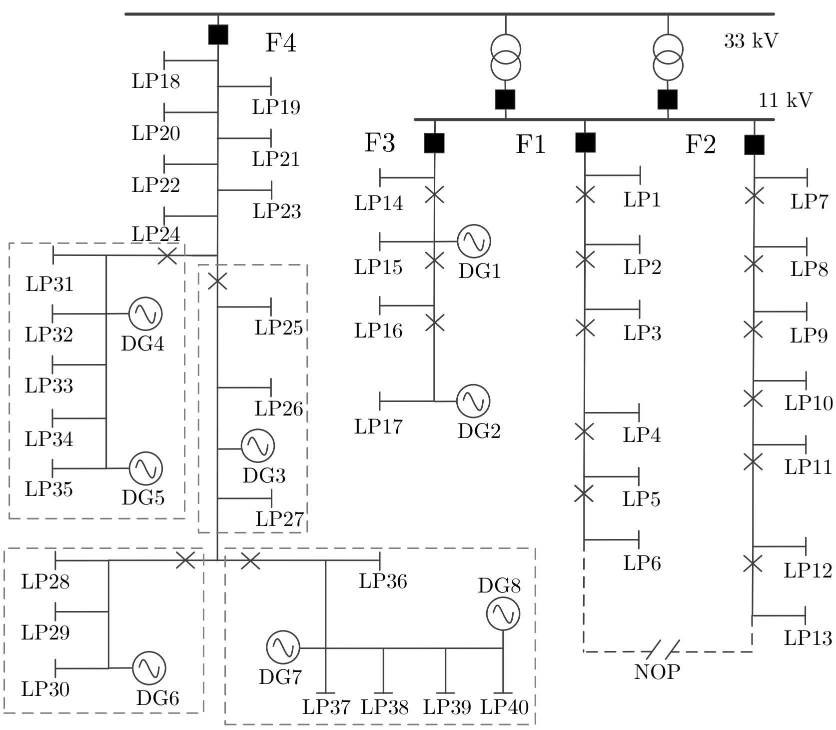


Figure 3.4: Single-line diagram of the Test Network

The failure statistic data of the components were obtained from [122]. Among these statistics, the values of aerial lines and replacement of secondary transformers were considered. The protection devices were assumed to operate as expected with a switching time of 1 hour. The failures of the components in the 33/11 kV substation were not included in the reliability indices. The annual unavailability of the DGs was 0.0055, 0.0205 and 0.0285 for dispatchable, solar and wind generation respectively, while the starting time of these DGs were 0.75, 0.25 and 0.25 hours. Data in [116] were used for the modelling of the renewable generation (wind and solar) and the demand. The CPT models of renewable generation are shown in Table 3.2.

3.4.2 Comparison of the Distributed Generation Models

Dispatchable Distributed Generation

The three modelling techniques were firstly compared by considering all the generators in Fig. 3.4 as dispatchable and based on conventional fossil fuels. As the generation was constant, the aim was to analyse the accuracy of the three models for addressing the fluctuations in the demand during the fault duration. The differences in SAIDI and ENS obtained for the three techniques applied to the test network are shown in Fig. 3.5 (differences expressed in percentage regarding to Profiles technique).

The models of demand based on CPT and time-segments exhibited their limitations at lower generation penetrations (*pl* of 0.25 and 0.5). The largest differences between Profiles and CPT techniques were -6 % in SAIDI and -9 % in ENS, both occurred at penetration of 0.25. These results show that CPT model reported more optimistic reliability indices because it assumes constant load levels during the faults. For Segments technique, the more noteworthy differences were -4 % in SAIDI and -5 % in ENS for a generation penetration of 0.5. These differences are mainly caused by the approximation applied for aggregating hourly profiles of a year into probabilistic segments of one typical day per month. When the results provided by Segments and CPT techniques are compared, it can be observed that the absolute errors were lower for Segments because this technique modelled the fluctuations of the load.

At generation penetrations over 0.75 the differences between the demand models were below 1 %, a small value taking into account the accuracy coefficient established for the simulation techniques (2 %). The reason is that the installed capacity of dispatchable DGs is sufficient to restore most of the load interrupted despite its variability.

Renewable Distributed Generation

In this case the performance of the three techniques in Table 3.3 was compared in presence of renewable wind and solar DGs. Table 3.4 shows the type of the DGs evaluated and Fig. 3.6 the differences in the SAIDI and ENS calculated by the techniques.

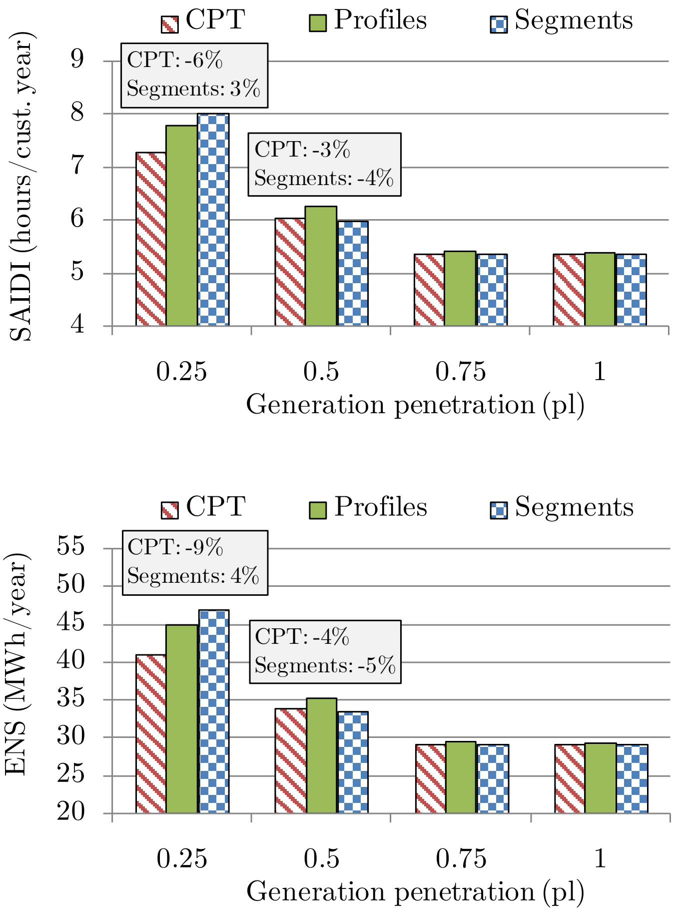


Figure 3.5: Comparison of SAIDI (up) and ENS (down) for the three techniques evaluated with dispatchable DGs

Table 3.4: Type of the DGs used in the renewable integration scenario

DG	Type	DG	Type	DG	Type	DG	Type
DG1	Conventional	DG3	Solar	DG5	Wind	DG7	Wind
DG2	Solar	DG4	Conventional	DG6	Wind	DG8	Solar

The CPT technique reported more optimistic reliability results than the Profiles technique. The mismatch between the two techniques grew with the increased levels of generation penetration. The SAIDI differences were from -3 % at generation penetration of 0.5 to -5 % at generation penetration of 1. The same trend was identified for the ENS, with the values ranging from -4 % to -6 %. The differences in the reliability indices are attributed to the fact that the CPT model considers a discrete number of power levels and neglects the fluctuations of renewable generation during failures. These fluctuations are needed to be considered for an accurate reliability evaluation, especially at increased levels of renewable generation penetration.

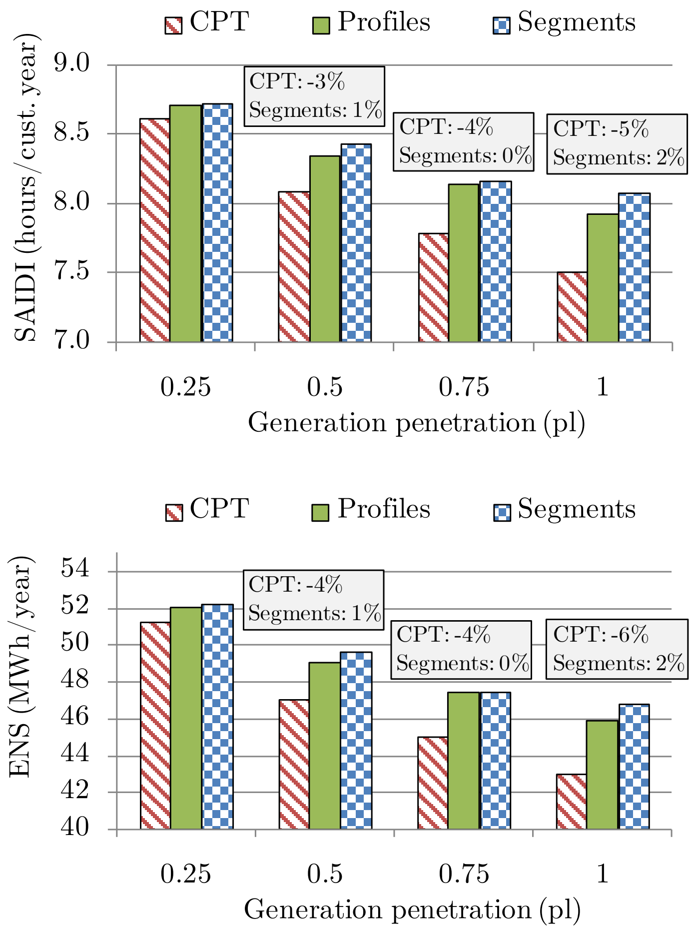


Figure 3.6: Comparison of SAIDI (up) and ENS (down) for the three techniques evaluated including renewable DGs

For the Segments technique the differences in SAIDI and ENS with respect to the Profiles were below 2 % for the worst case. These differences were mainly caused by 1) the averaging of yearly profiles in time-segments of one day per month, and 2) the accuracy coefficient established for stopping the MCS (2 % in this case).

In addition to network results for SAIDI and ENS, reliability results were also analysed at load point level for a more detailed comparison of the models. Fig. 3.7 shows the annual unavailability of the load points in feeder F4, measured in hours of interruption per year, after the supply restoration by DGs was applied (load points from 28 to 40). These results were obtained for a generation penetration of 1 because it was the value that reported larger errors of SAIDI and ENS in Fig. 3.6. According to results in Fig. 3.7, two groups of load points were identified: the first one was formed by load points 28-30 and 36-40, where all the generation was from renewable sources; and the second one was represented by load points 31 to 35, where the annual dispatchable generation was in average 8 times larger than the renewable generation.

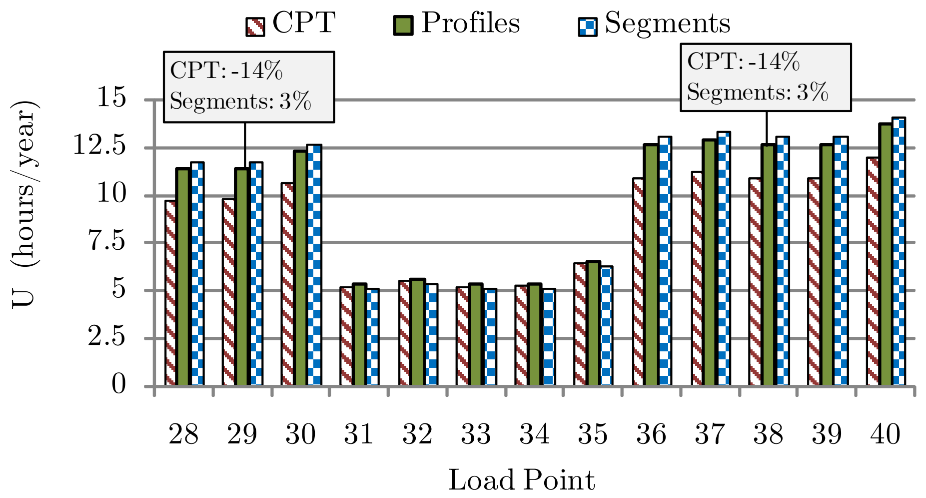


Figure 3.7: Comparison of unavailability obtained by different models of renewable DGs (generation penetration of 1)

The CPT technique reported differences of 14 % when compared to the Profiles technique for load points 28-30 and 36-40. These results demonstrated the incapacity of the CPT model when it comes to accurately addressing the variability of renewable generation at high penetration levels. In contrast, the differences between the Segments and the Profiles techniques for the same load points were about 3 %, significantly smaller than for the CPT technique. These results, in addition to the previous ones obtained for SAIDI and ENS, revealed that the Segments model can represent an alternative for the renewable DG modelling in reliability assessment. This technique is valid when the average values of reliability indices provide sufficient information for network planning decisions related to reliability. If more detailed results than average values are required (e.g. probability distributions) or increased accuracy is mandatory, the model based on hourly profiles over a year should be used.

Computational times

In addition to the reliability indices, the computational times were compared for the three techniques under evaluation. The obtained results are shown in Table 3.5 and were obtained by using a 2-core 2.4-GHz desktop. These results illustrate that CPT and Profiles techniques, both based on MCS, required intensive computational times between 505-530 seconds. In contrast, the Segments technique needed much lower computational times (between 133 and 138 times shorter) compared to the Profiles technique. These results demonstrated that the analytical technique using Segments model is a computationally-efficient option for the reliability assessment while provides acceptable levels of accuracy (as previously discussed in this section). This represents a clear advantage when a fast reliability analysis of multiple scenarios is required at the network planning stage.

Table 3.5: Comparison of computational times (in seconds) for the techniques evaluated

		Generation penetration			
Technique	DG type	0.25	0.5	0.75	1
CPT	Dispatchable	512	516	517	522
Profiles	Dispatchable	529	531	529	531
Segments	Dispatchable	3.8	3.9	3.9	3.9
CPT	Renewable	520	505	513	512
Profiles	Renewable	515	521	520	517
Segments	Renewable	3.7	3.8	3.8	4

3.5 Conclusions

This chapter has critically compared the most representative models of renewable DGs used for the reliability assessment of distribution networks. Firstly, the models have been discussed and the procedures they use to address the variability and fluctuations of renewable generation have been explained. Then, three representative techniques for modelling the variability of renewable generation and demand have been implemented and compared: CPT, profiles of a year and time-segments. The reliability indices and computational times have been obtained by using a test distribution network with DGs. Finally, a series of useful recommendations have been provided for modelling renewable generation in reliability assessment techniques. The main contributions of this chapter are in conducting the comparison of the models and in the recommendations provided for an appropriate model implementation.

The comparison of the models revealed that the hourly profiles over a year is the most accurate way to model the variability of renewable generation and load. These profiles need to be used with Monte Carlo Simulation techniques and, consequently, provide reliability indices with extended information in the form of probability distributions. However, high computational times are required for the calculation of indices and more memory is needed for storing the profile data.

The comparison also demonstrated that the assumptions applied in the CPT modelling produced significant errors in the reliability indices at increased levels of renewable generation. Therefore, these errors have to be considered if this model is selected for application. In contrast, the time-segments model is recommended for analytical techniques and represents a computationally efficient alternative to the hourly profiles, provided that average values of reliability indices yield sufficient information for making the planning decisions. These features make the representative time-segments the preferred model for time and resource efficient reliability studies in presence of renewable DGs.

In the conducted analysis, the fluctuations of renewable resources limit the capacity of DGs to improve the network reliability. Energy storage is a solution that can help in dealing with these fluctuations and can extend the reliability improvement. New methodologies are required to study these effects and analytical approaches represent a computationally-efficient solution. This is the principal objective of the following chapter.

Chapter 4

Analytical Technique for Reliability Assessment of Distribution Networks with Energy Storage

A wide scale deployment of energy storage systems in power distribution networks will lead to network reliability improvements. After a fault occurs in a network, energy storage can supply sustained power and help restore the supply, either in network areas isolated from the primary substation or in those re-connected to adjacent feeders of limited transfer capacity by emergency-ties. The reliability improvements introduced by energy storage need to be evaluated and quantified for both restoration modes. The objective of this chapter is to assess the energy storage contribution in these restoration modes and to seek analytical, less computationally intensive solutions for such evaluation. The proposed analytical technique uses a probabilistic model of energy storage to assess the charge and discharge processes over a fault duration and the related operational strategy. In this way, reliability indices are calculated by taking into account the energy storage actions during a fault as well as the time-evolution of renewable generation and demand. These features lead to more realistic modelling of energy storage in analytical techniques. The proposed analytical technique was firstly validated by using a case study where the results obtained by Monte Carlo Simulation (MCS) were used as a reference. Then, the proposed technique was applied to a distribution network to assess the reliability improvement provided by energy storage and to demonstrate the effectiveness and the accuracy of the proposed approach. Note that the content of this chapter has been published in [123].

4.1 Introduction

The integration of Distributed Generators (DGs) to power distribution systems opens up new opportunities for supply restoration in areas interrupted by network faults and, therefore, new opportunities for the system reliability improvement. As described in Chapter 2, one restoration option for those areas isolated by faults and unable to connect to alternative feeders is to operate in islanded mode. Another is to support the restoration by using adjacent feeders with emergency-ties of limited transfer capacity (tie-supported operation). However, the restoration capacity of both operating modes can be significantly reduced in presence of renewable, intermittent resources. Under these conditions, energy storage can be used to support renewable DGs during the supply restoration. The contribution of energy storage to reliability in islanded and tie-supported restoration options has to be assessed during the planning stage. As a result, network planners need new evaluation tools for this purpose.

Analytical and Monte Carlo Simulation (MCS) are the probabilistic approaches used to assess reliability of distribution systems. With regard to MCS, it samples the stochastic occurrence of faults facilitating the assessment of the variability and time-evolution of renewable generation and demand during faults [40, 43]. This allows the chronological operation of energy storage to be modelled in the reliability evaluation. However, a large number of simulation iterations and long computation times are required to obtain the results, representing the main disadvantage of MCS [22]. Despite the large computational times, MCS has been widely used to assess energy storage in reliability studies for distribution systems [57, 58, 59, 61]. In [59] the distributed energy storage devices were evaluated as an instrument to improve the reliability of bulk power systems. In [57] the reliability improvement of a rural distribution network with an energy storage system in the primary substation was sought. The energy storage was coordinated with renewable DGs in [58] to decrease the service interruption costs in the islanded operation. In [61] reliability was improved by the optimal allocation of energy storage operated in the islanded mode. However, the contribution of energy storage in tie-supported mode was not addressed by any of these references.

Analytical approaches represent a computationally-efficient alternative to MCS for the calculation of average values of reliability indices [43]. The main drawback in modelling of energy storage lies in the increased complexity required to address the variability and time-evolution of generation and demand during failures [62]. An effective modelling solution is to define probabilistic states of stored energy over the failure duration [62, 66]. However, these models do not include the charge and discharge processes of energy storage. Consequently, they cannot be used to apply strategies for energy storage operation to restore the supply. In literature there have been several analytical methods proposed to assess the reliability of distribution networks with renewable DGs in both islanded [26, 32, 33, 44, 45, 47] and tie-supported modes [56], but only a few papers reported on the application of analytical methods to energy storage assessment. In [124] an analytical method was proposed to assess the reliability improvement introduced by a renewable DG with an energy storage system operated in the islanded mode. In [66] the reliability of rural distribution networks including energy storage and photovoltaic systems was also evaluated in the islanded mode. However, in these references the contribution of energy storage in tie-supported restoration mode was not evaluated, and the chronological charge and discharge processes over the fault duration were not modelled. Therefore, the analytical methodologies have to be extended to include these features.

In this chapter, a novel analytical technique to assess the impact of energy storage on reliability of distribution networks is proposed. This impact is evaluated along with DGs and emergency-ties for islanded restoration mode as well as for tie-supported mode. The probabilistic evaluation takes into account the variability and the time-dependent fluctuations of renewable generation and demand during the failure, and models the chronological charges and discharges of energy storage in order to support generation shortages and reduce the interruption duration. Finally, all these features are included in the calculation of the reliability indices. Based on the previous works, the main contributions of this chapter can be summarized as follows:

1. A novel methodology is proposed to specifically assess the contribution of energy storage to reliability of distribution networks. This contribution is evaluated under islanded network conditions as well as in presence of emergency-ties of limited transfer capacity (tie-supported mode).

2. Compared to the existing analytical techniques, the proposed methodology provides more realistic computation of reliability indices because it has the following incremental extensions: a) it allows probabilistic modelling of chronological charges and discharges of energy storage during a failure, b) it properly assesses the time-dependent fluctuations of renewable generation and demand and c) it specifically models the strategy to restore the supply over the failure duration.

3. The proposed analytical technique is validated by using comparative case studies, demonstrating its accuracy and computational efficiency.

4. The contribution of energy storage to reliability is evaluated in islanded and tie-supported restoration modes for different levels of energy storage penetration.

The organization of this chapter is as follows: the methodology proposed is described in Section 4.2. It introduces the calculation of the reliability indices in presence of energy storage and how to address the time-dependent performance of the storage during faults. Section 4.3 presents the models used in the analytical technique, while Section 4.4 describes the analytical method for energy storage evaluation. In Section 4.5, the case study is presented. Finally, the conclusions are drawn in Section 4.6. Definitions of the symbols used in this chapter are described in the *Nomenclature* given at the beginning of this document.

4.2 Reliability Assessment Methodology

4.2.1 Reliability Indices

Reliability indices are used to quantify the impact of interruptions on distribution systems for both load points and network areas [21]. The reliability indices of the load points in a network (index i) are the failure rate, the average outage duration, the annual unavailability, and the energy-not-supplied. They are calculated according to:

$$\lambda_i = \sum_{j=1}^{N_j} \lambda_{i,j}, \qquad U_i = \sum_{j=1}^{N_j} \lambda_{i,j} r_{i,j}, \qquad r_i = \frac{U_i}{\lambda_i}, \tag{4.1}$$

$$ENS_i = La_i U_i. \tag{4.2}$$

The area indices determined are the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Energy Not Supplied (ENS). These indices are typically used in reliability assessments and are calculated from load point reliability indices in the way described in Appendix A.

4.2.2 Calculation of Load Point Reliability Indices

For the calculation of reliability indices, the zone branch methodology has been implemented because it permits the evaluation of complex fault isolation and restoration processes [125]. This methodology simulates the operation of protection devices when a fault occurs and identifies the areas of the network with different impacts on reliability. Fig. 4.1 shows an example of three types of areas created after isolation of fault j: Area 1 or upstream of the fault, Area 2 or inside the fault, and Area 3 or downstream of the fault [32, 53].

In these areas, failure rate $\lambda_{i,j}$ is equal to zero if the interruption lasts less than a certain time threshold (for example, five minutes in [21]). Otherwise, $\lambda_{i,j}$ is equal to the failure rate of the component that causes the fault (λ_j) [126].

The average interruption duration of the load points located in each area is determined by [3]:

$$r_{i,j} = \begin{cases} tsi_j + tsr_j & i \in Area\ 1 \\ tsi_j + r_j & i \in Area\ 2 \\ r_{i,j}^D & i \in Area\ 3 \end{cases} \tag{4.3}$$

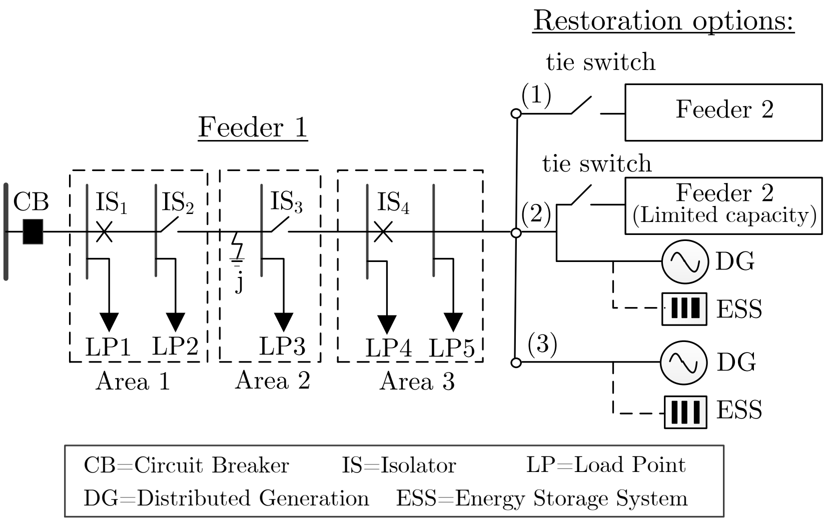


Figure 4.1: An example showing different network areas created after the fault isolation and supply restoration options for Area 3

Equation 4.3 shows that areas upstream of the fault (Area 1) are interrupted during the time require to identify the fault, isolate it and reconnect the area to the primary substation. The area in fault (Area 2) remains interrupted until the failure is repaired, while the interruption duration in areas downstream of the fault (Area 3, hereafter downstream areas) depends on the presence of alternative sources to restore the supply.

4.2.3 Restoration of Supply in Downstream Areas

The following options (shown in Fig. 4.1) are evaluated for the restoration of supply in downstream areas:

1. Alternative feeders and emergency-ties with sufficient transfer capacity to restore all the interrupted supply [127].

2. Alternative feeders and emergency-ties with limited transfer capacity supported by DGs and energy storage in tie-supported operation [55].

3. DGs and energy storage in islanded operation [45].

Therefore, it is assumed that DGs and energy storage installed in the distribution network participate in the supply restoration by operating in islanded and tie-supported modes. Energy storage helps in dealing with generation shortages originated from variable, renewable DGs and extends the supply restoration. This contribution of energy storage to reliability in both restoration modes is evaluated by the proposed analytical methodology.

4.2.4 Incorporating Energy Storage in the Analytical Approach

The analytical methodology is used to evaluate the reliability indices when energy storage (and also DGs) participates in the supply restoration of downstream areas. The chronological charge and discharge of energy storage over the failure duration are probabilistically modelled and represent one of the key challenges for the incorporation of energy storage operation in analytical approaches.

Probabilistic models of generation and demand are proposed to assess the power variability over time. Moreover, these models consider the chronological evolution of renewable generation and load, a requirement to simulate the time-dependent operation of energy storage during a fault. The availability of energy storage systems is also included in the evaluation. All these models are described in detail in Section 4.3.

Based on the probabilistic model, an analytical procedure is developed for the reliability indices calculation that includes the contribution of energy storage. The procedure performs an adequacy assessment at different fault conditions represented by renewable generation, demand and availability of DGs and ESSs. This adequacy assessment includes the performance of energy storage and the strategy used for its operation. The details of this analytical procedure are described in Section 4.4.

4.3 Proposed Models for Reliability Assessment

4.3.1 Models of Load and Renewable Generation

The models proposed for generation and load address their time-variability over a year in a probabilistic way. These models are used to evaluate the operation of energy storage under fault conditions because they take into account a) the chronological evolution of generation and load during a fault, and b) the variability of generation and load over a year.

The model is created by dividing the period of a year into representative time-intervals as in [44] (the reliability indices refer to probabilistic annual values). Fig. 4.2 shows an example where the representative time-intervals are one typical day for each month of the year (data from [116]). The number of representative time-intervals in one year and its time-frame (for example, day or week) are configurable.

Each representative time-interval has an annual probability (p_{rs}=1/12 for the typical day of a month in Fig. 4.2) and is formed of power profiles (either for renewable generation or demand). The profiles are further divided in time-steps (for example, hours or fractions of hour) with their respective powers and probabilities (p_h=1/24 for the hourly time-steps of a typical day in Fig. 4.2). The powers of the time-steps are obtained by averaging the power profiles of one or several years into representative time-intervals (one day per month in Fig. 4.2), while the annual probability of each time-step in a representative time-interval is calculated as:

$$p_{h,rs} = p_{rs} p_h \qquad \forall rs \in \{1, .., \mathbf{N_{rs}}\}, h \in \{1, .., \mathbf{N_{h,rs}}\}. \tag{4.4}$$

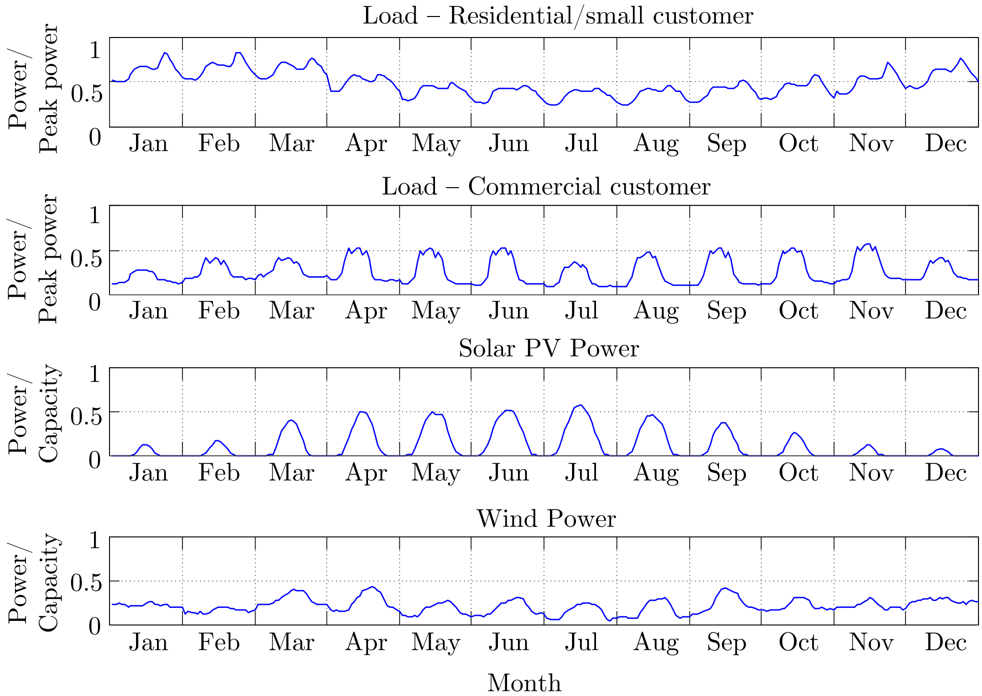


Figure 4.2: Representative time-intervals for one year (12 months x 24 hours). Normalised power referred to annual peak load or generation capacity

4.3.2 Reliability Models of Network Components

Lines and transformers in a network are modelled by using the conventional two-state Markov model: the up state indicates normal operating conditions and the down state failure conditions [22]. The two-state model is also used for DGs and ESSs, and their annual unavailability (caused by the down state) is quantified by the unit forced outage rate (FOR) [3]. The power at the up state is a constant value of rated power for fully dispatchable DGs, and obtained from the probabilistic profiles of the representative time-intervals for variable renewable DGs.

The DGs and ESSs used to restore a downstream area can be in different states (up and down) when a fault occurs. The probabilistic combination of these devices with their respective states forms a set of combinatorial states defined as restoration-states, each one with a specific capacity of restoration. Table 4.1 shows an example of the restoration-states, where each restoration-state indicates the status of the DG and ESS devices (1 for up and 0 for down) as well as the probability of the restoration state (p_{cr}). This probability is calculated by extending the method described for DGs in [32] in order to include ESSs as follows:

$$p_{cr} = \prod_{g \in N_g} \Big(\alpha_g^{cr}(1 - FOR_g) + (1 - \alpha_g^{cr}) FOR_g \Big) \cdot \prod_{s \in N_s} \Big(\alpha_s^{cr}(1 - FOR_s) + (1 - \alpha_s^{cr}) FOR_s \Big) \tag{4.5}$$

Table 4.1: An example of restoration-states in a downstream area with DGs and ESSs

State	DG_1	DG_g	DG_{Ng}	ESS_1	ESS_s	ESS_{Ns}	p_{cr}
1	0	α_g^1	0	0	α_s^1	0	p_1
...				...			...
cr	1	α_g^{cr}	0	0	α_s^{cr}	0	p_{cr}
...				...			...
N_{cr}	1	α_g^{Ncr}	1	1	α_s^{Ncr}	1	p_{Ncr}

4.4 Analytical Procedure for Energy Storage Evaluation

Before explaining the proposed procedure to assess reliability, the principal assumptions are described here:

- the operation of the distribution systems is radial,
- only sustained faults are evaluated,
- protection devices operate as expected and their failures are neglected,
- DGs and ESSs are disconnected when a fault occurs and re-connected once the fault is mitigated and the network reconfigured,
- the network is equipped with the appropriate protection and control systems for islanded operation,
- adequacy assessment of active power is performed without considering reactive power.

All these assumptions are commonly used in the reliability assessment of distribution networks [3, 26, 28, 45, 58].

4.4.1 Calculation of Interruption Duration

The procedure described in Section 4.2.2 is extended to include the contribution of energy storage to the reliability indices. This contribution is evaluated for all downstream areas and for all load points within these areas.

Fig. 4.3 shows an example of a time-interval registered by a load point in a downstream area during a failure. After the fault occurs, the switching time tsw_j covers the time required to identify the fault, isolate it and prepare the downstream area for the restoration. Then, the time-interval between the end of the switching time and the end of the fault is defined as restoration-evaluation time because it is the time used for the evaluation of the restoration feasibility. In addition to that, the time intervals interrupted during the restoration-evaluation time form the interruption duration $r^R_{i,j}$. Therefore, the total duration of a load point interruption in a downstream area can be calculated as:

$$r^D_{i,j} = tsw_j + r^R_{i,j}. \tag{4.6}$$

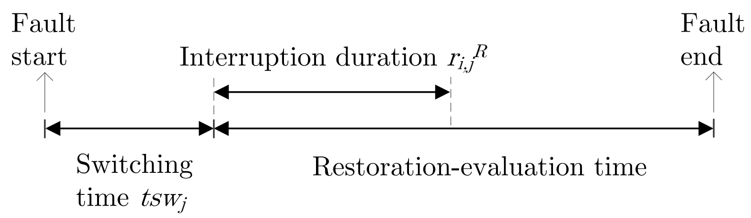


Figure 4.3: Definition of time-intervals during a fault in a downstream area

The calculation of the interruption duration $r^D_{i,j}$ takes into account the presence of alternative resources to restore the supply. In addition to emergency-ties and DGs, the effect of energy storage is specifically included. The following options are evaluated:

1. If the downstream area is not equipped with alternative supply sources, restoration is not possible. Then, tsw_j=tsi_j and $r^R_{i,j}$=r_j.

2. If the area is equipped with any emergency-tie of sufficient transfer capacity, the tie is used for the restoration of supply as in [128] regardless of the presence of DGs and energy storage. In this case, the interruption duration is:

$$tsw_j = max(tsi_j, t_{tie}), \qquad r^R_{i,j} = 0. \tag{4.7}$$

3. If the transfer capacity of emergency-ties is limited, their contribution to restore the supply is evaluated in combination with the DGs and the energy storage located in the downstream area. Therefore, the distributed energy resources are operated in the tie-supported mode and the switching time in this case is:

$$tsw_j = max(tsi_j, t_{tie}, st_g, st_s) \tag{4.8}$$

where it is assumed that all the DGs and ESSs in up state are started during the switching time to participate in the supply restoration.

4. In those downstream areas without emergency-ties, the DGs and the energy storage are used to restore the interrupted supply assuming the distributed resources equipped for the islanded operation. In this case, the switching time is:

$$tsw_j = max(tsi_j, st_g, st_s) \tag{4.9}$$

and also it is assumed that all the DGs and ESSs in the downstream area have to be started to participate in the supply restoration.

The average interruption duration $r^R_{i,j}$ in points 3 and 4 enumerated above is calculated by using the probabilistic procedure shown in Fig. 4.4. This procedure takes into account a) the availability of DGs and ESSs and b) the variability of renewable generation and demand during the fault. The first is evaluated by using the combinatorial restoration-states of devices described in Section 4.3.2 and the second by using the representative time-intervals explained in Section 4.3.1. The calculation steps in Fig. 4.4 are described as follows. First, the required data including the restoration-states and the representative time-intervals are uploaded. Then, restoration-state cr with probability p_{cr} is selected and its capacity to provide the interrupted supply evaluated. This evaluation is performed at different renewable generation and demand conditions during the failure given by each representative time-interval rs. In addition, the component failures can happen at different moments over the year and they are simulated by assuming a fault can occur at every time-step h of the representative time-interval rs with probability $p_{h,rs}$. For each of these particular conditions (restoration-state cr, representative segment rs and time step h), an adequacy assessment is performed to calculate the interruption duration $r^R_{i,j,cr,rs,h}$. The charges and discharges of energy storage during the failure are modelled. Finally, overall interruption duration $r^R_{i,j}$ aggregates all the values of $r^R_{i,j,cr,rs,h}$ taking into account the probabilistic conditions as Equation (4.10) shows.

$$r^R_{i,j} = \sum_{cr=1}^{N_{cr}} p_{cr} \sum_{rs=1}^{N_{rs}} \sum_{h=1}^{N_{h,rs}} p_{h,rs}\ r^R_{i,j,cr,rs,h} \tag{4.10}$$

4.4.2 Adequacy Assessment with Distributed Generation and Energy Storage

This section describes the adequacy assessment performed to calculate the interruption duration $r^R_{i,j,cr,rs,h}$ in (4.10). It corresponds to step 5 in Fig. 4.4 and evaluates the operation of energy storage during the failure in order to provide uninterrupted power supply under generation shortages.

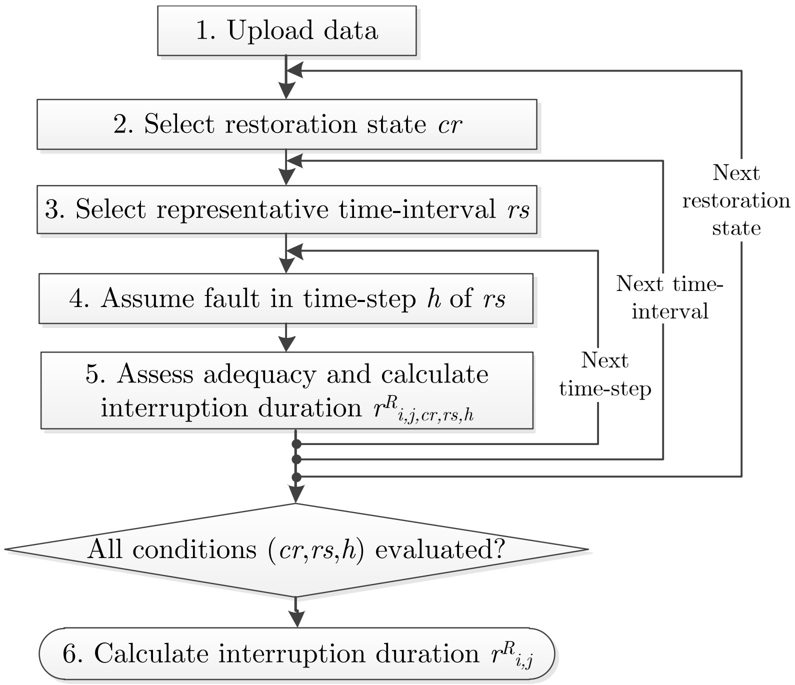


Figure 4.4: Procedure to calculate interruption duration $r^R_{i,j}$ in downstream areas with DGs and energy storage

Profiles of generation and demand during the failure

The adequacy assessment starts by quantifying the aggregated power profiles of demand and generation in the downstream area. These profiles are calculated for all the restoration-states of devices and for different conditions of renewable generation and demand over a year as follows:

$$Pl^{h,rs}(t) = \sum_{lpi \in N_{lpi}} P^{h,rs}_{lpi}(t) \qquad \forall t, \tag{4.11}$$

$$Pg^{cr,h,rs}(t) = \sum_{g \in N_g} \alpha^{cr}_g P^{h,rs}_g(t) + \sum_{tie \in N_{tie}} \alpha^{cr}_{tie} P^{h,rs}_{tie}(t) \qquad \forall t \tag{4.12}$$

where the transfer capacity of a feeder ($P^{h,rs}_{tie}$) is determined in such a way that the network constraints are preserved [48, 55]. It takes into account the demand, the DGs and the ESSs located in the downstream area evaluated and in the adjacent feeders interconnected via emergency-ties.

Fig. 4.5 shows an example of the aggregated profiles of generation ($Pg^{cr,h,rs}$) and load ($Pl^{h,rs}$) in a downstream area during a failure. After the switching time ends, the capability to restore the supply is evaluated over the restoration-evaluation time (from $t1$ to tf). If the duration of the representative time-intervals is shorter than the fault, these time-intervals are repeated as many times as necessary to cover the duration of the fault.

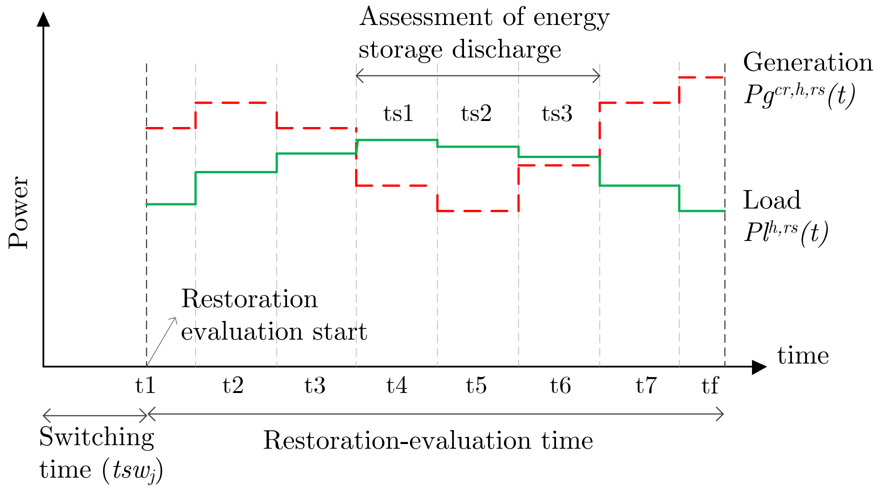


Figure 4.5: An example of generation and load profiles evaluated during a fault

Energy storage model

The charge and discharge processes of an energy storage during the failure are modelled chronologically by using (4.13)-(4.16), assuming the ESSs has an initial state of charge when the fault occurred.

$$SOC_s(t+1) = SOC_s(t) + \left(Pc_s(t)\eta c_s - \frac{Pd_s(t)}{\eta d_s} \right) \frac{\Delta t(t)}{C_s} \tag{4.13}$$

$$\underline{SOC}_s \leq SOC_s(t) \leq \overline{SOC}_s \tag{4.14}$$

$$Pc_s(t) = \begin{cases} \min\left((Pg^{cr,h,rs}(t) - Pl^{h,rs}(t))rc_s(t), \overline{Pc}_s \right) & Pg^{cr,h,rs}(t) > Pl^{h,rs}(t) \\ 0 & Pg^{cr,h,rs}(t) \leq Pl^{h,rs}(t) \end{cases} \tag{4.15}$$

$$Pd_s(t) = \begin{cases} \min\left((Pl^{h,rs}(t) - Pg^{cr,h,rs}(t))rd_s(t), \overline{Pd}_s \right) & Pg^{cr,h,rs}(t) < Pl^{h,rs}(t) \\ 0 & Pg^{cr,h,rs}(t) \geq Pl^{h,rs}(t) \end{cases} \tag{4.16}$$

Equation (4.13) models the chronological evolution of the SOC taking into account the energy charged and discharged in every cycle and (4.14) keeps the SOC within the operational limits. The power to charge an energy storage device is calculated by using (4.15), where the first term $(Pg^{cr,h,rs}(t) - Pl^{h,rs}(t))rc_s(t)$ represents the amount of power excess available to be charged in storage s after other storage devices with larger priority have been charged, and the second term $\overline{Pc}_s$ the limit of charging power. The power discharged from a storage device is determined in (4.16). In this equation, the first term $(Pl^{h,rs}(t) - Pg^{cr,h,rs}(t))rd_s(t)$ represents the total power required to get adequacy that has not been supplied yet by other storage devices with larger priority of discharge, and the second term $\overline{Pd}_s$ the limit of discharging power.

Each time an ESS is charged or discharged, the ratio of the total power available for charging an storage device is updated by:

$$rc_s(t) = 1 - \frac{\sum_{s \in \mathbf{Sp}} Pc_s(t)}{Pg^{cr,h,rs}(t) - Pl^{cr,h}(t)} \qquad \forall t \in Pg^{cr,h,rs}(t) > Pl^{h,rs}(t), \tag{4.17}$$

and the ratio of the total power required to be discharged from a storage device by:

$$rd_s(t) = 1 - \frac{\sum_{s \in \mathbf{Sp}} Pd_s(t)}{Pl^{h,rs}(t) - Pg^{cr,h,rs}(t)} \qquad \forall t \in Pg^{cr,h,rs}(t) \leq Pl^{h,rs}(t). \tag{4.18}$$

With respect to the priority of ESSs use, it is assumed that the ESSs with lower SOC are charged first while those ESSs with larger SOC are discharged first (SOC ranges between 0 and 1 as it measures the ratio between the stored energy and the storage capacity).

Restoration strategy with energy storage

Fig. 4.6 shows the proposed procedure to calculate average interruption duration $r^R_{i,j,cr,rs,h}$ defined in (4.10) and also the time-step from which restoration starts, $sr_{i,j,cr,rs,h}$, used later in (4.22) for the calculation of the energy-not-supplied. A specific strategy is applied to operate the energy storage, and it aims to reduce the duration of the interruptions and avoid repetitive interruptions of customers already restored [129]. In this way, the impact of this restoration strategy can be addressed by the analytical technique and quantified in the reliability indices.

The stages in Fig. 4.6 are described as follows. Firstly, during a fault the time-steps with generation shortage are identified by performing an adequacy assessment of the generation and load profiles calculated in Equations (4.11) and (4.12). Then, the capacity of energy storage to support the time-steps with generation shortages is evaluated, selecting these time-steps one by one as stage 2 in Fig. 4.6 indicates (the selected time-step is designed as ts). The evaluation starts, for example, in the last time-step with generation shortage ($t6$ in Fig. 4.5) and, once assessed, previous time-steps are selected for the evaluation in reverse chronological order ($t5$ and $t4$ in Fig. 4.5). These criteria pursue avoiding repetitive interruptions of already restored customers since a fault is commonly recorded during the switching time.

The following step (step 3) is to determine the maximum stored energy available at time-step ts, and it is obtained as:

$$SOC^M(ts) = \sum_{s \in N_s} SOC^M_s(ts). \tag{4.19}$$

The value of $SOC^M_s(ts)$ is calculated by using (4.13)-(4.14) and considering the discharge power Pd_s between $t1$ and $ts - 1$ is 0.

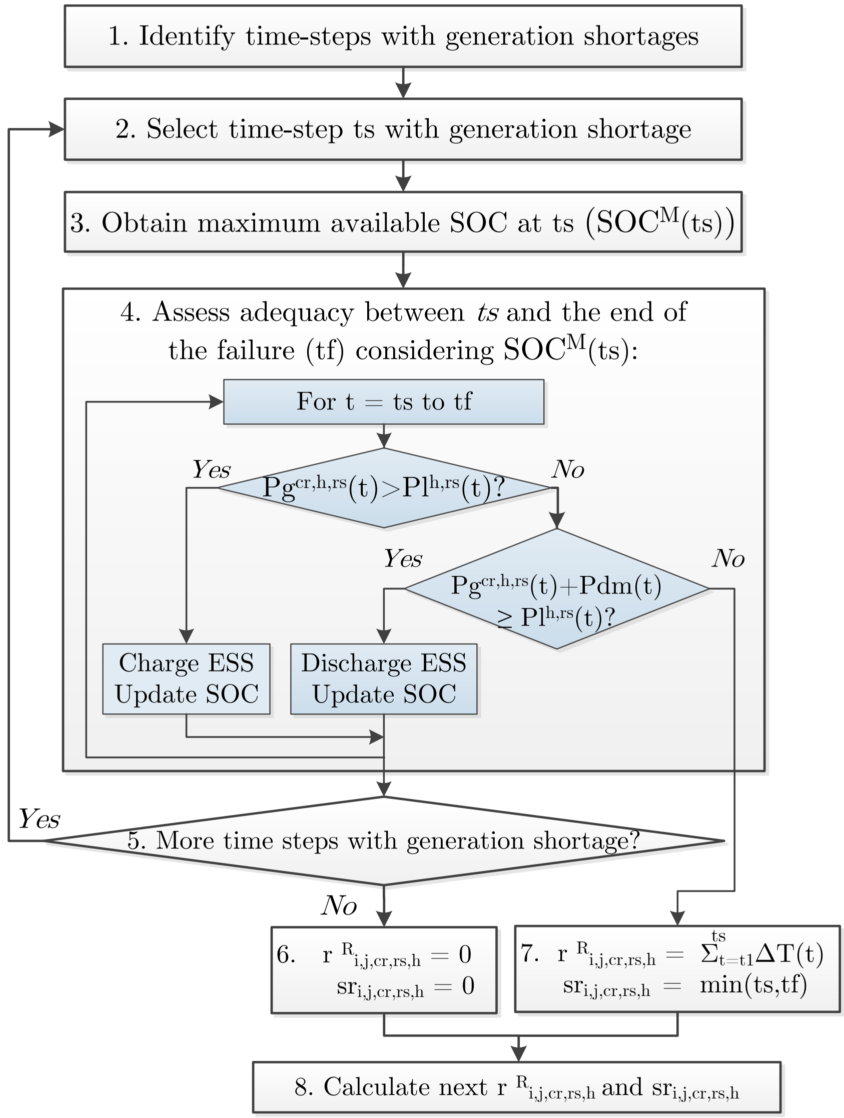


Figure 4.6: Proposed procedure to evaluate energy storage performance and restoration strategy during a fault

In the fourth step, the contribution of SOC^M to restore the supply between time-step ts and the end of the fault (tf) is evaluated. In each time-step, if generation exceeds the demand $(Pg^{cr,h,rs}(t) > Pl^{h,rs}(t))$, the energy storage is charged by a power determined by (4.15). By contrast, the energy storage is discharged at a time-step with generation shortage if the maximum power that can be discharged from all the ESSs (designed as $Pdm(t)$ and calculated by (4.20)) is sufficient to supply the generation shortage, i.e. the condition $Pg^{cr,h,rs}(t) + Pdm(t) > Pl^{h,rs}(t)$ is fulfilled. In such a case, the discharge power is calculated by (4.16). In the charge and discharge cycles the SOC is updated by using (4.13)-(4.14).

$$Pdm(t) = \sum_{s \in Ns} min\left(\frac{(SOC_s(t) - \underline{SOC}_s)C_s\eta d_s}{\Delta t(t)}, \overline{Pd}_s\right) \qquad t = ts, ..., tf \tag{4.20}$$

If the ESSs supply all the generation shortage during the analysed time interval (from ts to tf), the restoration of supply at time-step ts is considered feasible and then the evaluation continues to the previous time-steps with generation shortage (go to step 2 in Fig. 4.6). On the contrary, if all the supply from ts to tf is not restored, no further time-steps with generation shortages are assessed. This latter situation corresponds to step 7 in Fig. 4.6 and means that the supply remains interrupted from the start of the fault until time-step ts.

In the case of energy storage can provide all the generation shortages (step 6), the interruption duration $r^R_{i,j,cr,rs,h}$ is 0. Finally, the evaluation continues with the calculation of the next values of $r^R_{i,j,cr,rs,h}$ and $sr_{i,j,cr,rs,h}$ until all the combinations of faults conditions (defined by cr, rs and h) are evaluated.

4.4.3 Calculation of Energy-Not-Supplied

The analytical techniques in literature such as [126] typically calculate the ENS by considering the average customer load as in (4.2). The methodology proposed in this chapter also calculates the ENS of the load points located in Areas 1 and 2 of Fig. 4.1 by using their average load. However, the calculation of the ENS for the load points within the areas downstream of the fault (or Area 3 in Fig. 4.1) takes into account the variability of the load interrupted during the fault. The energy-not-supplied calculated by this procedure (ENS^*_i) is determined by (4.21)-(4.22) and provides more realistic evaluation compared to the procedure based on average values.

$$ENS^*_i = \lambda_{i,j} \sum_{j=1}^{N_j} \left(La_{i,j}tsw_j + ENS^R_{i,j}\right) \tag{4.21}$$

$$ENS^R_{i,j} = \sum_{cr=1}^{N_{cr}} p_{cr} \sum_{rs=1}^{N_{rs}} \sum_{h=1}^{N_{h,rs}} p_{h,rs} \sum_{t=t1}^{sr_{i,j,cr,rs,h}} Pl^{h,rs}(t)\Delta t(t) \tag{4.22}$$

4.5 Case Study

4.5.1 Test Network

The aim of the case study is to validate the proposed analytical methodology and to evaluate the contribution of energy storage to reliability. This is done by applying the proposed methodology to Bus 6 of Roy Billinton Test System shown in Fig. 4.7 and described in Appendix B, representing a typical test case used for testing methodologies for reliability assessment of distribution networks [121]. By using this test system, the restoration by islanded operation (feeders F3 and F4) and by tie-supported operation through alternative feeders (feeders F1 and F2) can be both evaluated.

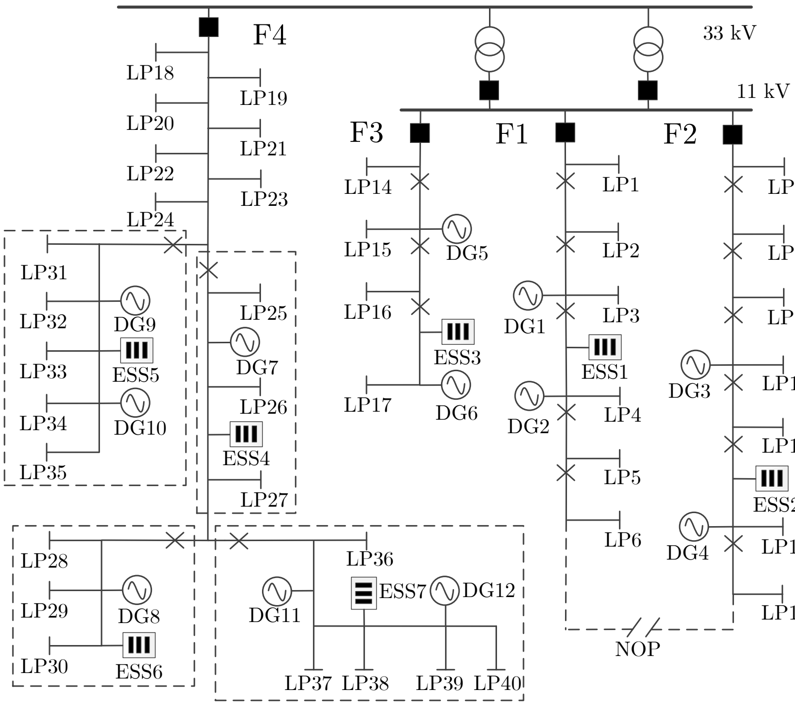


Figure 4.7: Single-line diagram of the test network (Bus 6)

The DGs in Fig. 4.7 were introduced to the original network in [121]. The type of these DG resources (conventional, wind or solar) and their capacities are shown in Table 4.2, while the reliability parameters are given in Table 4.3.

Table 4.2: Type and capacity of the DGs installed in Fig. 4.7

DG	Type	Capacity	DG	Type	Capacity
DG1	Solar	0.9 MW	DG7	Solar	0.8 MW
DG2	Solar	0.6 MW	DG8	Wind	0.9 MW
DG3	Conventional	0.8 MW	DG9	Conventional	1 MW
DG4	Wind	1 MW	DG10	Wind	0.8 MW
DG5	Conventional	1.3 MW	DG11	Wind	1.3 MW
DG6	Solar	2.3 MW	DG12	Solar	0.8 MW

The ESSs shown in Fig. 4.7 were also introduced to the original network in [121] and four scenarios of energy storage integration were evaluated. The ESSs in the first scenario (in further text referred to as *DG + Storage* x 1) had the energy storage capacity

Table 4.3: Reliability parameters of the DGs

Type	λ (failures/year)	r (hours/failure)	Start time (hours)
Conventional	1	48	0.75
Wind	4.17	60	0.25
PV	2	90	0.25

and rated powers of charge and discharge defined as in Table 4.4. The ESSs in the other three scenarios ($DG + Storage$ x 2), ($DG + Storage$ x 3) and ($DG + Storage$ x 4) had storage capacities and rated powers 2, 3 and 4 times larger than those defined for the first scenario. The fifth scenario had only the DGs without energy storage (referred to as *DG only*) and was used as reference to compare the impact of energy storage on reliability.

Table 4.4: Capacities (C_s) and rated powers ($\overline{Pc_s}$, $\overline{Pd_s}$) of ESSs, in MWh and MW respectively, for the Scenario ($DG + Storage$ x 1)

	ESS1	ESS2	ESS3	ESS4	ESS5	ESS6	ESS7
C_e	0.26	0.16	1.13	0.38	0.41	0.45	1.05
$\overline{Pc_e}$	0.05	0.03	0.23	0.08	0.08	0.09	0.21
$\overline{Pd_e}$	0.05	0.03	0.23	0.08	0.08	0.09	0.21

The ESSs were assumed to be batteries with the following features. The minimum and maximum SOC were 0.1 and 1 the total storage capacity respectively. The charge (ηc) and discharge (ηd) efficiencies were equal to 0.9. The initial SOC at the moment of the fault was assumed to be at 0.55, i.e. the half of the available storage capacity was reserved for restoring the supply when required. The starting time of the ESSs was of 1 minute. Moreover, the failures in the ESSs were neglected, an assumption typically used in the literature [58].

The reliability data of the components used in the network were obtained from [122]. The lines in the network were aerial, while the components of the substation and protection devices were assumed to be fully reliable. The switching time required for secure operation of the protection devices was 1 hour [122].

Under fault conditions in feeder F4, the protection devices were operated in order to create the downstream areas between the dashed lines in Fig. 4.7. The representative time-intervals shown in Fig. 4.2 were used to model the load and renewable generation. Commercial load profiles were also used for the farm load points in [121]. The capacity of feeders F1 and F2 was 2.1 MW, a value that provoked transfer restrictions between these feeders via the tie switch. The tie switch (NOP in Fig. 4.7) was assumed to be perfectly reliable to restore the supply when needed.

4.5.2 Validation of the Analytical Technique

In order to validate the analytical methodology proposed in this chapter, the results reported by the analytical technique were compared to those obtained by sequential MCS [22] under the same scenarios. This comparison was performed because MCS allows to address the chronological variability of generation and demand over time and, thus, the energy storage charge and discharge processes during faults [57, 58].

The properties of the MCS used for the validation allow an accurate comparison of the results provided by the two techniques. These properties are:

- It is a sequential MCS [22] in order to assess time-variability of generation and demand during faults.
- Reliability models of the components are the same as those used in the proposed analytical technique (2 states, up and down).
- Failure rate of each component is assumed to be exponentially distributed (a common assumption in MCS techniques to represent the failures of components over their life-time [120]).
- Repair times are assumed to be equal to the average repair times in order to allow an appropriate comparison between the two techniques.
- The restoration strategy was the same as the one proposed in the analytical technique. However, the hourly profiles of generation and demand over a whole year were considered by the MCS technique instead of the representative time-intervals used by the proposed analytical technique (note that power profiles over years were used to obtain the representative time-intervals).
- Coefficient of variation of 1.5 % was used as the stop criteria for the MCS [120].

The reliability results obtained from both analytical and MCS are shown in Fig. 4.8, and the respective computation times required for their calculation in Table 4.5. The computation times for both methods were obtained by using MATLAB (MathWorks) running on a 2-core 2.4-GHz, 64 bit desktop with Windows 7 operating system. The functions 'tic' and 'toc' in MATLAB were used to start and stop the stopwatch timer.

The differences between the network reliability results reported by the two compared methods (shown in Fig. 4.8) were below 0.5 % for SAIFI and 1.8 % for SAIDI (for the coefficient of variation in MCS of 1.5 %). In addition, the differences in reliability indices for each feeder were below 1.1, 2.1 and 1.7 % in feeders F1+F2, F3 and F4 respectively. These differences were conditioned to: the exponential distribution of component failure rate used in the MCS technique, the stop criteria uncertainty of MCS, and the approximation applied to obtain the representative time-intervals of generation and demand used in the analytical technique.

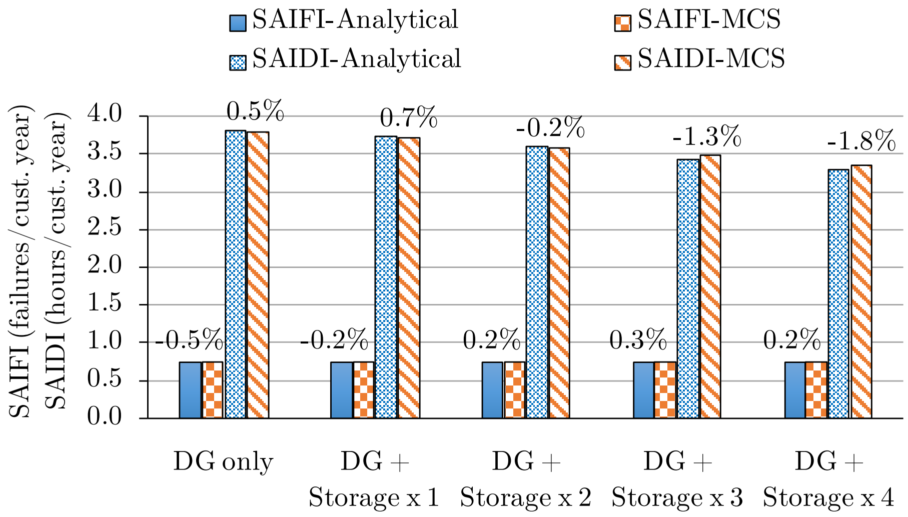


Figure 4.8: Comparison between the results obtained by the proposed analytical technique and by the MCS. Differences in % referred to MCS results

Table 4.5: Comparison between the computation times obtained by the proposed analytical technique and by the MCS

Scenario	Monte Carlo (sec.)	Analytical (sec.)
DG only	222.8	1.4
DG + Storage x 1	247.1	3.5
DG + Storage x 2	248.5	4.8
DG + Storage x 3	273.2	6.5
DG + Storage x 4	288.1	8.6

The computation times in Table 4.5 revealed the analytical technique was 50 times faster in average for the four scenarios of energy storage application. These time differences were caused by the distinction between the approaches of the two methodologies compared. On the one hand, the analytical technique simulated every network failure only once and then assessed its impact on reliability. On the other hand, MCS sampled stochastic occurrence of network failures until the reliability indices converged to a solution, causing a network failure to be evaluated several times (for example, several hundreds or even thousands). Therefore, the results demonstrated the proposed analytical methodology represented a computationally-efficient solution for the evaluation of the impact of energy storage and renewable DGs on reliability. The computation time of the analytical technique depended on several factors related to the analysed test system: the number of network failures evaluated in the study, the number of the DGs and ESSs that participated in the supply restoration of downstream areas, and the number of charge and discharge processes of energy storage devices (highly dependent on the size of the ESSs and the existence of generation shortages).

4.5.3 Impact of Energy Storage on Reliability

In this section the new analytical technique was used to evaluate the impact of the energy storage penetration on the test network reliability. The impact was assessed in the downstream areas of the faults that can be restored by islanded operation and by emergency-ties of limited transfer capacity (tie-supported operation). Table 4.6 reports the results of SAIDI in the network for the five scenarios analysed, while Fig. 4.9 shows the SAIDI reductions referred to the original distribution network without DGs. These results were obtained for each feeder in the test network shown in Fig. 4.7 ($F1$ to $F4$) and for the entire test network aggregating the four feeders (shown as $Total$). The SAIFI in the analysed scenarios was the same because the interruptions were not avoided but only reduced in duration.

The results revealed a significant reduction in the SAIDI for feeders F3 and F4. It was caused by the energy storage support to supply restoration during islanded operation. For example, the integration of only DGs improved the SAIDI of feeder F4 by 5.8 %. With the penetration of energy storage, the SAIDI improved further from 7.7 % in scenario ($DG + Storage$ x 1) to 20.6 % in scenario ($DG + Storage$ x 4) with four times larger energy storage. In both feeders F3 and F4, a 3-4 % of SAIDI improvement was obtained with the increase of energy storage size between consecutive scenarios.

The contribution of the energy storage to restore feeders F1 and F2 operating in tie-supported mode was lower than for those feeders operating in the islanded mode (F3 and F4). In the case of F1, the total margin of the SAIDI improvement by using distributed energy resources was 16 %. The penetration of only DGs improved SAIDI by 6 % while the integration of energy storage increased this value to 9 % in scenario ($DG + Storage$ x 4). Similar SAIDI reductions were obtained for energy storage in F2. In conclusion, energy storage in tie-supported operation improved reliability, although the results are strongly impacted by the transfer restrictions between feeders F1 and F2 at specific load and fault conditions.

Table 4.6: SAIDI in the evaluated scenarios (measured in hours/customer per year)

Scenario	F1	F2	F3	F4	Total
DG only	0.934	0.925	0.928	8.258	3.798
DG + Storage x 1	0.927	0.919	0.867	8.094	3.73
DG + Storage x 2	0.919	0.916	0.828	7.729	3.583
DG + Storage x 3	0.91	0.91	0.796	7.338	3.425
DG + Storage x 4	0.905	0.906	0.764	6.966	3.277

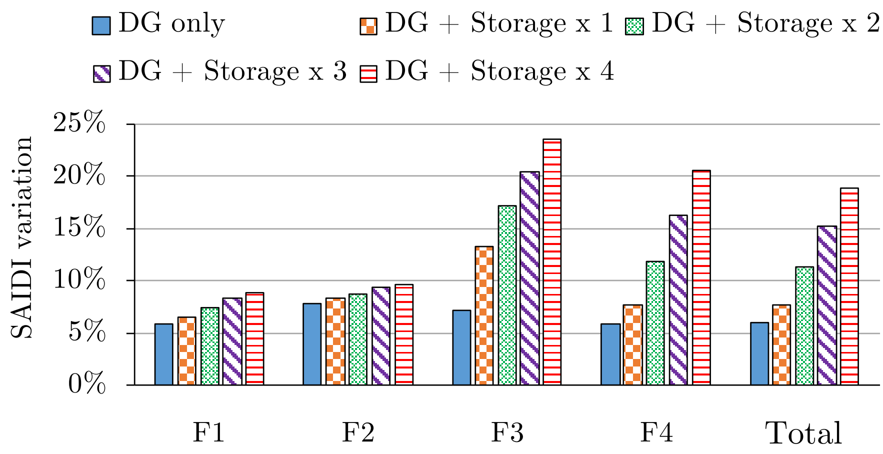


Figure 4.9: SAIDI reduction (%) in the evaluated scenarios

4.5.4 Comparison of Energy-Not-Supplied Results

Table 4.7 shows the energy-not-supplied ENS* calculated by using the new procedure proposed in this chapter, and Fig. 4.10 shows the differences between ENS* and the ENS calculated by using (4.2). The first method considers the time-dependent variability of load during the fault, while the second uses the conventional approach based on the average load values. The results were also obtained for each feeder of the test network ($F1$ to $F4$) and for the entire test network ($Total$).

The differences between ENS* and ENS were significant, in particular in those areas of the network where the energy-not-supplied was larger (feeders F3 and F4). In the test network (results in column $Total$), differences varied from 16 % in the case of DG without energy storage to 10 % in the scenario with energy storage ($DG + Storage$ x 4). It is important to notice that installing more energy storage reduced the energy-not-supplied and, consequently, the differences in the energy-not-supplied calculated by the two methods also decreased. Fig. 4.10 also shows that the use of the average load values overestimated the ENS in all energy storage scenarios. The results in this section revealed the importance of considering the fluctuations of demand profiles in the calculation of the energy-not-supplied.

4.6 Conclusions

In this chapter, a novel analytical technique has been proposed to evaluate energy storage contribution to reliability of distribution networks. The technique introduces a set of new features for an improved and more realistic assessment of energy storage compared to existing analytical methods. The first feature is its capacity to assess the impact of energy storage in network areas either restored by islanded operation or by

Table 4.7: ENS* (MWh/year) in the evaluated scenarios

Scenario	F1	F2	F3	F4	Total
DG only	1.125	1.214	2.012	41.05	45.4
DG + Storage x 1	1.108	1.194	1.935	39.98	44.22
DG + Storage x 2	1.097	1.189	1.873	38.47	42.63
DG + Storage x 3	1.085	1.178	1.810	36.73	40.81
DG + Storage x 4	1.078	1.174	1.739	35.07	39.06

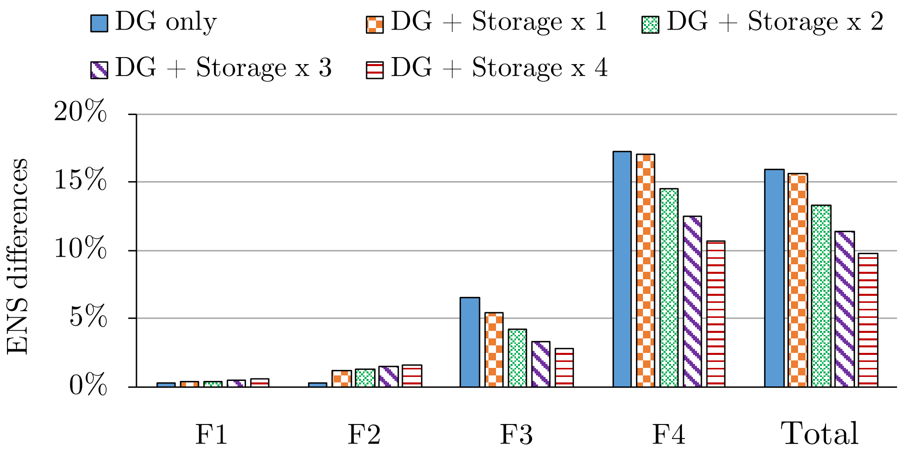


Figure 4.10: Differences between ENS and ENS*. Values in % referred to ENS*

adjacent feeders of limited transfer capacity. Another novel feature is its capability of modelling energy storage chronological charge and discharge processes during a fault and the corresponding restoration strategy. In addition to that, the variability and time-dependent fluctuations of renewable generation and demand are properly addressed and considered during the calculation of reliability indices.

The proposed technique was validated by comparing the obtained results with those computed by using sequential MCS —the latter accurately addresses the chronological operation of energy storage. The results produced by the analytical technique retained the accuracy of MCS (within the range of 2 %). However, the proposed technique required significantly lower computational efforts and times (reduced up to 50 times). Such performance makes the new technique a suitable candidate for the reliability assessment of network planning options including energy storage.

Further analyses with the proposed technique revealed that an increased penetration of energy storage improved the reliability of distribution networks in both restoration modes (up to 14 % in islanded operation and 3 % in adjacent feeders of limited transfer capacity). However, detailed cost-benefits analyses are needed to assess the feasibility of storage installations.

The principal features of this technique make it attractive for reliability assessment studies. In the following chapter this technique is used as a reference to support the selection of energy storage technology and its size for reliability improvement applications.

Chapter 5

Methodology for Energy Storage Selection in Reliability Improvement Applications

The exact contribution of energy storage to reliability of distribution networks is affected by several technical and economic factors. In this chapter, the impact of these factors is analysed and a methodology is developed for its evaluation. The analysed technical factors related to energy storage are the capacity, the rated power, the stored energy at the moment of the fault and the penetration level of renewable Distributed Generators (DGs), while the economic factors are the monetary benefits of the reliability improvement and the storage investment. The results obtained for a case study demonstrate the impact of the analysed parameters on reliability and also the importance of an appropriate energy storage selection. A preliminary version of this chapter has been published in [130].

5.1 Introduction

In Chapter 4 it has been demonstrated that energy storage can support supply restoration during outages and improve the distribution system reliability. However, the extent of the improvement needs to be evaluated by taking into account factors like ratings of renewable generation, size of energy storage, amount of stored energy when the faults occur (defined as initial SOC), cost incurred and benefit obtained. The analysis of these parameters is fundamental for an adequate selection of energy storage.

Several studies have been performed to assess the contribution of energy storage to reliability of distribution networks, as discussed in Chapters 2 and 4. In these studies, different parameters related to energy storage have been analysed and their impact on reliability evaluated. In [131], the contribution of energy storage to reliability was evaluated, yet neither the influence of technical parameters like energy storage size or renewable penetration nor economical parameters were evaluated. In [57] reliability indices were used to determine the storage size that meets a specific reliability target set by the utility. The study assumed that only energy storage with no DGs was used to restore the supply, resulting to be a economically unfeasible option. In [124] the reliability improvement provided by different energy storage sizes was evaluated but not its economic impact. In [58], apart from the reliability improvement, the associated benefit was evaluated for different energy storage sizes and levels of penetrations of renewable generation. However, the effect of the initial SOC was not considered (the storage was assumed to be fully charged when a fault occurred) and the cost-benefit analysis was not studied. In addition, it used Monte Carlo Simulation for the evaluation and the obtained high-computation-times represent a limitation for efficient evaluation of several energy storage options. The optimal location of energy storage to improve reliability was performed in [61]. It used a two-steps methodology that combined a genetic algorithm with Monte Carlo Simulation and compared different energy storage technologies. However, the methodology is complex and some assumptions were used to evaluate the performance of energy storage: the charging was neglected during faults, the storage was fully charged when the faults occurred and the chronological evolution of renewable generation and demand was neglected. To summarise, several parameters affect the contribution of energy storage to reliability, however, not all of them have been adequately considered at the same time for an effective energy storage selection.

In this chapter, the impact of energy storage on distribution network reliability is evaluated by taking into account the impact of the following technical and economic parameters: energy storage size (capacity and rated power), penetration of renewable DGs, level of initial SOC and storage cost. Different combinations of these parameters are evaluated by using the proposed methodology that provides results in the form of reliability and cost-benefit metrics. This methodology is then applied to a case study to demonstrate its features: evaluate the impact of the analysed parameters and select the energy storage parameters that ensure specific levels of reliability and profitability.

The chapter is organised as follows: the proposed methodology for technical and economic evaluation is described in Section 5.2. Section 5.3 discusses the impact of technical factors on reliability and provides recommendations for energy storage sizing. In Section 5.4, the cost-benefit results obtained for different energy storage technologies are presented. Finally, conclusions are drawn in Section 5.5.

5.2 Methodology for Assessment and Selection of Energy Storage

Fig. 5.1 shows the proposed methodology for evaluating the impact of different energy storage options on distribution network reliability. Technical results in the form of reliability indices (defined in Appendix A) and economic results in the form of cost-benefit indices are calculated by using the methodology. These results provide relevant information to:

1. Analyse the impact of different parameters related to energy storage: the penetration of distributed generation, the size of energy storage and the level of initial SOC.

2. Meet a specific target for reliability.

3. Determine the profitability of different energy storage options.

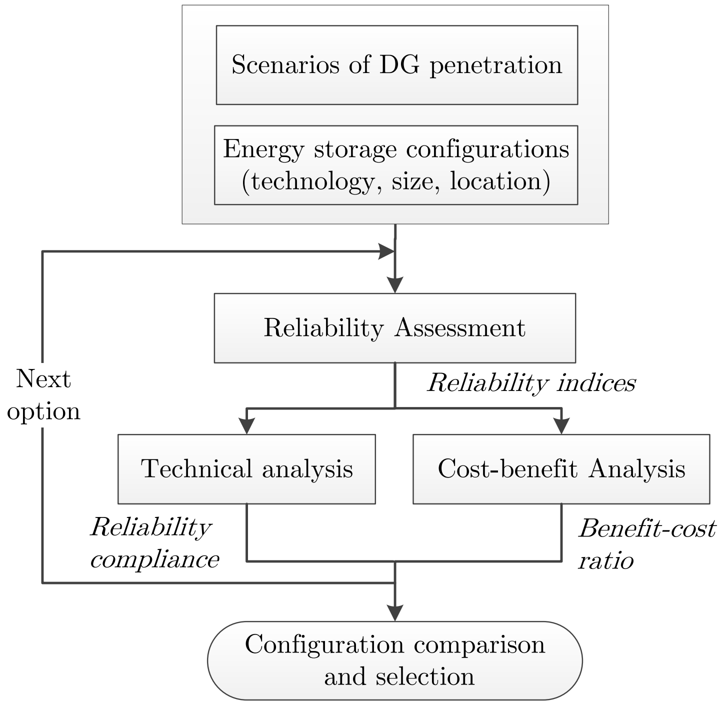


Figure 5.1: Flowchart of the proposed methodology for energy storage selection

The methodology uses the following steps as shown in Fig. 5.1. The possible options to be evaluated are defined first. These options contain information regarding to the penetration of renewable distribution generation and the energy storage configurations to be evaluated. Then, the reliability is assessed for each option. The obtained reliability indices are used to perform technical and cost-benefit analyses. The technical analysis evaluates the reliability improvement provided by each considered option and its capability to meet specific reliability requirements. The cost-benefit analysis determines the economic benefit of the reliability improvement and the required investment for each evaluated option. Finally, the results obtained for all the options are compared to draw concluding remarks and to select the appropriate energy storage. The following subsections explain in more detail each of the evaluation steps.

5.2.1 Definition of Energy Storage Configurations

The methodology allows the evaluation of different energy storage options for reliability improvement. These options represent the input to the analysis and are defined by the following parameters: the penetration level of renewable generation and the size, initial SOC and technology of energy storage.

The penetration level of distributed generation is defined for a specific network area as the ratio between the capacity of the DGs and the annual peak load of the area:

$$DG\ penetration\ level = \frac{Rated\ power\ of\ DGs}{Annual\ peak\ load}. \tag{5.1}$$

This DG penetration level includes both conventional and renewable resources.

The size of energy storage is analysed by its capacity and rated power. These parameters are represented in the analysis by the Storage Capacity Ratio (SCR) and the Storage Power Ratio (SPR), which are defined as:

$$SCR = \frac{Capacity\ of\ energy\ storage}{Rated\ power\ of\ renewable\ DGs}, \tag{5.2}$$

$$SPR = \frac{Rated\ power\ of\ energy\ storage}{Rated\ power\ of\ renewable\ DGs}. \tag{5.3}$$

As these formulas show, the ratios take into account the penetration level of renewable DGs, as energy storage is assumed to be used to support the variability of renewable generation.

The initial SOC represents the amount of stored energy at the moment when a fault occurs. This energy is used to support customers supply during faults and, thus, contribute to the reliability improvement. However, the initial SOC depends on the energy storage operation prior to the fault occurrence and is exposed to uncertainty that affects the reliability.

5.2.2 Reliability Evaluation Method

The analytical technique proposed in Chapter 4 is used to evaluate the reliability of the defined scenarios. This technique is selected because it allows an accurate and efficient evaluation of distribution systems with renewable DGs and energy storage. In particular, the computational efficiency makes this technique appropriate for the assessment of a large number of energy storage options.

The methodology proposed in this chapter calculates the reliability indices as specified in Chapter 4 either for a single load point i (λi, r_i and U_i) or for a network area (like SAIFI, SAIDI or ENS). In addition, this methodology is extended to determine the economic indices defined as Interruption Cost (IC) and Interrupted Energy Assessment Rate (IEAR). They are calculated for every load point of the network as:

$$IC_i = \sum_{j=1}^{N_j} ENS_{ij} CDF(r_{ij}), \tag{5.4}$$

$$IEAR_i = \frac{IC_i}{\sum_{j=1}^{N_j} ENS_{ij}}, \tag{5.5}$$

and for a network area as:

$$IC = \sum_{i=1}^{N_i} IC_i, \tag{5.6}$$

$$IEAR = \frac{IC}{\sum_{i=1}^{N_i} \sum_{j=1}^{N_j} ENS_{ij}}, \tag{5.7}$$

where N_i is the number of load points in the area studied, N_j is the number of failures evaluated, r_{ij} and $ENS_{i,j}$ are the interruption duration and the energy-not-supplied calculated in Chapter 4 for load point i and failure j, and CDF is the customer damage function. As described in [120], the value of CDF depends on the customer type (residential, industrial, commercial, etc.) and the duration of the interruption (r_{ij}). Typical units of these economical indices are $\$/kWh$ for IEAR and $\$/year$ for IC.

5.2.3 Technical Analysis

The technical analysis evaluates the impact of energy storage size, initial SOC and DG penetration on reliability. An integrated assessment of all these parameters is applied in order to take into account their interdependence. The obtained reliability indices are critically compared in order to identify the importance of these parameters for the reliability improvement provided by energy storage.

The technical analysis also helps with the selection of energy storage technology used for reliability studies. By using the results of the analysis, the energy storage parameters can be properly selected to achieve a specific reliability improvement. An example of application of the technical analysis is shown in Section 5.3.

5.2.4 Cost-benefit Analysis

The cost-benefit analysis proposed here focuses on the application of energy storage for reliability improvement. The analysis determines the amount of energy storage investment that can be recovered by reliability improvement. For this, the monetary savings obtained from improving reliability and the investment required are both calculated. As in the technical analysis, all the energy storage options defined in the study are evaluated. The economic impact of energy storage parameters like size, initial SOC or technology cost are all determined, providing necessary information for energy storage selection.

The following steps are applied to determine the benefit and the cost related to energy storage.

Benefit:

The benefit provided by the reliability improvement comes from the reduction in the interruption costs and, therefore, index IC_i is used for its calculation. This benefit is defined as:

$$Benefit = \sum_{i=1}^{N_i} \left(IC_i^{ref} - IC_i \right), \tag{5.8}$$

where IC_i^{ref} is the interruption cost of the scenario used as reference in the analysis (scenario without energy storage) and IC_i represents the interruption cost for the energy storage option under evaluation. As IC_i is an annual cost, the benefit also refers to an annual magnitude.

Cost:

The cost considered in the analysis corresponds to the annual investment in energy storage. It is calculated by dividing the total investment and the lifetime of the energy storage. This cost is determined for the different energy storage options that are analysed.

The storage investment (Inv) includes the cost of the energy storage and power conversion systems and it is calculated as defined in [132]:

$$Inv = P_s \left(C_{ci} EPr + C_{pi} + C_{cu} \right), \tag{5.9}$$

where P_s is the power of the energy storage, EPr is the ratio between capacity and power in the application (given by SCR/SPR), C_{ci} is the cost of energy storage per capacity unit (e.g. in $\$/kWh$), C_{pi} is the cost of energy storage per power unit (e.g. in $\$/kW$), and C_{cu} the cost of the conversion system per power unit.

The lifetime of energy storage devices depends on the evaluated technology and the operating conditions. Both of them have to be properly considered in the lifetime estimation.

Benefit-cost ratio:

Once benefit and cost are calculated, the benefit-cost ratio of an energy storage option is determined. It is defined in this chapter as the ratio between the benefit ($Benefit$) and the cost (Inv). This parameter represents an useful metric to determine the amount of annual investment that is returned by the reliability improvement only.

5.3 Case Study: Technical Analysis

5.3.1 Test Network

Fig. 5.2 shows the real MV distribution network that was used for the reliability evaluation and for testing the application of the proposed methodology. This network is called as Feeder c72 and details can be consulted in Appendix B. Failure statistics in [122] were used for network components.

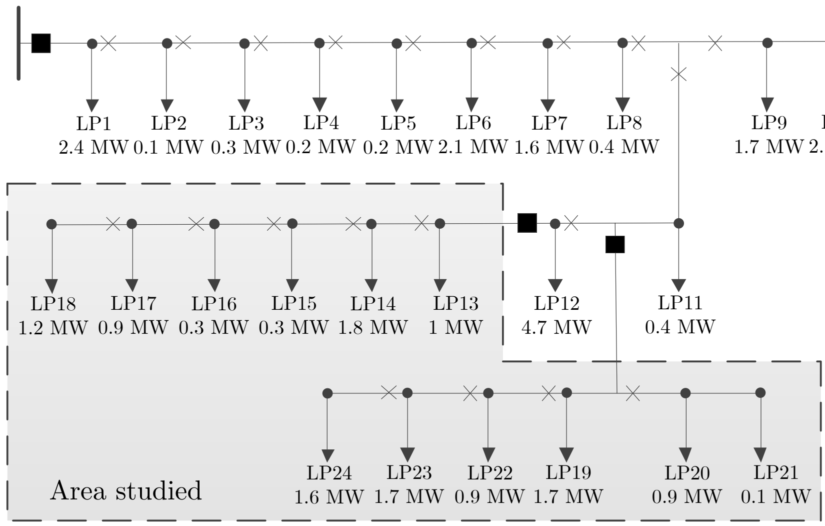


Figure 5.2: Topology of the studied network

The reliability indices for the whole network and for the network area marked as *Area studied* in Fig. 5.2 are provided in Table 5.1. This *Area studied* demonstrated SAIDI values larger than the average obtained for the network and was accordingly selected by the distribution company for more detailed reliability studies and possible improvements.

Table 5.1: Reliability indices of the original network without DGs and energy storage

Region	SAIFI interruptions/customer year	SAIDI hours/customer year	ENS MWh/year
All network	0.9	7.3	261
Area studied	1.7	12.7	98.8

As a possible solution to this problem, the reliability was evaluated for the case that *Area studied* was equipped to operate in islanded mode with DGs. Two scenarios were evaluated for the DGs: one including a mix of conventional, wind and solar DGs (*Mixed DG*), and the other with only wind and solar renewable DGs (*Renewable DG*). Table 5.2 shows the location, the rated power and the power-resource type of the DGs for both scenarios. The rated powers in Table 5.2 correspond to a DG integration level of 0.5 times the annual peak load, although in the evaluation more integration levels were analysed: 0.7, 0.9, 1.2, 1.4, and 1.6 (the same level was applied to all the DGs). The network is assumed to include active network management schemes to guarantee the network security in presence of high power generation [50]. Data of wind, solar and demand powers in [116] were used, considering the time-intervals shown in Fig. 4.2.

Table 5.2: Input data of the DGs for the two scenarios evaluated

DG	Location	Rated power (MW)	Type of DG	
			Mixed DG	Renewable DG
DG1	LP13	1	Conventional	Wind
DG2	LP16	2	Solar PV	Solar PV
DG3	LP17	2.5	Wind	Wind
DG4	LP19	4.4	Wind	Wind
DG5	LP20	0.9	Solar PV	Solar PV
DG6	LP23	1.5	Conventional	Solar

In addition to DGs, energy storage was also integrated in the analysed area. The energy storage devices in Table 5.3 were connected to the network. Their location was determined according to the design and technical requirements of the network. A range of energy storage sizes was evaluated in order to identify their impact on reliability and their relation with the penetration level of renewable DGs. The capacity ratio SCR was between 0.05 and 2.5, while the power ratio SPR between 0.05 and 0.4. Moreover, the rated powers to charge and discharge the energy storage were assumed to be equal. The rest of the parameters of the energy storage were charging and discharging efficiencies of 0.9, and minimum and maximum SOC of 0.1 and 1 the storage capacity, respectively. The annual unavailability of the energy storage devices was assumed negligible. This is a common assumption in reliability studies [58, 61].

Table 5.3: Energy storage devices integrated in the area studied

Device	Location	Capacity	Rated power
Storage 1	LP17	Given by SCR	Given by SPR
Storage 2	LP19		

5.3.2 Energy Storage Size Evaluation

The impact of the energy storage size was evaluated for the two DG scenarios (*Mixed DG* and *Renewable DG*). Fig. 5.3 and Fig. 5.4 show the SAIDI for the two scenarios respectively. The energy storage devices were assumed to be fully charged when the fault occurred (initial SOC of 1). SAIDI results were analysed because they provide information on the reduction of the interruption duration in the analysed scenarios. ENS results were also analysed but they are not shown here because their variation followed the same trend as SAIDI. Note that the values of SAIFI were the same as those in the original case because the sustained interruptions were not avoided (only reduced in duration).

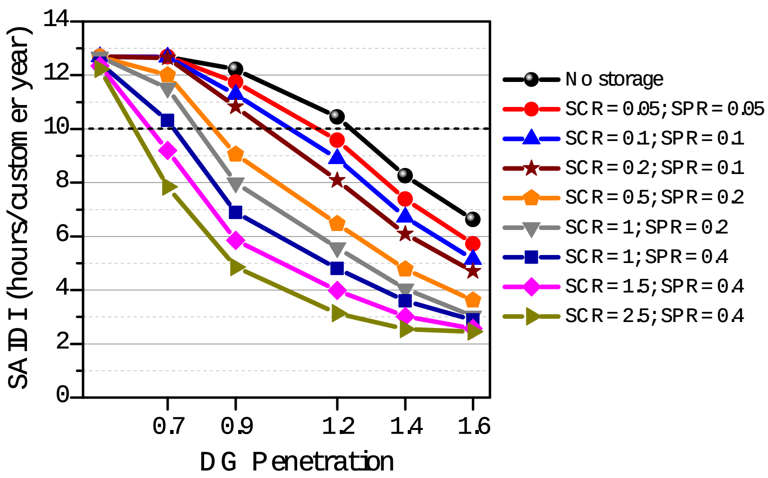


Figure 5.3: SAIDI for scenario *Mixed DG* and initial SOC of 1

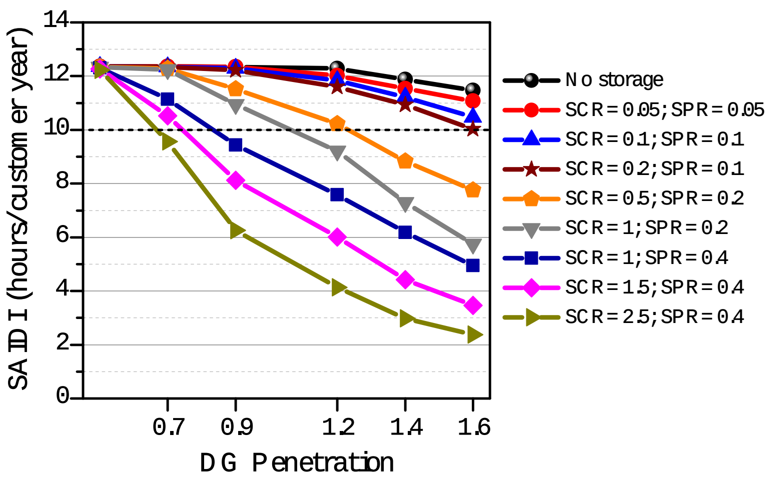


Figure 5.4: SAIDI for scenario *Renewable DG* and initial SOC of 1

Results for both scenarios demonstrated the improvement of the reliability largely depends on the size of the energy storage selected. This is clearly observed in the SAIDI obtained for different energy storage sizes at a certain DG penetration level. For example, assuming a DG penetration of 0.9 in scenario *Mixed DG*, the SAIDI ranges from 12.2 hours/customer when no storage is included to 4.9 hours/customer for the largest energy storage plotted (SCR=2.5, SPR=0.4).

When comparing the SAIDI obtained for the two scenarios of DG penetration in Fig. 5.3 and Fig. 5.4, some differences can be seen. The first difference occurs in absence of energy storage (results designed as *No storage*) and for DG penetrations larger than 0.9 times the annual peak load. In this case, the reliability improvement is 5 times larger in presence of some DGs from conventional resources (*Mixed DG*) than all DGs from renewable sources (*Renewable DG*).

The second notable difference occurred for small values of energy storage with capacity ratios SCR$\leq$ 0.2 and power ratios SPR$\leq$ 0.1. For these ratios, the *Mixed DG* scenario showed more significant reductions in SAIDI than *Renewable DG* scenario. For example, these reductions were of 2.4 hours/customer for *Mixed DG* and 0.7 hours/customer for *Renewable DG*, both referred to a DG penetration of 1.2 (SCR=0.2, SPR=0.1).

A third difference occurred in the evaluation of the largest energy storage sizes, that is with 0.5 $<$SCR$\leq$ 2.5 and 0.2 $<$SCR$\leq$ 0.4. For these ratios the SAIDI was significantly reduced in scenario *Renewable DG*, reporting values close to those provided in the scenario that included conventional generation (*Mixed DG*). Therefore, larger energy storage sizes were needed to improve reliability indices at increased levels of renewable DG penetration and, in this way, compensate the lower energy generated by renewable DGs for the same installed capacity.

5.3.3 Evaluation of Initial State-of-Charge

Previous analysis in Section 5.3.2 was performed assuming the energy storage devices were fully charged when the fault occurred (initial SOC of 1). However, the storage devices may have lower levels of stored energy when a fault occurs. For this reason, an analysis is performed to assess the impact the initial SOC has on reliability.

The SOC of energy storage is mainly determined according to the operational principles of the distribution network. In order to evaluate the impact of the initial SOC on reliability, different levels of SOC were assumed.

Fig. 5.5 and Fig. 5.6 show the SAIDI of scenarios *Mixed DG* and *Renewable DG* for an initial SOC of 0.2. The dashed lines in these figures were added to indicate the range of SAIDI values obtained with initial SOC of 1. If these results for the initial SOC of 0.2 and 1 are compared, it reveals that the energy initially stored has a significant impact on the reliability. The same energy storage size but with initial SOC of 0.2 instead of 1 reduced SAIDI 20 times less at DG penetration of 0.5, and 2 times less at DG penetration of 1.6. This happened for *Mixed DG* scenario, while for *Renewable DG* scenario SAIDI was reduced 12 and 3 times less for the same DG penetrations of 0.5 and 1.2. Therefore, the initial SOC has to be taken into consideration during the sizing of energy storage for reliability improvement purpose.

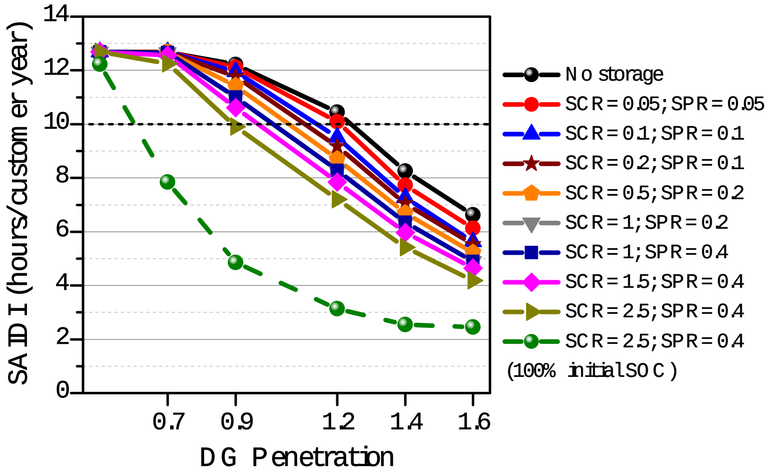


Figure 5.5: SAIDI for scenario *Mixed DG* and initial SOC of 0.2

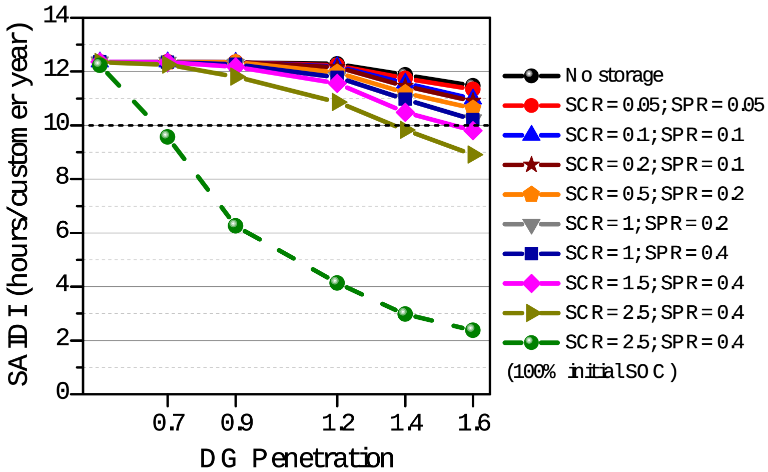


Figure 5.6: SAIDI for scenario *Renewable DG* and initial SOC of 0.2

A more extended analysis was performed to analyse the reliability for other values of initial SOC. Fig. 5.7 and Fig. 5.8 show the average ratio of SAIDI reduction provided by the energy storage sizes in Fig. 5.5 at the specified values of initial SOC (between minimum SOC of 0.1 and maximum SOC of 1). This ratio represents (in per unit) the margin of SAIDI reduction introduced by energy storage, which is 0 for the test system without energy storage, and 1 for the system with energy storage and initial SOC of 1.

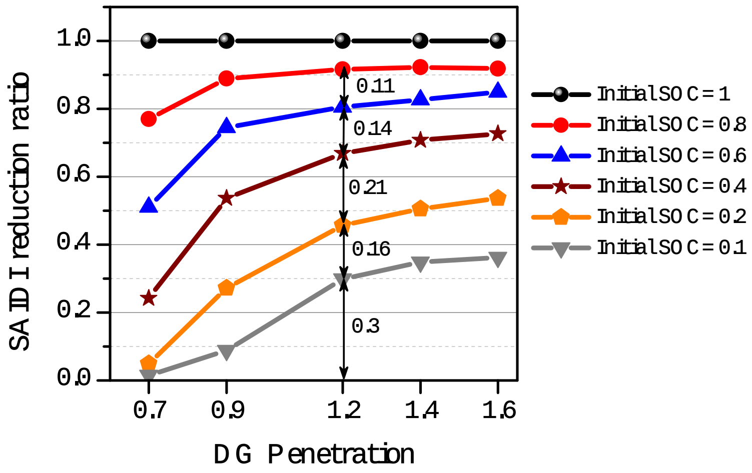


Figure 5.7: Average SAIDI reduction ratio provided by energy storage for scenario *Mixed DG*

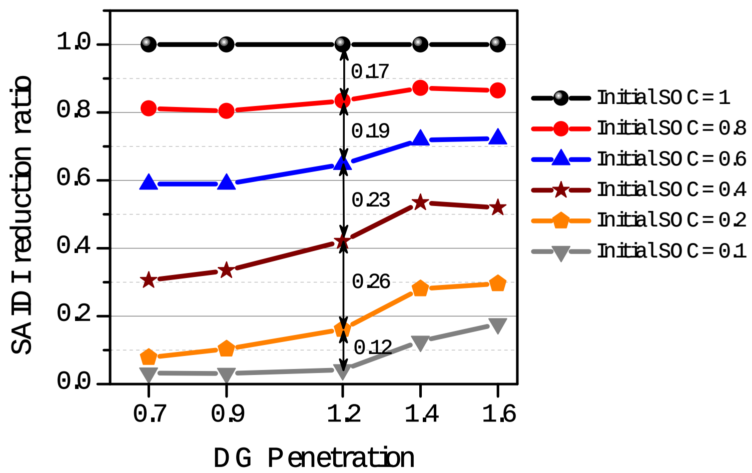


Figure 5.8: Average SAIDI reduction ratio provided by energy storage for scenario *Renewable DG*

The results of SAIDI reduction ratio indicate that a significant part of the reliability improvement introduced by energy storage came from using the energy initially stored to supply the generation shortages. However, this improvement depends on the value of initial SOC, the penetration level of distributed generation and the amount of renewable power. The initial SOC provided larger increases of SAIDI reduction ratios at DG penetration between 0.7-0.9. In this interval, the increase of initial SOC caused a similar SAIDI reduction ratio meaning that an increase of initial SOC of 0.2 provoked SAIDI reduction ratios around 0.2 or larger. However, the increase of the ratio was reduced as initial SOC and DG penetration augmented. For example, changing the initial SOC from 0.8 to 1 at DG penetrations of 1.4-1.6 provided a SAIDI reduction ratio of 0.08 in *Mixed DG* and a 0.14 in *Renewable DG*.

Apart from the initial SOC value, the rest of the reliability improvement provided by energy storage came from storing energy at periods with excess of generation during the fault. An idea of this improvement is observed in Fig. 5.7 and Fig. 5.8 for the initial SOC of 0.1 (minimum value of SOC). In *Mixed DG* scenario (Fig. 5.7), significant SAIDI reduction ratios between 0.3 and 0.36 were obtained at DG penetrations between 1.2 and 1.6. However, the ratios were smaller for lower DG penetrations and for *Renewable DG* scenario. In the latter scenario, SAIDI reduction ratios were 0.04 and 0.18 at DG penetrations of 1.2 and 1.6 respectively.

5.3.4 Energy Storage Size Selection

Results of reliability indices can be used to recommend the energy storage size that meets a specific reliability target. In this case study, it was assumed the distribution company set the target to reduce the SAIDI of the evaluated area to 10 hours of interruption per customer and year.

Results like those provided in Fig. 5.3 to Fig. 5.6 were used to evaluate the energy storage size that met the target in the area of study. The size was evaluated assuming a specific SOC of the energy storage. It was, therefore, assumed the initial SOC to be known and fixed by the network operator. The aggregated capacities and powers of the energy storage devices required to meet the target are shown in Table 5.4, assuming a DG penetration level of 0.9 times the annual peak load. These results highlight significant differences in the storage sizes between the values of initial SOC evaluated, and between the two scenarios with different share of renewable generation. If initial SOC is increased from 0.2 to 0.4: a) the storage capacity is reduced 2.8 times and the storage power 2 times in *Mixed DG* scenario, b) the maximum energy storage size analysed (SCR=2.5, SPR=0.4) fulfilled the reliability target in *Renewable DG* (*No solution* means that the maximum storage size evaluated did not meet the reliability target). Similarly, increasing initial SOC from 0.4 to 0.6 reduced the capacity 1.8 times for *Mixed DG* and 1.7 times for *Renewable DG*. If both scenarios of DG penetration are compared, the storage capacity required in *Renewable DG* was 3-4 times larger than in *Mixed DG*, while the storage power was 2.5-3.3 times larger.

5.4 Case Study: Cost-benefit Analysis

A cost-benefit analysis was performed for the test network described in 5.3.1. The analysis focused on evaluation of different energy storage options for reliability improvement according to the methodology described in Section 5.2.4. Therefore, only the benefits

Table 5.4: Energy storage size in the area studied to meet a reliability target of SAIDI<10 hours/customer per year (DG penetration of 0.9)

	Mixed DG		Renewable DG	
Initial SOC	Capacity (MWh)	Power (MW)	Capacity (MWh)	Power(MW)
0.1	No solution		No solution	
0.2	49	7.8	No solution	
0.4	17.6	3.9	61.5	9.8
0.6	9.8	3.9	37	9.8
0.8	7.8	2.9	24.6	9.8
1	6	3	24.6	7.4

obtained from the reliability improvement where considered in the results. The same ranges of SCR and SPR values described in 5.3.1 were analysed, while the penetration level of DGs was fixed to 1.2 times the annual peak demand for scenario $Mixed\ DG$.

Batteries were used as the energy storage technology for the evaluation because their applications in distribution systems have raised significant interest in recent years. Three battery technologies were evaluated: lead-acid, lithium-ion and vanadium redox flow. Their parameters of SOC limits, efficiencies, number of cycles and lifetime (in years) are shown in Table 5.5. Technical parameters are obtained from [132, 133, 134, 135], while the lifetimes of lead-acid and lithium-ion batteries are estimated by assuming 2 cycles per day with depth of 20 % under normal operating conditions. In addition, the investment costs for the three battery technologies are shown in Table 5.6 and are obtained from the recommendations in [132]. As this reference states, the power installation cost is set to zero for lead-acid and lithium-ion technologies because their capacity and power are linked and cannot be separated. In the analysed range of capacity and power ratios, the evaluated capacities are capable of providing the specified power. In contrast, the power and capacity of redox flow batteries can be separated during the design process and an independent cost is assigned to them. The cost of the converter for the batteries is 70 $\$/kW$.

Table 5.5: Technical parameters of the three energy storage technologies evaluated

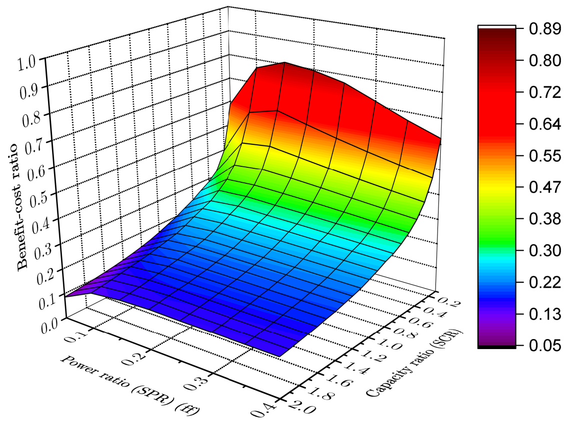
Technology	min SOC	max SOC	ηc	ηd	Cycles	Lifetime
Lead-acid	0.4	1	0.7	0.7	3250	4.5
Lithium-ion	0.1	0.9	0.9	0.9	4500	6.2
Redox flow	0.2	0.8	0.75	0.75	10000	13.7

Table 5.6: Cost of the three energy storage technologies evaluated

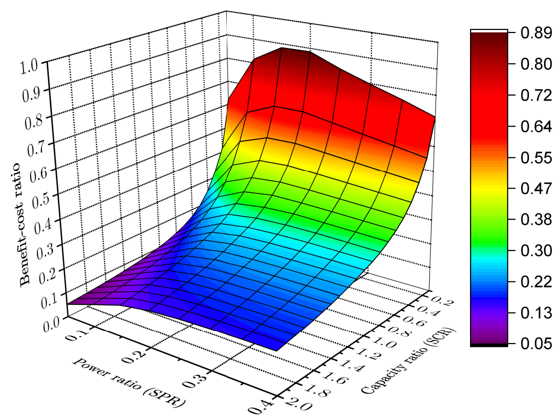
Technology	Cost ($/KWh)	Cost ($/kW)
Lead-acid	126	0
Lithium-ion	240	0
Redox flow	298	1312

5.4.1 Energy Storage Size and Technology Analysis

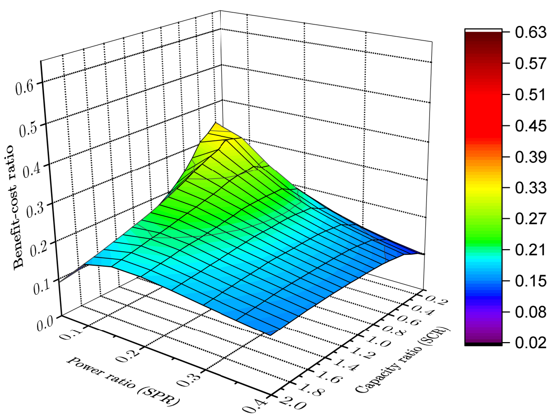
The energy storage profitability in terms of reliability improvement was analysed for the previously mentioned battery technologies and sizes. Results of the obtained benefit-cost ratio are shown in Fig. 5.9, where an average initial SOC of 0.6 was considered during normal operating conditions.



(a) Lead-Acid



(b) Lithium-ion



(c) Redox Flow

Figure 5.9: Benefit-cost ratio for different batteries (initial SOC of 0.6)

The results for the three technologies show that the benefit-cost ratios range from 5 to 90 % depending on the energy storage size and technology. Therefore, the benefit to reliability obtained by energy storage application can be significant and should be considered during planning studies. As this benefit is highly dependent on the energy storage size and technology used, both parameters should be properly analysed and selected.

When the results for the three technologies are compared, it can be seen that the benefit-cost ratios for lead-acid and lithium-ion have similar trends that are highly dependent on the storage capacity. At capacity ratio of 0.1, the benefit-cost ratio is in average 72 % for lead-acid and 79 % for lithium-ion, and it fall sharply until 15 and 13 % respectively at a capacity ratio of 2. These results reflect that the smaller the storage capacity, the more profitable the energy storage for reliability improvement application. Therefore, small capacities are preferred. This finding is derived from a) the high cost of batteries that increases with the installed capacity, and b) the significant reliability improvement provided by small energy storage devices (used to support renewable generation during outages).

In contrast, the benefit-cost ratio for vanadium redox flow batteries presents several differences with respect to lead-acid and lithium-ion technologies:

- The variation of the ratio with the storage size is less pronounced for redox flow batteries (between 10 and 34 %) than for other evaluated technologies (between 5 and 90 %).
- The ratio for redox flow batteries is highly influenced by power and capacity, while in the other technologies the ratio was mainly determined by capacity.
- Power ratios between 0.05 and 0.15 are the most profitable.

These results are conditioned by the investment required for the redox flow battery, as it is highly dependent on the installed power (see costs in Table 5.6).

In addition to the benefit-cost ratio, the economic benefit of reliability improvement is compared for the three energy storage technologies. In this case the comparison is performed for different energy storage capacities at a fixed power ratio of 0.15. This power ratio is selected because in this range the largest benefit-cost ratios were achieved. The results of this analysis are shown in Fig. 5.10, where the reliability improvement benefit (right y-axis) and the benefit-cost ratio (left y-axis) are represented by using dashed and continuous lines, respectively.

As it was expected, the larger the capacity installed, the larger the economic benefit obtained for the three analysed technologies. Although the benefits of lithium-ion and lead-acid increased with the capacity, the benefit-cost ratio decreased. This means that the extra benefits obtained are lower than the additional investment required in storage capacity. The difference between these two magnitudes is especially significant at capacity ratios between 0.1 and 0.7, where the benefit-cost ratio decreases from 81-88 % to 27-33 %. In contrast, for the same range of capacity ratios, increasing the capacity of redox flow technology augmented the benefit-cost ratio 3-5 %. Therefore, the energy storage size significantly impacts the profitability and tools like the one proposed in this chapter help in the appropriate size selection.

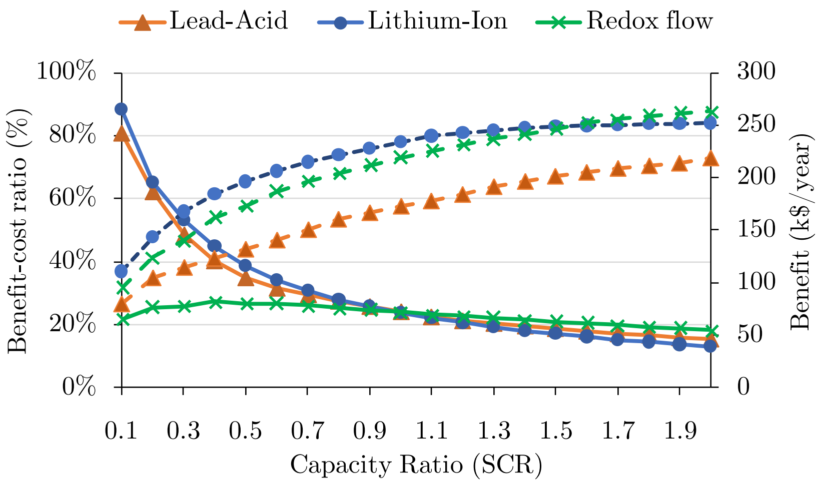


Figure 5.10: Benefit-cost ratio (in continuous line) versus reliability improvement benefit (in dashed line) for the evaluated energy storage technologies

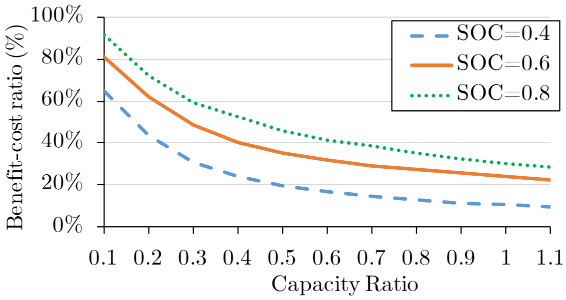
5.4.2 Economic Impact of State-of-Charge Uncertainty

In the technical study performed in Section 5.3 it was observed that initial SOC significantly affected reliability. Thus, the impact of the initial SOC on profitability is analysed in this section. Three values of initial SOC were evaluated, 0.4, 0.6 and 0.8, assuming that under normal operating conditions of the system (without failures) the SOC commonly remained between 0.4 and 0.8 of the battery capacity.

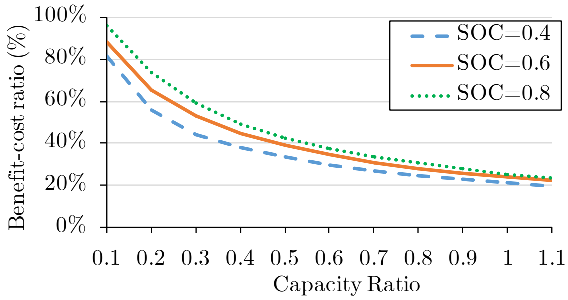
Fig. 5.11 shows the benefit-cost ratio obtained for the three values of the evaluated initial SOC. These results show that the initial SOC affects the energy storage profitability. The more significant differences were obtained for lead-acid technology, with average variation of -15 % for initial SOC of 0.4 and 9 % for initial SOC of 0.8 (differences with regard to initial SOC of 0.6). These differences were of -5 and 4 % for lithium-ion and of -5 and 3 % for redox flow respectively. Therefore, the uncertainty of the initial SOC has to be considered in the calculation of reliability indices and in the cost-benefit analysis.

5.5 Conclusions

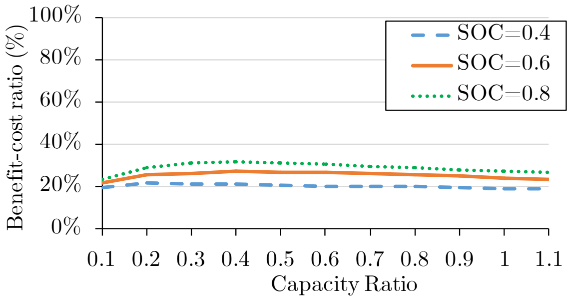
In this chapter the application of energy storage systems for reliability improvement of distribution networks has been analysed. The level of reliability improvement and



(a) Lead-Acid



(b) Lithium-Ion



(c) Redox Flow

Figure 5.11: Variability of the benefit-cost ratio for different values of initial SOC

the associated cost-benefit have been evaluated together. The evaluation has been conducted by using a novel methodology that is capable of assessing critical parameters for network reliability and energy storage profitability. These parameters are the size of energy storage, the initial SOC when a fault occurs, the penetration levels of DGs, the technology of energy storage and its cost. A case study has been used to analyse the impact of these parameters on reliability and profitability, and also to demonstrate how the assessment results can be used for an effective energy storage selection.

The study emphasised the importance of the correct energy storage sizing for reliability improvement. The sizing was found to be highly dependent on the analysed parameters, showing that the interdependence between these parameters has to be assessed from the technical and economic point of view.

The cost-benefit results showed that the reliability improvement benefits provided by energy storage can be used to recover a significant part of the storage investment. Therefore, this benefit has to be considered during network planning studies in addition to other benefits energy storage provides (e.g. peak-shaving, penetration of renewable generation or ancillary services). Nevertheless, it was found that the profitability of the investment related to reliability improvement is highly dependent on the cost of the energy storage technology, which in turn depends on the storage size. This finding reveals that energy storage size and technology have to be properly selected to obtain a specific profitability.

Three battery technologies (lead-acid, lithium-ion and vanadium redox flow) have been analysed and their impacts on reliability compared. The results have shown that lead-acid and lithium-ion batteries of small capacities could pay back more than the half of the energy storage investment, but the return ratios decreased sharply with the capacity. In the case of redox flow, the investment was higher than for the other technologies and the corresponding return ratios decreased. An expected reduction of the energy storage cost in the coming years would increase the amount of investment returned. Prospective analyses could be performed by using the tool proposed in this chapter.

The initial SOC when a fault occurs was found to be crucial with respect to reliability. Consequently, the proposed methodology should be extended to modelling the uncertainty of this parameter in a probabilistic way. Methodologies to simulate the operation of energy storage during non-fault conditions can be used for this purpose. In addition, these methodologies can help estimate the lifetime of energy storage technologies.

Apart from distributed generation and energy storage solutions, demand management can be also used to obtain further reliability improvements. All these solutions can be operated in a coordinated way during outages and provide more flexibility necessary for reliability improvement. Thus, their operation can be optimised in order to provide their maximum contribution to reliability. This represents the challenge addressed in the following chapter.

Chapter 6

Reliability Assessment of Active Distribution Networks with Optimal Coordinated Restoration

It is reasonable to assume that Active Distribution Networks (ADNs) will include Distributed Generators (DGs), energy storage systems and dispatchable loads that can be used to restore the supply in post-fault isolated areas. Restoration capacity of these solutions may not be sufficiently large to fully restore the load and an optimal coordination between them is fundamental for the reliability improvement. Until now the effect of such optimal coordination has not been considered in reliability studies and this chapter proposes a novel analytical methodology to address this issue. The optimal coordination is modelled in detail along with chronological variability and fluctuations of renewable generation and demand. The proposed model is used then to evaluate sequential and optimal operation of energy storage and demand management during outages and to calculate the corresponding reliability indices. A case study is used to validate the proposed methodology and emphasise the impact of optimal resources coordination on reliability. The content of this chapter has been submitted for publication in [136].

6.1 Introduction

In previous chapters, distributed generation and intentional islanded operation have been identified as promising options to restore the supply and improve the reliability of distribution systems. However, a significant part of this generation will likely use renewable energy resources like wind or solar and, consequently, will be exposed to variability and fluctuations that limit their capacity to improve reliability. Under these circumstances, energy storage devices and demand management can be used to compensate fluctuations of renewable generation and minimise the impact of interruptions [137]. The reliability improvement of energy storage has been discussed and demonstrated in Chapters 4 and 5, and it can be further increased if demand management actions are combined with energy storage use. A combination of the resources —distributed generation, energy storage and demand management —has to be evaluated in reliability assessment and their coordinated operation specifically considered.

Reliability assessment techniques for distribution networks have been extended to include renewable generation and possible islanded network operation (see Chapters 2 and 3). Intensive efforts have been dedicated in these techniques to evaluate the variability of renewable resources, as their power can be insufficient to restore all the demand in the interrupted areas. Under these circumstances, demand response actions can be applied to support the renewable generation and this effect has been studied in [26, 28, 138]. Another option to support renewable generation and improve reliability is energy storage, which has been studied in [58, 66, 123] for energy storage devices and in [100, 139] for parking lots. In these works, demand response and energy storage options are individually used to support renewable generation. If both options are combined, further reliability improvement can be obtained, but also increased complexity to model their coordinated operation is required.

The combined operation of energy storage and demand response offers additional flexibility in the supply restoration. Different real-time restoration strategies can be applied to manage energy storage and demand response during an interruption, producing different impacts on reliability. Therefore, the restoration strategy has to be considered in the reliability evaluation. These strategies aim to minimise the impact of interruptions, but this impact and the mentioned flexibility can be complex to be addressed in probabilistic reliability studies [140]. Moreover, increased computation efforts are required representing an important parameter in reliability studies where a large number of faults and conditions are assessed [22]. For these reasons, simple restoration strategies are commonly considered in reliability studies [22]. However, the impact of optimal restoration strategies has been evaluated in specific studies for realistic evaluation. For example, the contribution of optimal switching operation was considered in [140] and for optimal load shedding in [28, 89]. Moreover, optimal operation of parking lots together with renewable DGs was assessed in [100], and optimal management of multiple microgrids supporting ADNs in [81]. In addition, DGs, energy storage and dispatchable loads installed in ADNs can be coordinated together during outages to maximise reliability. However, none of the mentioned references take into account this optimal and coordinated management in the calculation of reliability.

In this chapter, reliability of ADNs with DGs, energy storage and load shedding is evaluated, and the impact of their optimal coordination during outages included in the evaluation. The methodology proposed for this evaluation firstly identifies the areas isolated by the faults and then models the variability of generation and demand by using probabilistic profiles (a requirement to assess the chronological performance of energy storage and demand management during outages). The effect of the optimal and coordinated operation of energy storage and load shedding is determined for each generation and demand condition and included in the calculation of reliability indices. The main contributions of this chapter are listed as follows:

1. A novel analytical methodology is proposed to assess the reliability of ADNs combining DGs, energy storage and load shedding. The methodology has the following distinguishing properties:

    (a) The optimal coordination of renewable DGs, energy storage and dispatchable loads is modelled during outages and their effect considered in the calculation of the reliability indices (effect not evaluated in the literature). A new procedure for reliability indices calculation is defined and it includes a novel linear optimisation problem specifically formulated for its application in the reliability assessment.

    (b) The proposed methodology is analytically formulated for efficient evaluation of the optimal coordination, as the analytical approach demands less computational resources than the alternative Monte Carlo Simulation [22]. Models of generation and demand based on probabilistic profiles are implemented to allow their variability and chronological fluctuations to be assessed by using the analytical approach.

    (c) Additional operational criteria not considered by existing reliability assessment methodologies are modelled: limited number of repetitive interruptions during a fault, coordination of non-dispatachable and dispatchable loads with several demand-control levels and specific rules for energy storage operation.

2. The comparative and sensitivity studies performed demonstrate the additional reliability improvement obtained by using the optimal coordinated restoration. The impact of different parameters is evaluated and critically analysed.

The chapter is organised as follows. The problem and the overview of the proposed solution are defined in Section 6.2. Section 6.3 introduces the procedure to calculate the reliability indices, while Section 6.4 presents the model for the generation and demand uncertainties. In Section 6.5, the procedure to assess the contribution of coordinated restoration to reliability is described and in Section 6.6 the case study presented. Finally, the conclusions are discussed in Section 6.7.

6.2 Problem Definition and Solution Proposed

6.2.1 Problem Definition

Fig. 6.1 shows the single-line diagram of a radial distribution network and the isolated area created when the fault j is cleared. This area is not equipped with tie switches for reconnection to other adjacent feeders, but incorporates DGs (conventional and renewable) and energy storage devices that can be used to supply power during outages. The area also includes non-dispatchable and dispatchable loads. The dispatchable loads are formed of different levels that can be independently controlled just as it is shown in Fig. 6.1 for bus 17. The isolated area is assumed to be equipped for islanded operation [141].

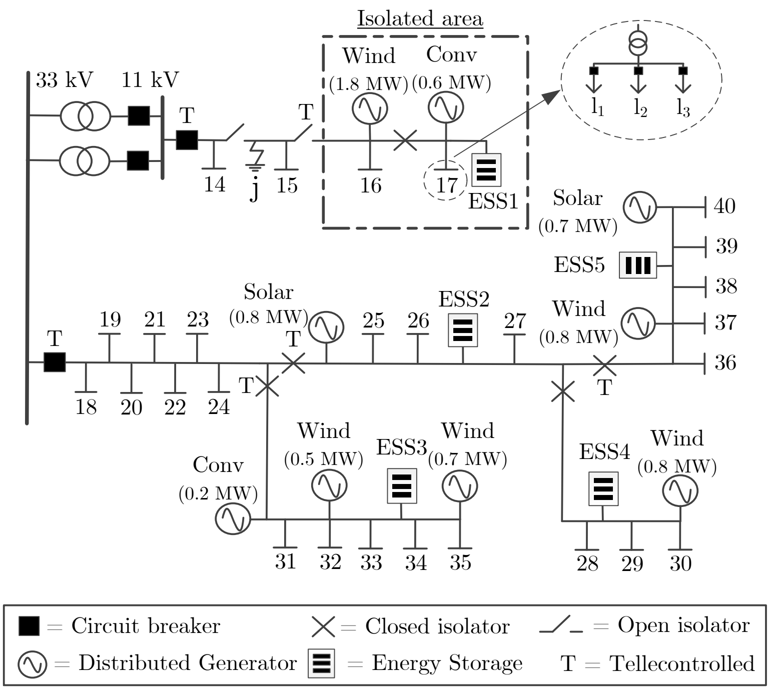


Figure 6.1: Example of a radial distribution network with an isolated area equipped to be operated in islanded mode

Fig. 6.2 shows the demand and generation profiles of the isolated area in Fig. 6.1. The time required to isolate and configure the isolated area is called tsw_j (switching time), while the time required to fix a defective element is called r_j (repair time). Supply restoration is evaluated along the repair time. As shown in Fig. 6.2, the power generated by the DGs is insufficient to supply the demand between the time instants it_2 and it_3. During this time interval energy storage devices and load shedding strategies allow the selective load restoration and reduce the impact of the interruption.

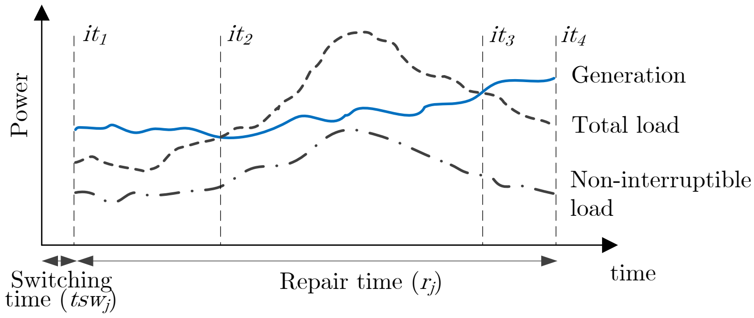


Figure 6.2: Example of generation and load during the fault of the isolated area in Fig. 6.1

Energy storage and load shedding introduce flexibility to supply restoration. This means they can be operated in different ways over the fault duration and a coordinated strategy that minimises the impact of interruptions can be used [129]. The application of the optimal strategy has an effect on the reliability indices of the customers within the isolated areas and this effect should be included in the reliability assessment of ADNs.

6.2.2 Overview of the Proposed Method

Fig. 6.3 shows the developed method for the reliability assessment of ADNs. It includes the new calculation steps proposed to evaluate the optimal restoration of isolated areas with DGs, energy storage and dispatchable loads (marked between dashed lines in the figure). Other features of the method are: 1) it is based on the analytical approach, 2) it uses the zone branch methodology proposed in [125] to address fault isolation and restoration actions, 3) it neglects failures of the protection devices (assumption commonly accepted in reliability studies [3]), and 4) average values of failure statistics and repair times are used for network components (a requirement for analytical techniques [3]).

To assess the reliability, the first step is to gather all the required data. Then, the impact of each component failure is evaluated, and this starts by simulating the operation of the protection devices and by identifying the isolated areas created [125]. For each isolated area, probabilistic scenarios for demand and generation are defined over a year period (more details in Section 6.4). After that, the adequacy of generation and demand is assessed for each defined scenario. The procedure described in Section 6.5 is used to model the optimal supply restoration and to calculate the impact of the interruptions. Finally, the reliability indices are calculated.

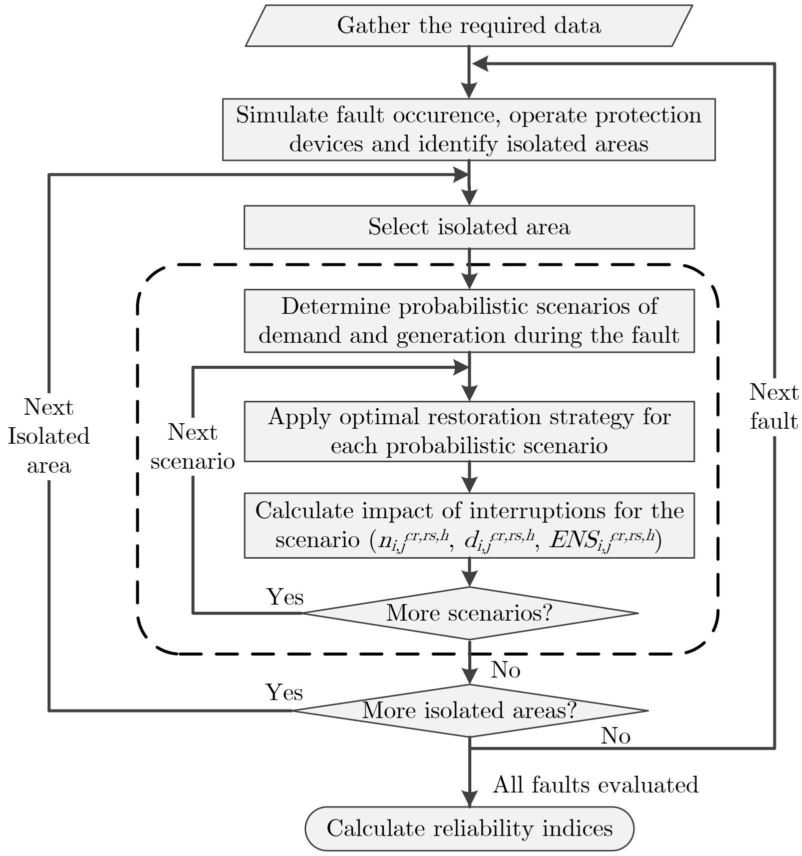


Figure 6.3: Proposed method for the reliability assessment of ADNs with optimal restoration of isolated areas

6.3 Reliability Indices Calculation

Area reliability indices defined in Appendix A are used to evaluate the reliability of a network (SAIFI, SAIDI and ENS are specifically used in this chapter). The area indices are determined from the load point reliability indices: failure rate λ_i, outage duration r_i, annual unavailability U_i, and energy-not-supplied ENS_i. The load point indices are calculated for each load in the network, where i and N_i denote the index and number of load points in the network. The following procedure is applied for their calculation [3]:

$$\lambda_i = \sum_{j=1}^{N_j} \lambda_{i,j}, \qquad U_i = \sum_{j=1}^{N_j} \lambda_j r_{i,j}, \qquad r_i = \frac{U_i}{\lambda_i}, \tag{6.1}$$

$$ENS_i = \sum_{j=1}^{N_j} ENS_{i,j}, \tag{6.2}$$

where j and N_j are the index and number of evaluated failures and λ_j is the annual rate of failure j. In addition, variables $\lambda_{i,j}$, $r_{i,j}$ and $ENS_{i,j}$ are the failure rate, interruption duration and energy-not-supplied of load point i caused by failure j. Their calculation depends on the network area where the load point is located and the presence of options to restore the supply. In the areas upstream of the fault and the areas under fault, the load point indices are calculated as described in Chapter 4:

- Areas upstream of the fault:
  - $\lambda_{i,j}$ is equal to λ_j if the interruption is sustained (longer than, for example, 5 min according to [21]); otherwise, it is 0.
  - $r_{i,j}$ is equal to the switching time tsw_j required to identify, isolate and restore the area.
  - $ENS_{i,j}$ is equal to $\lambda_{i,j} r_{i,j} La_i$, where La_i is the average load of the load point.
- Areas in fault:
  - $\lambda_{i,j}$ is equal to λ_j (the interruption is sustained).
  - $r_{i,j}$ is equal to the switching time tsw_j plus the failure repair time r_j.
  - $ENS_{i,j}$ is equal to $\lambda_{i,j} r_{i,j} La_i$.

In the areas downstream of the fault, the calculation depends on whether the load point is restored or not by the islanding operation.

Load points without islanded restoration

These load points can not be restored and the supply is interrupted until the failed component is repaired. Therefore, $\lambda_{i,j} = \lambda_j$, $r_{i,j} = tsw_j + r_j$ and $ENS_{i,j} = \lambda_{i,j} r_{i,j} La_{i,j}$.

Load points with islanded restoration

In this case $\lambda_{i,j}$, $r_{i,j}$ and $ENS_{i,j}$ are calculated as:

$$\lambda_{i,j} = \lambda_j \sum_{sn}^{N_{sn}} p_{sn} n_{i,j}^{sn}, \tag{6.3}$$

$$r_{i,j} = \sum_{sn}^{N_{sn}} p_{sn} r_{i,j}^{sn}, \tag{6.4}$$

$$ENS_{i,j} = \lambda_j \sum_{sn}^{N_{sn}} p_{sn} ENS_{i,j}^{sn}, \tag{6.5}$$

where sn denotes the scenario of generation and demand, N_{sn} the number of evaluated scenarios, and p_{sn} the probability of the scenario. These scenarios are defined and calculated as in Section 6.4. With regard to variables $n_{i,j}^{sn}$, $r_{i,j}^{sn}$ and $ENS_{i,j}^{sn}$, they represents the number of interruptions, their duration and the energy-not-supplied for scenario sn and are calculated according to the proposed procedure described in Section 6.5.

6.4 Renewable Generation and Demand Modelling

Renewable generation and demand uncertainties are modelled by using specific probabilistic scenarios. These scenarios represent the variability and time-dependency of generation and demand during outages. In addition, they include the state-of-charge (SOC) uncertainty of energy storage systems when a fault occurs. Such modelling allows the uncertainties to be assessed by using the analytical methodology.

6.4.1 Generation and Demand Profiles During Outages

The proposed scenarios use profiles as those shown in Fig. 6.2 to model the time-dependency of renewable generation and demand during outages. These profiles are divided in discrete time-steps in order to facilitate their evaluation. Each time-step has its own powers and duration in hours or fractions of hours.

Switching and repair times in Fig. 6.2 are analysed separately because the restoration of supply is evaluated only during the repair time. The nomenclature used to identify these two times is shown in Fig. 6.4. For fault j, ts and Ts_j are defined as the index and set of time-steps in the switching time, while t and T_j are the index and set of time-steps in the repair time. Also Δts_j and Δt_j are defined as the duration in hours of each time-step in the switching and repair times, respectively.

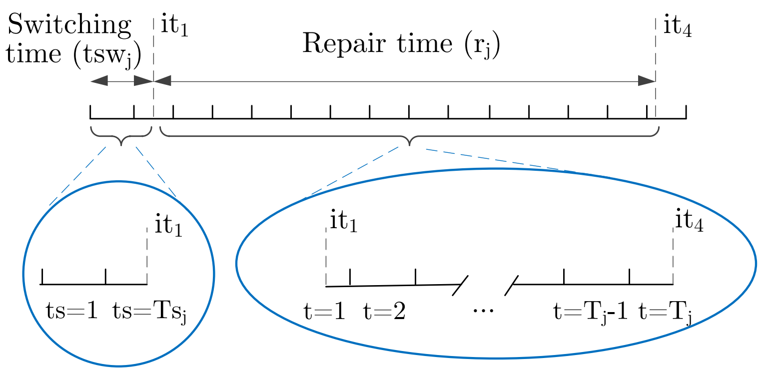


Figure 6.4: Nomenclature used to differentiate between switching and repair times

6.4.2 Scenarios Calculation

The following steps are performed to generate the probabilistic scenarios of renewable generation, demand and SOC:

1. Representative profiles of renewable generation and demand are obtained as described in Chapter 4, Section 4.3.1. Moreover, representative profiles of SOC are

included assuming normal operating conditions (they can be obtained from real data or by using algorithms as in [142]).

2. Different profiles of generation and demand are determined during an outage. These profiles are taken from the representative profiles defined in 1 by assuming that the analysed fault may occur at any time-step of the representative time-interval. Then, the profiles are assigned to the load points and renewable DGs in an isolated area. Moreover, the SOC in that time-step is assigned to each storage device representing its initial value when the fault occurs.

3. Probabilistic states of the DGs and storage devices in the isolated area are created as in Chapter 4, Section 4.3.2. Each device has two possible states, up and down, that are combined for all the devices in the area resulting in a set of probabilistic states.

4. Generation profiles in 2 are combined with the devices states in 3 to obtain the generation-demand scenarios used in the reliability evaluation. Their annual probability p_{sn} is determined as:

$$p_{sn} = p_{cr} p_{rs} p_h \quad \forall cr \in \mathbf{N_{cr}}, rs \in \mathbf{N_{rs}}, h \in \mathbf{N_h} \tag{6.6}$$

where p_{cr}, p_{rs} and p_h are the probabilities of generation state cr, representative time-interval rs and time-step h of the time-intervals, while N_{cr}, N_{rs} and N_h are the numbers of generation states, time-intervals and time-steps per interval.

6.5 Optimal Restoration Modelling in Reliability Assessment

6.5.1 Impact of the Interruptions

This section describes the proposed procedure to calculate the number of interruptions $n_{i,j}^{sn}$, their duration $r_{i,j}^{sn}$ and energy not supplied $ENS_{i,j}^{sn}$ (variables defined in Section 6.3). These variables measure the impact of a fault on customers located in a post-fault isolated area, and include the effect of the optimal and coordinated restoration using DGs, energy storage, dispatchable and non-dispatchable loads.

The calculation of $n_{i,j}^{sn}$, $r_{i,j}^{sn}$ and $ENS_{i,j}^{sn}$ differentiates between dispatchable and non-dispatchable load points. The dispatchable ones are equipped with several levels of load shedding as remedial action to decrease the demand during outages.

Non-dispatchable load points

In the isolated area, the impact of a fault on the load points that are not equipped with load shedding capability (index m, set S_m) is calculated as:

$$n_{i,j}^{sn} = \sum_{t=1}^{T_j} Rn^+(t) \qquad i \in \mathbf{S_m} \tag{6.7}$$

$$r_{i,j}^{sn} = tsw_j + \sum_{t=1}^{T_j} (1 - Rn(t))\, \Delta t_j(t) \qquad i \in \mathbf{S_m} \tag{6.8}$$

$$ENS_{i,j}^{sn} = \sum_{ts=1}^{Ts_j} Pb_m(ts)\Delta ts_j(ts) + \sum_{t=1}^{T_j} Pb_m(t)\,(1 - Rn(t))\,\Delta t_j(t) \qquad i \in \mathbf{S_m} \tag{6.9}$$

where Pb_m is the parameter representing the discretized demand profile during the fault, $Rn(t)$ is a binary variable equal to 1 only if all the non-dispatchable loads are restored at time-step t, and $Rn^+(t)$ is a binary variable equal to 1 only if all the non-dispatchable loads change from non-supplied to supplied state between $t-1$ and t. Variables Rn and Rn^+ are used to represent all the non-dispatchable load points in the isolated area because these loads have to be restored together at the same time-steps.

Dispatchable load points

In those load points equipped with several levels of load shedding (index k, set S_k) as described in Section 6.2.1, the impact of the fault is calculated for each level (index l, set $S_{k,l}$). The number of interruptions experienced by the customers in each level ($n_{i,j,l}$) is given by:

$$n_{i,j,l} = \sum_{t=1}^{T_j} Rs_{k,l}^+(t) \qquad i \in \mathbf{S_k}, l \in \mathbf{S_{k,l}} \tag{6.10}$$

where $Rs_{k,l}^+(t)$ is a binary variable equal to 1 if the level l changes from non-supplied to supplied state between $t-1$ and t (otherwise the variable is equal to 0).

The interruption duration caused by the fault on customers within load shedding level l, $r_{i,j,l}$, is:

$$r_{i,j,l} = tsw_j + \sum_{t=1}^{T_j} (1 - Rs_{k,l}(t))\, \Delta t_j(t) \quad i \in \mathbf{S_k}, l \in \mathbf{S_{k,l}} \tag{6.11}$$

where $Rs_{k,l}(t)$ is a binary variable equal to 1 if level l is restored at time-step t (otherwise it is 0).

Finally, the energy-not-supplied over the fault duration is defined for each level l as $ENS_{i,j,l}$ and calculated as:

$$ENS_{i,j,l} = \sum_{ts=1}^{Ts_j} Pb_{k,l}(ts)\Delta ts_j(ts) + \sum_{t=1}^{T_j} Pb_{k,l}(t)\left(1 - R_{k,l}(t)\right)\Delta t_j(t) \qquad i \in \mathbf{S_k}, l \in \mathbf{S_{k,l}} \tag{6.12}$$

where $Pb_{k,l}$ is a parameter representing the discretized demand profile over the fault for level l of load point k.

Then, the overall impact of the fault on a load point is calculated by aggregating the impacts of all its levels:

$$n_{i,j}^{sn} = \frac{\sum_{l \in \mathbf{S_{k,l}}} n_{i,j,l} Nc_{i,l}}{Nc_i} \qquad i \in \mathbf{S_k}, \tag{6.13}$$

$$r_{i,j}^{sn} = \frac{\sum_{l \in \mathbf{S_{k,l}}} r_{i,j,l} Nc_{i,l}}{Nc_i} \qquad i \in \mathbf{S_k}, \tag{6.14}$$

$$ENS_{i,j}^{sn} = \sum_{l \in \mathbf{S_{k,l}}} ENS_{i,j,l} \qquad i \in \mathbf{S_k}, \tag{6.15}$$

where Nc_i is the number of customers connected to load point i and $Nc_{i,l}$ the number of customers in level l (note that $Nc_i = \sum_{l \in S_{i,l}} Nc_{i,l}$).

The values of the binary variables Rn, Rn^+, $Rs_{k,l}$ and $Rs_{k,l}^+$ depends on the strategy applied to restore the supply. In complex systems as the one analysed here, there are multiple restoration options. Instead of using heuristic or approximate approaches to determine the variables, the mixed integer linear problem as defined in Sections 6.5.2 and 6.5.3 is used. Such problem formulation allows the impact of the optimal restoration on reliability indices to be assessed, while the linear approach guarantees the optimal solution and a fast calculation.

6.5.2 Equality and Inequality Constraints

Adequacy assessment

The active power adequacy in the isolated area is a fundamental criteria for reliability assessment of distribution networks with islanded operation [26, 28, 32, 45, 46, 79]. Here it is evaluated for each time-step of the fault by using:

$$\begin{aligned} &Rn(t) \sum_{m \in \mathbf{S_m}} Pb_m(t) + \sum_{k \in \mathbf{S_k}} \sum_{l \in \mathbf{S_{k,l}}} Rs_{k,l}(t) Pb_{k,l}(t) + \\ &\sum_{s \in \mathbf{S_s}} Pc_s(t) \leq \sum_{g \in \mathbf{S_g}} Pg_g(t) + \sum_{s \in \mathbf{S_s}} Pd_s(t) \qquad \forall t \end{aligned} \tag{6.16}$$

where g and S_g are the index and set of DGs in the isolated area, s and S_s are the index and set of energy storage systems, Pg_g is a parameter representing the power profile that DG g can generate over the fault duration, while Pc_s and Pd_s are continuous variables of the power charging and discharging the energy storage s.

The inequality in (6.16) guarantees that generation-demand adequacy is preserved while no additional variables are needed for modelling the power balance equality (note that Pg_g represents the maximum available power and it can be reduced to get the power balance). The reactive power balance and the network constraints are not included in the evaluation. This is a common assumption used for reliability assessment of ADNs [26, 28, 32, 45, 46, 79] that also helps to keep the linearity of the optimisation problem.

Energy Storage

The chronological charge and discharge of the energy storage systems are modelled by:

$$SOC_s(t+1) = SOC_s(t) + \frac{\Delta t_j(t)}{C_s}\left(Pc_s(t)\eta c_s - \frac{Pd_s(t)}{\eta d_s}\right) \qquad \forall s \in \mathbf{S_s}, \forall t, \qquad (6.17)$$

$$(\underline{Pc}_s, \underline{Pd}_s) \leq (Pc_s(t), Pd_s(t)) \leq (\overline{Pc}_s, \overline{Pd}_s) \quad \forall s \in \mathbf{S_s}, \forall t, \qquad (6.18)$$

$$\underline{SOC}_s \leq SOC_s(t) \leq \overline{SOC}_s \qquad \forall s \in \mathbf{S_s}, \forall t, \qquad (6.19)$$

$$SOC_s(1) = SOCini_s \qquad \forall s \in \mathbf{S_s}, \qquad (6.20)$$

where SOC_s is a continuous variable with the evolution of the SOC over the fault duration, $SOCini_s$ is the initial SOC when the fault occurs (given in the scenarios defined in Section 6.4), C_s is the storage capacity, ηc_s and ηd_s are the efficiencies to charge and discharge, parameters $\underline{SOC}_s$, $\underline{Pc}_s$ and $\underline{Pd}_s$ indicate the minimum limit of the associated variables, while $\overline{SOC}_s$, $\overline{Pc}_s$ and $\overline{Pd}_s$ the maximum limit.

In addition, the difference in the stored energy between the start and the end of the fault is defined as ΔD_s and calculated as in (6.21). It assumes the final SOC ($SOC_s(T+1)$) does not exceed the initial SOC and, in this way, unnecessary charging excesses are avoided during the outage period.

$$\Delta D_s = \frac{SOCini_s - SOC_s(T+1)}{\Delta t_j(t)}, \ \Delta D_s \geq 0 \quad \forall s \in \mathbf{S_s} \qquad (6.21)$$

Load shedding

The dispatchable loads are restored only if the non-dispatchable loads are also restored. This constraint is given by the topology of the isolated areas described in Section 6.2.1. The binary variables with the restoration state (Rn and $Rs_{k,l}$) are used for its modelling:

$$Rs_{k,l}(t) \leq Rn(t) \qquad \forall t, \forall k, \forall l \in \mathbf{S_{k,l}}. \qquad (6.22)$$

Number of interruptions during a failure

Additional constraints are required to limit the number of customer interruptions and restorations happened during a failure. This is an important parameter when fluctuations of renewable generation and demand are considered. One option is to set the number of interruptions to one [129]. Yet, permitting additional interruptions can reduce the outage duration and the energy-not-supplied. Consequently, a more extended formulation is proposed here for a generic number of permitted interruptions LI. The formulation for the non-dispatchable loads is:

$$\sum_{t=1}^{T_j+1} Rn^{+}(t) \leq LI \tag{6.23}$$

$$Rn(t) - Rn(t-1) = Rn^{+}(t) - Rn^{-}(t) \qquad t = 1,..,T_j+1 \tag{6.24}$$

$$Rn^{+}(t) + Rn^{-}(t) \leq 1 \qquad t = 1,..,T_j+1 \tag{6.25}$$

$$Rn^{+}, Rn^{-} \in \{0,1\} \tag{6.26}$$

where the binary variable Rn^{-} takes the value of 1 if load changes from supplied to not-supplied states, while Rn^{+} the value of 1 if load changes from not-supplied to supplied state as previously defined.

Constraint (6.23) guarantees that the number of transitions from interrupted to supplied states is lower than the limit LI; constraint (6.24) determines the transitions from not-supplied to supplied states and viceversa; and (6.25) avoids simultaneous transitions in variables $Rn^{+}(t)$ and $Rn^{-}(t)$. These equations preserve the linearity of the optimisation problem.

In the case of dispatchable loads, the number of interruptions is limited by extending Equations (6.23)-(6.26) to each level of load shedding as follows:

$$\sum_{t=1}^{T_j+1} Rs^{+}_{k,l}(t) \leq LI \qquad \forall\, k, \forall l \in \mathbf{S_{k,l}} \tag{6.27}$$

$$Rs_{k,l}(t) - Rs_{k,l}(t-1) = Rs^{+}_{k,l}t - Rs^{-}_{k,l}(t)$$
$$\forall\, k, \forall l \in \mathbf{S_{k,l}}, t = 1,..,T_j+1 \tag{6.28}$$

$$Rs^{+}_{k,l}(t) + Rs^{-}_{k,l}(t) \leq 1 \qquad \forall\, k, \forall l \in \mathbf{S_{k,l}} t = 1,..,T_j+1 \tag{6.29}$$

$$Rs^{+}_{k,l}, Rs^{-}_{k,l} \in \{0,1\} \qquad \forall\, k, \forall l \in \mathbf{S_{k,l}}. \tag{6.30}$$

where the binary variable $Rs^{-}_{k,l}$ measures the transitions from supplied to not-supplied states for each level of load shedding, and $Rs^{+}_{k,l}$ the transitions from not-supplied to supplied states as previously defined.

6.5.3 Optimisation Problem

The optimisation problem with objective function (6.31) and constraints (6.16)-(6.30) is proposed to calculate the continuous variables Pc_s, Pd_s, SOC_s and ΔD_s and the binary variables Rn, Rn^+, $Rs_{k,l}$ and $Rs^+_{k,l}$. These binary variables are defined in (6.7)-(6.12) and calculated in the optimisation problem (beside the continuous variables) to maximise the amount of energy restored during the fault. Then, they are used to determine the reliability indices that include the effects of the optimal restoration, as defined in Sections 6.3 and 6.5.1. This represents one of the principal advantages of the proposed formulation.

$$Max \sum_{t=1}^{T_j} \Bigg(\omega n Rn(t) \sum_{m \in \mathbf{S_m}} Pb_m(t) + \sum_{k \in \mathbf{S_k}} \sum_{l \in \mathbf{S_{k,l}}} \omega_{k,l} Rs_{k,l}(t) Pb_{k,l}(t) - c_1 \sum_{s \in \mathbf{S_s}} Pd_s(t) \Bigg) + c_2 \sum_{s \in \mathbf{S_s}} \Delta D_s \tag{6.31}$$

The first two terms in (6.31) represent the restored energy in non-dispatchable and dispatchable loads and both of them take into account the priority of the customers (ωn for non-dispatchable and $\omega_{k,l}$ for dispatchable loads). The third term avoids unnecessary energy storage discharges that do not increase the amount of restored energy. The fourth term aims to have a stored energy at the end of the fault as close as possible to the stored energy at the start of the fault. In the third and fourth terms, the weight factors c_1 and c_2 are used for modelling energy storage. Their values are chosen to avoid any alteration of the results obtained for the binary variables Rn and $Rs_{k,l}$ (for example, values of c_1 and c_2 20 times lower than ωn and $\omega_{k,l}$). This is because the use of energy storage to supply power during fault conditions is a priority.

6.6 Case Study

6.6.1 Test Network

The proposed method was then applied to study the contribution of the optimal and coordinated restoration to the reliability of two distribution systems. The first system (shown in Fig. 6.1) is formed by feeders 3 and 4 of Bus 6 Roy Billinton Test System [121], a well-know system for testing reliability assessment techniques that consider islanded operation [26, 28]. The second system (shown in Fig. 6.5) corresponds to a real 11 kV radial feeder and designed as Feeder c72. More details of both systems are provided in Appendix B. In these networks, islanded operation was evaluated for all the isolated areas caused by faults once reconfiguration actions are applied. In Fig. 6.5, the dashed lines represent the islands created by the operator when faults occur in upstream segments of these dashed areas.

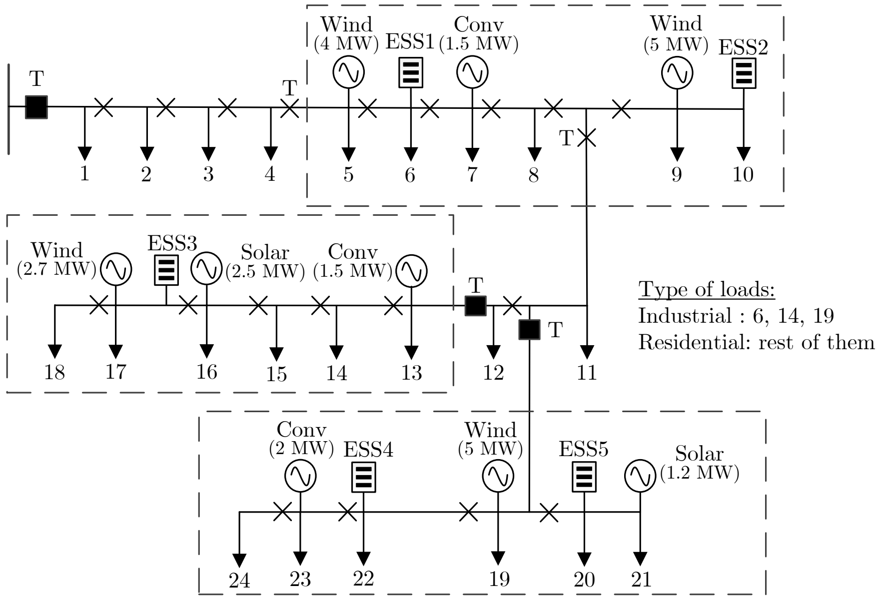


Figure 6.5: Single-line diagram of the second test system under study (Feeder c72)

Reliability indices in [122] were used for lines and transformers. Primary HV/MV substations were assumed to be fully reliable. The switching time was 1 hour for manual switches and 10 minutes for telecontrolled switches (marked with T in Fig. 6.5). The annual unavailability of the conventional, wind and solar generation was 0.006, 0.028 and 0.021, and their starting times 0.25 hours. The annual unavailability of energy storage was 0.004. The failures in the energy storage were neglected, a common assumption in literature [58, 66].

Data of demand, wind and solar powers in [116] were used to create the probabilistic scenarios. The procedure described in Section 6.4 was applied. The number of interruptions during a fault was limited to one (LI=1) except for the analysis in Section 6.6.5.

Four cases were analysed to determine the impact of the optimal and coordinated restoration strategy on reliability:

1. DG only: DGs in Figs. 6.1 and 6.5 were the unique resources used to restore the supply in the islands, as in [32, 45, 46].

2. DG and Energy Storage (DG+ESS): the energy storage devices in Figs. 6.1 and 6.5 were integrated into the case DG only. Their nominal capacities and powers are given in Table 6.1. In addition, all the energy storage devices have: $\underline{P_c}$ and $\underline{P_d}$ of 0 MW, $\overline{SOC}$ of 0.9, $\underline{SOC}$ of 0.1, and ηc, ηd of 0.9. The combined contribution of these resources was assessed in [58, 66, 123].

3. DG and Load Shedding (DG+LS): the load shedding functionality was added to the case DG only. The combined effect of these resources was analysed in [26,

Table 6.1: Nominal capacity and rated powers of the energy storage

System	Parameter	ESS1	ESS2	ESS3	ESS4	ESS5
Bus 6	C (MWh)	1.75	0.8	1.2	0.75	1.5
	$\overline{P_c}$, $\overline{P_d}$ (MW)	0.35	0.16	0.24	0.15	0.3
Feeder c72	C (MWh)	4	5	5.2	5	1.2
	$\overline{P_c}$, $\overline{P_d}$ (MW)	0.8	1	1.04	1	0.24

28]. Except in Section 6.6.4, all the results were obtained for the dispatchable loads defined in scenario Low of Table 6.3 and for one level of load shedding in these loads. The priority factors per customer type (ωn and $\omega_{k,l}$) were 10 for commercial/industrial, 1.9 for small/residential, and 0.5 for farms. The types of customers are specified in [121] and in Fig. 6.5.

4. DG, Energy Storage and Load Shedding (DG+ESS+LS): the three resources were coordinated and optimally operated for the selective restoration of the isolated areas. The proposed method in this chapter was used to calculate the corresponding impact on reliability. This effect is analysed here as it has not been studied in the literature.

6.6.2 Test Comparison

The reliability indices of the test networks were compared for the four cases evaluated. The objective was to analyse the impact of the optimal coordination of DGs, energy storage and dispatchable loads on reliability. Results of SAIDI and ENS are shown in Table 6.2, while the variations of these indices (referred to the case with only DG) are shown in brackets.

Table 6.2: SAIDI (hours/customer year) and ENS (MWh/year) for the evaluated cases

	Index	DG	DG+ESS	DG+LS	DG+ESS+LS
Bus 6	SAIDI	8.6	8.3 (-4.0%)	7.9 (-8.5%)	6.7 (-22.1%)
	ENS	45.6	44.4 (-2.8%)	43.5 (-4.7%)	39.8 (-12.7%)
Feeder c72	SAIDI	22.6	22.6 (-0.3%)	21.2 (-6.4%)	18.6 (-17.8%)
	ENS	683	682 (-0.2%)	650 (-4.9%)	578 (-15.4%)

In Bus 6, adding energy storage (DG+ESS) reduced ENS 2.8%, while including load shedding (DG+LS) reduced this index 4.7 %. In contrast, the optimal coordinated operation of energy storage and load shedding (DG+ESS+LS) reduced ENS 12.7 %, this is 5.2 % more than the aggregated contribution of the other two cases (12.7-2.8-4.7=5.2 %). In the case of SAIDI, the additional improvement introduced by the optimal coordinated restoration was even more significant: 9.6 % (22.1-4-8.5=9.6 %).

With regard to Feeder c72 system, this additional improvement was 10.3 % for ENS, and 11.1 % for SAIDI . Therefore, the reliability improvement introduced by the optimal coordinated operation of energy storage and load shedding was significantly larger than the improvements obtained by individual operation of these resources. In the following sections sensitivity analyses are presented to evaluate the contribution of the optimal coordination under different parameters.

6.6.3 Energy Storage Size Analysis

The impact of energy storage size on reliability was evaluated when the optimal restoration in DG+ESS+LS case was performed. Four values of capacity and other four of rated powers were evaluated, and they were expressed by using their capacity and power ratios. These ratios represented the capacity and rated powers of the energy storage devices with regard to the nominal values in Table 6.1 (ratios of 1 correspond to values in Table 6.1).

Fig. 6.6 shows the SAIDI and ENS indices obtained for the described analysis. In the figure, the largest evaluated energy storage size (capacity ratios of 2) reduced SAIDI 26 % and ENS 16 % in Bus 6 system, while these indices were reduced 25 % and 26 % for Feeder c72 system (% referred to the network without energy storage). These results proved that the size of energy storage has an important impact on the reliability improvement. However, this reliability improvement substantially depends on the combination of capacity and rated power as it can be seen in Fig. 6.6. In addition, the reliability improvement tends to saturate at capacity and power ratios larger than 1.5. All these results highlight the importance of selecting adequate capacity and rated power of energy storage in order to meet a specific reliability improvement.

6.6.4 Load Shedding Analysis

The impact of load shedding deployment on the test network reliability was also evaluated when the coordinated optimal restoration was applied. Three scenarios of load shedding deployment were analysed: Low, Medium and High. Table 6.3 shows the buses equipped with load shedding functionality (dispatchable loads) for each scenario, where Low scenario has the lower number of buses with load shedding and High scenario the largest number. In addition, each scenario was evaluated for the dispatchable loads equipped with 1, 3 and 5 levels of load shedding (set $S_{k,l}$). The powers of the levels at a load point were assumed to be equal. Nominal size of energy storage (Table 6.1) was assumed for all the configurations.

Fig. 6.7 shows the SAIDI and ENS of the test networks for the load shedding analysis. Scenarios with Low, Medium and High load shedding deployment reduced ENS 11, 16 and 20 % in Bus 6, and 15, 25 and 43 % for Feeder c72 (results given for 3 levels of

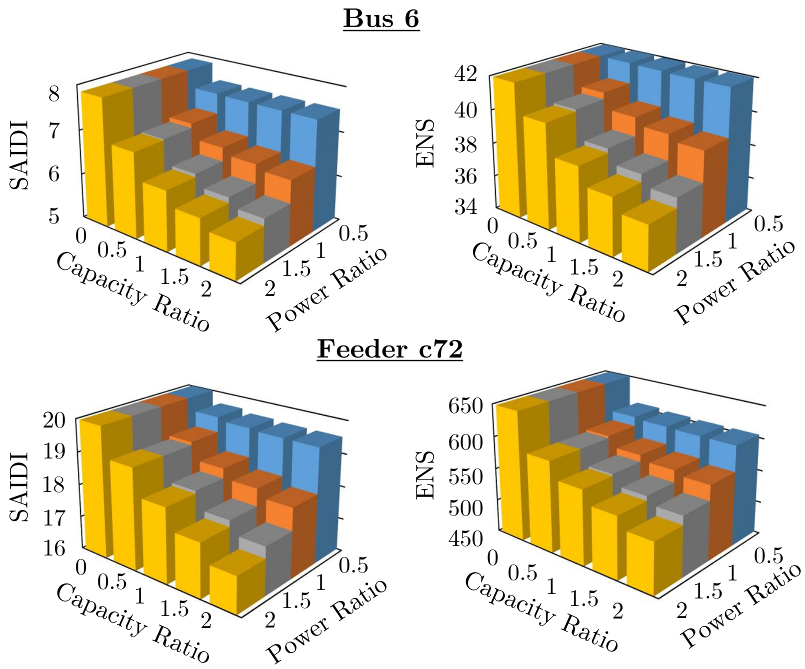


Figure 6.6: SAIDI (in hours/customer year) and ENS (in MWh/year) of the test networks for different energy storage sizes

Table 6.3: Buses with dispatchable loads for the scenarios of load shedding evaluation

Scenario	Buses in Bus 6	Buses in Feeder c72
Low	16, 26, 30, 32, 34, 35, 37, 38	7-9, 13, 17-18, 20, 22-23
Medium	Low + 15, 25, 29, 33, 40	Low + 5, 10, 15, 16, 19
High	Medium + 17, 27, 28, 31, 36, 39	Medium + 6, 14, 21, 24

load shedding and referred to the case without load shedding DG+ESS). SAIDI was also significantly reduced, although it was conditioned by the number of customers per load level. These results revealed the additional reliability improvement obtained by the increase of dispatchable loads in the networks and their optimal management.

With respect to the levels of load shedding per load point, increasing their number from 1 to 3 hardly improved reliability indices in Bus 6 (1 %). In the case of Feeder c72 system, this improvement presented relevant differences depending on the scenario: no improvement for Low, 3 % for Medium and 25 % for High. In contrast, in both test networks, increasing the number of levels from 3 to 5 had insignificant extra improvement. These differences were influenced by the power magnitude of the levels and demonstrate the need of considering this parameter in the reliability assessment.

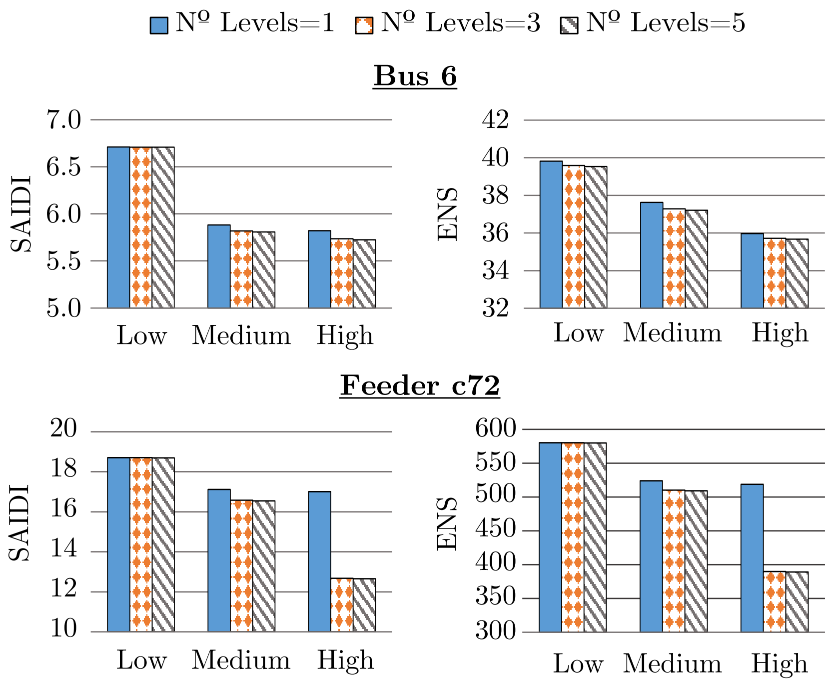


Figure 6.7: SAIDI (in hours/customer year) and ENS (in MWh/year) for the scenarios of load shedding evaluation

6.6.5 Analysis of the Number of Interruptions

In the previous analyses the maximum number of interruptions during a fault (*LI*) was limited to one in order to avoid repetitive interruptions of customers. This section quantifies the impact of different values of *LI* on the reliability indices.

Three values of *LI* were analysed: 1, 2 and 3. Results of the test networks for DG+ESS+LS case are shown in Table 6.4. Increasing *LI* from 1 to 2 in Bus 6 system (column *% LI 1-2* in Table 6.4) reduced (or improved) SAIDI 4.3 % and ENS 2.3 % but SAIFI increased (or worsened) 14 %. In the case of Feeder c72 system, the results were less favourable: SAIFI increased 22 % but SAIDI and ENS were only reduced 2.6 %. Increasing *LI* from 2 to 3 minimally improved SAIDI and ENS but SAIFI worsened additional 6 % in Bus 6 and 10 % in Feeder c72. Therefore, SAIDI and ENS can be improved by raising the *LI* limit but the increase in SAIFI has to be taken into account as it can be more critical.

6.7 Conclusions

In this chapter, a novel analytical methodology has been proposed to assess the reliability of active distribution networks with DGs, energy storage and dispatchable loads. The optimal coordination of these three solutions during interruptions has been mod-

Table 6.4: Reliability indices for different numbers of permitted interruptions during a fault (LI)

	Index	LI=1	LI=2	LI=3	% LI 1-2	% LI 1-3
Bus 6	SAIFI	1.33	1.52	1.60	14 %	20 %
	SAIDI	6.71	6.42	6.42	-4.3 %	-4.4 %
	ENS	39.8	38.9	38.9	-2.3 %	-2.4 %
Feeder c72	SAIFI	3.5	4.3	4.6	22 %	32 %
	SAIDI	18.6	18.2	18.2	-2.6 %	-2.6 %
	ENS	578.2	563.2	562.9	-2.6 %	-2.6 %

elled for its consideration in reliability studies. For an accurate assessment, details of the optimal restoration strategy and the chronological fluctuations of renewable generation, demand and stored energy have all been modelled in the methodology. An analytical formulation has been proposed because of its lower computational requirements compared to the alternative Monte Carlo Simulation.

The effectiveness of the proposed methodology was validated by using two test distribution networks. The results for both networks showed that optimally coordinated DGs, energy storage and dispatchable loads produced significant reliability improvements. The reliability results also indicated that there is a high sensitivity with respect to the energy storage size and the number of installed dispatchable loads. In addition to that, the control level of dispatchable loads and the number of repetitive interruptions during a fault were also identified as factors that affect reliability. All these parameters should be properly considered when the optimal coordinated restoration is applied.

Apart from energy storage and demand management other technologies can be coordinated to improve the reliability. Such solutions allow distribution networks to be restored not only by intentional islanding but also via interconnection to adjacent feeders not affected by the fault. All these issues are addressed in the following chapter.

Chapter 7

Evaluating the Impact of Active Network Management on Distribution System Reliability

Active Network Management (ANM) technologies provide additional tools necessary for increasing the penetration of distributed generation in power distribution systems. Under normal operating conditions, ANM technologies allow a massive integration of renewable generation without exceeding rated values of electrical equipment. In addition to that, these technologies can be used to restore the supply when there is a network outage, yet this additional use has been commonly neglected in reliability studies. In this chapter, a novel methodology to assess the contribution of ANM technologies to reliability of Active Distribution Networks (ADNs) is proposed. Technologies like renewable Distributed Generators (DGs) with controllable output power, On-Load Tap Changer (OLTC) transformers, demand control solutions and Soft-Open Points (SOPs) are all included in the reliability assessment, taking into account their operational properties for a realistic evaluation. Coordinated operation of these technologies during outages and performance of multi-terminal SOPs are also evaluated. The proposed methodology was tested on two distribution networks and the contribution of different ANM technologies to reliability assessed. The content of this chapter has been submitted for publication in [143].

7.1 Introduction

The evolution process from passive to active distribution systems (or ADNs) has led to an increase of network control capabilities and facilitate an effective integration of distributed energy resources. The ADNs, in addition to increasing sustainability and efficiency, have given rise to new opportunities for reliability improvement and their evaluation is of interest for network planning [9, 10]. However, ADNs increase the operational complexity and conventional methods used to calculate reliability cannot be seamlessly applied [6]. Thus, new solutions for reliability evaluation are emerging in the literature [10].

The deployment of ADNs allows the effective and secure integration of DGs in the distribution system. Nevertheless, the massive integration of DGs introduces important technical challenges especially if their output power cannot be controlled [23]. For example, voltage and thermal constraints in network equipment are often difficult to manage and these problems can be solved by using ANM technologies [144]. Examples of ANM applications are DGs with controllable active and reactive power injection, OLTC transformers with dynamically adjusted taps, loads with regulable demand and SOPs [145] —a SOP is a power-electronic-based device that replaces a Normally-Open Point (NOP) or tie switch to control power exchanges between feeders and reactive power injections. The operation of all these technologies can be coordinated and optimised during the normal operation of the network [144, 145]. However, the control capabilities of ANM can be also used during service interruptions to restore the supply. Therefore, ANM can have a significant impact on reliability and should be evaluated. This represents the main objective of this chapter.

Several methodologies have already been proposed to assess the reliability of ADNs as described in Chapter 2. Contribution of DGs has been extensively studied in the literature for both conventional and renewable energy sources [26, 31, 32, 45]. In these works, adequacy of generation and demand was studied to determine the restoration capability of DGs while variability of renewable energy resources was taken into account by using profiles and clusters, among others [45, 115]. However, additional control features of DGs such as output power regulation have been little studied. Demand response actions during outages were evaluated in [89, 92], but these studies did not consider DGs. Reliability was also evaluated by taking into account the contribution of DGs coordinated with other solutions [28, 58, 66, 81, 139]. In [26, 28], the DGs were coordinated with demand response systems and their effect studied. Combined use of DGs and electrical vehicles was evaluated in [139]. In [58, 66, 123], the impact of energy storage together with renewable DGs was evaluated, while reliability of ADNs with microgrids that cooperate during interruptions was evaluated in [79, 81]. In addition to these options, SOPs can also work in coordination with DGs and other ANM technologies, but their impact on reliability has not been studied yet. In this chapter, a novel reliability assessment methodology that includes SOPs and their coordination with other ANM technologies is developed.

Additional modelling work is necessary for an accurate evaluation of SOPs and other ANM technologies in reliability studies. In recent years, several models for two-terminals SOP devices have been proposed in literature and applied to operation (not reliability) studies [145, 146]. However, models of SOPs with more than two terminals (multi-terminal SOPs) have seldom been considered in the literature. These models are useful for the assessment of n-terminal SOPs in reliability studies. In addition to that, the assessment of the reactive power together with active power balance has to be considered for the evaluation of SOPs and ANM. The reactive power balance was included in [89, 92] in presence of demand response but it is commonly neglected in reliability studies of ADNs as stated in [81]. Satisfying the network constraints is another issue that needs to be considered, in particular voltage and thermal limits. However, these aspects have been seldom studied in the literature [48]. Another property that needs to be modelled is the coordinated operation of all ANM technologies during outages and how they can be managed to obtain optimal reliability improvement. Moreover, the options used for the restoration of the interrupted supply need to be considered and modelled. Two options for the restoration are via NOPs/SOPs and via islanded operation, and both of them should be considered in the evaluation [10]. All the features mentioned above are included in the methodology proposed in this chapter for an enhanced reliability assessment. Moreover, their implementation demands additional computational efforts as a consequence of the increased problem complexity. The use of analytical approaches can help reduce the computation burden [3].

In this chapter, the contribution of ANM to reliability is evaluated and a novel, analytical methodology proposed for this evaluation. The impact of controllable DGs, OLTCs transformers, demand management and SOPs (both two-terminal and multi-terminal) is included in the reliability indices. In addition, optimal operation of ANM and uncertainty of generation and demand are considered. The contributions of this chapter are summarised in the following list:

1. An analytical method to calculate reliability indices including the effect of different ANM technologies is developed. Coordinated operation of those technologies, network constraints and active/reactive power balance are considered in order to improve accuracy. Moreover, the use of an analytical approach reduces the computational burden compared to the alternative Monte Carlo Simulation.

2. Reliability improvements provided by SOPs are evaluated for the first time as well as the combined use of all the ANM technologies previously mentioned. A novel model is proposed to evaluate multi-terminal SOPs.

3. The proposed methodology can assess reliability of ADNs with post-fault interrupted areas restored via NOPs/SOPs or via islanded operation. The effect of ANM is evaluated for all these network topologies.

4. The results demonstrate the effectiveness of the proposed methodology and the contribution of ANM to reliability.

The chapter is organised as follows. In Section 7.2, an overview of reliability assessment in ADNs is presented. In Section 7.3, the proposed methodology is introduced, while in Sections 7.4, 7.5 and 7.6 its details are described. In Section 7.7, a case study consisting of two distribution networks is presented. Finally, conclusions are drawn in Section 7.8.

7.2 Overview of Active Network Management and Reliability Assessment

7.2.1 Description of Active Network Management

Fig. 7.1 shows an example of an ADN that includes the following controllable technologies: OLTC transformers ($T1$ and $T2$), DGs ($DG1$ to $DG7$), demand management systems in buses 5, 7, 9, 10, and 12, and a SOP between buses 9 and 15. With an appropriate ANM scheme, these technologies could facilitate optimal and safe operation of the distribution system with high penetration of renewable energy sources. The impact of ANM in network studies is commonly evaluated by assuming normal operation of electrical equipment (without failures) [142, 144]. However, if equipment fails, ANM technologies can be also used to restore the interrupted supply. The impact of this operating mode on reliability is analysed in detail here.

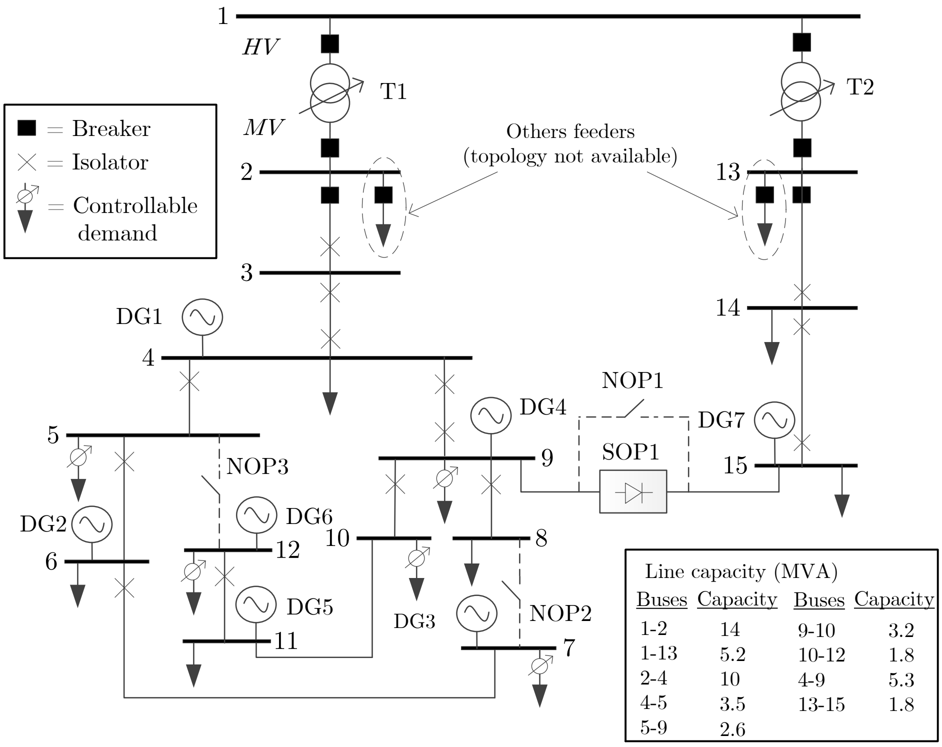


Figure 7.1: Distribution system with ANM technologies

7.2.2 Reliability Assessment and Restoration-of-Supply Modes

Reliability of distribution systems is evaluated by calculating the impact of network faults on the customer supply. For each fault, the operation of protection devices is simulated and then the areas formed in the network are identified [26]. Fig. 7.2 shows a common scenario with the typical areas formed after a fault isolation [32]. The customers within the fault area remain disconnected until the defective component is repaired. Meanwhile, the customers connected to the area upstream of the fault are interrupted until they are reconnected to the primary substation. For areas downstream of the fault there are two options to restore the supply:

1. NOP-SOP restoration: the areas are reconnected to an adjacent feeder by closing a NOP or by operating a SOP. This option is similar to the emergency-tie restoration defined in Chapter 2, but SOPs can also be used to restore the supply in addition to NOPs.

2. Islanded restoration: if the areas do not have NOPs nor SOPs, they may be operated in islanded mode [45]. This means that these areas remain isolated from the main grid until defective components are repaired, and the available DGs in the area are used to restore the supply. The network must be equipped with appropriate protections and controls to apply this option [45].

In both restoration options the generation capacity may be insufficient to restore all the supply and ANM technologies can help maximise the restoration and improve reliability. In this chapter, this is investigated and a novel methodology is proposed to evaluate it.

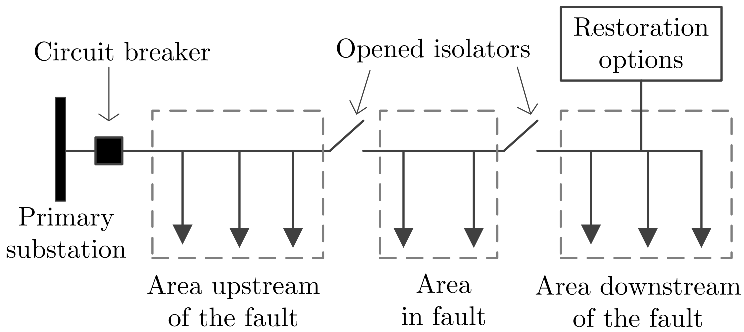


Figure 7.2: Example of areas created by a fault in a MV distribution network

7.3 Proposed Methodology

Fig. 7.3 shows a flowchart representing the steps of the proposed methodology. In the steps marked with dashed lines, optimal operation of ANM technologies is modelled and its impact on reliability quantified for different network topologies. An analytical probabilistic approach is applied for the reliability indices calculation to take advantage of its computational efficiency [3]. The following assumptions are made in accordance with the reliability evaluation practices and SOP performance:

1. The distribution network is radially operated with the exception of feeders interconnected via SOPs.

2. Protections, communications and control devices do not fail and operate as expected.

3. Loads are equipped with protections to avoid propagation of faults to other network areas.

4. SOPs are also equipped with protections to avoid propagation of faults between adjacent feeders.

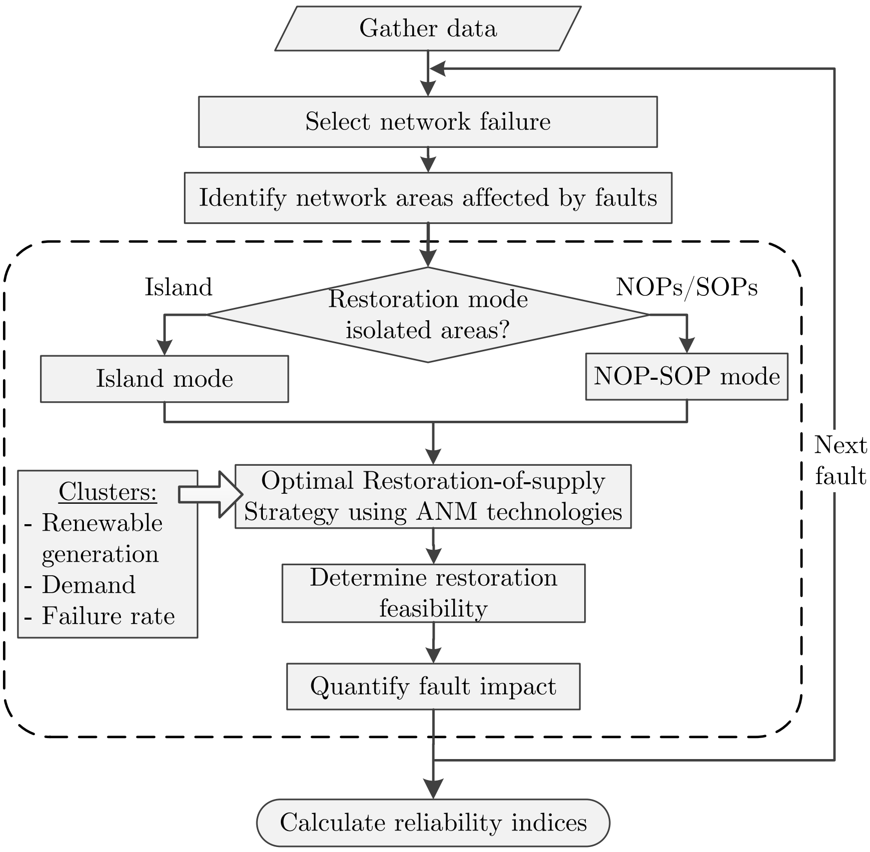


Figure 7.3: Proposed methodology for reliability assessment of ADNs with ANM technologies installed

The steps of the methodology can be summarised as follows. Firstly, all the data are gathered. This includes the network topology, generation and demand profiles and statistics of component failures. Then, the impact of each failure is evaluated for the areas described in Section 7.2.2. Uncertainty of renewable generation and demand during outages is taken into account and it is modelled by using clusters [28, 66]. These clusters are explained in Section 7.4. For each cluster, restoration feasibility is assessed by taking into account optimal operation of ANM technologies and constraints of network elements. The proposed model for the evaluation of the restoration feasibility is described in Section 7.6. Once the impact of network faults has been quantified, reliability indices are calculated as explained in Section 7.5.

7.4 Evaluation of Uncertainties: Renewable Generation, Demand and Failure Rate

Uncertainty of renewable generation and demand can be modelled by using clusters [45, 66]. It lies in grouping historical data profiles (for example, one or several years) in representative clusters. In this chapter, a clustering technique called k-means is applied for this purpose [119]. Each cluster (index c) includes the availability of renewable resources (ν_{gr}^{c}), demand in buses (P_i^c, Q_i^c) and its annual probability (ρ_c). The number of clusters (N_c) is selected by using the graphical elbow code method [66].

The failure rate of components (measured in failures per year) can vary along the period of a year as [147] demonstrates. This effect is also included in the clusters so that each one has its own failure rate of components. The units are the same than in the conventional failure rate, but it considers the failure probability associated to the data points contained in each cluster. To calculate the cluster failure rates, the following method is proposed:

1. Divide a year in different time-intervals (for example, months) and gather the failure probability for these time-intervals. This probability is called $\rho_{j,t}$, where j is the failure evaluated (N_j is the number of failures) and t the time-interval (N_t is the number of time-intervals).

2. Identify the time-intervals of the data points located in a cluster, as the failure probability depends on the time-interval.

3. Determine the failure rate of each component for the cluster c. This is calculated as follows:

$$\lambda_{j,c} = \lambda_j \frac{\sum_{t=1}^{N_t} n_{t,c}\rho_{j,t}}{\sum_{t=1}^{N_t} n_{t,c}\rho_t} \tag{7.1}$$

   where λ_j is the average rate of failure j, ρ_t is the annual probability of time-interval t, and $n_{t,c}$ is the number of data points from the time-interval t located in cluster c. Note that ρ_t and $\rho_{j,t}$ are annual probabilities, where $\sum_{t=1}^{N_t} \rho_t = 1$ and $\sum_{t=1}^{N_t} \rho_{j,t} = 1$.

7.5 Reliability Indices Incorporating Active Network Management

Reliability indices of network areas as SAIFI, SAIDI and ENS are calculated as described in Appendix A. Only sustained interruptions larger than 5 minutes are considered as defined in [21]. Area indices are calculated by aggregating individual indices of load points, i.e. the failure rate λ_i, the outage duration r_i, the annual unavailability U_i and the energy-not-supplied ENS_i. These indices are calculated in this chapter as:

$$\lambda_i = \sum_{c=1}^{N_c} \lambda_{i,c}\rho_c, \qquad U_i = \sum_{c=1}^{N_c} U_{i,c}\rho_c, \tag{7.2}$$

$$r_i = U_i/\lambda_i, \qquad ENS_i = \sum_{c=1}^{N_c} ENS_{i,c}\rho_c, \tag{7.3}$$

where $\lambda_{i,c}$, $U_{i,c}$ and $ENS_{i,c}$ are the individual reliability indices for cluster c. These indices take into account the use of ANM technologies and are calculated as follows:

$$\lambda_{i,c} = \sum_{j=1}^{N_j} \lambda_{j,c}\Big((1-\xi_{i,c})\chi_{i,c} + \xi_{i,c}\Big), \tag{7.4}$$

$$\begin{aligned} U_{i,c} = \sum_{j=1}^{N_j} \lambda_{j,c}\Big(&(1-\xi_{i,c})(tsw_j + r_j)\chi_{i,c} \\ &+ \xi_{i,c}(tsw_j + r_j\chi_{i,c})\Big), \end{aligned} \tag{7.5}$$

$$ENS_{i,c} = P_i^d \sum_{j=1}^{N_j} \lambda_{j,c}\Big(tsw_j + r_j\chi_{i,c}\Big), \tag{7.6}$$

where tsw_j is the switching time for the failure j [3], r_j is the time required to repair the failure j, $\xi_{i,c}$ indicates if the switching time tsw_j is longer than the sustained interruption threshold ($\xi_{i,c}$=1) or shorter ($\xi_{i,c}$=0), and $\chi_{i,c}$ represents the restoration feasibility and the ratio of shed power at load i. The variable $\chi_{i,c}$ depends on the network area where the load i is located (see Fig. 7.2). For areas upstream of the fault $\chi_{i,c} = 0$, while $\chi_{i,c} = 1$ for faulted areas. For areas downstream of the fault, $\chi_{i,c}$ can take the following values:

- One if restoration for cluster c is unfeasible ($IF_{i,c} > 0$).
- Zero if restoration is feasible ($IF_{i,c} = 0$) and the demand cannot be managed at the load point i ($i \in ND$, where ND represents the set of loads without demand management).
- $\sigma_{i,c}$ if restoration is feasible and the demand can be managed at load point i ($i \in D$, where D is the set of loads with demand management). Variable $\sigma_{i,c}$ represents the ratio of load curtailed.

The variable $IF_{i,c}$ shows if restoration is feasible, and it is calculated by taking into account the value of $\sigma_{i,c}$ for those loads without demand management ($i \in ND$) as follows:

$$IF_{i,c} = \sum_{i \in ND} \sigma_{i,c}. \tag{7.7}$$

These values of $\sigma_{i,c}$ are determined by evaluating the restoration strategy described in the following section.

7.6 Restoration-of-supply Incorporating Active Network Management

An optimisation problem has been formulated to model the optimal and coordinated restoration with ANM technologies. The objective function is (7.8), while the constraints are (7.9)-(7.32). This is a mixed integer non-linear problem, where variable δ_{gr} is binary and the others are continuous. Using the optimal power flow equations as reference, additional extensions are proposed to model and include in the reliability assessment the dispatchable and not-dispatchable loads, the minimisation of the interrupted demand, the control capabilities of renewable DGs and the multi-terminal SNOPs.

$$\begin{aligned} \min \sum_{i \in D} (\beta_i^I \sigma_{i,c} P_i^c + \gamma_i^I) + \sum_{g \in G} (\alpha_g P_g^2 + \beta_g P_g + \gamma_g) + \\ \sum_{gcp \in GCP} (\beta_{gcp} P_{gcp}) + \sum_{gr \in \{GR,GN\}} (\beta_{gr} P_{gr} + \gamma_{gr}) + \\ \sum_{e \in E} c_e^{sop} S_e^{sop} + \sum_{i \in ND} (\beta^h \sigma_{i,c} P_i^c) \end{aligned} \tag{7.8}$$

subjected to:

$$\begin{aligned} \sum_{gcp \in i} P_{gcp} + \sum_{g \in i} P_g + \sum_{gr \in i} P_{gr} + \sum_{ei \in SC} P_{ei}^{sop} = \\ \sum_{iy \in L} P_{iy}^{line} + g_i^s V_i^2 + (1 - \sigma_{i,c}) P_i^c \qquad \forall i \end{aligned} \tag{7.9}$$

$$\begin{aligned} \sum_{gcp \in i} Q_{gcp} + \sum_{g \in i} Q_g + \sum_{gr \in i} Q_{gr} + \sum_{ei \in SC} Q_{ei}^{sop} = \\ \sum_{iy \in L} Q_{iy}^{line} - b_i^s V_i^2 + (1 - \sigma_{i,c}) Q_i^c \qquad \forall i \end{aligned} \tag{7.10}$$

$$P_{iy}^{line} = \frac{V_i^2}{\tau_{iy}^2} g_{iy} - \frac{1}{\tau_{iy}} V_i V_y [g_{iy} cos(\theta_i - \theta_y - \phi_{iy}) + b_{iy} sin(\theta_i - \theta_y - \phi_{iy})] \qquad \forall iy \in L \tag{7.11}$$

$$P_{yi}^{line} = V_y^2 g_{iy} - \frac{1}{\tau_{iy}} V_i V_y [g_{iy} cos(\theta_y - \theta_i + \phi_{iy}) + + b_{iy} sin(\theta_y - \theta_i + \phi_{iy})] \qquad \forall iy \in L \tag{7.12}$$

$$Q_{iy}^{line} = -\frac{V_i^2}{\tau_{iy}^2}(b_{iy} + \frac{bs_{iy}}{2}) - \frac{1}{\tau_{iy}} V_i V_y [g_{iy} sin(\theta_i - \theta_y - \phi_{iy}) - b_{iy} cos(\theta_i - \theta_y - \phi_{iy})] \qquad \forall iy \in L \tag{7.13}$$

$$Q_{yi}^{line} = -V_y^2(b_{iy} + \frac{bs_{iy}}{2}) - \frac{1}{\tau_{iy}} V_i V_y [g_{iy} sin(\theta_y - \theta_i + \phi_{iy}) + b_{iy} cos(\theta_y - \theta_i + \phi_{iy})] \qquad \forall iy \in L \tag{7.14}$$

$$(P_{iy}^{line})^2 + (Q_{iy}^{line})^2 \leq (S_{iy}^{max})^2 \qquad \forall iy \in L \tag{7.15}$$

$$(P_{yi}^{line})^2 + (Q_{yi}^{line})^2 \leq (S_{iy}^{max})^2 \qquad \forall iy \in L \tag{7.16}$$

$$(P_{gcp})^2 + (Q_{gcp})^2 \leq (S_{gcp}^{max})^2 \qquad \forall gcp \tag{7.17}$$

$$V_i^{min} \leq V_i \leq V_i^{max} \qquad \forall i \tag{7.18}$$

$$-\pi/3 \leq \theta_i \leq \pi/3 \qquad \forall i \tag{7.19}$$

$$P_g^{min} \leq P_g \leq P_g^{max} \qquad \forall g \tag{7.20}$$

$$Q_g^{min} \leq Q_g \leq Q_g^{max} \qquad \forall g \tag{7.21}$$

$$\tau_{iy}^{min} \leq \tau_{iy} \leq \tau_{iy}^{min} \qquad \forall iy \in TT \tag{7.22}$$

$$\tau_{iy} = 1 \qquad \forall iy \in NT \tag{7.23}$$

$$P_{gr} = \delta_{gr} \nu_{gr}^c S_{gr}^{max}, \quad Q_{gr} = 0 \qquad \forall gr \in GN \tag{7.24}$$

$$(P_{gr})^2 + (Q_{gr})^2 \leq (\nu_{gr}^c S_{gr}^{max})^2 \qquad \forall gr \in GC \tag{7.25}$$

$$Q_{gr}^{min} \leq Q_{gr} \leq Q_{gr}^{max} \qquad \forall gr \in GC \tag{7.26}$$

$$0 \leq P_{gr} \qquad \forall gr \in GC \tag{7.27}$$

$$0 \leq \sigma_{i,c} \leq 1 \qquad \forall i \tag{7.28}$$

$$\sum_{ei \in SC} P_{ei}^{sop} + Ploss_{ei}^{sop} = 0 \qquad \forall e \tag{7.29}$$

$$(P_{ei}^{sop})^2 + (Q_{ei}^{sop})^2 \leq (S_{ei}^{max})^2 \qquad \forall e, \forall i, ei \in SC \tag{7.30}$$

$$Ploss_{ei}^{sop} = a_e (I_{ei}^{sop})^2 + b_e I_{ei}^{sop} + c_e \qquad \forall e, \forall i, ei \in SC \tag{7.31}$$

$$(I_{ei}^{sop})^2 = \frac{(P_{ei}^{sop})^2 + (Q_{ei}^{sop})^2}{V_i^2} \qquad \forall e, \forall i, ei \in SC \tag{7.32}$$

where the symbols are defined in the *Nomenclature* section at the beginning of the document.

The objective function (7.8) minimises the interruption costs as the principal target apart from the restoration costs. The first term represents the interruption cost of loads equipped with demand management systems. The following three terms are the operation costs of conventional DGs, external grid and renewable DGs, respectively. Generic cost function have been used although other functions can be used as well [148]. The fifth term represents operation costs of SOPs, while the last term models an excessive cost for reducing loads that cannot be shed. This term is included so that the optimisation problem also converges in those cases where restoration is unfeasible ($IF_{i,c} > 0$).

Active and reactive power balances are modelled with (7.9) and (7.10). Commonly, reactive power balance is not evaluated in reliability studies [3, 81]. However, it has been included in this case to take into consideration voltage limitations and thermal constraints.

Equations (7.11)-(7.14) model active and reactive power flows in lines [148]. These equations corresponds to conventional power flow equations where the effect of OLTC transformers is included (taps are assumed to be in the high-voltage side). Capacity limits of power lines and primary substations connected to the external grid are included with (7.15)-(7.17). Constraints (7.18)-(7.19) keep voltage in buses within limits. Equations (7.20)-(7.21) model active and reactive power limits of conventional DGs. The upper and lower limits of the OLTC transformers taps are considered with the constraints (7.22)-(7.23). A continuous variable (τ_{ij}) is used to model the position of taps as in [148].

Renewable DGs with intermittent generation are modelled with (7.24)-(7.27). Two types of DGs are included based on their features. The first type are on-off DGs (set GN), which are modelled with (7.24). $\delta_{gr} = 1$ means connected, while $\delta_{gr} = 0$ means disconnected. The output power of these units cannot be regulated. With the second type of renewable DGs (set GC) active and reactive power injection can be adjusted. These are modelled with (7.25)-(7.27) [142].

The constraint (7.28) guarantees that the demand curtailed in buses is between minimum and maximum values. In addition, it preserves a linear relationship between active and reactive power curtailed. Otherwise, all reactive power would be curtailed first as no economic penalty is foreseen.

Fig. 7.4 shows the electrical diagram of a multi-terminal SOP. The equations proposed to model this device are (7.29)-(7.32). Equation (7.29) guarantees active power balance in the SOP, while (7.30) limits the current injected by the device [145, 146]. The constraint (7.31) is used to evaluate the losses of the electronic power converters. A quadratic function of the current is used to model the losses, with coefficients as in [146]. Finally, Equation (7.32) is used to determine the magnitude of the current injected by each converter into bus i.

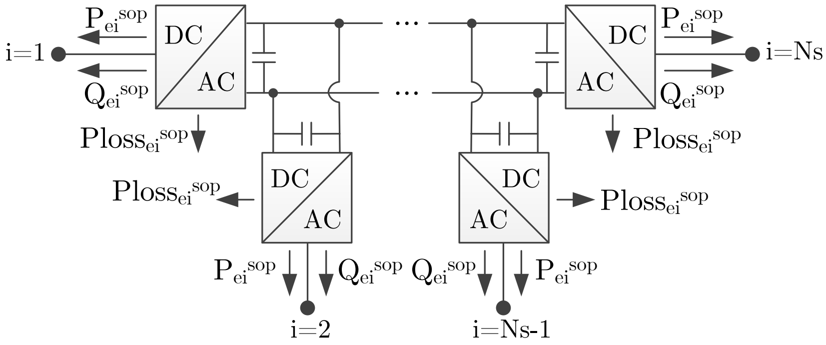


Figure 7.4: Electrical diagram of a multi-terminal SOP interconnecting Ns buses

7.7 Case Study

7.7.1 Test Network Description

Two typical distribution networks have been used to test the proposed methodology. The first one is the European MV benchmark distribution network [149] (hereafter EU Benchmark) and its topology is depicted in Fig. 7.1. The second one is the IEEE 33 bus network and it is depicted in Fig. 7.5. Its demand is 1.7 times the one specified in [150]. The DGs and ANM technologies shown in Figs. 7.1 and 7.5 have been added to the original networks. The maximum and minimum position of the taps in OLTCs transformers are 0.96 and 1.04. The reactive power limits of adjustable DGs are $\pm 0.33\ P_{gr}^{max}$.

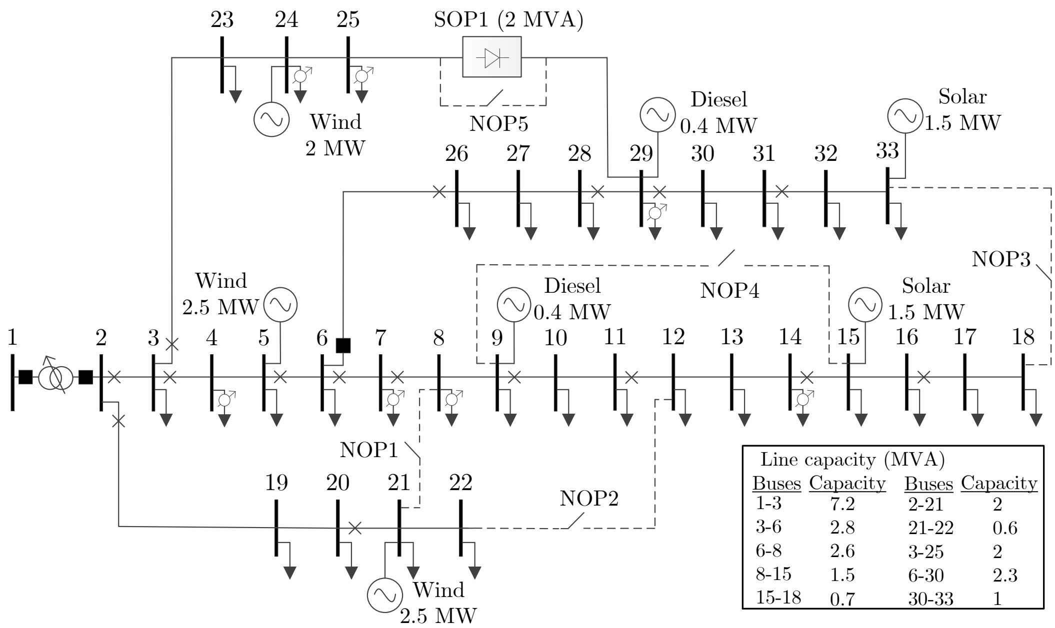


Figure 7.5: Single-line diagram of IEEE 33 buses test network including ANM

The impact of ANM was evaluated for two test network topologies. The first topology (NOP-SOP topology) corresponds to what is shown in Figs. 7.1 and 7.5, where the networks are equipped with NOPs/SOPs. In the second topology (Islanded topology), no NOPs nor SOPs are considered and islanded operation is applied. Apart from these differences, the Islanded topology has some additional features:

- The installed capacity of DGs is larger than in the NOP-SOP topology. In Fig. 7.1 the capacity of the DG in bus 6 is increased from 0.4 to 0.8 MW and an additional DG of 1.2 MW is installed in bus 8, while in Fig. 7.5 a solar and a wind DGs of 1.5 MW are added to buses 11 and 12, respectively.

- All the DGs have adjustable active and reactive power outputs to help make islanded operation feasible.

- The voltage limits are less restrictive (0.9-1 pu versus 0.95-1.05 pu for the NOP-SOP topology).

Real data obtained from [116] are used to calculate the clusters. It includes information on wind and solar resources (ν_{gr}^{c}), residential and industrial demand (P_i^c) and energy price in the primary substations (β_{gcp}). The interruption costs (parameters β_i^I and γ_i^I) are obtained from [120] and $\beta^h = 50$ thousand \$/MW are assigned to loads without demand management. Operation costs are obtained from [151] for DGs and from [152] for SOPs.

Annual statistics of power line failures, cables and transformers are obtained from [122], while their probability of failure per month ($\rho_{j,t}$, $t = 1, .., 12$) from [147]. Failures of renewable DGs are included in the calculation of clusters by making the resource availability equal to zero when a DG fails. Simultaneous failures of network components with diesel DGs and ANM technologies are neglected because of their low probability [3]. ENS index is used in the following sections to show the contribution of ANM and SOPs to reliability.

7.7.2 Impact of Active Network Management and Network Constraints

In this section a comparison of reliability indices is provided when ANM technologies are applied and network constraints considered. The comparison is performed for both the NOP-SOP and the Islanded topologies. The following cases are evaluated for each topology:

1. Case *Base*: network constraints (capacity in lines and voltage in buses) and ANM technologies are not considered and only an adequacy assessment of active power is performed. This is a common practice for this type of studies [26, 45].

2. Case *Constraints*: network constraints are included, but not ANM technologies nor DGs. The Islanded topology was not evaluated in this case because it lacks of DGs.

3. Case *Only DG*: network constraints and DGs are considered, but not the ANM. The DGs have adjustable active and reactive power injection.

4. Case *With ANM*: the network constraints and all the ANM technologies described in Section 7.7.1 (OLTCs, controllable DGs, demand management and SOPs) are included.

The ENS obtained for the four cases and for the two network topologies (NOP-SOP and Islanded) are shown in Table 7.1. There are significant differences between the results of cases *Base* and *Constraints*. When the constraints were included in the EU Benchmark network, the ENS increased from 4.16 to 27.85 MWh/year in the NOP/SOP topology, and from 8.44 to 19.88 MWh/year in the Islanded topology. Therefore, network constraints have a significant impact on the reliability.

Results in Table 7.1 show that ANM technologies (case *With ANM*) achieved a significant reduction of the ENS compared to the case in which only DGs are used (case *Only DG*). In the EU Benchmark network, the ENS was reduced from 18.16 to 10.31 MWh/year for the NOP-SOP topology and from 19.88 to 12.79 MWh/year for the Islanded topology. For the IEEE 33 bus network, these topologies provided a reduction from 4.29 to 3.59 MWh/year, and from 4.62 to 4.20 MWh/year, respectively. These results reveal the positive contribution of ANM to the reliability.

Table 7.1: ENS (MWh/year) for the four cases evaluated

Case	EU Benchmark		IEEE 33	
	NOP-SOP	Islanded	NOP-SOP	Islanded
Base	4.16	8.44	3.31	3.93
Constraints	27.85	-	4.44	-
Only DG	18.16	19.88	4.29	4.62
With ANM	10.31	12.79	3.59	4.20

7.7.3 Sensitivity Analysis of Renewable Generation

The contribution of ANM to reliability was also evaluated for different penetration levels of renewable generation. These levels were defined by the parameter *pl*, which multiplies the capacity of the renewable DGs shown in Figs. 7.1 and 7.5. In this analysis, values of *pl* between 0 and 1.6 were evaluated and the results are shown in Fig. 7.6 for EU Benchmark network and in Fig. 7.7 for IEEE 33 bus network (the results correspond to NOP-SOP topology).

In both networks, the results show a significant contribution of ANM at different levels of renewable penetration (differences between *Only DG* and *With ANM* cases). For example, at DG penetration of $pl = 0.8$, the application of ANM reduced ENS an additional 29 % for EU Benchmark network and 13.8 % for IEEE 33 bus network (percentages referred to *Constraints* case).

The results also indicate different trends between the two networks. These trends depend on the network topology and the type of the installed DGs (diesel, wind or solar).

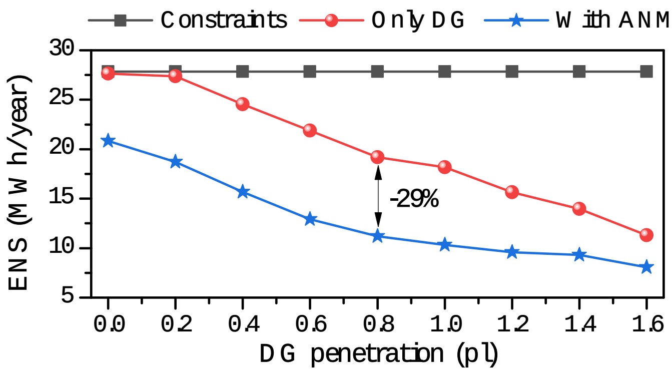


Figure 7.6: Impact of ANM for different DG penetration levels in EU Benchmark network

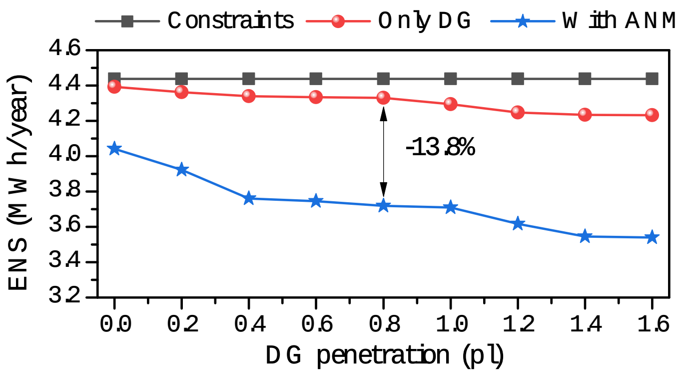


Figure 7.7: Impact of ANM for different DG penetration levels in IEEE 33 bus network

7.7.4 Impact of each Active Network Management Technology

A specific analysis was performed to clarify the sensitivity of the ENS to each ANM technology. The previously defined NOP-SOP topology was evaluated since it included all the ANM technologies. In addition, each ANM technology was evaluated for the networks under the following cases: 1) with the NOPs in the original test networks (*With*

NOP), 2) with the NOPs and the two-terminals SOP 1 in Figs. 7.1 and 7.5 replacing the corresponding NOP (*With SOP*), and 3) similar to case 2) but with a three-terminal SOP connected between buses 7-9-15 of Fig. 7.1 and another SOP between buses 25-29-12 of Fig. 7.5. The results are shown in Figs. 7.8 and 7.9, where the 100 % value represents the range in which reliability can be improved (i.e. the difference between cases *Base* and *Constraints*). By comparing the obtained results, the following findings are identified:

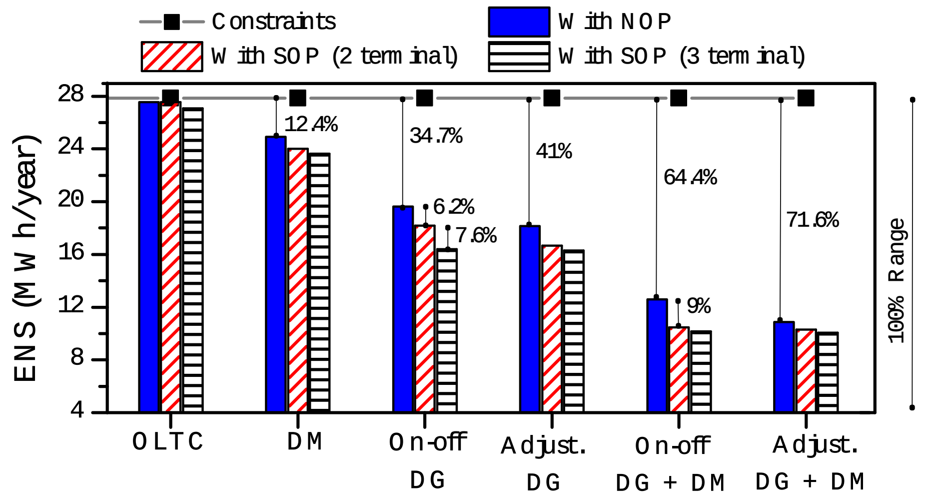


Figure 7.8: Comparison of ENS results for the ANM technologies in EU Benchmark network

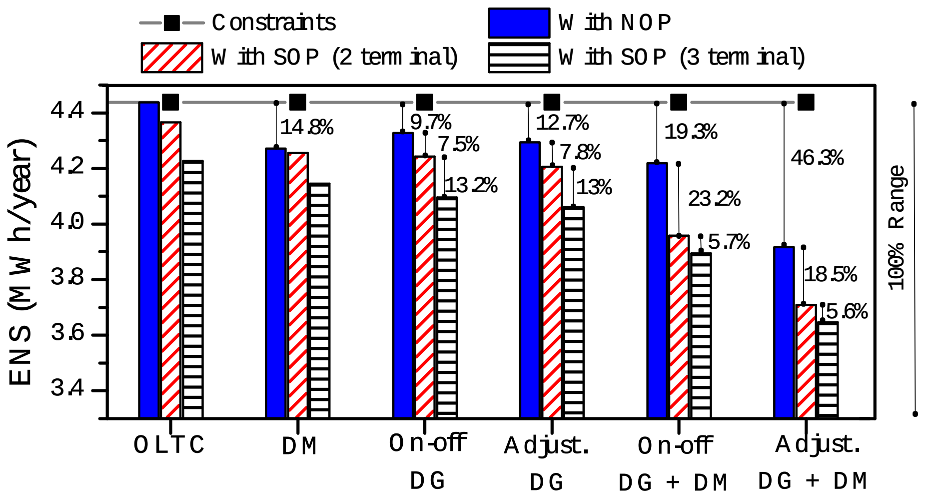


Figure 7.9: Comparison of ENS results for the ANM technologies in IEEE 33 buses network

- OLTC in transformer, alone, hardly improved reliability (1.2 % in EU Benchmark and 0 % in IEEE 33 bus). These results were expected as the control capabilities of OLTC are limited.

- Demand management (*DM*) and DGs (both on-off or adjustable DGs) improved reliability. Demand management reduced ENS 12.4 % in EU Benchmark network and 14.8 % in IEEE 33 bus network, while DGs 34.7-41 % and in 9.7-12.7 % in both networks respectively. These results show the potential of these technologies to actively participate in the power balance during outages.

- The more advanced the control of adjustable DGs was (*Adjust. DG*), the larger the improvement in reliability compared to on-off DGs became (6.2 % in the EU Network, 3 % in the IEEE 33 bus network).

- Combining the ANM technologies (OLTC, demand management and DGs) and managing them optimally provided an important reduction of the ENS. This situation can be observed in *On-Off DG+DM* and *Adjust. DG+DM* cases when compared to *On-Off DG* and *Adjust. DG*. For example, an additional 30 % of improvement was obtained for EU Benchmark network.

- Adding the two-terminal SOPs (*With SOP (2 terminal)*) improved reliability in all the cases shown in Figs. 7.8 and 7.9. The improvements were more significant with DGs: an extra 9 % was obtained for the case *On-off DG + DM* in the EU Benchmark network, and 23.2 % for the same case in the IEEE 33 bus system. Moreover, the SOP contribution in the IEEE 33 bus network was more pronounced compared to the other ANM technologies. These improvements were due to the optimal control of SOPs to transfer power between feeders and provide reactive power.

- Replacing the two-terminal by the three-terminal SOP (*With SOP (3 terminal)*) provided additional improvements. These improvements were more relevant in those cases with DGs but not with demand management (*On-off DG* and *Adjust. DG*). In the EU Benchmark, the most significant additional improvement was of 7.6 % for the *On-off DG* case, and of 13 % for the *On-off DG* and *Adjust. DG* cases in IEEE 33 bus network. The extra terminal increased the capacity to transfer power between areas and supply reactive power.

7.8 Conclusions

The impact of ANM on reliability of distribution networks has been studied and a novel analytical methodology proposed to perform the assessment. Technologies like renewable DGs, OLTC transformers, controllable loads and SOPs have been modelled and included in the formulation. Unlike the existing techniques, the proposed methodology allows the reliability evaluation in presence of SOPs and also when ANM technologies are combined. In addition, the optimal ANM coordination during interruptions and the operation of multi-terminal SOPs have been included in the evaluation, while the computational burden is preserved by using an analytical approach.

Results obtained by applying the methodology to two different distribution networks confirmed the positive contribution of ANM to reliability and its role in decreasing the interrupted load. Also, it was found the ENS was more reduced once the ANM technologies were combined and optimally coordinated.

More specifically, the proposed methodology was used to assess the SOP technology and its impact on reliability. It was demonstrated that by replacing NOPs with two-terminal SOPs a significant improvement of reliability was achieved. This improvement was more pronounced in the networks including DGs thanks to the SOP capacity to control power transfers and supply reactive power. Three-terminal SOPs were also tested and were found to be more effective than two-terminal SOPs.

Chapter 8

Conclusions and Future Research

Providing a continuous electricity supply is one of the main targets of power distribution companies and reliability is a fundamental criterion in planning distribution systems. The modernization of the grid and the integration of solutions like Distributed Generators (DGs), energy storage, demand response, power-electronics-based technologies and active network management create new opportunities to improve and guarantee the reliability of Active Distribution Networks (ADNs). In this scenario, the development of new methodologies for the evaluation of these solutions in reliability studies is essential.

In this thesis, novel analytical tools for the reliability assessment of ADNs have been developed. In order to do so, the following steps have been undertaken. First, the existing reliability assessment methodologies from the literature have been critically reviewed and the main challenges in the research field identified. Then, novel analytical methodologies have been proposed for the modelling of renewable generation, energy storage, demand control, power-electronics devices and active network management practices. All the developed tools have been validated by using real and benchmark test networks. Finally, the tools have been applied to assess the reliability of ADNs under different network scenarios and the obtained results have been discussed.

The original contributions of the thesis, main conclusions and recommendations for future work are presented in the following sections.

8.1 Original Contributions

The main original contributions of this thesis can be listed as follows:

1. A literature review of the methodologies for reliability assessment of ADNs. To the best knowledge of the author, this is the first systematic study of the state-of-the-art conducted on this topic. Modelling recommendations, current trends and research challenges are provided.

2. A critical comparison of the renewable DG models used in reliability assessment. Apart from the modelling approach, results of reliability indices and computational efficiency are used to provide recommendations related to the model selection.

3. The formulation of novel analytical tools for reliability assessment of ADNs including distributed generation, energy storage, demand response, power-electronics links and active network management actions. The proposed tools allow an extended evaluation of these ADNs and are capable of assessing different distribution network topologies (radial topologies restored via emergency-ties or via islanded operation, and meshed topologies with feeders interconnected by using power-electronics converters). Moreover, the analytical formulation of these tools takes advantage of its superior computational efficiency in comparison to simulation-based methodologies. The above-mentioned proposed tools consist of:

   (a) An analytical technique to assess energy storage in reliability studies. It accurately models the chronological operation of energy storage during interruptions. In addition, it represents an efficient alternative to the simulation methodologies commonly used for energy storage evaluation.

   (b) A methodology to help with the selection of energy storage technology and size in reliability studies. The methodology considers both technical and economic parameters.

   (c) A tool to assess reliability of distribution networks with DGs, energy storage and demand response. The optimal coordination of these three resources is considered in the reliability assessment, effect not evaluated by the existing methodologies.

   (d) A technique to evaluate the impact of active network management technologies on reliability (impact not evaluated in the literature). Control actions on renewable DGs, loads, transformers and, in particular, power-electronic-based links are all modelled for their accurate evaluation.

4. New probabilistic models of renewable generation, demand and stored energy. The models are formulated to capture the chronological fluctuations of power and stored energy during outages and to evaluate these parameters in analytical techniques like those proposed in this thesis. Therefore, the models allow a more realistic evaluation when compared to other analytical techniques found in the literature.

5. The validation of the tools proposed in this thesis and the illustration of how the evaluated solutions (like DGs, energy storage, demand response, power-electronics

devices and active network management) contribute to reliability of distribution networks.

8.2 General Conclusions

- Different models of renewable DGs have been evaluated in reliability studies. Those based on probabilistic time-segments of a year (e.g. one typical day per month) have been demonstrated to be appropriate for efficient evaluation of renewable generation.

- Integration of energy storage and active network management technologies in ADNs has been analysed. In several of the analysed scenarios, the obtained reliability improvements were larger than those obtained when only distributed generation is used. The improvement has been demonstrated for different network topologies, either restored via islanded operation or via emergency ties.

- The proposed analytical technique for energy storage evaluation has been validated by using a comparison with Monte Carlo Simulation. Sufficiently accurate reliability indices have been obtained for only a fraction of the computation time (50 times faster in average for the analysed cases).

- The selection of energy storage for reliability improvement has been studied. It was found it is highly affected by technical parameters like energy storage size, level of stored energy at the moment of the fault and penetration of renewable distributed generation. Therefore, all these parameters should be properly considered in the energy storage selection.

- Profitability of energy storage has been analysed for reliability improvement applications. The obtained benefit covers a significant part of the energy storage investment (in specific cases up to 90 %). However, it highly depends on the cost and size of the energy storage technology considered, reporting benefit-cost ratios between 5 and 90 % in the conducted analyses. These economic results are important for energy storage investment and have to be summed up with other benefits provided by energy storage.

- During outages distributed generation, energy storage and demand management can be used in a coordinated way to improve reliability. This effect has been analysed and it has been found that an optimal coordination significantly improved reliability in comparison to their individual, non-coordinated operation. The levels of penetration of energy storage and demand management should be appropriately defined in order to fulfil specific reliability improvements.

- Active network management technologies can be used to improve the network reliability. The contribution of different combinations of technologies has been evaluated, confirming that the more flexibility and control options are the larger the reliability improvement.

- The reliability improvement offered by power-electronic-based links like Soft-Open Points (described in Chapter 7) has been found to be of an outstanding importance, up to 29 % in the analysed cases). This improvement was more notable in presence of distributed generation and, in addition, it was demonstrated to be superior for links with multiple terminals.

- Renewable generation, energy storage, demand management and other controllable technologies in ADNs introduced additional complexity in the reliability assessment of distribution networks. Consequently, using Monte Carlo based simulation techniques for this evaluation would demand increased computation times. The development of analytical formulations and deterministic optimisation problems has helped to reduce the computational burden needed for the evaluation.

8.3 Suggestions for Further Research

The following topics are suggested for further research:

1. In presence of energy storage, probabilistic time-segments over a year have been used to model chronological variation of renewable generation and demand. Although this type of model has been validated, further research can be performed in the development of alternative models. For example, techniques can be used to determine the optimal number of generation-demand scenarios that guarantee accuracy and improve computational efficiency.

2. The amount of stored energy when a fault occurs depends on prior operation of energy storage. This stored energy can vary with the operating conditions and it affects to reliability. For a more realistic reliability evaluation, existing algorithms in the literature can be used to determine the state-of-charge under normal operating conditions and then be combined with the methodologies proposed in this thesis for reliability assessment.

3. The tools developed in this thesis for reliability assessment can be extended to incorporate additional solutions like electric vehicle, microgrids or demand flexibility. Moreover, restoration strategies based on the coordination of these and other solutions can be modelled.

4. Further work is needed to evaluate the profitability of reliability improvement in ADNs. Cost-benefit analyses of different solutions addressed in this thesis can be conducted. Moreover, methodologies for optimal reliability improvement can be developed.

5. The methodologies proposed in this thesis can be extended to evaluate resilience of ADNs, as it has been identified as a topic of great interest in recent years for the planning of future distribution systems.

8.4 Publications

The papers published and submitted during the elaboration of this thesis are listed below sorted by the date of publication or submission.

8.4.1 Journal Papers

1. A. Escalera, B. Hayes, and M. Prodanović, "A survey of reliability assessment techniques for modern distribution networks," Renewable and Sustainable Energy Reviews, vol. 91, pp. 344-357, 2018. Journal Impact Factor Quartile: Q1.

2. A. Escalera, M. Prodanović, and E. D. Castronuovo, "Analytical methodology for reliability assessment of distribution networks with energy storage in islanded and emergency-tie restoration modes," International Journal of Electrical Power & Energy Systems, vol. 107, pp. 735-744, 2019. Journal Impact Factor Quartile: Q1.

3. A. Escalera, E. D. Castronuovo, M. Prodanović and J. Roldán-Perez, "Reliability assessment of distribution networks with optimal restoration based on distributed generation, energy storage and demand management," submitted, 2019.

4. A. Escalera, M. Prodanović, E. D. Castronuovo and J. Roldán-Perez, "Contribution of active network management technologies to distribution system reliability," submitted, 2019.

8.4.2 Conference Papers

1. A. Escalera, B. Hayes, and M. Prodanović, "Reliability assessment of active distribution networks considering distributed energy resources and operational limits," in CIRED Workshop 2016, June 2016, pp. 1-4.

2. B. Hayes, A. Escalera, and M. Prodanović, "Event-triggered topology identification for state estimation in active distribution networks," in 2016 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Oct 2016, pp. 1-6.

3. A. Escalera, B. Hayes, and M. Prodanović, "Analytical method to assess the impact of distributed generation and energy storage on reliability of supply," in CIRED, vol. 2017, no. 1, pp. 2092-2096, Oct 2017.

4. A. Escalera, M. Prodanović, E. D. Castronuovo, and R. Segovia, "Reliability evaluation of grid-connected microgrids with high penetration of renewable distributed energy resources," in CIRED Workshop 2018, June 2018, pp.1-4.

5. A. Escalera, M. Prodanović, E. D. Castronuovo, and J. C. Mazuera, "A comparison of the renewable distributed generation models used in reliability assessment," in 2018 IEEE Int. Conf. on Probabilistic Methods Applied to Power Systems (PMAPS), June 2018, pp. 1-6.

6. A. Escalera, M. Prodanović, and E. D. Castronuovo, "An analysis of the energy storage for improving the reliability of distribution networks," in 2018 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Oct 2018, pp. 1-6.

7. A. Escalera, M. Prodanović, and E. D. Castronuovo, "Economic evaluation of energy storage used for reliability improvement in distribution networks," paper accepted in CIRED Conference 2019, June 2019.

Bibliography

[1] C. Singh and R. Billinton, *System Reliability Modelling and Evaluation.* London: Hutchinson Educational Publishers, 1977.

[2] K. H. LaCommare, J. H. Eto, L. N. Dunn, and M. D. Sohn, "Improving the estimated cost of sustained power interruptions to electricity customers," *Energy*, vol. 153, pp. 1038 – 1047, 2018.

[3] R. Billinton and R. Allan, *Reliability Evaluation of Power Systems*, 2nd ed. New York: Plenum Press, 1996.

[4] M. Cepin, *Assessment of Power System Reliability, Methods and Applications.* London: Springer, 2011.

[5] R. Allan and R. Billinton, "Probabilistic assessment of power systems," *Proceedings of the IEEE*, vol. 88, no. 2, pp. 140–162, Feb 2000.

[6] Smart Grids Security and R. T. Force, "The need for a fundamental review of electricity networks reliability standards," White Paper, 2016.

[7] Federal Energy Regulation Commission (FERC), "Distributed energy resources - Technical considerations for the bulk power system," Staff Report, Docket No. AD18-10-000., Tech. Rep., Feb 2018.

[8] R. Hidalgo, C. Abbey, and G. Joós, "A review of active distribution networks enabling technologies," in *IEEE PES General Meeting*, July 2010, pp. 1–9.

[9] K. Moslehi and R. Kumar, "A reliability perspective of the Smart Grid," *IEEE Trans. Smart Grid*, vol. 1, no. 1, pp. 57–64, June 2010.

[10] A. Escalera, B. Hayes, and M. Prodanović, "A survey of reliability assessment techniques for modern distribution networks," *Renewable and Sustainable Energy Reviews*, vol. 91, pp. 344 – 357, Aug 2018.

[11] R. Billinton, “Bibliography on the application of probability methods in power system reliability evaluation,” *IEEE Trans. Power App. Syst.*, vol. PAS-91, no. 2, pp. 649–660, March 1972.

[12] P. S. E. Committee, “Bibliography on the application of probability methods in power system reliability evaluation 1971-1977,” *IEEE Trans. Power App. Syst.*, vol. PAS-97, no. 6, pp. 2235–2242, Nov 1978.

[13] R. N. Allan, R. Billinton, and S. H. Lee, “Bibliography on the application of probability methods in power system reliability evaluation 1977-1982,” *IEEE Trans. Power App. Syst.*, vol. PAS-103, no. 2, pp. 275–282, Feb 1984.

[14] R. N. Allan, R. Billinton, S. M. Shahidehpour, and C. Singh, “Bibliography on the application of probability methods in power system reliability evaluation: 1982-1987,” *IEEE Trans. Power Syst.*, vol. 3, no. 4, pp. 1555–1564, Nov 1988.

[15] R. N. Allan, R. Billinton, A. M. Breipohl, and C. H. Grigg, “Bibliography on the application of probability methods in power system reliability evaluation: 1987-1991,” *IEEE Trans. Power Syst.*, vol. 9, no. 1, pp. 41–49, Feb 1994.

[16] R. Billinton, M. Fotuhi-Firuzabad, and L. Bertling, “Bibliography on the application of probability methods in power system reliability evaluation 1996-1999,” *IEEE Trans. Power Syst.*, vol. 16, no. 4, pp. 595–602, Nov 2001.

[17] S. Chapel, “Reliability of electric utility distribution systems: EPRI white paper,” *Final Rep.*, Oct 2000.

[18] H. M. Lopes-Ferreira, H. Faas, G. Fulli, W. Kling, and J. P. Lopes, “Reliability analyses on distribution networks with dispersed generation: a review of the state of the art,” in *Conf. Smart Electricity Systems and Interoperability*, 2010, pp. 1–17.

[19] J. Lin, L. Cheng, Y. Chang, K. Zhang, B. Shu, and G. Liu, “Reliability based power systems planning and operation with wind power integration: A review to models, algorithms and applications,” *Renewable Sustainable Energy Reviews*, vol. 31, pp. 921–934, Mar 2014.

[20] C. L. T. Borges, “An overview of reliability models and methods for distribution systems with renewable energy distributed generation,” *Renewable Sustainable Energy Reviews*, vol. 16, no. 6, pp. 4008–4015, Aug 2012.

[21] “IEEE guide for electric power distribution reliability indices,” *IEEE Std 1366, 2012 Edition*, May, 2012.

[22] R. Billinton and P. Wang, "Teaching distribution system reliability evaluation using Monte Carlo simulation," *IEEE Trans. Power Syst.*, vol. 14, no. 2, pp. 397–403, May 1999.

[23] R. E. Brown and L. A. A. Freeman, "Analyzing the reliability impact of distributed generation," in *Power Engineering Society Summer Meeting*, vol. 2, July 2001, pp. 1013–1018.

[24] T. Kaipia, P. Peltoniemi, J. Lassila, P. Salonen, and J. Partanen, "Power electronics in smartgrids - impact on power system reliability," in *CIRED Seminar 2008: SmartGrids for Distribution*, June 2008, pp. 1–4.

[25] Z. Esau and D. Jayaweera, "Reliability assessment in active distribution networks with detailed effects of pv systems," *Journal of Modern Power Systems and Clean Energy*, vol. 2, no. 1, pp. 59–68, Mar 2014.

[26] S. Conti, R. Nicolosi, and S. A. Rizzo, "Generalized systematic approach to assess distribution system reliability with renewable distributed generators and microgrids," *IEEE Trans. Power Del.*, vol. 27, no. 1, pp. 261–270, Jan 2012.

[27] S. Conti, S. A. Rizzo, E. F. El-Saadany, M. Essam, and Y. M. Atwa, "Reliability assessment of distribution systems considering telecontrolled switches and microgrids," *IEEE Trans. Power Syst.*, vol. 29, no. 2, pp. 598–607, March 2014.

[28] C. Chen, W. Wu, B. Zhang, and C. Singh, "An analytical adequacy evaluation method for distribution networks considering protection strategies and distributed generators," *IEEE Trans. Power Del.*, vol. 30, no. 3, pp. 1392–1400, June 2015.

[29] E. N. Dialynas and R. N. Allan, "Local generating facilities in the reliability evaluation of power distribution systems," *IEEE Trans. Power Syst.*, vol. 1, no. 4, pp. 62–67, Nov 1986.

[30] ——, "Reliability modelling and evaluation techniques for power distribution networks with local generation," *IEE Proc. Generat., Transm. Distrib.*, vol. 134, no. 5, pp. 348–356, September 1987.

[31] I. S. Bae and J. O. Kim, "Reliability evaluation of distributed generation based on operation mode," *IEEE Trans. Power Syst.*, vol. 22, no. 2, pp. 785–790, May 2007.

[32] K. Zou, A. P. Agalgaonkar, K. M. Muttaqi, and S. Perera, "An analytical approach for reliability evaluation of distribution systems containing dispatchable and nondispatchable renewable DG units," *IEEE Trans. Smart Grid*, vol. 5, no. 6, pp. 2657–2665, Nov 2014.

[33] S. Conti, G. Faraci, A. La Corte, R. Nicolosi, S. A. Rizzo, and G. Schembra, "Effect of islanding and telecontrolled switches on distribution system reliability considering load and green-energy fluctuations," *Applied Sciences*, vol. 6, no. 5, pp. 1–26, 2016.

[34] X. Zhang, Z. Bie, and G. Li, "Reliability assessment of distribution networks with distributed generations using Monte Carlo method," *Energy Procedia*, vol. 12, pp. 278 – 286, 2011.

[35] Y. G. Hegazy, M. M. A. Salama, and A. Y. Chikhani, "Adequacy assessment of distributed generation systems using Monte Carlo simulation," *IEEE Trans. Power Syst.*, vol. 18, no. 1, pp. 48–52, Feb 2003.

[36] R. Arya, S. Choube, and L. Arya, "Reliability evaluation and enhancement of distribution systems in the presence of distributed generation based on standby mode," *Int. J. Elec. Power*, vol. 43, no. 1, pp. 607 – 616, 2012.

[37] P. Wang and R. Billinton, "Reliability benefit analysis of adding WTG to a distribution system," *IEEE Trans. Energy Convers.*, vol. 16, no. 2, pp. 134–139, Jun 2001.

[38] ——, "Time-sequential simulation technique for rural distribution system reliability cost/worth evaluation including wind generation as alternative supply," *IEE Proc. Generat., Transm. Distrib.*, vol. 148, no. 4, pp. 355–360, Jul 2001.

[39] J. Lin and X. Wang, "Reliability evaluation for distribution system with distributed generation," in *2010 Asia-Pacific Power and Energy Engineering Conf.*, March 2010, pp. 1–4.

[40] G. Celli, E. Ghiani, F. Pilo, and G. G. Soma, "Reliability assessment in smart distribution networks," *Electr. Pow. Syst. Res.*, vol. 104, pp. 164–175, 2013.

[41] S. Conti and S. A. Rizzo, "Monte Carlo simulation by using a systematic approach to assess distribution system reliability considering intentional islanding," *IEEE Trans. Power Del.*, vol. 30, no. 1, pp. 64–73, Feb 2015.

[42] H. Guo, V. Levi, and M. Buhari, "Reliability assessment of smart distribution networks," in *2015 IEEE Innovative Smart Grid Technologies - Asia (ISGT ASIA)*, Nov 2015, pp. 1–6.

[43] A. Sankarakrishnan and R. Billinton, "Sequential Monte Carlo simulation for composite power system reliability analysis with time varying loads," *IEEE Trans. Power Syst.*, vol. 10, no. 3, pp. 1540–1545, Aug 1995.

[44] M. Fotuhi-Firuzabad and A. Rajabi-Ghahnavie, "An analytical method to consider DG impacts on distribution system reliability," in *2005 IEEE/PES Transmission Distribution Conf. Expo.: Asia and Pacific*, 2005, pp. 1–6.

[45] Y. M. Atwa and E. F. El-Saadany, "Reliability evaluation for distribution system with renewable distributed generation during islanded mode of operation," *IEEE Trans. Power Syst.*, vol. 24, no. 2, pp. 572–581, May 2009.

[46] M. Al-Muhaini and G. T. Heydt, "Evaluating future power distribution system reliability including distributed generation," *IEEE Trans. Power Del.*, vol. 28, no. 4, pp. 2264–2272, Oct 2013.

[47] S. Conti and S. A. Rizzo, "Modelling of microgrid-renewable generators accounting for power-output correlation," *IEEE Trans. Power Del.*, vol. 28, no. 4, pp. 2124–2133, Oct 2013.

[48] A. C. Neto, M. G. da Silva, and A. B. Rodrigues, "Impact of distributed generation on reliability evaluation of radial distribution systems under network constraints," in *Int. Conf. Probabilistic Methods Applied to Power Systems (PMAPS)*, June 2006, pp. 1–6.

[49] S. S. Duttagupta and C. Singh, "A reliability assessment methodology for distribution systems with distributed generation," in *2006 IEEE Power Engineering Society General Meeting*, 2006, pp. 1–7.

[50] V. A. Evangelopoulos, P. S. Georgilakis, and N. D. Hatziargyriou, "Optimal operation of smart distribution networks: A review of models, methods and future research," *Electr. Pow. Syst. Res.*, vol. 140, pp. 95 – 106, 2016.

[51] L. F. Rocha, C. L. T. Borges, and G. N. Taranto, "Reliability evaluation of active distribution networks including islanding dynamics," *IEEE Trans. Power Syst.*, vol. PP, no. 99, pp. 1–1, 2016.

[52] A. Escalera, B. Hayes, and M. Prodanović, "Reliability assessment of active distribution networks considering distributed energy resources and operational limits," in *CIRED Workshop 2016*, June 2016, pp. 1–4.

[53] W. Li, P. Wang, Z. Li, and Y. Liu, "Reliability evaluation of complex radial distribution systems considering restoration sequence and network constraints," *IEEE Trans. Power Del.*, vol. 19, no. 2, pp. 753–758, April 2004.

[54] C. L. C. de Castro, A. B. Rodrigues, and M. G. Silva, "Reliability evaluation of radial distribution systems considering voltage drop constraints in the restoration process," in *2004 Int. Conf. on Probabilistic Methods Applied to Power Systems (PMAPS)*, Sept 2004, pp. 106–111.

[55] A. M. L. da Silva, L. C. Nascimento, M. A. da Rosa, D. Issicaba, and J. A. P. Lopes, "Distributed energy resources impact on distribution system reliability under load transfer restrictions," *IEEE Trans. Smart Grid*, vol. 3, no. 4, pp. 2048–2055, Dec 2012.

[56] M. Abdullah, A. Agalgaonkar, and K. Muttaqi, "Assessment of energy supply and continuity of service in distribution network with renewable distributed generation," *Applied Energy*, vol. 113, pp. 1015 – 1026, 2014.

[57] D. Aming, A. Rajapakse, T. Molinski, and E. Innes, "A technique for evaluating the reliability improvement due to energy storage systems," in *2007 Canadian Conf. Electrical and Computer Engineering*, April 2007, pp. 413–416.

[58] Y. Xu and C. Singh, "Adequacy and economy analysis of distribution systems integrated with electric energy storage and renewable energy resources," *IEEE Trans. Power Syst.*, vol. 27, no. 4, pp. 2332–2341, Nov 2012.

[59] ——, "Power system reliability impact of energy storage integration with intelligent operation strategy," *IEEE Trans. Smart Grid*, vol. 5, no. 2, pp. 1129–1137, March 2014.

[60] I. Hernando-Gil, I. S. Ilie, A. J. Collin, J. L. Acosta, and S. Z. Djokic, "Impact of DG and energy storage on distribution network reliability: A comparative analysis," in *2012 IEEE Int. Energy Conf. and Exhibition (ENERGYCON)*, Sept 2012, pp. 605–611.

[61] A. S. A. Awad, T. H. M. El-Fouly, and M. M. A. Salama, "Optimal ESS allocation and load shedding for improving distribution system reliability," *IEEE Trans. Smart Grid*, vol. 5, no. 5, pp. 2339–2349, Sept 2014.

[62] P. Paliwal, N. Patidar, and R. Nema, "A novel method for reliability assessment of autonomous pv-wind-storage system using probabilistic storage model," *Int. J. Elec. Power*, vol. 55, pp. 692 – 703, 2014.

[63] C. L. T. Borges and M. Costa, "Reliability assessment of microgrids with renewable generation by an hybrid model," in *2015 IEEE Eindhoven PowerTech*, June 2015, pp. 1–6.

[64] T. Adefarati and R. Bansal, "Reliability assessment of distribution system with the integration of renewable distributed generation," *Applied Energy*, vol. 185, pp. 158 – 171, 2017.

[65] Y. Chen, Y. Zheng, F. Luo, J. Wen, and Z. Xu, "Reliability evaluation of distribution systems with mobile energy storage systems," *IET Renew. Power Gener.*, vol. 10, no. 10, pp. 1562–1569, 2016.

[66] A. Narimani, G. Nourbakhsh, G. Ledwich, and G. Walker, "Optimum electricity purchase scheduling for aggregator storage in a reliability framework for rural distribution networks," *Int. J. Elec. Power*, vol. 94, pp. 363 – 373, 2018.

[67] H. Saboori, R. Hemmati, and M. A. Jirdehi, "Reliability improvement in radial electrical distribution network by optimal planning of energy storage systems," *Energy*, vol. 93, pp. 2299 – 2312, 2015.

[68] W. Liu, S. Niu, and H. Xu, "Optimal planning of battery energy storage considering reliability benefit and operation strategy in active distribution system," *Journal of Modern Power Systems and Clean Energy*, vol. 5, no. 2, pp. 177–186, Mar 2017.

[69] D. Rastler (EPRI), "Electricity Energy Storage Technology Options," Tech. Rep., 2010.

[70] R. H. Lasseter, "Microgrids and distributed generation," *J. Energy Eng.*, vol. 133, no. 1, pp. 144–149, Mar 2007.

[71] S. A. Arefifar and Y. A. R. I. Mohamed, "DG mix, reactive sources and energy storage units for optimizing microgrid reliability and supply security," *IEEE Trans. Smart Grid*, vol. 5, no. 4, pp. 1835–1844, July 2014.

[72] H. Baghaee, M. Mirsalim, G. Gharehpetian, and H. Talebi, "Reliability cost-based multi-objective pareto optimal design of stand-alone wind/pv/fc generation microgrid system," *Energy*, vol. 115, pp. 1022 – 1041, 2016.

[73] J. Mitra, M. R. Vallem, and C. Singh, "Optimal deployment of distributed generation using a reliability criterion," *IEEE Trans. Ind. Appl.*, vol. 52, no. 3, pp. 1989–1997, May 2016.

[74] S. Wang, Z. Li, L. Wu, M. Shahidehpour, and Z. Li, "New metrics for assessing the reliability and economics of microgrids in distribution system," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2852–2861, Aug 2013.

[75] I. S. Bae and J. O. Kim, "Reliability evaluation of customers in a microgrid," *IEEE Trans. Power Syst.*, vol. 23, no. 3, pp. 1416–1422, Aug 2008.

[76] E. N. Dialynas and L. Daoutis, "Modelling and evaluation of microgrids reliability and operational performance and its impact on service quality," *Eur. T. Electr. Power*, vol. 21, no. 2, pp. 1255–1270, 2011.

[77] H. Liang, J. Su, and S. Liu, "Reliability evaluation of distribution system containing microgrid," in *2010 China Int. Conf. Electricity Distribution (CICED)*, Sept 2010, pp. 1–7.

[78] H. Bai, S. Miao, P. Zhang, and Z. Bai, "Reliability evaluation of a distribution network with microgrid based on a combined power generation system," *Energies*, vol. 8, no. 2, pp. 1216–1241, Feb 2015.

[79] Z. Bie, P. Zhang, G. Li, B. Hua, M. Meehan, and X. Wang, "Reliability evaluation of active distribution systems including microgrids," *IEEE Trans. Power Syst.*, vol. 27, no. 4, pp. 2342–2350, Nov 2012.

[80] P. M. Costa and M. A. Matos, "Assessing the contribution of microgrids to the reliability of distribution networks," *Electr. Pow. Syst. Res.*, vol. 79, no. 2, pp. 382 – 389, 2009.

[81] H. Farzin, M. Fotuhi-Firuzabad, and M. Moeini-Aghtaie, "Role of outage management strategy in reliability performance of multi-microgrid distribution systems," *IEEE Trans. Power Syst.*, vol. 33, no. 3, pp. 2359–2369, May 2018.

[82] M. E. Khodayar, M. Barati, and M. Shahidehpour, "Integration of high reliability distribution system in microgrid operation," *IEEE Trans. Smart Grid*, vol. 3, no. 4, pp. 1997–2006, Dec 2012.

[83] X. Xu, J. Mitra, T. Wang, and L. Mu, "Evaluation of operational reliability of a microgrid using a short-term outage model," *IEEE Trans. Power Syst.*, vol. 29, no. 5, pp. 2238–2247, Sept 2014.

[84] ——, "An evaluation strategy for microgrid reliability considering the effects of protection system," *IEEE Trans. Power Del.*, vol. 31, no. 5, pp. 1989–1997, Oct 2016.

[85] X. Xu, T. Wang, L. Mu, and J. Mitra, "Predictive analysis of microgrid reliability using a probabilistic model of protection system operation," *IEEE Trans. Power Syst.*, vol. 32, no. 4, pp. 3176–3184, July 2017.

[86] J. R. Araújo, E. N. M. Silva, A. B. Rodrigues, and M. G. da Silva, "Assessment of the impact of microgrid control strategies in the power distribution reliability indices," *Journal of Control, Automation and Electrical Systems*, vol. 28, no. 2, pp. 271–283, Apr 2017.

[87] U.S. Department of Energy, "Benefits of demand response in electricity markets and recommendations for achieving them," Tech. Rep., Feb 2006.

[88] S. Mohagheghi, F. Yang, and B. Falahati, "Impact of demand response on distribution system reliability," in *2011 IEEE Power and Energy Society General Meeting*, July 2011, pp. 1–7.

[89] A. Safdarian, M. Z. Degefa, M. Lehtonen, and M. Fotuhi-Firuzabad, "Distribution network reliability improvements in presence of demand response," *IET Generat., Transm. Distrib.*, vol. 8, no. 12, pp. 2027–2035, 2014.

[90] I. S. Ilie, I. Hernando-Gil, A. J. Collin, J. L. Acosta, and S. Z. Djokic, "Reliability performance assessment in smart grids with demand-side management," in *2011 2nd IEEE PES Int. Conf. and Exhibition on Innovative Smart Grid Technologies*, Dec 2011, pp. 1–7.

[91] A. L. A. Syrri and P. Mancarella, "Reliability evaluation of demand response to increase distribution network utilisation," in *2014 Int. Conf. Probabilistic Methods Applied to Power Systems (PMAPS)*, July 2014, pp. 1–6.

[92] A. L. Syrri and P. Mancarella, "Reliability and risk assessment of post-contingency demand response in smart distribution networks," *Sustain. Energy Grids Netw.*, vol. 7, pp. 1 – 12, 2016.

[93] H. Xie, Z. Bie, B. Hua, and G. Li, "Reliability assessment of distribution power systems considering the TOU pricing," in *2013 IEEE Region 10 Conference (TENCON 2013)*, Oct 2013, pp. 1–4.

[94] B. Zeng, G. Wu, J. Wang, J. Zhang, and M. Zeng, "Impact of behavior-driven demand response on supply adequacy in smart distribution systems," *Applied Energy*, vol. 202, pp. 125 – 137, 2017.

[95] A. Moshari and A. Ebrahimi, "Reliability-based nodal evaluation and prioritization of demand response programs," *Int. Trans. Electrical Energy Systems*, vol. 25, no. 12, pp. 3384–3407, 2015, eTEP-14-0375.R2.

[96] J. Tan and L. Wang, "Enabling reliability-differentiated service in residential distribution networks with PHEVs: A hierarchical game approach," *IEEE Trans. Smart Grid*, vol. 7, no. 2, pp. 684–694, March 2016.

[97] N. Good, K. A. Ellis, and P. Mancarella, "Review and classification of barriers and enablers of demand response in the smart grid," *Renewable Sustainable Energy Reviews*, vol. 72, pp. 57 – 72, 2017.

[98] N. Z. Xu and C. Y. Chung, "Well-being analysis of generating systems considering electric vehicle charging," *IEEE Trans. Power Syst.*, vol. 29, no. 5, pp. 2311–2320, Sept 2014.

[99] ——, "Reliability evaluation of distribution systems including vehicle-to-home and vehicle-to-grid," *IEEE Trans. Power Syst.*, vol. 31, no. 1, pp. 759–768, Jan 2016.

[100] H. Farzin, M. Fotuhi-Firuzabad, and M. Moeini-Aghtaie, "Reliability studies of modern distribution systems integrated with renewable generation and parking lots," *IEEE Trans. Sustain. Energy*, vol. 8, no. 1, pp. 431–440, Jan 2017.

[101] A. Kavousi-Fard, M. A. Rostami, and T. Niknam, "Reliability-oriented reconfiguration of vehicle-to-grid networks," *IEEE Trans. Ind. Informat.*, vol. 11, no. 3, pp. 682–691, June 2015.

[102] C. X. Wu, C. Y. Chung, F. S. Wen, and D. Y. Du, "Reliability/cost evaluation with PEV and wind generation system," *IEEE Trans. Sustain. Energy*, vol. 5, no. 1, pp. 273–281, Jan 2014.

[103] D. Haughton and G. T. Heydt, "Smart distribution system design: Automatic reconfiguration for improved reliability," in *IEEE PES General Meeting*, July 2010, pp. 1–8.

[104] Y. He, G. Andersson, and R. N. Allan, "Modeling the impact of automation and control on the reliability of distribution systems," in *IEEE Power Engineering Society Summer Meeting, 2000*, vol. 1, 2000, pp. 79–84 vol. 1.

[105] A. M. L. da Silva, A. M. Cassula, L. C. Resende, R. M. Almeida, M. T. Yamasaki, and G. M. F. Paula, "Reliability evaluation of distribution systems considering automatic reclosers," in *2004 Int. Conf. Probabilistic Methods Applied to Power Systems (PMAPS)*, Sept 2004, pp. 100–105.

[106] H. Zheng, Y. Cheng, B. Gou, D. Frank, A. Bern, and W. Muston, "Impact of automatic switches on power distribution system reliability," *Electr. Pow. Syst. Res.*, vol. 83, no. 1, pp. 51–57, 2012.

[107] S. Conti, A. L. Corte, R. Nicolosi, and S. Rizzo, "Impact of cyber-physical system vulnerability, telecontrol system availability and islanding on distribution network reliability," *Sustain. Energy Grids Netw.*, vol. 6, pp. 143 – 151, 2016.

[108] A. Safdarian, M. Farajollahi, and M. Fotuhi-Firuzabad, "Impacts of remote control switch malfunction on distribution system reliability," *IEEE Trans. Power Syst.*, vol. 32, no. 2, pp. 1572–1573, March 2017.

[109] S. Kazemi, M. Fotuhi-Firuzabad, and M. Lehtonen, "Reliability worth assessment of an advanced centralized feeder automation scheme," in *2008 IEEE Electric Power And Energy Conf. (EPEC)*, Oct 2008, pp. 1–8.

[110] S. Kazemi, M. Fotuhi-Firuzabad, and R. Billinton, "Reliability assessment of an automated distribution system," *IET Generat., Transm. Distrib.*, vol. 1, no. 2, pp. 223–233, March 2007.

[111] S. Kazemi, M. Lehtonen, and M. Fotuhi-Firuzabad, "Reliability worth assessment of an automatic loop restoration scheme for urban distribution networks," in *2010 IEEE PES Innovative Smart Grid Technologies Conf. Europe (ISGT Europe)*, Oct 2010, pp. 1–8.

[112] Y. He, L. Soder, and R. N. Allan, "Distribution automation: impact of communication system on reliability of automatic control," in *2001 IEEE Porto Power Tech Proc.*, vol. 3, 2001, p. 6 pp. vol.3.

[113] I. A. Tondel, J. Foros, S. S. Kilskar, P.Hokstad, and M. G. Jaatun, "Interdependencies and reliability in the combined ICT and power system: An overview of current research," *Applied Computing and Informatics*, 2017.

[114] R. S. de Carvalho and S. Mohagheghi, "Analyzing impact of communication network topologies on reconfiguration of networked microgrids, impact of communication system on smart grid reliability, security and operation," in *2016 North American Power Symposium (NAPS)*, Sept 2016, pp. 1–6.

[115] A. Escalera, M. Prodanović, E. D. Castronuovo, and J. C. Mazuera, "A comparison of the renewable distributed generation models used in reliability assessment," in *2018 IEEE Int. Conf. on Probabilistic Methods Applied to Power Systems (PMAPS)*, June 2018, pp. 1–6.

[116] "European commision SmartHG project website," accessed 24 April 2019. [Online]. Available: http://smarthg.di.uniroma1.it/

[117] W. S. Andrade, C. L. T. Borges, and D. M. Falcao, "Modeling reliability aspects of distributed generation connected to distribution systems," in *2006 IEEE Power Engineering Society General Meeting*, 2006, pp. pp.1–6.

[118] P. Giorsetto and K. F. Utsurogi, "Development of a new procedure for reliability modeling of wind turbine generators," *IEEE Trans. Power App. Syst.*, vol. PAS-102, no. 1, pp. 134–143, Jan 1983.

[119] S. Lloyd, "Least squares quantization in PCM," *IEEE Trans. Information Theory*, vol. 28, no. 2, pp. 129–137, March 1982.

[120] R. Billinton and W. Li, *Reliability Assessment of Electric Power Systems Using Monte Carlo Methods.* New York: Plenum Press, 1994.

[121] R. Billinton and S. Jonnavithula, "A test system for teaching overall power system reliability assessment," *IEEE Trans. Power Syst.*, vol. 11, no. 4, pp. 1670–1676, Nov 1996.

[122] R. N. Allan, R. Billinton, I. Sjarief, L. Goel, and K. S. So, “A reliability test system for educational purposes-basic distribution system data and results,” *IEEE Trans. Power Syst.*, vol. 6, no. 2, pp. 813–820, May 1991.

[123] A. Escalera, M. Prodanović, and E. D. Castronuovo, “Analytical methodology for reliability assessment of distribution networks with energy storage in islanded and emergency-tie restoration modes,” *Int. J. Elec. Power*, vol. 107, pp. 735 – 744, May 2019.

[124] A. Escalera, B. Hayes, and M. Prodanović, “Analytical method to assess the impact of distributed generation and energy storage on reliability of supply,” *CIRED*, vol. 2017, pp. 2092–2096(4), Oct 2017.

[125] A. Chowdhury and D. Koval, *Power Distribution System Reliability: Practical Methods and Applications.* New Jersey: John Wiley & Sons, Inc., 2009.

[126] R. Billinton and P. Wang, “Distribution system reliability cost/worth analysis using analytical and sequential simulation techniques,” *IEEE Trans. Power Syst.*, vol. 13, no. 4, pp. 1245–1250, Nov 1998.

[127] R. N. Allan, E. N. Dialynas, and I. R. Homer, “Modelling and evaluating the reliability of distribution systems,” *IEEE Trans. Power App. Syst.*, vol. PAS-98, no. 6, pp. 2181–2189, Nov 1979.

[128] R. Billinton and P. Wang, “A generalized method for distribution system reliability evaluation,” in *IEEE WESCANEX 95. Communications, Power, and Computing. Conf.*, vol. 2, May 1995, pp. 349–354 vol.2.

[129] S. Ćurčić, C. S. Ozveren, L. Crowe, and P. Lo, “Electric power distribution network restoration: a survey of papers and a review of the restoration problem,” *Electr. Pow. Syst. Res.*, vol. 35, no. 2, pp. 73 – 86, 1995.

[130] A. Escalera, M. Prodanović, and E. D. Castronuovo, “An analysis of the energy storage for improving the reliability of distribution networks,” in *2018 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*, Oct 2018, pp. 1–6.

[131] I. Hernando-Gil, I. S. Ilie, and S. Z. Djokic, “Reliability performance of smart grids with demand-side management and distributed generation/storage technologies,” in *2012 3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)*, Oct 2012, pp. 1–8.

[132] IRENA, “Electricity storage and renewables: Costs and markets to 2030,” International Renewable Energy Agency, Tech. Rep., Oct 2017.

[133] A. Stan, M. Swierczynski, D. Stroe, R. Teodorescu, S. J. Andreasen, and K. Moth, "A comparative study of lithium ion to lead acid batteries for use in ups applications," in *2014 IEEE 36th Int. Telecommunications Energy Conference (INTELEC)*, Sep. 2014, pp. 1–8.

[134] *U.S. Battery, US 24DC XC2 - DATA SHEET. Accesed on 24 April 2019, https://www.rjbatt.com.au/wp-content/uploads/2014/01/US-24DC-XC2.pdf.*

[135] J. Dulout, B. Jammes, C. Alonso, A. Anvari-Moghaddam, A. Luna, and J. M. Guerrero, "Optimal sizing of a lithium battery energy storage system for grid-connected photovoltaic systems," in *2017 IEEE Second Int. Conf. DC Microgrids (ICDCM)*, June 2017, pp. 582–587.

[136] A. Escalera, E. D. Castronuovo, M. Prodanović, and J. Roldán-Perez, "Reliability assessment of distribution networks with optimal restoration based on distributed generation, energy storage and demand management," *submitted*, 2019.

[137] Y. Zhou, P. Mancarella, and J. Mutale, "Modelling and assessment of the contribution of demand response and electrical energy storage to adequacy of supply," *Sustain. Energy Grids Netw.*, vol. 3, pp. 12 – 23, 2015.

[138] S. Wang, Z. Li, L. Wu, M. Shahidehpour, and Z. Li, "New metrics for assessing the reliability and economics of microgrids in distribution system," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2852–2861, 2013.

[139] M. Moeini-Aghtaie, H. Farzin, M. Fotuhi-Firuzabad, and R. Amrollahi, "Generalized analytical approach to assess reliability of renewable-based energy hubs," *IEEE Trans. Power Syst.*, vol. 32, no. 1, pp. 368–377, Jan 2017.

[140] P. Wang and W. Li, "Reliability evaluation of distribution systems considering optimal restoration sequence and variable restoration times," *IET Generat., Transm. Distrib.*, vol. 1, no. 4, pp. 688–695, July 2007.

[141] Econnect Ltd, "Islanded operation of distribution networks," Distributed Generation Coordinating Group (DGCG), Tech. Rep., 2005.

[142] L. H. Macedo, J. F. Franco, M. J. Rider, and R. Romero, "Optimal operation of distribution networks considering energy storage devices," *IEEE Trans. Smart Grid*, vol. 6, no. 6, pp. 2825–2836, Nov 2015.

[143] A. Escalera, M. Prodanović, E. D. Castronuovo, and J. Roldán-Perez, "Contribution of active network management technologies to distribution system reliability," *submitted*, 2019.

[144] L. F. Ochoa, C. J. Dent, and G. P. Harrison, "Distribution network capacity assessment: Variable DG and active networks," *IEEE Trans. Power Syst.*, vol. 25, no. 1, pp. 87–95, Feb 2010.

[145] C. Long, J. Wu, L. Thomas, and N. Jenkins, "Optimal operation of soft open points in medium voltage electrical distribution networks with distributed generation," *Applied Energy*, vol. 184, pp. 427 – 437, 2016.

[146] W. Cao, J. Wu, N. Jenkins, C. Wang, and T. Green, "Benefits analysis of soft open points for electrical distribution network operation," *Applied Energy*, vol. 165, pp. 36 – 47, 2016.

[147] Y. He, "Study and analysis of distribution equipment reliability data," ELFORSK, Tech. Rep., March 2010.

[148] J. Zhu, *Optimization of Power System Operation*, 1st ed. New Jersey: John Wiley & Sons, Inc, 2009.

[149] E. A. K. Strunz and et.al, "Benchmark systems for network integration of renewable and distributed energy resources," Cigre Task Force C6.04.02, Tech. Rep., May 2013.

[150] M. E. Baran and F. F. Wu, "Network reconfiguration in distribution systems for loss reduction and load balancing," *IEEE Trans. Power Del.*, vol. 4, no. 2, pp. 1401–1407, April 1989.

[151] S. Golshannavaz, S. Afsharnia, and F. Aminifar, "Smart distribution grid: Optimal day-ahead scheduling with reconfigurable topology," *IEEE Trans. Smart Grid*, vol. 5, no. 5, pp. 2402–2411, Sept 2014.

[152] C. Wang, G. Song, P. Li, H. Ji, J. Zhao, and J. Wu, "Optimal siting and sizing of soft open points in active electrical distribution networks," *Applied Energy*, vol. 189, pp. 301 – 309, 2017.

Appendix A

Reliability Indices of Distribution Networks

This appendix describes and defines indices typically used to evaluate the reliability of distribution systems according to IEEE Guide for Electric Power Distribution Reliability Indices [21]. The indices presented here only measure sustained interruptions longer than a set specific value (for example, 5 minutes in [21]).

A.1 Preliminary Definitions

The following terms and parameters are defined in advance to facilitate the understanding of reliability indices:

- Load point is the element of the distribution network where customers are connected and, therefore, power consumed.
- The subscript i identifies the load points in the network.
- N_i denotes the number of load points in the network area evaluated.
- Nc_i is the number of customers connected to load point i.
- Ncs_i is the number of different customers connected to load point i that are interrupted.
- The subscript j identifies an interruption event.
- TPI_j is the installed capacity to supply the customers interrupted by event j.
- TP is the total installed capacity to supply the customers.
- $\hat{r}_j$ is the interruption duration of event j.

A.2 Reliability Indices Classification

Fig. A.1 shows the classification of reliability indices used in this thesis. Load point and area reliability indices are separately treated. The former measure the reliability of a load point, while the latter do it for an entire network or a network area.

In addition, the area reliability indices have been classified to three categories according to the measured variables: customer interruptions, non-supplied load and interruption cost.

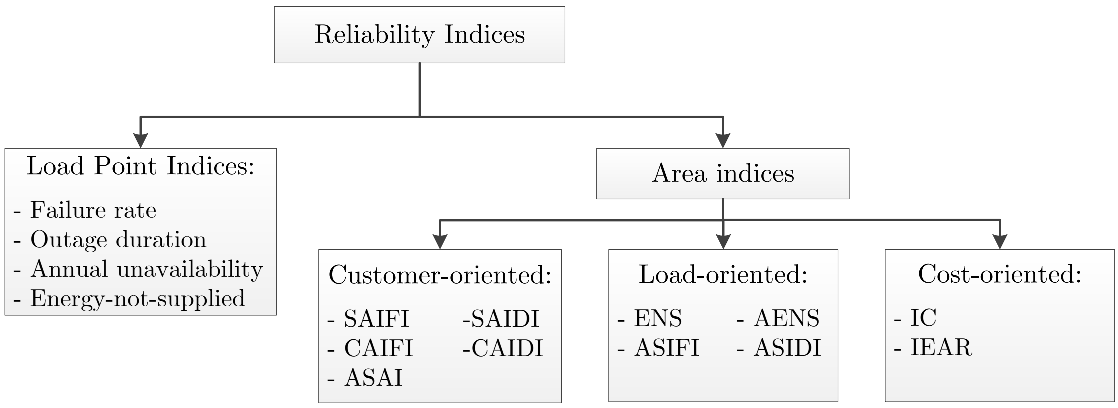


Figure A.1: Classification applied for reliability indices

A.3 Load Point Reliability Indices

The following indices are used to measure the reliability of network load points:

- Failure rate λ_i: is the number of interruptions experienced by a load point, expressed in number of interruptions per year.

- Outage duration r_i: represents the average duration of the interruptions in a load point, in hours of interruption per failure.

- Annual unavailability U_i: is the annual interruption time, measured in hours of interruption per year.

- Average energy-not-supplied ENS_i: is the annual energy interrupted in a load point as a consequence of network failures.

A.4 Area Reliability Indices

A.4.1 Customer-orientated Indices

SAIFI: System Average Interruption Frequency Index

The SAIFI indicates how often the customers experience interruptions over a year. It is calculated as:

$$SAIFI = \frac{Total\ number\ of\ customers\ interrupted}{Total\ number\ of\ customers\ served} = \frac{\sum_{i=1}^{N_i} \lambda_i Nc_i}{\sum_{i=1}^{N_i} Nc_i}. \tag{A.1}$$

This index is quantified in average number of interruptions per customer and year.

SAIDI: System Average Interruption Duration Index

The SAIDI measures the average duration of interruptions per customer over a year and is calculated as:

$$SAIDI = \frac{Total\ duration\ of\ customers\ interruptions}{Total\ number\ of\ customers\ served} = \frac{\sum_{i=1}^{N_i} U_i Nc_i}{\sum_{i=1}^{N_i} Nc_i}. \tag{A.2}$$

The units are hours of interruption per customer and year. Also, it is common to use minutes instead of hours.

CAIFI: Customer Average Interruption Frequency Index

The CAIFI indicates the frequency of interruption events considering only those customers affected by the interruptions.

$$CAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ different\ customers\ interrupted} = \frac{\sum_{i=1}^{N_i} \lambda_i Nc_i}{\sum_{i=1}^{N_i} Ncs_i}. \tag{A.3}$$

The units are number of interruptions per customer affected and year.

CAIDI: Customer Average Interruption Duration Index

This index represents the average time required to restore the service. It is calculated as:

$$CAIDI = \frac{Total\ duration\ of\ interruptions\ in\ customers}{Total\ number\ of\ customers\ interrupted} = \frac{\sum_{i=1}^{N_i} U_i Nc_i}{\sum_{i=1}^{N_i} \lambda_i Nc_i}. \tag{A.4}$$

The units are hours (or minutes) of interruption per customer interrupted and year.

ASAI: Average Service Availability Index

The ASAI measures the fraction of time that a customer have been supplied during a period of time. This index is typically measured in percentage and is calculated as:

$$ASAI = \frac{Customer\ hours\ service\ availability}{Customer\ hours\ service\ demand} = \frac{\sum_{i=1}^{N_i} Nc_i\ (Hyear - U_i)}{\sum_{i=1}^{N_i} Nc_i\ Hyear}. \tag{A.5}$$

where $Hyear$ indicates the number of hours in a year.

A.4.2 Load-orientated Indices

ENS: Energy Not Supplied

This index represents the energy interrupted and not supplied to customers. It is calculated by aggregating the energy-not-supplied to each load point (ENS_i) as Equation A.6 shows. The units are energy (e.g. MWh) per year.

$$ENS = \sum_{i=1}^{N_i} ENS_i \tag{A.6}$$

AENS: Average Energy Not Supplied

The AENS measures the average energy-not-supplied to a customer in the system. The unit is energy per customer and it is calculated as:

$$AENS = \frac{Total\ energy\ not\ supplied}{Total\ number\ of\ customers\ served} = \frac{ENS}{\sum_{i=1}^{N_i} Nc_i}. \tag{A.7}$$

ASIFI: Average System Interruption Frequency Index

This index measures the equivalent load interrupted as a proportion of the installed load in the evaluated area. The installed power is used for the calculation instead of the number of customers, this being the main difference compared to SAIFI index.

$$ASIFI = \frac{Total\ connected\ kVA\ of\ load\ interrupted}{Total\ connected\ kVA\ served} = \frac{\sum_j TPI_j}{TP}. \tag{A.8}$$

ASIDI: Average System Interruption Duration Index

The ASIDI index is calculated by using the same principle as SAIFI but it is based on load rather than customers. The mathematical expression for its calculation is:

$$ASIDI = \frac{Total\ connected\ kVA\ duration\ of\ load\ interrupted}{Total\ connected\ kVA\ served} = \frac{\sum_j \hat{r}_j\ TPI_j}{TP}. \tag{A.9}$$

A.4.3 Cost-orientated Indices

IC: Interruption Cost

The Interruption Cost represents the economic losses caused by the interruption events occurring in the network. This index aggregates the interruption costs of all the network load points (IC_i):

$$IC = Total\ cost\ of\ interruptions = \sum_{i=1}^{N_i} IC_i. \tag{A.10}$$

Typical units are \$/year.

IEAR: Interrupted Energy Assessment Rate

The IEAR indicates the average cost per unit of energy interrupted in the system. It is calculated as in Equation A.11 and typical units are \$/kWh.

$$IEAR = \frac{Total\ cost\ of\ interruptions}{Total\ energy\ not\ supplied} = \frac{IC}{ENS}. \tag{A.11}$$

Appendix B

Additional Information on the Test Distribution Systems Used for the Evaluation

This appendix describes the details for two of the distribution systems used for the evaluation in this thesis, called as Bus 6 of Roy Billinton Test System and Feeder c72. These systems are described in this section as they are used in several of the case studies presented in the thesis. The appendix gathers information required for the reliability assessment.

B.1 Bus 6 RBTS

The Bus 6 of Roy Billinton Test System is a MV rural distribution network typically used to test methodologies for reliability assessment. The system is described in [121]. In this section, the network information necessary for the reliability assessment is presented.

The network topology is shown in Fig. B.1. It is formed by four radial feeders, designed as F1, F2, F3 and F4, and 40 load points. Feeders F1, F2 and F3 are operated at a voltage of 11 kV, while feeder F4 at 33 kV. Feeders F1 and F2 can be reconnected by the Normally-Open Point designed as NOP in Fig. B.1.

The Bus 6 has a peak load of 20 MW and delivers power to agricultural, residential, small industrial and commercial customers. Network load data is provided in Table B.1.

The failure rates and repair times of network components are shown in Table B.2. These values have been obtained by taking the data from [122] as reference. The failure rates of power lines are expressed as a function of the line lengths. The lengths of the feeder sections are shown in Table B.3, where *Id of the feeder section* corresponds to the number of the sections marked in Figure B.1.

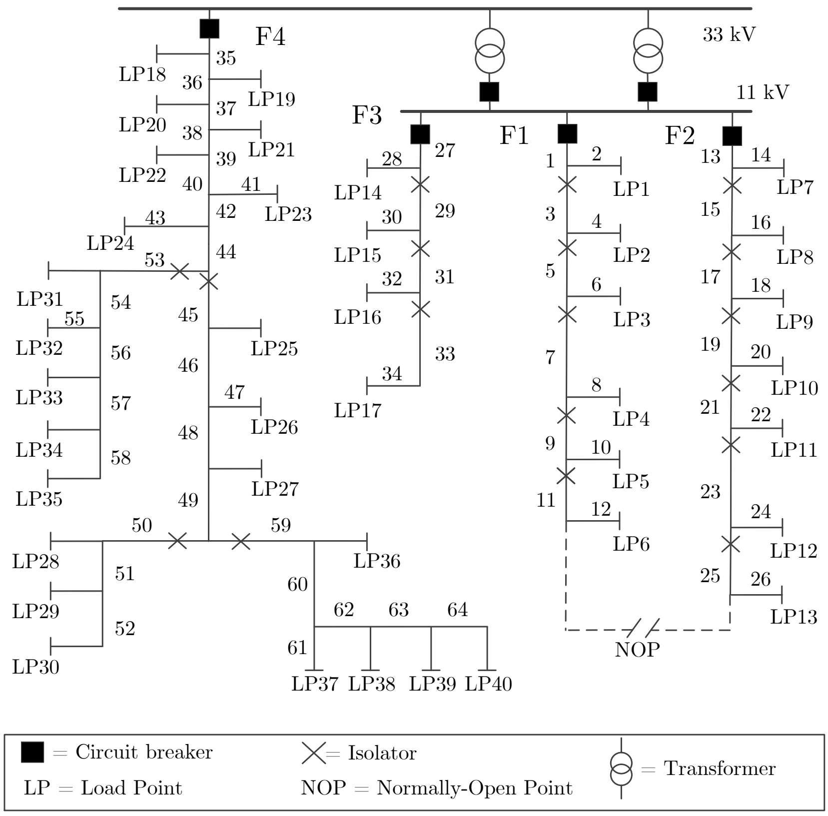


Figure B.1: Single-line diagram of Bus 6 from Roy Billinton Test System

Table B.1: Data of the load points in Bus 6 system (load in MW)

Load points	Customer type	Peak load	Average load	Number of customers
1,3,9	residential	0.3171	0.1775	138
2,4,11,19	residential	0.3229	0.1808	126
5,6	residential	0.3864	0.2163	118
7,8,10,18,23	residential	0.2964	0.1659	147
12,13,22	residential	0.3698	0.2070	132
25,28,31,36	residential	0.2776	0.1554	79
27,29,33,39	residential	0.2831	0.1585	76
14,17	commercial	0.8500	0.4697	10
15	small	1.9670	1.6391	1
16	small	1.0830	0.9025	1
32,37	farm	0.5025	0.1929	1
20,30,34	farm	0.6517	0.2501	1
21,35	farm	0.6860	0.2633	1
24,40	farm	0.7965	0.3057	1
26,38	farm	0.7375	0.2831	1

Table B.2: Data of failures in network components

Component	λ	r
transformers	failures/year	hours/failure
33/11 kV	0.15	15
11/0.415 kV	0.15	10
lines	failures/year km	hours/failure
33 kV	0.046	8
11 kV	0.065	5
cables	failures/year km	hours/failure
11 kV	0.04	30

Table B.3: Length of feeder sections in Bus 6 system

Id of the feeder section	Length (km)
2 3 8 9 12 13 17 19 20 24 25 28 31 34 41 47	0.6
1 5 6 7 10 14 15 22 23 26 27 30 33 43 61	0.75
4 11 16 18 21 29 32 35 55	0.8
38 44	0.9
37 39 42 49 54 62	1.6
36 40 52 57 60	2.5
35 46 50 56 59 64	2.8
45 51 53 58 63	3.2
48	3.5

B.2 Feeder c72

Feeder c72 system corresponds to a 11 kV radial distribution network located in Spain. The topology of the system is shown in Fig. B.2.

The network is formed of 24 load points. The number of customers per load point is shown in Table B.4, while the average power demand over a year is depicted next to each load point in Fig. B.2 and expressed in MW.

Reliability indices of network components were assumed to be equal to those shown in Table B.2 for Bus 6 system. All the power lines were aerial with lengths in kilometres as depicted in Fig. B.2.

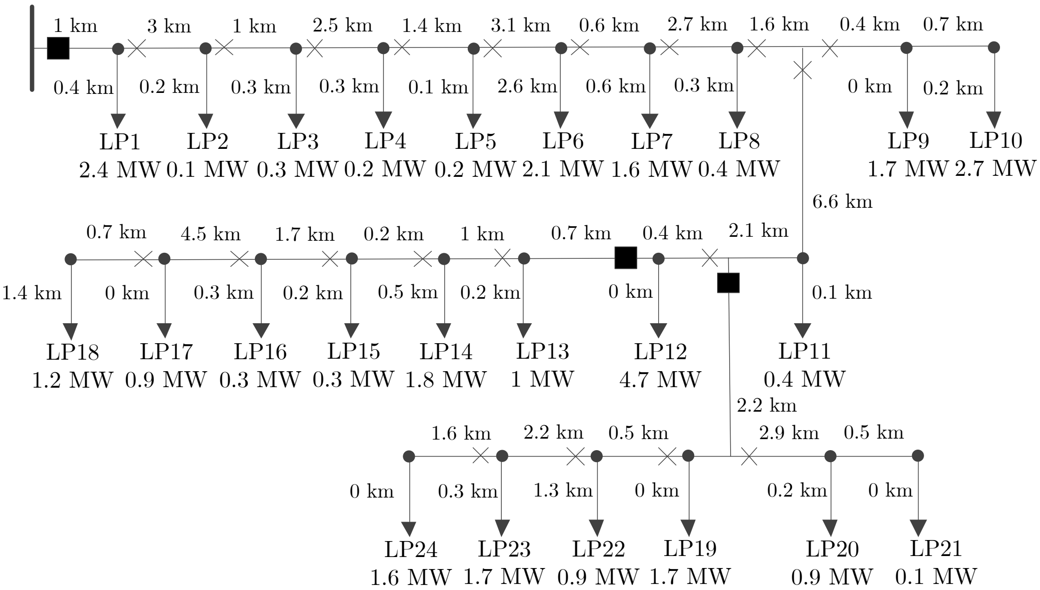


Figure B.2: Single-line diagram of Feeder c72

Table B.4: Number of customers per load point for Feeder c72 system

Load point	Customers	Load point	Customers	Load point	Customers
1	245	9	171	17	92
2	11	10	273	18	117
3	26	11	43	19	171
4	21	12	544	20	85
5	21	13	97	21	7
6	213	14	184	22	85
7	160	15	26	23	171
8	43	16	32	24	160