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Stine Fleischer Myhre

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Doctoral thesis

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Norwegian University of Science and Technology
Thesis for the Degree of
Philosophiae Doctor
Faculty of Information Technology and Electrical
Engineering
Department of Electric Power Engineering

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Trondheim, May 2023

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Preface

The presented research in this thesis was carried out at the Norwegian University of Science and Technology (NTNU) in the Department of Electric Power Engineering. The work started in August 2019, and my main supervisor has been Professor Olav Bjarte Fosso with Dr. Oddbjørn Gjerde and Professor Poul E. Heeegaard as co-supervisors.

The work was a part of work package 1 *smart grid development and asset management* at FME CINELDI. The funding for the work was provided by CINELDI - Centre for Intelligent Electricity Distribution, an eight-year Research Centre under the FME-scheme (Centre for Environment-Friendly Energy Research, 257626/E20). The financial support for the centre was provided by the Research Council of Norway and the CINELDI partners.

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My gratitude goes to CINELDI for letting me be a part of this big and interesting project. I would like to thank the people in Work Package 1 in CINELDI Oddbjørn Gjerde, Iver Bakken Sperstad, Inger Anne Tøndel, Eivind Solvang, and Susanne Sandell to make me feel welcome in the work package.

I would like to thank all my colleagues at NTNU for the good work environment and for making me feel at home at work, where a big thank you goes to Bodil Vuttudal Wold for your great work for the department. Furthermore, I will especially thank my good office mates Marthe Fogstad Dynge and Ugur Halden. Furthermore, I will reach a big thank you to the extended EMPS Ph.D. group for taking me in and being my work family, Kasper Emil Thorvaldsen, Marthe Fogstad Dynge, Matias Vistnes, Aurora Flataker, Sigurd Bjarghov, Linn Emelie Schaffer, Ugur Halden, Erik Bjørnerem, Emil Dimanchev, Runar Mellerud, Luke Whittington, and Kjersti Berg. Additionally, I would like to thank Sjur Føyen, Jalal Khodaparast, Chendan Li, Salman Zaferanlouei, and Paula Bastos Garcia Rosa for taking care of a new Ph.D. student when I first arrived at the department. Additionally, I will express my deepest gratitude to Gro Klæboe, you have been a great mentor, colleague, and friend. Thank you for being there for me, believing in me and supporting me during this time. You have been of great support and a wonderful friend to talk to.

In the end, I would like to thank my family for the endless support and encouragement to make my own path. I would like to thank my siblings for being there for me during my long stay here in Trondheim, you will finally get me home. Lastly, my greatest gratitude goes to my partner, Jonas. I believe I would not have been able to get through the Ph.D. without your support.

Summary

The electrical power system is under constant development, and multiple changes will occur in the upcoming years, leading to a more intelligent and active system with the integration of ICT, distributed generation, and flexible resources. The increased complexity obtained through the modernization of the power system raises a pressing need for appropriate tools and approaches to assess the power system's reliability.

As a response, the RELSAD—RELiability tool for Smart and Active Distribution networks, a framework constructed as a reliability assessment tool for calculating and evaluating the reliability of modern distribution systems, is proposed in this thesis. RELSAD is an extensive tool, developed as a Python package and published in the Journal of Open Source Software (JOSS), that takes the new behavior and components in the distribution system into account. The complexity of traditional as well as Cyber-Physical Distribution Systems (CPDS) is modeled in the tool through a highly customizable object-oriented framework. The developed sequential Monte Carlo simulation tool facilitates the reliability assessment of complex systems with a great level of detail.

Three studies addressing important aspects seen in modern distribution systems have been conducted using the developed simulation tool:

1. In the first study, an investigation of a distribution network with an embedded microgrid including renewable energy sources and a battery was conducted. The study addressed how the microgrid affects the reliability of both the distribution network and the microgrid when the microgrid participates actively during outages in the system. The reliability is evaluated based on variations of microgrid placement, operation mode, and battery capacity. Additionally, the study includes a comprehensive sensitivity analysis to map how the microgrid battery capacity, power line repair time, and power line failure rate affects the reliability from both system perspectives. The study results in a suggestion for optimal conditions for minimizing the impact on the microgrid while maximizing the contributions to the distribution system. Additionally, it emphasizes the that the reliability impact of the microgrid is highly dependent on system size and load priority.

2. The second study investigated the impact of Vehicle-to-Grid (V2G) on the reliability of a modern distribution network. The study proposes new reliability indices that aim to highlight the impact on the EVs in the network when they are providing V2G services. Additionally, a comprehensive sensitivity study of the reliability indices is conducted to analyze the reliability impacts. The results revealed that EVs can offer good reliability support for failures that result in short outages of the system. The sensitivity analysis

demonstrated that the charging capacity and the number of available EVs in the network have a great impact on the reliability support. The proposed indices provided valuable insight from the EV perspective and illustrated that an EV was expected to be used rarely and for relatively short periods during a year, resulting in low wear on the battery of the EVs.

3. The third study investigated the impact on the reliability of a CPDS in terms of survivability quantification. The results from this study show clear reliability improvements in the distribution system when ICT was implemented. However, the study also illustrated that the reliability could be worsened when the ICT system did not function properly.

The developed reliability assessment tool has many possible applications related to the evaluation of distribution system reliability as illustrated in the performed case studies. The development and open-source publication of RELSAD lay the foundation for further open and transparent research improving the reliability assessment of modern distribution systems. By sharing the source code publicly, RELSAD can be validated and further developed by researchers and users, resulting in a higher-quality tool.

Contents

Abbreviations

AD Anderson-Darling

ASAI Average Service Availability Index

ASUI Average Service Unavailability Index

BFS Breadth-First-Search

CAIDI Customer Average Interruption Duration Index

CENS Cost of Energy Not Supplied

CPDS Cyber-Physical Distribution System

DFS Depth-First-Search

DG Distributed Generation

DMS Direct Management System

DSO Distribution System Operator

ENS Energy Not Supplied

EU European Union

EV Electric Vehicle

FBS Forward-Backward Sweep

FMEA Failure Mode and Effects Analysis

HILP High Impact Low Probability

ICT Information and Communication Technology

IED Intelligent Electronic Device

IQR Interquartile range

JOSS The Journal of Open Source Software

KS Kolmogorov-Smirnov

MCS Monte Carlo Simulation

Non-SMCS Non-sequential Monte Carlo Simulations

NR Newton-Rapson

OPF Optimal Power Flow

PV Solar Photovoltaic

RBTS Roy Billinton Test System

RELRAD RELiability in RADial Systems

RELSAD RELiability tool for Smart and Active Distribution networks

RES Renewable Energy Resources

SAIDI System Average Interruption Duration Index

SAIFI System Average Interruption Frequency Index

SMCS Sequential Monte Carlo Simulations

SoC State of Charge

SoS Security of electricity Supply

TTF Time To Failure

TTR Time To Repair

V2G Vehicle-to-Grid

1 Introduction

This chapter provides the background and motivation for the work performed in this thesis. Furthermore, the research questions and objectives are discussed and the contributions of this thesis are elaborated. The publications that are the main work behind the contributions are listed and named. These will be used subsequently for referring to the publications. Lastly, the outline of the thesis is presented.

1.1 Background and Motivation

The electrical power system is under constant development, and multiple changes will occur in the upcoming years [1, 2]. Figure 1.1 illustrates a representation of how the electrical power system is developing into a more intelligent and active system. The traditional electrical power system has been solely hierarchical with centralized power production where the power is transferred in one direction from the bulk generation over the grid layers to the end user. In December 2019, the European Commission presented the European Green Deal, the goal of which is to make the European Union (EU) climate-neutral by 2050 [3]. With this, the focus on reducing green gas emissions is strong. As a response to becoming climate-neutral, renewable energy sources (RES) such as solar and wind power are being integrated into the power systems [4, 5]. In May 2022, the EU presented the EU Solar Energy Strategy [6]. The aim of the strategy is to end the dependency on fossil fuels from Russia and as such achieve 320 GW of solar photovoltaic (PV) by 2025 and 600 GW by 2030. These sources are often integrated into the distribution network, resulting in a more decentralized generation compared to traditional bulk energy generation. Additionally, rooftop PV is estimated to be able to provide 25% of EU's electricity consumption [6, 7]. This will directly affect the distribution network and the security of supply of the system.

Additionally, through the mission to become climate-neutral by 2050, an increase in electrification is taking place in Europe [8]. For instance, the transport sector is being electrified. As a part of this, multiple countries have initiated measures to ban the sale of new carbon-emitting passenger cars. In the UK, the sale of petrol and diesel cars is planned to end by 2030 [9], the EU is planning to ban the sale by 2035 [10], while in Norway only zero-emission cars are to be sold from 2025 [11]. This will result in a higher share of Electric Vehicles (EVs) on the road and at customer sites. According to a study conducted by The Institute of

Transport Economics, EVs will constitute on average 45.9-61.2% of all cars by 2030 in Norway [12]. However, the share of EVs might differ between the different regions in the country, resulting in some parts with a high share and others with a lower. In addition, end users are becoming prosumers by using local production capacity such as PV and battery installations at the end user sites [13]. All of these changes transform the distribution system to become more decentralized, complex, and dynamic with a bidirectional flow of power [14, 15].

To meet the requirements of the distribution system, the system is becoming smarter with the increased implementation of Information and Communication Technology (ICT) components. This is also illustrated in Figure 1.1 where a cyber layer is added to the whole power system. The integration of ICT systems is predicted to be the key enabler for the future power systems [16], where the introduction of ICT will lay the foundation for more intelligent systems and the transition to smart grids. The smart grid shift aims to make the power systems more reliable, robust, efficient, flexible, and resilient, in this way, increase the reliability of the system [16]. Additionally, this will enforce faster electrification as an important factor to reach the green shift. The implementation of ICT allows for systems where smart monitoring and control are possible with a system that can be operated through automation. This can enhance possibilities for the active operation of the system, control and utilization of flexible resources and energy storage, and automatic fault handling.

With the integration of ICT, the distribution systems become Cyber-Physical Distribution Systems (CPDS) – A system defined by both a cyber and a physical part [17]. This makes the distribution system more complex where dependencies between the different layers will arise. The distribution system will depend on the ICT system to function correctly to ensure that the system is operating safely, while the ICT system will depend on electrical power from the grid. An example of cascading failures of interconnected systems such as a CPDS is illustrated in the electrical blackout that affected Italy in September 2003 [18]. Here, the shutdown of power stations led to the failure of nodes in the ICT system, which in turn caused a shutdown of the power stations. This illustrates the importance of understanding the new complexity of the distribution system.

All of these developments are contributing to changes in the power system. The increased complexity of the system requires system operators to observe the network in different manners to ensure a safe operation of the network and to uncover vulnerabilities in the system. Additionally, with new technology as described and the desire to reduce system costs, the system will operate closer to its limits. This transforms the distribution system into a modern system. A modern distribution system is in this thesis defined to be an active and smart distribution system [19]. An active distribution system is a system that is able to utilize and control the sources in the system. A smart distribution system is able to perform intelligent monitoring, control, and communication by utilizing integrated ICT systems [19].

It will be important to understand the complexity of the system and utilize the system components in a smart and active manner for better operation of the power system. For reliability purposes, we need to develop appropriate tools and approaches to assess the reliability of the evolved and complex distribution system. The modern distribution system is constituted by a great variety of component types, and the integration of these components with their behavior and how they affect the distribution system needs to be considered to assess the reliability of the system. In [20], a survey on reliability assessment techniques for modern distribution systems is presented and discussed. The survey concludes that there is a need for new methods that consider the interconnection of the system and are able to fully assess the reliability of modern distribution systems. It will, therefore, be necessary to find an approach that takes the new components, their behavior, and the increased complexity of the distribution system into account.

As a response, this thesis proposes a framework constructed as a reliability assessment tool for calculating and evaluating the reliability of modern distribution systems. The work consists of an extensive tool that takes the new behavior and components in the distribution system into account. The complexity of the system and the CPDS is considered and modeled in the tool. Generation units and flexible sources such as RES, batteries, microgrids, and EVs are implemented where the possibility of active participation of these sources is included. Additionally, the possibility of analyzing distribution systems with integrated ICT systems and components is implemented.

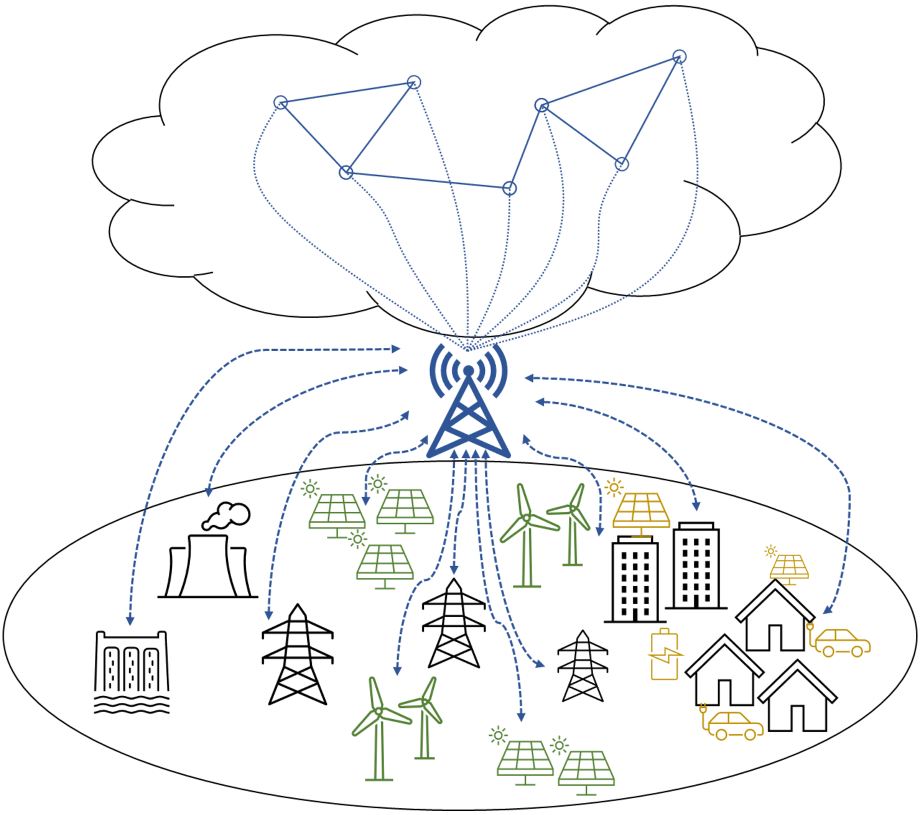


Figure 1.1: The evolution of the electrical power system to a modern power system. The shift from a fully centralized and hierarchical structure toward a more modern power system. Implementation of renewable energy sources, flexible energy sources such as batteries and electric vehicles, and ICT components.

1.2 Research Questions and Objective

The main research question of this Ph.D. thesis is:

How to assess and calculate the reliability of modern distribution systems with higher complexity and more automation where active and smart participation of components such as flexible resources and ICT components occurs?

The presented research question has further been divided into three parts:

1. How to calculate the reliability of smart and active distribution systems

with increased complexity?

2. How will active participation of components such as microgrids, distributed generation, and flexible sources impact the reliability of the future distribution network?

3. How will ICT systems and components impact the reliability of the future distribution network?

The research questions have resulted in the main objective of this thesis, which is to *develop a reliability assessment tool for modern distribution systems*, laying the basis for the contributions to this work. The main focus of the thesis is to develop a framework for reliability assessments of modern distribution systems. Additionally, the framework has been tested on cases that aim to answer the main objectives from different angles.

1.3 Contributions

The research questions have laid the foundation for the contributions of this Ph.D. work. A major contribution of this thesis is *the development and verification of an independent simulation tool for reliability assessment of modern distribution systems*. An important contribution of the developed reliability assessment tool is new knowledge and insights regarding the reliability of smart and active distribution networks. The simulation tool is designed to handle the following complex features of the modern distribution system:

- Inclusion of active component participation in the network that allows for a more dynamic and active distribution network.
- Inclusion of ICT systems and components that allows for modeling of complex CPDS with the new system behavior and dependencies in the system.

Three studies addressing important aspects seen in modern distribution systems have been conducted using the simulation framework. The studies are:

1. An investigation of a distribution network with an embedded microgrid. The study addresses the reliability from both the distribution network and the microgrid perspective where the microgrid participates actively during outages in the system. The distribution system with the embedded microgrid is developed to replicate a realistic and modern distribution system. This is done systematically by gathering data for the system through procedures where the reliability data is based on statistics from the Norwegian

distribution systems. The reliability is evaluated based on varying the location of the microgrid, operation mode, and battery capacity. Additionally, the study includes a comprehensive sensitivity analysis to map how the microgrid battery capacity, power line repair time, and power line failure rate affects the reliability from both system perspectives.

2. An investigation of the impact of V2G on the reliability of a modern distribution network. In the study, a realistic and modern distribution system is modeled with a dynamic load profile and EVs. The reliability data is based on reliability statistics from the Norwegian DSO and the availability data and the share of EVs in the network was calculated based on statistics and scenario-based analysis of the future EVs in Norway. The study proposes new reliability indices that aim to highlight the impact on the EVs in the network when they are providing V2G services. Additionally, a comprehensive sensitivity study of the reliability indices are conducted to analyze the reliability impacts.

3. An investigation of the impact of a CPDS in terms of survivability quantification. In this study, a CPDS is designed to evaluate how ICT components and networks impact the reliability of a modern distribution network. The reliability of the CPDS is evaluated using RELSAD where ICT components and systems are modeled with their behavior and dependencies. A stochastic survivability simulation approach is implemented to capture the variations in the system parameters when analyzing the reliability of the CPDS. The results is evaluated through reliability indices and survaivability quantifications.

All the listed contributions are presented in this thesis. The developed simulation framework facilitates the reliability assessment of complex systems with a great level of detail. The presented studies display how embedded microgrids and V2G can improve the distribution network reliability and how the reliability of the ICT components affects the reliability of the power system.

1.4 List of Publications

The research and results from this work have been submitted for publication in different scientific journals. These publications constitute the foundation of this work. The main publications of this thesis are listed below and will be referred to as Papers I, II, and III.

I S. F. Myhre, O. B. Fosso, P. E. Heegaard, and O. Gjerde, “RELSAD: A Python package for reliability assessment of modern distribution systems”, in *Journal of Open Source Software (JOSS)*, vol. 7, p. 4516, oct. 2022. DOI: 10.21105/joss.04516

II S. F. Myhre, O. B. Fosso, O. Gjerde, and P. E. Heegaard, "Reliability Assessment for Distribution Systems with Embedded Microgrids", arXive, 2023. Under review. DOI: 10.48550/ARXIV.2111.07674

III S. F. Myhre, O. B. Fosso, O. Gjerde, and P. E. Heegaard, "A Study on V2G impact on the Reliability of Modern Distribution Networks", arXive, 2023. Under review. Under review. DOI: 10.48550/ARXIV.2302.10069

In addition, two other papers have been written and published on topics related to the thesis. However, they are not included as own contributions since the developed tool was not used in these studies. One of the papers, however, has contributed to one of the case studies that will be presented later in this thesis:

- S. F. Myhre, O. B. Fosso, P. E. Heegaard, O. Gjerde, and G. H. Kjølle, "Modeling Interdependencies with Complex Network Theory in a Combined Electrical Power and ICT System", in *16th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), 2020.* DOI: 10.1109/PMAPS47429.2020.9183667
- M. Vistnes, S. F. Myhre, O. B. Fosso, and V. V. Vadlamudi, "A Monte Carlo Method for Adequacy Assessment of Cyber-Physical Distribution Systems", in *17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), 2022.* DOI: 10.1109/PMAPS53380.2022.9810570

1.5 Outline of the Thesis

This thesis is divided into three main parts. First, in Chapter 2, a theoretical foundation related to the reliability evaluation of distribution systems is presented. Additionally, the concept of Cyber-Physical Distribution Systems is discussed. The second part constitutes Chapter 3, in which the developed reliability assessment framework for modern distribution systems is outlined. The third part addresses the performed case studies where the developed reliability assessment tool is used as a basis for the reliability calculation. The studies address some of the presented objectives and contributions. The case studies are presented in Chapter 4, Chapter 5, and Chapter 6. In Chapter 7, a conclusion with suggested potential further work is presented.

2 Theoretical Foundations and State-of the-Art

This chapter presents the fundamentals and the state-of-the-art related to the reliability assessment of distribution networks. The chapter discusses how modern distribution systems might behave and outlines how to assess the reliability of modern distribution networks. First, traditional reliability methods of distribution systems are presented, divided into analytical approaches and simulation. Then, the operation of modern distribution systems is presented and reliability methods for modern distribution systems are discussed. Finally, the complexity of cyber-physical distribution systems is introduced and methodologies related to describing the complexity and the new dependencies is presented.

2.1 Traditional Reliability Methods for Distribution Networks

Distribution system reliability assessment is typically load-point oriented. This is related to the common tree structures of the distribution networks, which are often operated radially or weakly meshed, where the downstream load points of a failure experience the biggest impact. The reliability of power supply to a customer in a distribution network can be measured by how possible interruptions impact the customer and the Distribution System Operator (DSO) during fault conditions in the network. With the increased penetration of DGs and ICT components in the distribution systems, outages might have a greater impact on the rest of the system, and in some cases, the outages can be more severe due to the system's complexity. Reliability assessment of distribution networks is important to make design decisions that minimize the risk of unwanted events.

Two commonly used approaches for analyzing the reliability of the distribution system are 1) analytical approaches and 2) simulation, particularly Monte Carlo simulation (MCS) [21]. The analytical approaches use simplified models with averaged quantities to estimate the reliability indices. The analytical models are generic and can be applicable to multiple cases. MCS, however, allows for a more detailed representation of the reliability indices by generating reliability indices through numerous independent instances including stochastic variations.

In this section, the traditional reliability assessment methodologies are discussed. It distinguishes between analytical approaches and MCS and presents the commonly used methods within the two approaches.

2.1.1 Analytical Approaches

In analytical approaches, complex models or methods are broken down into parts for a better understanding of the problem as a whole [21]. The evaluation of the distribution system reliability can be based on a mathematical representation of the problem where average values of the system parameters and the reliability indices are used. One of the major advantages of analytical approaches is the low computational time of the reliability evaluation. Analytical approaches are traditionally more commonly used by engineers for reliability assessment due to the low computational time and simple approach. In many scenarios, the analytical approaches are suitable for performing the reliability assessment, making it the preferred approach [21].

The most commonly used strategies for reliability assessment of distribution systems are state-space diagrams, failure mode and effects analysis (FMEA), event trees, fault trees, and minimal cut sets [22]. The methods use different approaches to evaluate the reliability of a distribution network. In this section, the most important methods are described in more detail. Further information can be found in [21, 22].

State-Space Diagrams and Markov Models

The power system components can be in several operating states. Based on the component type, typical states are: normal operating state, failed, open, closed, and undergoing repair. The possible operating states for the power system are all the different combinations of the system component operating states. The transition from one state to another, e.g., when a power line goes from a normal operating state to a failed state, is a stochastic process with a certain probability of occurring.

Markov models are models of a stochastic nature where the processes have the Markov property, meaning that the conditional probability law of the future process behavior only depends on the present state [23]. By possessing this property, the system process evolution can be described by a starting state and its conditional probability laws, regardless of how the system arrived at the starting state.

State-space diagrams represent the system based on all possible operating states. The transitions between states are modeled as Markov processes, and the state space diagram is often referred to as the Markov diagram. Figure 2.1 illustrates a simple Markov model comprising three different states and the transitions between them. The state space diagrams with the defined transitions make way for calculating system metrics such as reliability indices [22].

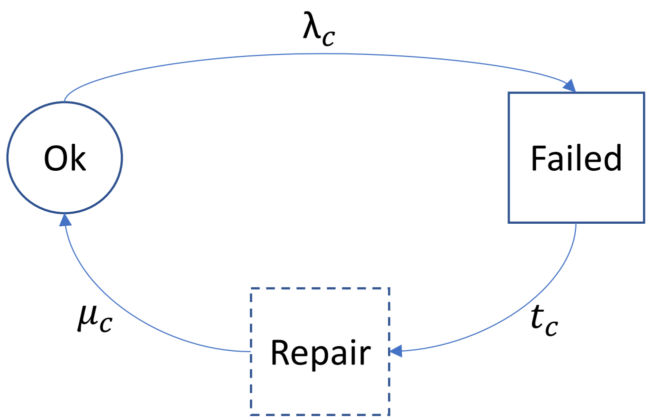


Figure 2.1: A simple Markov model with three different possible component states. λ_c is the failure rate of component c, μ_c is the repair rate of component c, and t_c is the time from component failure until the component is under repair.

Failure Mode and Effects Analysis (FMEA)

The FMEA is a systematic strategy that is based on *what ifs*. This can be used to identify all the possible failure modes in a system with their causes and consequences [22]. FMEA identifies the failure state that occurs independently for each component in the system iteratively where the failure is repaired before the approach identifies the next. During the procedure of identifying the failure states, the effects on the system and the customers in the system can be evaluated and used to calculate reliability indices.

The main advantage of FMEA is the method's ability to give a detailed description of the behavior of a failure in the distribution system while evaluating the consequences of different failure modes in the system. The disadvantage of FMEA is the method's repetitive pattern, which makes it is hard to assess the consequence of multiple failures. [22]

Fault Trees and Event Trees

When considering the reliability of a power system, we are interested in both how an outage event can occur and how the system can recover from the outage.

Fault trees and event trees may be used to assess these issues [22, 24]:

- **Fault trees**
  Fault trees are tree structures representing the potential ways that, for example, an interruption in a power system can occur. The fault tree reveals how vulnerable the load points in a power system are in terms of faults in the system. Reliability indices regarding interruption frequency and outage time duration can be calculated by using fault trees.

- **Event trees**
  Event trees are tree structures representing the possible scenarios initiated by a fault. The event tree reveals both how severe the fault potentially may become, and how to recover from the fault most effectively. Reliability indices regarding outage time duration can be calculated by using event trees.

Minimal Cut Set Method

Another commonly used method for the reliability assessment of distribution systems, both radially operated and meshed systems, is the minimal cut set method. This method is often used in combination with other methods such as fault trees [22]. In a minimal cut set, the individual load points are analyzed by building up the system of small sets that cannot be reduced further without missing information. Figure 2.2 illustrates a small system with six buses. The power is transferred from bus 1 to bus 6 through the other buses. For bus 6 to be supplied one of the three paths (the minimal cut sets)

1. Path 1: bus 1 - bus 2 - bus 6
2. Path 2: bus 1 - bus 3 - bus 4 - bus 6
3. Path 3: bus 1 - bus 5 - bus 6

needs to be functioning. The load point reliability in the minimal cut set is assessed by considering which component in the system influences the given load point resulting in an outage of the load point.

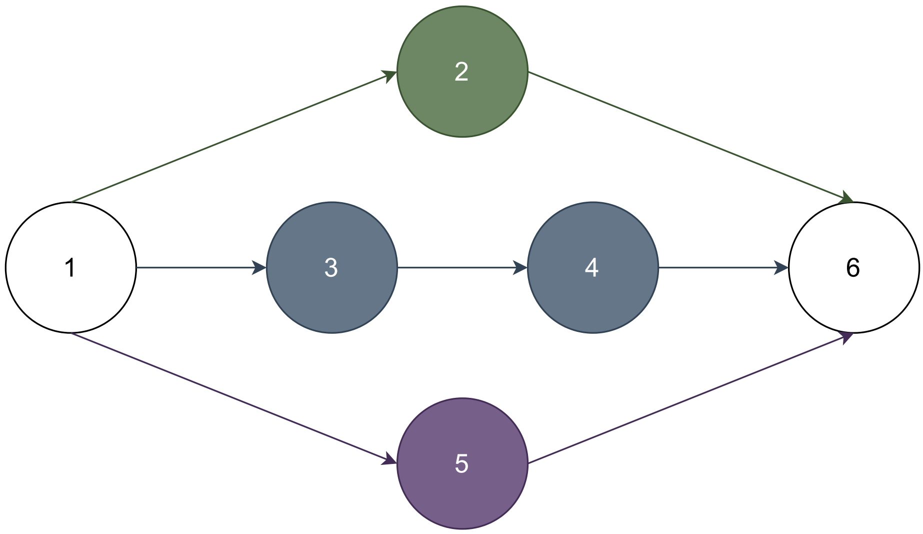


Figure 2.2: An example of a small network where one of three paths need to be functioning in order for bus 6 to be supplied.

RELiability in RADial Systems (RELRAD)

In [25], an analytical method for reliability assessment of radially operated distribution systems, RELRAD —RELiability in RADial systems, has been developed. The main focus of RELRAD is to assess which load points are affected when a given component in the system fails. The individual load point reliability indices are calculated based on the fault contributions from all the network components. In this way, RELRAD connects the component failure to load point outages. RELRAD differs from the minimal cut set as RELRAD investigates which components lead to interruptions whereas minimal cut sets assess the individual load points directly by the cut sets. Instead of using the cut set, the effects of component failures can be linked to the different load points in a table.

The RELRAD approach for calculating reliability indices is:

1. Locate which components lead to an interruption in the system.
2. Accumulate the reliability indices for each component that leads to an interruption for a load point. Repeat this for all load points.
3. Calculate the reliability indices for each load point and for the system.

2.1.2 Monte Carlo Simulation

Monte Carlo simulation is a simulation model that uses random variables to predict different outcomes based on probability. The technique allows for detailed investigations based on statistical distributions where the impacts and uncertainties on a system can be estimated [21]. The main advantage of MCS compared to analytical approaches is the ability to evaluate the stochastic nature of complex systems. Analytical approaches often rely on averaged quantities, decreasing the level of detail, while Monte Carlo approaches handle detailed inputs. However, the MCS can be time-consuming since it requires a high number of iterations per simulation to achieve results that converge.

The MCS methods are mainly divided into two classifications [21]:

1. **Sequential Monte Carlo simulation (SMCS)**
In an SMCS, the states such as the up and down state of the different components in the system are simulated chronologically following a timeline. The state of the components is often represented by a two-state model as seen in the state space diagram in Figure 2.3. However, it is possible to represent the state of a component with more than two states. The period of the component state is often represented through Time to Failure (TTF) and Time to Repair (TTR). The TTF represents the duration the component is in the Up state where the component is working, while TTR represents the duration the component is in the Down state where the component is not working. A timeline-based simulation with the state transition is illustrated in Figure 2.4 where the TTF and TTR are shown. The states will then be dependent on the previous state. The system behavior is modeled as it occurs in reality where a sequence of random events that can be dependent on the previous event, progresses through the simulation time. An SMCS facilitates the investigation of dependencies between states and multiple independent contingencies at the same time increment. This makes the evaluation of complex and realistic systems with a high level of detail possible. An SMCS is performed for a given number of iterations to obtain reliable statistical distributions of the simulation results. The disadvantage of an SMCS is that it can be very time-consuming.

2. **Non-sequential Monte Carlo simulation (Non-SMCS)**
In a non-SMCS, however, the states such as presented in Figure 2.3 of a component in the system are simulated randomly. There is no concept of time and the period of simulation is reproduced a given number of times. The contingencies that will occur in the system are determined prior to the simulation start and are randomly selected based on probabilities. The result of the simulation is then obtained by simulating the states separately where all the events are assumed to be mutually exclusive.

Investigation of power system reliability involves modeling stochastic outage behaviors with impact varying from single components to entire network sections. The severity of the outages is closely linked to the demand levels during the outage events. In analytical approaches, where average quantities typically are used, the level of detail might be insufficiently captured. MCS methods are well suited for these types of problems. In addition to modeling the problem with a high level of detail, the resulting statistical distributions obtained by the MCS methods make way for a more detailed understanding of the system behavior. The MCS method maps the system behavior for all types of iterations, from the worst-case scenarios to the best-case scenarios.

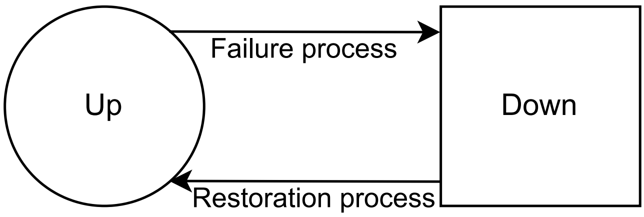


Figure 2.3: State space diagram of a component illustrating the transition (failure and restoration process) of the two states for the component.

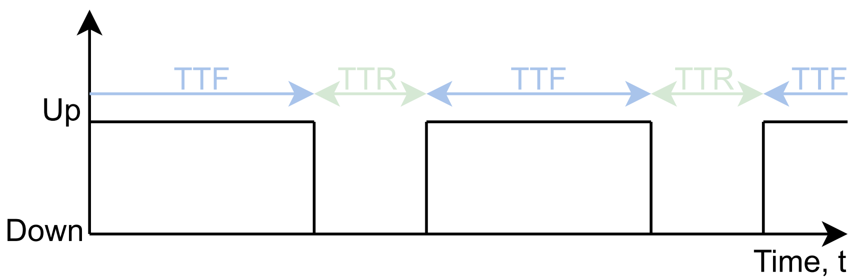


Figure 2.4: Simulated timeline illustrating the transition between up and down states of a component in the system with Time to Failure and Time to Repair.

2.2 Reliability of Modern Distribution Systems

In a more modern distribution system, the methods of assessing the distribution system reliability change. With the modern distribution network, the way of operating the system might differ. For distribution networks with higher penetration of DGs, flexible resources, and ICT, the components can be utilized better during outages in the system and by that support the system. This section will describe how fault handling of modern distribution networks can be operated and discuss reliability assessment methods for the future distribution network.

2.2.1 The Reliability Evaluation of the Future Distribution Networks with Generation Sources

In a traditional radially operated passive distribution network with the one-way transfer of power, as seen in Figure 2.5a, a failure of, for example, a line in the network, will result in all the downstream load points being isolated from the main power source unless there is an alternative supply route. In Figure 2.5b, a failure has occurred on a line in the distribution network and has been isolated. This results in the load points, highlighted in the red dotted box, downstream of the failed line to be isolated from the rest of the distribution network. Since there is no alternative supply route or any generation unit in this area, these load points will not be supplied until the failure is repaired and the line reconnected.

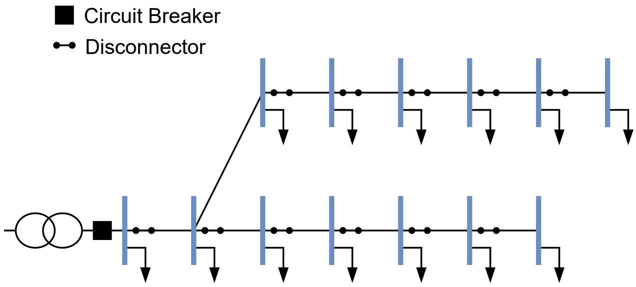
However, for modern distribution networks, this might change. If there is a generation unit of some sort (microgrid, battery, distributed generation, flexible resources, and so on) present in the network, the fault situation can change. By using the available sources and flexibility present in the system, some load might be restored and other problems such as low voltage and bottlenecks can be avoided. The idea is that the sources can then support the system in two different modes: 1) *isolated operation* and 2) *grid-connected operation or supportive operation.*

Isolated operation

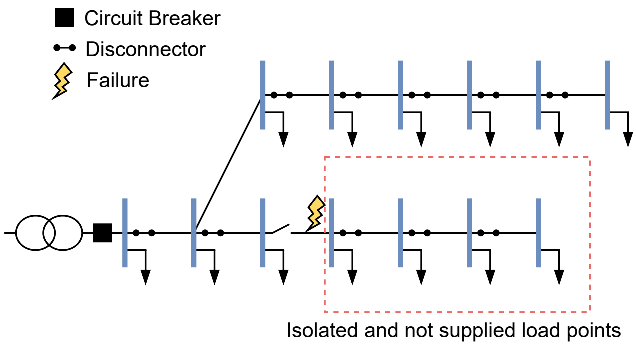
If a failure occurs on, for example, a line in the distribution system, as seen in Figure 2.6a, the downstream load points will be isolated from the overlaying network and traditionally these load points will not be supplied. However, if a generation source is present in this isolated part of the network, at least parts of the supply can be restored. The source will then operate in an island mode during the outage time of the system. When the failure is repaired, the isolated part can be reconnected to the overlying grid again. In this operation, the source must be able to withhold the balance in the system along with the frequency and voltage levels in the isolated part of the network.

Supportive operation

Normally, in distribution systems, some alternative supply chains might exist that can be used to redirect power in the network in case of outages. If possible,



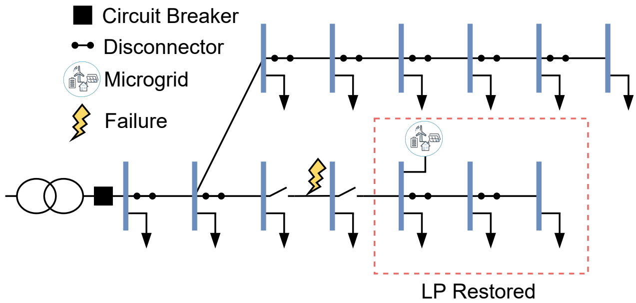
(a) Traditional radially operated distribution system



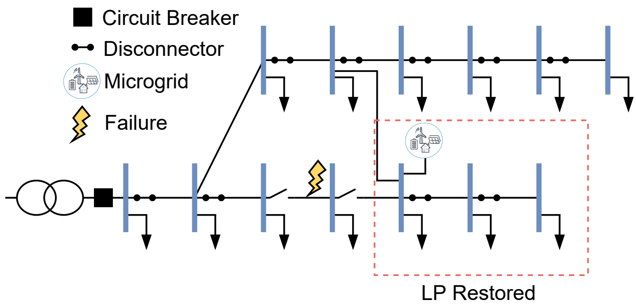
(b) Traditional radially operated distribution system with a failure on a line

Figure 2.5: Illustration of possible fault handling of passive distribution networks.

the backup line can be connected and help supply loads in the system in areas that would have been isolated during the outage. However, some of these lines have low capacity limits and might end up being congested, or they might end up creating bottlenecks in the network. Local generation sources of flexible sources in the distribution network might alleviate congestion and bottlenecks and help with voltage problems in the system. Figure 2.6b illustrates how a generation source can support the system during a fault in the system. The load points could have been restored with only the connection of the alternative line, but the source is now able to support the system with local production.



(a) Supply restored with microgrid for island mode with isolated part of the distribution system



(b) Supply restored with alternative supply chain and microgrid support

Figure 2.6: Illustration of how a fault situation can be handled in a modern distribution network. The microgrid represents all kinds of generation sources and flexible sources.

2.2.2 Reliability Approaches for Modern Distribution Systems

The distribution network has become modernized and is becoming more active and smart. An active distribution network is a network including different distributed energy sources such as DGs, loads, and energy storage that can utilize and control these sources. Whereas, a passive distribution network is only a part of the traditional bulk power system. A smart distribution network can, among other features, perform intelligent monitoring, control, and communications, and makes self-healing mechanisms possible [19,26]. These features are made possible by the implementation of ICT in the power system.

It is difficult to fully represent the behavior of modern distribution systems with a general mathematical representation. The dynamic behavior and variations in the system can be challenging to model. Analytical reliability assessment methods are most applicable for the analysis of passive systems where a simplified representation of the system is sufficient. Systems with high complexity are harder to represent in this manner. The analytical approaches are limited in the sense that they involve several important simplifications. The analytical methods are frequency-based, limiting the level of detail since averaged quantities are often used. The lack of time discretization often leads to the use of averaged loading values at the load points. By averaging the load levels, we also average the severity of each outage. Furthermore, Distributed Generation (DG) is typically modeled with averaged generation values, where the variational aspect of the generation behavior is lost. While the analytical approaches are less detailed than simulations, they are less computationally expensive. A simulation approach can be more suitable for evaluating complex systems of a stochastic nature. However, the fundamentals of the methods are strong, and with adjustments, they can be utilized for modern networks as well.

In the literature, DGs have been proven to improve the reliability of distribution networks [27–30]. Analytical approaches have been suggested for investigating the reliability impact of DGs on distribution systems where the common strategy is as discussed in this section, where the DG supports load points in islanded operation or supports the network during congestion [27–30]. Early research has been performed to assess this, with analytical approaches designed to investigate the potential impact DG has on the distribution network [27,28]. However, these studies consider DG with given output power where all the load in the island needs to be restored. In [29,30], analytical approaches are developed to assess the reliability of a distribution network containing dispatchable and non-dispatchable RES. In both [29, 30], they allow for a frequency-based variation in the output power of the DG and load to better account for the behavior of the components.

Probabilistic modeling of energy storage systems is proposed in [31], where an analytical approach for reliability evolution of RES-based energy systems is developed. Furthermore, in [32] the impact of mobile energy storage systems on the distribution system reliability is assessed. Here, both an analytical approach based on Markov models and a MCS-based model are developed for the reliability assessment. Microgrids are flexible resources that can be used for reliability improvement of modern distribution networks. One of the benefits of utilizing a microgrid is that it is designed to be an independent system and will therefore have already implemented control strategies for system operation. In [33, 34], an analytical approach is developed to assess the contribution of a microgrid to the reliability of a distribution system. The contribution of the microgrid is determined based on the ratio between the demand and supply from the microgrid.

MCS has been one of the most widely used methods to assess the reliability of modern distribution systems. This is due to the advantage of better representing the stochastic nature of the system and modeling the active and smart components, which make it easier to describe the new behavior of the system. In [35,36], a non-SMCS method is developed to assess the reliability of more complex distribution systems. Some studies have proposed an SMCS approach for reliability assessment of modern distribution networks [36–39].

Different approaches to assess the reliability of generation units are found in the literature. In [30, 40], Markov models with multiple states have been used to model the stochastic behavior of generation technologies such as wind power, solar power, and batteries, to assess their impact on the reliability of modern distribution systems. In [41], a detailed stochastic model is developed to capture the effects of various insolation levels that can be experienced on a PV panel. An analytical multi-state model is developed in [42] to assess the reliability of DG. Furthermore, in [43–46], frameworks for assessing the reliability of distributed generation and energy storage are proposed. In [47], an MCS approach is developed for assessing the reliability of distribution networks including microgrids.

Load flow analysis is a methodology that gives the opportunity to describe the electrical behavior of the system during different operation states, including failures in the network. In a reliability assessment methodology, load flow calculations can be included to map the current state of the distribution system and illustrate how a modern distribution system behaves under different operation states. Load flow calculations are included in [48, 49], where reliability assessment of modern distribution networks including DGs and EVs are considered. Additionally, optimization can be used to find optimal conditions. In [50], optimal placement of energy storage for increased reliability of modern distribution systems is assessed through a mixed integer problem.

In the research, there is still a need for a complete reliability assessment method for an integrated evaluation of modern distribution networks that comprehends the increased system complexity [20]. Often, assumptions are made about the system behavior, and most of exsisting studies focus on the reliability of the generation sources, as illustrated in this section. To evaluate the reliability of a modern distribution network, a model of the network that includes the integrated smart and active compnents is required. This includes modeling the dependencies and the behavior of the system. One challenge is to model the complexity of the system. The right assumptions about the system's behavior and the consequence of failures in the system need to be made to correctly model the system.

This thesis aims to answer the highlighted issues by providing an independent simulation tool in which the system complexity, behavior, dependency, and components are considered. Compared to previous studies, this thesis brings forward a transparent and fundamental reliability assessment tool applicable for evaluating the reliability of many different cases. The reliability assessment tool can easily be further improved and built upon.

2.2.3 Cyber-Physical Distribution Systems

With the integration of ICT and the shift to smarter grids, distribution systems are transforming into Cyber-Physical Distribution Systems (CPDS). With CPDS, the complexity of the system increases as now its behavior is defined by both the physical power system and the cyber system, making it a system-of-systems [17]. Along with the system-of-systems behavior, the complexity of the system increases with newly arisen dependencies and interdependencies in and between the systems. Interdependency is defined as *a bidirectional relationship between two infrastructures in which the state of each infrastructure influences or is correlated to the state of the other* [51]. In a CPDS, such dependencies will arise.

To perform a reliability assessment of CPDS, the behavior of the system needs to be defined. This can be challenging since there can be multiple scenarios that result in undefined outcomes of the system. In literature, the complexity of the systems is often investigated separately, and little research has been performed to evaluate the combined system [52, 53]. However, there exist multiple methods that can be used to find both the dependencies and interdependencies of CPDS.

In [52], an overview of methods that can be used to model and identify interdependencies of CPDS is given. Markov modeling is a commonly used strategy to illustrate the possible operating states and the transition between the states of a system. Markov modeling is a stochastic modeling approach that uses the probability values of the states to predict the future behavior of the system. In [54], dependencies between the systems in a cyber-physical power system are modeled by using Markov models.

An agent-based model is a computational model that simulates the actions and interactions of *agents*—an agent can represent a component in the system, to model the behavior of a system. The agent-based model has been used to model and analyze physical and cyber-attacks on cyber-physical systems in [55]. Petri nets are a graphical and mathematical modeling approach that uses different nodes to describe the system states and transitions [56]. The relations and interdependencies of the system can be characterized by direct arcs that illustrate the run from a place to a transition. Petri nets are used to model coordinated cyber-physical attacks of smart grids in [56]. Whereas in [57], Petri nets have been used to model the security and resilience of cyber-physical systems. In [58], the interdependencies and the ICT impact on the distribution system are modeled by combining stochastic activity networks and numerical analysis.

Another approach to investigate the behavior of interdependent systems is through complex network theory or graph theory. In complex network theory, the system is described through graphs that consist of edges/links and vertices/nodes that can illustrate the physical interactions and interdependencies in a CPDS.

In [59], graph theory is used to investigate the importance of the system nodes of a CPDS. In [60], graph theory is utilized to model the interdependency of a cyber-physical power system related to cascading failures.

Fault trees and reliability block diagrams are other approaches that can be applied to identify and describe different causes of faults in a CPDS. A reliability block diagram can be made based on fault trees. In a reliability block diagram, the combinations of components needed to perform a system function are illustrated. In [61], the reliability assessment of a CPDS is assessed based on fault trees. The fault tree is modeled to establish the impact the cyber layer has on the CPDS.

The described methods can also be combined with MCS. Additionally, Monte Carlo can be used as a tool to model the complexity of CPDS. In [38], a MCS tool is developed to quantify the adequacy of a CPDS. The methodology gives a better understanding of the impact the complexity and interdependencies have on the system's adequacy. Whereas in [62] and [63], a non-sequential MCS model is developed for the reliability assessment of CPDS.

3 Reliability Assessment Tool for Modern Distribution Networks—RELSAD

This chapter is based on Paper I. Paper I consitutes the basis of this thesis and accounts for the most considerable contribution. This chapter presents the developed reliability assessment tool for modern distribution systems. First, the chapter introduces the reliability assessment tool and the reason for developing this tool. Second, the structure of the tool is presented. Third, the core functionality and the procedures in the tool are described. Implemented reliability indices and proposed new indices are outlined before a brief section aiming to validate the tool is presented.

3.1 Introduction

To calculate the reliability of future smart and flexible distribution systems, an appropriate method is needed. The traditional approaches will not be able to utilize the full potential of the active components in the distribution system and a form of simulation approach will be more advantageous. Since the active components interact with the distribution system based on multiple independent factors, such as failures and weather conditions, the simulation of their impact on the distribution system must cover all possible scenarios. An MCS approach, which makes use of a random sampling of inputs, is well suited for this type of problem.

Therefore, RELSAD—RELiability tool for Smart and Active Distribution networks—was developed in this Ph.D. work. RELSAD is a reliability assessment tool for modern distribution systems with a SMCS model. SMCS was chosen to allow for multiple failures to occur simultaneously. The reliability assessment tool aims to facilitate reliability calculation and analysis for the DSO. RELSAD was developed to give a foundation for the reliability assessment of modern distribution systems where the changed behavior and the increased complexity in the distribution network are considered. RELSAD uses the same load point-oriented approach for calculating the reliability indices as RELRAD. In addition, RELSAD considers the active participation of components such as microgrids, distributed generation, batteries, and ICT components. In Figure 3.1, an overview of the RELSAD model is illustrated. RELSAD is constructed to take input attributes such as attributes related to topology, reliability, and specifications for the different components. The output of RELSAD is various reliability index distributions. All of the stages in RELSAD will be described in this section.

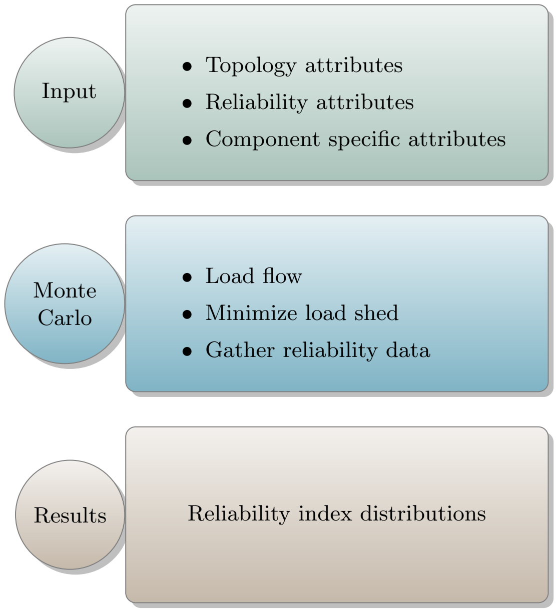


Figure 3.1: Overview of the RELSAD model. A full description can be found in the software documentation [64].

RELSAD is a Python-based reliability assessment tool that aims to be a foundation for the reliability calculation of modern distribution networks. RELSAD is fully developed by the author as a part of this thesis and is the core and main contribution of this work. RELSAD has been submitted and approved as an open tool software to The Journal of Open Source Software (JOSS) [65]. The tool and documentation are open and available at GitHub [66]. Additionally, a fully thorough documentation page for the tool has been written and can be found in [64]; an example of usage is added in the appendix of this thesis (see. Appendix A. The documentation page contains the installation description, example of usage, background information, and the API of the tool.

The main contributions of RELSAD is listed as follows:

1. RELSAD is implemented as a general reliability assessment tool for modern distribution networks. The active and smart participation of different sources and components in the system is considered and the behavior of a modern distribution system is modeled. RELSAD is developed to be user-

friendly and is made provision for easy implementation of other features in the tool.

2. The availability of new generation sources is increased through the implementation of RES and flexible resources such as batteries. With more distributed generation, an active distribution system can be achieved by utilizing and controlling these sources. In an active distribution system, the network can be pushed to work closer to its limits where the flexibility of DG can be used during situations in the network. With a network working closer to its operation limits, the DSO risk more frequent faults in the system. However, in an active distribution system, the sources in the network can be utilized to support during faults and in that sense help to maintain the security of supply in the network. RELSAD provides suitable and flexible features for modeling the behavior of a variety of active distribution systems. The tool facilitates investigations of how active participation of flexible resources and DG impacts the security of supply in the network.

3. The integration of ICT components in the distribution system facilitates increased automation, monitoring, and control of the system. This gives the DSO the opportunity to among others perform faster fault detection and isolation of faults, automatic switching, and self-healing. ICT also enhances the opportunities to control active components and the behavior of the system. This results in a smart and quickly adaptive system that can work closer to the operating limits of the network. However, the complexity of the system increases. With a complex system working closer to its limits, faults occurring in the system might become more severe. RELSAD is designed to investigate the complex integration of ICT components into the distribution system. By this, the severity of faults in complex systems can be analyzed extensively, providing better foundations for network operation and development planning.

RELSAD provides some of the following opportunities:

- Distributions of important reliability indices from representative samples of instances for the scenario of interest. The distributions facilitate detailed investigation of the uncertainty and variation of the reliability indices for the modeled scenarios, and can be used to increase understanding and improve decision making.
- Option for investigation of network sensitivities involving different parameters such as repair time, failure rate, load and generation profiles, placement of sources, and component capacities and how they impact the system reliability.
- Implementation and investigation of diverse and advanced network constellations spanning from small passive distribution systems to large active

networks including DGs, batteries, microgrids, and ICT where the networks are operated radially.

- Investigation and analysis of the reliability of Cyber-Physical Networks for generic topologies and constellations.

To be able to evaluate the reliability of a complex system, the components and the systems must be modeled along with the behavior and the dependencies that can occur between components in the systems. The challenge of modeling complex systems is acquiring the ability to fully comprehend the complexity so that the right assumptions about the behavior and dependencies are made during the different scenarios the system can encounter. Through RELSAD, we aim to answer this by providing an open-source tool that can simulate the reliability of such distribution systems independently. In RELSAD the system complexity, components, behavior, and dependencies in the system are considered. The motivation behind RELSAD is to give the community, scientists, and network operators the ability to make their own network and use RELSAD as a tool to simulate different reliability outcomes of their system. The vision for RELSAD is to create a starting point to fulfill the request for a transparent reliability assessment tool for modern distribution networks.

3.2 Tool Structure

RELSAD is constructed in an object-oriented fashion, where the systems and system components are implemented with specific features simulating their real-life behavior. The networks and the system components can be grouped into two categories, namely electrical and ICT. In Figure 3.2, the overall class structure of the tool is illustrated. This section aims to present the structure of the tool where the implemented networks and the components in RELSAD are described. The presentation of the tool structure addressed how the network and system component classes are implemented. In the documentation, an example of usage and how to construct a system with different networks and components is illustrated (see: [67]). The description of how a system is constructed with information about how to run and analyze the provided system can be seen in Appendix A.

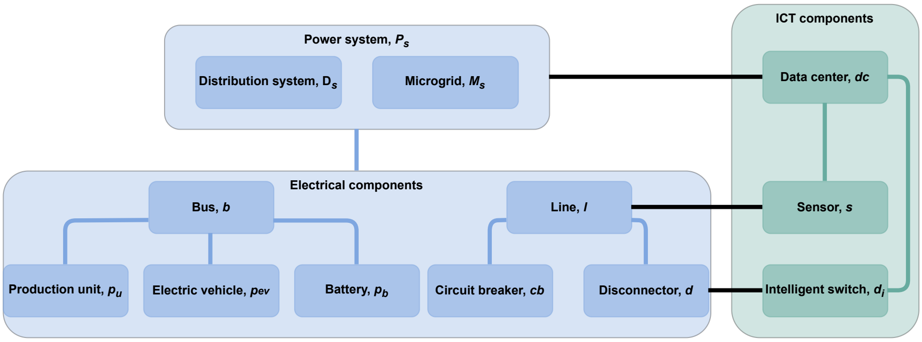


Figure 3.2: Structure over the electrical power networks.

3.2.1 Electrical Power Network

RELSAD implements the power system in a hierarchical manner, where the different network types are gathered into an overall power system. The overall power system represents the entire system as an entity. The system hierarchy in RELSAD is as follows:

1. Power system, P_s
2. Transmission system, T_s
3. Distribution system, D_s
4. Microgrid, M_s

Figure 3.3 illustrates the electrical power system structure in RELSAD, where a power system, P_s, is the parent network of all the other networks in the system. In this section, the different electrical power networks presented in Figure 3.3 are described.

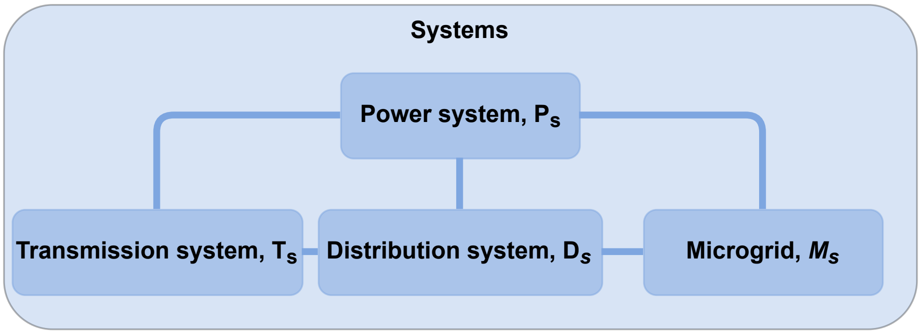


Figure 3.3: Overview of the network and component structure in RELSAD.

Transmission Network—Overlying Network

Since RELSAD is a tool for modern distribution networks, the focus of prior research has primarily been on integrating and evaluating distribution networks. As a result, the transmission network and the interconnection between a distribution network and a transmission network or an overlying distribution network have not been emphasized.

In RELSAD, the connection between a distribution network and the overlying network is solved by implementing a simplified transmission network that simulates the basic features of an overlying network. The simplified transmission network is represented by a bus in the system that aims to imitate the transformer station between the distribution network and the overlying network. The underlying distribution networks are connected to the transmission system through a power line.

Distribution Network

In RELSAD, one or multiple distribution networks can be constructed. The structure of the distribution networks is based on the components such as buses and lines in the network. A distribution network is created by adding the associated components. When constructing a distribution network, the user can decide if the distribution network should be connected to an overlying network or work as an isolated network.

- **With overlying network**:
  The overlying network must be specified as the parent network (the overlying network) of the distribution system. The line connecting the distribution network to the overlying network is defined as the connected line. The connected line illustrates the connection to the substation connecting

the distribution network to the overlying network.

- **Isolated network**:
  Distribution networks that are not connected to an overlying network will function similarly to microgrids and need to be self-sufficient to meet the demand in the network.

Microgrid

Microgrids are implemented as an additional network type. A microgrid is constructed similarly to the distribution network and can be constructed to be connected to an overlying network, for example, a distribution network, or to work in an isolated mode without any overlying network. The main feature that separates a microgrid from a distribution network is the implementation of microgrid modes. The microgrid modes are controlled through a created controller for the microgrid. In RELSAD, three different modes are constructed (these will be discussed in Chapter 4). In the future, it will be possible to construct several microgrid modes.

3.2.2 ICT Network

The ICT network is a network type that handles communication between ICT components. The network is constructed with a similar structure to the electric power network types in RELSAD, where the ICT network is built up by ICT nodes and lines. The main task of the network is to transfer ICT signals between the different ICT components in the system. The user can choose two ways of modeling the ICT network, an idealized version and a fallible version.

- **Ideal ICT network**:
  The structure of the ICT network is ignored, assuming that all ICT components are connected flawlessly. In this case, no ICT network definition must be performed by the user.

- **Fallible ICT network**:
  The ICT network is constructed with specified ICT nodes and lines. The ICT components in the system are connected to each other through the network. In this case, the signal communication between ICT components may fail if ICT nodes or lines connecting the components have failed. Otherwise, transferring ICT signals will be faultless. The ICT communication is implemented in a simplified manner, where a signal is considered to be successfully transmitted if there is a path between the communicating ICT components. A depth-first-search (DFS) algorithm is used to validate if a valid path between the communicating ICT components exists (a more

detailed description is given in Section 6.1).

3.2.3 Electrical Power Components

The structure of the electrical power components can be seen in Figure 3.4. This section briefly presents the implementation of these components.

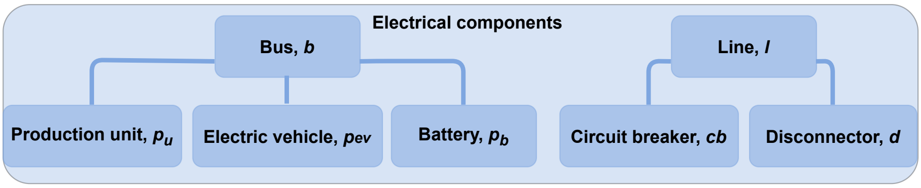


Figure 3.4: The electrical power component structure i RELSAD

Electrical Power Bus

The electrical power buses are modeled to imitate a typical power substation. The buses are used to connect the power lines of the system and to contain components such as generation units, batteries, EV parks, and ICT nodes. To simulate the substation behavior, multiple types of attributes are implemented:

- **Topology attributes**:
  Electrical power lines connected to the bus and spatial coordinates.
- **Power flow attributes**:
  Power flow attributes used to perform power flow calculations are implemented. This includes active and reactive load or a generation unit at the bus, voltage magnitude and angle, apparent power reference, active and reactive losses, etc.
- **Reliability attributes**:
  A number of customers related to the bus, failure rates, and repair times related to the transformer are modeled. The repair time is specified as chosen repair time distribution. All the reliability attributes can be specified by the user.

The electrical buses in the system can contain a load. The load is specified by the user and can either be constant or time varied. For time-varying loads, the load at a bus can be allocated through an array containing the load for each time increment. In RELSAD, the simulation timeline is calculated based on user-specified values for time increment, start time, and end time. Load profiles that do not match the chosen simulation timeline are interpolated linearly to fit the timeline.

Multiple load types can be added to the buses. These can be load types such as household, industry, municipal buildings, etc. The load type is specified by the user. In addition, the specific interruption cost related to the different customer categories can be specified. Otherwise, the default value for the specific interruption cost is 1.

Generation Unit

In RELSAD, the generation units are implemented generically, meaning that the tool does not consider the type of generation source, only the amount of generated power. A bus in the system can contain multiple generation units. Some implemented generation unit attributes are:

- **Topology attributes**:
  The bus the generation unit is connected to.
- **Generation unit data**:
  Active and reactive power generation, active and reactive power limits on the generation unit. These attributes can be set by the user.

The amount of generation for a generation unit is defined similarly to the specification of a load on a bus. The generation can either be constant or time varied. For a time-varying generation, an array containing the generation for each time increment can be added. In addition, for generation profiles that do not match the simulation timeline, the generation will be interpolated linearly to fit the timeline.

Battery

A battery is implemented either to charge, discharge, or do nothing in a time step. The charging or discharging of a battery in a time step is limited by the power balance in the system, the inverter capacities for the battery, and the stored energy in the battery. The State of Charge (SoC) at a time t

$$SoC_t = \frac{E_{bat,t}}{E_{cap}} \tag{3.1}$$

indicates the level of charge of a battery relative to the battery capacity, E_{cap}. The SoC can be limited between a selected minimum and maximum SoC that restricts the SoC to not going below or exceeding these limitations. The energy stored in the battery at time t

$$E_{bat,t} = E_{bat,t-1} + \eta_{charge} P_{charge,t} \Delta t - \frac{P_{disch,t}}{\eta_{disch}} \Delta t \tag{3.2}$$

changes based on the charging, P_{charge}, and the discharging, P_{disch}, of the battery at time t during the time step, Δt. The charging and discharging are limited by the battery efficiency.

Some of the implemented battery attributes are:

- **Topology attributes**:
  The bus the battery unit is connected to.
- **Battery data**:
  The modeled battery-related attributes include active and reactive power charged or discharged by the battery, active and reactive charging/discharging limits for the battery, battery specifications such as maximum battery capacity, minimum and maximum allowed SoC values, and battery efficiency. The battery specifications and limitations can be decided by the user.

In addition, the battery has some implemented modes to work with the controller of the microgrid which is described in Chapter 4.

Electric Vehicle

A model of electric vehicles (EVs) is implemented in RELSAD. The EVs are implemented as an additional type to the batteries. This is in order to include the option of simulating systems with vehicle-to-grid (V2G) possibilities. An EV can be connected to a bus in the system and together with other implemented EVs on the same bus, form an EV park for that given bus. The functionality of the EV park is to aggregate the vehicles at a bus into a park for each bus in the system. The number of EVs on a bus can be specified by the user. An EV park is modeled to build up an aggregated battery solution with the available vehicles specified on each bus in the system. Figure 3.5 illustrates this aggregated battery solution for the EV park at a bus.

There are implemented multiple attributes for the EV park, some of them are listed as follows:

- **Topology attributes**:
  The bus the EV park is connected to.

- **Battery attributes**:
  An EV park is modeled similarly to a battery in RELSAD. The same battery attributes apply to the EV park. Battery specifications for each EV in the park and the specifications for the park can be decided by the user.

- **EV park data**:
  The EV park contains information on the number of EVs in the park, availability distribution of vehicles in the park, and a flag indicating if V2G is activated or not.

- **Reliability attributes**:
  For EVs, an availability distribution that gives the amount of available EVs in an EV park can be specified. Attributes for calculating EV-related indices are included. These attributes are related to the experienced interruption of a vehicle, the duration a vehicle is used for V2G, and the charging demand of the vehicles. The EV-related indices are elaborated in Section 3.4. No attributes related to repair time and failure frequency of the vehicles in an EV park are modeled. This is a feature that can be implemented.

The user can specify if V2G should be activated or not for the EVs. The functionality of the EV park will then be decided based on if V2G is activated or not:

- **V2G activated**:
  The EV park can charge and discharge the cars similarly to a battery.

- **V2G not activated**:
  Only charging the EVs in the EV park is possible.

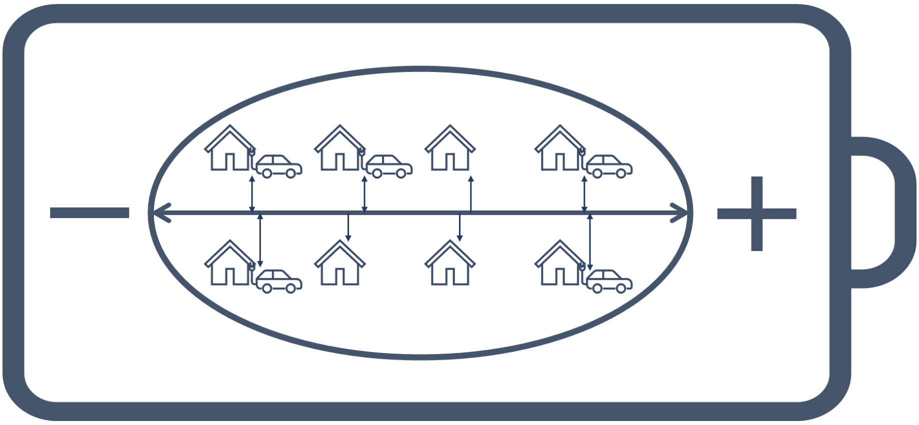


Figure 3.5: Aggregated battery solution for the EVs at a bus. The figure illustrates how an aggregated battery solution is created

Electrical Power Line

The power lines are constructed to connect power buses and transfer power between the buses to the end users in the system. The power lines may contain components such as:

- Circuit breaker, cb
- Disconnector, d
- Sensor, s
- Intelligent switch, d_i

The modeling of these components is presented later in this section.

The implemented attributes for the power lines include:

- **Topology attributes**:
  The buses connected to the line, to and from the bus.
- **Power flow attributes and line data**:
  Power flow attributes used to perform power flow calculations are implemented. This includes line data such as resistance, reactance, line capacity, active and reactive power losses, and reference values. Additionally, the cross-section area and line length can be defined.

- **Reliability attributes**:
  The line is modeled with a failure rate and repair time. The repair time is specified as a user-chosen repair time distribution. These features can be user-specified. A Line state attribute is implemented to give the failure status of the line.

Circuit Breaker

A circuit breaker is an electrical safety switch that is used to disconnect parts of the system to protect equipment from damage and avoid risks in relation to overcurrent or short circuits. In RELSAD, the circuit breaker will automatically react when an unwanted event happens in the system to isolate the fault. The breaker can be reset when the unwanted event is cleared.

In RELSAD, when a failure occurs, the closest circuit breaker to the failed component will react and disconnect the system until the fault is isolated. In addition, a sectioning time–the time it takes from the occurrence of a failure until the fault is isolated–can be added to the circuit breaker. The circuit breakers are added to the wanted lines in the system:

- **Topology attributes**:
  The line the circuit breaker is connected to and spatial coordinates.
- **Circuit breaker state**:
  An attribute indicating if the circuit breaker is open or closed.
- **Reliability attributes**:
  No reliability attributes are implemented for the circuit breaker. This is a feature that can be implemented in RELSAD.

Disconnector

A disconnector is a switch that is used to disconnect sections of the system and break the circuit. They can either be manually or automatically operated. The location of the disconnectors decides the division of sections of a system. In a radially operated system, all load points downstream of a disconnector will be isolated when the disconnector is opened.

In RELSAD, the disconnectors can be placed at the end of any line segment in the system, and the sections of the system are determined by the placement of the disconnectors. These are used to disconnect and connect line segments and isolate downstream faults in the system. The modeled disconnector attributes are:

- **Topology attributes**:

The line the disconnector is connected to and spatial coordinates.

- **Disconnector state**:
  An attribute indicating if the disconnector is open or closed.
- **Component attributes**:
  An intelligent switch component can be placed on a disconnector.
- **Reliability attributes**:
  No reliability attributes are implemented for the disconnector. This is a feature that can be implemented.

3.2.4 ICT Components

Controller

The controller is the head of the procedures performed in RELSAD, including isolating and monitoring the system components during outages. The power system must be connected to a controller that executes necessary operations during simulations. Two types of controllers are implemented:

- **Manual**
  Represents a traditional method of controlling the system where multiple actions are performed manually. The manual controller can not fail. The manual controller includes the following attributes:
  - **Reliability attributes**
    A manual sectioning time when outages are being isolated. The sectioning time can be specified by the user.
- **Smart**
  A smart controller with a high share of automation. The smart controller may fail in two ways:
  1. hardware failure
  2. software failure

  The failure types are elaborated in more detail in Section 3.3.2. The smart controller includes the following attributes:
  - **Topology attributes**
    ICT node, used if an ICT topology is defined.
  - **Reliability attributes**
    Failure rates and repair times for hardware and software failures, probabilities and durations for recovering strategies, and manual sectioning time if recovery strategies fail.

During initialization, the main controller distributes a controller to each child network in the power system, creating a control system. This subdivision of the controller facilitates the distribution of sectioning times during failures in the power system. The control system is made to simulate a central control strategy similar to a control center at a system operator (DMS system).

Intelligent Switch

In RELSAD, intelligent switches are implemented to make the system more automated. The intelligent switch objects can be placed on disconnectors in the system and, therefore, be used to automatically control the disconnectors. An intelligent switch can receive commands about the switch position from a controller and automatically open/close the switch. The implemented attributes for the intelligent switch include:

- **Topology attributes**:
  The connected disconnector and ICT node.
- **Reliability attributes**:
  The intelligent switch is implemented to encounter failures. For now, the failure of an intelligent switch only covers mechanical failures of the switch. This includes the failure rate and repair time attributes that can be user-specified. A state attribute is modeled that gives the operation state of the intelligent switch (failed or OK). The failure procedure of the intelligent switch is described in more detail in Section 3.3.1.

Sensor

The sensor object is implemented to send information about the state of the connected electrical power line to the controller. This includes information about the failure status of the line. The sensors are implemented similarly to the function of an intelligent electronic device (IED). The sensor will send signals through the ICT network to the system controller that simulates the DMS system at the DSO. The sensors can be placed on lines in the system and can be used to give information about the status of the lines and detect faulty lines. The sensor can detect a failure on downstream lines in the network. The implemented attributes for the sensor object are:

- **Topology attributes**:
  The connected electrical power line, the connected ICT node, and the coordinates of the sensor.
- **Reliability attributes**:
  The sensor is implemented to be able to fail. The sensor is only implemented

with one failure rate that represents multiple types of failures. The different types of failures are represented based on the possible recovery strategies of the sensor. This includes:

- Software failures that require the sensor to send a new signal or reboot.
- Mechanical failure that requires the sensor to be manually repaired.

The recovery strategies have associated probabilities of succeeding. Duration for recovery strategies and the sensor state are implemented attributes. The failure procedure of the sensor is described in Section 3.3.1.

ICT nodes and lines

To make a complete ICT network, ICT nodes and lines are modeled. They function similarly to the electrical power buses and lines, where the ICT nodes connect the ICT lines.

The implemented attributes for ICT nodes are:

- **Topology attributes**:
  Spatial coordinate of the node, ICT lines connected to the node.
- **Reliability attributes**:
  Failure rate and repair time of the ICT node. This can be user-specified.

The implemented attributes for an ICT line are:

- **Topology attributes**:
  The ICT nodes connected to the line, to and from node.
- **Reliability attributes**:
  Failure rate and repair time of the ICT line. This can be user-specified. The state of the line, if the line is failed or not, and if the line is connected or disconnected.

3.2.5 Creation of a Power System

The creation of a power system in RELSAD follows a specific order. Depending on the features the user wants to add to their power system, the creation of component and network types may be skipped. The steps are as follows:

1. Create a controller

2. Create a power system - P_s
3. For ICT communication modeling, create ICT nodes and ICT lines, initialize an ICT network, and add the nodes and lines to the network
4. Create power buses, power lines, and switches on the lines
5. For modeling of ICT control behavior, create ICT components
6. For modeling of distributed generation, create batteries, EV parks, and generation units for specified buses
7. Create networks belonging to the P_s. This can be transmission networks–T_s, distribution networks–D_s, microgrids–M_s, and ICT networks–I_s. The network structure is hierarchical, where the microgrids must be connected to a parent distribution network.

3.3 Procedures

A simulation in RELSAD is performed over a given period of time, for example, a year, where the decided load and generation for this period are being run for a selected number of iterations. For each iteration, a random drawing of failures for the system components is based on failure probabilities for each component. Furthermore, each iteration is developed incrementally with a user-specified time increment, for example, hourly increments.

In this section, the incremental procedure is explained and all the underlying features will be presented in their own sections.

3.3.1 Incremental Procedure

This section explains the incremental procedure step-wise with references to other sections in this chapter that describe each step in more detail. The incremental procedure can be seen in Figure 3.6. The isolation procedure for lines is performed by the controller through a control loop. The conduction of the control loop varies depending on whether the system is simulated with or without ICT features. The procedure will be discussed for both cases.

The simulation starts with initializing the system for all the networks before the incremental procedure is started. The incremental procedure commences by setting the load, cost associated with the load, and generation at the buses in the network. After that, the procedure checks the system for failures. The control loop in RELSAD is then performed. Section 3.3.2 describes in more detail how the control loop of the system and failures in the system are decided and how

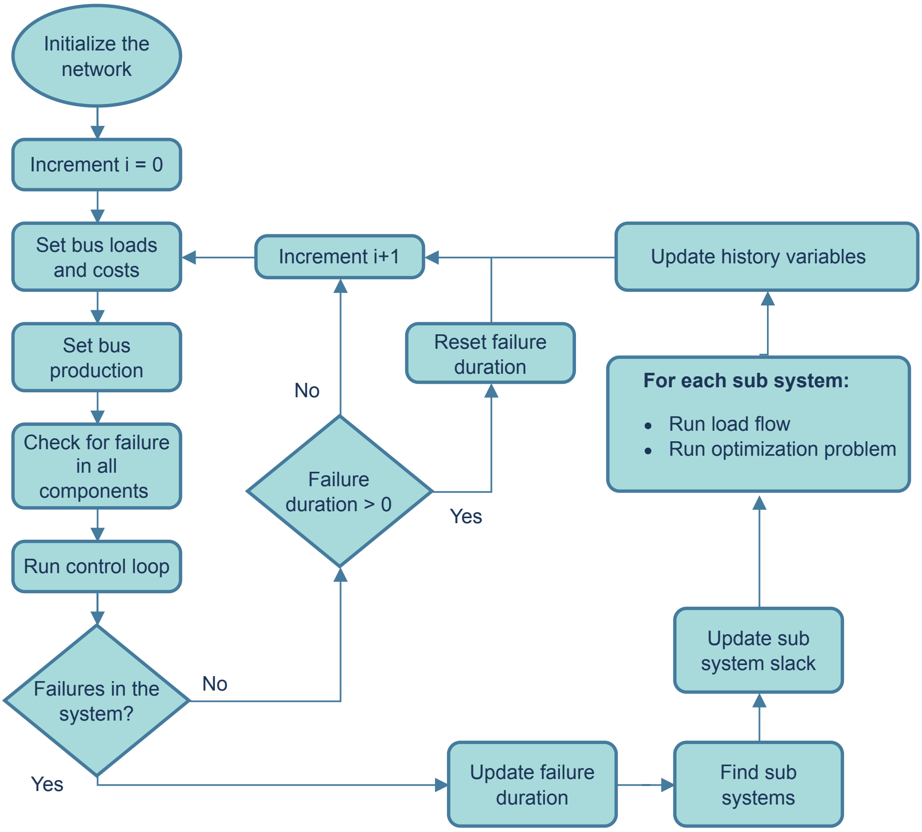


Figure 3.6: Flow chart of the incremental procedure in RELSAD.

they are handled. If there are no failures in the system, meaning that there is neither an ongoing failure nor a new failure, RELSAD will first check if there were failures in the previous increments that have been repaired before going to the next increment. If there were recently repaired failures from previous increments, the algorithm resets the failure time count.

If there are one or multiple failures in the system, RELSAD will check for which type of failure has occurred. There could be no new failures, meaning that there is an ongoing failure, or there could be a new failure on one or more components. If there is an ongoing sectioning time, meaning that the failure is not isolated yet, it will be considered as a new failure. If the failure is already accounted for, RELSAD will move on by updating the failure duration by counting down the repair time of the component. The other type of failures will be discussed before the rest of the procedure is presented. The description for the rest of the incremental procedure will be divided based on the inclusion of ICT.

Failure of Transformer at Substation

One possible fault situation is a new failure on a transformer at a bus in the network. A failure on a transformer influences the customers and generation units connected to this bus. In the simulation, RELSAD sets the load and generation at this bus to zero. The load at the bus is shed, and the generation unit is not able to deliver any power to the distribution network. This remains until the transformer is repaired. The repair time of the transformer can be specified based on a chosen statistical distribution (see Section 3.3.2 for more information related to the implemented repair time distributions).

Isolating Procedure of Failures on Lines without ICT

Another possibility is that there is a failure on a line in the system. The procedure for isolating this failure will be different based on if ICT is included or not. For no ICT, RELSAD will check if the line is isolated. If the line is already isolated, the algorithm moves along. For lines that are not isolated, a line isolating procedure will occur. The control loop procedure for manual operation is presented in Section 3.3.2, and the procedure for isolating the line without ICT is:

1. Open circuit breakers—The closest circuit breakers to the failed line will open.
2. Set sectioning time—A sectioning time can be decided by the user. This is the time it takes for the DSO to locate and isolate the failure, and it decides the time the circuit breaker will remain open.
3. Isolate the failure with disconnectors-—When the sectioning time has run out, the failed line will be isolated by the closest located disconnectors. The controller locates the section containing the failed line and opens the section disconnectors. When the failed line is isolated, the circuit breaker is closed.
4. Divide the network into subnetworks-—When the disconnectors are open, the system will be divided into subnetworks. This procedure is described in more detail in Section 3.3.4.
5. Set slack bus for each subnetwork—For each subnetwork, a slack bus will be delegated to perform load flow calculations. The criteria for setting the slack bus is based on a prioritized order: 1) the bus represents the transformer station to the overlying network, 2) the bus contains a battery object, 3) the bus contains a production unit object, and 4) the bus contains an EV park object. The bus satisfying the highest prioritized criteria is chosen as the slack bus. If none of the buses satisfy any of the criteria, the power flow calculation cannot be performed.

Isolating Procedure of Failures on Lines with ICT

If ICT is included, the algorithm will first investigate if a fallible ICT network, as described in Section 3.2.2, is modeled. If there is a fallible ICT network implemented, the algorithms checks if there is a connection between the communicating ICT components. For situations where there is no connection, meaning that there are failures in the ICT network, the electrical line will need manual supervision, and the procedure described for isolating lines without ICT is followed. If there is no ICT network or there is a connection between the communicating ICT components, the sensors connected to the line will be checked in the control loop. If the sensor is functioning, the correct information about the lines in the system is given, and the isolating procedure below is conducted where the system follows the control loop procedure for ICT as described in Section 3.3.2:

1. Open circuit breakers-—The closest circuit breakers to the failed line will open. If the sectioning time is too low, this will not be seen in the output file, since the circuit breaker will open and close at the same time increment.
2. Set sectioning time—The sectioning time is initialized to be zero when ICT is included. However, the sectioning time can increase based on the status of the ICT components in the system. If there is a failure on an ICT component, the sectioning time will accumulate based on the severity of the failure. The failure types and the severity will be discussed later in this section.
3. Isolate the fault with disconnectors—When the sectioning time has run out, the failed line will be isolated by the closest located disconnectors. The controller signals the line sensors to locate the failed line. When the failed line is located, the controller signals the intelligent switches to open the section disconnectors. The disconnectors will then open, and the circuit breaker can be closed.
4. Divide the network into subnetworks—When the disconnectors are open, the system will be divided into subnetworks. This procedure is described in more detail in Section 3.3.4.
5. Set slack bus for each subnetwork—For each subnetwork, a slack bus will be delegated in order to perform load flow calculations.

However, a failure of the sensor can occur. The failure is not discovered until the line connected to the sensor is checked. The repair procedure for the sensor is as follows:

1. Send a new signal—The controller tries to ask for a new signal from the sensor. The sending of a new signal will succeed to repair the sensor with a given probability. This takes a specified amount of time that is accumulated in the sectioning time.

2. Reboot the sensor—If the sending of a new signal is not functioning, a reboot of the sensor is conducted. The reboot procedure succeeds to repair the sensor with a given probability. This takes a specified amount of time that is accumulated into the sectioning time.

3. Manual repair—If the rebooting of the sensor is unable to repair the sensor, the sensor needs manual repair. The manual repair time is specified by the user.

If either sending a new signal or the reboot of the sensor is successful, the control procedure can follow as described in Section 3.3.2 and the isolating procedure for ICT can be conducted. However, if manual repair of the sensor is required, the line needs to be checked manually and the isolating procedure without ICT needs to be followed.

For isolating the failed line, the intelligent switches connected to the disconnectors isolating the line will receive a signal to automatically open. If the intelligent switch is not in a failed state, the opening/closing of the disconnector is successful. However, a mechanical failure on the intelligent switch can occur. This failure is not discovered until this switch is asked to open/close. If there is a failure on the intelligent switch, manual repair of this switch needs to be conducted and the disconnector needs to be manually opened/closed. This will add to the total sectioning time of the system.

After the failure procedure, a load flow calculation is performed. This is done to find the electrical consequence of a fault in the system. Since RELSAD investigates radially operating systems, a Backward-Forward sweep procedure is implemented as the load flow solver. This is elaborated in Section 3.3.5. In the load flow procedure, a load flow is performed for each subnetwork in the system. In addition, a simple optimization problem is included in the load flow procedure (see: Section 3.3.5) for optimizing the load shed based on the specific interruption cost of the loads in the system. After the load flow, the history variables from the procedure for each component in the system are calculated.

After the load flow procedure, the status of the networks and the system as a whole is updated. The history variables from the incremental procedure are used to, eventually, calculate the reliability indices for the system. In Section 3.3.3, additional information for the calculation of indices is discussed.

3.3.2 Failure Procedure and Repair Time

The system is constructed with user-specified failure rates and repair times for the components that have implemented reliability attributes as described earlier. The failure rate is given as a probability of a component being failed. The repair time is either modeled to follow a chosen statistical distribution or to be a fixed value. Figure 3.7 illustrates an example of a simple Markov model of the system components. The system components are implemented with three different possible states, a working state when the component is up and running, a failed state where the component is down and not working, and a repair state where the component is under repair.

For each increment in the timeline, the failure status of each of these components is calculated based on the failure probability. If a component enters a new time increment with a failed status, the failure status is not drawn again. New failures only occur on working components. The failure procedures differ based on the chosen controller type (manual controller or smart (ICT) controller). This section will describe these two procedures for an increment in detail.

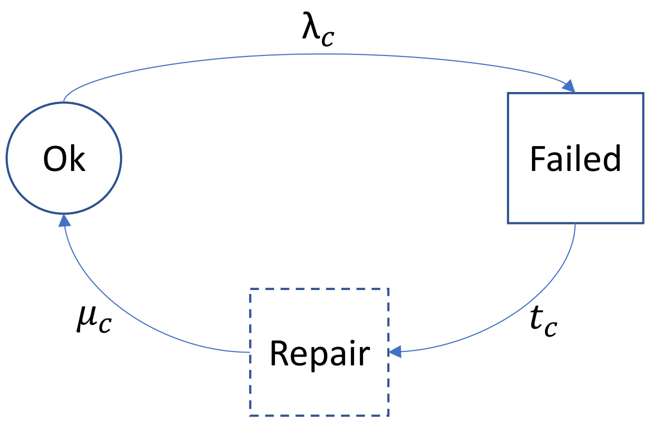


Figure 3.7: A simple Markov model of the system components. λ_c is the failure rate of component c, μ_c is the repair rate of component c, and t_c is the time from component failure until the component is under repair.

Without ICT—Manual Controller

When a manual controller type is chosen, the controller itself can not fail since it is based on manual operation. The manual controller calls on the manual control procedures for the child networks controller of the main power system. These procedures perform manual inspections on the network lines and require a specified sectioning time. During the manual inspections, failed lines are disconnected, and repaired lines are connected. When the sectioning time is finished, and the failed lines are isolated, the circuit breaker is closed.

With ICT—Smart Controller

When ICT components such as sensors and intelligent switches are included, a smart controller can be chosen. The smart controller, however, can fail. For each time increment, the failure status of the smart controller is decided. This can result in two different types of failures for the controller, namely software failure and hardware failure. If a hardware type failure occurs, the smart controller will be repaired manually for a certain amount of time. During the repair time of the hardware failure, a manual procedure (as described previously) is conducted.

If a software failure type occurs, the controller will try to repair this failure. The software repair procedure is:

1. Asking for a new signal—The DSO tries to ask for a new signal from the controller. The sending of a new signal will succeed to repair the failure with a given probability. This takes a specified amount of time that is accumulated in the sectioning time.
2. Reboot the controller—If asking for a new signal is not functioning, a reboot of the controller is conducted. The reboot procedure succeeds to repair the failure on the controller with a given probability. This takes a specified amount of reboot time that is accumulated into the sectioning time.
3. Manual repair—If the reboot failed, the controller will have to be manually repaired. This requires a specified amount of manual repair time and a manual control procedure is conducted.

Repair Time

In RELSAD, the component repair time is either fixed or drawn from a specified statistical distribution. The implemented statistical distributions are:

- Uniform distribution
- Gamma distribution
- Truncated normal distribution

The set of available statistical distributions provides the user flexibility and customization options for defining desired repair time distributions. However, other repair time distributions can be implemented. As of now, only the transformers at the electrical buses and the electrical power lines offer options to define repair times by statistical distributions.

3.3.3 Information for the Calculation of Indices

The reliability indices in RELSAD are calculated based on system component attributes for each Monte Carlo iteration. These are modeled attributes that are not user-specified. The attributes include measured load shed, experienced interruption, and accumulated outage duration for the component. Within the system, all components contribute with their status of reliability metrics. These are combined to replicate the expressions of analytical average-based reliability indices. During a MCS, the relevant component reliability metrics are gathered for each increment. The component reliability metrics are combined to calculate reliability indices. This results in a distribution of reliability indices, mapping the behavior of the system for a great variety of instances. This information allows for a more detailed analysis of the reliability impact on the systems. The implemented reliability indices are described in Section 3.4.

3.3.4 Subsystems

To enable load flow calculation during component failures, the system has to be divided into subsystems with all working components (the failed components will be isolated). This division is conducted by identifying the connected paths to neighboring buses from source buses until all buses belong to a sub-system. The procedure goes as follows:

1. Choose a source bus
2. Add connected neighboring buses to the subsystem
3. Find new free source bus and repeat the steps

This procedure is performed for every increment where a failure has occurred in the system. The procedure allows for automatic adaptation of the power system for every type of failure situation, which is the basis of the incremental Monte Carlo functionality of RELSAD.

3.3.5 Load Flow

In RELSAD, a load flow solver is implemented to evaluate the electrical consequences of faults in the system. For modern distribution networks, a form of load flow can be necessary to assess the behavior of the network during faults in the system. The load flow solver is implemented to perform load flow calculations during faults in modern distribution networks. The data values used in the load flow calculation are converted into per-unit (PU) values in RELSAD. This makes the system independent of voltage values and avoids taking into account which side of the transformer is referred to since the PU does not change.

Since the network is radially operated, a Forward-Backward Sweep (FBS) approach is adopted as the load flow solver [68]. The reasons for choosing FBS are:

- The main focus has been on radially operated distribution networks; a more complex load flow solver has not been needed.
- FBS was chosen due to the method's simplicity to perform load flow calculations for radially operated systems. The approach does not need to go through the Jacobian matrix and hence avoids convergence problems.
- Load flow calculations can be time-consuming and result in increased simulation time. FBS is a relatively fast load flow calculation approach, and when not needed, it is not necessary to add more complexity to the load flow calculation that might result in a longer simulation time.

The choice of load flow solver has been satisfactory for the studies conducted in this thesis. However, it is easy to implement other types of load flow solvers in RELSAD. More advanced load flow methods such as Newton-Raphson (NR) and Optimal Power Flow (OPF) can be adopted. Table 3.1 shows the main features of and differences between some possible load flow solvers. However, this has not been the focus of the thesis. This section aims to introduce the FBS algorithm that is implemented in RELSAD. In addition, a simple load shedding optimization problem is implemented and will be described.

Table 3.1: Comparison of different load flow solvers

	Network topology	**Main features**
FBS	Radial	Calculates the load flow iteratively backward and forward
NR	Radial and meshed	Calculate the load flow through iterative equation solving
OPF	Radial and meshed	Find a steady state operating state of the system based on an objective function and system constraints
	Advantages	**Disadvantages**
FBS	Fast, no convergence problems, robust	Not suitable for meshed operated networks
NR	Can handle both radial and meshed network topologies, simple to use, widely used	Can encounter convergence problems, can be time-consuming, the equations must be differentiable
OPF	Can handle both radial and meshed network topologies, find optimal solution, considers network constraints	Can encounter problems in finding global optimum, can be complex, time-consuming for complex systems

In the FBS approach, the load flow is calculated by updating the power flow through a backward sweep before the voltage magnitudes and angles at the system buses are updated in a forward sweep.

Backward Sweep

In the backward sweep, the active and reactive power over the lines are calculated. The active and reactive power over line l for iteration k, P_l, and Q_l, are calculated by adding the accumulated active and reactive load, $P_l^{'}$ and $Q_l^{'}$, at the downstream buses and the accumulated active and reactive power losses, P_l^* and Q_l^*, over the downstream lines including the power loss over line l and the load at the current bus

$$P_l = P_l^{'} + P_l^* \tag{3.3}$$

$$Q_l = Q_l^{'} + Q_l^* \tag{3.4}$$

where the accumulated active and reactive load at the buses are calculated as

$$P_l^{'} = P_i^{load} + \sum_{d_b} P_{d_b}^{load} \tag{3.5}$$

$$Q_l^{'} = Q_i^{load} + \sum_{d_b} Q_{d_b}^{load} \tag{3.6}$$

Here P_i^{load} is the active load at bus i, Q_i^{load} is the reactive load at bus i, and $P_{d_b}^{load}$ and $Q_{d_b}^{load}$ are the active and reactive loads at the downstream buses, respectively.

The accumulated active and reactive power losses are calculated as

$$P_l^{*} = P_l^{loss} + \sum_{d_l} P_{d_l}^{loss} \tag{3.7}$$

$$Q_l^{*} = Q_l^{loss} + \sum_{d_l} Q_{d_l}^{loss} \tag{3.8}$$

Here P_l^{loss} and Q_l^{loss} are the active and reactive power loss over line l, respectively, and $P_{d_l}^{loss}$ and $Q_{d_l}^{loss}$ are the active and reactive power loss of the downstream lines, respectively.

The active and reactive power loss over a line is further calculated as

$$P_l^{loss} = R_l \frac{P_l^{'2} + Q_l^{'2}}{V_j^2} \tag{3.9}$$

$$Q_l^{loss} = X_l \frac{P_l^{'2} + Q_l^{'2}}{V_j^2} \tag{3.10}$$

Where R_l and X_l are the line resistance and reactance, respectively, and V_j is the voltage at the ending bus.

Forward Sweep

In the forward sweep, the bus voltage magnitudes and angles are updated by using the updated active and reactive power from the backward sweep. Then the voltage magnitude at bus i in relation to the voltage magnitude at bus j for iteration k can be calculated by

$$\begin{aligned} V_i = V_j - I_l(R_l + jX_l) = \\ \sqrt{V_j^2 - T_1 + T_2} \end{aligned} \tag{3.11}$$

where the term T_1 and T_2 are

$$T_1 = 2(P_l R_l + Q_l X_l)$$
$$T_2 = \frac{(P_l^2 + Q_l^2)(R_l^2 + X_l^2)}{V_j^2}$$

The voltage angle can be updated as

$$\delta_i = \delta_j + \arctan \frac{Im(V_i)}{Re(V_i)} \tag{3.12}$$

where δ_j is the voltage angle of bus j, $Im(V_i)$ is the imaginary part of V_i, and $Re(V_i)$ is the real part of V_i.

Load Shed Optimization Problem

Due to the potential island operation of parts of the distribution system, power balance needs to be ensured. For this, a simple load shedding optimization problem is included. The objective of the load shedding optimization problem, seen in Equation (3.13), is to minimize the total shed load in the network based on the *Cost of energy not supplied* (CENS). This is subjected to load flow balance and the capacity limitations over the power lines, the load, and the generation in the distribution system. In RELSAD, the load shedding happens over a time increment, resulting in shed energy for that increment:

$$\underset{P_n^s}{\text{minimize}} \quad \mathcal{P}_s = \sum_{n=1}^{N_n} C_n \cdot P_n^s \tag{3.13}$$

subject to:

$$\begin{aligned}
\sum_{i=1}^{N_l} \alpha_i \cdot P_i^l = \sum_{j=1}^{N_g} \nu_j \cdot P_j^g - \sum_{k=1}^{N_n} & \quad \eta_k \cdot (P_k^d - P_k^s) \\
\min P_j^g \leq P_j^g \leq \max P_j^g & \quad \forall j = 1, \ldots, N_g \\
0 \leq P_k^s \leq P_k^d & \quad \forall k = 1, \ldots, N_n \\
\left| P_i^l \right| \leq \max P_i^l & \quad \forall i = 1, \ldots, N_l
\end{aligned}$$

Here, C_n is the cost of shedding load at bus n while P_n^s is the amount of shed power at bus n. P_j^g is the generation from generator j. P_k^d is the load demand at bus k while P_i^l is the power transferred over line i. $\alpha_i = 1$ if line i is the starting point, -1 if line i is the ending point. $\nu_j = 1$ if there is a production unit at bus j, otherwise it is 0. $\eta_k = 1$ if there is a load on bus k, otherwise it is 0.

3.4 Reliability Indices

There exist multiple reliability indices that aim to measure and quantify the reliability of a distribution network. In RELSAD, some traditional reliability indices presented by Billinton and Allan are implemented [21]. In addition to the traditional reliability indices, some new indices for EVs and V2G operation are proposed. In this section, the implemented traditional reliability indices and the proposed new indices are presented. In the future, other reliability indices can easily be implemented in RELSAD.

The reliability indices are based on the three basic reliability parameters:

1. The fault frequency or the average failure rate, λ_s

$$\lambda_s = \sum \lambda_i \tag{3.14}$$

   where λ_i is the failure rate at load point i

2. The annual average outage time, U_s

$$U_s = \sum \lambda_i r_i \tag{3.15}$$

   where r_i is the outage time at load point i

3. The average outage time, r_s

$$r_s = \frac{U_s}{\lambda_s} = \frac{\sum \lambda_i r_i}{\sum \lambda_i} \tag{3.16}$$

Furthermore, the traditional reliability indices can be divided into *load- and production-oriented indices* and *customer-oriented indices* [21].

3.4.1 Load- and Production-Oriented Indices

The load- and production-oriented indices aim to indicate the electrical consequence of faults in the system [21]. This includes the reliability indices Energy Not Supplied (ENS), interrupted power, and CENS.

1. Energy Not Supplied (ENS)

$$\texttt{ENS}_s = U_s P_s \tag{3.17}$$

The ENS gives the amount of energy that is not met in the system where P_s is the interrupted power in the system.

2. Interrupted power

$$P_s = \sum \lambda_i P_i \tag{3.18}$$

The interrupted power gives the amount of power that is not met in the system. P_i is the interrupted power at load point i.

3. Cost of Energy Not Supplied (CENS)

$$\texttt{CENS}_s = \sum \texttt{ENS}_i c_{l,i} \tag{3.19}$$

The CENS gives the interruption cost for the system based on the amount of energy that is not supplied. $c_{l,i}$ is the specific interruption cost for load type l at load point i.

3.4.2 Customer-Oriented Indices

The customer-oriented indices aim to indicate the reliability of the distribution system based on the interruption experienced by the customers [21]. In RELSAD, the following indices are implemented:

1. System Average Interruption Frequency Index

$$\texttt{SAIFI} = \frac{\sum_{\forall i} \lambda_i N_i}{\sum N_i} \tag{3.20}$$

where N_i is the *total number of customers served* at bus i, and $\sum_{\forall i} \lambda_i N_i$ is the *total number of customer interruptions*. `SAIFI` is a measure of the frequency of interruptions the customers in the system expect to experience. Any interruption seen by the consumer is counted as a fault, regardless of origin.

2. System Average Interruption Duration Index

$$\texttt{SAIDI} = \frac{\sum U_i N_i}{\sum N_i} \tag{3.21}$$

where $\sum_{\forall i} U_i N_i$ is *total number of customer interruption* durations. `SAIDI` is a measure of the expected duration of interruptions a customer is expected to experience.

3. Customer Average Interruption Duration Index

$$\texttt{CAIDI} = \frac{\sum U_i N_i}{\sum_{\forall i} \lambda_i N_i} = \frac{\texttt{SAIDI}}{\texttt{SAIFI}} \tag{3.22}$$

CAIDI is the ratio between SAIDI and SAIFI and measures the average duration each given customer in the system is expected to experience.

4. Average Service Unavailability Index

$$\mathtt{ASUI} = \frac{\mathtt{SAIDI}}{T} \tag{3.23}$$

where T is the number of hours in the iteration (8760 for a year). ASUI gives the indication of the unavailability of the system or a component.

5. Average Service Availability Index

$$\mathtt{ASAI} = 1 - \mathtt{ASUI} \tag{3.24}$$

ASAI gives the availability of the system or component.

3.4.3 EV- and V2G-Oriented Indices

Since the EVs will be affected by outages in the distribution system, three reliability indices for the EV and V2G support are proposed. The reason to propose indices for the EVs is to enable an analysis of the impact outages in the system have on the EVs in the network as well as on the EVs's experience when V2G support is activated. These proposed indices related to EVs and V2G are a major contribution of Paper III (see Chapter 5 for more detail on how these indices are used in a case study), but they will be elaborated in this section since they are a part of the implemented indices in RELSAD.

1. Average EV Demand Not Served

$$\mathtt{EV}_{\mathtt{Demand}} = \sum U_{EV_i}(P_{ch_i} + P_{dis_i}) \tag{3.25}$$

where, U_{EV_i} is the expected outage time EV i experiences, P_{ch_i} is the amount EV i charges or wants to charge, while P_{dis_i} is the amount of power EV i discharges.

This index aims to give an indication of how much power the EVs are not being served. During an outage in the system, an EV can experience periods where the it is unable to charge since the system, for example, is not connected to a source of power. When the EV is used for V2G services, the index will increase since the EV will then discharge power in addition. This means that the amount of discharged power will be added to the charge demand of the EV. This index can be used to give an indication of how much power an EV contributes and the amount of demand the EV ends up with.

2. Average EV Interruption Frequency

$$\mathtt{EV_{Int}} = \frac{\sum_{\forall EV} \rho_{EV_i} N_{EV_i}}{\sum N_{EV_i}} \tag{3.26}$$

here, $\sum_{\forall EV} \rho_{EV_i} N_{EV_i}$ represents the total number of times EVs are used for V2G. Where ρ_{EV_i} is the expected amount of times one EV is used for V2G services, $\sum N_{EV_i}$ is the total number of EVs in the distribution system, and N_{EV_i} is the total number of EVs at a bus (number of EVs in an EV park).

This index is based on SAIFI. The index gives the average number of interruptions an EV experiences due to V2G services in the system. In a simulation, the fraction of EVs that are used for V2G services in an EV park is found and multiplied by the number of EVs in the EV park to give an estimation of how many cars in that EV park are used. This index can be applied to illustrate how often an EV is used for V2G services. The index is sensitive to the frequency of failures in the system. For more frequent outages in the system, the more EVs will be used.

3. Average EV Interruption Duration

$$\mathtt{EV_{Dur}} = \frac{\sum U_{EV_i} N_{EV_i}}{\sum N_{EV_i}} \tag{3.27}$$

This index is based on SAIDI. The index gives the average duration of the EVs used for V2G services in the system. This index accumulates the amount of time every EV in the system is being used for V2G services and divides it by the number of EVs in the system. The index gives an indication of how long an EV can be expected to be used for V2G services during a given period. The index will increase with a longer outage time of the system since the EVs will most likely be used for longer periods at a time. The duration will also increase if the network is exposed to outages often.

3.5 Validation

To verify that the implemented methods in RELSAD work correctly, RELSAD is validated against an analytical approach. Validation of RELASD is conducted by testing the tool against the analytical approach RELRAD. The benchmarking of RELSAD is performed on the passive operation of the network since the analytical approaches are unable to consider the active and smart operation of the distribution system. In this section, a convergence validation will be conducted before the validation of RELSAD against the analytical approach RELRAD is presented. The validation will be conducted to garner results for the load point reliability and the system reliability indices. The benchmarking is conducted against two different distribution networks: 1) a small 6-bus network and 2) Roy Billinton test system (RBTS) Bus 5 distribution network [69].

3.5.1 Convergence Validation of Indices

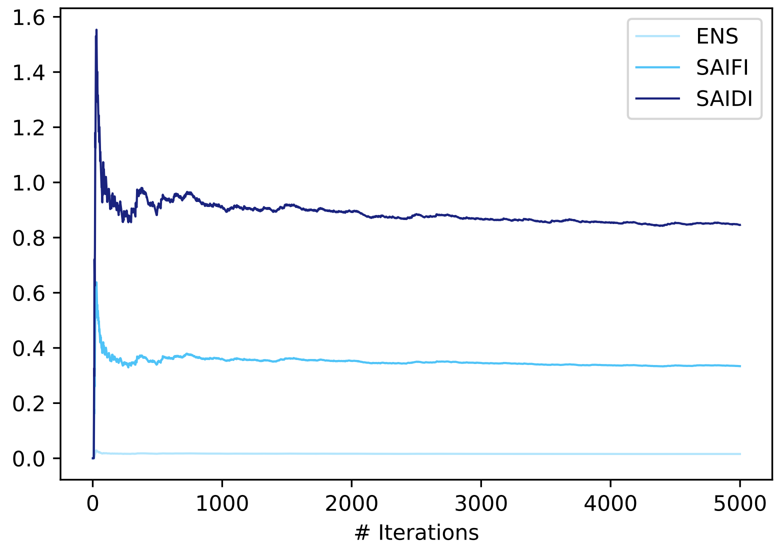


Figure 3.8: Convergence plot for `ENS`, `SAIDI`, and `SAIFI` for the 6 bus network.

To ensure that the reliability indices converge in RELSAD, a test is performed. The convergence plot is shown in Figure 3.8 for the three reliability indices `ENS`, `SAIDI`, and `SAIFI`. The convergence plot is given for the reliability indices for the 6 bus network seen in Figure 3.9. The convergence results are similar for the other test network as well. The distribution system is simulated with 5,000 iterations and as seen in the figure, all the reliability indices converge clearly. The indices converge early where only small variations in the results can be seen below 1,000 iterations.

3.5.2 Validation Against Analytical Approach

Since RELSAD uses the same load point-oriented approach for calculating the reliability indices as RELRAD, it is natural to use RELRAD as the analytical approach for validation. The validation is performed by simulating two different networks and comparing results. This section presents the reliability assessment results from the validation of the two distribution networks.

6-Bus Network

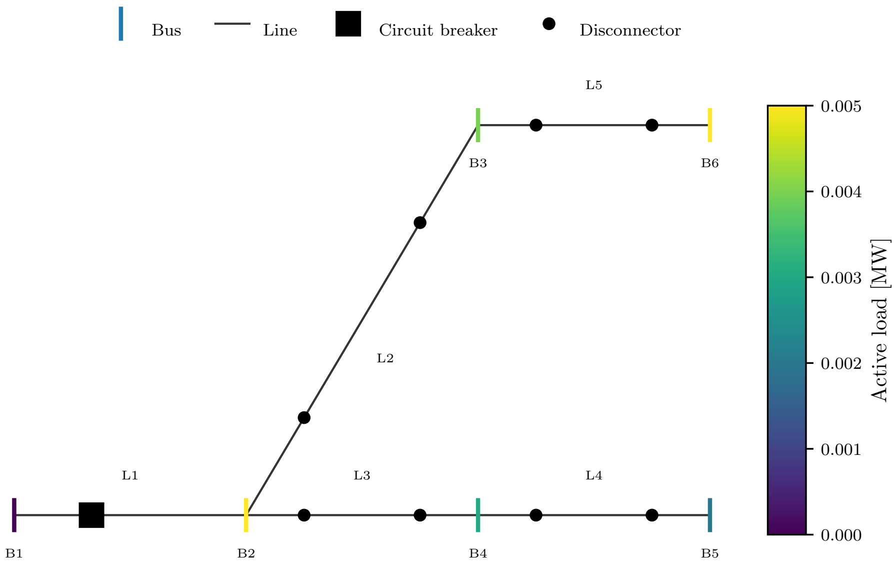


Figure 3.9: The topology of 6 bus network including a heat map of the load in the network per customer.

Small 6-bus Distribution Network

In Figure 3.9, the topology of the 6-bus network is illustrated. The network is constructed with one circuit breaker on L1 and one disconnector on each of the other lines. All the lines in the system are 1 km long and where the average failure rate of each line is 0.07 failures/km/year. The outage time of each line is four hours and the sectioning time of the circuit breaker is one hour. The load at each bus can be seen in the topology figure (Figure 3.9) of the system. This network is implemented equally in both RELSAD and RELRAD. The network is constructed as a passive network with a constant load at each bus, to be able to evaluate RELSAD against the analytical approach.

The results from the reliability assessment for the load point reliability are displayed in Table 3.2. Here the result is given for the `ENS` at the load point and the average interruption frequency and outage duration the load point experiences. The reliability indices for the system are given in Table 3.3. The tables show the reliability results from the analytical approach and the estimated results from the simulation performed by RELSAD. Additionally, the tables include the percentage difference between the analytical results and the results obtained from the simulation. The results reveal very small variations in the reliability results from the analytical approach and RELSAD. By investigating the reliability result for the load point reliability, there might be a tendency for higher deviation at load points on the end of radials. Since the system is radially operated, the load points furthest from the bus connected to the overlying network, will experience more faults, resulting in the higher deviation for the buses at the end of the radials. For the system reliability indices, the highest difference can be seen in the results of `ENS`, which illustrate that RELSAD gives lower average energy not supplied per year compared to the analytical approach. All the differences are well within variations as seen in Billintons and Wang's paper comparing analytical techniques for distribution system reliability assessment with SMCS techniques [70]. However, this is a small test system; for larger and more complex systems, the differences might change.

Table 3.2: The load point reliability result for both the analytical and the simulation approach.

Load point	**Average Energy Not supplied [MWh/year]**		
	Analytical	Simulation	Difference [%]
B2	0.0032	0.0031	-3.1250
B3	0.0036	0.0035	-2.7778
B4	0.0027	0.0026	-3.7037
B5	0.0023	0.0022	-4.3478
B6	0.0060	0.0060	0.0000
Load point	**Average interruption frequency [f/year]**		
	Analytical	Simulation	Difference [%]
B2	0.3500	0.3463	-1.0571
B3	0.3500	0.3446	-1.5429
B4	0.3500	0.3416	-2.4000
B5	0.3500	0.3355	-4.1429
B6	0.3500	0.3463	-1.0571
Load point	**Average outage time duration [h/year]**		
	Analytical	Simulation	Difference [%]
B2	0.6300	0.6302	0.0317
B3	0.9100	0.8951	-1.6374
B4	0.9100	0.8959	-1.5495
B5	1.1900	1.1751	-1.2521
B6	1.1900	1.2215	2.6471

Table 3.3: The reliability indices for both the analytical and the simulation approach.

Indices	**Analytical**	**Simulation**	**Difference [%]**
`ENS` [MWh/year]	0.0178	0.0174	-2.2472
`SAIFI` [int./year]	0.3500	0.3441	-1.6857
`SAIDI` [h/year]	0.9395	0.9409	0.1490
`CAIDI` [h/int./year]	2.6842	2.7365	1.9484
`ASAI`	0.9999	0.9999	0.0000

RBTS Bus 5 Distribution Network

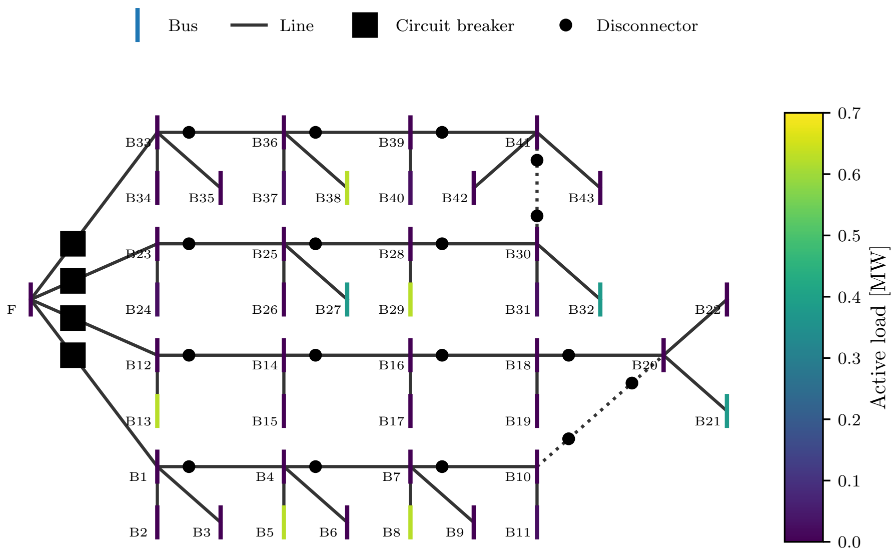


Figure 3.10: The topology of the RBTS bus 5 network including a heat map of the load in the network per customer.

The Roy Billinton test system (RBTS) Bus 5 distribution network is seen in Figure 3.10. The network illustrates the network connected to bus 5 in the commonly used RBTS test system. The distribution network represents a typical urban type network with multiple different customer groups. The network consists of four different feeders built up by 43 overhead lines and 26 loads. Additionally, four backup lines, as illustrated in the network, are implemented. There is a circuit breaker at the start of each of the four feeders and some lines on the feeders have disconnectors. Additional disconnectors are added to the backup lines in the system. This is done to isolate the backup lines as individual sections. The reliability data and the load data of the system can be found in [69, 71]. The sectioning time of the system is one hour and the repair time of the lines is four hours. The network is implemented in both RELRAD and RELSAD and is operated passively.

The results for the reliability assessment for the load point reliability for some selected load points in the system are given in Table 3.4. The table illustrate the `ENS` and the average experienced interruption frequency and outage duration for the selected load points. The results illustrate that there are low variations between the result from the analytical approach and RELSAD. The tendency with higher deviations for buses at the end of radials is similar in this case. The increase in network complexity and size does not appear to affect the validation results.

The reliability indices for the whole system (all four feeders) are given in Table 3.5. Here, the results for the analytical approach and RELSAD are similar where the variations between the comparing methods are small. The highest difference can be seen for `ENS`, which can be expected based on the variation in `ENS` for the load point reliability.

Table 3.4: The average interruption frequency and outage duration for some selected load points for both the analytical and the simulation approach.

Load point	**Average Energy Not supplied [MWh/year]**		
	Analytical	Simulation	Difference [%]
B2	0.4398	0.4450	1.1824
B6	0.4135	0.4111	-0.5804
B15	0.2391	0.2336	-2.3003
B21	0.3605	0.3421	-5.1040
B32	0.3556	0.3707	4.2463
B38	0.6072	0.6199	2.1084
B42	0.4216	0.4210	-0.1423
B43	0.3248	0.3243	-0.1539
Load point	**Average interruption frequency [f/year]**		
	Analytical	Simulation	Difference [%]
B2	0.4842	0.4872	0.6196
B6	0.4842	0.4872	0.6196
B15	0.4453	0.4312	-3.1664
B21	0.4453	0.4314	-3.1215
B32	0.4322	0.4486	3.7945
B38	0.4648	0.4722	1.5921
B42	0.4648	0.4722	1.5921
B43	0.4648	0.4722	1.5921
Load point	**Average outage time duration [h/year]**		
	Analytical	Simulation	Difference [%]
B2	1.0303	1.0426	1.1938
B6	0.9913	0.9858	-0.5548
B15	0.7443	0.7272	-2.2975
B21	0.9718	0.9038	-6.9973
B32	0.9393	0.9792	4.2478
B38	0.9718	0.9924	2.1198
B42	1.0108	1.0094	-0.1385
B43	1.0108	1.0094	-0.1385

Table 3.5: The reliability indices for both the analytical and the simulation approach.

Indices	Analytical	Simulation	Difference [%]
`ENS` [MWh/year]	10.3164	10.4009	0.8191
`SAIFI` [int./year]	0.4626	0.4633	0.1513
`SAIDI` [h/year]	0.9320	0.9309	-0.1180
`CAIDI` [h/int./year]	2.0147	2.0058	-0.4418
`ASAI`	0.9999	0.9999	0.0000

3.6 General Discussion

One main objective of this thesis is to develop and verify a method to assess the reliability of modern distribution systems. RELSAD is a reliability assessment tool that has been implemented in a general manner that allows for complex and different network topologies operated radially. Since RELSAD was developed from scratch, some notable decisions and assumptions have been made during the development of the tool. The tool and these decisions will be discussed here.

Choice of Programming Language

Python was chosen as the programming language for RELSAD. The main reason for selecting Python is the large and broad community of fellow developers with numerous mature high-quality open-source modules. This large community creates opportunities for further community-based use and development of the tool. In addition, it is a familiar modular platform and programming language. Further, Python is easy to use and understand. However, Python is not necessarily the optimal language for such a tool. The tool is based on MCS and is able to assess the different types of networks and network configurations. Some of these assessments require a long simulation time. With Python, the simulation time might take longer compared to if a programming language such as C++, C or Fortran was used. In the future, it could be relevant to switch to a more computationally efficient programming language to decrease the computation.

Choice of Load Flow Solver

RELSAD aims to evaluate the reliability of modern distribution systems. This requires the tool to be able to assess active and smart distribution networks. To investigate the behavior of the system and find the electrical consequences of outages in the system, a load flow solver is implemented. The implemented solver is a Backward-Forward Sweep approach. This is a simple but efficient method to calculate the load flow of radially operated systems assuming steady-state conditions. Load flow calculations can be a slow process, and in a simulation with multiple processes, the load flow calculation can sink the simulation, resulting in increased simulation time. The simulations performed in this thesis are conducted over a period of one year when steady-state conditions of the system are assumed. For these purposes, the FBS solver in addition to the simple optimization problem has been sufficient to cover the trends and to calculate the reliability indices of the study. In addition, their simple nature makes the simulations easier and faster.

However, other load flow solvers can be implemented to allow for other types of analysis. The Newton-Rahpshon load flow can be added for the analysis of meshed systems. Furthermore, more advanced optimal power flow problems can be implemented to better reflect the operating states of a distribution system. Here, another objective function can be constructed, for example, based on the minimization of operation cost. More constraints related to the operation of the system such as requirements for voltage levels can be included. A more advanced optimal power flow solver would enhance the analysis of the reliability since other aspects of the distribution system operation can be added and evaluated.

The implemented load flow solver addresses static systems. However, RELSAD allows for user-specified increments, enabling the possibility of short time steps that can imitate the situation of a more quickly changing system. For quasi-static analysis, continuation power flow can be implemented [72]. Continuation power flow provides the opportunity to calculate the margins to voltage instability where network sensitivities can be used to find a solution to the load flow [73,74]. In regard to more dynamic system analysis, for example, analysis of transient periods, a load flow solver comprehending the fluctuation in the system and the dependability between time steps should be implemented.

Implemented Algorithms

In RELSAD, multiple decisions and assumptions constitute the basis for the implementation of the different algorithms. The controller with the control loop is the main core of the functionality of RELSAD. The controller might not necessarily grasp the reality in every situation. Particularly, the smart controller includes assumptions regarding failures on the ICT components. This includes the propagation, discovery, and repair of the ICT component failures. Additionally, the complex interconnection between the power system and the ICT components has its limitations in the model. This is notable since it gives the basis for the system behavior and the reliability results from the simulation. The controller serves an important role in the system behavior and to include other aspects it will need to be adjusted, or a new controller with another control scheme can be implemented.

Additionally, the components and systems in RELSAD are implemented where assumptions have been made in the modeling process. Mostly the components are implemented in a general way that includes the main features of the component. However, it does not distinguish between, for example, different types of circuit breakers. For an analysis where more detailed features of components are needed, new components can be added.

For validation purposes, RELSAD performs the reliability calculations of passive networks accurately, as seen in Section 3.5. Additionally, RELSAD is a general tool that can handle multiple network topologies. However, for active networks and networks including ICT, benchmarking is challenging since there is no method to validate the results against. To account for this to some degree, multiple tests in RELSAD have been made to ensure that the implemented algorithms work as expected and perform the right assessment of the network.

Open Source Access

The decision was made to publish RELSAD as open-source software. This heightens the possibility of an increased user base and offers the opportunity for further development of the tool and the mindset behind the tool. The availability of fundamental tools might increase knowledge in the field and encourage more research. Additionally, by making the tool open and available, a greater potential for troubleshooting and validation of the code and results are possible. This will help improve the quality of the tool and the research.

4 Case 1: Reliability Assessment for Distribution Systems with Embedded microgrids

This chapter is based on Paper II and aims to investigate how microgrids might impact the reliability of distribution systems. After a brief introduction, the microgrid controller modeling is presented. The case study is then provided before the results are shown and discussed. In the end, a conclusion follows.

4.1 Introduction

Microgrids are an increasingly studied concept related to the improvement of system reliability [75]. Because microgrids can operate in two different modes, grid-connected and islanded, a microgrid can disconnect and still continue to supply its loads when there are faults in the distribution network. Additional to this attribute, microgrids can support the distribution network during faults in the system, which might lead to increased reliability of the distribution system. Some research has already been done to investigate the potential reliability improvement with technologies such as DG and flexible resources integrated into distribution systems. In [76], an overview of how flexible resources may impact the security of electricity supply (SoS) is provided. The study also includes a review of methods and indicators to quantify the impact. An overview of power system flexibility and system security concerning is provided in [77]. A survey of reliability assessment techniques for modern distribution systems is offered in [20]. Here, multiple modeling techniques used for assessing distribution system reliability are investigated concerning active components in the system. The availability and impact of active components, such as DG [37, 78], energy storage units [79], and systems with a combination of these [80, 81], have been investigated. The literature illustrates that DG and flexible resources might have a positive impact on the reliability of distribution systems if administrated wisely.

Some studies have investigated the possibility of islanding parts of the distribution system during failure events. In [34] and [33], an analytical approach is used to find the contribution from the microgrid to the reliability of the distribution system. The contribution of the microgrid is determined during possible operating conditions of the microgrid and the DG inside the microgrid and is evaluated based on the ratio between demand and supply. A simulation-based approach with Monte Carlo has been used in [36] for intentional islanding of the distribution system. However, the paper does not consider the active participation of flexible resources and DG to restore supply. Furthermore, a sequential Monte Carlo method is used in [82] to evaluate the impact of local and mobile generation units. Here, parts of the system will be islanded, with some units operating as microgrids. In [83], the reliability of a distribution system with support from a microgrid including combined heat and power supply system is assessed. However, the microgrid does not include renewable energy resources (RES). In addition, some research related to the reliability of multi-microgrids has been conducted in [84], [85], and [86]. These papers do not consider the interaction between the microgrid and the distribution system, nor is the reliability of the microgrid investigated to any significant degree.

The aim of Paper II is to investigate how a microgrid including RES may improve the distribution system reliability. Through varying the microgrid placement, operation mode, and battery capacity, we aim to map the reliability impact from the perspective of both the microgrid and distribution network. Through the investigation, we aim to identify the optimal conditions for the microgrid in order to minimize the impact on the microgrid while maximizing the contributions to the distribution system. In addition, we provide a general methodology for evaluating how microgrids perform from a reliability perspective through the use of RELSAD.

The contribution of Paper II and this case study is to propose a methodology to assess the reliability of a distribution network with the active participation of a microgrid. Additionally, the reliability impact the microgrid experiences during its different operating modes is investigated. The study will also contribute to a thorough analysis of the reliability impacts where the results are evaluated based on statistical analysis and reliability indices. A sensitivity analysis is performed where the parameters for the failure rate, repair time, and battery capacity of the battery in the microgrid are adjusted to investigate the effect on the reliability of the distribution network and the microgrid. In addition, a study on the effect of the microgrid location on the reliability of the distribution network is performed. The distribution system with the embedded microgrid is developed to replicate a realistic and modern distribution system. This is done systematically by gathering data for the system through procedures where the reliability data is based on statistics from the Norwegian distribution systems, see 4.2.3 and 4.3.1.

4.2 Method

In this study, the microgrid was constructed to have different operating modes. The different operating modes of the microgrid are managed by the modeled microgrid controller in RELSAD. This section will describe the operating modes of the controller and the theory about statistical testing that is used to evaluate the results of the study.

4.2.1 Microgrid Controller

The reliability evaluation of a system with embedded microgrids is dependent on the operating mode of the microgrid during outages in the systems. During island mode, the microgrid will function as an independent system. Alternatively if the microgrid is connected to the overlaying network, it could either be supported by the overlaying network or support the overlying network during outages. The microgrid controller is implemented to follow different types of operating modes for the microgrid. Here, the possibilities for operating modes can be extensive, but for the purpose of this study, three different operating modes were implemented:

1. No support mode—During failures in the system, the microgrid will work in island mode during the down time of the failure.
2. Full support mode—After the sectioning time, the microgrid will reconnect to the distribution network (if possible) and contribute to the operation of the distribution network.
3. Limited support mode—After the sectioning time, the microgrid will reconnect to the distribution network (if possible), but will only contribute with limited power from the battery so that the microgrid can ensure self-sufficiency for a limited period of time. This means that the battery will store enough power to operate the microgrid for four peak hours. The battery will in this operation mode function as a backup source and the SoC will not be drawn when a failure occurs but will start with max SoC.

The microgrid controller was implemented to focus on performing the correct fault handling; the remaining features are simplified.

Algorithm 1 shows the controller procedure for fault handling of the microgrid, M_s. The controller starts by updating the sectioning time of the circuit breaker, *cb*, in the system. This is in case the system was in a sectioning time from the previous time increment. Then, if there is a new failure on a line, l, in the system, the microgrid circuit breaker will open to disconnect the microgrid during the sectioning time. The algorithm will check for failures in the microgrid; the procedure is similar to the one presented in Section 3.3. If there is a failure on the line with the circuit breaker, the circuit breaker will remain open and disconnect the microgrid no matter the operating mode.

Algorithm 1: Microgrid controller procedure

```
Update sectioning time;
if cb is open and sectioning time ≤ 0 or l recovered from failure then
    Check l in M_s for failure;
    if l with cb not failed then
        if M_s in island (survival) mode then
            if No failed l in D_s then
                Disconnect failed sections;
            end
        else
            Disconnect failed sections;
            Close cb;
        end
    end
end
```

The procedure after updating the sectioning time can vary based on the operating mode of the microgrid. If the microgrid is to operate in island mode during the outage period (survival mode), the circuit breaker will remain open, disconnecting the microgrid, until the fault is repaired. For modes where the microgrid is to support the distribution network, D_s, the circuit breaker will be closed after the fault is isolated and disconnected. This will result in the microgrid being in one of three states during outages in the system: 1) in islanded mode, 2) in island mode with parts of the distribution network, or 3) connected to the distribution network and the overlying network.

4.2.2 Statistical Analysis

Statistical analysis is important to confirm the proposed hypotheses. A statistical test checking for equal means can be performed to quantify whether the result data sets from various scenarios differ. This is performed to determine if the result data sets are significantly different or not. There are two classes of hypothesis tests, namely 1) *parametric* [87] and 2) *non-parametric* [88]. Both classes are bound by assumptions about the distribution of the result data sets. Parametric tests are restricted to normally distributed data sets with equal variance, while non-parametric tests have looser restrictions. For this reason, parametric tests have stronger statistical power, making them the preferred choice if the data set satisfies its assumptions. To decide which class of tests to use, an evaluation of the distribution of the results data set must be carried out.

The evaluation of normality can be done by performing an Anderson-Darling (AD) test. The AD test is used to establish if a data set comes from a population with a specific statistical distribution [89]. The outcome of the test is measured by the deviation A^2, between the number of samples and a weighted logarithmic expression of the data in the data set. An increasing deviation between A^2 and zero decreases the probability of the data set being of a specific statistical distribution.

If the AD test for normality fails, non-parametric tests must be used to check for equal means. In this study, the Kolmogorov-Smirnov (KS) [88] test is used for this purpose. The KS test quantifies the distance between two data sets, indicating if the data sets are drawn from the same population.

Sensitivity Analysis

Sensitivity analysis is important since it provides a mapping of the behavior of the model and illustrates how the results are affected by various parameters. Factorial design is a more advanced form of sensitivity analysis used to investigate and understand the effect of independent input variables on a dependent output variable [90]. One of the most significant advantages of factorial design compared to a conventional sensitivity analysis, that only studies the effect of one variable at a time, is the ability to quantify the influence the variables have on the output variable *and* on the other investigated variables. However, this drastically increases the number of combinations to investigate, which will lead to more simulation time; for example, a factorial design test with three factors that consider two levels each leads to a total of $2^3 = 8$ combinations.

Box Plot

In this thesis, box plots are frequently used to illustrate the results of the performed reliability assessments. As such, a short introduction to box plots is provided. A box plot is an effective way of displaying the properties of a statistical sample [90]. Figure 4.1 highlights the different features found in a box plot. The most dominant feature is the rectangular box that encloses the Interquartile range (IQR) of the data. The IQR spans the sample data from the 25th percentile (Q1) to the 75th percentile (Q3). Within the IQR box, the *median* value of the sample is marked with a line. At each side of the IQR box, two *whiskers* extend. The *whiskers* display the more extreme observations of the sample, spanning a distance of $1.5 \times \text{IQR}$ from the Q1 and Q3 observations, respectively. The stars marked beyond the *whiskers* are referred to as the sample *outliers*. These observations are considered unusually far from the bulk of the sample data.

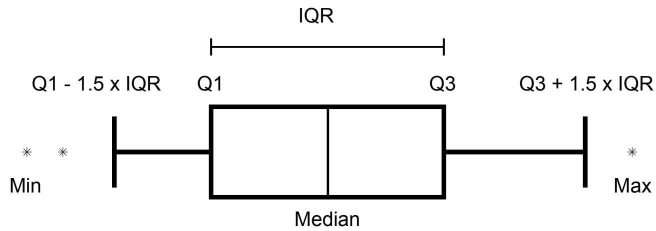


Figure 4.1: Figure illustrating the different box plot features.

4.2.3 Calculation of Wind and Solar Power Profiles

This section describes the methodology to construct the wind and solar power profiles for the microgrid. The data for the air temperature, solar irradiance, and wind speed is based on weather data from a location in Norway.

Calculation of Solar Power Profiles

In this study, the solar power profiles are generated as in [91], where the output power from the solar panels is calculated based on the fill factor power model. The fill factor power model uses the relationship between the irradiance of the sun and the cell temperature with the open-circuit voltage and short circuit current. The power generated from a solar module is then [91]

$$P_{out} = FF \cdot I_{SC} \cdot \frac{E}{E_0} \cdot V_{OC} \cdot \frac{\ln(K \cdot E)}{\ln(K \cdot E_0)} \cdot \frac{T_0}{T_{cell}} \tag{4.1}$$

where E is the irradiance at the moment, E_0 is the standard irradiance (1,000 W/m^2), I_{SC} is the short circuit current of the module, V_{OC} is the open circuit voltage of the module, and T_0 is the reference temperature or standard module temperature (298 K). K is a constant term

$$K = \frac{I_{SC}}{E_0 I_0} \tag{4.2}$$

The fill factor, FF is

$$FF = \frac{P_{mpp}}{V_{OC} I_{SC}} \tag{4.3}$$

where the maximum power output

$$P_{mpp} = V_{mpp} I_{mpp} \tag{4.4}$$

Here, V_{mpp} and I_{mpp} are the maximum power point voltage and current for the solar module, respectively.

The cell temperature of a solar model is calculated as

$$T_{cell} = T + \frac{NOCT - 10}{800} \cdot S \tag{4.5}$$

where T is the air temperature based on the weather data, $NOCT$ is the nominal operating cell temperature in degrees, and S is the solar insolation.

Calculation of Wind Power Profiles

In this study, the wind power is generated based on the wind power curve for the specific wind turbine where the current wind speed decides the output power. The output power of a given wind turbine is calculated based on Equation (4.6)

$$P_i = P_{i-1} + (P_{i+1} - P_{i-1}) \cdot \frac{v_i - v_{i-1}}{v_{i+1} - v_{i-1}} \tag{4.6}$$

where P_{i-1} is the rated power of the wind turbine for speed v_{i-1} and P_{i+1} is the rated power of the wind turbine for wind speed v_{i+1}. The wind speed v_{i-1} is the closest lower wind speed to the measured wind speed at the turbine height, v_i, while v_{i+1} is the closest higher wind speed to v_i.

The wind speed v_i at the turbine height is

$$v_i = v_0 \cdot (\frac{H}{H_0})^{\alpha} \tag{4.7}$$

where v_0 is the measured wind speed from the weather data station at height H_0, H is the height of the wind turbine, and α is the friction coefficient of the terrain where the wind turbine is placed.

4.3 Case study

4.3.1 The Reliability Test Network

The method is demonstrated on the IEEE 33-bus network, which has primarily been used as the test network in this thesis. The network is chosen since it is a commonly known distribution network of a decent size, and it can be seen in [92]. Additionally, evaluation and replication of the study are more convenient when a commonly known network is investigated. In the study, the network is operated completely radially without any backup connections. To take advantage of the features in RELSAD and to create a more realistic and dynamic customer profile of the network, hourly load and generation profiles are used. The load profiles are generated based on the FASIT requirement specifications [93]. The requirements specification gives load profiles for different customer groups such as households, farms, offices, and industries, to mention just some. The load profiles are generated based on temperature and follow a simple formula where

$$P_{load} = A_{i,t}T_t + B_{i,t} \tag{4.8}$$

Here, $A_{i,t}$ is the temperature-dependent parameter from the requirements for load category i at hour t, T is the temperature in degrees at hour t, whereas $B_{i,t}$ is the non-dependent parameter for load category i at hour t.

The loads with different customer categories are distributed well in the distribution network to map a real network. Figure 4.2 gives the 33-bus network as a heat map illustrating the mean load at each bus in the system. The weather data used to generate the profiles are collected from a weather station at Rygge in eastern Norway and is the same dataset used to calculate the wind and solar profiles.

In Paper II, failures occurring on the lines in the system (both distribution network and microgrid) are addressed. The reliability data is collected from the yearly reliability statistics from the Norwegian DSOs and can be seen in [94]. The average failure rate for overhead lines is 0.07 failures/year/km and will be used as the failure rate for the lines in the system. The failure procedure follows, as explained in Section 3.3. Since the impedance of the lines are known [92], the length of the lines in the system was calculated based on the impedance.

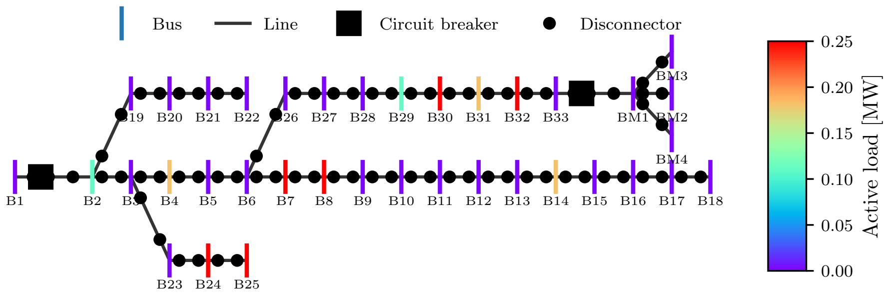


Figure 4.2: The distribution network topology illustrated through a bus heat map. The heat map gives the mean load at each bus in the system. The microgrid is located on B33.

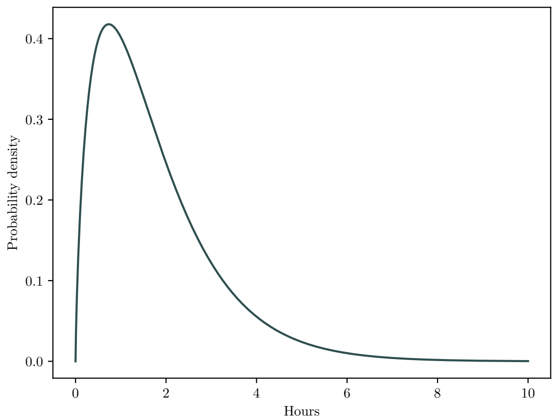


Figure 4.3: Gamma distribution of the repair time of the lines in the system. The repair time follows yearly statistics from the Norwegian DSO and will be less than two hours, 67% of the time.

The yearly reliability statistics from the DSOs are also used to give a repair time profile for the fault in the system. The statistics for the repair time are provided based on the number of failures that results in different down times of the system. In the statistics, 67% of the faults lasted for less than two hours. This is used as a basis to create a repair time distribution for the failures that follows a gamma distribution, as seen in Figure 4.3. In addition to the repair time, a sectioning time of one hour is added to the failures to illustrate the time it takes for the DSO to find and isolate the faults in the system.

4.3.2 The Implemented Microgrid

The microgrid is located at bus B33 in the distribution network, BM1-BM4, as seen in Figure 4.2. The microgrid contains solar power generation, wind power generation, a battery storage system, and some load. The specification of the microgrid are displayed in Table 4.1. The wind and solar profiles are generated based on weather data and as seen in Section 4.2.3.

The microgrid is operated in grid connection mode when there are no failures in the system. However, when a failure occurs in the distribution grid, the microgrid will shift to island operating. Then, after the sectioning time, the microgrid will follow different microgrid modes as described in Section 4.2.1.

Table 4.1: Microgrid specifications

Component	**Specification**
Battery	Max capacity: 1 MWh
	Inverter capacity: 500 kW
	Efficiency: 0.95
	Min SOC: 0.1
Wind & Solar power	Max power: $\sim$ 3.5 MW
Load	Peak load $\sim$ 200 kWh

Battery Strategy

In multiple cases, batteries in the power system will sell and buy power in a power market or flexibility market. When batteries participate in such markets, the stored energy in the battery will vary over time. This is taken into account by drawing the SoC level of the battery when a failure occurs in the system. The drawing of the SoC level follows a uniform distribution since no information about the possible market strategy is given. This will make a more realistic case with varied contributions from the battery.

4.3.3 Scenarios

The case study investigates three different scenarios that are based on the microgrid modes described in Section 4.2.1.

A sensitivity analysis is conducted in addition to the scenarios. The sensitivity analysis is conducted as a full factorial design where changes in the battery capacity, repair time distribution, and failure rate are investigated. The parameter values used for the factorial design are shown in Table 4.2. The repair times still follow the gamma distribution, but the *67% and less* value is changed. Additionally, how the microgrid location affects the reliability of supply in the distribution network is explored.

Table 4.2: Parameter values used in the factorial design study

		Name
Battery	1	Bat$_1$
[MWh]	2	Bat$_2$
		Name
	1	r$_1$
Repair time	2	r$_2$
[h]	3	r$_3$
		Name
	0.05	λ_1
Failure rate	0.07	λ_2
[failures/year]	0.09	λ_3

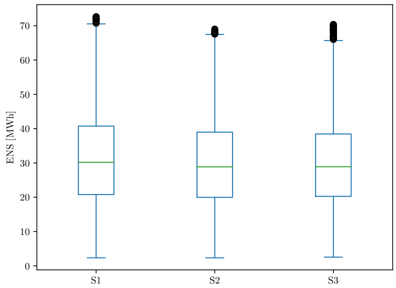
4.4 Results and Discussion

The results from the case study and Paper II are presented in this section. In the study, steady-state conditions are assumed for all the reliability studies. The simulation converges after approximately 3,000 iterations, when all the simulations are simulated for 5,000 iterations.

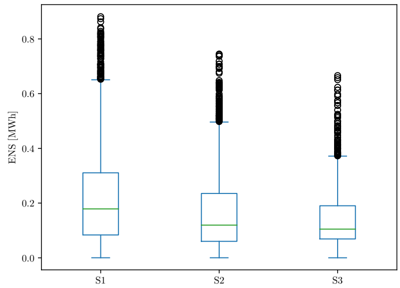
4.4.1 Result from the Scenarios

In Figure 4.4a, a box plot of the frequency distribution of ENS for the distribution network is illustrated. It can be observed from the box plot that there is a slight decrease in ENS for Scenarios 2 and 3 where the microgrid supports the distribution system during faults, compared to Scenario 1 where the microgrid operates in island mode during faults. Comparing Scenarios 2 and 3, there are only minor differences. The result is more apparent in Table 4.3 and Figure 4.5a where the mean values of the reliability indices for the distribution network are presented for the three scenarios. Overall, the mean ENS decreases by 4.27% for Scenario 2 and 4.62% for Scenario 3 compared to Scenario 1.

Table 4.3 and Figure 4.5a display the result for the other investigated reliability indices (SAIFI, SAIDI, and CAIDI) for the distribution network. By analyzing these indices, some small differences between the scenarios can be observed. The



(a) Box plot for the distribution network



(b) Box plot for the microgrid

Figure 4.4: Box plot of the frequency distribution of Energy Not Supplied for the distribution network and the microgrid for the three scenarios.

down time for the system decreases with support from the microgrid. The reason for this is that some load points will experience a decreased period of shedding. However, the failure frequency will increase. In most cases, the microgrid generation and battery are unable to preserve supply during the entire outage period, resulting in some load points experiencing a *new* outage period when the generation is low or the battery is empty. In addition, the down time for Scenario 3 is slightly higher than for Scenario 2. This is a result of the microgrid storing power for its own load, resulting in less power for the distribution system.

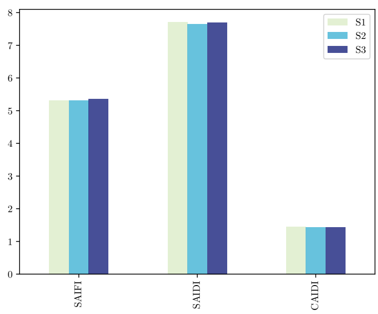
Table 4.3: Mean values of the reliability indices for the distribution network

	S1	**S2**	**S3**
ENS [MWh]	31.7518	30.3975	30.2834
SAIFI [-]	5.3566	5.3630	5.3925
SAIDI [h]	7.7945	7.7261	7.7745
CAIDI [h]	1.4551	1.4406	1.4417

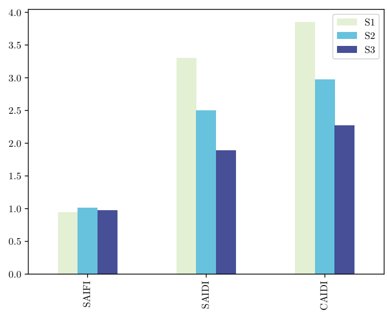
The amount of `ENS` experienced by the microgrid for the different scenarios can be seen in Figure 4.4b. The differences between the scenarios are clearer when investigating them from the perspective of the microgrid. Here, Scenario 1 will result in most shedding, since the microgrid has to survive in island mode during the fault in the distribution network or the microgrid. The reason is that since the SoC level of the battery is following a distribution, in situations where the SoC and the generation from wind and solar power are low, the microgrid is unable to ensure self-sufficiency. This case would be different if, for example, the battery is used as a backup in this scenario or if the microgrid could reconnect to the distribution network for cases where the microgrid location is not affected by the fault in the system.

Scenario 2 is somewhat better since the microgrid will reconnect to the distribution system. For situations where the microgrid is in the same subsystem as the main feeder of the distribution system, the microgrid will be ensured supply. Scenario 3 is the case that will give a very small `ENS`. The shedding and outliers in the box plot are a result of failures inside the microgrid, long repair time on some failures, and some *high impact low probability* (HILP) cases. These cases are the result of two failures happening in close approximation, leading to a discharged battery before the last fault is removed.

The mean values of the reliability indices for the microgrid can be seen in Figure 4.5b and Table 4.4. The indices indicate that there is a considerable decrease in the interruption duration for Scenario 3 compared to the others. Scenario 3 also leads to a lower interruption frequency. The increase in interruption frequency for Scenario 2 is caused by a low generation and an empty battery that is not sufficient to supply the microgrid load, resulting in the microgrid load experiencing additional interruption. The `ENS` for Scenario 3 decreased by 69.32% compared to Scenario 1, whereas the `ENS` for Scenario 2 decreased by 26.63%.



(a) Bar plot for the distribution network.



(b) Bar plot for the microgrid

Figure 4.5: Bar plot of the mean values of the reliability indices for the distribution network and the microgrid. (`SAIFI` is given in frequency of disturbances while `SAIDI` and `CAIDI` are given in hours).

Table 4.4: Mean values of the reliability indices for the microgrid

	S1	S2	S3
ENS [MWh]	0.1258	0.0923	0.0386
SAIFI [-]	0.5345	0.5556	0.2554
SAIDI [h]	1.8814	1.3890	0.5122
CAIDI [h]	3.5201	2.4999	2.0059

Statistical Testing

Statistical testing was performed on the results for both the distribution network and the microgrid for the three different scenarios. First, the AD test was used to investigate if the results are normally distributed. As seen in Table 4.5 and Table 4.6, the normality test failed for both the distribution network and the microgrid, indicating that none of the results are normally distributed. The test statistics, A^2, are very high, demonstrating with high certainty that the result is not normally distributed.

The non-parametric test was then performed to investigate if the results originate from the same population. A significance level of 5% was chosen, meaning that the null hypothesis, which is that a result is taken from the same population, is rejected if the p-value of the test is lower than 0.05. The result for the distribution network is shown in Table 4.5. The table reveals that Scenario 1 is significantly different from Scenarios 2 and 3. However, Scenarios 2 and 3 are not significantly different, meaning they are from the same population. This result indicates that there is a significant difference between receiving support from the microgrid during unintentional outages in the distribution system compared to no support. However, the actual network impact might vary. The result for the microgrid is shown in Table 4.6. The outcome shows that all the scenario results are significantly different from each other. This illustrates the importance of backup supply for the microgrid, either through the distribution system or through the microgrid sources. Since all the scenarios are significantly different, Scenario 3 is the best scenario identified from the microgrid perspective when measuring `ENS`.

Table 4.5: Statistical test of the three scenarios in the distribution network.

Scenario	**AD test** A^2	**Scenarios**	**KS test** p-value
S1	22.34	**S1 vs. S2**	0.00
S2	20.68	**S1 vs. S3**	0.00
S3	18.42	**S2 vs. S3**	0.53

Table 4.6: Statistical test of the three scenarios in the microgrid.

Scenario	**AD test** A^2	**Scenarios**	**KS test** p-value
S1	452.52	**S1 vs. S2**	0.00
S2	509.56	**S1 vs. S3**	0.00
S3	993.91	**S2 vs. S3**	0.00

4.4.2 Sensitivity Analysis

Since there was no significant difference between the results from Scenario 2 and 3 for the distribution system and Scenario 3 gave the best overall result for the microgrid, this case was used for the sensitivity analysis. A full factorial design study was performed on Scenario 3. The investigated parameters and parameter values can be seen in Table 4.2.

The results from the factorial design study are illustrated in Figure 4.6 for the distribution network and in Figure 4.7 for the microgrid. The plots indicate both the effect each parameter has on the `ENS` in the system and how the parameters affect each other.

When investigating the result for the distribution network (Figure 4.6), the failure rate of the lines gives the largest contribution to `ENS` in the system. Increased battery capacity, however, does not affect the `ENS`. This effect is a consequence of the battery being placed at one location in the network, meaning it is not able to contribute to all possible outage scenarios in the network since it will be isolated from the fault. In addition, the battery is limited by the inverter and the energy in the battery. Unlike the battery, the line failure rate and repair time affect all the lines in the system.

Investigating the results from the microgrid perspective (Figure 4.7), the battery capacity has a more important role compared to the distribution system. There is a clear interaction effect between the battery capacity and the repair time. The `ENS` in the microgrid is more sensitive to variations in repair time when the battery capacity is low. This is a consequence of the microgrid being able to supply the microgrid load for more hours during special HILP events, as discussed. A smaller but similar interaction effect is seen between the battery capacity and the failure rate. When the battery capacity is small, the microgrid is more vulnerable to failures.

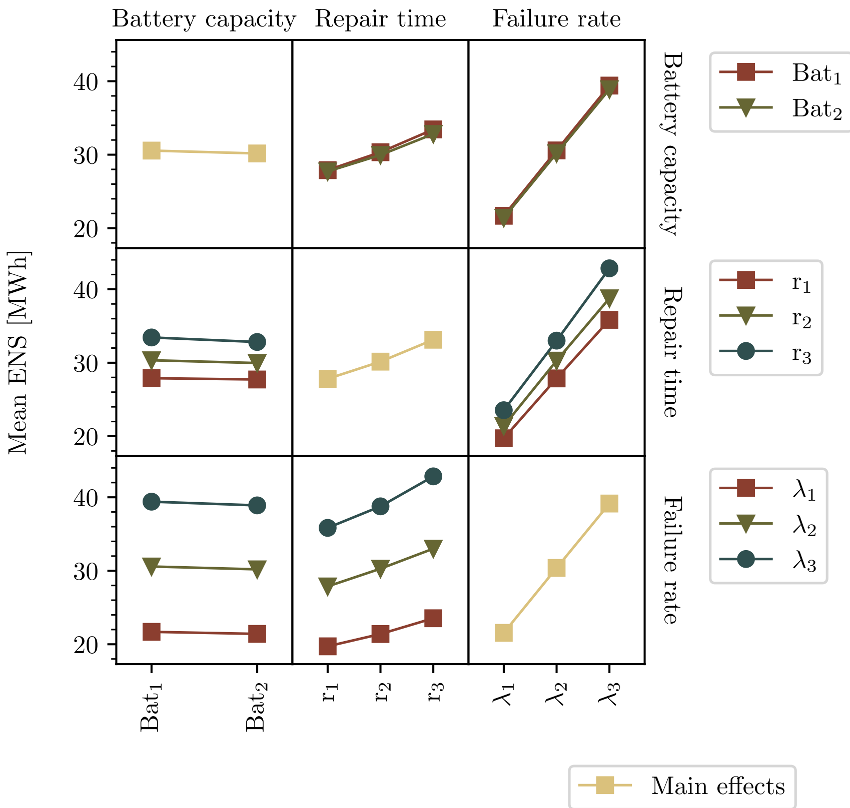


Figure 4.6: Interaction plot for the distribution network of the mean `ENS` for the battery, outage time, and failure rate parameters.

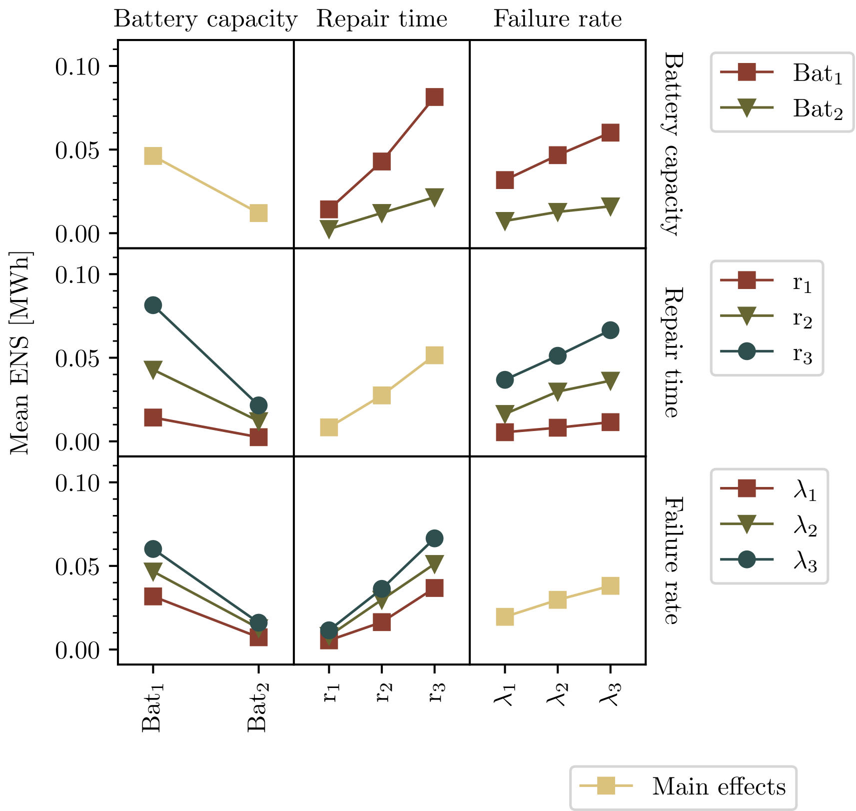


Figure 4.7: Interaction plot for the microgrid of the mean `ENS` for the battery, outage time, and failure rate parameters.

4.4.3 Microgrid Location Study

The impact the microgrid placement has on the `ENS` in the distribution network is also investigated. Simulations varying the microgrid location to cover all the distribution network buses were conducted. The results are presented in Figure 4.8. Each bus is colored based on the `ENS` of the distribution system with the microgrid located at the respective bus. The results indicate that it is beneficial to place the microgrid at the end of long radials. In this study, it will be at B18 in the distribution system.

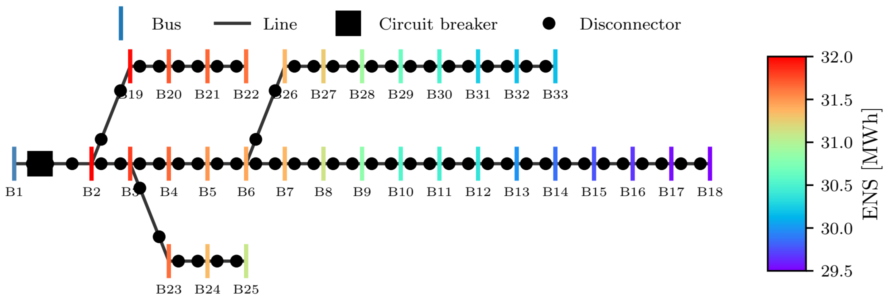


Figure 4.8: Heat map showing ENS in the distribution network for different placements of the microgrid.

4.4.4 General Discussion

When analyzing the results from the microgrid scenario study, the statistics show that receiving support from the microgrid for the distribution network has a significant effect on the ENS. However, the difference between the results of the different scenarios is minor. From the microgrid location study, we know that the placement of the microgrid is an important reliability factor. In addition, since multiple failures can occur at locations where the microgrid is not able to provide support, the distribution network might benefit more if the generation sources were scattered at different locations in the system. Another impacting factor is the availability of wind and solar power in the microgrid and the energy level of the battery when a failure occurs. This decides the amount of power the microgrid can contribute.

The reliability of the microgrid, however, is very dependent on the microgrid controller mode. This is a factor that could change the results if other modes for the microgrid controller are applied. The results indicate that Scenario 3 is the best cross-over strategy for both the microgrid and the distribution system when analyzing ENS. This could change for the microgrid if other strategies were applied. RELSAD and the methodology made for calculating the reliability of such a case facilitate the implementation and use of multiple different modes for the microgrid controller. In addition, the result could be different if other measures are investigated, such as a cost-benefit analysis.

An interesting result seen from both the distribution network and the microgrid perspective is the increase in SAIFI for the scenarios with support from the microgrid. It was expected that SAIDI would decrease as a result of the microgrid supporting the distribution system since the total duration of load shedding for some load points would decrease. However, based on how SAIFI is measured, the index will increase as a consequence of load points experiencing a new outage period when the microgrid generation units are not able to restore all the supply for the entire outage period.

The sensitivity analysis also revealed some interesting results. The distribution network is very sensitive to the failure rate whereas the microgrid is sensitive to the battery capacity and the repair time. In this scenario, the microgrid is designed to ensure self-sufficiency by storing energy in the battery. For some situations where the repair time is long or multiple failures occur at the same time, the microgrid benefits from a larger battery capacity. Several interaction effects are evident for the microgrid, while none are apparent for the distribution network. The two most significant interaction effects seen for the microgrid are linked to the battery capacity, while the battery capacity does not influence the ENS for the distribution network. The results from the sensitivity analysis are a consequence of the network sizes. The distribution system is large compared to the microgrid and the load is large compared to the generation in the microgrid. Since the microgrid load is prioritized, the amount of energy support from the microgrid is restricted. In addition, the microgrid can only support failures that are not isolated from the microgrid. Since the distribution system is a relatively large system, local conditions become less severe seen from the whole system perspective. However, they are still important for issues locally as seen from the microgrid perspective. This is also something that could be seen if smaller parts of the distribution system connected to the microgrid were investigated. The size of the network and distinguishing between local and global perspectives are therefore important factors when analyzing the ENS for the given parameters.

4.5 Conclusion

This study has successfully investigated how a microgrid including RES may improve the distribution system reliability. The reliability impact was mapped through investigations of variations in microgrid placement, operation mode, and battery capacity, resulting in a suggestion for the optimal conditions for the microgrid with respect to minimizing the impact on the microgrid while maximizing the contributions to the distribution system. Statistical testing was performed to evaluate the results and indicated a significant difference in receiving support from the microgrid compared to no support. However, the effect could be seen as moderate. The contribution is dependent on the microgrid and the location of the microgrid. Since the microgrid is located in one place, there will be multiple cases where the microgrid is not able to support the distribution network. This is a result of effects seen on the system as a whole against effects seen locally in the system. The significance of the result, however, makes way for further investigations of the possibility of using microgrids or other sources as reliability support for the distribution network. This can lead to further studies of other reliability support possibilities or other system configurations such as distribution networks consisting of multiple microgrids. The presented methodology for evaluating how microgrids perform from a reliability perspective using RELSAD shows great promise. The study investigated the reliability of electricity supply both from the perspective of the distribution network and from the perspective of the microgrid. The tool facilitates analysis of multiple different cases and the results are detailed distributions that serve as a good basis for further analysis. Additionally, the tool is general and modular, lowering the barrier to implementing different operation modes and studying different system topologies.

5 Case 2: A Study on V2G impact on the Reliability of Modern Distribution Networks

This chapter is based on the study conducted in Paper III. The aim of this chapter is to investigate the impact of V2G on the reliability of modern distribution networks. The study illustrates how V2G is implemented in RELSAD and proposes some reliability indices for EVs. A short introduction starts the chapter before the modeling of EVs and V2G is presented. A case study will then be introduced before the results are shown and discussed. The chapter ends with a conclusion.

5.1 Introduction

According to a study conducted by The Institute of Transport Economics, EVs will constitute on average 45.9–61.2% of all cars by 2030 in Norway [12]. The actual EV share might differ between the different regions in the country, resulting in regions with a high share of EVs and others with a low share of EVs. With a high share of EVs in the distribution systems, the potential of using EVs as grid support is increasing. By utilizing the EVs with, for example, Vehicle-to-Grid (V2G) technology, demand response measures such as frequency regulation, voltage support, and reactive and active power support can be possible. With V2G, the EVs that are connected to a charging station can support the network by transferring active and/or reactive power back to the power grid. Some studies have investigated the potential of utilizing EVs with V2G to support the grid. V2G technology has been investigated for voltage regulation in distribution systems [95], primary frequency regulation [96,97], and regulation of small microgrids [98]. In [99], a method for primary frequency regulation from an EV fleet is proposed. The study concludes with positive results and adds recommendations for ensuring a safe and stable operation when utilizing V2G.

An interesting study on a military microgrid system is conducted in [100]. The study investigates V2G and vehicle-to-vehicle opportunities for power generation in a military microgrid. The study shows economic benefits due to reduced fuel costs and a benefit better than the already existing solution, indicating that EVs have an impact. However, the study points out the need for technology upgrades.

Other studies have explored the possibility of increased reliability with V2G support. In [101], a framework based on a non-sequential MCS is developed to evaluate the reliability of a modern distribution system. The framework is used to investigate how integrated renewable generation and EV parking lots influence reliability. The results indicate a significant improvement when V2G is activated. A sequential Monte Carlo framework is developed in [102] in which V2G and vehicle-to-home for reliability purposes are researched. The studies indicate a benefit of utilizing the available EVs for V2G services of the power system. However, the amount of support can be limited by multiple factors such as EV availability and the technology related to charging, and will need to be further evaluated. In addition, in the literature, the impact on the degradation of EVs is not considered to any great extent.

The aim of Paper III is to investigate the impact V2G services have on the reliability of modern distribution networks for short repair times. By providing three new EV-related indices, we aim to identify and investigate the impact experienced by the EVs when V2G is used. In addition, we provide a general methodology for evaluating how EVs perform from a reliability perspective through the use of RELSAD.

The contribution of this study is to propose a methodology to assess the reliability of a modern distribution network with V2G opportunities. The study investigates different cases where the reliability of the distribution network is assessed with and without V2G options. Additionally, three EV-related indices are proposed to determine the impact on the EVs in the system. The study contributes a thorough analysis of the reliability impacts by conducting a sensitivity analysis where the reliability indices are investigated deeply. The parameters that are explored are the charging capacity of the EVs, the share of EVs in the distribution network, and the repair time of components in the system. The distribution system with V2G opportunities is developed to replicate a realistic and modern distribution system. This is done systematically by gathering data for the system through procedures where the reliability data is based on statistics from the Norwegian distribution systems, see 5.2.2 and 5.3.1, the EV availability data is based on statistics from The Norwegian Electric Vehicle Association (*Elbilforeningen*), see 5.2.1, and the EV share data is based on statistics from The Institute of Transport Economics.

5.2 Method

RELSAD is used as the tool for performing the reliability analysis of this study. See Chapter 3 for more description of RELSAD. In addition, for this study, EVs with V2G properties were implemented. In Section 3.2, a description of how EVs are implemented in RELSAD is elaborated. Furthermore, some EV indices are proposed in this study; they are described in Section 3.4.3. These indices will be used together with traditional reliability indices to analyze the results of the study. This section will describe how the availability of EVs and repair times of the distribution system components were estimated in this study. Additionally, the modeling and functionality of V2G are described.

5.2.1 Availability Distribution

To activate V2G support in the distribution network, the availability of EVs in the network needs to be established. Modeling of the availability of EVs is decided based on the number of EVs that are charging at home. This lays the foundation for EV availability to be based on charging patterns.

The charging pattern of Norwegian EVs is examined in a survey conducted by The Norwegian Electric Vehicle Association (*Elbilforeningen*). The survey was completed in 2019 with more than 16,000 respondents [103] and will be used as a basis for estimating the availability of EVs in the distribution network. The result of the survey is summarized in Figure 5.1 and Figure 5.2. Figure 5.1 illustrates at which time the EV owners usually charge their EV. In Figure 5.2, the frequency for home charging is shown. This results corresponds well with the result on charging patterns obtained in [104] and give a good basis for evaluating the expected availability of EVs that are charging at home during a specific time in the distribution networks.

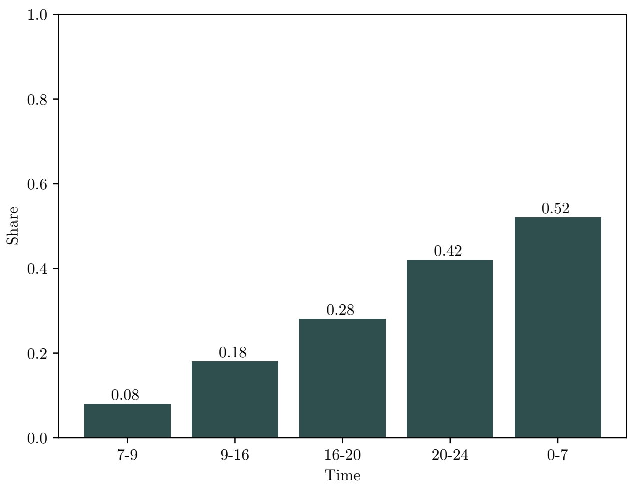


Figure 5.1: The normal charging time of an EV, based on [103].

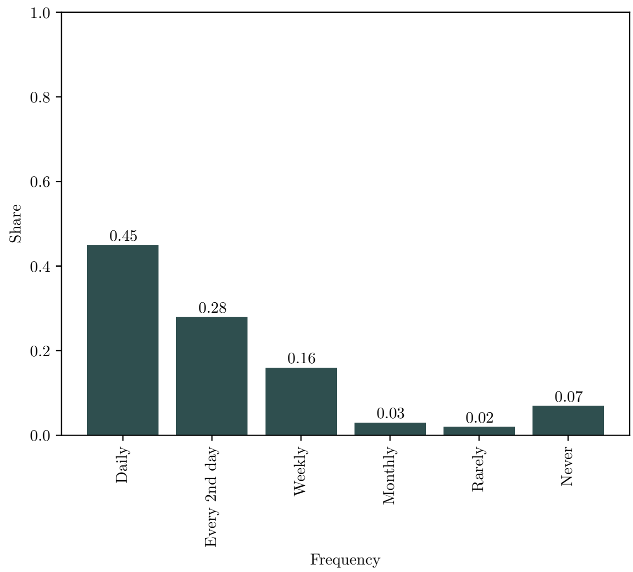


Figure 5.2: The home charging frequency of an EV owner, based on [103].

Based on the distributions in Figure 5.1 and Figure 5.2, and the amount of EVs in the distribution network, the probability of an EV being charged at home can be calculated as

$$A_{EV} = n_{customers} \cdot X_{EV} \cdot C(t) \cdot D_{EV} \tag{5.1}$$

Here, $n_{customers}$ is the number of households in the distribution network, X_{EV} is the percentage share of vehicles that are EVs in the distribution network, $C(t)$ is the share of EVs charging at time t (based on Figure 5.1), and D_{EV} is the estimated daily charge frequency. The daily charge frequency gives a probability of the EV to be charged at home and based on Figure 5.2, $D_{EV} = 0.45 + 0.28 \cdot 0.5 + 0.16 \cdot 1/7 + 0.03 \cdot 1/30 = 0.61$.

5.2.2 Repair Time Distribution

In this study, events resulting in varied down times are considered. Therefore, the repair time of the system components will vary within a range of possible repair times. The repair time used in this study is based on yearly reliability statistics for the Norwegian DSOs and is described in Section 5.3.1. There exist multiple possible distributions that can be used to decide the repair time of an event, such as Log-normal-, gamma-, and normal distributions [105]. In this study, truncated normal distributions will be used.

Truncated Normal Distribution

A truncated normal distribution has a probability distribution similar to a normal distribution but is bounded by either an upper or lower limit or both.

The probability density function of a normal distribution can be expressed as

$$f(x) = \frac{e^{-\frac{(x-\mu)^2}{(2\sigma)^2}}}{\sigma\sqrt{2\pi}} \tag{5.2}$$

where μ is the location or mean parameter of the distribution and σ is the scale parameter or standard deviation. Truncated normal distributions are good distributions to use for repair times that are limited by boundaries. Figure 5.3 illustrates how the truncated normal distributions look with different location parameters. In the figure, a high, low, and normal mean value is illustrated.

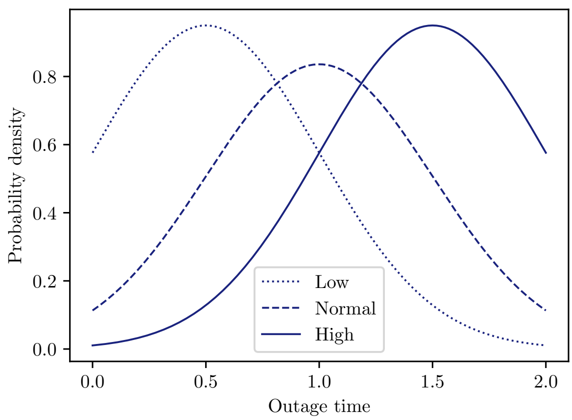


Figure 5.3: Truncated normal distributions of the repair time for three different location parameters. Here, the distribution is illustrated with a low, high, and normal mean value.

5.2.3 EV and V2G Algorithm

In Algorithm 2, the EV park procedure during faults in the network is displayed. Since RELSAD is a reliability assessment tool aiming to evaluate the reliability of a system, only situations with faults are considered.

The algorithm is called upon when a failure occurs in network N, in the current time increment. Then the number of cars in an EV park is determined based on an availability distribution. In this study, the availability is calculated as described in Section 5.2.1. Next, the SoC state of each EV in the EV park is specified following a given distribution (in this study, it follows a uniform distribution). The SoC state is stated between the maximum and minimum allowed SoC state. Then the network balance of network N, N_b is calculated. This is used to find out the demand for each EV and the load and generation of the network.

If V2G is activated for the EV park, the EV will either be charged or discharged depending on the load balance. If there is available generation, the EVs can be charged; if there is a lack of generation, the EVs might be discharged to be used for support. After this, the load balance of the network is updated.

If V2G is not activated, charging of the EVs is only possible if there is a surplus of generation in the network (or connected to the overlying network). The load balance of the network is then updated.

In the end, the history variables of the EVs in the EV parks are updated and used to calculate the indices.

Algorithm 2: EV park procedure during faults in the network

```
if Failure in network, N, happened in current increment then
    Draw number of cars;
    foreach car do
        Draw SoC state;
    end
end
Get network load balance, N_b;
foreach car do
    if Vehicle to grid mode is active then
        Charge/discharge car battery;
        Update N_b;
    else
        Charge car battery;
        Update N_b;
    end
end
Update history variables;
```

5.3 Case Study

5.3.1 The Reliability Test Network

Similar to the approach in Chapter 4, the method is demonstrated on the IEEE 33-bus network [92]. The implementation of the network is similar, with an equivalent load picture. The load is generated similarly to in Section 4.3, however, in this study, a time increment of five minutes is used. Since the load profiles have hourly increments, the load profiles are interpolated to fit the simulated time increment. Figure 5.4 illustrates the test network as a heat map of the mean load in the network. The figure also gives the placement of the EV parks in the network.

The repair time follows the distribution described in Section 5.2.2. The repair time data is based on yearly reliability statistics from the Norwegian DSOs [94]. The repair times used in this study span over a time of up to two hours. This time is chosen based on two reasons; 1) the availability of disruption data from the Norwegian DSOs [94] and 2) its illustration of to what degree the EVs can support the distribution network for short and longer repair periods. Based on the reliability statistics from the Norwegian DSO, the failure rate corresponding the repair time statistics is 0.026 failures/year/km. This failure rate is based on a collection of the failure rate of multiple components with outage times up to

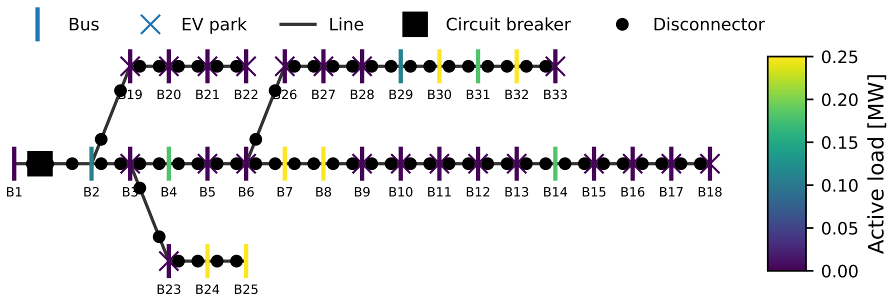


Figure 5.4: The system topology. The buses with EVs are shown with an X. The plot illustrates a heat map of the mean load at each bus in the system.

two hours [94].

EVs in the Distribution System

The EV parks in the system are connected to the buses containing household loads. The availability of the EVs in each EV park follows the procedure outlined in Section 5.2.1. The mapping of EVs compared to houses in the distribution network is at 46% in this study. This is based on the predicted average share of EVs in 2030 in Norway [12]. With an EV share of 46%, the distribution network will have a maximum of 290 cars. Due to the availability based on the individual charging pattern, the number of available EVs will be fewer.

5.3.2 Description of the Cases

The case study investigates four different cases, summarized as:

- **Scenario 1: EV**—No V2G, no support during failures in the network.
- **Scenario 2: V2G**—V2G is activated, the available EVs can support during failures in the network.
- **Scenario 3: EV and battery**—V2G is not activated, batteries are included.
- **Scenario 4: V2G and battery**—V2G is activated and batteries are included.

The presented scenarios aim to investigate the difference in impact by having V2G support compared to no support (only regular EVs). In Cases 1 and 2, the impact from V2G is addressed when no other generation sources are available. In addition, Cases 3 and 4 are included to investigate the impact of V2G when other energy sources are added. In Cases 3 and 4, two batteries are integrated into the system at B18 and B33. These batteries are implemented to serve as a backup supply for the network and will be fully charged. The reason for including the batteries is to pinpoint the actual impact V2G serves. Since the charging capacity and the battery capacity of EVs are low, there is a limited amount of energy the EVs can possibly support. By including other sources, the opportunity of ascertain the impact might increase. The data used for the cases are summarized in Table 5.1.

Table 5.1: Data for the Case Study

Parameter	**Value**	
EV battery capacity [kWh]	70	
Charging capacity EVs [kW]	3.6	
Share of EVs	0.46	
Repair time distribution	Normal	Loc: 1 Scale: 0.5
Battery capacity [MWh]	0.5	
Inverter capacity [MW]	0.25	
Efficiency	0.95	
Min SoC	0.1	

5.3.3 Sensitivity Analysis

In addition to the case study, a similar sensitivity analysis as conducted in Chapter 4 is performed in this study. The sensitivity analysis is conducted as a full factorial design to determine the impact of different parameters. The investigated parameters are:

- **Charging capacity**—Since the charging capacity on the EVs can vary, we will investigate which effect the invert capacity has on the reliability of the system and the EVs in the network.
- **Share of EVs in the network**—The share of EVs in the distribution network is increasing rapidly, and in the future, some locations are estimated to have a share of EVs close to 100% EVs [12]. Therefore, different percentages of EV share (X_{EV}) in the network will be investigated. This is also to investigate how an increased share of EVs will impact the reliability of the distribution network.

- **Repair time**—The study investigates various repair times of up to two hours. To evaluate the effect of the repair time, the repair time distribution will be adjusted to investigate the reliability impact and the impact on the EVs in the system.

The parameter values used in the factorial design can be seen in Table 5.2.

Table 5.2: Sensitivity analysis data

Charging capacity [kW]		EV share [%]		Repair time distribution		
$\mathbf{P_1}$	3.6	$\mathbf{X_1}$	0.46	$\mathbf{r_1}$	Low	Loc: 0.5 Scale: 0.5
		$\mathbf{X_2}$	0.64	$\mathbf{r_2}$	Normal	Loc: 1 Scale: 0.5
$\mathbf{P_2}$	7.2	$\mathbf{X_3}$	0.82	$\mathbf{r_3}$	High	Loc: 1.5 Scale: 0.5

5.4 Results and Discussion

This section presents the results of the case study conducted in Paper III. The study assumes steady-state conditions. The simulations in this study are performed with increments of five minutes and are simulated for one year. The simulation converges after approximately 1,500 iterations, 3,000 iterations are conducted for each simulation.

5.4.1 Results from the Cases

Figure 5.5 illustrates a box plot of the frequency distribution of `ENS` in the distribution network for the four scenarios. We observe a decrease in `ENS` when V2G services are provided to the distribution network, compared to no service. The average `ENS` in the distribution network for the scenarios is displayed in Table 5.3. The decrease in `ENS` is 5.51% when comparing Scenario 1 and Scenario 2. By comparing Scenario 3 and Scenario 4, the decrease in `ENS` is 6.36% when activating V2G. The results indicate, that with V2G, the EVs are able to support the system for short outages. This was also evident in Scenario 4 where the battery can provide for longer outages and the EVs can serve as a support to the battery.

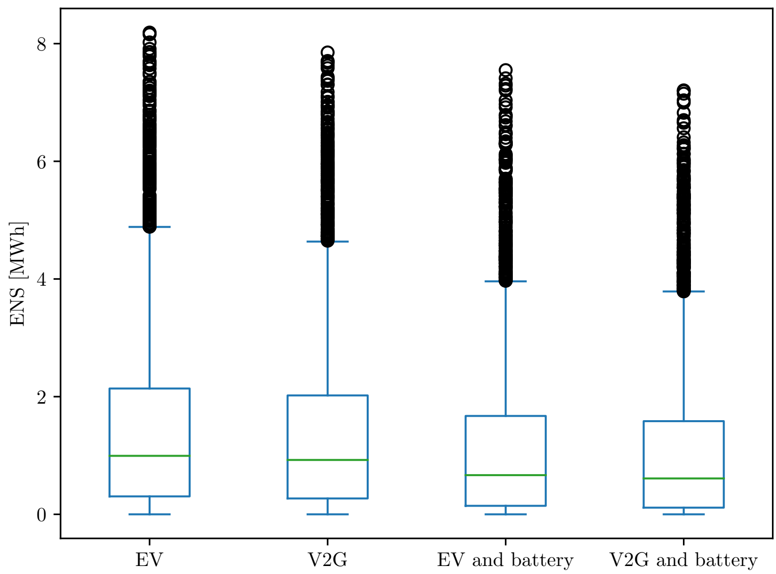


Figure 5.5: Box plot of the frequency distribution of `ENS` in the distribution system.

By examining the other reliability indices, `SAIFI` and `SAIDI`, for the scenarios, as seen in Table 5.3, it is apperent that `SAIFI` is decreasing between Scenario 1 and Scenario 2 and between Scenario 3 and Scenario 4. This illustrates that the total number of interruptions decreases by activating V2G. However, by assessing `SAIDI`, we see that the decrease is not significant. This indicates that the load shedding is due to the reduction in the number of interruptions the load points experience but that the interruption is prevented for short outages only.

The results for the EV indices are also shown in Table 5.3. As expected, the average EV demand not served for the EVs will almost double when V2G is activated. This is a result of the available EVs being used for V2G services and the demand not served then increasing since the EVs will be discharged as well. The other two EV indices, $\mathtt{EV}_{\mathtt{Int}}$ and $\mathtt{EV}_{\mathtt{Dur}}$, will be zero for the scenarios without V2G since the EVs will not be used as a service. For the two scenarios with V2G activated, it is evident that on average an EV owner can expect to experience the EV being used for support 0.15 times during a year for Scenario 1. This is a little higher for Scenario 4 when the batteries are introduced, where the expected interruption is then 0.32 times a year. The reason for this increase could be that when the batteries are used as the main provider and the EVs are there for support, there could be time increments where the battery can provide the necessary demand but others where the EVs need to be used. This will result in the V2G support being turned on and off during an outage and the total number of interruptions will increase. In both Scenario 2 and Scenario 4, the EVs are supporting an average of 38 minutes during a year. These results illustrate that the EVs are neither used often nor for long durations during a year when these reliability parameters are considered.

Table 5.3: Distribution system and EV oriented reliability indices

	Case 1	**Case 2**	**Case 3**	**Case 4**
ENS [MWh]	1.5809	1.4938	1.2529	1.1732
SAIFI [-]	0.4011	0.3881	0.3392	0.3142
SAIDI [h]	1.1348	1.1346	1.0200	0.9998
EV_{Demand} [MWh]	0.0362	0.0708	0.0055	0.0116
EV_{Dur} [h]	0.00	0.6336	0.00	0.6461
EV_{Int} [-]	0.00	0.1546	0.00	0.3185

5.4.2 Sensitivity Analysis

A full factorial design was conducted based on the parameters presented in Table 5.2. The sensitivity analysis was conducted for Scenario 2, and the results for all the presented indices are given. First, in Figure 5.6, the interaction plot for mean ENS is displayed. The figure shows that the repair time is the parameter that impacts the ENS the most. In addition, we observe a small interaction effect between the charging capacity and the share of EVs. This is an expected result, since a higher share of EVs in addition to more charging capacity results in more support.

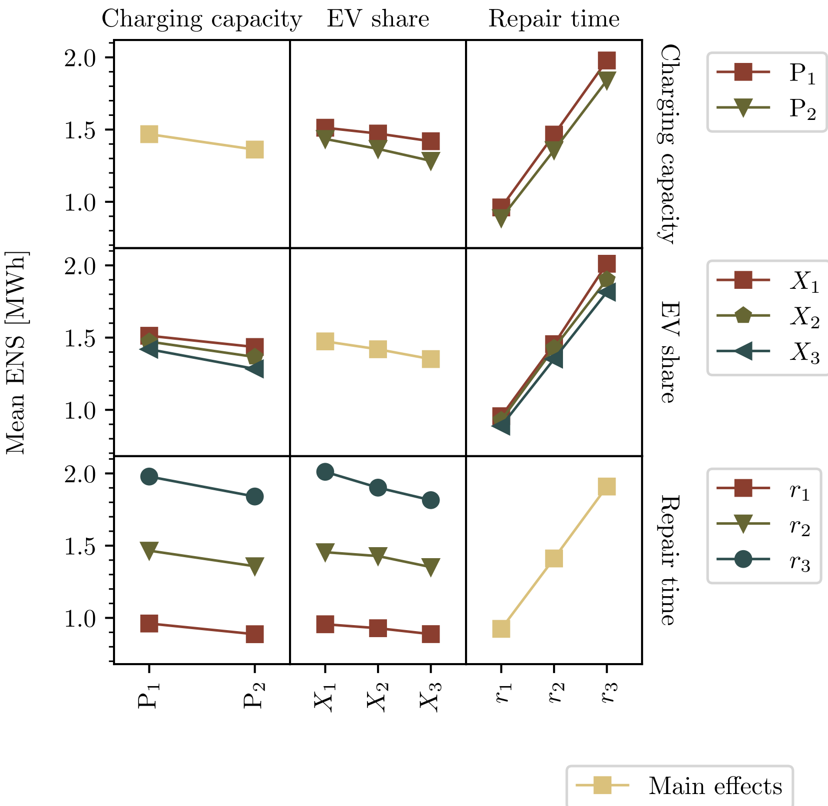


Figure 5.6: Interaction plot of the mean ENS of the distribution system for the parameters charging capacity, EV share, and repair time. The plot illustrates that the repair time affects ENS whereas there is a small interaction effect between the charging capacity and the EV share.

The interaction plots for mean SAIDI can be observed in Figure 5.7. The interaction plot for SAIDI is very similar to the interaction plot for ENS. The repair time gives the largest contribution as expected since a higher repair time gives longer down times in the system. The charging capacity and the share of EVs have almost no effect on SAIDI, which was also illustrated in the results presented in Table 5.3. Similar to the result for ENS, we observe a weak interaction effect between the charging capacity and the share of EVs. This result indicates that higher EV share and charging capacity decrease the total down time and that might indicate that longer outages can be served.

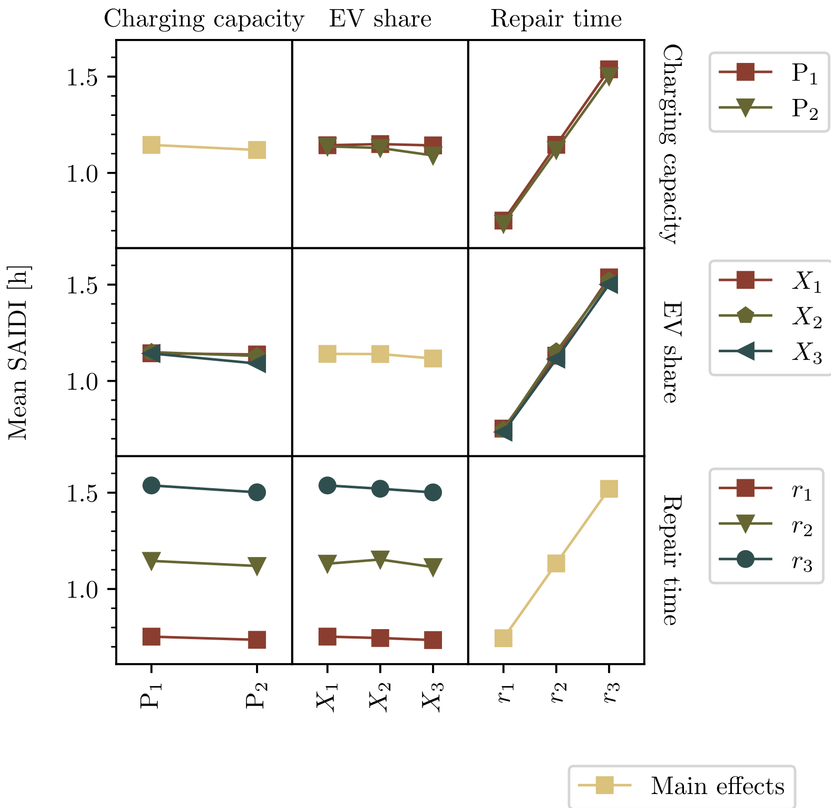


Figure 5.7: Interaction plot of the mean `SAIDI` indices of the distribution system for the parameters charging capacity, EV share and repair time. The plot illustrates that the repair time affects `SAIDI` whereas there is a small interaction effect between the charging capacity and the EV share.

For mean `SAIFI`, seen in Figure 5.8, the charging capacity and the share of EVs have a strong effect. Again, an interaction effect is evident between these two parameters. The interaction effect is stronger for `SAIFI` compared to the results for `ENS` and `SAIDI`, which is a result of these parameters affecting the indices more. This is expected since a higher share of EVs and greater charging capacity enable the EVs to supply more load. The repair time, however, has a low effect and only increases the interruption frequency slightly for higher repair times.

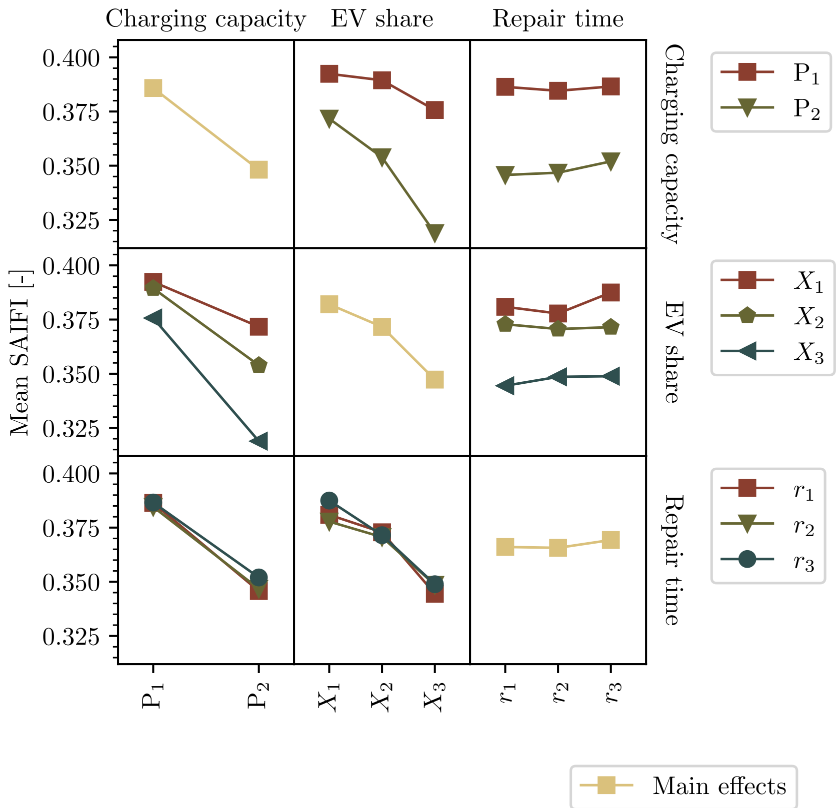


Figure 5.8: Interaction plot of the mean `SAIFI` indices of the distribution system for the parameters charging capacity, EV share, and repair time. The plot illustrates that the charging capacity and the EV share have a strong affect on the `SAIFI`.

The interaction plot for the mean $\mathtt{EV_{Demand}}$ is presented in Figure 5.9. The result illustrates that the demand for the EVs is slightly affected by the repair time. The trend is decreasing, which could be a result of the EVs being emptied since the repair time is long. The charging time, however, leads to a considerable increase in demand. With higher charging capacity, more power can be discharged from the EVs, and this will result in an increased demand for the EVs. The demand increases with an increased share of EVs as more EVs are in need of energy. As seen in the other results, there is a weak interaction effect between the charging capacity and the share of EVs for $\mathtt{EV_{Demand}}$ indices as well.

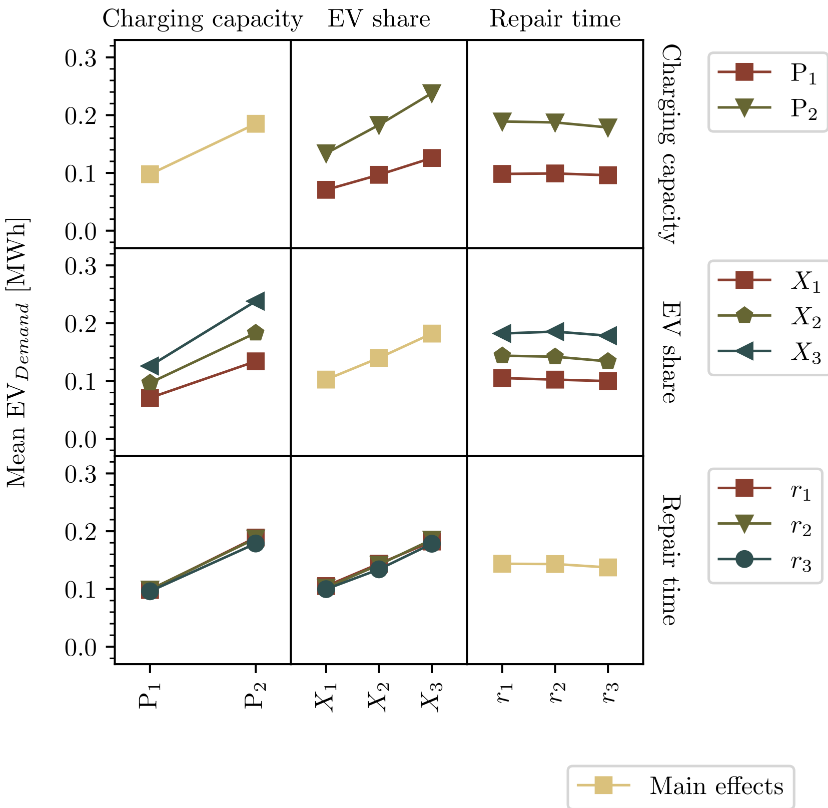


Figure 5.9: Interaction plot of the mean $\texttt{EV}_{\texttt{Demand}}$ indices of the distribution system for the parameters charging capacity, EV share, and repair time. The plot illustrates that the $\texttt{EV}_{\texttt{Demand}}$ is affected by the charging capacity and the EV share.

The result for mean $\texttt{EV}_{\texttt{Dur}}$ in Figure 5.10 is similar to the results for mean ENS and SAIDI. This is expected since this index is similar to SAIDI. The charging capacity and the share of EVs have no effects on the index. However, the repair time has a large effect since a longer down time results in longer periods of support for the EVs.

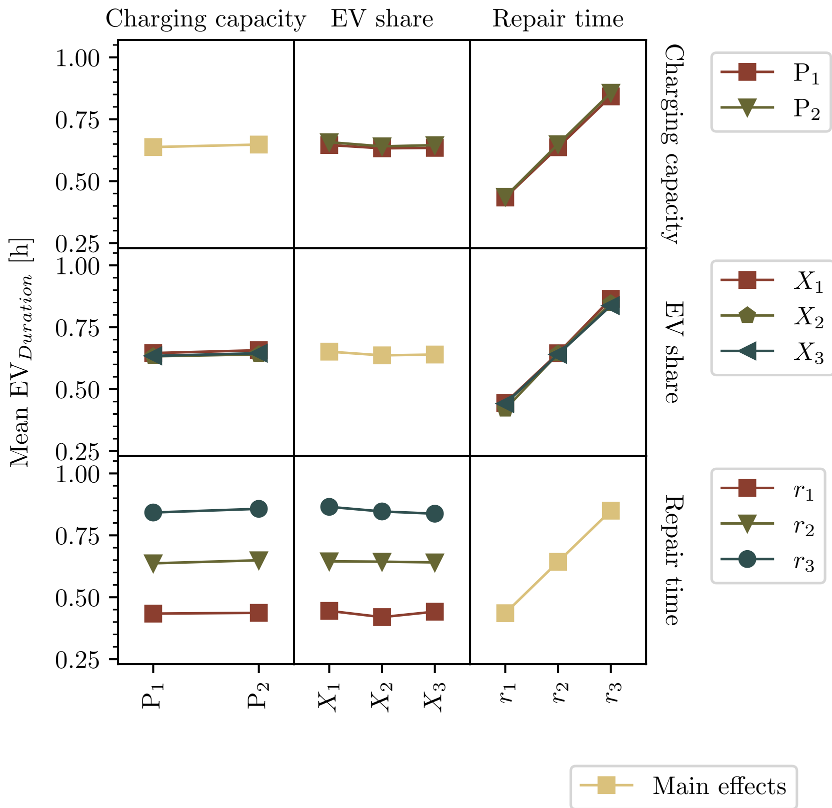


Figure 5.10: Interaction plot of the mean $\texttt{EV}_{\texttt{Dur}}$ indices of the distribution system for the parameters charging capacity, EV share, and repair time. The plot illustrate that the repair time affects the $\texttt{EV}_{\texttt{Dur}}$.

The interaction plot for mean $\texttt{EV}_{\texttt{Int}}$ is illustrated in Figure 5.11. We can see from the results that none of the parameters have any significant effect on the interruption of EVs in the system. We expect that the number of interruptions experienced by an EV will stay fairly constant until load balance is achieved.

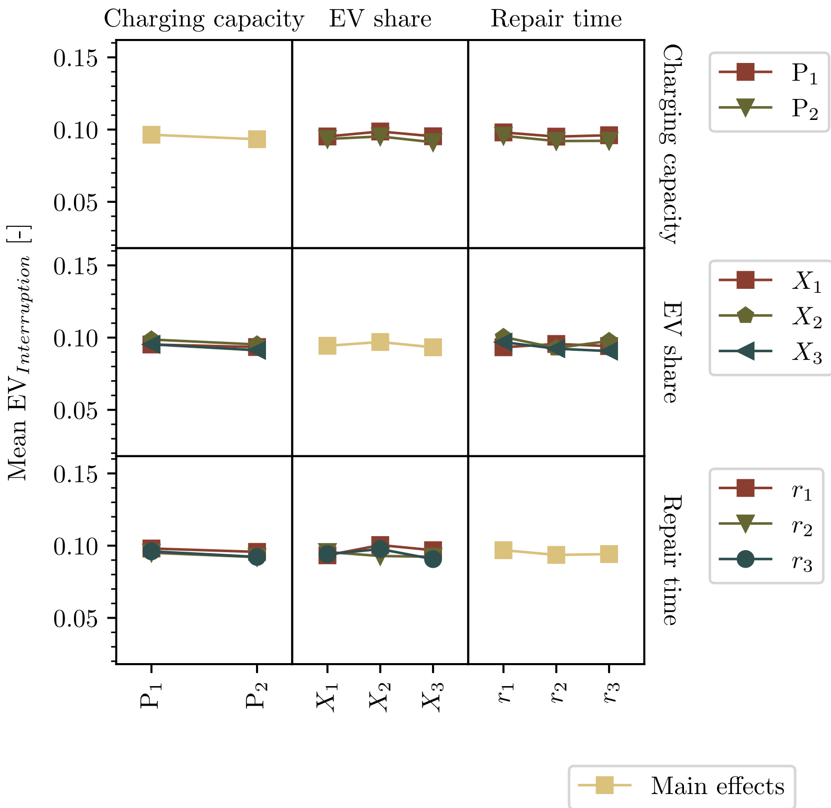


Figure 5.11: Interaction plot of the $\texttt{EV}_{\texttt{Int}}$ indices of the distribution system for the parameters charging capacity, EV share and repair time. The results illustrates that $\texttt{EV}_{\texttt{Int}}$ is not affected by any of the parameters.

5.4.3 General Discussion

When analyzing the results from the case study, it can be observed that the EVs do in fact have an impact on the reliability of the distribution network when V2G is activated. However, the scenarios indicated that this type of V2G support is more suitable for short outage periods. The effect from the V2G could be more significant if other generation source solutions are also available in the system, such as renewable energy sources and batteries. An indication of this was given in the scenario where V2G and batteries were included when longer down times could be provided for and the EVs served as a backup. This result seems to be a general result due to the small contributions the EVs can provide. Since the EVs are restricted by the charging capacity, the EVs are limited to small power contributions compared to other sources such as a battery. Since the simulated failure types have a low probability of occurring, the results indicate that the EVs are not used very often within a year. Since the interruption frequency is so low, an EV owner will most likely not be affected during a year. The total duration an EV is used is also very low, under 40 minutes, meaning that most of the used EVs can restore their demand relatively fast after being used for support. This is encouraging for motivating participation in such V2G programs. The total degradation of the EV battery will also be very low when the EV is used so rarely and during short periods when the charging capacity is low. If, in addition, the EV owner benefits for participating, increased participation can be expected. Further, the benefits from V2G need to be assessed through a cost-benefit analysis.

The duration-based indices ($\mathtt{ENS}$, $\mathtt{SAIDI}$, and $\mathtt{EV}_{\mathtt{Dur}}$) are very sensitive to the repair time of the system components where the other parameters have small effects. The frequency-based ones ($\mathtt{SAIFI}$ and $\mathtt{EV}_{\mathtt{Int}}$), however, are not. Longer repair time means a longer down time of the network, but for $\mathtt{SAIFI}$ and $\mathtt{EV}_{\mathtt{Int}}$, longer repair time does not impact an already started interruption significantly. The share of EVs, however, will affect $\mathtt{SAIFI}$ since more EVs mean that more load can be supplied and fewer EVs need to be used. However, this is not the case for $\mathtt{EV}_{\mathtt{int}}$ since there is no saturation in the network and all the available EVs are used to support the network. The interaction effect between the charging capacity and the share of EVs is observed for multiple indices. This indicates that with higher charging capacity and a number of EVs, more support can be given. Something to note is that the results might be sensitive to the strategy for choosing which EV parks and EVs to use for the V2G service. In this study, the EV parks were ordered by the id of the parent bus and the EVs within the EV parks were chosen randomly.

5.5 Conclusion

In this study, the impact of V2G on the reliability of a modern distribution system for short repair times was investigated. The results illustrate that EVs used for V2G support do have an impact on the reliability. However, the support is more suitable for short down times and in combination with other generation sources where the EVs can serve as a backup. In addition, the impact on the EVs is small since the cars are affected rarely for a short duration at the time. We provided three new EV-related indices that successfully captured the impact experienced by the EVs when V2G is used. The EV-related indices were used to gain valuable insight into the EV perspective of the V2G service. A thorough sensitivity analysis was conducted to analyze how the EV charging capacity, EV share, and repair time of components in the system affect the reliability indices of the system and the EVs. The EV indices give an estimate of both the frequency and duration the EVs are used for V2G services which further provides the impact the EVs will experience. The proposed indices seem to capture the overall system effect experienced by the EVs, and may therefore be suitable for use in further investigations. The presented methodology for evaluating how EVs perform from a reliability perspective using RELSAD shows great promise. The study investigated the reliability of electricity supply both from the perspective of the distribution network and from the perspective of the EVs. The tool facilitates analysis of multiple different cases and the results are detailed distributions that serve as a good basis for further analysis.

6 Case 3: Survivability Quantification of a Cyber-Physical Distribution System

This chapter is based on an additional contribution to this thesis. The aim of this chapter is to investigate how ICT components and networks impact the reliability of a modern distribution network in terms of survivability quantification. In this study, RELSAD is used as the reliability assessment tool to perform the reliability study. This work is a continuation of our published paper "Modeling Interdependencies with Complex Network Theory in a Combined Electrical Power and ICT System". In this study, RELSAD is used to evaluate the reliability of a CPDS. The study demonstrates the concepts of survivability quantification and how an ICT system might influence the distribution network. The survivability quantification is illustrated through a possible high impact low probability (HILP) case where the survivability of the network with ICT is presented. The concept is demonstrated using a small example combined distribution network and ICT system constructed for this study.

6.1 Network Survivability Modeling

In [59], we conducted a study that investigated the importance of the system's nodes in a combined electrical power distribution system and an ICT system. The study applies complex network theory to model the interdependencies between the systems and uses that as a basis to investigate how important the nodes in the combined system are. Two different approaches are used to investigate the node importance: 1) betweenness centrality that highlights the importance of the nodes through shortest paths and 2) a node attack approach that takes out components in the system one by one to investigate the system's survivability [59]. This study has laid the foundation for further investigating the reliability of CPDS. The aim of the study conducted in Case 3 is to investigate how ICT components and networks impact the reliability of a modern distribution network. The reliability of the CPDS is evaluated using RELSAD where ICT components and systems are modeled with their behavior and dependencies. A stochastic survivability simulation approach is implemented to capture the variations in the system parameters when analyzing the reliability of the CPDS. Additionally, a

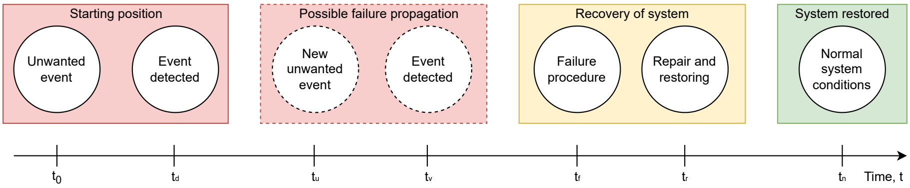


Figure 6.1: The sequence of the failure and possible failure propagation. The sequence illustrates the timeline from when the unwanted event occurs until the system is back to normal operating conditions.

depth-first-search is applied to find routes in the ICT network when faults in the ICT network occurs. The reliability of the CPDS is evaluated through reliability indices and survivability quantifications.

The survivability of a system indicates how capable the system is to continuously deliver the intended services in compliance with the given requirements during failures and unwanted events in the system [106, 107]. For a distribution system, this means, for example, the ability of the system to supply the loads in the network during unwanted events and failures. The survivability of a system can be measured by different metrics. For a distribution system, the survivability can be calculated by measuring, for example, energy not supplied, voltage levels, or outage duration of components and load points.

The system operators decide how they want to quantify the survivability of their network. The most desired outcome is that the system has the same operating level as under normal conditions. However, other criteria may be acceptable, such as a maximum level of energy not supplied over a given period. The criterion is dependent on the customers and their needs.

6.1.1 Sequence of Unwanted Events

Modeling of network survivability is performed by following a sequence of unwanted events, as illustrated in Figure 6.1. The sequence is based on the network survivability modeling in [107]. The start of the event and the simulation begins at time zero in the failed state of the system. From there, the simulation proceeds until the desired *normal* operation condition is obtained. Upon the occurrence of the unwanted event, the event is detected by the system. This could, for example, be a failure on a line in the system that occurs at time t_0, and the DSO detects this failure at time t_d when the circuit breaker trips. Along the sequence of events, new possible events can occur in the system. This could be a failure on a new line or a failure of another component in the system. The fault procedure of the network starts at time t_f, and the repair and restoration of the system, begin at time t_r. After this, the system can be restored and operate under normal system conditions.

6.1.2 Survivability Simulation Approach

To simulate a sequence of unwanted events, RELSAD is implemented with the ability to perform sequential simulations. The sequential simulation starts with the unwanted event and simulates the situation as described in Figure 6.1 until the system is back to normal conditions or the user-specified end time. The increment of the sequence can be decided by the user. The sequence of unwanted events in the system can be simulated in different manners. The two different approaches are: 1) stochastic simulation and 2) deterministic simulation. These two approaches are discussed briefly in this section. RELSAD is developed to support both approaches.

Stochastic Simulation

In a stochastic simulation approach, MCS can be used to simulate the sequence of unwanted events. In this case, variations in system parameters such as repair times and failure rates of components can be used. The variations in the parameters can be utilized through, for example, statistical distributions.

In a stochastic simulation approach, a given sequence of unwanted events can be simulated for a selected number of iterations. The outcome will provide reliability and survivability metrics that account for variations in the system parameters. The result can be presented as statistical distributions. The advantage of a stochastic simulation approach is the opportunity to map the resulting metrics over a broad range of possible conditions. The resulting distribution of results reveals the worst and best case scenario for the simulated sequence of unwanted events. In this study, a stochastic simulation approach is used.

Deterministic Simulation

In a deterministic simulation, all the component parameters are fixed values. The sequence of unwanted events will then be simulated once with a given characteristic of the system. In this case, the result will be single metrics describing the performance of the system for the given condition. The advantage of a deterministic simulation is the fast computational time.

6.1.3 Depth-First-Search

In telecommunication, different approaches can be used to transfer signals over the ICT network. Some common approaches for signal and package transferring are [108]:

- **Broadcast**:
  Broadcast transfer is based on a one-to-all approach of signal transfer. This means that there is a one-way transfer of communication from a transmitter to a number of receivers.
- **Unicast**:
  Unicast is an approach where the information is sent from one transmitter to another point/receiver. This means that, compared to broadcast, that there is only one sender and one receiver.
- **Multicast**:
  In multicast, the information is communicated from one transmitter to a given group of receivers. In multicast, the communication is built up as a tree structure.

In this study, a depth-first-search (DFS) approach is used to find possible communication routes between two communicating ICT components in the ICT network. This can be based on a multicast approach of sending information through the ICT network by building up a tree structure. In a DFS algorithm, the network is traversed depth-wise branch by branch. For this implementation, the sending ICT component is chosen as a root node and the receiving ICT component is chosen as a leaf node, by this building up a tree structure. When the leaf node in question is encountered from the DFS starting at the root node, we know that the ICT components are connected. The ICT components are assumed to be able to communicate with each other when they are connected in the ICT network [109]. The DFS algorithm is chosen because we assume that the ICT components are usually far away from each other. If they are close to each other, a breadth-first-search (BFS) would be more efficient.

The modeling of the CPDS and the dependencies are presented in Chapter 3.

6.2 Case Study

6.2.1 Test System

This method is demonstrated on a small distribution network consisting of six buses seen in Figure 6.2. The topology figure also illustrates a heat map of the demand in the distribution network. In addition to the electrical components in the distribution network, an ICT layer is added. The topology of the combined CPDS is shown in Figure 6.3. For simplicity, all the disconnectors have an intelligent switch connected and all the lines have a sensor connected. The figure also illustrates the implemented ICT network that consists of ICT nodes and lines.

The reliability specifications for the distribution network with the ICT components and network are illustrated in Table 6.1.

Table 6.1: Failure rate and repair time of the system components. The failure rate and repair time for the power system components are based on interruption statistics from the Norwegian power system [94], while the failure and repair rates for the ICT components and network are based on [110]. Here, the lines are assumed to have average length.

Component	**Failure rate [failure/year]**	**Outage time/repair time**
Line	0.07	Truncated Normal Loc: 4 h Scale: 1 min/max: 0/6 h
Intelligent switch	0.03	2
Sensor	0.023	New signal: 2 sec Reboot: 5 min Manual repair: 2 h
Controller (hardware failure)	0.2	2.5 h
Controller (software failure)	12	New signal: 2 sec Reboot: 5 min Manual repair: 0.3 h
ICT line	0.068	Truncated Normal Loc: 3 h Scale: 1 min/max: 0/6 h

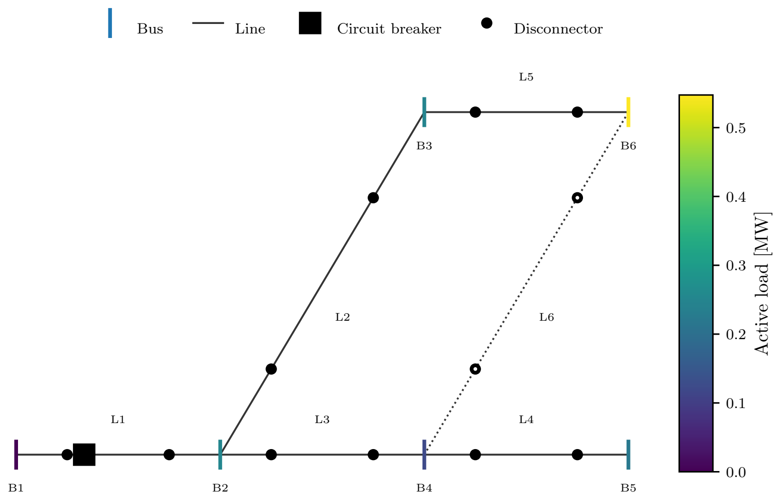


Figure 6.2: The distribution system topology includes a heat map of the load at each bus in the network.

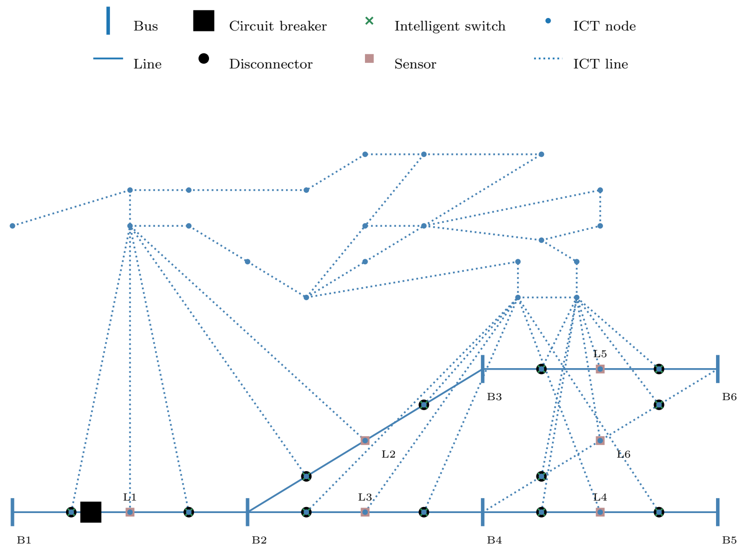


Figure 6.3: The system topology with the ICT network. The ICT network is illustrated with dotted lines, while the power system is illustrated with solid lines.

6.2.2 Scenario Description

In this study, three different scenarios are simulated and listed as follows:

1. **Scenario 1: No ICT implemented**—In this scenario, no ICT is added to the distribution network. The distribution network operates passively and the sectioning time is one hour.
2. **Scenario 2: ICT is implemented**—In this scenario, the ICT components and network as described are added to the distribution network. The influence of the ICT components on the distribution network is described.
3. **Scenario 3: Survivability study**—This scenario illustrates a possible HILP scenario. The study can resemble a possible outage situation that can occur when there are, for example, multiple failures in the ICT network, some extreme weather conditions, or cyberattacks that have resulted in down time in the network. The procedure performed in this study follows what is described in Section 6.1. The system will start with a failure on L3 in the distribution network and two of the ICT lines as seen in Figure 6.4. Additionally, after 30 minutes, a failure on L5 occurs.

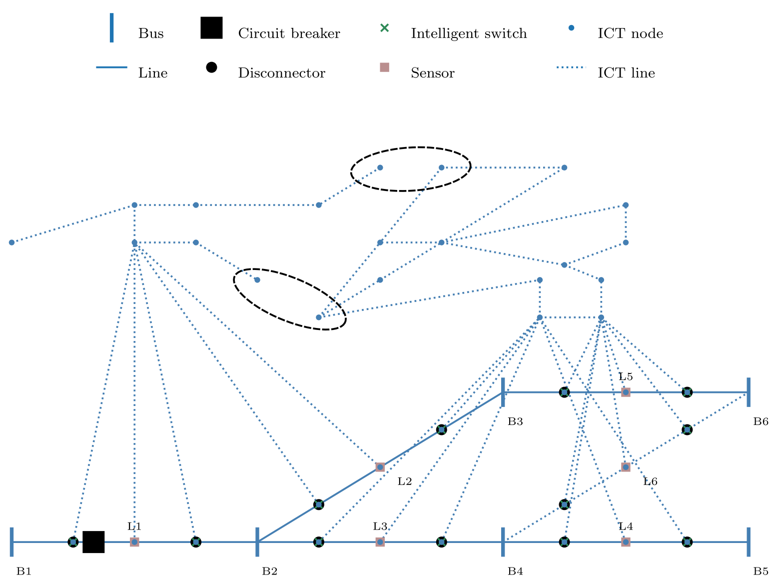


Figure 6.4: The cyber-physical distribution network illustrating the two ICT lines that are failed in scenario 3. The failed ICT lines are removed from the topology figure and black circles are drawn around the failed ICT lines.

6.3 Results and Discussion

In this section, the results from the case study described in Section 6.2.2 are presented and discussed. The presentation of the results is divided into two different subsections. First, the results from Scenario 1 and Scenario 2 are presented and discussed. Then the results from Scenario 3 are presented and discussed. Finally, a general discussion of the results is presented.

Scenario 1 and Scenario 2 are simulated with 5,000 iterations with an increment step of five minutes. Scenario 3 is simulated with 2,000 iterations with an increment step of 0.5 minutes.

6.3.1 Results from Scenario 1 and Scenario 2

In Scenario 1 and Scenario 2, the distribution network is simulated without and with ICT, respectively. The load point reliability for the network is given in Table 6.2, Table 6.3, and Table 6.4 for the `ENS`, average load point interruption, and the average outage duration, respectively. The reliability indices for the system are given in Table 6.5. The results illustrate a clear reliability improvement when ICT is implemented in the network. The contribution from ICT is highest for the load points close to the overlying network. Especially the bus the furthest away from the overlying network (B5), experiences lower reliability improvements when ICT is induced compared to the other load points in the network. This could be a result of this bus being affected by many faults in the system. However, in this study, all the lines and the disconnectors have connected sensors and intelligent switches. This is not necessarily the case in a distribution system where the sensors, for example, will only be implemented on some line segments due to cost of installation. This will affect the results of the simulation.

For the system reliability indices, the same trend is apperent. When ICT is included, the reliability is improved. For situations with ICT, both `SAIFI` and `SAIDI` decrease since the ICT speeds up the sectioning time of the system. In this study, it is assumed to be zero when the ICT system and components are functioning. This results in fewer customers experiencing a failure interruption and the total failure duration of the system decreases since the system can isolate the failed components faster and restore supply.

Table 6.2: The ENS load points in the network without and with ICT implemented.

Load point	**Average Energy Not supplied [MWh/year]**		
	No ICT	ICT	Difference [%]
B2	0.1654	0.0167	-89.9033
B3	0.1631	0.0162	-90.0674
B4	0.0815	0.0081	-90.0613
B5	0.3158	0.1764	-44.1417
B6	0.3657	0.0362	-90.1012

Table 6.3: The experienced average interruption frequency for the load points in the network without and with ICT implemented.

Load point	**Average interruption frequency [failure/year]**		
	No ICT	ICT	Difference [%]
B2	0.5983	0.0418	-93.0135
B3	0.5983	0.0418	-93.0135
B4	0.5981	0.0418	-93.0112
B5	0.5983	0.2169	-63.7473
B6	0.5985	0.0420	-92.9825

Table 6.4: The average outage duration for the load points in the network without and with ICT implemented.

Load point	**Average outage duration [h/year]**		
	No ICT	ICT	Difference [%]
B2	0.6643	0.0668	-89.9443
B3	0.6643	0.0668	-89.9443
B4	0.6643	0.0668	-89.9443
B5	1.4233	0.7909	-44.4320
B6	0.6651	0.0671	-89.9113

Table 6.5: The reliability indices for the distribution system without and with ICT implemented.

Indices	NO ICT	ICT	Difference [%]
ENS	1.0916	0.2535	-76.7772
SAFI	0.5983	0.1064	-82.2163
SAIDI	0.9443	0.3339	-64.6405

6.3.2 Results from Scenario 3

In Scenario 3, the sequence simulation is initialized with a failure of L3 and two ICT lines. The failed ICT lines can be seen in Figure 6.4 in which the failed ICT lines are removed from the figure and black circles are drawn over the line segments. After 30 minutes, a failure on L5 in the distribution system occurs. The sequence simulation is performed as a stochastic simulation where the repair time of the components might vary between the different iterations. Additionally, the given failure rate of the components is still valid for the simulation, meaning that other failures in the system can occur.

In Figure 6.5 and Figure 6.6, histograms of both the `ENS` and the `SAIDI` for the system are illustrated. Likewise, as reveald in both of the two other case studies in this thesis (Chapter 4 and Chapter 5), `SAIDI` and `ENS` follow each other closely. This is expected since the energy not supplied only occurs when there is a fault in the system. In addition, the shedding lasts for the same period of time as the repair time of the components in the system.

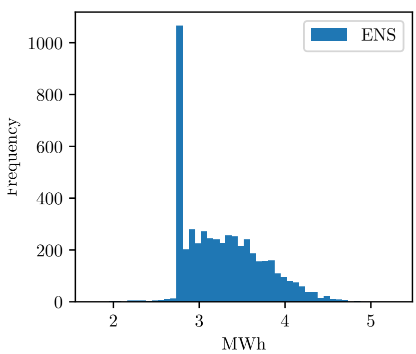


Figure 6.5: `ENS` for the system

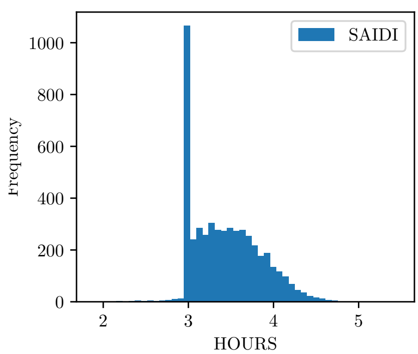


Figure 6.6: `SAIDI` for the system

The result shows a high peak in both figures. In Figure 6.6 we see that the peak is situated around three hours of down time in the system. This is linked to the

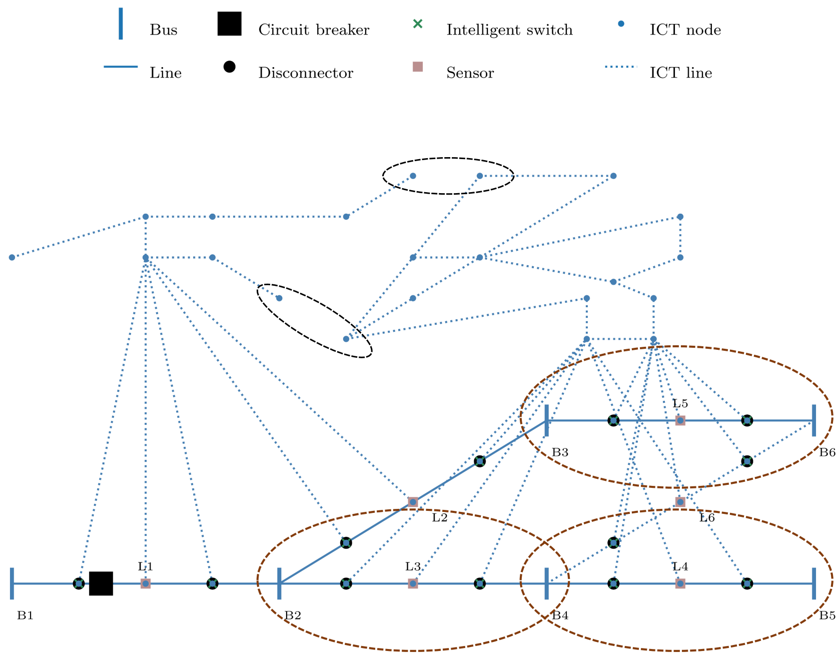


Figure 6.7: The cyber-physical distribution network illustrating the three areas, marked with brown circles, that the controller is unable to reach due to the failed ICT lines. The failed ICT lines are removed and black circles are drawn over the failed ICT line segments.

accumulated sectioning time the system experiences since the controller is unable to get in touch with three of the sensors at the beginning of the simulation due to the failed ICT lines. Figure 6.7 illustrates the three sections of the distribution system the controller is unable to reach due to the failed ICT lines. The instances with a repair time of three hours or less would have been recovered earlier if the controller had been able to make contact with the sensors at an earlier stage. This behavior illustrates the importance of having a functioning ICT communication network when assessing the power system's reliability. Here, the power supply is delayed by a fault in the ICT communication network, affecting the instances gathered in the high peak. If the ICT communication had been functioning, the results would be distributed evenly on the left side of the spike as well since only the down time of the failed component would affect the system. This scenario represents a typical HILP case where the DSO needs to send out repair teams to multiple locations for manual inspections since they have lost contact with a large part of the network.

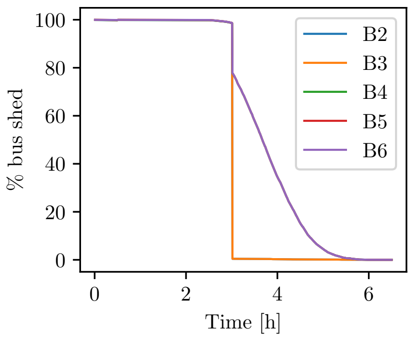


Figure 6.8: Survivability buses

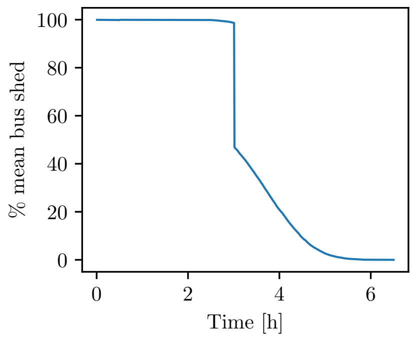


Figure 6.9: Survivability system

In Figure 6.8 and Figure 6.9, the average survivability plots for the system buses and the system as a whole are illustrated, respectively. The figures shows the percentage load shed on the different buses in the system and for the whole system during the failure period. The results show that during the first three hours, all the buses in the system experience a load shed since the circuit breaker is open. After that, buses B2 and B3 are supplied again since the circuit breaker is closed after the sectioning time. The rest of the system buses will experience a load shed until lines L3 and L5 are repaired.

6.3.3 General Discussion

The case study explored in this chapter has illustrated that, with the implementation of ICT, the reliability of the distribution system can be improved significantly. However, there are some considerations that need to be made for this study. First, it is not necessarily the case that all the line segments would have implemented sensors. Sensors are costly and for placement of sensors on the lines in the system, a study investigating optimal placing and investment cost compared to the cost of energy not supplied should be considered. Additionally, the ICT network is very simplified and assumptions are made related to the topology of the ICT network. Besides, the distribution system would likely experience a small sectioning time related to failures in the system even if ICT is available in the system. Therefore, the results for the scenario with ICT is most likely too optimistic.

Scenario 3 illustrated a type of HILP case for the system. The case clearly indicates that in some situations where the ICT system does not function properly, the outcome of the system can be more severe compared to a case where no ICT was implemented. The same situations without ICT would have resulted in a manual repair procedure of the system immediately after the circuit breaker opened. However, in this case, the communication and monitoring of the network are not functioning properly, resulting in a restoration procedure that takes longer time since several of the elements in the restoration procedure with ICT are not responding. An important factor that affects the result is the added sectioning time the system experiences when sections in the system are out of reach for the distribution system controller. In this study, each unreachable section added another hour to the sectioning time. This value might vary, and a more thorough study could be conducted to determine how the system responds under such circumstances.

6.4 Conclusion

The aim of this study was to investigate how the implementation of ICT affects a distribution system. Additionally, a possible HILP case resulting in a major outage of both the distribution system and the ICT was investigated to determine the survivability of the system. The results illustrate a clear reliability improvement when ICT is included in the distribution system. With ICT components, the failure location and isolation process of the failure can be faster. As a result, load points upstream of the failed line are not affected by the failure.

However, when investigating HILP cases, the result can be the opposite. On a general basis, more automation and monitoring of the distribution system will increase the reliability of the system. However, in situations where the ICT system does not function properly, the consequences of failures in the distribution system might become more severe. This emphasizes the importance of investigating the system's behavior and the consequences of such events as well to understand the complexity of the system and to take preventative measures.

7 Conclusion and Further Work

This chapter provides some concluding remarks for the work performed in this thesis. The conclusion aims to answer the objective and the proposed research questions. In addition, some possible further work is suggested.

7.1 Conclusion

One main objective of this thesis has been to develop a methodology for evaluating the reliability of smart and modern distribution systems to gain new knowledge and insights. A motivation behind the objective is the lack of reliability assessment methods for modern distribution systems that fully grasp the increased complexity of the system and the modeling of all the new actors with their respective behavior in the system. For this reason, to answer research question one: *How to calculate the reliability of smart and active distribution systems with increased complexity?*, this thesis has provided a reliability assessment tool (RELSAD) for modern distribution systems that has proven to be general and able to consider the assessment of different complex networks and studies. The tool was developed in the popular programming language Python and published in the Journal of Open Source Software (JOSS). An open-source code and a popular programming language facilitate further development and validation from a broad group of researchers and users. RELSAD is designed in a modular way, paving the way for flexible expansions and additions of a wide spectrum of components and network types. The modular approach is also robust in terms of validation and debugging of new implementations.

The complexity of a modern distribution system is modeled in RELSAD where the dependencies in the system and between components are addressed. Additionally, the behavior of a modern distribution system and the components are implemented. The possibility of random component failures based on realistic failure rates results in a database covering a great spectrum of all possible failure combinations. This includes HILP scenarios that are difficult to capture otherwise. Additionally, the tool provides the opportunity of detailed results based on statistical distributions where analysis of network sensitivities can be performed. Through the sensitivity analysis, different parameters can be considered so the impact on the network can be investigated.

Multiple examples of the usage of RELSAD have been provided through the different case studies presented in this thesis. The case studies illustrate how we can analyze complex problems in a detailed manner by exploiting the resulting distributions of different system and component metrics through statistical methods. This form of detailed analysis can be valuable in the development and design of new and existing green distribution systems. Additionally, the case studies try to answer the research questions of the thesis.

Case 1 and Case 2 (Chapter 4, Chapter 5) aim to answer research question two: *How will active participation of components such as microgrids, distributed generation, and flexible resources impact the reliability of the future distribution system?* In Case 1, an embedded microgrid including renewable energy sources and a battery was modeled. The system was modeled to represent a realistic distribution network with a microgrid where weather data and reliability statistics from the Norwegian DSO was used as a basis. The impact of the microgrid on the reliability of the distribution network was investigated based on reliability indices through variations of microgrid placement, operation mode, and battery capacity. The results indicate that the optimal conditions for minimizing the impact on the microgrid while maximizing the contributions to the distribution system are operating with the *limited support mode* combined with a placement at the end of the longest radial and a large battery capacity. In addition, a sensitivity analysis illustrated that the size of the network in question is of great importance when analyzing some reliability indices. The microgrid contributes to the system buses based on the load priority, making the reliability impact to the smaller sub-system of highly prioritized buses greater than the impact to the entire system. This means that small differences globally may have a great impact locally. If we consider high-priority loads from critical infrastructure such as for instance hospitals and mental institutions, the reliability impact from the microgrid may be crucial.

In Case 2, the aim was to investigate the impact V2G services have on the reliability of modern distribution networks. In this relation, EVs with V2G opportunities were implemented and new EV indices proposed to investigate the strain on the EVs. The EVs with home charging were used to support the distribution network during outages to see the effect on the distribution system's reliability. The network was modeled to represent a realistic network where reliability statistics from the Norwegian DSO was used to estimate the reliability parameters for the network. Additionally, the availability and share of EVs in the network was calculated based statistics and scenario-based analysis of the future EVs in Norway. The results revealed that EVs can offer good reliability support for failures that result in short outages of the system. The EVs are more suitable for support during short outages because of the small battery capacity and the low charging capacity on the home chargers. Through the sensitivity analysis the effect on the reliability of the distribution network and the EVs in the system where highlighted, illustrating that charging capacity and the number of available EVs in the network have a great impact on the reliability support.

The proposed EV indices provide insight into both the frequency and duration with which the EVs in the system are used for V2G services. These insights from the EVs perspective are important when evaluating the impact of V2G services. The proposed indices illustrated that an EV was expected to be used rarely and for relatively short periods during a year, resulting in low wear on the battery of the EVs.

Case 3 (Chapter 6) aims to illustrate how the implementation of ICT functions in RELSAD by providing a study with a CPDS. In addition, research question three was answered: *How will ICT systems and components impact the reliability of the future distribution network?* The case study investigated how the implementation of ICT systems affects the reliability of a distribution system. The results from the study illustrate that there can be a clear reliability improvement when ICT is included. However, the result also indicated that in situations where the ICT system does not function properly, the outcome can be severe and result in worse reliability for the system. The results highlighted the importance of investigating the system behavior and the reliability consequences of events with a low probability of occurring. By doing so, an increased understanding of the system's complexity can be achieved.

7.2 Further Work

For this thesis, the developed reliability assessment tool has been the main emphasis. Therefore, suggestions for further work will be addressed related to the expansion of RELSAD:

- **More advanced restoration algorithms:** In RELSAD, the different controllers are implemented with the control sequence of the restoration of the system. Here, some assumptions are made in the control sequence of the restoration of the power system. However, more advanced restoration algorithms should be implemented to investigate a more complex system after a failure has occurred. Additionally, a more advanced microgrid controller could be implemented to address more aspects of the interaction between a microgrid and a distribution system.
- **Possibilities for network optimization and meshed networks:** In RELSAD, a load flow solver for radial operated distribution systems is applied. The possibility to analyze meshed networks could be implemented. In addition, a simple load shedding optimization problem is adopted to optimize the shedding of load in the network. The possibility to investigate the network under optimal conditions and more complex optimization problems should be further investigated. This could include, for example, optimal power flow, optimal operation of the network, and optimal usage

of sources.

- **More complex ICT system:** For future studies of CPDS, a more complex ICT system with more components could be included. Additionally, the interdependencies and the impact of the interdependencies in the CPDS should be further studied and implemented to investigate the reliability of a more complex CPDS.
- **Validation of modern distribution system behavior:** RELSAD has been validated against a traditional analytical approach for the passive operation of the system. However, it is hard to validate the tool when a modern distribution system where active and smart participation of the system components is considered. To ensure that the implemented features work properly, small tests for RELSAD have been devised. However, this is not sufficient to fully validate the implemented behavior of a modern distribution system.

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Publications

Paper I

The paper **"RELSAD: A Python package for reliability assessment of modern distribution systems"** was by **The Open Journal** in the **Journal of Open Source Software(JOSS)**. The final published paper is reprinted here without changes in compliance with the CC-BY 4.0 license[1] it is published under.

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The Journal of Open Source Software

RELSAD: A Python package for reliability assessment of modern distribution systems

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Summary

The electrical power distribution system is under constant development and multiple changes will occur in the upcoming years. Through the integration of new technology such as Renewable Energy Resources (RES) and flexible resources such as microgrids, battery energy storage systems, and electrical vehicles, the distribution system becomes more active where bidirectional power flow is possible. In an active distribution system, utilization and control of the different sources are possible. Additionally, the system becomes smarter through the integration of Information and Communication Technology (ICT) where intelligent monitoring, automated control, and communication are possible. These changes increase the complexity of the distribution network and new dependencies and interdependencies in the system arise with the modernization of the system.

The traditional reliability analysis methods for power systems do not consider the new components and technology, and the behavior and impact these have on the distribution network. Therefore, new considerations need to be taken to address these new changes in the system. This paper presents an open-source reliability assessment tool for smart and active distribution systems named `RELSAD`.

`RELSAD` – RELiability tool for Smart and Active Distribution networks is a Python-based reliability assessment tool that aims to function as a foundation for reliability calculation of modern distribution systems. RELSAD can be used by scientists, engineers, and Distribution System Operators (DSO) for the planning and operation of modern distribution system where the goal is to investigate the reliability of a given system. The tool allows for Monte Carlo simulation based reliability analysis of modern distribution networks, and sequential simulation of the network behavior with user-defined loading and failure evolution to investigate the impact of the introduction of for instance ICT components. The package supports user-selected time increment steps over a user-defined time period. In the tool, active components such as microgrids, distributed generation, batteries, and electrical vehicles are implemented. To evaluate smart power systems, ICT components such as automated switches, sensors, and control system for the power grid are also implemented. In addition to component implementation, in order to evaluate the reliability of such complex systems, the complexity, dependencies within a system, and interdependencies between systems and components are accounted for.

`RELSAD` offers the following features:

- A foundation for calculating the reliability of modern distribution systems with smart and active components that account for the increased complexity of the system.

*First author

- An extensive reliability analysis foundation with important and new reliability indices that aims to give a complete picture of the reliability of both the power system and the components in the system.
- Inclusion of active participation of different power sources such as distributed generation, microgrids and batteries.
- Inclusion of ICT system and components and the interdependencies between the ICT and power systems.

Statement of need

One of the most important tasks of the DSO is to ensure a safe operation of the power system where the needed electrical power reaches the end-users. With the increased complexity of the system, new situations affecting the distribution system reliability will occur. Power system reliability addresses the issues of interruption in service and the loss of power supply. The traditional reliability analysis methods for distribution systems do not fully comprehend the increased complexity in the system and do not account for the structural changes and time dependencies brought by, for example, RES and ICT. With the increased penetration of RES with power that vary over time, analyzing the power system under varying conditions is important for the reliability of the system.

In literature, reliability evaluation of distribution systems is conducted either through analytical approaches or by simulation. Billinton & Allan (1992) have been pioneers in power system reliability and describe multiple analytical approaches for evaluating the reliability of distribution systems. In an analytical approach, a mathematical representation of the distribution system is constructed by evaluating the components and the relation between them. Markov models can be applied to capture the dynamics in the system behavior. An alternative approach, RELRAD – an analytical approach for distribution system reliability assessment, uses the fault contribution from all the power system components to calculate the individual load point reliability in a radially operated system (Kjølle & Sand, 1992). However, these methods consider passive operation of the network and are therefore not optimal when analyzing modern distribution systems.

Simulation gives a more accurate representation of a modern system where active networks are to be considered. In (Escalera et al., 2018), Monte Carlo simulation is highlighted as a good approach for evaluating the reliability of modern power systems. In addition, the paper points out the need for new reliability assessment tools for such systems. In such a tool, the dynamics and the interconnection of the system can be studied. There is some literature that has used Monte Carlo simulation as a method to evaluate the reliability of modern distribution systems (Borges, 2012; Celli et al., 2013; Quevedo et al., 2017). However, the literature does not bring forward a general and open method or tool for the reliability assessment of modern distribution systems.

The reliability of the distribution system is often described through customer-oriented indices. The customer-oriented indices aim to indicate the reliability of the distribution system based on the interruption experienced by the customers in the system. Some of the most commonly used indices are the System Average Interruption Frequency Index (SAIFI) which gives the average experienced interruption for the customers and the System Average Interruption Duration Index (SAIDI) which gives the average experienced duration of interruption for the customers. Additionally, indices such as Energy not Supplied and component-oriented indices which for example give the expected availability of the component, are also common to use. In RELSAD, multiple indices are implemented in order to give the user a great opportunity for reliability analysis.

`RELSAD` is a simulation tool that uses Monte Carlo simulations for the reliability assessment of distribution systems. The tool is based upon some principles from the analytical approach

RELRAD when calculating the individual load point reliability of the system. Compared to the traditional methods, RELSAD comprehends the complexity and time dependencies that arise in modern distribution systems.

Package structure

RELSAD consists of an electric power system model and an ICT system model that constitutes the system network model. Figure 1 gives an overview of how the systems and components in RELSAD are structured. In addition, the connection between the components and networks is illustrated. The user builds up one network or several networks or can use the implemented test networks. In the distribution network, components such as lines, buses, and switches (discounters and circuit breakers) can be added to make the system topology. In addition to the distribution network, an ICT network can be constructed and connected to the distribution system through ICT components. The implemented ICT components are illustrated in Figure 1. The sensors can be placed on the electrical lines in the distribution system, and will then be able to monitor the line. The intelligent switch can be placed on disconnectors in the system to allow for automated control of the switch. Through an ICT network, the sensor and the intelligent switch can communicate with the controller (data center) representing the operation center of the DSO.

The components in the network can be assigned reliability data were given specifications of the components can be decided. Additionally, the user is free to set the load and generation profiles for the loads and generation units in the network. The user can then select the time increment and period of the simulation.

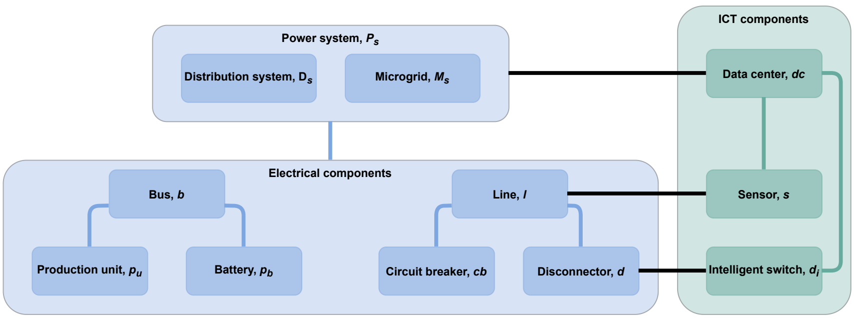

Figure 1: The structure of the systems and components in RELSAD.

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Paper II

The paper **"Reliability Assessment for Distribution Systems with Embedded Microgrids"** has been submitted to a scientific journal.

Reliability Assessment for Distribution Systems with Embedded Microgrids

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***Abstract*— The electrical distribution system is moving toward a more decentralized, complex, and dynamic system. The system is experiencing a higher penetration of distributed energy resources, flexible resources, and active end-users, leading to an active distribution system. If these components are used actively, they can have a positive effect on the distribution system's reliability. This paper aims to investigate how a microgrid with renewable energy sources and energy storage might influence the reliability of electricity supply in a radially operated distribution system. The reliability is investigated from both the distribution system and the microgrid perspective with the application of different scenarios. The study includes an extensive sensitivity analysis. In this study, we use our developed reliability assessment tool for distribution networks. The tool is an open available software where the example network and datasets are embedded. The reliability assessment tool is based on Monte Carlo simulations where load flow calculations are included to capture the behavior of the system and system components. In this paper, the reliability tool is extended to include microgrids and microgrid controller opportunities that handle interaction strategies with the distribution network. The model is demonstrated on the IEEE 33-bus network. The result is confirmed through statistical testing showing the statistical significance of providing support from the microgrid on the distribution system's reliability.**

***Keywords*—Active Distribution Systems, Distribution System Reliability, Microgrid, Monte Carlo.**

I. Introduction

The electrical power system is constantly developing, and in the upcoming years, a lot of changes will take place [1], [2]. The power system is moving from being hierarchical with the one-way transfer of energy, to a more decentralized system where the system boundaries will be more invisible. The biggest changes can be seen in the MV distribution system, which will be more decentralized, complex, and dynamic with higher penetration of distributed energy resources and active end-users [3], [4]. This will transform the distribution system into an active system with bidirectional power flows that will change the system's behavior.

From a reliability perspective, this creates new possible solutions. With more flexible resources in the system and integration of distributed generation (DG), there is a potential to increase the system's reliability. Microgrids are an increasingly studied concept related to the improvement of system reliability [5]. The main attribute of microgrids is the possibility to operate in two different modes: 1) *Grid-connected mode* and 2) *Islanded mode*. Thus, the microgrid can operate in an islanded mode during outages in the main system. If the microgrid and the distribution system work together, there is a potential for improved reliability related to unintentional outages in the system. By islanding parts of the distribution system with the microgrid, the microgrid could be the provider of these distribution system load points.

For microgrid support to work, an interaction between the distribution system operator (DSO) and the microgrid owner must be in place. The type of interaction is dependent on who owns the microgrid. In [6], [7], and [8], this theme is discussed. In addition, regulatory frameworks related to the responsibility of islanded load points need to be established. The regulatory interaction frameworks will not be considered in this paper but are nevertheless important aspects to consider for the application of such support.

A. Related work

Some research has already been done to investigate the potential reliability improvement with technologies such as DG and flexible resources integrated into distribution systems. In [9], an overview of how flexible resources may impact the security of electricity supply (SoS) is provided. The study also includes a review of methods and indicators to quantify the impact. A review of power system flexibility and flexibility concerning system security is provided in [10]. A survey of reliability assessment techniques for modern distribution systems is assessed in [11]. Here, multiple modeling techniques used for assessing distribution system reliability are investigated concerning active components in the system. The availability and impact of active components, such as DG [12], [13], energy storage units [14], and systems with a combination of these [15], [16], have been investigated. The literature illustrates that DG and flexible resources might have a positive impact on the reliability of distribution systems if administrated wisely.

Some studies have investigated the possibility of islanding parts of the distribution system during failure events. In [17] and [18], an analytical approach is adopted to evaluate the contribution from the microgrid to the distribution system reliability. The contribution of the microgrid is determined during possible operating conditions of the microgrid and the DG inside the microgrid and is evaluated based on the ratio between demand and supply. A simulation-based approach with Monte Carlo Simulations (MCS) has been used in [19] for intentional islanding of the distribution system. However, the paper does not consider the active participation of flexible resources and DG to restore supply. Furthermore, a sequential Monte Carlo Simulation (SMCS) method is used in [20] to evaluate the impact of local and mobile generation units. Here, parts of the system will be islanded, with some units operating as microgrids. In [21], the reliability of a distribution system with support from a microgrid including combined heat and power supply system is assessed. However, the microgrid does not include renewable energy resources (RES). In addition, some research related to the reliability of multi-microgrids has been assessed in [22], [23], and [24]. These papers do not consider the interaction between the microgrid and the distribution system, nor is the reliability of the microgrid investigated to any significant extent.

B. Contributions

This paper investigates how a microgrid including RES may improve the reliability of a distribution system. We aim to map the reliability impact from the perspective of both the microgrid and the distribution network by varying the microgrid placement, operation mode, and capacity. Through the analysis, we aim to identify the optimal conditions for the microgrid to minimize the impact on the microgrid while maximizing the contributions to the distribution system. In addition, we provide a general methodology for evaluating how microgrids perform from a reliability perspective through the use of our developed reliability assessment tool, RELSAD.

We have created a reliability assessment tool, RELSAD (RELiability tool for Smart and Active Distribution networks), for assessing the reliability of modern distribution systems [25]. RELSAD is an open-source software with an associated documentation page [26]. The documentation page records the example network with the datasets. In this paper, RELSAD is extended to include microgrids and the interaction between distribution systems and microgrids. Additionally, a microgrid controller with some different control modes is proposed. The presentation of the method focuses on the reliability analysis of a distribution system with the integration of a microgrid. The contributions of this paper are:

- A methodology to assess the reliability of a distribution network with the active participation of a microgrid. Additionally, the reliability impact the microgrid experiences during the different operating modes of the microgrid is investigated.
- Demonstration of the method on a realistic case study where the reliability of both the distribution system and the microgrid is evaluated with different scenarios for microgrid support. The case study is conducted on the IEEE 33-bus network where distribution system data is gathered systematically through procedures described in Sec. IV-A. The reliability data of the distribution system is based on statistics from the Norwegian distribution systems.
- A comprehensive sensitivity analysis of how microgrid battery capacity, line repair time, and line failure rate affects the Energy Not Supplied (ENS) of both the distribution system and the microgrid.
- An investigation of how the microgrid location affects the ENS of the distribution system.

C. Paper structure

The rest of this paper is organized as follows: section II introduces the concept of failure handling in modern distribution systems with microgrids. In section III, the method for calculating reliability in a distribution system with a microgrid is introduced and explained. The case study conducted on the IEEE 33-bus network is discussed in section IV. The case study results are illustrated and discussed in section V. The sensitivity analysis and the investigation of the microgrid location is also presented in section V. The paper is concluded, and future work is discussed, in section VI.

II. The reliability evaluation of the future distribution systems with microgrids

In a traditional radially operated distribution system with the one-way transfer of power, as seen in Fig. 1, a failure of, for example, a line in the network, will result in all the downstream load points being isolated from the main power source unless there is an alternative supply route. In Fig. 2, a fault has occurred on a line in the distribution system and has been isolated. This results in the load points, highlighted in the red dotted box, downstream of the failed line, being isolated from the rest of the distribution system. Since there is no alternative supply route or any generation unit in this area, these load points will not be supplied until the failure is repaired and the line reconnected.

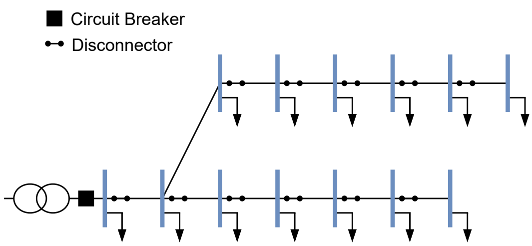

Figure 1: Traditional radially operated distribution system.

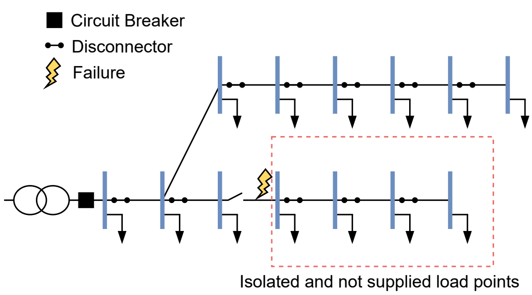

Figure 2: Traditional radially operated distribution system with a fault.

However, if there is a flexible resource such as a microgrid present in the network, the situation might be changed. The aim is to use the flexibility in the system to restore or to support the network during periods with, e.g., faults in the network and capacity problems. A microgrid can support the system in two different modes: 1) *isolated operation* and 2) *grid-connected operation or supportive operation*.

1) Isolated operation: If a failure occurs on, for example, a line in the distribution system as seen in Fig. 3, the downstream load points will be isolated from the overlaying network and traditionally these load points will not be supplied. However, if a microgrid or another flexible resource is present in this isolated part of the network, at least some parts of the supply can be restored. The microgrid will then operate in an island mode during the outage time of the faulty component. When the fault is repaired, the isolated part can be disconnected from the overlying grid again.

In this operation, the microgrid must be able to withhold the balance in the system along with the frequency and voltage levels in the isolated part of the network. This means that the microgrid is in charge of all the security of supply aspects during the period of isolated operation.

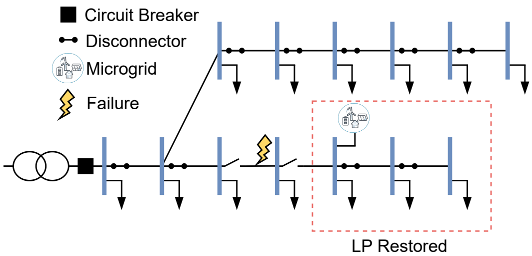

Figure 3: Supply restored for the microgrid in island mode with isolated part of the distribution syste.

2) Supportive operation: Normally, in distribution systems, some alternative supply chains might exist that can be used in case of redirection of power or failure in the network. Then the line can be connected and help supply loads in the system in areas that would have been isolated during the faulty period. However, some of these lines have low capacity limits and might end up being congested, or they might end up creating bottlenecks in the network. Local production in the distribution network might alleviate congestion and bottlenecks. Fig. 4 illustrates how a microgrid can support the system during a fault in the system. The load points could have been restored with only the connection of the alternative line, but the microgrid is now able to support the system with local production.

III. Methodology

In this section, we present the developed reliability methodology. First, the concept for reliability evaluation of modern distribution systems is presented. Second, we introduce our developed reliability assessment tool with the extension to include microgrids and the interaction between microgrids and distribution networks. Finally, the statistical analysis used for evaluating simulation results is presented.

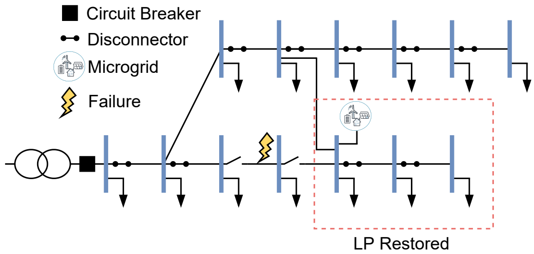

Figure 4: Supply restored with alternative supply chain and microgrid support.

A. Reliability evaluation of modern distribution systems

In general, there are two ways of analyzing the reliability in the distribution system, namely through analytical approaches or simulation, with MCS frequently used [27]. The analytical approaches use simplified models with averaged quantities to estimate the reliability indices. MCS, however, allow for a more detailed representation of the reliability indices by generating reliability indices through numerous independent instances including stochastic variations. The numerous instances result in a detailed distribution of reliability indices. Analytical models are more generic and are often, therefore, more applicable for different cases, whereas MCS models will offer a more detailed analysis of the system to be modeled.

To calculate the reliability of future smart and flexible distribution systems, an appropriate method is needed. The traditional approaches will not be able to utilize the full potential of the active components in the distribution system, and a form of simulation approach can be advantageous. Since the active components interact with the distribution system based on multiple independent factors, such as failures and weather conditions, the simulation of their impact on the distribution system must cover all possible scenarios. A MCS approach, which makes use of random sampling of input, is well suited for these types of problems.

In this regard, RELSAD—RELiability tool for Smart and Active Distribution networks was developed. RELSAD is a reliability assessment tool for modern distribution systems with an SMCS model. The software is developed as an open-source Python package and is published as a scientific tool [25]. Additionally, a documentation page for the software has been written and can be seen in [26]. RELSAD was developed to give a foundation for the reliability assessment of modern distribution systems where the changed behavior and the increased complexity in the distribution network are considered. The tool also aims to facilitate reliability calculation and analysis for the DSO. Through RELSAD, the following features are provided:

- Calculation of detailed results in the form of distributions and statistics on important reliability indices.
- Opportunity for investigation of network sensitivities involving different parameters such as repair time, failure rate, load and generation profiles, placement of sources, and component capacities and their impact on the system.

- Implementation and investigation of diverse and advanced network constellations spanning from small passive distribution systems to large active networks including DG, batteries, and microgrids where the networks are operated radially.
- The ability to investigate and analyze the reliability of Cyber-Physical Networks.

In this paper, RELSAD is extended to include microgrids and interaction strategies between the microgrid and the distribution network during outages in the system. It will describe the core functionality of RELSAD in addition to the contribution and implementation of microgrids and the microgrid controller with the fault handling procedure.

B. Reliability indices

There are different reliability indices used for measuring and quantifying the reliability in distribution systems. Many of these indices are implemented in RELSAD. The reliability indices can be divided into *customer-oriented indices* and *load- and production-oriented indices* [27]. The three basic reliability parameters are the fault frequency or the average failure rate, λ_s, the annual average outage time, U_s, and the average outage time, r_s. In a radial network, the three different reliability parameters can be calculated as in eq. 1, eq. 2, and eq. 3. Here, λ_i and r_i are the failure rate and outage time at load point i, respectively. These equations are used to assess the load-point reliability. However, these do not contain any information about the electrical consequence of a fault or the cost related to a fault. The rest of this section will describe the reliability indices used in this paper.

$$\lambda_s = \sum \lambda_i \tag{1}$$

$$U_s = \sum \lambda_i r_i \tag{2}$$

$$r_s = \frac{U_s}{\lambda_s} = \frac{\sum \lambda_i r_i}{\sum \lambda_i} \tag{3}$$

Load- and Production-oriented indices: The load- and production-oriented indices aim to indicate the electrical consequence of faults in the system [27]. The total ENS in a system can be calculated as seen in eq. 4

$$\texttt{ENS}_s = U_s P_s \tag{4}$$

The interruption cost for the system can be calculated as seen in eq. 5 [28]. Here, c_i is the specific interruption cost for each customer category at load point i.

$$\texttt{CENS}_s = \sum \texttt{ENS}_i c_i \tag{5}$$

Customer-oriented indices: The customer-oriented indices aim to indicate the reliability of the distribution system based on the interruption experienced by the customers [27]. In this paper, three important indices are investigated:

1) System Average Interruption Frequency Index

$$\texttt{SAIFI} = \frac{\sum_{\forall i} \lambda_i N_i}{\sum N_i} \tag{6}$$

where N_i is the *total number of customers served*, and $\sum_{\forall i} \lambda_i N_i$ is the *total number of customer interruptions*. `SAIFI` is a measure of the frequency of interruptions the customers in the system expect to experience. Any interruption seen from the consumer is counted as a fault, regardless of origin.

2) System Average Interruption Duration Index

$$\texttt{SAIDI} = \frac{\sum U_i N_i}{\sum N_i} \tag{7}$$

where $\sum_{\forall i} U_i N_i$ is *total number of customer interruption* durations. `SAIDI` is a measure of the expected duration of interruptions a customer is expected to experience.

3) Customer Average Interruption Duration Index

$$\texttt{CAIDI} = \frac{\sum U_i N_i}{\sum_{\forall i} \lambda_i N_i} = \frac{\texttt{SAIDI}}{\texttt{SAIFI}} \tag{8}$$

`CAIDI` is the ratio between `SAIDI` and `SAIFI` and measures the average duration each given customer in the system is expected to experience.

C. Structure of RELSAD

In Fig. 5, an overview of the RELSAD model is illustrated. RELSAD considers different user-specified attributes such as:

- **Topology attributes:** such as spatial coordinates and connected components.
- **Reliability attributes:** such as failure rates and outage distributions.
- **Component specific attributes:** such as, for a battery, this could be the battery capacity, the inverter capacity, efficiency, and charging limitations.

The core of the software is the simulation where different operations are performed. The general functionality of RELSAD is described in Sec. III-D and the microgrid-specific functionalities are described in Sec. III-E.

The output or results of the RELSAD software are given as reliability index distributions. Multiple different distributions of the results can be given and the investigated reliability indices in this paper are described in Sec. III-B.

RELSAD is constructed in an object-oriented fashion, where the systems and system components are implemented with specific features simulating their real-life behavior. RELSAD is a general tool that can consider any network that operates radially. In RELSAD, a power system - P_s is first created before distribution systems - D_s and other networks such as Microgrids - M_s are created inside the P_s. After this, the electrical system components can be created and added to associated network layers. The possible electrical components are lines - l, buses - b, disconnectors - d, circuit breakers - cb, generation units - p_u, and batteries - p_b. In addition, a load - p_d can be assigned to each bus. This is described in more detail in the documentation page of the software [26].

D. Core functionality of RELSAD

In this section, the core functionality of RELSAD is described. The reliability assessment of a system is solved through SMCS in RELSAD. To account for the active

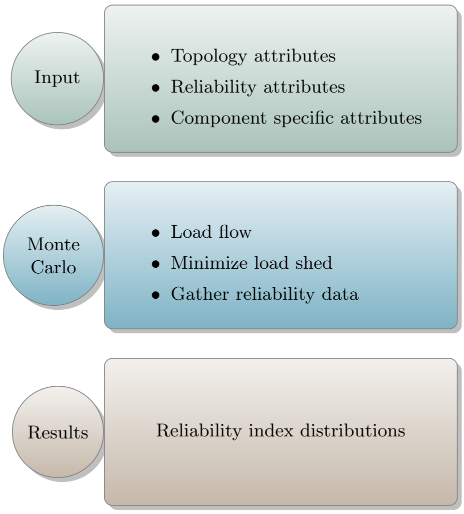

Figure 5: Overview of the RELSAD model. A full description can be found in the software documentation [26].

participation of different technologies such as microgrids, DG, and batteries, a load flow solver is implemented to evaluate the electrical consequence of faults in the system. Through load flow calculations, the behavior of the system during different scenarios can be evaluated. In RELSAD, a Forward-Backward sweep (FBS) approach is implemented as the load flow solver. In the FBS approach, the load flow is calculated by updating the power flow through a backward sweep before the voltage magnitudes and angles at the system buses are updated in a forward sweep [29].

Due to the potential island operation of parts of the distribution system with and without the microgrid, power balance needs to be ensured. To achieve this, a simple load shed optimization problem is included. The objective of the load shed optimization problem, seen in eq. 9, is to minimize the total load shed in the network based on the price of shedding different load types. The price is based on the *Cost of Energy Not Supplied* (CENS). This is subjected to load flow balance and the capacity limitations over the power lines, the load, and the generation in the distribution system:

$$\underset{P_n^s}{\text{minimize}} \quad \mathcal{P}_s = \sum_{n=1}^{N_n} C_n \cdot P_n^s \tag{9}$$

subject to:

$$\sum_{i=1}^{N_l} \alpha_i \cdot P_i^l = \sum_{j=1}^{N_g} \nu_j \cdot P_j^g - \sum_{k=1}^{N_n} \eta_k \cdot (P_k^d - P_k^s)$$

$$\min P_j^g \leq P_j^g \leq \max P_j^g \qquad \forall j = 1, \dots, N_g$$

$$0 \leq P_k^s \leq P_k^d \qquad \forall k = 1, \dots, N_n$$

$$\left| P_i^l \right| \leq \max P_i^l \qquad \forall i = 1, \dots, N_l$$

Here C_n is the cost of shedding load at node n while P_n^s is the amount of power shed at node n. P_j^g is the production from generator j. P_k^d is the load demand at node k while P_i^l is the power transferred over line i. α_i = 1 if line i is the starting point, -1 if line i is the ending point. ν_j = 1 if there is a production unit at node j, otherwise it is 0. η_k = 1 if there is a load on node k, otherwise it is 0.

*1) **Incremental procedure of fault handling in RELSAD:*** The SMCS in RELSAD is constructed to have a user-chosen increment. This can, for example, be a second, a minute, an hour, or a day. The incremental procedure of the fault handling model implemented in RELSAD is illustrated in Algorithm 1. After a P_s is created with associated systems and components, the incremental procedure will set the load and generation at the system buses for the current time increment. Then the failure status of each component is calculated based on random sampling and the failure rate of the different components. If any component is in a failed state, the network with the failed components will be divided into sub-systems, and a load flow and load shedding optimization problem will be solved for each sub-system. The load flow and load shedding optimization problem are included to calculate the electrical consequence of a fault when active components are present. When this is performed, the historical variables of the components are updated. The historical variables can then further be used to evaluate the reliability of the P_s, the different networks in the power system, and the individual load points. An example of this is provided in the documentation page for the software [26]. The rest of this section describes the different procedures of the reliability evaluation in greater detail.

Algorithm 1: Increment procedure

Set bus p_d and p_u for the current time increment;
Draw component fail status;
if *Failure in* P_s **then**
    Find sub-systems;
    foreach *sub-system* **do**
        Update p_b and p_{EV} demand (charge or discharge rate, discharge of EVs if V2G is activated);
        Run load flow;
        Run load shedding optimization problem;
    end
    Update history variables;
end

E. Microgrid reliability

Reliability evaluation will depend on the operation mode of the microgrid controller. If the microgrid is in island mode, it will function as an independent system. Whereas, if the microgrid is connected to the overlying distribution system during the outage period, it will be a part of the distribution system and the systems need to interact. In [30], new metrics for the reliability of microgrids in island mode are proposed. In this study, the microgrid is designed to primarily be connected to the distribution system. The island mode of the microgrid is only achieved during outages in one of the systems. This will then make the regular reliability indices well-suited for evaluating the reliability of the microgrid.

To achieve the right commands and the interaction between the microgrid and the distribution system, a microgrid controller is implemented. The microgrid controller will in this paper focus on performing the correct fault handling; the remaining features of the controller are simplified as they are of minor importance to this study. Here, the possibilities for operating modes can be extensive, but for this study, three different operating modes were implemented:

1) **No support mode (island mode)**—During failures in the system, the microgrid will work in island mode during the down time of the failure.
2) **Full support mode**-—After the sectioning time, the microgrid will reconnect to the distribution network (if possible) and contribute to the operation of the distribution network.
3) **Limited support mode**-—After the sectioning time, the microgrid will reconnect to the distribution network (if possible) but will only contribute with limited power from the battery so that the microgrid can ensure self-sufficiency for a limited period of time. This means that the battery will store enough power to operate the microgrid for four peak hours. The battery will, in this scenario, function as a backup source, and the SoC will not be drawn when a failure occurs but will start with max SoC.

The microgrid controller was implemented to focus on performing the correct fault handling; the remaining features are simplified.

Algorithm 2 illustrates the controller procedure for fault handling in the microgrid. First, the *sectioning time* of the cb is updated if needed. The sectioning time is the time it takes from a failure occurring on a line until the fault is located and disconnected. The sectioning time of the cb is updated in case the system was in a sectioning time in the previous time step. Then, if a new outage happens in one of the systems, D_s, and M_s, the circuit breaker of the M_s will open. In the M_s, all lines will be checked for failures. If the line containing the circuit breaker has failed, then the circuit breaker should remain open regardless of the M_s mode. If not, the algorithm will check in which mode the M_s should operate. If the M_s is supposed to operate in island mode during faults in the D_s, the procedure will check for failed lines in the D_s. In case of no failed lines in the D_s, the failed sections in the M_s are disconnected and the circuit breaker is closed. If the microgrid is in a supportive mode, where it can be islanded with parts of the D_s buses, the failed sections in the M_s are disconnected before the circuit breaker is closed.

This will result in the M_s being in one of three states during an outage in the P_s: 1) in island mode, 2) in island mode with parts of the D_s, or 3) connected to the D_s with the possibility of supply from the overlying network.

Algorithm 2: Microgrid controller procedure

Update sectioning time;
if *cb is open and sectioning time $\leq$ 0 or l recovered from failure* **then**
    Check l in M_s for failure;
    if *l with cb not failed* **then**
        if *M_s in island (survival) mode* **then**
            if *No failed l in D_s* **then**
                Disconnect failed sections;
                Close cb;
            end
        else
            Disconnect failed sections;
            Close cb;
        end
    end
end

F. Statistical analysis

1) Statistical difference: Statistical analysis is important to confirm the hypotheses made by researchers. A statistical test checking for equal means can be performed to quantify whether the result data sets from various scenarios differ. There are two classes of hypothesis tests, namely 1) *parametric* [31] and 2) *non-parametric* [32]. Both classes are bounded by assumptions about the distribution of the result data sets. Parametric tests are restricted to normally distributed data sets with equal variance, while non-parametric tests have looser restrictions. For this reason, parametric tests have stronger statistical power, making them the preferred choice if the data set satisfies its assumptions. To decide which class of tests to use, an evaluation of the distribution of the results data set must be carried out.

The evaluation of normality can be done by performing an Anderson-Darling (AD) test. The AD test is used to establish if a data set comes from a population with a specific statistical distribution [33]. The outcome of the test is measured by the deviation A^2, between the number of samples and a weighted logarithmic expression of the data in the data set. An increasing deviation between A^2 and zero decreases the probability of the data set being of a specific statistical distribution.

If the AD test for normality fails, non-parametric tests must be used to check for equal means. In this paper, the Kolmogorov-Smirnov (KS) [32] test is used for this purpose. The KS test quantifies the distance between two data sets, indicating if the data sets are drawn from the same population.

2) Sensitivity analysis: Sensitivity analysis is important since it provides a mapping of the behavior of the model and illustrates how the results are affected by various parameters.

Factorial design is a more advanced form of sensitivity analysis used to investigate and understand the effect of independent input variables on a dependent output variable [34]. One of the key advantages of factorial design compared to a conventional sensitivity analysis—that only studies the effect of one variable at a time—is the ability to quantify the influence the variables have on the output variable *and* on the other investigated variables. However, this drastically increases the number of combinations to investigate; which will lead to more simulation time, for example, a factorial design test with three factors that consider two levels each leads to a total of $2^3 = 8$ combinations.

IV. Reliability test system

In this section, the reliability test system with the procedures for data gathering, and the case study are presented. First, we introduce the IEEE 33-bus system, which is the distribution network used for reliability assessment in this paper. Secondly, we present the microgrid and the microgrid parameters that are studied. Finally, the case scenarios are outlined.

A. Procedures for developing the test network

The method is demonstrated on the IEEE 33-bus system seen in Fig. 6. The IEEE 33-bus system is chosen since it is a commonly used test network, and therefore, makes it easier for evaluation and replication. The network is operated fully radially without any backup connections, and possible islanded operation with the microgrid will be investigated. To account for a more realistic distribution network, the customers in the network with their demand profiles are distributed to map a real network. To make a dynamic demand profile of non-constant load, load profiles generated based on the FASIT requirement specification with hourly time variation of the load are used [35]. In Fig. 6, the mean load at each bus is illustrated through a heat map. The maximum load in the distribution system is scaled to approximately double the size of the traditional load values in the IEEE 33-bus system (see [36] for the original network). The distribution system is constructed to include different types of loads, such as households, farms, industry, trade, and office buildings, to build a more dynamic customer profile in the system and include the priority of the loads. The weather data is collected from a location in eastern Norway. The load data can be seen in [37].

In this study, only failures on the lines in the network will be addressed. The reliability data used in the study is collected from yearly reliability statistics from the Norwegian distribution systems [38]. The average failure rate of the lines is 0.07 failures/year/km. The lines in the test system are based on the original lines in the IEEE 33-bus network [36]. However, the length of the lines is calculated based on the impedance of the lines and gives lines of different lengths in the system.

In the statistics from the Norwegian DSOs, the repair time of the line is given as a percentage of the amount of time a failure lasts for a given time period. On average, the repair time will be less than two hours, 67% of the time. For creating various line repair times, the repair time follows a gamma distribution as seen in Fig. 7 where the line repair time will be two hours or less, 67% of the time.

B. Microgrid

The microgrid is placed on bus 33 at the end of the radial arm in the distribution system. The microgrid contains wind power, solar power, a battery, and some load. The specifications of the microgrid can be seen in Tab. I. The wind and solar power profiles are generated based on weather data from the same location in Norway with hourly variation and follow the methods presented in [26].

The microgrid is operated in grid-connection mode most of the time, but if a line failure occurs in the distribution system or the microgrid, the microgrid will shift to island operation.

Table I: Microgrid specifications

Component	Specification
Battery	Max capacity: 1 MWh
	Inverter capacity: 500 kW
	Efficiency: 0.95
	Min SOC: 0.1
Wind & Solar power	Max power: $\sim$ 3.5 MW
Load	Peak load $\sim$ 200 kWh

1) **Battery strategy:** In multiple cases, batteries in the power system will sell and buy power in a power market or flexibility market. If the battery participates in such a market, the stored energy in the battery will vary over time, and might not be full when a failure occurs. In this study, we have considered variations of stored energy in the battery by calculating the state of charge (SoC) level. The SoC level is assumed to follow a uniform distribution since we do not have any information about the market strategy. This will create a more realistic case where the battery is not necessarily full when a failure occurs.

2) ***Description of the different scenarios:*** The case study investigates three different scenarios, which are based on three different operating modes for the microgrid, namely: 1) *no support mode*, 2) *full support mode*, and 3) *limited support mode*, as described in Sec III-E. The reliability for both the distribution system and the microgrid will be measured in ENS.

V. Results and discussion

This section presents the results of the three conducted reliability studies. First, the results for the three described scenarios are provided from both the distribution system and microgrid perspective. Second, we present a sensitivity analysis of how the battery capacity, line repair time, and line failure rate affect the ENS of both the distribution system and the microgrid. Finally, the investigation of how the microgrid location affects the ENS of the distribution system is detailed. Steady-state conditions are assumed for all the reliability studies. The simulations converge after approximately 3,000 iterations, and the study has been performed with 5,000 iterations.

A. Microgrid scenario study

1) ***The distribution system perspective:*** In Fig. 8, a box plot of the ENS for the distribution system is illustrated. It can be observed from the box plot that there is a slight decrease in ENS for Scenarios 2 and 3 where the microgrid supports the distribution system during faults, compared to Scenario 1 where the microgrid operates in island mode during faults. Comparing Scenarios 2 and 3, there are only minor differences.

The result is more apparent in Tab II where the mean values of the discussed reliability indices are presented for the three scenarios. Overall, the mean ENS decreases by 4.27% for Scenario 2 and 4.62% for Scenario 3 compared to Scenario 1. This effect could be increased by having multiple generation sources or microgrids spread around the network. Since the microgrid is located in one place

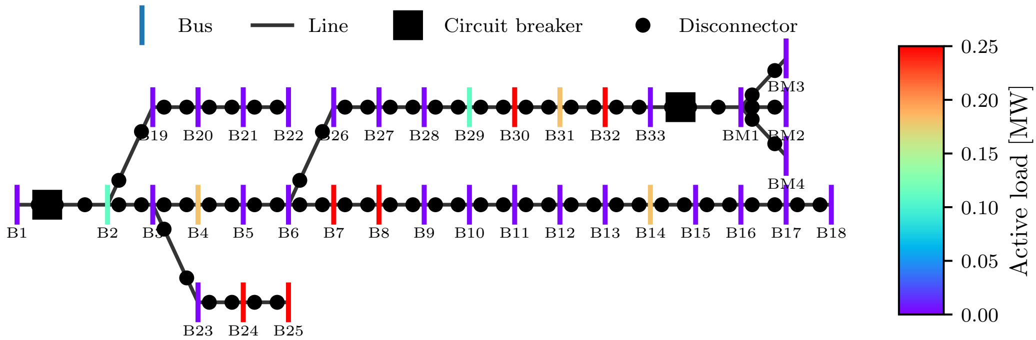

Figure 6: The system topology. The microgrid is placed on B33. The plot illustrates a heat map of the mean load at each bus in the system.

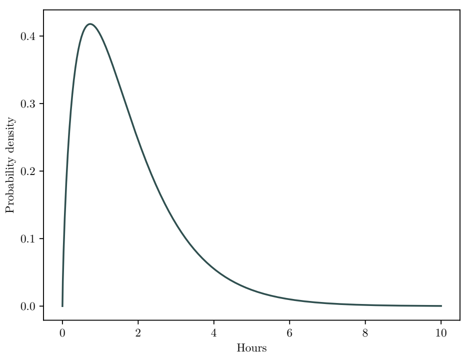

Figure 7: Gamma distribution of the repair time of the lines in the system.

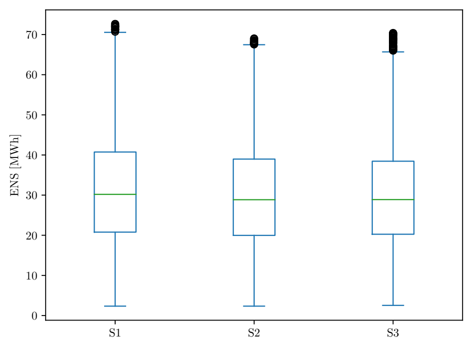

Figure 8: Box plot of the frequency distribution of energy not supplied in the distribution system for the three scenarios.

in the microgrid, there will be several cases where the microgrid is unable to support the grid since the isolated part is not connected to the microgrid. In addition, since the microgrid prioritizes its own load, the distribution system will get less support.

Table II: Mean values of the reliability indices for the distribution system

	S1	S2	S3
ENS [MWh]	31.7518	30.3975	30.2834
SAIFI [freq.]	5.3566	5.3630	5.3925
SAIDI [h]	7.7945	7.7261	7.7745
CAIDI [h]	1.4551	1.4406	1.4417

Fig. 9 and Tab. II display the other investigated reliability indices (SAIFI, SAIDI, and CAIDI) for the distribution system. By analyzing these indices, some small differences between the different scenarios can be observed. The down time for the system decreases with support from the microgrid. The reason for this is that some load points will experience a decreased period of shedding. However, the failure frequency will increase. In most cases, the microgrid generation and battery are unable to preserve supply during the entire outage period, resulting in some load points experiencing a *new* outage period when the generation is low or the battery is empty. In addition, the down time for Scenario 3 is slightly higher than for Scenario 2. This is a result of the microgrid storing power for its own load, leading to less power for the distribution system.

Statistical testing was performed on the results from the three different scenarios. First, the AD test was used to investigate if the results are normally distributed. As seen in Tab. III, the normality test failed, indicating that none of the results are normally distributed. The test statistics, A^2, are very high, indicating with high certainty that the result is not normally distributed.

The non-parametric test was then performed to investigate if the result originates from the same population. A significance level of 5% was chosen, meaning that the null hypothesis, which is that the result is taken from the same population, is rejected if the p-value of the test is lower than 0.05. Tab. III shows that Scenario 1 is significantly different from Scenarios 2 and 3. However, Scenarios 2 and 3 are not significantly different, meaning they are from the same population. This result indicates that there is a significant difference between receiving support

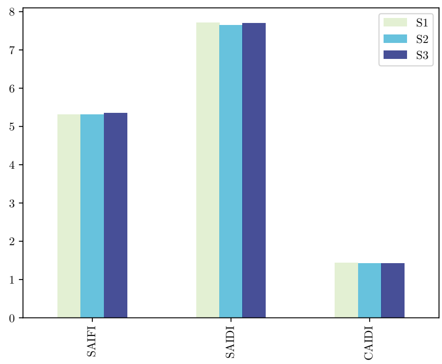

Figure 9: Bar plot of the mean values of the reliability indices for the distribution system. (SAIFI is given in frequency of disturbances while SAIDI and CAIDI are given in hours).

from the microgrid during unintentional outages in the distribution system compared to no support. However, the actual network impact might vary.

Table III: Statistical test of the three scenarios in the distribution system

Scenario	AD test A^2	Scenarios	KS test p-value
S1	22.34	**S1 vs. S2**	0.00
S2	20.68	**S1 vs. S3**	0.00
S3	18.42	**S2 vs. S3**	0.53

*2) **The microgrid perspective**:* The amount of ENS from the microgrid perspective for the different scenarios can be seen in Fig. 10. The differences between the scenarios are clearer when investigating them from the perspective of the microgrid. Here, Scenario 1 will result in most shedding, since the microgrid has to survive in island mode during faults in the distribution system without a backup supply. Scenario 2 is somewhat better since the microgrid will reconnect to the distribution system. For situations where the microgrid is in the same sub-system as the main feeder of the distribution system, the microgrid will be ensured supply. Scenario 3 is the case that will give a very small ENS. The shedding and outliers in the box plot are a result of faults inside the microgrid, long repair time on some failures, and some *high impact low probability* cases. These cases are the result of two failures happening in close approximation, leading to a discharged battery before the last fault is removed.

The mean values of the reliability indices for the microgrid can be seen in Fig. 11 and Tab. IV. The indices indicate that there is a considerable decrease in the interruption duration for Scenario 3 compared to the others. Scenario 3 also leads to a lower interruption frequency. The increase in interruption frequency for Scenario 2 is caused by low generation and an empty battery that is not sufficient to supply the microgrid load resulting in the microgrid load experiencing additional interruption. The ENS for Scenario 3 decreased by 69.32% compared to Scenario 1, whereas the ENS for Scenario 2 decreased by 26.63%.

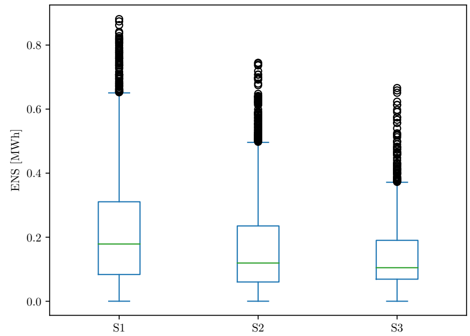

Figure 10: Box plot of the frequency distribution of energy not supplied in the microgrid for the three scenarios.

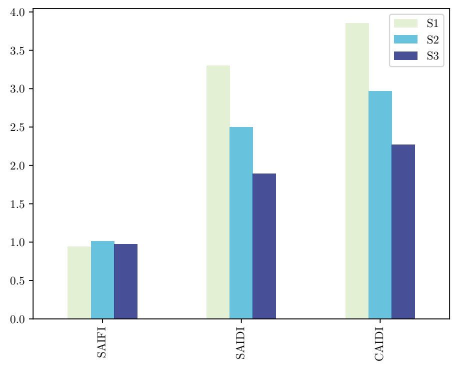

Figure 11: Bar plot of the mean values of the reliability indices for the microgrid. (SAIFI is given in frequency of disturbances while SAIDI and CAIDI is given in hours).

Table IV: Mean values of the reliability indices for the microgrid

	S1	S2	S3
ENS [MWh]	0.1258	0.0923	0.0386
SAIFI [freq.]	0.5345	0.5556	0.2554
SAIDI [h]	1.8814	1.3890	0.5122
CAIDI [h]	3.5201	2.4999	2.0059

The same statistical tests were performed on the reliability result for the microgrid. The result can be seen in Tab. V. None of the results passed the normality test, which can be expected based on the formation of the box plots. The same non-parametric test was performed with a significance level of 5%. The outcome shows that all the scenario results are significantly different from each other. The result highlights the importance of backup supply for the microgrid, either through the distribution system or through the microgrid sources. Since all the scenarios are significantly different, Scenario 3 is the best scenario from the microgrid perspective when measuring ENS.

Table V: Statistical test of the three scenarios in the microgrid

Scenario	AD test A^2	Scenarios	KS test p-value
S1	452.52	**S1 vs. S2**	0.00
S2	509.56	**S1 vs. S3**	0.00
S3	993.91	**S2 vs. S3**	0.00

B. Sensitivity analysis

Since there was no significant difference between the results from Scenario 2 and 3 for the distribution system and Scenario 3 gave the best overall result for the microgrid, this is the most appropriate case to investigate further. A full factorial design study was performed on Scenario 3, which was chosen based on the results obtained from the reliability assessment. The investigated parameters and parameter values can be seen in Tab. VI. The repair time of the lines still follows a gamma distribution as described, and the parameters indicate that the repair time will be less than the given parameter value for 67% of the time. No lower limit values for the battery capacity were chosen since the battery in Scenario 3 is dimensioned for the peak load in the microgrid. Scenario 3, as it is illustrated in this study, is not applicable if the battery capacity is decreased.

Table VI: Parameter values used in the factorial design study

		Name
Battery [MWh]	1	$\mathtt{Bat}_1$
	2	$\mathtt{Bat}_2$
		Name
Repair time [h]	1	$\mathtt{r}_1$
	2	$\mathtt{r}_2$
	3	$\mathtt{r}_3$
		Name
Failure rate [failures/year]	0.05	λ_1
	0.07	λ_2
	0.09	λ_3

The results from the factorial design study are illustrated in Fig. 13 for the distribution system and in Fig.14 for the microgrid. The plots indicate both the effect each parameter has on the `ENS` in the system and how the parameters affect each other.

When investigating the result for the distribution system (Fig. 13), the failure rate of the lines gives the largest contribution to `ENS` in the system. Increased battery capacity, however, does not affect the `ENS`. This effect is a consequence of the battery being placed at one location in the network, and which is not able to contribute to all possible outage scenarios in the network since it will be isolated from the fault. Unlike the battery, the line failure rate and repair time affect all the lines in the system.

Investigating the results from the microgrid perspective (Fig. 14), the battery capacity has a more important role compared to the distribution system. There is a clear interaction effect between the battery capacity and the repair time. The `ENS` in the microgrid is more sensitive to variations in repair time when the battery capacity is low. This is a consequence of the microgrid being able to supply the microgrid load for more hours during special *high impact low probability* events, as discussed. A smaller but similar interaction effect is seen between the battery capacity and the failure rate. When the battery capacity is small, the microgrid is more vulnerable to failures.

C. Microgrid location study

We have also investigated the impact of the microgrid placement on the `ENS` in the distribution system. Simulations varying the microgrid location to cover all the distribution system buses were conducted. The results are presented in Fig. 12. Each bus is colored based on the `ENS` of the distribution system with the microgrid located at the respective bus. The results indicate that it is beneficial to place the microgrid at the end of long radials. In this study, it will be at B33 in the distribution system.

D. Discussion

When analyzing the results from the microgrid scenario study, the statistics show that receiving support from the microgrid for the distribution system has a significant effect on the `ENS`. However, the difference between the results of the different scenarios is minor. From the microgrid location study, we know that the placement of the microgrid is an important reliability factor. In addition, since multiple failures can occur at locations where the microgrid is not able to provide support, the distribution system might benefit more if the generation sources were scattered at different locations in the system. Another impacting factor is the availability of wind and solar power in the microgrid and the energy level of the battery when a failure occurs. This decides the amount of power the microgrid can contribute.

The reliability of the microgrid, however, is very dependent on the microgrid mode. This is a factor that could change the results if other modes for the microgrid controller are applied. The results indicate that Scenario 3 is the best cross-over strategy for both the microgrid and the distribution system when analyzing `ENS`. This could change for the microgrid if other strategies were applied. In addition, the result could be different if other measures are investigated, such as a cost-benefit analysis.

An interesting result seen from both the distribution system and the microgrid perspective is the increase in SAIFI for the scenarios with support from the microgrid. It was expected that SAIDI would decrease as a result of the microgrid supporting the distribution system since the total duration of load shedding for some load points would decrease. However, based on how SAIFI is measured, the index will increase as a consequence of load points experiencing a new outage period when the microgrid generation units are not able to restore all the supply for the entire outage period.

The sensitivity analysis revealed some interesting results. The distribution system is very sensitive to the failure rate whereas the microgrid is sensitive to the battery capacity and the repair time. In this scenario, the microgrid is designed to ensure self-sufficiency by storing energy in the battery. For some situations where the repair time is long or multiple failures occur at the same time, the microgrid benefits from a larger battery capacity. Several interaction effects are apparent for the microgrid, while

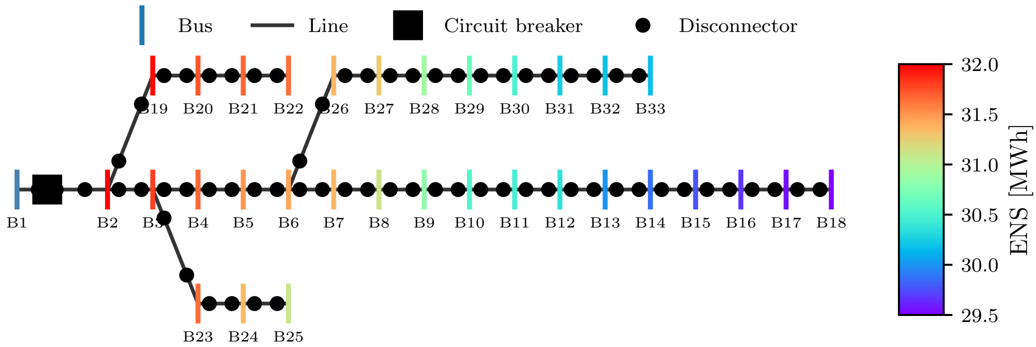

Figure 12: Heat map showing ENS in the distribution system for different placements of the microgrid.

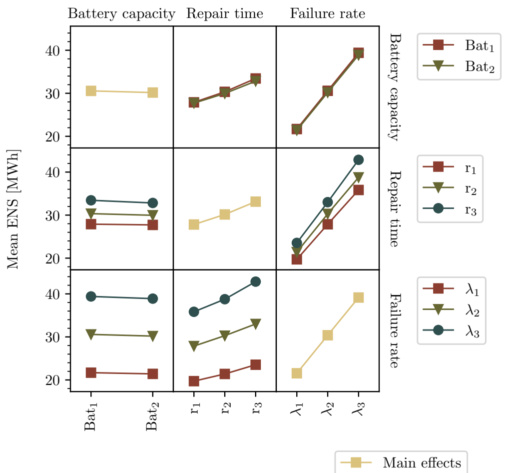

Figure 13: Interaction plot for the distribution network of the mean ENS for the battery, outage time, and failure rate parameters.

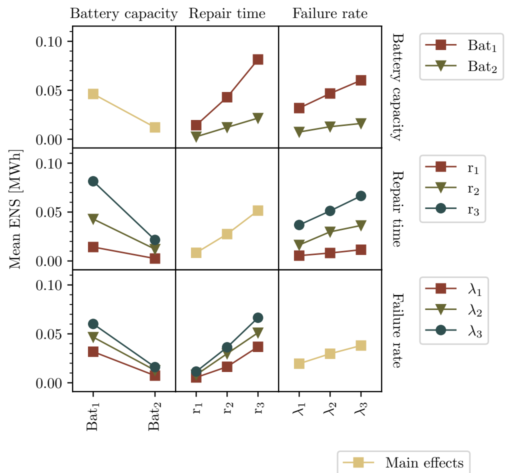

Figure 14: Interaction plot for the microgrid of the mean ENS for the battery, outage time, and failure rate parameters.

none are evident for the distribution system. The two most significant interaction effects seen for the microgrid are linked to the battery capacity, while the battery capacity does not influence the ENS for the distribution system. The results from the sensitivity analysis are a consequence of the network sizes. The distribution system is large compared to the microgrid and the load is large compared to the generation in the microgrid. Since the microgrid load is prioritized, the amount of energy support from the microgrid is restricted. In addition, the microgrid can only support faults that are not isolated from the microgrid. Since the distribution system is a relatively large system, local conditions become less severe seen from the whole system perspective. However, they are still important for issues locally as seen from the microgrid perspective. This is also something that could be seen if smaller parts of the distribution system connected to the microgrid were investigated. The size of the network and distinguishing between local and global perspectives are therefore important factors when analyzing the ENS for the given parameters.

VI. Concluding Remarks

This study has successfully investigated how a microgrid including RES may improve the reliability of a distribution system. The reliability impact was mapped through investigations of variations in microgrid placement, operation mode, and battery capacity, resulting in a suggestion for the optimal conditions for the microgrid with respect to minimizing the impact on the microgrid while maximizing the contributions to the distribution system. Statistical testing was performed to evaluate the results and indicated a significant difference in receiving support from the microgrid compared to no support. However, the effect could be seen as moderate. The contribution is dependent on the microgrid and the location of the microgrid. Since the microgrid is located in one place, there will be multiple cases where the microgrid is not able to support the distribution network. This is a result of effects seen on the system as a whole against effects seen locally in the system. The significance of the result, however, makes way for further investigations of the possibility of using microgrids or other sources as reliability support for the distribution network. This can lead to further studies of other reliability support possibilities or other system configurations such as distribution networks consisting of multiple microgrids. The presented methodology for evaluating how microgrids perform from a reliability perspective using RELSAD shows great promise. The study investigated the reliability of electricity supply both from the perspective of the distribution network and from the perspective of the microgrid. The tool facilitates analysis of multiple different cases and the results are detailed distributions that serve as a good basis for further analysis. Additionally, the tool is general and modular, lowering the barrier to implementing different operation modes and studying different system topologies.

VII. Acknowledgment

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Paper III

The paper **"A Study on V2G impact on the Reliability of Modern Distribution Networks"** has been submitted to a scientific journal.

A Study on V2G impact on the Reliability of Modern Distribution Networks

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***Abstract*— The increased penetration of electrical vehicles (EVs) in the distribution system creates a power system with many small moving batteries. With better charging technologies and market structures, the opportunity of using EVs for reliability purposes increases. By utilizing EVs for Vehicle-to-Grid (V2G), they can support the distribution network during outages or other issues. In this paper, we aim to investigate the impact V2G has on the reliability of modern distribution networks. We propose three new EV-oriented reliability indices to provide an overview of the impact experienced by the EVs in the system. For the reliability study, we use our developed reliability assessment tool for distribution networks. The tool is an open available software where the example network and datasets are embedded. We have extended this reliability tool to include a method for evaluating and calculating the reliability of distribution networks containing EVs with V2G possibilities. The paper also includes a thorough sensitivity analysis to further investigate the V2G impact of different parameters.**

***Keywords*—Active Distribution Systems, Distribution System Reliability, Microgrid, Monte Carlo.**

I. Introduction

The European Union (EU) has a goal to reduce greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels, and by 2050, become climate-neutral [1]. The greenhouse gas emissions from the transport sector constitute a large portion of the total greenhouse gas emissions in most countries. The transportation sector alone accounted for 24.6% of the greenhouse gas emissions in the EU during 2018 [2]. In Norway, the greenhouse gas emission from the transportation sector was 15.6% in 2020 [3]. Due to the aim to reduce global greenhouse gas emissions, an increase in electrification is taking place.

Several countries have initiated measures to ban the sale of new carbon-emitting passenger cars. In the UK, the sale of petrol and diesel cars is planned to end by 2030 [4], the EU is planning to ban the sale by 2035 [5], while in Norway only zero-emission cars are to be sold from 2025 [6]. This will result in a higher share of electric vehicles (EV)s on the road. According to a study conducted by The Institute of Transport Economics, EVs will constitute on average 45.9–61.2% of all cars by 2030 [7]. However, this might differ between the regions of the country, resulting in regions with a high share of EVs and others with a low share of EVs.

With a high share of EVs in the distribution systems, the potential of using EVs as grid support is increasing. By utilizing the EVs with, for example, vehicle-to-grid (V2G) technology, demand response measures such as frequency regulation, voltage support, and reactive and active power support can be possible. With V2G, the EVs that are connected to a charging station can support the network by transferring active and/or reactive power back to the power grid, becoming, in this way, small mobile batteries.

A. *Related work*

Some studies have investigated the potential of utilizing EVs with V2G to support the grid. V2G technology has been investigated for voltage regulation in distribution systems [8], primary frequency regulation [9], [10], and regulation of small microgrids [11]. In [12], a method for primary frequency regulation from an EV fleet is proposed. The study concludes with positive results and adds recommendations for ensuring a safe and stable operation when utilizing V2G.

An interesting study on a military microgrid system is conducted in [13]. The study investigates V2G and vehicle-to-vehicle possibilities for power generation in a military microgrid. The study reports economic benefits due to reduced fuel costs and a benefit better than the already existing solution, indicating that EVs have an impact. However, the study points out the need for technology upgrades.

Some other studies have investigated the possibility of increased reliability with V2G support. In [14], a framework based on a non-sequential Monte Carlo simulation is developed to evaluate the reliability of a modern distribution system. The framework is used to investigate how integrated renewable generation and EV parking lots influence the reliability. The results indicate a significant improvement in which V2G is activated. A Sequential Monte Carlo Simulation (SMCS) framework is developed in [15] where V2G and vehicle-to-home for reliability purposes are investigated.

The studies indicate a benefit of utilizing the available EVs for V2G services of the power system. However, the amount of support can be limited by multiple factors such as the EV availability and the technology related to charging, and will need to be further evaluated. In addition, in the literature, the impact on the degradation of the EVs is not considered to any great extent.

B. Contribution

In this paper, we aim to investigate the impact V2G service has on the reliability of modern distribution networks for short repair times. The paper utilizes V2G to increase the reliability of radially operated distribution networks. By providing three new EV-related indices, we aim to identify and investigate the impact experienced by the EVs when V2G is used. In addition, we provide a general methodology for evaluating how EVs perform from a reliability perspective through the use of RELSAD. The study will focus on failures resulting in repair times of up to 2 hours, and the impact of V2G support will be investigated for the given down time.

The contribution of this paper is to propose a reliability assessment method that considers V2G properties with a study to evaluate the impact on the reliability of modern distribution network. The method is an extension of our developed reliability assessment tool, RELSAD (RELiability tool for Smart and Active Distribution networks) [16]. RELSAD is an open-source software with an associated documentation page [17]. In this paper, RELSAD is extended to include EVs and V2G opportunities. The main contributions of this research paper are:

- A general methodology to assess the reliability of modern distribution networks with modeled V2G services. The potential and impact of V2G support for increased reliability of modern distribution systems will be assessed.
- Provide three new EV-related indices for describing the impact V2G services has on the EVs in the distribution network.
- Extensive sensitivity analysis to provide a greater picture of the method and the impact of V2G support. The sensitivity analysis is conducted as a full factorial design. The evaluated parameters are repair time distribution, the charging capacity of the EVs, and the share of EVs in the network.
- Provide a study on a realistic and modern distribution system. This is done systematically by gathering data for the system through procedures described in Sec III and Sec IV. This include using statistics from the Norwegian distribution systems, the Norwegian Electric Vehicle Association, and The Institute of Transport Economics in Norway. The proposed method is demonstrated through a case study on the IEEE 33-bus distribution network.

C. Paper structure

The rest of this paper is organized as follows: Section II introduces EVs. In Section III, the reliability assessment approach is presented along with how the EVs are implemented. The developed EV indices are outlined in Section III as well. The case study is discussed in IV before the results are presented and discussed in Section V. Lastly, some concluding remarks will be offered in Section VI.

II. Theory

This section explores the current practice of EV charging, battery degradation, and how EVs can be used for ancillary services in the network.

A. Charging infrastructure

There exist multiple infrastructures for EV charging. The infrastructure can roughly be divided between home charging and charging stations with different charging performances such as fast charging and high-performance charging. The charging capacity at the charging stations can differ, from slow chargers with a capacity below 22 kW to super chargers with a capacity of over 100 kW [18]. Home charging, however, is a slower charging method, often with power capacities varying between 2-11 kW [19]. The charging capacity is dependent on the car, the installed capacity of the charger, the AC or DC charger, and the voltage output of the network. There are two different methods for home charging, charging through charging boxes or through a socket.

Charging methods and practices differ between countries [18]. The reason for this is the coverage of charging stations compared to EV owners with their own home charging. In Scandinavian countries, it is more common to have home charging. Public charging stations typically have higher charging capacities and are often used during short periods of time. However, in Asia, the share of public charging stations with slow charging is high.

B. Battery degradation

During the lifetime of an EV, the battery will experience degradation. The degradation of the battery is a result of multiple factors, such as structure degradation of the cells in the battery, charge, and discharge of the battery, temperature, and the aging and use of the EV [20].

In [21], a methodology for quantifying the difference in battery degradation with and without V2G services is proposed. The paper provides a case study investigating how different support mechanisms, such as peak shaving, frequency regulation, and net load shaping, impact EV battery degradation compared to the cases where EVs do not offer grid services. The results illustrate that the battery degradation as a result of V2G services is minor, and the paper concludes that if the V2G services are only used in emergency events, the degradation will be inconsequential. The case study conducted in [20] supports this result. Here, battery degradation from providing primary frequency control support is investigated. The result illustrates that the battery degradation is 2% when an EV supports the grid with 9 kW every day for five years.

Charging and discharging of a battery will over time contribute to the total degradation of an EV battery. Charging/discharging with a high rate results in higher battery degradation compared to slow charge/discharge. However, if the service is used rarely and the support is limited, the battery will not experience a large degradation as a result of V2G services.

C. EVs used for ancillary services

Charging boxes allow for smart home charging. Here, the opportunities for an EV owner to activate different charging strategies can be made possible. Through such a system, the EV owner could, for example, decide to be a part of a flexibility market. In such a flexibility market, the EV owner could agree to let a power supplier use the EV for V2G service, and in return be compensated.

In Ref. [22], a pilot project is initiated to investigate how different technologies including EVs are used for providing flexibility in an electronic bid ordering market. The EV owner could choose to be a part of the flexibility market through their smart home charger controlled by the supporting electricity company. During peak load hours, the EVs participating could be used to decrease the load in the power system by pausing the charging of the EVs. In the future with new standards and business models, V2G can be a part of the market solutions and constitute an important role in flexibility and reliability in the power system [23].

III. Methodology

This section aims to present the developed reliability method and the proposed EV-oriented reliability indices. In this section, we will first present the implemented reliability indices with the proposed EV-oriented reliability indices. Second, we outline the approach for the used reliability attributes in the system. Third, the methodology used for estimating the availability of EVs is described before the repair time distribution of the components is given. In the end, RELSAD, the developed reliability assessment tool, is presented and the implementation of V2G is discussed.

A. Reliability indices

There are different reliability indices used for measuring and quantifying the reliability in distribution networks. They can be divided into *customer-oriented indices* and *load- and production-oriented indices* [24]. In this paper, three classically used reliability indices are included. In addition, we have developed three indices related to the impact the EVs experience during V2G operation.

The three basic reliability parameters used for calculating reliability indices are: 1) the fault frequency or the average failure rate, λ_s, 2) the annual average outage time, U_s, and 3) the average outage time, r_s.

1) Load- and Production-oriented indices: The load- and production-oriented indices aim to indicate the electrical consequence of faults in the system [24]. In this paper, the total Energy not Supplied (ENS) in a system is investigated. ENS can be calculated as:

$$\texttt{ENS}_s = U_s P_s \tag{1}$$

2) Customer-oriented indices: The customer-oriented indices aim to indicate the reliability of the distribution system based on the interruption experienced by the customers [24]. In this paper, three important indices will be investigated:

1) System Average Interruption Frequency Index

$$\texttt{SAIFI} = \frac{\sum_{\forall i} \lambda_i N_i}{\sum N_i} \tag{2}$$

where N_i is the *total number of customers served* at bus i, and $\sum_{\forall i} \lambda_i N_i$ is the *total number of customer interruptions*. SAIFI is a measure of the frequency of interruptions the customers in the system expect to experience. Any interruption seen by the consumer is counted as a fault, regardless of origin.

2) System Average Interruption Duration Index

$$\texttt{SAIDI} = \frac{\sum U_i N_i}{\sum N_i} \tag{3}$$

where $\sum_{\forall i} U_i N_i$ is *total number of customer interruption* durations. SAIDI is a measure of the expected duration of interruptions a customer is expected to experience.

3) EV-oriented indices: Since the EVs will be affected by outages in the distribution system, their own EV indices are established.

1) Average EV Demand Not Served

$$\texttt{EV}_{\texttt{Demand}} = \sum U_{EV_i}(P_{ch_i} + P_{dis_i}) \tag{4}$$

where, U_{EV_i} is the expected outage time EV i experience, P_{ch_i} is the amount EV i charges or wants to charge, while P_{dis_i} is the amount of power EV i discharges. This index aims to give an indication of how much power the EVs are not being served. During outages in the system, an EV can experience periods where the EV is unable to charge as a result of the ongoing fault in the system. When an EV is used for V2G services, the index will increase since the EV is discharging power in addition to having a demand. This means that the amount of discharged power from the EV will be added to the demand not served for the EV. This index can be used to give an indication of how much power an EV contributes and the amount of demand from the EVs in the system.

2) Average EV Interruption Frequency

$$\texttt{EV}_{\texttt{Int}} = \frac{\sum_{\forall EV} \rho_{EV_i} N_{EV_i}}{\sum N_{EV_i}} \tag{5}$$

Here, ρ_{EV_i} is the expected amount of times an EV is used for V2G services, $\sum N_{EV_i}$ is the total number of EVs in the distribution system, and N_{EV_i} is the total number of EVs at a bus. This index is based on SAIFI. This index gives the average number of interruptions an EV experiences due to V2G services in the system. In a simulation, the fraction of EVs that are used for V2G services in an EV park is found and multiplied by the amount of EVs in the EV park to give an estimation of how many cars in that EV park are used for V2G. This index can be used to illustrate how often an EV is estimated to be used for V2G services. The index is sensitive to the frequency of failures in the system. With a higher frequency of failures, the system will require the EVs to support more frequently.

3) Average EV Interruption Duration

$$\texttt{EV}_{\texttt{Dur}} = \frac{\sum U_{EV_i} N_{EV_i}}{\sum N_{EV_i}} \tag{6}$$

This index is based on SAIDI. The index gives the average duration of the EVs used for V2G services in the system. This index accumulates the amount of time every EV in the system is being used for V2G

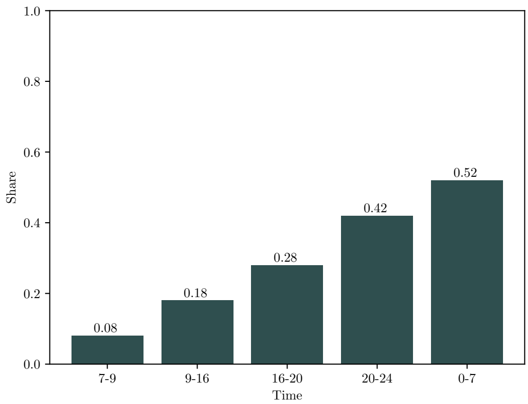

Figure 1: The normal charging time of an EV, based on [25].

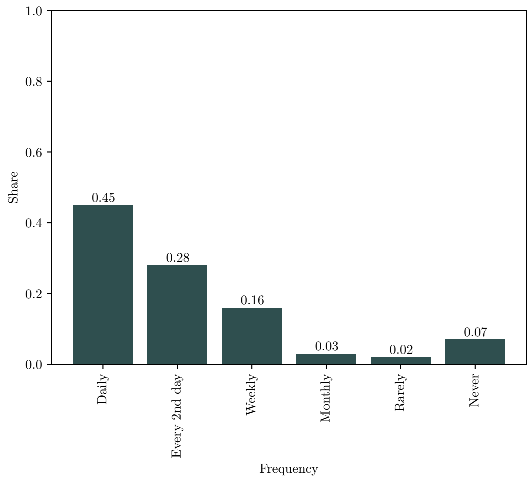

Figure 2: The home charging frequency of an EV owner, based on [25].

services and divides it by the number of EVs in the system. The index gives an indication of how long an EV can be expected to be used for V2G services during a given period. The index will increase with a longer down time of the system since the EVs will most likely be used for longer periods at a time.

B. Availability distribution of the EVs in the distribution network

For activating V2G support in the distribution network, the availability of the EVs in the network needs to be established. The availability of the EVs can be decided based on the number of EVs that are charging. Therefore, the availability can be estimated based on the charging patterns of EVs.

The charging pattern of Norwegian EVs is examined in a survey conducted by The Norwegian Electric Vehicle Association (*Elbilforeningen*). The survey was conducted in 2019 with more than 16,000 respondents [25] and will be used as a basis for estimating the availability of EVs in the distribution system. The result of the survey is summarized in Fig. 1 and 2. Fig. 1 illustrates at which time the EV owners usually charge their EV. In 2, the frequency for home charging is shown. These results correspond well with the result on charging patterns obtained in [26] and give a good estimation for evaluating the expected availability of EVs that are charging at home during a specific time in the distribution networks.

Based on the distributions in Fig. 1 and Fig. 2 and the amount of EVs in the distribution system, the probability of an EV being charged at home is:

$$A_{EV} = n_{customers} \cdot X_{EV} \cdot C(t) \cdot D_{EV} \tag{7}$$

Here, $n_{customers}$ is the number of households in the distribution system, X_{EV} is the percentage share of vehicles that are EVs in the distribution network, $C(t)$ is the share of EVs charging at time t, and D_{EV} is the estimated daily charge frequency. The daily charge frequency is based on the result from Fig. 2 and gives a probability of the EV being charged at home. Based on Fig. 2, $D_{EV} = 0.45 + 0.28 \cdot 0.5 + 0.16 \cdot 1/7 + 0.03 \cdot 1/30 = 0.61$.

C. Repair time distribution

In this paper, events resulting in varied down times are considered. Therefore, the repair time of the system components will vary within a range of possible repair times. The repair time used in this paper is based on yearly reliability statistics for the Norwegian DSOs and is described in Sec IV. There exist multiple possible distributions that can be used to decide the repair time of an event, such as Log-normal-, gamma-, and normal distributions [27]. In this paper, truncated normal distributions will be used.

1) Truncated normal distribution: A truncated normal distribution has a probability distribution similar to a normal distribution but is bounded by either an upper or lower limit or both.

The probability density function of a normal distribution can be expressed as

$$f(x) = \frac{e^{-\frac{(x-\mu)^2}{(2\sigma)^2}}}{\sigma\sqrt{2\pi}} \tag{8}$$

where, μ is the location or mean parameter of the distribution and σ is the scale parameter or standard deviation. Truncated normal distributions are good distributions to use for repair times that are limited by boundaries. Fig. 3 illustrates how the truncated normal distributions look with different location parameters (high, low, and normal mean).

D. Reliability evaluation of modern distribution system - RELSAD

The electrical power system is rapidly modernizing with higher penetration of renewable energy sources, flexible energy sources, and Information and Communication Technology (ICT). The modernization of the power system results in a more complex system structure with increased dependencies. The traditional methods for reliability assessment of power systems do not consider these changes.

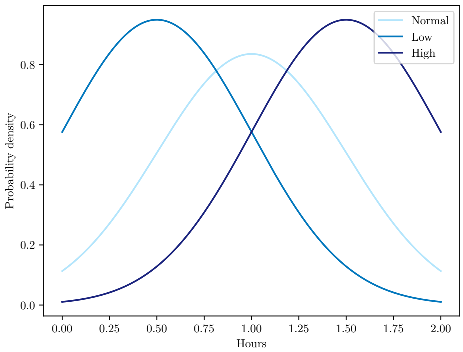

Figure 3: Truncated normal distributions of the repair time for three different location parameters (low, high, and normal).

In response, we developed RELSAD—RELiability tool for Smart and Active Distribution networks.

RELSAD is a reliability assessment tool for modern distribution networks based on SMCS. The software is developed as an open-source Python package and is published as a scientific tool [16]. Additionally, a documentation page for the software has been written [17]. RELSAD was developed to give a foundation for the reliability assessment of modern distribution systems where the changed behavior and the increased complexity in the distribution network are considered.

RELSAD provides the following features:

- Calculation of detailed results in the form of distributions and statistics on important reliability indices.
- Opportunity for investigation of network sensitivities where different parameters such as repair time, failure rate, load and generation profiles, placement of sources, and component capacities and their impact on the system.
- Implementation and investigation of diverse and advanced network constellations spanning from small passive distribution systems to large active networks including DGs, batteries, microgrids, and EVs where the networks are operated radially.
- The ability to investigate and analyze the reliability of Cyber-Physical Networks.

In this paper, RELSAD is extended to include EVs and V2G possibilities. This paper will describe the core functionality of RELSAD in addition to the contribution and implementation of EVs with V2G.

E. Structure of RELSAD

In Fig. 4, an overview of the RELSAD model is illustrated. RELSAD considers different attributes such as

- **Topology attributes:** such as spatial coordinates and connected components.
- **Reliability attributes:** such as failure rates and repair time distributions.

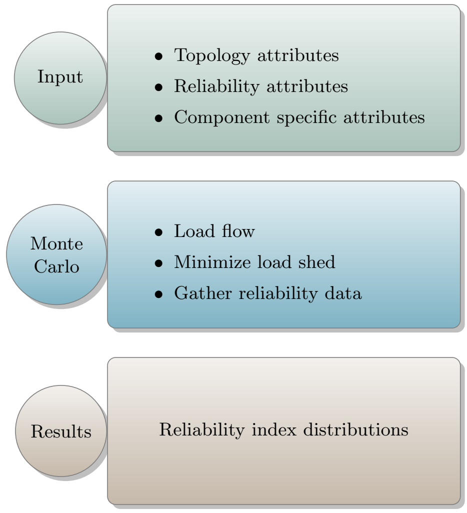

Figure 4: Overview of the RELSAD model. A full description can be found in the software documentation [17].

- **Component specific attributes:** such as, for an EV, this could be the battery capacity, the inverter capacity, efficiency, and charging limitations.

The core of the software is the simulation where different operations are performed. The general functionality of RELSAD is described in Sec. III-F and the EV and V2G specific functionalities are described in Sec. III-G.

The output or results of the RELSAD software are given as reliability index distributions. Some of the different distributions that can be investigated are described in Sec. III-A such as the proposed EV-oriented reliability indices.

RELSAD is constructed in an object-oriented fashion, where the systems and system components are implemented with specific features simulating their real-life behavior. RELSAD is a general tool that can consider any network that operates radially. In RELSAD, a power system - P_s is first created before distribution systems - D_s and other systems such as Microgrids - M_s are created inside the P_s. After this, the electrical system components can be created and added to associated network layers. The possible electrical components are lines - l, buses - b, disconnectors - d, circuit breakers - cb, generation units - p_u, batteries - p_b, and EV parks - p_{EV}. In addition, a load - p_d can be assigned to each bus. This is described in more detail in the documentation page of the software [17].

F. Core functionality of RELSAD

In this section, the core functionality of RELSAD is described. The reliability assessment of a system is solved through SMCS in RELSAD. To account for the active participation of different technologies such as DGs, batteries, and EVs, a load flow solver is implemented to evaluate the electrical consequence of faults in the system. Through load flow calculations, the behavior of the system during different scenarios can be evaluated. In RELSAD, a

Forward-Backward sweep (FBS) approach is implemented as the load flow solver. In the FBS approach, the load flow is calculated by updating the power flow through a backward sweep before the voltage magnitudes and angles at the system buses are updated in a forward sweep [28].

Due to the potential island operation of parts of the distribution system, power balance needs to be ensured. To achieve this, a simple load shed optimization problem is included. The objective of the load shed optimization problem, seen in eq. 9, is to minimize the total load shed in the network based on the price of shedding different load types. The price is based on the *Cost of energy not supplied* (CENS). This is subjected to load flow balance and the capacity limitations over the power lines, the load, and the generation in the distribution system:

$$\underset{P_n^s}{\text{minimize}} \quad \mathcal{P}_s = \sum_{n=1}^{N_n} C_n \cdot P_n^s \tag{9}$$

subject to:

$$\begin{aligned} \sum_{i=1}^{N_l} \alpha_i \cdot P_i^l = \sum_{j=1}^{N_g} \nu_j \cdot P_j^g - \sum_{k=1}^{N_n} \quad & \eta_k \cdot (P_k^d - P_k^s) \\ \min P_j^g \leq P_j^g \leq \max P_j^g \qquad & \forall j = 1, \dots, N_g \\ 0 \leq P_k^s \leq P_k^d \qquad & \forall k = 1, \dots, N_n \\ \left| P_i^l \right| \leq \max P_i^l \qquad & \forall i = 1, \dots, N_l \end{aligned}$$

Here C_n is the cost of shedding load at node n while P_n^s is the amount of power shed at node n. P_j^g is the production from generator j. P_k^d is the load demand at node k while P_i^l is the power transferred over line i. α_i = 1 if line i is the starting point, -1 if line i is the ending point. ν_j = 1 if there is a production unit at node j, otherwise it is 0. η_k = 1 if there is a load on node k, otherwise it is 0.

1) Incremental procedure of fault handling in RELSAD: The SMCS in RELSAD is constructed to have a user-chosen increment. This can, for example, be a second, a minute, an hour, or a day. The incremental procedure of the fault handling model implemented in RELSAD is illustrated in Algorithm 1. After a P_s is created with associated systems and components, the incremental procedure will set the load and generation at the system buses for the current time increment. Then the failure status of each component is calculated based on random sampling and the failure rate of the different components. If any component is in a failed state, the network with the failed components will be divided into sub-systems, and a load flow and load shedding optimization problem will be solved for each sub-system. The load flow and load shedding optimization problem are included to calculate the electrical consequence of a fault when active components are present. When this is performed, the historical variables of the components are updated. The historical variables can then further be used to evaluate the reliability of the P_s, the different networks in the power system, and the individual load points. An example of this is illustrated in the documentation page for the software [17]. The rest of this section describes the different procedures of the reliability evaluation in greater detail.

Algorithm 1: Increment procedure

Set bus p_d and p_u for the current time increment;
Draw component fail status;
if *Failure in* P_s **then**
    Find sub-systems;
    foreach *sub-system* **do**
        Update p_b and p_{EV} demand (charge or discharge rate, discharge of EVs if V2G is activated);
        Run load flow;
        Run load shedding optimization problem;
    end
    Update history variables;
end

G. V2G implementation in RELSAD

EVs and V2G possibilities are implemented in RELSAD. The EVs are implemented to be connected to the buses in the system and as susch form an EV park at the bus. Furthermore, the number of EVs in an EV park can be decided based on a user-defined availability distribution. Each EV park can be flagged to allow for V2G possibilities or not. The specifications, such as battery capacity, inverter capacity, and min and max SoC, of the EVs in the EV park, can be set by the user.

The behavior of the EVs in an EV park works similarly to that of a battery. The EVs can be charged and if V2G is possible, the EVs can be discharged. The charging and discharging of the EVs are restricted by the specifications of the EV.

1) V2G and EV algorithm: In Algorithm 2, the EV park procedure during faults in the network is displayed. Since RELSAD is a reliability assessment tool aiming to evaluate the reliability of a system, only situations with faults are considered. It is presumed that when no faults in the network are present, the network is working correctly.

The algorithm is called upon when a failure occurs in network N, in the current time increment. Then the number of cars in an EV park is determined based on an availability distribution. Next, the SoC state of each EV in the EV park is calculated following a given distribution (in this study, it follows a uniform distribution). The SoC state is stated between the maximum and minimum allowed SoC state. Then the network balance of network N, N_b is calculated. This is in order to find out the demand of each EV and the load and generation of the network.

If V2G is activated for the EV park, the EV will either be charged or discharged depending the load balance. If there is an available generation, the EVs can be charged; if there is a lack of generation, the EVs might be discharged to be used for support. After this, the load balance of the network is updated.

If V2G is not activated, charging of the EVs is only possible if there is a surplus of generation in the network (or connected to the overlying network). The load balance of the network is then updated.

In the end, the history variables of the EVs in the EV parks are updated.

Algorithm 2: EV park procedure during faults in the network

```
if Failure in network, N, happened in current
  increment then
    Draw number of cars;
    foreach car do
        Draw SoC state;
    end
end
Get network load balance, N_b;
foreach car do
    if Vehicle to grid mode is active then
        Charge/discharge car battery;
        Update N_b;
    else
        Charge car battery;
        Update N_b;
    end
end
Update history variables;
```

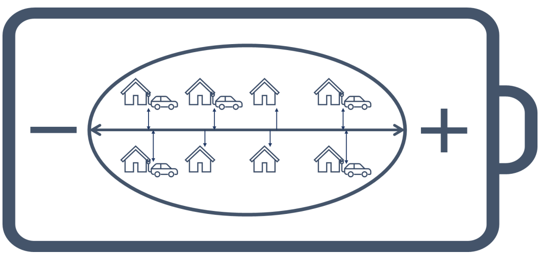

Figure 5: Aggregated battery solution for EVs at a bus in the system. The figure illustrates how an aggregated battery solution is created for an EV park for the EVs at a bus in the network.

2) Aggregated battery solution: In this paper, the amount of EVs in the distribution network will be based on the number of households in the network. Therefore, EVs charged in places other than at home will not contribute to the study. The amount of EVs that in theory are able to contribute is decided based on the total amount of households in the distribution network. From there, predictions about the share of households that owns an EV can be decided.

For simplicity, the model is built up to make an aggregated battery solution as seen in Fig. **??**. The aggregated battery idea illustrates the situation on a bus in the system. The bus has a given number of households, and based on the availability of EVs, measured as in Sec. III-B, a given number of EVs will be connected to the bus. From this, the SoC level of each EV will be estimated based on a uniform distribution between the minimum and maximum levels of the SoC in the EV. This information will then be added to the aggregated battery for the bus. The aggregated battery for the bus will contain information about the EVs on the bus, the aggregated amount of power in the battery, and the total charging capacity of the battery.

IV. Case Study

A. Procedures for developing the test network

The method is demonstrated on the IEEE 33-bus network seen in Fig. 6. This network is chosen since it is a commonly used test network, making it easier for evaluation and replication. To account for a more realistic distribution network, the customers in the network with their demand profiles are distributed to map a real network. To make a dynamic demand profile of non-constant load, load profiles generated based on the FASIT requirement specification [29]. The generated load profiles give hourly time variations of the load. In order to evaluate the system with smaller time increments, the load is interpolated to the simulated time increment. The load from FASIT differs in customer groups and includes households, farms, trade, office buildings, and industry. The temperature data for generating the load profiles are collected from a weather station located in the east of Norway. In Fig.6, the mean load at each bus in the network is illustrated through a heat map.

The repair time follows the distribution described in Sec. III-C. The repair time data is based on yearly reliability statistics from the Norwegian DSOs [30]. The repair times used in this paper span over a time of up to two hours. This time is chosen based on two reason: 1) the availability of disruption data from the Norwegian DSOs [30] and 2) this is a time span that will illustrate to what degree the EVs can support for some longer outage periods. Based on the reliability statistics from the Norwegian DSO, the failure rate corresponding the repair time statistics is 0.026 failures/year/km. This failure rate is based on a collection of the failure rate of multiple components with outage times up to two hours [30].

1) EVs in the distribution system: The EV parks in the system are connected to the buses containing household loads. In Fig. 6, the buses with an X have EV parks connected. The availability of the EVs in each EV park follows the procedure outlined in Sec. III.

The mapping of EVs compared to houses in the distribution system is sat at 46%. This is based on the predicted average share of EVs in 2030 in Norway [7]. With an EV share of 46%, the distribution network will have a maximum of 290 cars. Due to the availability based on the individual charging pattern, the number of available EVs will be fewer.

B. Scenario descriptions

The case study investigates four different cases:

- **Case 1: EV**—No V2G, no support during failures in the network.
- **Case 2: V2G**—V2G is activated, and the available EVs can support during failures in the network.
- **Case 3: EV and battery**—V2G is not activated, batteries are included.
- **Case 4: V2G and battery**—V2G is activated and batteries are included.

The cases aim to investigate the difference in impact by having V2G support compared to no support (only regular EVs). In Cases 1 and 2, the impact from V2G is addressed when no other generation sources are available. In addition,

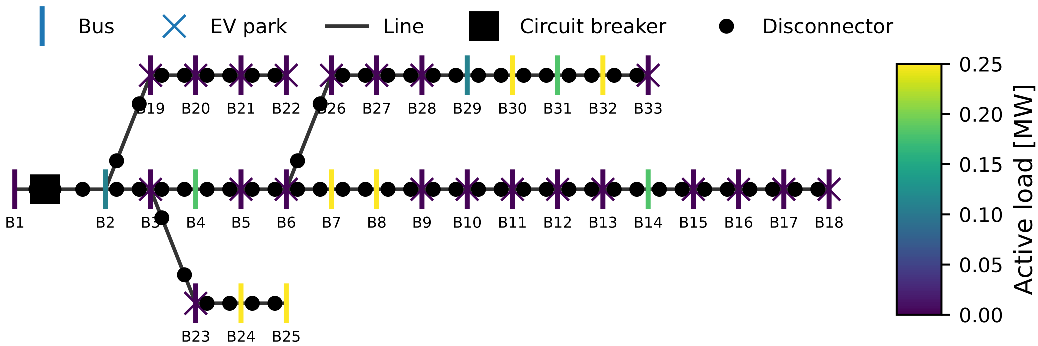

Figure 6: The system topology. The buses with EVs are shown with an X. The plot illustrates a heat map of the mean load at each bus in the system.

Cases 3 and 4 are included to investigate the impact of V2G when other energy sources are added. In Cases 3 and 4, two batteries are integrated into the system at B18 and B33. These batteries are implemented to serve as a backup supply for the network and will be fully charged. The reason for including the batteries is to pinpoint the actual impact V2G serves. Since the charging capacity and the battery capacity of EVs are low, there is a limited amount of energy the EVs can possibly support. By including other sources, the opportunity to identify the impact might increase.

The data used in the scenarios are summarized in Tab. I.

Table I: Data for the case study

Parameter	Value	
EV battery capacity [kWh]	70	
Charging capacity EVs [kW]	3.6	
Share of EVs	0.46	
Outage time distribution	Normal	Loc: 1 Scale: 0.5
Battery capacity [MWh]	0.5	
Inverter capacity [MW]	0.25	
Efficiency	0.95	
Min SoC	0.1	

C. Sensitivity analysis

In addition to the case study, a sensitivity analysis is conducted to investigate the importance of the different parameters. The sensitivity analysis is conducted as a full factorial design where the effect independent input parameters have on both the output variables and the other input parameters. The investigated parameters are:

- **Charging capacity**—Since the charging capacity on the EVs can vary, we will investigate which effect the invert capacity has on the reliability of the system and the EVs in the network.
- **Share of EVs in the network**—The share of EVs in the distribution network is increasing rapidly, and in the future, some locations are estimated to have a share of EVs close to 100% EVs [7]. Therefore, different percentages of EV share (X_{EV}) in the network will be investigated. This is also to investigate how an increased share of EVs will impact the reliability of the distribution network.
- **Repair time**—The study investigates various repair times of up to two hours. To evaluate the effect of the repair time, the repair time distribution will be adjusted to investigate the reliability impact and the impact on the EVs in the system.

The parameter values used in the factorial design can be seen in Tab. II.

Table II: Sensitivity analysis data

Charging capacity [kW]		EV share [%]		Outage time distribution		
$\mathbf{P_1}$	3.6	$\mathbf{X_1}$	0.46	$\mathbf{r_1}$	Low	Loc: 0.5 Scale: 0.5
		$\mathbf{X_2}$	0.61	$\mathbf{r_2}$	Normal	Loc: 1 Scale: 0.5
$\mathbf{P_2}$	7.2	$\mathbf{X_3}$	0.87	$\mathbf{r_3}$	High	Loc: 1.5 Scale: 0.5

V. Result and Discussion

This section aims to present the results from the case study and the sensitivity analysis. The results from the case study are detailed first before the results from the sensitivity analysis are given. Finally, a discussion of the result is presented.

Each simulation in the study is simulated with 3,000 iterations where the same random seed is used for all cases to ensure the same basis for all the cases. The convergence is achieved after approximately 1,500 iterations. The increment value is of five minutes. The example network with the dataset can be located in the documentation page of the software [17].

A. Scenario results

In Fig. 7, a box plot illustrating the frequency distribution of `ENS` in the distribution system for the four cases is presented. We observe a decrease in `ENS` when V2G service is provided to the distribution system, compared to their respective cases without V2G services. The average `ENS` in the distribution system for the cases can be seen in Tab. III. The decrease in `ENS` is 5.51% when comparing Case 1 and Case 2. By comparing Case 3 and Case 4, the decrease in ENS is 6.39% when activating V2G. The results indicate that, with V2G, the EVs are able to support the system for short outages. This is also shown in Case 4 where the battery can provide for longer outages and the EVs can serve as a support to the battery.

By investigating SAIFI and SAIDI for the cases, seen in Tab. III, SAIFI is decreasing between Case 1 and Case 2 and between Case 3 and Case 4. This illustrates that the total number of interruptions decreases by activating V2G. However, by evaluating SAIDI, we see that the decrease is not significant. This indicates that the load shedding is due to the reduction in the number of interruptions the load points experience but that the interruption is prevented for short outages only.

The results for the EV indices are also shown in Tab. III. As expected, the average EV demand not served for the EVs will almost double when V2G is activated. This is a result of all the available EVs being used for V2G services and the demand not served increases since the EVs will be discharged as well. The other two EV indices, $\mathtt{EV_{Int}}$ and $\mathtt{EV_{Dur}}$, will be zero for the cases without V2G since the EVs will not be used as a service. For the two cases with V2G activated, it is evident that on average an EV owner can expect to experience the EV being used for support 0.15 times during a year for Case 1. This is a little higher for Case 4 when the batteries are introduced, where the expected interruption is then 0.32 times a year. The reason for this increase could be that when the batteries are used as the main provider and the EVs are there for support, there could be time increments where the battery can provide the necessary demand but others where the EVs need to be used. This will result in the V2G support being turned on and off during an outage and the total number of interruptions will increase. In both Case 2 and Case 4, the EVs are supporting an average of 38 minutes during a year. These results illustrate that the EVs are neither used often nor for long durations during a year when these reliability parameters are considered.

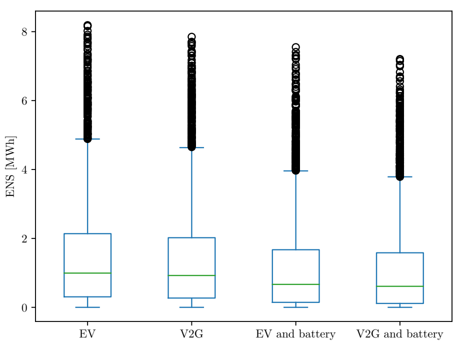

Figure 7: Box plot of the frequency distribution of ENS in the distribution system.

B. Sensitivity analysis

A full factorial design was conducted based on the parameters presented in Fig. II. The sensitivity analysis was conducted on Case 2, and the results for all the presented indices are given. First, in Fig. 8, the interaction plot for mean ENS is shown. The figure shows that the repair time is the parameter that impacts the ENS the most. In addition, we observe a small interaction effect between the charging capacity and the share of EVs. This is an expected result, since a higher share of EVs in addition to more charging capacity results in more support.

Table III: Distribution system and EV oriented reliability indices

	Case 1	Case 2	Case 3	Case 4
ENS [MWh]	1.5809	1.4938	1.2529	1.1732
SAIFI [-]	0.4011	0.3881	0.3392	0.3142
SAIDI [h]	1.1348	1.1346	1.0200	0.9998
$\mathtt{EV_{Demand}}$ [MWh]	0.0362	0.0708	0.0055	0.0116
$\mathtt{EV_{Dur}}$ [h]	0.00	0.6336	0.00	0.6461
$\mathtt{EV_{Int}}$ [-]	0.00	0.1546	0.00	0.3185

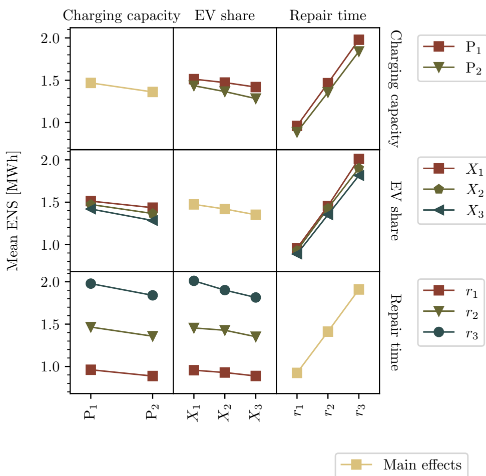

Figure 8: Interaction plot of the mean ENS of the distribution system for the parameter's charging capacity, EV share, and repair time. The plot illustrates that the repair time affects ENS where there is a small interaction effect between the charging capacity and the EV share.

The interaction plots for mean SAIDI can be observed in Fig. 9. The interaction plot for SAIDI is very similar to the interaction plot for ENS. The repair time gives the largest contribution as expected since a higher repair time gives longer down times in the system. The charging capacity and the share of EVs have almost no effect on SAIDI, which was also illustrated in the results presented in Fig. III. Similar to the result for ENS, we observe a weak interaction effect between the charging capacity and the share of EVs. This result indicates that higher EV share and charging capacity decrease the total down time and that might indicate that longer outages can be served.

For mean SAIFI seen in Fig. 10, the charging capacity and the share of EVs have a strong effect. Again, an interaction effect is seen between these two parameters.

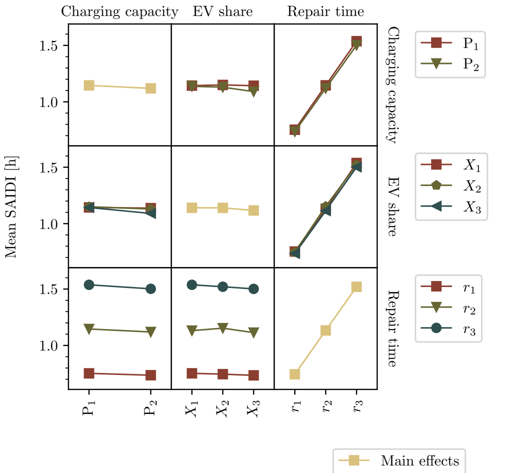

Figure 9: Interaction plot of the mean SAIDI indices of the distribution system for the parameter's charging capacity, EV share, and repair time. The plot illustrates that the repair time affects SAIDI whereas there is a small interaction effect between the charging capacity and the EV share.

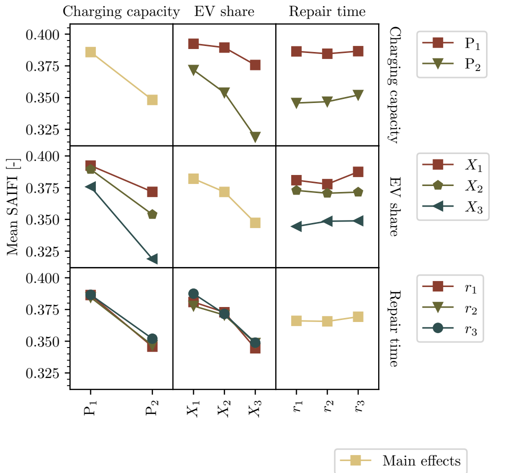

Figure 10: Interaction plot of the mean SAIFI indices of the distribution system for the parameters charging capacity, EV share, and repair time. The plot illustrates that the charging capacity and the EV share have a strong effect on the SAIFI.

The interaction effect is stronger for SAIFI compared to the results for ENS and SAIDI, which is a result of these parameters affecting the indices more. This is expected since a higher share of EVs and greater charging capacity enable the EVs to supply more load. The repair time, however, has a low effect and is only increasing the interruption frequency slightly for higher repair times.

The interaction plot for the mean $\texttt{EV}_{\texttt{Demand}}$ is presented in Fig. 11. The result illustrates that the demand for EVs is slightly affected by the repair time. The trend is decreasing, which could be a result of the EVs being emptied since the repair time is longer. The charging time, however, experiences a considerable increase in demand. With higher charging capacity, more power can be discharged from the EVs, and this will result in an increased demand for the EVs. The demand increases with an increased share of EVs as more EVs are in need of energy. As seen in the other results, there is a weak interaction effect between the charging capacity and the share of EVs for $\texttt{EV}_{\texttt{Demand}}$ indices as well.

The result for mean $\texttt{EV}_{\texttt{Dur}}$ in Fig. 12 is similar to the results for mean ENS and SAIDI. This is expected since this index is similar to SAIDI. The charging capacity and the share of EVs have only small effects on the index. However, the repair time has a large effect since a longer repair time results in longer periods of support for the EVs.

The interaction plot for mean $\texttt{EV}_{\texttt{Int}}$ is illustrated in Fig. 13. We can see from the results that none of the parameters have any significant effect on the interruption of EVs in the system. We expect that the number of interruptions experienced by an EV will stay fairly constant until the distribution network is saturated.

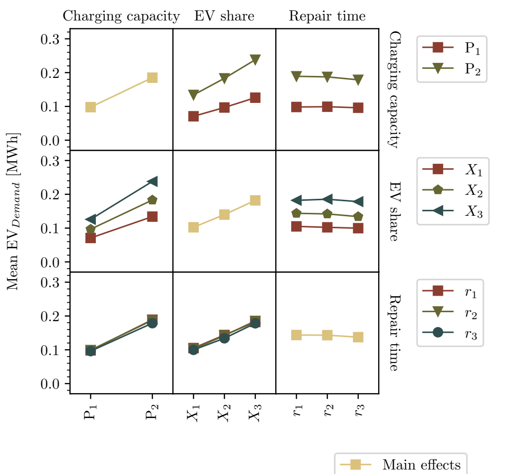

Figure 11: Interaction plot of the mean $\texttt{EV}_{\texttt{Demand}}$ indices of the distribution system for the parameter's charging capacity, EV share, and repair time. The plot illustrates that the $\texttt{EV}_{\texttt{Demand}}$ is affected by the charging capacity and the EV share.

C. Discussion

When analyzing the results from the case study, it can be observed that the EVs do in fact have an impact on the reliability of the distribution network when V2G is activated. However, the cases indicated that this type of V2G support is more suitable for short outage periods.

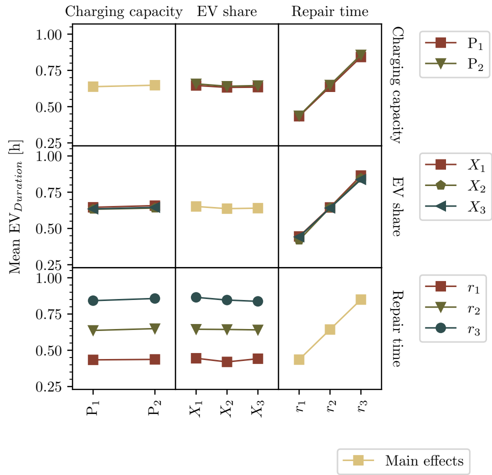

Figure 12: Interaction plot of the mean $\mathtt{EV_{Dur}}$ indices of the distribution system for the parameter's charging capacity, EV share, and repair time. The plot illustrates that the repair time affects the $\mathtt{EV_{Dur}}$.

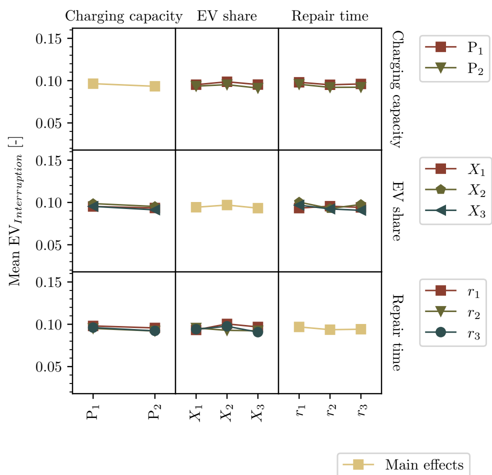

Figure 13: Interaction plot of the $\mathtt{EV_{Int}}$ indices of the distribution system for the parameter's charging capacity, EV share, and repair time. The results illustrate that $\mathtt{EV_{Int}}$ is not affected by any of the parameters.

The effect from the V2G could be more significant if other generation source solutions are also available in the system, such as renewable energy sources and batteries. An indication of this was given in the case where V2G and batteries were included when longer outages could be provided for and the EVs served as a backup. This result seems to be a general result due to the small contributions the EVs can provide. Since the EVs are restricted by the charging capacity, the EVs are limited to small power contributions compared to other sources such as a battery. Since the simulated failure types have a low probability of occurring, the results indicate that the EVs are not used very often during a year. Since the interruption frequency is so low, an EV owner will most likely not be affected within a year. The total duration an EV is used is also very low, under 40 minutes, meaning that most of the used EVs can restore their demand relatively fast after being used for support. This is encouraging for motivating participation in such V2G programs. The total degradation of the EV battery will also be very low when the EV is used so rarely and during short periods where the charging capacity is low. If EV owners also receive benefits for participating, increased participation can be expected. In addition, the benefits from V2G need to be assessed through a cost-benefit analysis.

The duration-based indices ($\mathtt{ENS}$, $\mathtt{SAIDI}$, and $\mathtt{EV_{Dur}}$) are very sensitive to the repair time of the system components where the other parameters have small effects. The frequency-based ($\mathtt{SAIFI}$ and $\mathtt{EV_{Int}}$), however, are not. Longer repair time means a longer down time of the network, but for $\mathtt{SAIFI}$ and $\mathtt{EV_{Int}}$, longer repair time does not impact an already started interruption significantly. The share of EVs, however, will affect the frequency-based indices since more EVs mean that more load can be supplied and fewer EVs need to be used. However, this is not the case for $\mathtt{EV_{int}}$ since there is no saturation in the network and all the available EVs are used to support the network. The interaction effect between the charging capacity and the share of EVs is observed for multiple indices. This indicates that with higher charging capacity and a number of EVs, more support can be given. Something to note is that the results might be sensitive to the strategy for choosing which EV parks and EVs to use for the V2G service. In this study, the EV parks were ordered by the id of the parent bus and the EVs within the EV parks were chosen randomly.

VI. Conclusion

In this study, the impact of V2G on the reliability of a modern distribution system for short repair times was investigated. The results illustrate that EVs used for V2G support do have an impact on the reliability. However, the support is more suitable for short down times and in combination with other generation sources where the EVs can serve as a backup. In addition, the impact on the EVs is minor since the cars are affected rarely for a short duration at the time. We provided three new EV-related indices that successfully captured the impact experienced by the EVs when V2G is used. The EV-related indices were used to gain valuable insight into the EV perspective of the V2G service. A thorough sensitivity analysis was conducted to analyze how the EV charging capacity, EV share, and repair time of components in the system affect the reliability indices of the system and the EVs. The EV indices give an estimate of both the frequency and duration the EVs are used for V2G services which further provides the impact the EVs will experience. The proposed indices seem to capture the overall system effect experienced by the EVs, and may therefore be suitable for use in further investigations. The presented methodology for evaluating how EVs perform from a reliability perspective using RELSAD shows great promise. The study investigated the reliability of electricity supply both from the perspective of the distribution network and from the perspective of the EVs. The tool facilitates analysis of multiple different cases and the results are detailed distributions that serve as a good basis for further analysis.

VII. Acknowledgment

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Appendices

Appendix A: RELSAD: Example of Usage

In this appendix a part of the documentation page for RELSAD [64] is included. The part aims to illustrate the usage of RELSAD with examples. Additionally, descriptions of how to run and analyze the provided examples are included. For more details on RELSAD see the documentation page [64].

CHAPTER TWO

USAGE

This section contains a tutorial and descriptions on how to run and analyze the provided examples.

2.1 Tutorial

Here, we describe the workflow of *RELSAD* containing the necessary steps for running a reliability analysis. First, multiple ways of defining the network is presented. Second, an example of how to run an analysis is shown. Finally, we show a way of visualizing the results.

2.1.1 Traditional power system, system setup

Here we present the creation of a small example network in *RELSAD*. The network consists of 6 buses and 6 lines, where one of the lines is a backup line. We introduce simplified loads.

Imports

To create a power system the necessary imports need to be added.

We will make use of os, numpy, pandas and matplotlib in this tutorial:

```
import os
import numpy as np
import pandas as pd
import matplotlib.pyplot as plt
```

For importing components from *RELSAD*:

```
from relsad.network.components import (
    Bus,
    Line,
    Disconnector,
    CircuitBreaker,
    ManualMainController,
)
```

For importing systems and networks from *RELSAD*:

```
from relsad.network.systems import (
    PowerSystem,
    Transmission,
    Distribution,
)
```

To run time dependent simulations, the time utilities of *RELSAD* must be imported:

```
from relsad.Time import (
    Time,
    TimeUnit,
    TimeStamp,
)
```

Adding statistical distribution for, for example, outage time of components, is done by using the statistical distribution utilities of *RELSAD*, which needs to be imported:

```
from relsad.StatDist import (
    StatDist,
    StatDistType,
    NormalParameters,
)
```

The statistical distribution utilities of *RELSAD* enables a variety of custom distributions, including normal and uniform distributions.

To prioritize the bus loadings during outages, the user may define cost functions that can be related to chosen buses. To use this feature, the *CostFunction* class must be imported:

```
from relsad.load.bus import CostFunction
```

To plot the network topology, we import the *plot_topology* function:

```
from relsad.visualization.plotting import plot_topology
```

The *Simulation* class must be imported to be able to run simulations:

```
from relsad.simulation import Simulation
```

Create components

First, we create the components for our system.

Creating buses:

```
# Failure rate and outage time of the transformer on the bus
# are not necessary to add, this can be added on each bus.
# Their default values are 0 and Time(0) respectively.

B1 = Bus(
    name="B1",
    n_customers=0,
    coordinate=[0, 0],
)
```

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```
B2 = Bus(
    name="B2",
    n_customers=1,
    coordinate=[1, 0],
)

B3 = Bus(
    name="B3",
    n_customers=1,
    coordinate=[2, 1],
)

B4 = Bus(
    name="B4",
    n_customers=1,
    coordinate=[2, 0],
)

B5 = Bus(
    name="B5",
    n_customers=1,
    coordinate=[3, 0],
)

B6 = Bus(
    name="B6",
    n_customers=1,
    coordinate=[3, 1],
)
```

Creating lines:

```
# Failure rate and outage time of the lines can be added to each line.
# The default value of the line failure rate is 0, while the default
# outage time is 0 (Uniform float distribution with max/min values of 0).

# For adding statistical distributions, in this case a
# truncated normal distribution:

line_stat_repair_time_dist = StatDist(
    stat_dist_type=StatDistType.TRUNCNORMAL,
    parameters=NormalParameters(
        loc=1.25,
        scale=1,
        min_val=0.5,
        max_val=2,
    ),
)

fail_rate_line = 0.07

L1 = Line(
```

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```
    name="L1",
    fbus=B1,
    tbus=B2,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)
L2 = Line(
    name="L2",
    fbus=B2,
    tbus=B3,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)
L3 = Line(
    name="L3",
    fbus=B2,
    tbus=B4,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)
L4 = Line(
    name="L4",
    fbus=B4,
    tbus=B5,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)
L5 = Line(
    name="L5",
    fbus=B3,
    tbus=B6,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)

# Backup line

L6 = Line(
    name="L6",
    fbus=B4,
    tbus=B6,
    r=0.5,
```

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```
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)

# Set L6 as a backup line

L6.set_backup()
```

Creating circuit breaker:

```
E1 = CircuitBreaker(
    name="E1",
    line=L1,
)
```

Creating disconnectors:

Disconnectors can be added to the lines in the system. A line can have zero, one or two disconnectors connected. In this example, we add several disconnectors for each line. If a circuit breaker is placed on a line, can also have two disconnectors:

```
DL1a = Disconnector(
    name="L1a",
    line=L1,
    bus=B1,
)
DL1b = Disconnector(
    name="L1b",
    line=L1,
    bus=B2,
)
DL2a = Disconnector(
    name="L2a",
    line=L2,
    bus=B2,
)
DL2b = Disconnector(
    name="L2b",
    line=L2,
    bus=B3,
)
DL3a = Disconnector(
    name="L3a",
    line=L3,
    bus=B2,
)
DL3b = Disconnector(
    name="L3b",
    line=L3,
    bus=B4,
)
DL4a = Disconnector(
```

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```
    name="L4a",
    line=L4,
    bus=B4,
)
DL4b = Disconnector(
    name="L4b",
    line=L4,
    bus=B5,
)
DL5a = Disconnector(
    name="L5a",
    line=L5,
    bus=B3,
)
DL5b = Disconnector(
    name="L5b",
    line=L5,
    bus=B6,
)

# For backup line
DL6a = Disconnector(
    name="L6a",
    line=L6,
    bus=B4,
)
DL6b = Disconnector(
    name="L6b",
    line=L6,
    bus=B6,
)
```

Initialize power system

For systems without ICT, a manual main controller is added with a name and a desired sectional time:

```
C1 = ManualMainController(name="C1", sectioning_time=Time(0))
```

Then the power system is created:

```
ps = PowerSystem(controller=C1)
```

Create networks

After creating the components in the network, the components need to be added to their associated networks and the associated networks must be added to the power system. First, the bus connecting to the overlying network (often transmission network) is added. In this case the overlying network is a transmission network, which is created by:

```
tn = Transmission(
    parent_network=ps,
    trafo_bus=B1,
)
```

The distribution network contains the rest of the components, and links to the transmission network with line L1. This is done by the following code snippet:

```
dn = Distribution(
    parent_network=tn,
    connected_line=L1,
)
dn.add_buses([B2, B3, B4, B5, B6])
dn.add_lines([L2, L3, L4, L5, L6])
```

Visualize topology

To validate the network topology, it can be plotted in the following way:

```
fig = plot_topology(
    buses=ps.buses,
    lines=ps.lines,
    bus_text=True,
    line_text=True,
)

fig.savefig(
    "test_network.png",
    dpi=600,
)
```

The plot should look like this:

Load and generation

In *Load and generation preparation*, examples of how to generate load and generation profiles are provided. The generated profiles can be used to set the load and generation on the buses in the system. The load and generation profiles can then be added to the buses in the system.

For illustration purposes, we defines some constant loads in this tutorial:

```
load_household = np.ones(365 * 24) * 0.05  # MW
```

We refer to the example simulations for more realistic load handling.

In addition, a cost related to the load can be added to the bus. For generating the specific interruption cost for a load category:

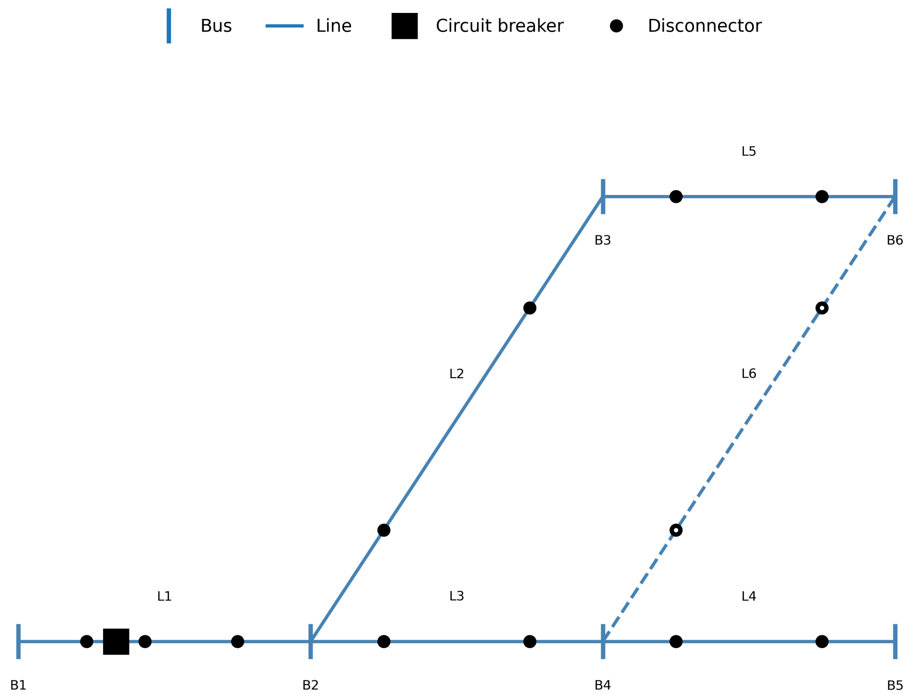

Fig. 2.1: Test network

```
household = CostFunction(
    A=8.8,
    B=14.7,
)
```

Load and cost can be added to the buses:

```
B2.add_load_data(
    pload_data=load_household,
    cost_function=household,
)

B3.add_load_data(
    pload_data=load_household,
    cost_function=household,
)
```

2.1.2 Traditional power system, Monte Carlo

Here we present how to run a small Monte Carlo simulation of the behavior of the network presented in the *system setup* section to illustrate how *RELSAD* can be used.

Monte Carlo simulation

To run a Monte Carlo simulation the user must specify:

- The number of iterations, *iterations*
- Simulation start time, *start_time*
- Simulation stop time, *stop_time*
- Time step, *time_step*
- Time unit presented in results, *time_unit*
- A callback function, *callback*
- List of Monte Carlo iterations to save, *save_iterations*
- Saving directory for results, *save_dir*
- Number of processes, *n_procs*

```
sim = Simulation(power_system=ps, random_seed=0)
sim.run_monte_carlo(
    iterations=10,
    start_time=TimeStamp(
        year=2019,
        month=0,
        day=0,
        hour=0,
        minute=0,
        second=0,
    ),
```

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```
    stop_time=TimeStamp(
        year=2020,
        month=0,
        day=0,
        hour=0,
        minute=0,
        second=0,
    ),
    time_step=Time(1, TimeUnit.HOUR),
    time_unit=TimeUnit.HOUR,
    callback=None,
    save_iterations=[1, 2],
    save_dir="results",
    n_procs=1,
)
```

The callback argument allows the user to specify events on an incremental basis. It is useful of you want to investigate how a given set of events impact the system reliability for varying repair time etc.

The results from the simulation are found in the specified *save_dir*. They include system reliability indices as well as bus information.

Here we plot *ENS* (Energy Not Supplied) for the power system:

```
path = os.path.join(
    "results",
    "monte_carlo",
    "ps1",
    "ENS.csv",
)

df = pd.read_csv(path, index_col=0)
fig, ax = plt.subplots()
df.hist(ax=ax)

fig.savefig(
    "ENS.png",
    dpi=600,
)

print(df.describe())
```

The plot should look like this:

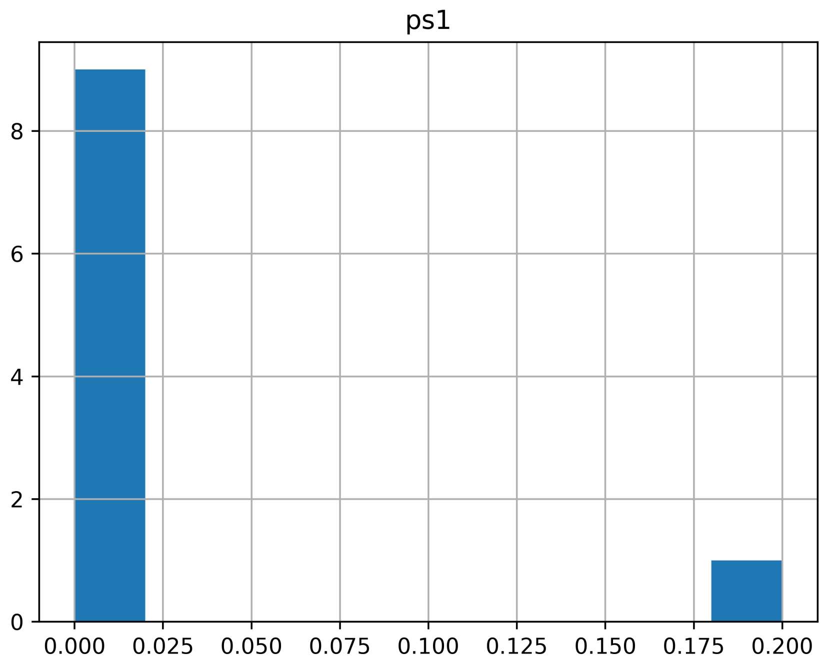

Fig. 2.2: ENS

2.1.3 Traditional power system, Sequential

Here we present how to run a small sequential simulation of the behavior of the network presented in the *system setup* section to illustrate how *RELSAD* can be used.

Sequential simulation

To run a sequential simulation the user must specify:

- Simulation start time, *start_time*
- Simulation stop time, *stop_time*
- Time step, *time_step*
- Time unit presented in results, *time_unit*
- A callback function, *callback*
- Saving directory for results, *save_dir*

```
def callback(ps, prev_time, curr_time):
    dt = curr_time - prev_time
    if curr_time <= dt:
        ps.get_comp("L2").fail(dt=dt)
        ps.get_comp("L6").fail(dt=dt)
    elif Time(1.95, unit=dt.unit) < curr_time < Time(2.05, unit=dt.unit):
        ps.get_comp("L3").fail(dt=dt)


sim = Simulation(power_system=ps, random_seed=0)
sim.run_sequential(
    start_time=TimeStamp(
        year=2019,
        month=0,
        day=0,
        hour=0,
        minute=0,
        second=0,
    ),
    stop_time=TimeStamp(
        year=2019,
        month=0,
        day=0,
        hour=10,
        minute=0,
        second=0,
    ),
    time_step=Time(0.1, TimeUnit.HOUR),
    time_unit=TimeUnit.HOUR,
    callback=callback,
    save_dir="results",
)
```

Here we used the callback function to specify that line *L2* and *L6* will fail at the start of the simulation, while line *L3* will fail after two hours. The callback function enables easy customization and implementation of scenarios of interest.

To run a deterministic sequential simulation the user must set all failure rates to zero and all repair times to constant values. Otherwise, the simulation will exhibit a stochastic behavior.

Here we plot *ENS* (Energy Not Supplied) for the power system:

```
path = os.path.join(
    "results",
    "sequence",
    "ps1",
    "ENS.csv",
)

df = pd.read_csv(path)
fig, ax = plt.subplots()
df.plot(
    x="HOUR",
    y="ps1",
    ax=ax,
)

fig.savefig(
    "ENS.png",
    dpi=600,
)

print(df.describe())
```

The plot should look like this:

2.1.4 Active power systems

The traditional power system shown in the tutorials presenting *Monte Carlo* and *sequential* simulations types can be expanded with active and smart components.

This page illustrates how these components and features are initialized and specifies where they must be included in the system definition.

Active generation units

Three types of active generations units can be added:

- Production units
- Batteries
- EV parks (Electric vehicle parks)

The active generation units must be initialized before any network initializations.

In order to add generation units the components need to be imported:

```
from relsad.network.components import (
    Production,
    Battery,
    EVPark,
```

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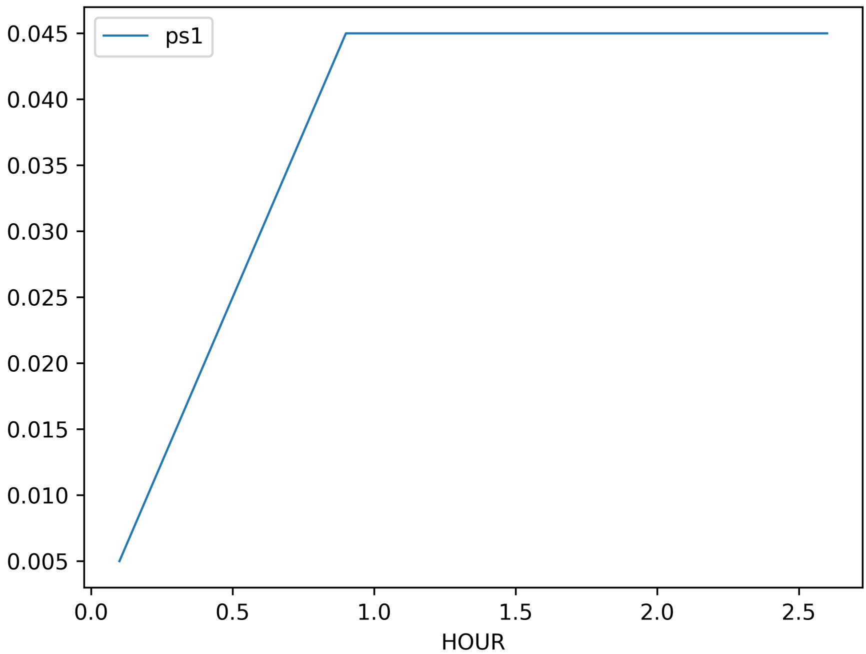
ps1
0.045
0.040
0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.0
0.5
1.0
1.5
2.0
2.5
HOUR

Fig. 2.3: ENS

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```
)
from relsad.Table import Table
```

The *Table* class must be used to define the amount of EVs in the EV park as a function of time.

Then the active generation units need to be created:

```
# A generation unit:

P1 = Production(
    name="P1",
    bus=B3,
)

# A battery:

Bat1 = Battery(
    name="B1",
    bus=B6,
)

# An EV park

num_ev_table = Table(
    x=np.arange(0, 24),  # Hour of the day
    y=np.ones(24) * 10,  # Number of EVs
)

EVPark(
    name="EV1",
    bus=B5,
    num_ev_dist=num_ev_table,
    v2g_flag=True,
)
```

The production unit is placed on bus *B3* and the battery is placed on bus *B6*.

Here, the EV park is placed in bus *B5* and *num_ev_table* defines a constant number of ten cars in the EV park throughout the day. The possibilities of vehicle-to-grid can be decided using the *v2g_flag*.

Generation can be added to a production unit on the bus:

```
generation_profile = np.ones(365 * 24) * 0.02  # MW
P1.add_prod_data(
    pprod_data=generation_profile,
)
```

The generation profile is specified by the variable *generation_profile*. Here it is defined to provide a constant production of 0.02 MW throughout the year. A way of creating generation profiles is shown in *Load and generation preparation*.

Grid connected microgrids

For evaluating a network with a microgrid, an additional network class needs to be imported:

```
from relsad.network.systems import Microgrid
```

Furthermore, microgrid mode enumeration class needs to be imported from the *MicrogridController* class:

```
from relsad.network.components import MicrogridMode
```

The Microgrid mode is used to specify the produre the microgrid should follow.

Then the components in the microgrid can be created:

```
# Buses:

M1 = Bus(
    name="M1",
    n_customers=1,
    coordinate=[-1, -2],
)

M2 = Bus(
    name="M2",
    n_customers=1,
    coordinate=[-2, -3],
)

M3 = Bus(
    name="M3",
    n_customers=1,
    coordinate=[-1, -3],
)

# Lines:

ML1 = Line(
    name="ML1",
    fbus=B2,
    tbus=M1,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)

ML2 = Line(
    name="ML2",
    fbus=M1,
    tbus=M2,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
```

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```
)

ML3 = Line(
    name="ML3",
    fbus=M1,
    tbus=M3,
    r=0.5,
    x=0.5,
    fail_rate_density_per_year=fail_rate_line,
    repair_time_dist=line_stat_repair_time_dist,
)

# Circuit breaker:

E2 = CircuitBreaker(name="E2", line=ML1)

# Disconnectors:

DML1a = Disconnector(
    name="ML1a",
    line=ML1,
    bus=B2,
)
DML1b = Disconnector(
    name="ML1b",
    line=ML1,
    bus=M1,
)
DML2a = Disconnector(
    name="ML2a",
    line=ML2,
    bus=M1,
)
DML2b = Disconnector(
    name="ML2b",
    line=ML2,
    bus=M2,
)
DML3a = Disconnector(
    name="ML3a",
    line=ML3,
    bus=M1,
)
DML4b = Disconnector(
    name="ML4b",
    line=ML3,
    bus=M3,
)
```

After the microgrid components are created, the microgrid network can be created and the components can be added:

```
m = Microgrid(
```

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```
    distribution_network=dn,
    connected_line=ML1,
    mode=MicrogridMode.FULL_SUPPORT,
)
m.add_buses([M1, M2, M3])
m.add_lines([ML2, ML3])
```

Islanded networks (microgrids)

For evaluating islanded networks or microgrids, the distribution network or microgrid network can be initiated without an overlying transmission network. Below is an example of how this is done. Note that the *connected_line* variable is set to *None* in this case:

```
dn = Distribution(
    parent_network=ps,
    connected_line=None,
)
dn.add_buses([B1, B2, B3, B4, B5, B6])
dn.add_lines([L1, L2, L3, L4, L5, L6])
```

Power system with ideal ICT network

This section illustrates basic usage of the ICT features implemented in *RELSAD*. First, we illustrate how to include ICT components without an ICT network. In this case, the communication between the ICT components is considered to be ideal, without any probability of failing.

The ICT components must be initialized before any network initializations.

For including ICT components imported the following:

```
from relsad.network.components import (
    MainController,
    Sensor,
    IntelligentSwitch,
)
```

A smart controller is initiated as follows:

```
C1 = MainController(name="C1")
```

In addition, different failure rates and repair times for the controller can be specified.

Intelligent switches are added to disconnectors as shown here:

```
Isw1 = IntelligentSwitch(
    name="Isw1",
    disconnector=DL2a,
)
```

A failure rate for the intelligent switch can also be specified. There can only be one intelligent switch on each disconnector.

A sensor can be added on a line:

```
S1 = Sensor(
    name="S1",
    line=L2,
)
```

Failure rates and repair time of the sensor can be specified. There can only be on sensor on each line.

Power system with fallible ICT network

Second, inclusion of ICT components with an ICT network is shown. In this case, the communication between the ICT components might fail leading to potential downtime.

For including an ICT network, the following must be imported:

```
from relsad.network.systems import ICTNetwork
from relsad.network.components import (
    ICTNode,
    ICTLine,
)
```

To add the ICT network, ICT nodes and ICT lines must be defined and added to a ICT network:

```
# ICT nodes
ICTNC1 = ICTNode(
    name="ICTNC1",
)
ICTNISW1 = ICTNode(
    name="ICTNISW1",
)
ICTNS1 = ICTNode(
    name="ICTNS1",
)

# ICT lines
ICTL1 = ICTLine(
    name="ICTL1",
    fnode=ICTNC1,
    tnode=ICTNISW1,
)
ICTL2 = ICTLine(
    name="ICTL2",
    fnode=ICTNC1,
    tnode=ICTNS1,
)
ICTL3 = ICTLine(
    name="ICTL3",
    fnode=ICTNS1,
    tnode=ICTNISW1,
)

# ICT network
ict_network = ICTNetwork(ps)
ict_network.add_nodes(
```

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```
    [
        ICTNC1,
        ICTNISW1,
        ICTNS1,
    ]
)
ict_network.add_lines(
    [
        ICTL1,
        ICTL2,
        ICTL3,
    ]
)
```

Here, we only initiate a “dummy-network” to illustrate a minimal example of the ICT network definition. In a real simulation, the network is much more comprehensive. We refer to the CINELDI example network which is located in the package source code for a more comprehensive example.

2.2 CINELDI example

To run the CINELDI example do the following:

```
$ cd examples/CINELDI
$ python run.py
```

This will produce a directory called “results” containing the simulation results. The directory has the following structure:

```
results
├── monte_carlo
│   ├── B1
│   ├── B2
│   ├── B3
│   ├── B4
│   ├── B5
│   │   └── EV1
│   ├── B6
│   ├── dist_network1
│   ├── M1
│   ├── M2
│   ├── M3
│   ├── microgrid1
│   ├── ps1
│   └── trans_network1
└── sequence
    ├── 1
    │   ├── battery
    │   ├── bus
    │   ├── circuitbreaker
    │   ├── disconnector
    │   ├── dist_network1
```

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```
    │   ├── distribution_controllers
    │   ├── ev_parks
    │   ├── line
    │   ├── microgrid1
    │   ├── microgrid_controllers
    │   ├── ps1
    │   └── trans_network1
    └── 2
        ├── battery
        ├── bus
        ├── circuitbreaker
        ├── disconnector
        ├── dist_network1
        ├── distribution_controllers
        ├── ev_parks
        ├── line
        ├── microgrid1
        ├── microgrid_controllers
        ├── ps1
        └── trans_network1
```

As you can see, the results are divided into a Monte Carlo directory and a sequence directory. They contain Monte Carlo and sequential results respectively.

Below is an example of how to read and obtain some distribution metrics for the *ENS* (Energy Not Supplied) index of the power system (ps1) using *pandas*.

```
import os
import pandas as pd

path = os.path.join(
    "results",
    "monte_carlo",
    "ps1",
    "ENS.csv",
)

df = pd.read_csv(path, index_col=0)

print(df.describe())
```

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