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Reliability of the Electric Power Distribution System for Alternative Reserve Configurations

Master's Thesis in Electric Power Engineering

ARON VON SCHÉELE

Department of Energy and Environment
Electric Power Engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
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Abstract

This thesis addresses the reliability of the electric power distribution system in Gothenburg. Six typical loop configurations with different reserve capacities are presented and evaluated. Each loop configuration is evaluated in three different areas with different load and customer profiles. Markov modelling is used to model the reliability of the loop configurations and their respective outage time with regard to the customers. Failure and restoration statistics from the DSO in Gothenburg, Göteborg Energi Nät AB, are used as input parameters to the models of the different loop configurations. The Markov models are applied on a real case in Gothenburg with seasonal variations of the connected load. The current, existing configuration of the examined loops does not allow any additional load to be connected while still allocating for reserve capacity. Two alternatives to increase the capacity of the loops are presented as well as the economical implications of the two loop scenarios. The results show that it is feasible to connect two loops with seasonal varying loads as well as it resulting in a economically viable alternative. Thorough temperature variation calculations for the cables should be made in order to evaluate the implications of the presented alternatives.

Keywords: Reliability evaluation, electric power distribution system, Markov modelling, NEPLAN, reserve capacity, time varying load, thermal ageing, XLPE

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Aron von Schéele, Gothenburg, 29/05/2013.

Abbreviations and Indices

$\boldsymbol{\pi}$	Markov probability vector
ΔP	Difference in dissipated power from initial to final value [W/m]
ΔT	Temperature difference [°C]
λ	Transition probability to reach a specific state
λ_{CB}	Failure frequency for circuit breakers [fault/(unit·year)]
λ_{CM}	Common mode failure frequency
λ_{C}	Failure frequency for cables [fault/(km·year)]
λ_{Fu}	Failure frequency for fuses [fault/(unit·year)]
λ_{Ss}	Failure frequency for secondary substations [fault/(unit·year)]
λ_{T}	Failure frequency for transformers [fault/(unit·year)]
$\mathbf{I}$	Identity matrix
$\mathbf{P}$	Markov probability matrix
μ	Restoration rate
μ_{Fu}	Restoration rate of a fuse fault
μ_{LDc}	Restoration rate by using a load disconnector fault
μ_{Ss}	Restoration probability of a secondary substation fault
μ_{T}	Restoration rate of a transformer fault
ϕ	Angle between current and voltage
τ	Thermal time constant for the material [s]

θ_f	Final conductor temperature
θ_i	Initial conductor temperature
$^{\circ}C$	Degrees Celcius
A_C	Area of conductor
C_{A-E}	Cables A-E
K_T	Thermal resistivity of the material $[^{\circ}C \cdot m/W]$
k_C	Constant used when calculating cable conductor area
P_{Fin}	Final value of dissipated power [W/m]
P_{Init}	Initial value of dissipated power [W/m]
Ss_{1-9}	Secondary substations 1-9
Ss_P	Proposed secondary substation
V_{tot}	Corresponding total voltage drop
Elforsk	Swedish Electrical Utilities R & D Organisation
Matlab	Matrix Laboratory developed by MathWorks
Neplan	Modelling software developed by Busarello + Cott + Partner AG
AC	Alternating Current
Al	Aluminium
C1	First cable in the loop
C2	Remaining cables in the loop
CF	Net Cash Flow
CM	Corrective Maintenance
DSO	Distribution System Operator
e.g.	exempli gratia, for example
EDS	Electrical Distribution System
EI	Energimarknadsinspektionen
EPS	Electric Power System
Eqv	Equivalent

GENAB	Göteborg Energi Nät AB
GUI	Graphical User Interface
Hrs	Hours
IEC	International Electrotechnical Commission
K-station	130/11 kV distribution substation in Gothenburg power system.
KSEK	Thousand Swedish Crowns
LDc	Load Disconnector
LXXX	Corresponding underground cable with designation LXXX
Min	Minutes
N-1	One arbitrary component can be removed from operation
N-2	Two arbitrary components can be removed from operation
N/A	Not Applicable
NPV	Net Present Value
P	Power [W]
PM	Preventive Maintenance
Q	Reactive power [VAr]
R	Resistance [Ω]
r	Outage time
RC	Remote Controlled
S	Apparent power [VA]
SAIDI	System Average Interruption Duration Index [min]
SEK	Swedish Crowns
U	Unavailability [min]
X	Reactance [Ω]
XLPE	Cross-linked Polyethylene

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Chapter 1

Introduction

This chapter gives the background to the thesis as well as providing an overview of the aim and scope of the thesis. The method used to solve the problem and provide results is also introduced.

1.1 Background

The main task of electric power systems and system operators is to provide their customers with a reliable and economically feasible supply of electricity [1]. In order to provide a reliable supply of electricity, there is a built in reserve capacity within the grid to cope with contingencies, increased demand and scheduled maintenance. This reserve capacity must be designed and constructed in the most economically and technically optimal way in order to ensure reliable power transmission as well as the lowest possible cost [1].

In view of new regulation [12], the distribution system operator (DSO) in Gothenburg, Göteborg Energi Nät AB (GENAB), need to be able to optimise the utilisation and installation of their reserve capacity in the system. This optimisation is required since there is a necessity to maximise reliability as well as minimise cost. GENAB have stated that there is need to have dimension criteria when planning for future reserve capacity and the implications of new investments and their utilisation [13]

Reliability is defined by the International Electrotechnical Commission (IEC) as "the ability to perform a required function under given conditions for a given time interval" [14]. Reliability of the electric power system (EPS) can be increased by either shortening the duration of the interruptions of the power supply or by lowering the frequency by which interruptions occur [15]. The probability that a component in the system will fail is generally increased when the number of components rises. By introducing alternative paths and reserve capacity, the disruption time for the customers and SAIDI (System Average Interruption Duration Index) will be reduced. This reserve capacity may be utilised under a couple of hours every year which leads to that the reliability of the system may be decreased. By calculating the impact of using reserve capacity and its impact on SAIDI, it is easier to determine if the risk taken is acceptable. Risk is defined as the ”effect of uncertainty on objectives” [16] which implies that risk can both have positive and negative implications.

1.2 Aim and Scope

This thesis is focused on analysing reserve alternatives to loop configurations and their impact on SAIDI in the electrical distribution system (EDS). The results are used to propose dimension criteria that can be used by the DSO in the general case of the medium voltage distribution system in Gothenburg. The medium voltage distribution system in Gothenburg is composed mostly of 11 kV underground cables and it is the different configurations of the underground cables that has been analysed.

The EDS in Gothenburg is supplied by a number of 130/11 kV distribution substations and supplies over 1600 secondary 11/0.4 kV substations. Since the customer and load concentration differs throughout the Gothenburg area, three areas will be analysed and examined. The geographical areas that will be examined are City, Urban and Industry. Provided statistics from GENAB are used as input in the models to provide a high correlation between the models and reality. One part in maximising the reliability and utilising the reserve in an efficient manner is to use probabilistic methods to analyse the probabilities of potential faults and contingencies. By performing simulations and creating simplified models of the system it is possible to acquire the data needed to make motivated and analysed decisions on utilisation and future investment of the reserve capacity.

The dimension criteria include the maximum amount of 11/0.4 kV secondary substations per loop that can use the same reserve as well as including the eventual implications on SAIDI and reliability associated with the utilisation. These criteria are presented for different cases that are applicable in the Gothenburg region. The criteria should also take current carrying capacity of the underground cables and the resulting voltage drop into consideration. By using appropriate models of the power system to portray the different cases, the impact on SAIDI (System Average Interruption Duration Index) could be calculated. The created reliability models were applied on an existing, critical case in the Gothenburg distribution system and two different reserve capacity scenarios are analysed and considered. The cost of the investments as well as the resulting implications were compared.

1.3 Methods of Assessment

In order to compare the implications of the different reserve capacity configurations for the City, Urban and Industry areas, a number of different system structures were modelled. The different cases were modelled as radial distribution loops with the maximum number of substations per section. The components and their functional status in the distribution system affect the system and connected customers in various ways. The ways that the system and customers are affected can be modelled as different states.

To evaluate the probability of the system transitioning between these states, Markov modelling is a technique that can be used. In this thesis, Markov modelling is applied and used to model the system using statistics to find the probabilities and consequences associated with the different cases that are modelled. To validate the models, a sensitivity analysis was made to see how the models responded to a wide span of input data. The input data was collected from available GENAB statistics [5] as well as from reports published by the Swedish Electrical Utilities R & D Organisation (Elforsk) [6].

To model and simulate the voltage and current characteristics of different loads and cases Neplan was used. Neplan is a software that allows the user to create power system models and simulate them with regards to different parameters. A load flow module was used to see the effect on the voltage drop and current limits that were related to the different cases. Apart from the load flow, Neplan also has a reliability module that can be used to simulate and calculate the reliability and probability of an outage in the system. The reliability module was used to compare and validate the results with the created Markov models and to analyse if the created models were reasonable and functional.

The models were applied to an existing critical case in Gothenburg. The chosen case has reached its maximum current carrying capability and the load can not be increased without decreasing the reliability within the loops. Two reserve alternatives, each with two substation scenarios are presented. The reliability and impact on SAIDI as well as the economical implications of the alternatives and scenarios are evaluated.

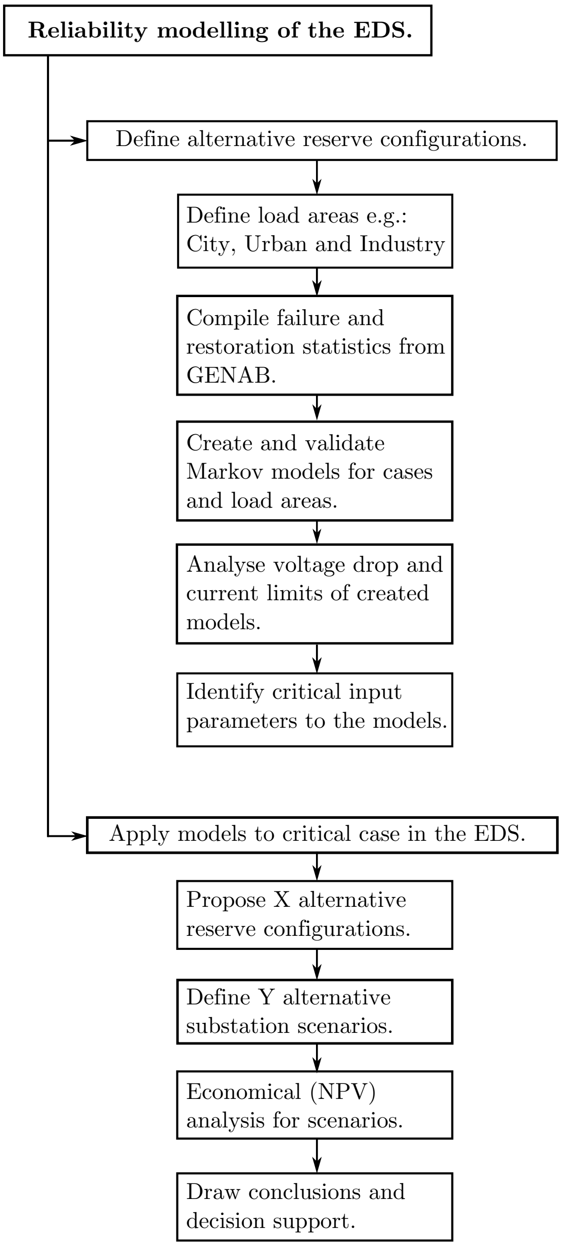


Figure 1.1: Overall approach used to evaluate the reliability of alternative loop configurations in the electrical distribution system. X = 2 and Y = 2 were used for the case study.

1.4 Thesis Outline

The thesis starts with a broad overview of how reliability can be evaluated, and the methods associated with evaluation. After the introduction to reliability evaluation, there is a more in depth description of the methods applied in this project and case. A number of different underground cable, secondary substation and reserve capacity configurations are presented and evaluated. The methods of evaluation are described as well as the input data used. The input data for the failure rates of components are based on failure statistics of the EDS in Gothenburg. Two different software models and techniques were used and compared. These are also described as well as some alternative methods to increasing the reliability in the EDS. The statistical models are applied on a real case in Gothenburg and two investments in reliability are analysed and compared. A sensitivity analysis of the created mathematical models was made, as well as a presentation and validation of the results from the models.

Chapter 2

Evaluating Reliability

This chapter introduces definitions and methods used in this thesis project to evaluate and validate reliability. It also highlights some of the characteristics of cables and their related faults that need to be taken into consideration when planning electric power underground cable systems and loop configurations.

2.1 Reliability and Maintenance

Disturbances in the electrical distribution system contribute most to the majority of customer outages per year compared to the generation and transmission systems [1],[17]. A way to reduce the duration of the customer outages is to increase the reliability and reserve capacity within the distribution network. An increase in reliability can be achieved by increased maintenance of the components within the system and thereby lowering the probability of failure. The duration of outages for the customer can be reduced by adding redundancy and reserve capacity for the supply of electricity.

Maintenance of components in the system can be coordinated or uncoordinated. Uncoordinated maintenance is when a component is taken out of operation and maintained independently of the other components in the same branch [1]. Coordinated maintenance (CM) is when a component is taken out of operation for maintenance along with the other components in the same branch. This increases reliability since the probability of another branch failing simultaneously is lower [1]. Coordinated maintenance is more costly with regards to manpower but may be advantageous in comparison with redundancy according to [1]. When the EDS primarily consists of underground cables, redundancy is necessary since the majority of faults are cable faults that have long restoration times [5]. Preventive maintenance (PM) is scheduled maintenance with the objective of reducing the failure rate and prolonging the lifetime of the component [15]. Corrective maintenance is maintenance carried out after the fault and has the objective of returning the component into a functioning state [18].

2.1.1 Definitions

- $\lambda_X = \frac{Number\ of\ faultsofcomponentX\ per\ year}{Total\ number\ of\ Xunits}$ [fault/(year)].
- $\lambda_C = \frac{Number\ of\ cable\ faults\ per\ year}{Total\ length\ of\ cable}$ [fault/(km·year)].
- SAIDI $= \frac{\sum_{i=1}^{n} U_i N_i}{\sum_{i=1}^{n} N_i}$ [min/year] *(System Average Interruption Duration Index)* for n load points and with N being the number of customers connected to each load point and U being the unavailability [1].
- N-1 criteria = An arbitrary component should be able to be taken out of operation during a fault without affecting the connected customers [19].
- N-2 criteria = Two arbitrary components should be able to be taken out of operation during a fault without affecting the connected customers [19].

2.1.2 Common Mode Failures

Common mode failures are multiple failures that are caused by a common external event, with the failures not being the result of each other [1]. The probability of two independent failures occurring simultaneously (N-2) is the product of the individual probabilities. Since the independent probabilities might be small, the combined simultaneous probability of the independent events occurring simultaneously would become very small. The probability of a common mode failure with the same effects as multiple independent failures might be higher [1]. Typical causes of common mode failures in the EDS might be weather induced overvoltages or excavations affecting independent but parallel underground cables. A general IEEE state space diagram for common mode failures is seen in Figure 2.1 with λ_{CM} representing the transition rate of a common mode failure.

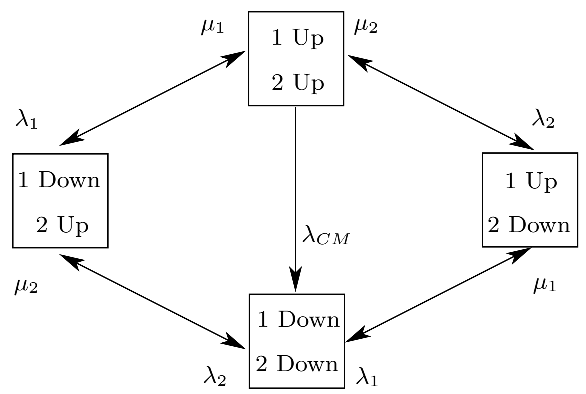


Figure 2.1: IEEE model used for common mode faults [1]

2.2 Probabilistic Methods

The system reliability of the different cases was primarily modelled using existing mathematical probabilistic models. These models produced output data to be used in indices (such as SAIDI) that provide a general conception of the reliability of the examined EDS. The statistical data that was input into the created mathematical models are the mean, yearly failure rates of the components and the related mean power supply interruption duration for the customer. The failure and restoration statistics for the components might vary significantly from year to year but they have an asymptotic characteristic that makes it possible to use the mean value. Using statistical mean values as input data does not take into account the variations in power system behaviour throughout a year and might not provide an accurate indication of the electrical power system [18].

2.3 Reliability Modelling of the Distribution System

The complexity of a distribution system model increases with each component added to the model and there are a number of techniques used to reduce the complexity of the model. By using the network reduction technique it is possible to calculate and create equivalent components and thereby reduce the number of variables [1]. Another technique used to simplify the system is to use failure modes and effects analysis [1]. By visually identifying the failure modes and possible failures and their effects, it is possible to reduce the complexity. This method also allows for a more detailed result compared to the network reduction technique [1].

2.3.1 Markov Modelling

Steady state Markov models were used in this work to find the probability that the customer was affected by faults throughout the year. These probabilities were used to evaluate the effect on SAIDI of the different cases. Markov modelling does not depend on the initial state and is useful since it is possible to define an infinite amount of states [18]. The amount of states in the model can vary, depending on the amount of components in the system and is related to 2^n where n is the amount of components [20]. Specifying a large number of states is exceptionally time consuming and not a viable solution if practical models are to be developed. Markov modelling was used in this case to find the time per year that the system is situated in a specific state with regard to the customers. This decreases the complexity and level of detail within the model and delivers a favourable end result. The cost of the contingency in relation to the customer is also simplified with this type of model.

Markov Modelling Theory

To solve for the steady state probabilities in the system, the following matrix **P** and related equations must be solved [20].

$$\boldsymbol{\pi}\mathbf{P} = \boldsymbol{\pi} \tag{2.1}$$

$$\sum_{i=1}^{N} \pi_i = 1 \tag{2.2}$$

P is the Markov probability matrix relating to the transition and restoration rates between the specified states. Solving for $\boldsymbol{\pi}$ gives N steady state equations along with Equation 2.2 that can be used to solve for the probability vector as described in Section 3.7.1.

The probability vector, $\boldsymbol{\pi}$, is used to express the probability that the system is in a specific state for a given time frame. Since the probabilities used in this case were based on a yearly basis, $\boldsymbol{\pi}$ gives the time each year that the system spends in the specified states. The states are specified with regard to the type of fault and the number of customers affected and therefore allows for easy calculation of customer indices such as SAIDI. An example of Markov modelling applied on a test system is given in Section 3.3.

2.3.2 NEPLAN Modelling

NEPLAN is a software program developed by Bussarello + Cott + Partner AG (BCP AG) that is used to simulate electricity, gas and heat networks [21]. The software has reliability and load flow modules that were used to simulate the effect and impact on the EPS that the different configurations had. NEPLAN also provides a comparison and serves as validation between the created Markov models and the simulations. NEPLAN has a user friendly graphical user interface (GUI) as well as a vast library of modifiable components that allow the user to easily customise the network to accommodate his or her requirements.

NEPLAN Load Flow, Voltage Stability and Reliability Modules

NEPLAN was primarily used to calculate the load flow in the different cases. The load flow module allows input of current and voltage limits that allow the user to easily evaluate if the proposed system design is feasible and if it can operate within specified limits. The reliability module is used to simulate the impact that faults have on the stability of voltage and current as well as the impact on customers connected to the secondary substations. Failure probabilities can be implemented for almost all components and the reliability module can be used to calculate customer indices such as SAIDI.

2.4 Faults in the Electrical Distribution System

Typical causes of faults in the EDS are short circuits between phases, phase to earth faults and unintended openings of circuit breakers and fuses. When a short circuit fault occurs, the current through the conductor is increased by many times that of the rated current. This increases the temperature of the conductor and surrounding materials which may lead to damage and deformation of the conductors and insulation as well as a risk of fire [22]. It is not only at the location of the fault that is affected but also the components connected to the same loop and areas in the vicinity. The busbars of the neighbouring substations might be deformed due to the high currents as well as voltage dips for the nearby loops [22]. The most common fault in the Gothenburg network are cable faults [5]. According to [22], 80 % of cable faults are phase to earth faults while 15 % and 5% of faults are initially phase to phase and three phase faults respectively. It is therefore important that all the components in the circuit are chosen to withstand the high fault currents that may occur.

Cable Calculations and Selection

Repairing a damaged underground cable can be costly and time consuming and it is therefore especially important that the cable can withstand high fault currents in the event of a fault occurring. The withstand capability of the cable to short circuit currents and thermal stresses depend on the area of the conductor and the material of the insulation [23]. The minimum cable conductor area, A_C, needed to withstand a short circuit current can be calculated for aluminium conductors by:

$$A_C = \frac{\sqrt{i^2 t}}{k_C} \tag{2.3}$$

$$k_C = 148\sqrt{\ln(1 + \frac{\theta_f - \theta_i}{228 + \theta_i})} \tag{2.4}$$

where k_C is a constant used to calculate the area A_C, θ_i is the initial conductor temperature in $°C$, t is the time duration of the short circuit in s and θ_f is the final conductor temperature in $°C$ [24].

Table 2.1: The specifications for XLPE and oil-paper insulated cables [4] and the respective maximum operating currents calculated and utilised by GENAB.

Cable type	Max operating temperature	Short circuit temperature	Dielectric loss factor $\tan(\delta)$	Dielectric constant ϵ_r	Insulation resistance	Max operating current
XLPE	$90°C$	$250°C$	0.0004	2.3	$10^{17}\Omega \cdot cm$	270 A
Oil-paper	60-70$°C$	140-170$°C$	0.003	3.7	$10^{14}\Omega \cdot cm$	210 A

To determine the maximum operating current, rating factors for the specific location that the cable will be utilised in are used. The rating factors depend on the location's ground temperature, ambient temperature, the ground's thermal resistivity, the laying depth of the cables, the formation of the cable bundles and the distance between the cable bundles [25].

Oil-paper insulated cables are due to historic reasons a large part of GENAB's cable system while aluminium core XLPE cables have been used by Göteborg Energi for the last decades for all new underground cable installations as well as to replace older, faulty oil-paper insulated underground cables. XLPE or cross linked polyethylene insulated cables have been in production since the early 1970's [25] and provide a number of advantages over oil-paper insulated cables. Oil-paper insulated cables have lower maximum operating and short circuit current ratings due to their lower operating and short circuit temperature limits compared to XLPE insulated cable, as presented in Table 2.1. Oil-paper insulated cables also have a higher dielectric loss factor and dielectric constant as well as a lower insulation resistance [4] in comparison with XLPE insulated cables.

Thermal Effects of XLPE Cable Ageing

As seen in Table 2.1, the maximum operating temperature for XLPE cables is 90 $°C$. The maximum temperature is defined due to that the ageing of the cable is dependent on the temperature of the insulation [26]. Not allowing the cable to exceed 90 $°C$ gives an estimated lifetime of 30 years for the cable. During short switching operations and limited time emergencies it is possible to allow the cable to reach a temperature of 105 $°C$ without affecting the lifetime of the cable [26]. It is recommended that the time that the temperature reaches 105 $°C$ is a consecutive maximum of four hours and that there is a maximum total of 100 hours in consecutive months that the cable is exposed to 105 $°C$. It is also recommended that the cable should only reach 105 $°C$ for a maximum total of 500 hours during its lifetime [26]. The ageing of the XLPE insulation has an exponential Arrhenius relationship to temperature which results in that the ageing of the cable being strongly dependent on the temperature [26]. When the temperature increases over 90 $°C$, the insulation becomes brittle and starts to oxidise. Brittle cables are problematic if the cable is exposed to high mechanical stresses. Figure 2.2 shows the estimated relationship between temperature and expected lifetime for XLPE cables.

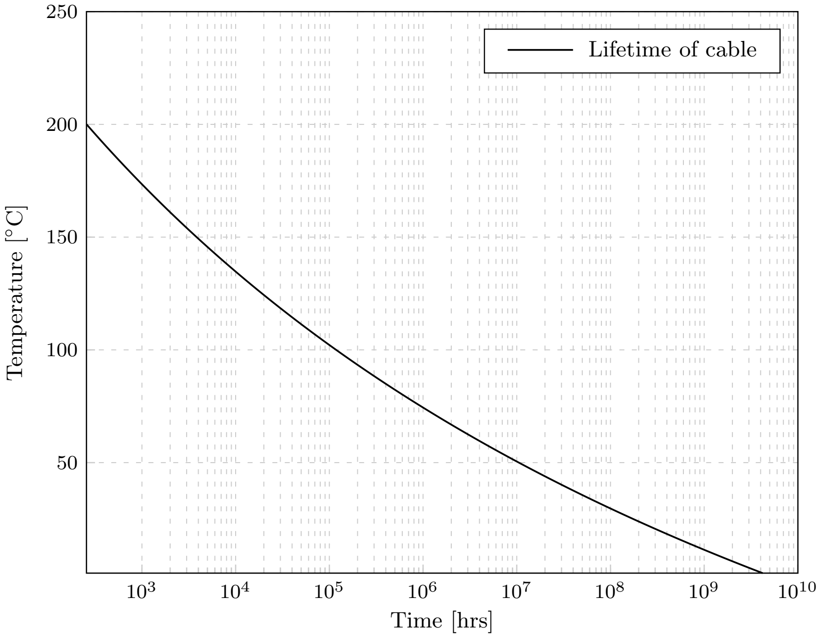


Figure 2.2: Estimated Arrhenius relationship of expected lifetime of XLPE cable vs temperature [2].

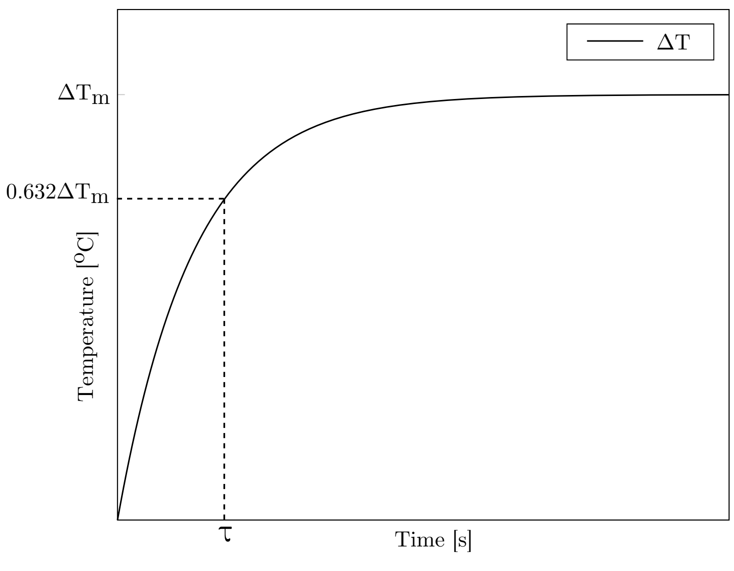


Figure 2.3: The temperature increase modelled as a step response of the current increase in the cable. ΔT_m is the steady state temperature increase that the current increases results in and τ is the thermal time constant [3].

The temperature of the insulation does not rise instantly with the conductor temperature but follows the behaviour of a first order step response [3], as seen in Figure 2.3. The temperature stabilises and reaches an equilibrium after some time depending on the thermal time constant of the insulation. The temperature increase due to a current increase in the cable can be calculated by:

$$P = I^2 R \, [W/m] \tag{2.5}$$

$$\Delta P = P_{Fin} - P_{Init} \, [W/m] \tag{2.6}$$

$$\Delta T = \Delta P \cdot K_T (1 - e^{\frac{-t}{\tau}}) \, [^\circ C] \tag{2.7}$$

where P is the dissipated power [W/m], I is the current through the cable [A], R is the resistance of the cable per meter $[\Omega/m]$, ΔT is the temperature difference [°C], ΔP is the difference in dissipated power from initial to final value [W/m], K_T is the thermal resistivity of the material $[^\circ C \cdot m/W]$, t is the time [s] and τ is the thermal time constant for the material [s]. The thermal time constant represents the time for the material to reach 63.2% of the steady state temperature [3] [27]. Typical values for τ and K for XLPE cables are seen in Table 2.2.

Table 2.2: Typical thermal properties of XLPE cables

Property	Value
Thermal time constant τ	2100 [s] [3]
Thermal resistivity K	2.7 $[^\circ C \cdot m/W]$ [28]

Voltage Drop The maximum allowable voltage drop in GENAB's distribution system is 7 % and a high power factor near 1 is desired. For high voltage customers, such as industry, GENAB allow that the reactive power is a maximum 15 % of the active power consumed. This corresponds to a power factor of 0.989.

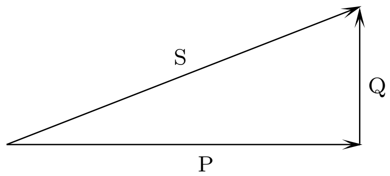


Figure 2.4: Phase diagram showing relationship between active, reactive and apparent power.

$$\cos\phi = \frac{P}{S} = \frac{P}{\sqrt{P^2 + Q^2}} \tag{2.8}$$

The relationship between power factor and consumed power can be seen in Figure 2.4 and Equation 2.8. The voltage drop is also influenced by the resistance, reactance and length of the cable as well as the current through it. The voltage drop of a given length can be calculated by:

$$V_{drop} = \sqrt{3} I (R_c \cos\phi + X_c \sin\phi) L \tag{2.9}$$

where I is the current [A], R_c is the cable resistance $[\Omega/km]$, X_c is the cable reactance $[\Omega/km]$, ϕ is the power factor angle and L is the length of the cable [km] [24].

Chapter 3

Application of Reliability Models on Gothenburg's Distribution System

This chapter examines the Gothenburg distribution system and the different components that are included to assess the loop reserve alternatives' impact on SAIDI. Statistics for faults have been examined as well as the secondary substation configurations of the radial loops. A real critical case is also examined with comparison between two reserve capacity scenarios. The studied case has reached its maximum current carrying capability and the load can not be increased without reducing the reliability within the loops.

3.1 Cases for the Gothenburg System

GENAB's electrical distribution system is large and complex. It consists of 2357 km of underground cables [5] and 1644 secondary substations [5]. A number of different, general and appropriate loop configurations and load profiles were examined and modelled. The models in this study are presented from the customer perspective and are related to the number of customers affected by a contingency and not specifically the precise component or situation that caused the contingency.

Loop Configurations

The configuration of the electrical distribution system varies throughout Gothenburg and there is therefore a need to differentiate between the studied cases. The cases have been differentiated by the reserve capacity and therefore in the maximum number of connected substations in the loop, along with the corresponding load profile for the specific geographical area.

Load Profiles

The chosen geographical areas have different load profiles and have been characterised as either City, Urban or Industry. The power, customer and substation density are all parameters that need to be taken into consideration for the different load profiles. Most of GENABS's 11 kV distribution system is composed of underground cables with the exception of a few overhead lines. All new installations are made with underground cables and therefore there are no overhead lines taken into consideration when designing the models in this study.

System Configurations

A way to increase the reserve capacity in the system is by adding an additional reserve cable to the loop, or a "third leg". This enables an increase of the number of secondary substations in the loop since the reserve capacity is higher in case of a contingency. Adding a reserve cable does not have influence on SAIDI if there are no new customers directly connected to the reserve cable. If customers are connected to the reserve cable, it is possible that SAIDI is increased since the probability of a fault increases. Therefore there is a trade-off between adding and utilising reserve capacity in the network. Six reserve capacity cases have been evaluated and each case has been evaluated with the City, Urban and Industry load profiles. The maximum number of substations for each case and load profile is presented in Table 3.12 and 3.13. The cases and configurations are chosen with regards to common configurations in the Gothenburg distribution system.

Case 1 The simplest case of a radial loop can be seen in Figure 3.1. The disconnectors and sectionaliser allows the feeder to isolate the fault and supply the remaining parts from the other sections feeder. This configuration is limited in the sense that each section must have the current carrying capacity to be able to supply the whole loop in case of a fault. Therefore there is a limit in the number of secondary substations that can be installed in each section of the loop.

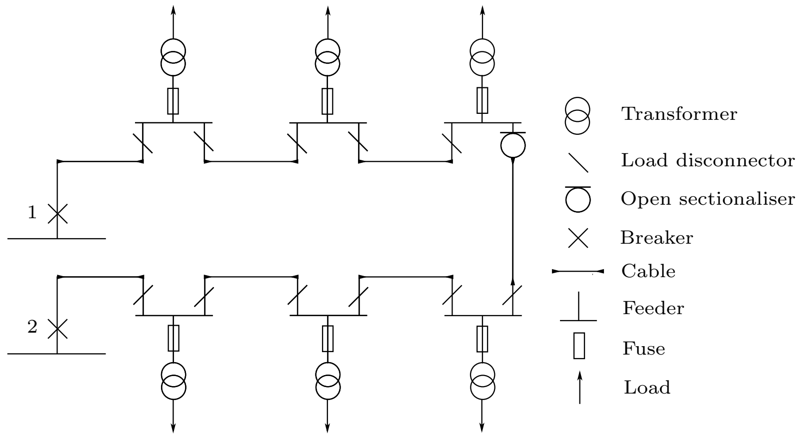


Figure 3.1: Sectionalised loop configuration with three secondary substations per section for Case 1.

Case 2 Figure 3.2 shows how the system is designed when a reserve cable is connected to the last secondary substation in the first section. The reserve cable eliminates the problem that Case 1 has with the limited number of secondary substations on each section. During a fault it can be connected and provide power to either section by closing the sectionalising disconnectors. During normal operation, however, the reserve cable might not be loaded. This may make the reserve cable an underutilised expenditure that only provides value to the system during a contingency. It does however allow the number of substations on each section in the loop to be increased.

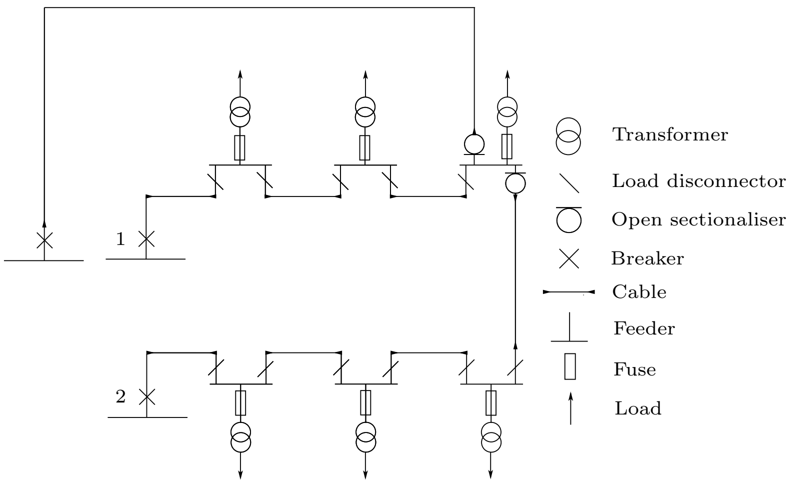


Figure 3.2: Sectionalised loop configuration with three secondary substations per section and a reserve cable for Case 2.

Case 3 Figure 3.3 shows an increased utilisation of the reserve cable by adding a secondary substation to the cable. This configuration allows the cable to provide a larger number of secondary substations than Case 1 and utilises the cable more than in Case 2. The downside of adding a secondary substation on the reserve cable is that it possibly reduces the number of secondary substations in each section compared to case 2 or possibly increasing the complexity in the busbar configuration of the last secondary substation in the first section where the reserve cable is connected. This is described in more detail in Section 3.9.1.

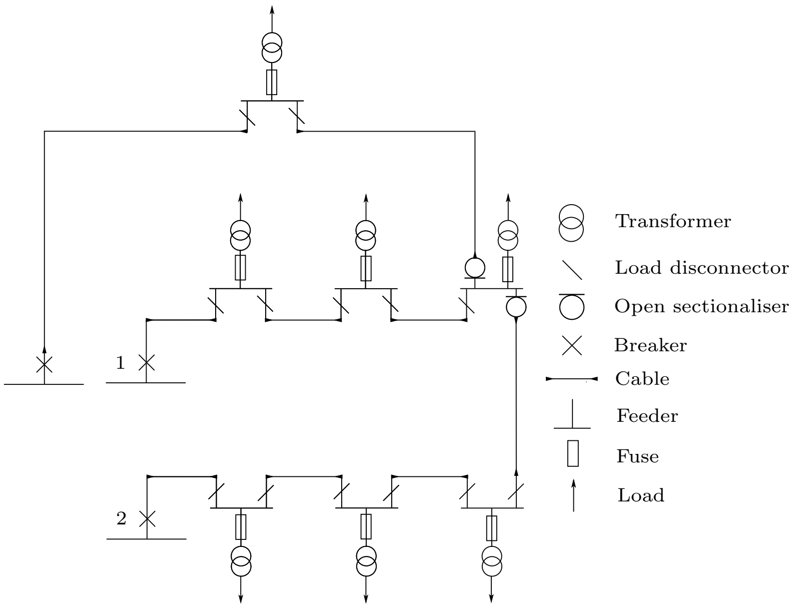


Figure 3.3: Sectionalised loop configuration with three secondary substations per section and a substation on the reserve cable for Case 3.

Case 4 If the cost of investment of a reserve cable is too high, there is the alternative of connecting two radial loops to provide backup for each other. This alternative may be less costly than building a reserve cable. Connecting two radial loops together provides an adequate amount of reserve capacity but only during N-1 conditions. In the case that there are two simultaneous faults, this will not be a completely viable solution. The cable between the loops might be able to supply some but not all secondary substations. This case can also be utilised with two heavily loaded loops with seasonal variations and a real case from the Gothenburg EPS is examined in Section 3.8.

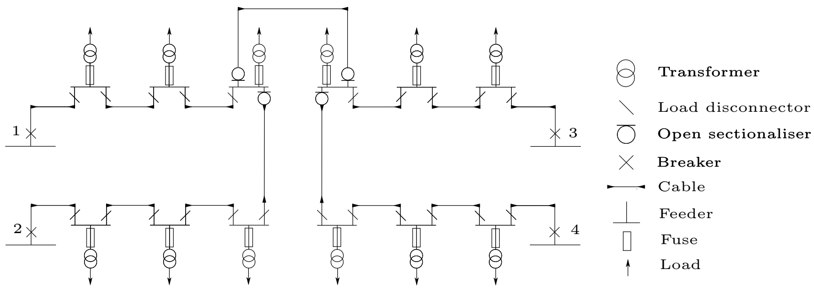


Figure 3.4: The sectionalised loop configuration for Case 4 consisting of two connected loops.

Case 5 Figure 3.5 is identical to Case 4 with the exception of the addition of a reserve cable. The reserve cable increases the maximum number of secondary substations for nearly all of the sections (except section 4) as well as providing reserve capacity for all N-1 contingencies. For N-2 contingencies the number of substations per section depends on the current carrying capacity of each cable.

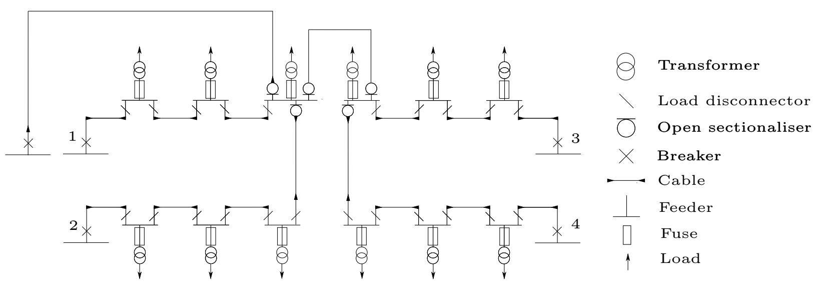


Figure 3.5: Two connected sectionalised loops with three substations for each section and a connected reserve cable for Case 5.

Case 6 A larger and more complex case is presented in Figure 3.6. Here there is a total of 8 sections that have a reserve through the reserve cable, the other section in their loop and the adjoining loop. This case provides a relatively high amount of reliability but at the expense of the number of secondary substations that can be connected due to the current carrying capability of the underground cables during a contingency.

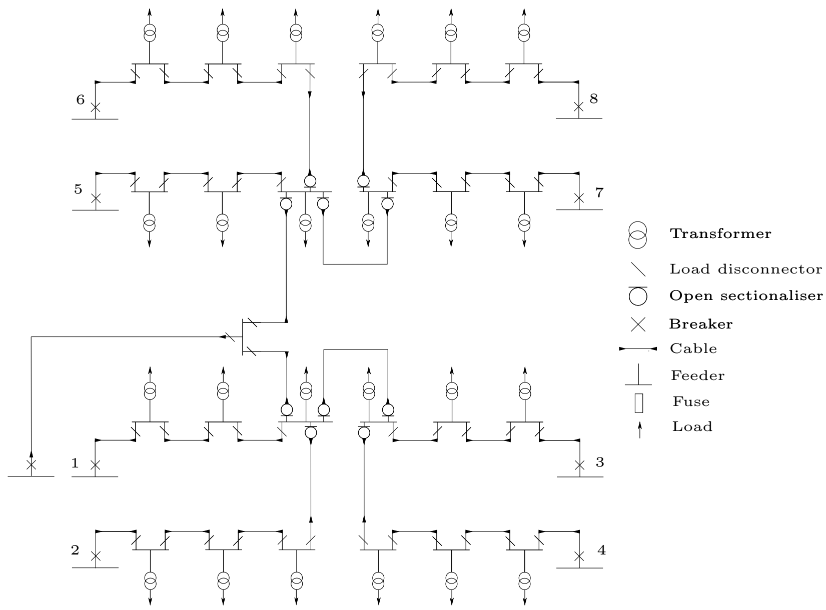


Figure 3.6: Four sectionalised loops connected with a reserve cable for Case 6.

3.2 Assumptions For Evaluation of the Cases

A number of assumptions were made in order to differentiate the different cases from each other. A common assumption for all the models was that only (N-1) faults would be examined when creating the Markov and NEPLAN models. The (N-1) criteria implies that the system should be in a functional state even though one arbitrary component fails [19]. It was decided that this was a valid assumption for distribution system models. Common mode failure is applied for one model in Section 3.9.2 to see by which extent SAIDI is affected and how SAIDI can be reduced. Another assumption was that all loops were fed from a distribution station through a circuit breaker and that each secondary substation has the same number of customers for each area respectively. The number of customers per secondary substation was based on existing values in the corresponding areas of Gothenburg's EDS. The underground cable distance between the secondary substations on the same loop is assumed to be equal and the cable between the 130/11 kV distribution substations and the first substation in the loop is assumed to be the same for each loop for the Markov models.

Table 3.1: The assumptions taken for the City, Urban and Industry areas.

	Transformers	Disconnector mechanism
City	2×800 kVA	Remote controlled
Urban	1×800 kVA	Manually controlled
Industry	2×800 kVA	Manually controlled

The main types of components and their related faults that have been modelled are underground cables, circuit breakers, secondary substations (disconnectors and bus bars) and transformers. The probabilities for these types of faults occurring are used as well as the time to restore the electricity supply to the customer independently of the repair time. The faults in the loop are modelled with regards to the consequence for the customers. This can be that all customers in the loop are without power, all customers connected to one secondary substation are without power or that all customers connected to a single transformer are without power. As mentioned before in Section 2.3.1, these types of models allow easier SAIDI calculations and evaluation of the risk and cost associated with faults.

3.3 Test System for Markov Models

An example of a typical simple radial loop with three transformers per section is modelled in Figure 3.7. The sections are ideally fed from separate distribution substations or at the very least from separate transformers in the same distribution substation. A circuit breaker for each section is present in the configuration and each secondary substation has two load disconnectors and one transformer. This is how the urban variants of the cases were modelled. As can be seen in Figure 3.7, the third secondary substation includes a sectionaliser which is open but can be closed when necessary. It is assumed that the breaker and fuses to the transformers break instantaneously. It is also assumed that the time to connect and disconnect load disconnectors is constant and that different disconnectors can be maneuvered simultaneously.

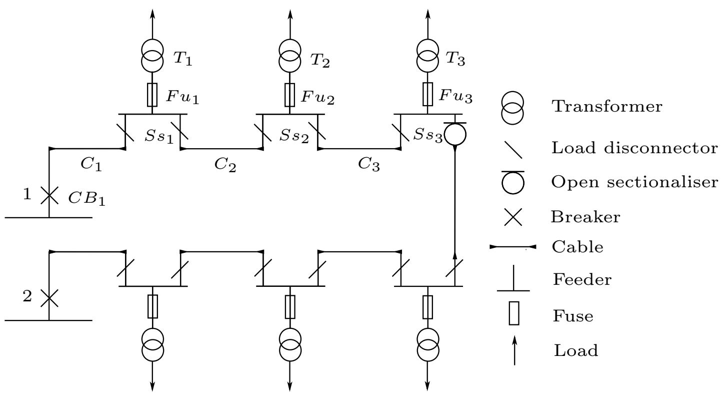


Figure 3.7: Sectionalised loop whose first section is used as a test system for Markov models.

The following states are used for the test system in Figure 3.7:

- 0: Normal operation
- 1: One whole substation and its customers are affected.
- 2: All substations and their customers are affected by a cable or circuit breaker fault.
- 3: All substations are affected by a disconnector or busbar fault.
- 4: One whole substation is affected by a transformer fault.
- 5: One whole substation is affected by a fuse fault.

λ are the transition probabilities to reach the specific state and μ are the corresponding restoration times to leave the states.

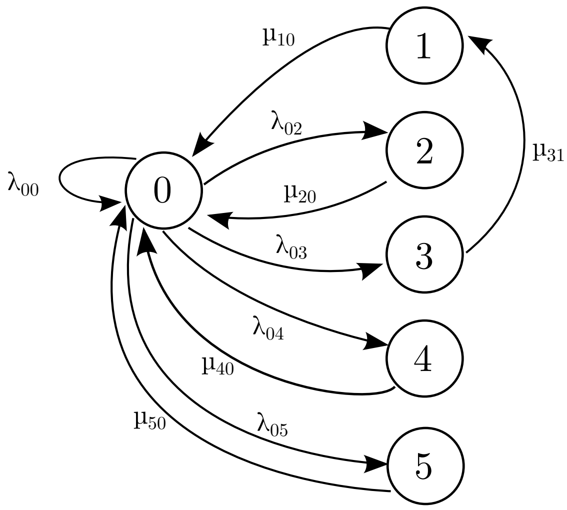


Figure 3.8: A state space transition diagram of the test system used with Markov modelling.

Table 3.2: Restore times and state changes for faults in the test system.

Faulty component	Minimum restore time	State changes
Circuit breaker	r_{LDc}	0→2→0
Cable 1	r_{LDc}	0→2→0
Substation 1	r_{LDc}	0→3→1
	r_{Ss}	1→0
Transformer 1	r_T	0→4→0
Fuses in 1	r_{Fu}	0→5→0
Cable 2	r_{LDc}	0→2→0
Substation 2	r_{LDc}	0→3→1
	r_{Ss}	1→0
Transformer 2	r_T	0→4→0
Fuses in 2	r_{Fu}	0→5→0
Cable 3	r_{LDc}	0→2→0
Substation 3	r_{LDc}	0→3→1
	r_{Ss}	1→0
Transformer 3	r_T	0→4→0
Fuses in 3	r_{Fu}	0→5→0

Table 3.3: Restore times and a description of the task involved.

Restore time	Description
r_{LDc}	Switching time for load disconnector
r_{Ss}	Time to repair substation
r_{Fu}	Time to exchange fuse
r_T	Time to repair/exchange transformer

Table 3.2 shows that there are a number of component faults that result in the system transitioning into the identical state, such as faults in Substations 1, 2 or 3. This simplifies the Markov model by allowing the probabilities to be weighed according to how large the total probability that the system will be in that specific state is. The transition probabilities and related restore times for the specific components can be seen in Tables 3.3-3.4. It is assumed that the first cable C_1 is longer than C_2 and C_3 and therefore C_1 has a higher fault probability. It is also assumed that the components in all substations are identical with the same probability of a fault occurring.

Table 3.4: The transition probabilities related to the faults occurring during the year in the test system.

Faulty component	Transition probability
Transformer	λ_T [fault/(unit·year)]
Substation	λ_{Ss} [fault/(unit·year)]
Cable	λ_{C1} , λ_{C2}=λ_{C3} [faults/(year·km)]
Circuit breaker	λ_{CB} [fault/(unit·year)]
Transformer fuses	λ_{Fu} [fault/(unit·year)]

A Markov **P** matrix relating to Figure 3.8 can be created by applying the probabilities and transition rates for the different components and states.

Table 3.5: Example of Markovian **P** matrix related to the test system in Figure 3.8.

State	**0**	**1**	**2**	**3**	**4**	**5**
0	λ_{00}	0	λ_{02}	λ_{03}	λ_{04}	λ_{05}
1	μ_{10}	μ_{11}	0	0	0	0
2	μ_{20}	0	μ_{22}	0	0	0
3	0	μ_{31}	0	μ_{33}	0	0
4	μ_{40}	0	0	0	μ_{44}	0
5	μ_{50}	0	0	0	0	μ_{55}

The elements in the Markov matrix in Table 3.5 are presented in Equations 3.1-3.6.

$$\begin{aligned} \lambda_{02} &= \lambda_{C1} + \lambda_{C2} + \lambda_{C3} + \lambda_{CB} \\ &= \lambda_{C1} + \lambda_{CB} + 2 \cdot \lambda_{C2} \end{aligned} \tag{3.1}$$

$$\begin{aligned} \lambda_{03} &= \lambda_{Ss1} + \lambda_{Ss2} + \lambda_{Ss3} \\ &= 3 \cdot \lambda_{Ss1} \end{aligned} \tag{3.2}$$

$$\begin{aligned} \lambda_{04} &= \lambda_{T1} + \lambda_{T2} + \lambda_{T3} \\ &= 3 \cdot \lambda_{T1} \end{aligned} \tag{3.3}$$

$$\begin{aligned} \lambda_{05} &= \lambda_{Fu1} + \lambda_{Fu2} + \lambda_{Fu3} \\ &= 3 \cdot \lambda_{Fu} \end{aligned} \tag{3.4}$$

$$\lambda_{00} = 1 - (\lambda_{02} + \lambda_{03} + \lambda_{04} + \lambda_{05}) \tag{3.5}$$

The transition probabilities, λ, are seen in Equations 3.1-3.5. The transition rates, μ, can be modelled as the inverse of the restoration times. In order to use the different restoration times, μ, in the **P** matrix, they need to be converted to the corresponding time as part of a year, as seen in Equation 3.6. If the outage time r is in minutes, this is done by dividing r by $(60 \cdot 24 \cdot 365)$.

$$
\begin{aligned}
\mu_{10} &= \frac{1}{r_M} & \mu_{11} &= 1 - \mu_{10} \\
\mu_{20} &= \frac{1}{r_{LF}} & \mu_{22} &= 1 - \mu_{20} \\
\mu_{31} &= \frac{1}{r_{LF}} & \mu_{33} &= 1 - \mu_{31} \\
\mu_{40} &= \frac{1}{r_T} & \mu_{44} &= 1 - \mu_{40} \\
\mu_{50} &= \frac{1}{r_{Fu}} & \mu_{55} &= 1 - \mu_{50}
\end{aligned}
\tag{3.6}
$$

By adding a $\boldsymbol{\pi}$ vector that is equal to 1, as presented in Section 2.3.1, the matrix can be solved to get the steady state vector of the system [18].

3.4 Voltage Drop and Current Limits in NEPLAN

Distribution system cables are limited in both the voltage drop over the cable as well as the current carrying capability of the cable. These are parameters that must be taken into consideration when planning new secondary substations. The voltage drop is influenced by the cable impedance, the length of the cable, the power factor and the current through it. By depicting the six studied cases in NEPLAN for City, Urban and Industry load profile and substation configurations, the voltage drop and resulting currents could be found.

Using Equation 2.9, the voltage drop for the first section in the test system is shown in Equation 3.7. The index of the voltage drop, V_i in Equation 3.7, refers to which cable section in Figure 3.7 that is contributing to the total voltage drop. The busbars in each substation are deemed ideal. The total, V_{tot}, is the total voltage drop at substation 3.

$$
\begin{aligned}
V_1 &= \sqrt{3} \cdot 3I(R_c \cos\phi + X_c \sin\phi)C_1 \\
V_2 &= \sqrt{3} \cdot 2I(R_c \cos\phi + X_c \sin\phi)C_2 \\
V_3 &= \sqrt{3} \cdot I(R_c \cos\phi + X_c \sin\phi)C_3 \\
V_{tot} &= \sqrt{3} \cdot I(R_c \cos\phi + X_c \sin\phi)(3C_1 + 2C_2 + C_3)
\end{aligned}
\tag{3.7}
$$

3.5 Calculated Fault Statistics and Recovery Time

Fault statistics were provided from GENAB regarding the types of faults, when they occurred and when they were repaired. The fault statistics were gathered from April 2006 - April 2012 and included the estimated location of the outage, the cause of the outage and the failed component. When looking from the customer perspective, the outage time or restore time to full power supply to the customer is significant. It is the outage time in contrast to the the repair time of the fault that affects the customers power supply. Due to differences in the method of reporting outage times, it was required to manually analyse each type of fault and the specified restoration time. Short faults are defined as < 3 minutes and long faults are defined as > 3 minutes [29]. The types of faults that were analysed were cable faults, secondary substation faults and transformer faults. Due to the seldom occurrence of transformer faults, these statistics along with specific component faults and restoration times, were sourced from Elforsk reports [6].

The examined components in Gothenburg's distribution system includes underground cables (XLPE and oil-paper based insulation), 11/0.4 kV transformers, circuit breakers, load disconnectors, transformer fuses and the secondary substations as a whole.

Table 3.6: Cable faults 2007-2011 in GENAB's 11 kV system [5]. Total length of underground cable: 2357135 m.

Cable faults	Total faults/year	λ_C [fault/(km·year)]	Repair time [hrs]	Outage time [min]
2007	63	0.0267	114.37	61.5
2008	44	0.0187	80.3	131
2009	57	0.0242	73.65	44.86
2010	51	0.0216	162	71.09
2011	63	0.0267	163.11	60.86
Average	55.6	0.0236	118.69	73.86

The total length of the underground cable in GENAB's distribution system as well as the number of system stations was sourced from GENAB's software program dpPower. Table 3.6 shows the faults and relevant data for the underground cables in Gothenburg. The cable fault probability λc was calculated in the equation from the definitions in Section 2.1.1.

Table 3.7: The probability of a transformer failure in Gothenburg's distribution system 2007-2011 [5] [6]. Total number of 11/0.4 kV transformers: 2164.

Transformer faults	Total faults 2007-2011	λ_T [fault/(unit·year)]	Avg. repair time [hrs]	r_T Avg. outage time [hrs]
2007-2011	3	0.000277	11.18	8.72

Table 3.8: The probability of a secondary substation failure in Gothenburg's distribution system 2007-2011[5]. Total number of secondary substations: 1644.

Secondary substation faults	Total faults/year	λ_{Ss} [fault/unit·year]	Repair time [hrs]	r_{Ss} Outage time [min]
2007	37	0.0225	12.1	33.67
2008	20	0.0122	7.77	469
2009	12	0.0073	14.16	12
2010	15	0.0091	7.74	49.75
2011	26	0.0158	11.29	87.375
Average	22	0.0134	10.61	130.359

Table 3.9: Statistics from ELFORSK 2005 [6] along with the utility company from where the statistics originate from.

Type of Fault	Utility Company	[fault/(km·year)] or [fault/(unit·year)]
Circuit breaker	Göteborg Energi	$\lambda_{CB} = 0.011$
Indoor load disconnector	Göteborg Energi	$\lambda_{DC} = 0.002$
Fuses 10-20 kV	Göteborg Energi	$\lambda_{FU} = 0.003$
11/0.4 kV Transformer fault	Vattenfall	$\lambda_{T,ALT} = 0.0096$

Since the failure statistics for specific components were not found 2007-2011, the values in Table 3.9 serve as guidelines. Transformers rarely malfunction and therefore there may not be enough fault statistics to be certain that the value λ_T in Table 3.7 is accurate. Therefore $\lambda_{T,ALT}$ from Vattenfall is also introduced as a comparison.

3.6 Power Density and Secondary Substation Configuration

To determine the distances between the secondary substations, the power density in the different cases was found. By examining and calculating the area and yearly maximum load that a distribution substation feeds, the power density could be found and the results are presented in Table 3.10. As can be seen the power density of the city area is much higher than that of the urban and industrial areas.

Table 3.10: Calculated power density for the different areas used to determine the location of and distance between the secondary substations.

Examined station	Area km^2	Max apparent power [MVA]	Power density [MVA/km^2]
City - K11	6.7	41.15	6.15
Urban - K10	28	54.96	1.96
Industry - K9	18.2	42.41	2.33

3.6.1 Location of Secondary Substations in the Examined Areas

The Swedish Energy Markets Inspectorate (EI) recommend that 600 metres is the maximum distance between low voltage customer and secondary substation [30]. With a distance larger than 600 metres it is recommended that a new secondary substation is built in order to ensure the possibility to connect new low voltage customers as well as quality in the electricity distribution [30]. The locations of the secondary 11/0.4 kV substations in the different cases were calculated from the power density of the area as well as the different maximum ratings for the cables and components. By maximising the number of substations on each section of the loop as well as including reserve capacity to cover all N-1 contingencies, the extreme cases could be calculated. The cable lengths and secondary substation placement of the corresponding cases are presented in Figures 3.9-3.17.

Assumptions

It is assumed that the maximum rated current for the underground cable is 270 A as described in Section 2.4 and that each symmetrical section can have a maximum load of 270/2 = 135 A without a reserve cable. Each 800 kVA distribution transformer is assumed to use a maximum current of $\frac{0.8}{\sqrt{3}\cdot 11}$=0.042=42 A on the 11 kV side and each distribution transformer is assumed to not be maximum loaded simultaneously. Therefore the drawn currents will be aggregated and adjusted using a utilisation factor calculated for each area. It is also assumed that the substations in the different areas are designed according to Table 3.1.

Utilisation Factor of Transformers for City, Urban and Industry areas

The utilisation factor is needed to account for the fact that not all transformers will be loaded at their max rating simultaneously. The utilisation factor was calculated by examining existing loops in the three different City, Urban and Industry areas chosen in Gothenburg. The maximum current drawn from the 130/10 kV distribution substation in the normal loading case for the year 2012 was found for each area. This number was divided by the installed capacity of the sectionalised loop to find the utilisation factor as seen in Table 3.11.

Table 3.11: The utilisation factors for the City, Urban and Industry areas.

Area	Installed capacity	Max current of installed capacity	Max current	Utilisation factor
City - K11	5500 kVA	289 A	169 A	58.5 %
Urban - K10	4000 kVA	210 A	103 A	49 %
Industry - K9	5000 kVA	262 A	147 A	56 %

Number of Secondary Substations per km^2

- City: $\frac{6.15\ MVA\ /km^2}{(1.6 \cdot 0.585)} = 6.57 = 7$ substations/km^2
- Urban: $\frac{1.96\ MVA\ /km^2}{(0.8 \cdot 0.49)} = 4.0 = 4$ substations/km^2
- Industry: $\frac{2.33\ MVA\ /km^2}{(1.6 \cdot 0.56)} = 2.6 = 3$ substations/km^2

Max Substations per Section

It is necessary to calculate the maximum number of substations per section in order for the maximum current carrying capacity of the cable not to be exceeded. The current for each substation in the different load areas is:

- City: $0.585 \cdot 2 \cdot 42 = 49\ A$
- Urban: $0.49 \cdot 42 = 21\ A$
- Industry: $0.56 \cdot 2 \cdot 42 = 47\ A$

The maximum number of 2 × 800 kVA substations per section for each case is presented in Table 3.12 for City and Industry. The values in Tables 3.12 and 3.13 are based on the 270 A maximum rated current for each cable and that each section must be able to withstand a N-1 contingency at their calculated maximum utilisation power. The cases were simulated in NEPLAN and verified that the current and voltage drop limits were not reached.

Table 3.12: The maximum number of 2 × 800 kVA substations per section for the City and Industry areas.

Section	1	2	3	4	5	6	7	8	Third leg	Total
Case 1	3	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5
Case 2	5	4	N/A	N/A	N/A	N/A	N/A	N/A	0	9
Case 3	4	3	N/A	N/A	N/A	N/A	N/A	N/A	1	8
Case 4	3	2	2	3	N/A	N/A	N/A	N/A	N/A	10
Case 5	5	4	4	3	N/A	N/A	N/A	N/A	0	16
Case 6	5	4	4	3	5	4	4	3	0	32

Table 3.13: The maximum number of 800 kVA substations per section for each Urban areas.

Section	1	2	3	4	5	6	7	8	Third leg	Total
Case 1	6	6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	12
Case 2	11	11	N/A	N/A	N/A	N/A	N/A	N/A	0	22
Case 3	11	10	N/A	N/A	N/A	N/A	N/A	N/A	1	22
Case 4	5	5	5	5	N/A	N/A	N/A	N/A	N/A	20
Case 5	11	11	11	10	N/A	N/A	N/A	N/A	0	44
Case 6	11	11	11	10	11	11	11	10	0	86

3.6.2 Secondary Substation Placement

To be able to calculate the length of the cable between stations as well as the number of loops required per km, the power density was used. The results are seen in Figures 3.9 to 3.17. This information is required when analysing the Markov models as well as providing input data to the NEPLAN models as seen in Section 4.1. Some different configurations for the City, Urban and Industry case are presented depending on if there is a reserve cable and whether it is utilised.

City

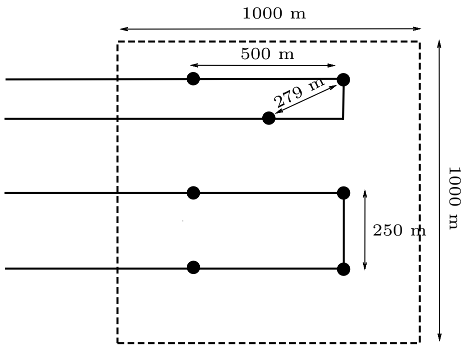


Figure 3.9: Secondary substation placement for the City area without reserve cable: 2 loops or 4 sections/km^2.

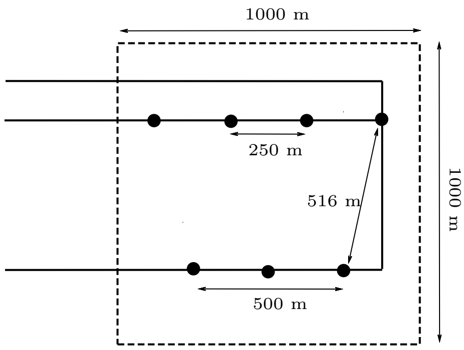


Figure 3.10: Secondary substation placement for the City area with reserve cable: 1 loop or 2 sections/km^2

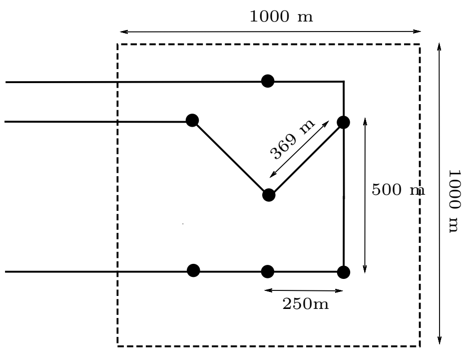


Figure 3.11: Secondary substation placement for the City area with reserve cable and 2 · 800 kVA station on it: 1 loop or 2 sections/km^2

Urban

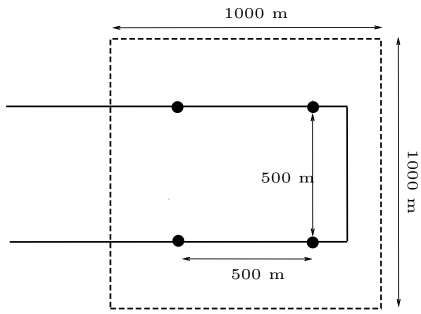


Figure 3.12: Secondary substation placement for the Urban area without reserve cable: 0.5 loops or 1 sections/km^2

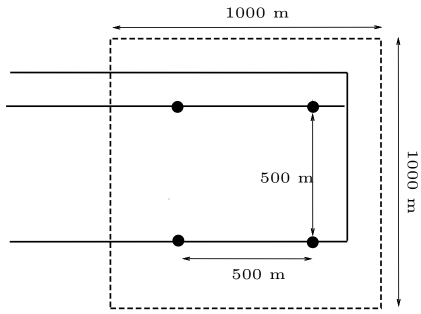


Figure 3.13: Secondary substation placement for the Urban area with reserve cable: 0.5 loops or 1 sections/km^2

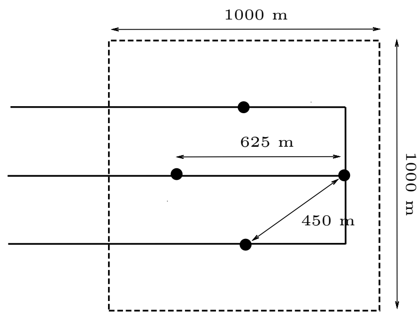


Figure 3.14: Secondary substation placement for the Urban area with reserve cable and 800 kVA station on it: 0.5 loops or 1 sections/km^2

Industry

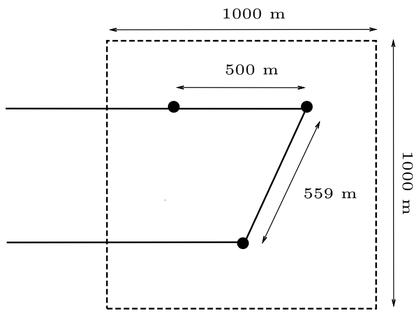


Figure 3.15: Secondary substation placement for the Industry area without reserve cable: 0.5 loops or 1 section/km^2

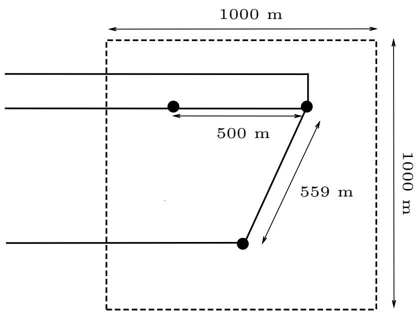


Figure 3.16: Secondary substation placement for the Industry area with reserve cable: 1 loops or 2 sections/km^2

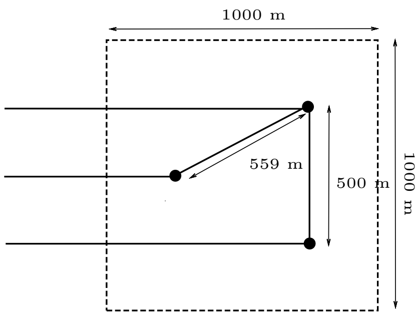


Figure 3.17: Secondary substation placement for the Industry area with reserve cable and a 2 · 800 kVA station on it: 0.5 loops or 1 section/km^2

3.6.3 Number of Customers for Each Area

The installed capacity in the secondary substations per number of customers varied considerably between the City, Urban and Industry areas, as seen in Table 3.14. To calculate the installed capacity per customer, existing substations on loops in each area were analysed. These were the same loops that were analysed in Section 3.6.1.

Table 3.14: Installed power in kVA per customer for each examined area.

Area	Number of customers	Installed capacity per substation
City	165	2 ×1250 kVA
	155	3 ×1000 kVA
Average	160	17.2 kVA /customer
Urban	243	800 kVA
	308	2×800 kVA
	585	2×800 kVA
Average	379	3.52 kVA /customer
Industry	9	500 kVA
	16	800 kVA
	28	2×800 kVA
	13	800 kVA
Average	17	56 kVA /customer

The reason for the variation in the installed capacity per customer is because of the difference in the load profiles of the different areas and customers. Urban areas have a higher amount of residential load with many low load customers. Industrial areas are more energy intensive per customer with the same applying to the city areas where the load per customer is higher compared to urban, residential areas.

3.7 Software for Modelling

This chapter will present the method for modelling the different cases for both the Markov model case and the Neplan case.

3.7.1 MATLAB Modelling

Matlab by MathWorks was used to create and solve the Markov models for the different cases. Matlab is a powerful software that allows for easy implementation and representation of data in the Markov models. A total of 18 different models were created for the 6 cases for the City, Urban and Industry areas. Each individual case and area has specifications and Markov states that are different from another area. This makes the process of defining states and designing the matrices for each case highly work intensive and time consuming.

Mathematical Model Input

Equations 2.1- 2.2 are solved in the following manner.

$$\begin{aligned} \boldsymbol{\pi}\mathbf{P} &= \boldsymbol{\pi} \\ \boldsymbol{\pi}\mathbf{P} - \boldsymbol{\pi} &= \mathbf{0} \\ (\mathbf{P} - \mathbf{I})\boldsymbol{\pi} &= \mathbf{0} \end{aligned} \tag{3.8}$$

This is represented in MATLAB by the following matrices where $\mathbf{P}$ is an $N \times N$ matrix and $\mathbf{I}$ is an $N \times N$ identity matrix [31].

$$\begin{bmatrix} (\mathbf{P} - \mathbf{I}) \\ 1\,1\,\ldots\,1 \end{bmatrix} \begin{bmatrix} \pi_1 \\ \vdots \\ \pi_N \end{bmatrix} = \begin{bmatrix} 0 \\ \vdots \\ 0 \\ 1 \end{bmatrix}$$

This produces the vector $\boldsymbol{\pi}$ that consists of a probability distribution of the states that the system can be in throughout a year. The distributions are then multiplied by $(60 \cdot 24 \cdot 365)$ to calculate the number of minutes per year that the system is in each state. Each state represents the unavailability, U, to a number of customers which then can be used to calculate SAIDI as described in Section 2.1.1.

3.7.2 NEPLAN Modelling

The reliability module in NEPLAN allows the user to input failure statistics and repair times for almost all components. One component that is not available for input of failure statistics are fuses. Instead the fuses can be modelled as breakers but this presents other problems when calculating indices such as SAIDI, since the number of customers affected is higher for a failed breaker compared to a failed fuse. The failed fuse modelled as a breaker requires the operation of the breaker in the distribution substation leading to more customers affected while the failure of a fuse only affects the customers connected to the specific load point in most cases. The cases were instead modelled in NEPLAN without fuses firstly because there wasn't a practical or feasible way and secondly because the calculated input failure statistics for the secondary substations already included fuse failure for the secondary substation failure probability. The secondary substation failure probability was modelled in NEPLAN as a failure in the busbars. This has the same end result for the loop and the connected customers as secondary substation failures modelled using the Markov modelling technique.

3.8 Reserve Capacity With Respect to Load Variations Through Time

If the maximum current carrying capacity of the loop is reached during peak load demand, the possibility exists that there will be insufficient reserve capacity in the case of a faulty component in the loop. This results in that there can be no increase of the load in the loop. By adding a reserve cable, as in Case 2, the current carrying capacity within the loop is increased. There is a cost related to adding a reserve cable and the investments needs to be well motivated with loading forecasts for the future. There is also an economical risk involved when installing a reserve cable since it may be underutilised and cost more in installation and maintenance than the income gained from the added load.

A real, critical case from an industrial estate in Gothenburg was analysed. The chosen case has reached its loading limits and does not allow the load to be increased without affecting the reserve capacity of the system. In order to increase the load, the current reserve configurations of the loops need to be altered. Two alternative reserve configurations and scenarios are presented in Figure 3.18. K1 and K2 in Figure 3.18 represent the busbars of the corresponding 130/11 kV distribution substations. The chosen case has both secondary substations owned by GENAB and secondary substations owned by industrial 11 kV customers. In the current configuration it is not possible to increase the load for cable C_B without exceeding the current limits for the cable. Instead of investing in a potentially costly reserve cable, it has been evaluated if it is possible to connect two loops (as in Case 4) to act as reserve for each other and this scenario will be referred to as *Alternative 1*. The feasibility of Alternative 1 is compared to the scenario of adding a reserve cable, C_R, from the distribution substation K2 and this is referred to as *Alternative 2*. Adding a reserve cable would increase the current capacity of the loop by a total of 270 A which would make it possible to increase the load. The two chosen loops have different, seasonal load patterns that may make it feasible for them to serve as reserve to one another.

The implications and benefits of investing in the two alternatives was evaluated. The investment of a reserve cable (Alternative 2) is compared with Alternative 1 by calculating the probability that the current in the cables would exceed the current limit of 270 A. The effects of adding a seasonally varying 800 kVA or a 2×800 kVA secondary substation Ss_P to the C_B cable was also evaluated. MATLAB was used to model the behaviour of the loops and calculate the probabilities and implications of the additional secondary substations.

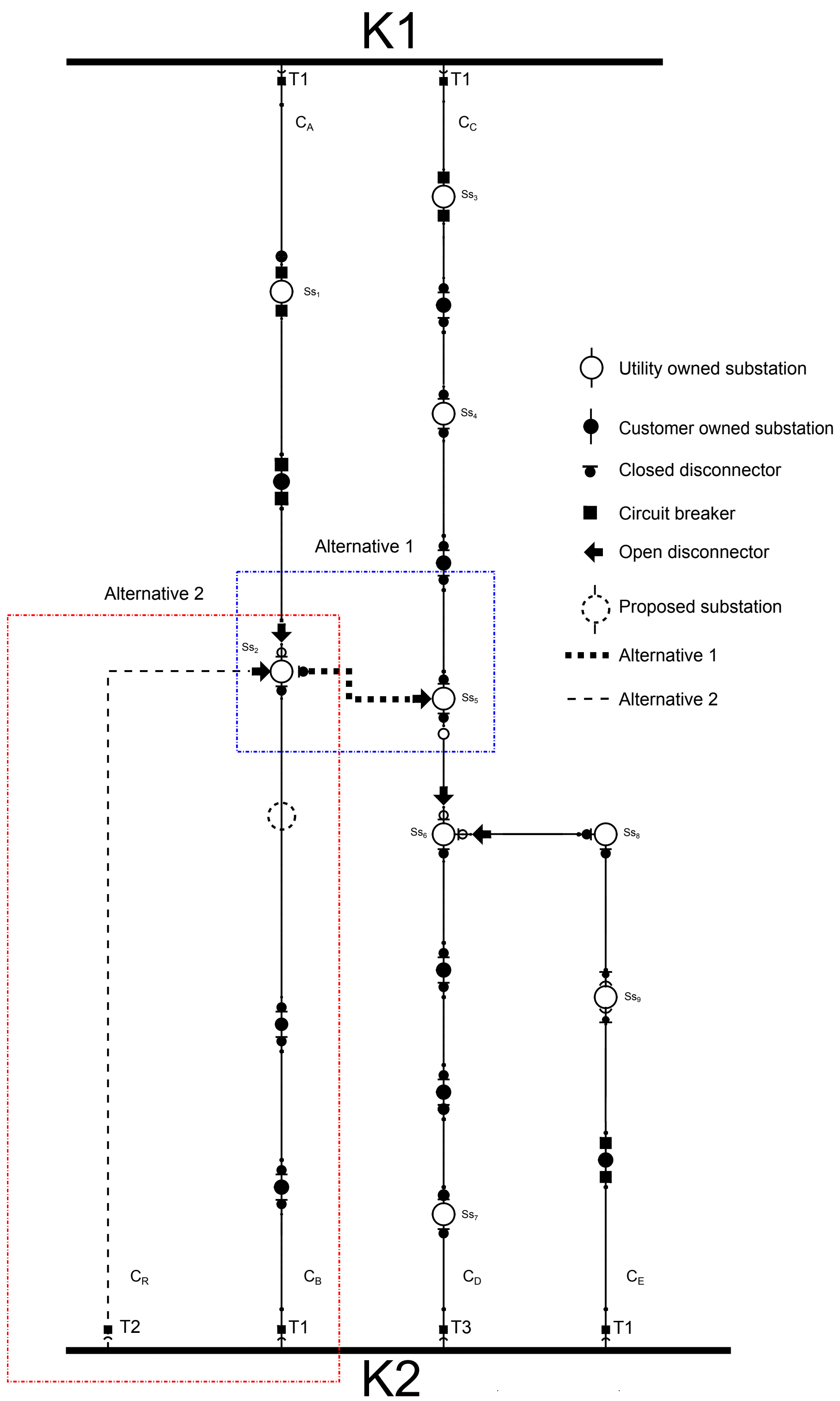


Figure 3.18: The chosen case of industrial estate as well as the dashed lines representing proposed alternative connection points between substations.

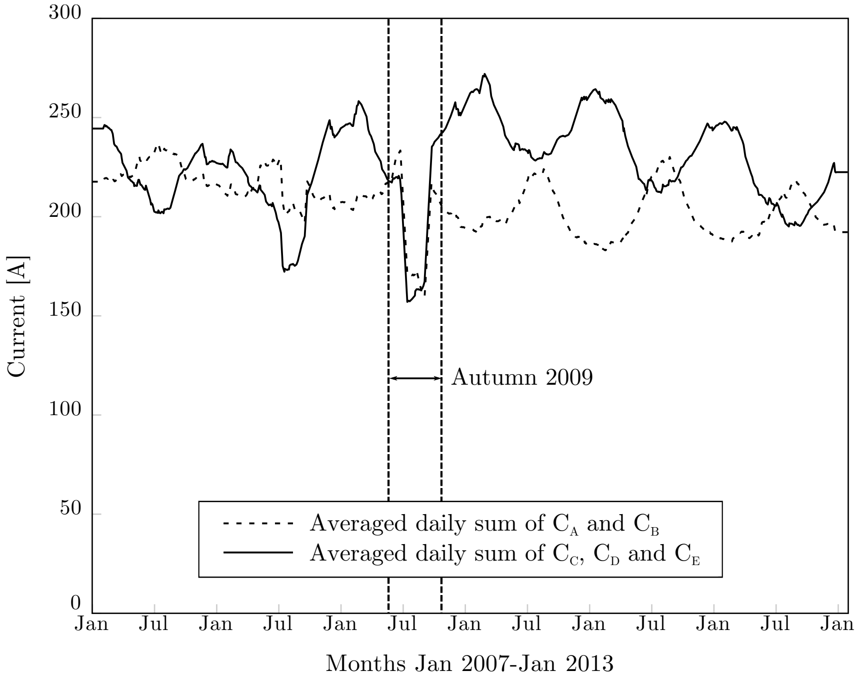
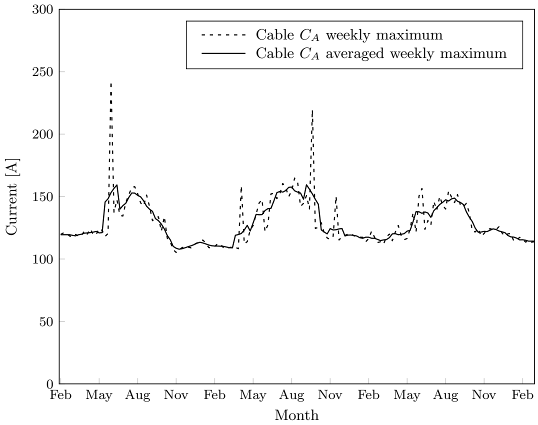


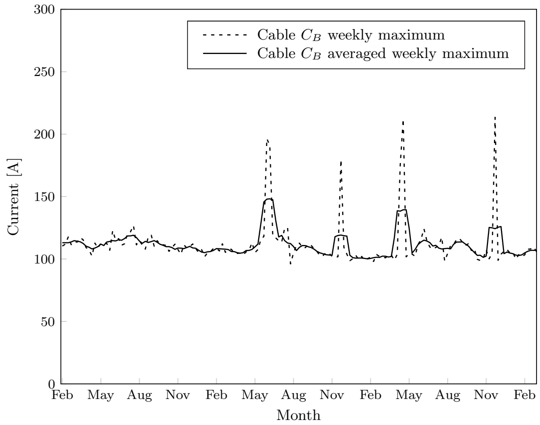
Figure 3.19: The load variations for the sum of the loops from Jan 2007 - Jan 2013.

Figure 3.19 shows the the average variation of the sum of the currents in the corresponding loops over time between January 2007 to January 2013. The statistical data available from this time period is composed of both reliable and unreliable data. The deviations in August 2008 and July/August 2009, the areas shown in Figure 3.19, are due to metering failure where all the collected values for a total of 27 days were missing or incorrect.

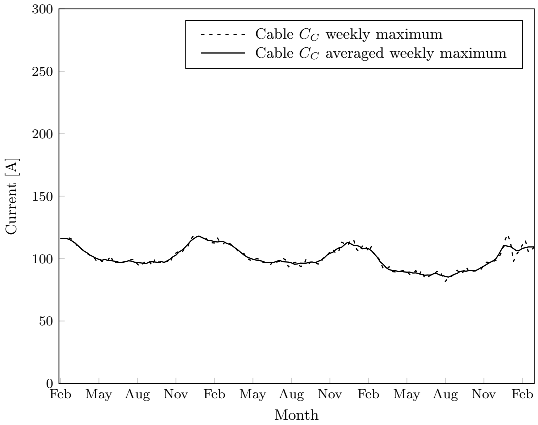
Variations in the load throughout the year for the different feeder cables in Figure 3.18 were found by taking a weekly maximum and taking a moving average of the accumulated maximums. The years 2010-2013 clearly show the summer and winter load characteristics of the loops and these results are presented in Figures 3.20a - 3.20e. The sum of the incoming feeder cables for the two loops is presented in Figure 3.20f. This sum is based on a daily maximum and not a weekly maximum in order to achieve a more accurate result. As seen in Figure 3.20f, loop [C_C+C_D+C_E] has a peak load during the winter and loop [C_A+C_B] has a peak load during the summer. Since the load in loop [C_A+C_B] increases during the summer, there is an indication that the load might consist of industry that requires cooling. The load in loop [C_C+C_D+C_E] is of a more traditional Swedish sort with higher loads during the winter months.



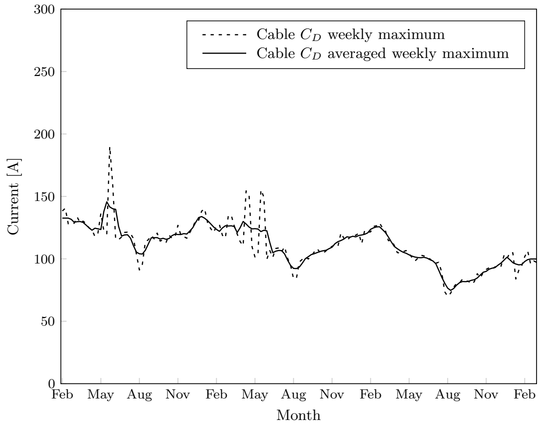
(a) The load variations for cable C_A from Feb 2010 - Feb 2013.



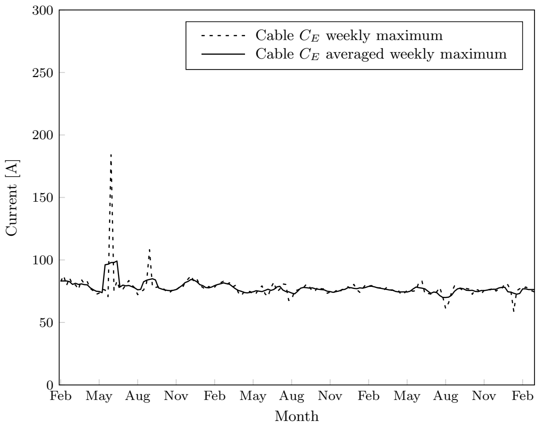
(b) The load variations for cable C_B from Feb 2010 - Feb 2013.



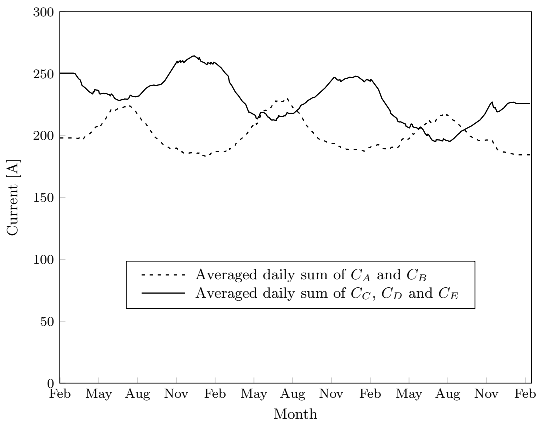
(c) The load variations for cable C_C from Feb 2010 - Feb 2013.



(d) The load variations for cable C_D from Feb 2010 - Feb 2013.



(e) The load variations for cable C_E from Feb 2010 - Feb 2013.



(f) The load variations for the whole loops from Feb 2010 - Feb 2013.

Figure 3.20: Load variations for Cables C_A-C_E

3.8.1 Reserve Alternatives for a Critical Case

Two alternatives are presented and compared for the chosen case in Figure 3.18. The cost of the investments are compared using the net present value method and the results are presented in Section 4.4.3.

Alternative 1 - Connecting Two Seperate Loops

The resulting currents of connecting the C_B cable and C_C cable as well as the case of the C_A and C_C cables was analysed. The bridging of these cables would be between stations Ss_2 and Ss_5, as seen in Figure 3.18. This location was chosen due to the substations geographic proximity to each other. The maximum current rating capacity of the cable is 270 A. The currents in the connected cables must not increase above 270 A in order for the insulation integrity and properties of the cable to remain unaltered. The hourly current measurements for each cable were added together and the algorithm in Figure 3.21 was used to find the number of hours per year that the sum of the currents exceeded 270 A. The effects of adding a 800 kVA or 2 × 800 kVA substation with the same load factor was evaluated by the flow chart in Figure 3.22. C_A and C_C in Figure 3.18 are fed from the same distribution transformer $T1$ in K13. Due to this, the reserve configuration is not a viable solution even though the probability of the current in $[C_A{+}C_C]$ exceeding 270 A is less compared to the case of $[C_B{+}C_C]$ being connected. Connecting C_B and C_C is therefore a better choice.

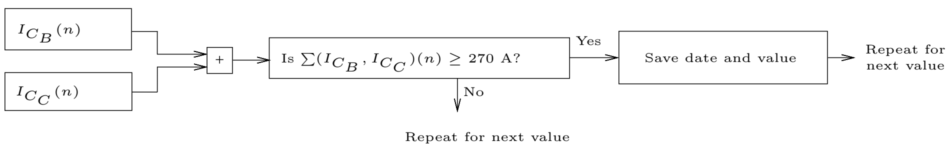


Figure 3.21: Flow chart of the algorithm determining the probability of the current in cable C_B and cable C_C exceeding 270 A 2007-2013.

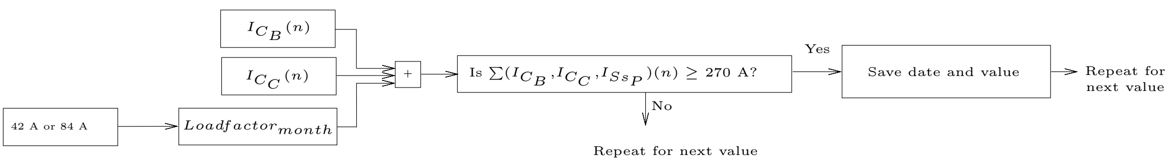


Figure 3.22: Flow chart of the algorithm determining the the probability of the current for cable C_B and cable C_C with the additional substation Ss_P exceeding 270 A 2007-2013.

The number of hours and corresponding probability of exceeding the max current per year for the different cases is presented in Section 4.4. To estimate the probability of exceeding the current limit, the exceeding hours per year is divided by the total number of hours per year ($24 \cdot 365 = 8760\ hours$). Since the values from 2008 differ greatly from the other years, the median values have also been included in the results in Section 4.4.

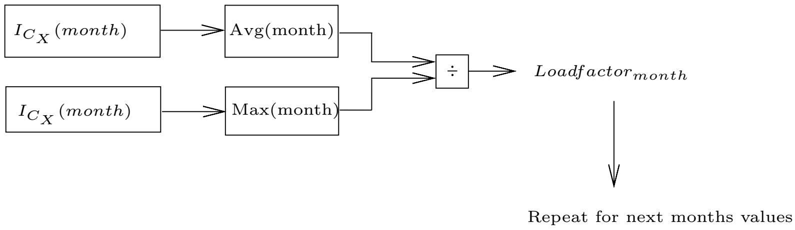


Figure 3.23: Flow chart of how the load factor for cable X was calculated each month. The average and maximum current value was found for each month and then divided by each other.

Connecting C_B and C_C results in higher reserve capacity in the system. To evaluate the possibliity of increasing the load, the effects of adding an additional 800 kVA secondary substation to C_B was evaluated. It is assumed that the added 800 kVA secondary substation has an averaged load profile that resembles the load profiles of the rest of the loads connected to the C_B. This serves as a worst case scenario since the load would be more even if a winter load profile had been used instead. To model the load behaviour of the new secondary substation, the load factor for the cable was calculated and then multiplied by the maximum current drawn by the substation ($\frac{0.8}{\sqrt{3} \cdot 11} = 0.042 = 42\ A$). The current was then added to the existing current of the C_B cable and the results are presented in Table 4.13. The load factor was calculated using Equation 3.9 [32] and calculated using Tables 4.10 and 4.11. The flow chart for the method to find the monthly load factors is seen in 3.23. and the result of the load monthly factors is presented in Section 4.4.

$$LF = \frac{I_{average}}{I_{max}} \tag{3.9}$$

Alternative 2 - Investing in a Reserve Cable

The current carrying capacity of the loop can also be increased by investing in a reserve cable from the K2 distribution substation to the Ss_2 secondary substation. This would increase the current carrying capacity from a maximum of 135 A for both cables, to a maximum of 270 A for C_B. The maximum current for C_A would be (270 - I_{Ss_2}) A depending on the busbar configuration of substation Ss_2. The possibilities for the busbar configuration are described in Section 3.9.1. Motivating the investment is important and support from load forecasts that indicate an increase in load for the chosen loop if the investment is required.

3.8.2 Investment Comparisons

The *net present value* (NPV) method was used to compare the two alternatives to evaluate which one was more economically sound. The net present value takes into account the incomes and expenditures over the economic lifetime and compares them at the present time [33]. The net values are discounted using a discount rate to its present value and the investment is assumed to be taken at time $t = 0$. The discount rate is determined by the investors and can take inflation, interest rate on borrowed capital, interest compared to other alternatives and risk into account [33]. The best alternative is the one that generates the highest NPV after the economic lifetime of the investment. The economic lifetime is the time where it is economically sound to utilise the investment [33]. The net present value with regard to time and discount rate can be calculated by:

$$NPV(i,N) = \sum_{t=0}^{N} \frac{CF_t}{(1+i)^t} \tag{3.10}$$

where i = discount rate, t = year, CF = net cash flow for the year and N = economic lifetime in years [33]. The discount rate in this evaluation is chosen at 6 % which is the chosen discount rate that GENAB uses for investment calculations [34].

The net cash flow is the income less the costs for the investment during the year. The income from customers in Gothenburg's distribution system for industrial customers is based on a fixed annual fee, a dynamic fee based on the energy in kWh provided and a fee based on the maximum, monthly momentary power consumed. The fees differ depending on the installed fuse at the customer is below or above 63 A. It is problematic to model and predict the potential income of adding an additional secondary substation and therefore the income modelling was based depending on existing customers connected to the loops in the chosen case. The substation chosen to model an additional 800 kVA is Ss_5 and the substation chosen to model an additional 2 × 800 kVA substation is substation Ss_2 in Figure 3.18. The information available for each station was the fuse installed and the annual energy consumption in kWh.

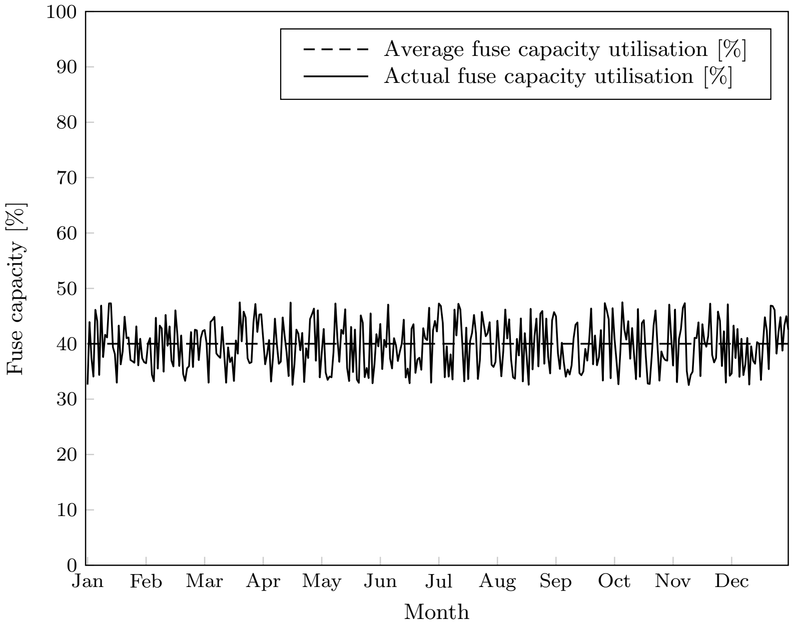


Figure 3.24: Example of maximum load modelled as an average of 40 % throughout the year.

The method used to model the maximum monthly power consumption assumed that the customer's load was relatively constant without large power variations throughout the year as seen in Figure 3.24. The cost for the investments and different alternatives are sourced from EBR's cost catalogue. Swedenergy is a Swedish trade organisation composed of Swedish electrical utility companies that annually publish the EBR cost catalogue. The catalogue compiles the average costs of power system installations and is used when planning investments in the power network [9]. The estimated maintenance costs are also sourced from EBR's cost catalogue.

3.9 Busbar Configuration and Common Mode Failure Impact on the EDS

This section presents methods to increase reliability and decrease customer outage time that have not been presented before. The busbar configuration in the substations determine the ability of the DSO to sectionalise the loop in case of a fault. By increasing the ability to sectionalise, the number of affected customers during a fault can potentially be reduced. It is necessary to analyse common mode faults in order to analyse the effects of an N-2 contingency. An example of potential common mode failure exposure is when the main feeder and the reserve cable lie in parallel in the same cable trench out of the distribution substation. Since they lie in parallel, they are exposed to the same potential failures for these sections of the cables.

3.9.1 Busbar Configuration to Increase Number of Connected Substations If Reserve Cable is Used

By investing in equipment and altering the busbar configuration in the substation where the reserve cable is connected allows for more stations to be added the loop. As was seen in Table 3.13 and 3.12 in Section 3.6.1, the number of substations per section is decreased if a reserve cable with a substation is introduced (Case 3). This is due to the fact that in the case of a fault on Loop 2, the third station of Loop 1 in Figure 3.3 also needs to be supplied by the reserve cable due to the busbar configuration seen in Figure 3.25.

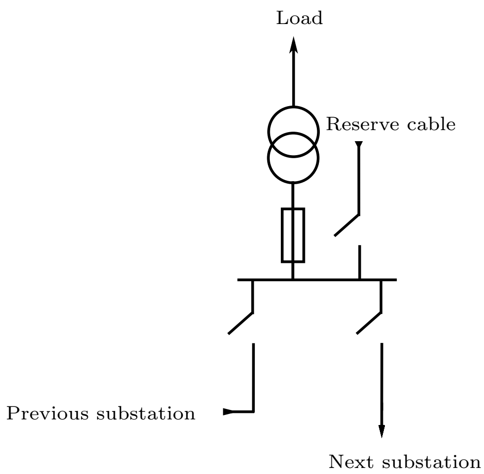


Figure 3.25: Common busbar configuration without possbility of sectionalising.

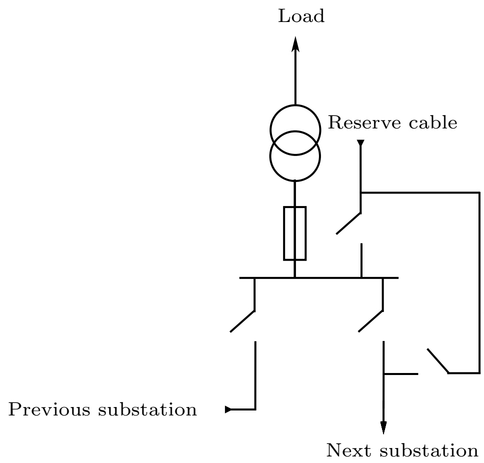


Figure 3.26: Busbar configuration with switches that allow the reserve cable to be connected to either section in the loop of Case 2.

If a switch is added in the busbar configuration as in Figure 3.26, there is an option to connect the reserve cable to the second loop without supplying the third station of the first section with power. This allows the number of stations on the second section of the loop to be increased by one additional station.

3.9.2 Common Mode Failures

Only N-1 faults have been discussed in the previous sections but two simultaneous failures (N-2) can have large consequences for the power system. It is difficult to assess the probability of a common cause failure both because of the relatively low frequency of common mode failures in the distribution system and the fact that a lot of the common mode failures are unique in the manner that the components are affected. In the IEEE model presented in Section 2.1.2, it is assumed that all restoration rates are mutually independent of each other and this is a valid assumption since the repair time is different for each affected component. The equivalent transition and restoration rates of common mode failures associated to Figure 2.1 can be calculated by:

$$\lambda_{Eqv} = \lambda_1 \lambda_2 (r_1 + r_2) + \lambda_{CM} \tag{3.11}$$

$$r_{Eqv} = \frac{r_1 r_2}{r_1 + r_2} \tag{3.12}$$

$$\mu_{Eqv} = \frac{1}{r_{Eqv}} \tag{3.13}$$

where λ_{CM} is the transition probability for common mode faults for components 1 and 2, λ_1, r_1, λ_2 and r_2 are the failure rates and restoration times of components 1 and 2 respectively [1].

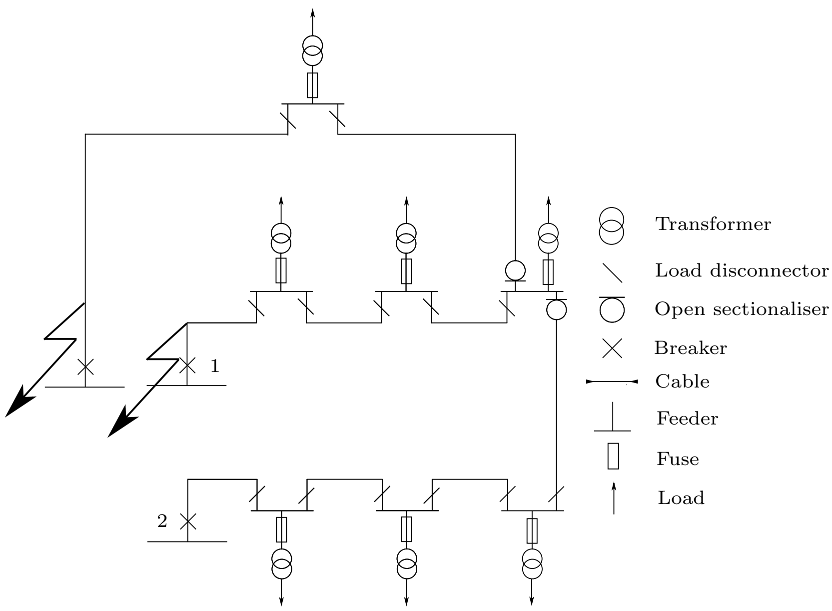


Figure 3.27: Example of common mode fault applied on Case 3.

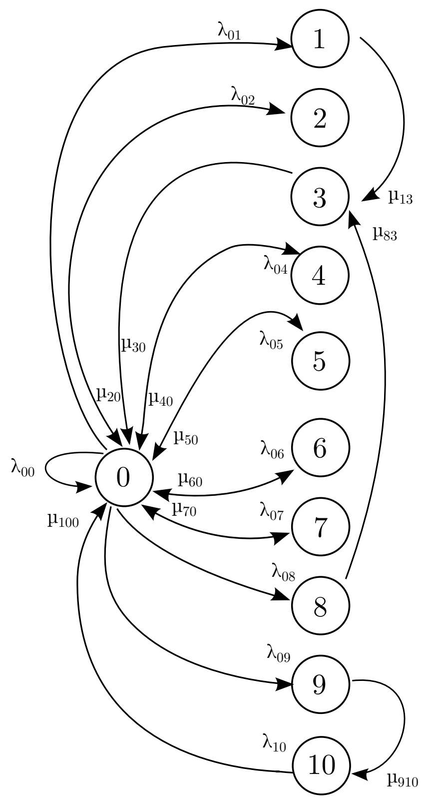


Figure 3.28: State space transition diagram Case 3 with common mode faults.

Common mode faults for Case 3 were modelled using the states presented in Figure 3.28. Case 3 was examined since it offers a high number of customers affected during a common mode fault. Case 3 differs from the other cases with a reserve cable since it includes an additional station added to the reserve cable. A common mode fault on the reserve cable and the distribution substation feeder affects all the substations in the first section as well as the substation connected to the reserve cable. Case 3 is the therefore the most critical case when examining common mode faults.
The states that were used are the following.

- 0: Normal operation
- 1: One whole substation and its customers are affected by a disconnector or busbar fault.
- 2: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 3: All substations in section 1 are affected by a disconnector or busbar fault.
- 4: One whole substation is affected by a transformer fault.
- 5: One whole substation is affected by a fuse fault.
- 6: The substation on the reserve cable is affected by a cable or circuit breaker fault.
- 7: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 8: All substations in section 2 are affected by a disconnector or busbar fault.
- 9: All substations in section 1 and the substation on the reserve cable is affected by a common mode fault.
- 10: All of the substations on the first section except the last don't have power.

Case 3 from section 3.1 was used as a test system for common mode failure. The case, presented in Figure 3.27 consists of two sections of a loop and a reserve cable with a substation on it. It is assumed that the feeder cables to the first section and the reserve cable lay in parallel in the same trench and that they therefore have a possibility of being affected by a common mode fault. It is also assumed that the probability of a common mode fault, λ_{CM} in Figure 2.1, is one tenth of the transition probability of a normal cable fault. The case was modelled using the Urban area load profile and the number of substations per loop as presented in Table 3.13. The results of the common mode fault analysis are presented in Chapter 4.

Chapter 4

Results and Discussion

This chapter presents the results of the created Markov models as well as a comparison of the results with NEPLAN. *The results from the examined case and reserve capacity alternatives in Gothenburg are also presented as well as the results from the economical analysis of the alternatives respectively. The common mode failure results are introduced along with proposed guidelines for a more optimal reserve capacity against common mode faults. A sensitivity analysis of the created Markov models as well as an analysis of the results is included as well.*

4.1 Input data

The statistical input data in the models is presented in Table 4.1. The input data for the number of substations per section is presented in Tables 4.2 and 4.3. The input data for the length of the modelled underground cables is seen in Table 4.4.

Table 4.1: The statistical data used as input parameters to the models.

Input parameter	Value
r_T	8.72 [hrs]
r_{LDc} manually/remote controlled	120/15 [min]
r_{Ss}	10.61 [hrs]
λ_T	0.00028 [fault/(unit·year)]
λ_{Ss}	0.0134 [fault/(unit·year)]
λ_C	0.0236 [fault/(km·year)]
λ_{CB}	0.011 [fault/(unit·year)]

Table 4.2: The maximum number of 2 × 800 kVA substations per section for the City and Industry case.

Section	1	2	3	4	5	6	7	8	Third leg	Total
Case 1	3	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5
Case 2	5	4	N/A	N/A	N/A	N/A	N/A	N/A	0	9
Case 3	4	3	N/A	N/A	N/A	N/A	N/A	N/A	1	8
Case 4	3	2	2	3	N/A	N/A	N/A	N/A	N/A	10
Case 5	5	4	4	3	N/A	N/A	N/A	N/A	0	16
Case 6	5	4	4	3	5	4	4	3	0	32

Table 4.3: The maximum number of 800 kVA substations per section for each Urban variant of the cases.

Section	1	2	3	4	5	6	7	8	Third leg	Total
Case 1	6	6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	12
Case 2	11	11	N/A	N/A	N/A	N/A	N/A	N/A	0	22
Case 3	11	10	N/A	N/A	N/A	N/A	N/A	N/A	1	22
Case 4	5	5	5	5	N/A	N/A	N/A	N/A	N/A	20
Case 5	11	11	11	10	N/A	N/A	N/A	N/A	0	44
Case 6	11	11	11	10	11	11	11	10	0	86

Table 4.4: The distance between the secondary substations to fulfil the power density requirements in the different cases.

	City	Urban	Industry
Case 1	500 m	500 m	559 m
Case 2	516 m	500 m	559 m
Case 3	500 m	625 m	559 m

In order to calculate the voltage drop and current limits for the loops, the transformer and cable technical data needed to be input into the model. These are presented in Table 4.5 and 4.6. The busbars and disconnectors are considered ideal with no voltage drop across them. The cable lengths were input as described in Table 4.4. The maximum lengths between the substations presented in Table 4.4 provide an estimate for the underground cable lengths of the different cases. Fuses are not modelled in NEPLAN, as described in Section 3.7.2, but there is the possibility to include fuse fault probabilities in the created Markov models.

Table 4.5: Technical data for underground cables provided as input for NEPLAN models [7].

Nexans 3 x 240 mm^2 XLPE Al cables 12kV	Value
Impedance [Ω/km]	0.195
AC Resistance [Ω/km]	0.161
Inductance [mH/km]	0.348
Reactance [Ω/km]	0.109
1 s short circuit current rating [kA]	22.9
Continuous current carrying capacity in ducts [A]	340

Table 4.6: Technical data for 800 kVA transformer provided as input for the NEPLAN model [8]

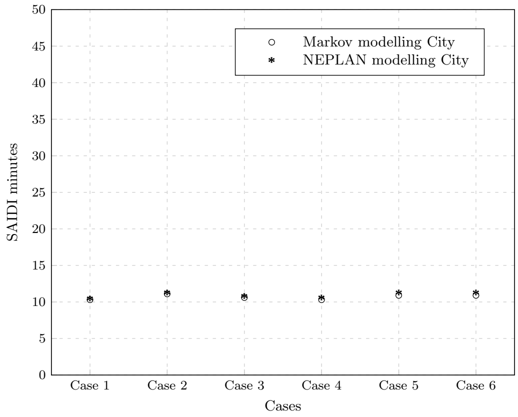
Siemens 4JB 5944-3PA	Value
Rated Power S_n[kVa]	800
Max rated voltage high voltage side U_m [kV]	12
Impedance voltage U_z [%]	6
No-load losses P_0 [W]	1450
Load losses P_k [W]	10700

4.2 Output data and validation of the Markov models

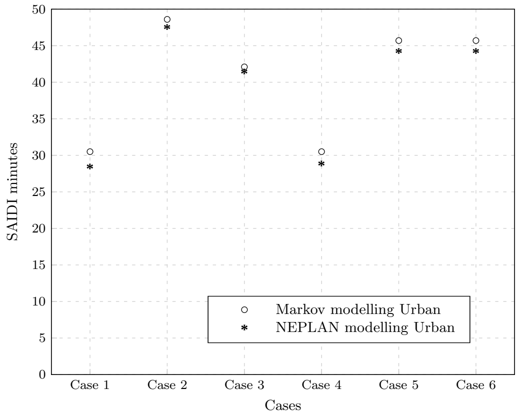
In order to validate the created Markov models, Neplan was used to design and simulate the different cases and areas. The results of the different cases simulated using Markov modelling and the comparison with Neplan respectively, are presented in Table 4.7 and Figure 4.1. As can be seen there is a correspondence between the two different modelling techniques for all cases. The results for the Urban areas, especially Case 2, differ from City and Industry due to the higher number of substations in the loops for the Urban area, as seen in Table 4.3. The result for the City and Industry areas differ since the disconnector switching mechanism and related outage time differ between the two areas.

Table 4.7: The results of the simulated SAIDI for the different models and cases. The difference between the modelling methods is shown in both minutes and %.

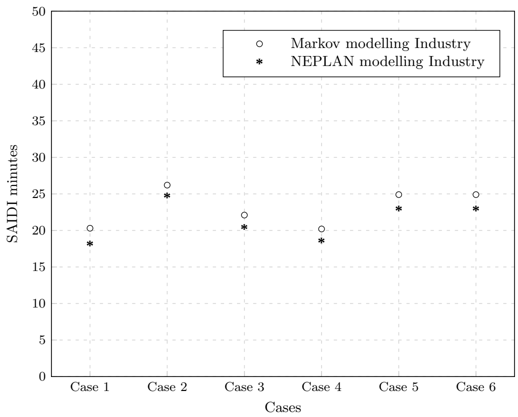
	SAIDI Markov [min/year]	SAIDI Neplan [min/year]	Difference [min]	Difference percentage
Case 1				
City	10.3	10.5	0.2	2 %
Urban	30.5	28.5	-2	-6.6 %
Industry	20.3	18.2	-2.1	-10.3 %
Case 2				
City	11.1	11.3	0.2	1.8 %
Urban	48.6	47.6	1	-2.1 %
Industry	26.2	24.8	-1.4	-5.3 %
Case 3				
City	10.6	10.8	0.2	2 %
Urban	42.1	41.5	-0.6	-1.4 %
Industry	22.1	20.5	-1.6	-7 %
Case 4				
City	10.3	10.6	0.4	3 %
Urban	30.5	28.9	-1.6	-5 %
Industry	20.2	18.6	-1.6	-8 %
Case 5				
City	10.9	11.3	0.3	3.7 %
Urban	45.7	44.3	-1.4	-3.2 %
Industry	24.9	23	-1.9	-7.6 %
Case 6				
City	10.9	11.3	0.4	3.7 %
Urban	45.7	44.3	-1.4	-3.2 %
Industry	24.9	23	-1.9	-7.6 %



(a) Validation of models for City Area.



(b) Validation of models for Urban area.



(c) Validation of models for Industry area.

Figure 4.1: Validation and comparison of results of the different cases for City, Urban and Industry areas.

4.3 Voltage Drop for the Examined Cases and Areas

The voltage drop and current limits for the different cases and areas was determined by modelling the different cases in NEPLAN. The load module in Neplan was used to find the maximum currents and the resulting maximum number of substations per section, seen in Tables 4.2-4.3. As seen in Table 4.8, the maximum voltage drop for the cases is never over 7 %.

Table 4.8: Results of the maximum voltage drop for the different Cases and areas.

	Lowest voltage	Voltage drop
Case 1		
City	98.84 %	1.16 %
Urban	98.68 %	1.32 %
Industry	98.68 %	1.32 %
Case 2		
City	97.99 %	2.01 %
Urban	96.63 %	3.37 %
Industry	98.08 %	1.92 %
Case 3		
City	98.47 %	1.53 %
Urban	96.99 %	3.01 %
Industry	98.45 %	1.55 %
Case 4		
City	98.88 %	1.12 %
Urban	97.81 %	2.19 %
Industry	98.93 %	1.17 %
Case 5		
City	97.99 %	2.01 %
Urban	96.52 %	3.48 %
Industry	98.08 %	1.92 %
Case 6		
City	98.88 %	1.12 %
Urban	96.63 %	3.37 %
Industry	98.08 %	1.92 %

4.4 Reserve Capacity and Seasonal Variations

To be able to evaluate if Alternative 1 is feasible, the number of hours that the currents for the loops exceeded 270 A was found. The effects on the reserve capacity of adding either a seasonally varying 800 kVA substation or a 2 × 800 kVA substation to C_B was also found. To evaluate the consequences on the lifetime of the cables due to overloading, the corresponding temperature increases were found. The economical implications of the alternatives were found as well as the technical.

4.4.1 Evaluation of Currents for the Alternatives With Additional Substations

Table 4.9: Number of hours as well as the percentage of the year that the current exceeded 270 A for each case.

	[C_B+C_C]	[C_B+C_C]	[C_A+C_C]	[C_A+C_C]
2007	0 hours	0 %	5 hours	0.06 %
2008	79 hours	0.9 %	102 hours	1.16 %
2009	0 hours	0 %	0 hours	0 %
2010	0 hours	0 %	2 hours	0.022 %
2011	22 hours	0.25 %	3 hours	0.034 %
2012	14 hours	0.16 %	0 hours	0 %
Average 2007-2012	19.17 hours/year	0.22 %	18.7 hours/year	0.21%
Median 2007-2012	7 hours/year	0.08 %	2.5 hours/year	0.03 %

Table 4.10: Average over 2007-2012 of maximum currents for cables C_A, C_B, C_C, C_D and C_E for each month

	C_A	C_B	C_C	C_D	C_E
January	120 A	122 A	100 A	142 A	84 A
February	119 A	122 A	100 A	141 A	96 A
March	119 A	122 A	95 A	138 A	81 A
April	134 A	139 A	89 A	136 A	79 A
May	140 A	141 A	84 A	152 A	79 A
June	192 A	149 A	85 A	152 A	102 A
July	155 A	145 A	103 A	119 A	84 A
August	155 A	131 A	84 A	111 A	81 A
September	143 A	126 A	106 A	122 A	87 A
October	165 A	121 A	107 A	130 A	79 A
November	130 A	126 A	98 A	127 A	88 A
December	123 A	148 A	104 A	130 A	83 A

Table 4.11: Average over 2007-2012 of currents for cables C_A, C_B, C_C, C_D and C_E for each month

	C_A	C_B	C_C	C_D	C_E
January	79 A	65 A	65 A	75 A	50 A
February	81 A	67 A	69 A	80 A	51 A
March	81 A	67 A	65 A	76 A	49 A
April	80 A	65 A	59 A	70 A	47 A
May	83 A	64 A	55 A	64 A	45 A
June	87 A	68 A	52 A	63 A	45 A
July	88 A	69 A	55 A	52 A	47 A
August	81 A	59 A	47 A	44 A	42 A
September	87 A	68 A	58 A	60 A	49 A
October	86 A	61 A	60 A	66 A	45 A
November	81 A	63 A	66 A	69 A	49 A
December	84 A	65 A	70 A	72 A	50 A

Table 4.12: Averaged load factors 2007-2012 for cables C_A, C_B, C_C, C_D and C_E.

	C_A	C_B	C_C	C_D	C_E
January	66%	53%	65%	53%	60%
February	68%	55%	69%	56%	56%
March	68%	55%	68%	55%	61%
April	60%	49%	66%	52%	60%
May	60%	47%	65%	44%	56%
June	48%	46%	61%	43%	48%
July	57%	49%	57%	44%	56%
August	52%	45%	56%	40%	51%
September	61%	54%	60%	50%	56%
October	55%	50%	61%	52%	57%
November	63%	51%	67%	54%	57%
December	68%	46%	67%	55%	61%

Table 4.13: Annual number of hours that the current exceeded 270 A for [C_B+C_C] with an added 800 kVA secondary substation.

	[C_B+C_C] + 800 kVA substation	[C_B+C_C]+ 800 kVA substation
2007	0 hours	0 %
2008	102 hours	1.16 %
2009	1 hours	0.01 %
2010	0 hours	0 %
2011	28 hours	0.32 %
2012	15 hours	0.17 %
Average 2007-2012	24.3 hours/year	0.28 %
Median 2007-2012	8 hours/year	0.09 %

As can be seen in Tables 4.9 and 4.13, the number of hours per year that the 270 A limit would have been exceeded is increased from an average of 19.17 hours to an average of 24.3 hours corresponding to a 27 % increase. The average probability of exceeding the 270 A limit is however still relatively small for the [C_B+C_C] + 800 kVA substation case (0.28 %). If the median value is used instead of the mean value, the probability is increased by 12.5 % from 0.08 % to 0.09 %. This might be a more reasonable answer since the values in 2008 were higher compared to the other years.

The effects of adding a 2×800 kVA substation instead of a 800 kVA substation was also evaluated. This case would stress the system more since the load would be higher.

Table 4.14: Annual number of hours that the current exceeded 270 A for [C_B+C_C] with an added 2×800 kVA secondary substation.

	[C_B+C_C] + 2×800 kVA substation	[C_B+C_C] + 2×800 kVA substation
2007	0 hours	0 %
2008	124 hours	1.4 %
2009	12 hours	0.14 %
2010	2 hours	0.02 %
2011	33 hours	0.37 %
2012	25 hours	0.29 %
Average 2007-2012	32.7 hours/year	0.37 %
Median 2007-2012	29 hours/year	0.33 %

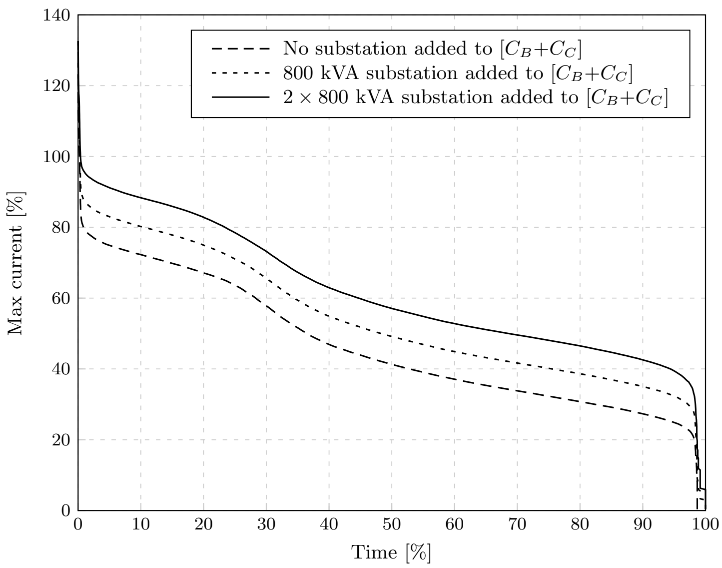


Figure 4.2: Percentage of max current vs percentage of time for the [C_B,C_C] loop and its alternatives.

For comparison, the effects of adding a 2×800 kVA substation without altering the existing reserve capacity configuration was evaluated and the results are presented in Table 4.15.

Table 4.15: Annual number of hours that the current exceeded 270 A for $[C_A{+}C_B]$ with an added 2×800 kVA secondary substation.

	$[C_A{+}C_B]$ + 2×800 kVA substation	$[C_A{+}C_B]$ + 2×800 kVA substation
2007	1982 hours	22.6 %
2008	1370 hours	15.6%
2009	970 hours	11.1 %
2010	469 hours	5.4 %
2011	456 hours	5.2 %
2012	297 hours	3.4 %
Average 2007-2012	924 hours/year	10.6 %
Median 2007-2012	719.5 hours/year	8.2 %

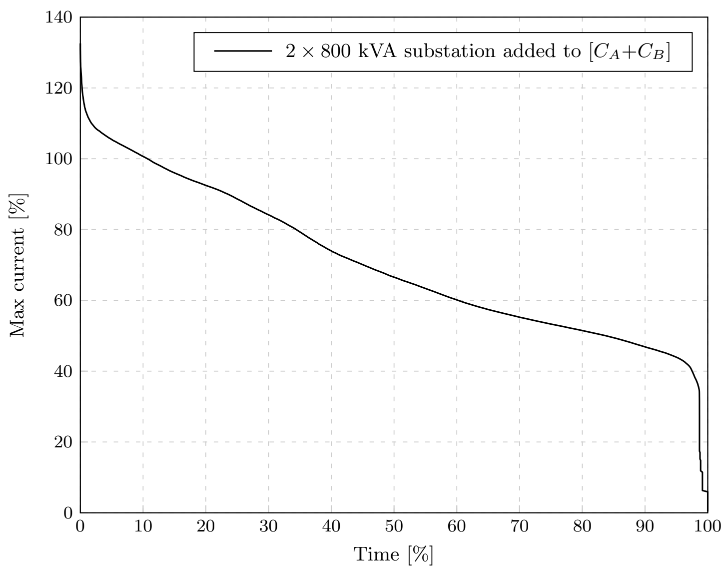


Figure 4.3: Percentage of max current vs percentage of time for the unmodified $[C_A{+}C_B]$ loop with the addition of a 2×800 kVA substation.

4.4.2 Temperature Increase in the Cable Due to Overloading

To model the maximum temperature increase in the cable for Alternative 1, a worst case scenario was found. The worst case scenario was found by evaluating how long and for what current values the cables were overloaded for. The most severe cable overload was found between 11:00-14:00 on 2008-07-10 with a maximum current of 300 and 320 A for the two substation scenarios respectively. It is assumed that the current increase at 11:00 is modelled as a step function and that the initial current loading of the cable is 270 A with a temperature 90 °C.

Using Equations 2.5-2.7 and the values in Tables 2.2 and 4.5, the corresponding temperature increase could be calculated.

Alternative 1 With 800 kVA Substation

$$\Delta P = I_2^2 R - I_1^2 R = 300^2(0.000166) - 270^2(0.000166) = 2.84\, W/m \tag{4.1}$$

$$\Delta T = \Delta P \cdot K(1 - e^{\frac{-t}{\tau}}) = 2.84 \cdot 2.7(1 - e^{\frac{-4 \cdot 3600}{2100}}) = 7.6°C \tag{4.2}$$

$$T_2 = T_1 + \Delta T = 90 + 7.6 = 97.6°C \tag{4.3}$$

The temperature T_2, is the steady state temperature after the four hours that the cable is exposed to the overloading.

Alternative 1 With 2×800 **kVA Substation**

$$\Delta P = I_2^2 R - I_1^2 R = 320^2(0.000166) - 270^2(0.000166) = 4.9\, W/m \tag{4.4}$$

$$\Delta T = \Delta P \cdot K(1 - e^{\frac{-t}{\tau}}) = 4.9 \cdot 2.7(1 - e^{\frac{-4 \cdot 3600}{2100}}) = 13.2°C \tag{4.5}$$

$$T_2 = T_1 + \Delta T = 90 + 13.21 = 103.2°C \tag{4.6}$$

The temperature increase of the cable in Alternative 2 is not considered since the current never exceeds 270 A for the proposed reserve alternative in Alternative 2.

4.4.3 Economical Aspects of the Two Alternatives

The cost for the different alternatives and scenarios is evaluated using the Net Present Value method. By calculating the annual future income and costs into the present value, the alternatives can be compared. It also makes it easy to see and compare the time the investments take until they break even.

Alternative 1: Connecting two loops together

The cost of connecting two loops together is composed of installing cable and remote controlled load disconnectors and presented in Table 4.17.

Table 4.16: Cost of cable and remote controlled load disconnectors for Alternative 1 [9].

Component	Cost	Number of units or length	Cost
XLPE $3 \times 240mm^2$ 12kV cable	711 000 SEK/km	0.6 km	426 600 SEK
RC load disconnector	96 000 SEK	2	192 000 SEK
Total cost			618 600 SEK

Alternative 2: Adding a reserve cable

The capacity within the loops is significantly increased if a reserve cable added. The cost is however higher compared to alternative 1 in Section 4.4.3.

Table 4.17: Cost of cable and remote controlled load disconnectors for Alternative 2 [9] [10].

Component	Cost	Number of units or length	Cost
XLPE $3 \times 240mm^2$ 12kV cable	711 000 SEK/km	1.75 km	1 244 250 SEK
RC load disconnector	96 000 SEK	1	96 000 SEK
630 A 12 kV cubicle w/ breaker	333 000 SEK	1	333 000 SEK
Total cost			1 673 250 SEK

Cost of Adding Substations to the Loop

Table 4.18: The cost of an additional 800 kVA substation [9].

Component	Cost	Number of units or length	Cost
800 kVA substation	205 000 SEK	1	205 000 SEK
800 kVA 12/0.4 kV transformer	101 000 SEK	1	101 000 SEK
Total cost			306 000 SEK

Table 4.19: The cost of an additional 2 × 800 kVA substation [9]

Component	Cost	Number of units or length	Cost
2 × 800 kVA substation	425 000 SEK	1	425 000 SEK
800 kVA 12/0.4 kV transformer	101 000 SEK	2	202 000 SEK
Total cost			627 000 SEK

Table 4.20: The cost of maintenance per year for the substations [9].

Component	Cost	Number of units	Cost
Substation inspection	668 SEK	1	668 SEK
Disconnector maintenance	330 SEK	2	660 SEK
Total annual cost			1 328 SEK

Table 4.21: Total cost for the different investment alternatives with annual maintenance excluded.

Alternative	Total cost
Alternative 1 + 800 kVA substation	924 600 SEK
Alternative 1 + 2 × 800 kVA substation	1 245 600 SEK
Alternative 2 + 800 kVA substation	1 979 250 SEK
Alternative 2 + 2 × 800 kVA substation	2 300 250 SEK

Income From the Different Alternatives

The annual income from the customers is based, as described in Section 3.8.2, on an annual subscription fee, the annual energy usage and the maximum value of the power used each month. The fees are presented in Table 4.22. The typical 800 kVA and 2×800 kVA substations that were analysed are presented in Appendix B. It was assumed that the maximum power used each month is an average of the total energy used divided by the number of hours in a year.

Table 4.22: Fees for 0.4 kV industrial customers in Gothenburg 2013 [11].

Subscription	Subscription fee	Energy transmission fee	Power fee
Max 63 A	624 SEK/year	0.152 SEK/kWh	16.8 SEK/(kW,month)
Over 63 A	4 700 SEK/year	0.068 SEK/kWh	38.2 SEK/(kW,month)

Reliability For the Different Alternatives and Associated Cost

The outage time for each alternative and year was found by using the created Markov models for Case 2 and Case 4. The number of substations, cable length and the number of customers connected was modified for each alternative. The monetary cost of an outage due to a component failure only includes the potential compensation to the customer and the loss of income due to undelivered energy. The cost of the component repair is not included due to the uncertain nature of the cost with regard to the uniqueness of each component failure. GENAB compensate customers for outages longer than 12 hours [35] and as seen in Tables 3.6 - 3.8, the average outage time for the different faults is never over 12 hours. This results in that there is only a need to include the loss of income due to undelivered energy. The Markov models do not differentiate customers based on their fuse type and therefore an average income per lost kWh was calculated for the typical substations in Appendix B. The undelivered energy was modelled as the annual average power for each customer connected to the substation and this is seen in Table 4.23. The lost income for undelivered energy was averaged as $\frac{0.152+0.068}{2} = 0.11\ SEK/kWh$ and multiplied with the corresponding time in Table 4.24.

Table 4.23: Input parameters for undelivered energy during an outage.

Parameter	Average power consumption
800 kVA substation	9.75 kW
2×800 kVA substation	17.25 kW

Table 4.24: Reliability result and cost for each alternative and additional substation scenario.

Alternative	Annual outage time	Annual Cost
Alternative 1 with 800 kVA substation	13.43 min	5.76 SEK
Alternative 1 with 2 × 800 kVA substation	13.43 min	6.58 SEK
Alternative 2 with 800 kVA substation	14.25 min	6.11 SEK
Alternative 2 with 2 × 800 kVA substation	13.77 min	6.87 SEK

Net Present Value for the Two Alternatives

The annual income is based on the GENAB's 2013 rates with estimated maintenance costs included. The discount rate used in the calculations is 6 % which is the discount rate used by GENAB with investment calculations [34]. The monthly maximum power usage is modelled, as described in Section 3.8.2, as the average power used for different utilisation times. The chosen stations and their respective fuse and annual energy consumption is presented in Appendix B. The net present values for the alternatives are shown in Figures 4.4-4.7.

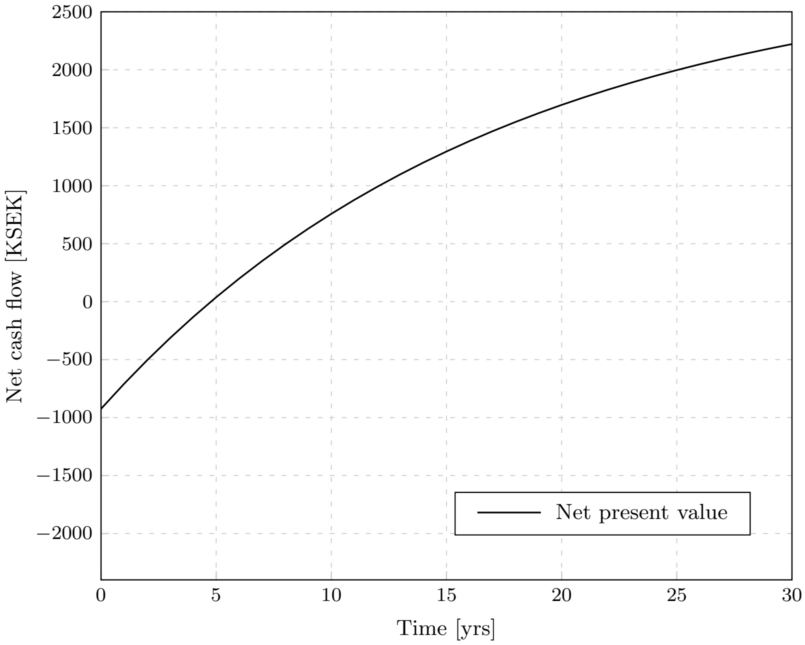


Figure 4.4: Net present value for Alternative 1 with 800 kVA substation using an average monthly power maximum.

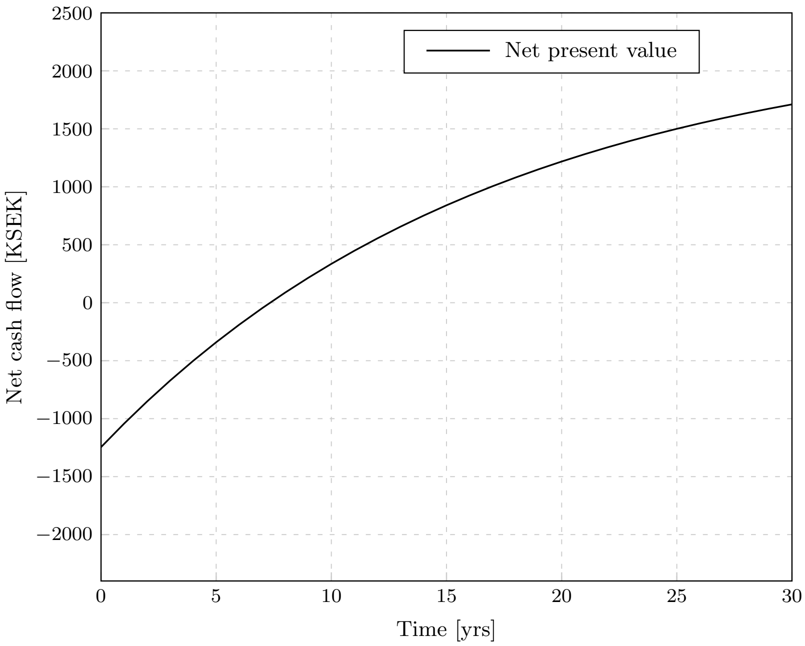


Figure 4.5: Net present value for Alternative 1 with 2 × 800 kVA substation using an average monthly power maximum.

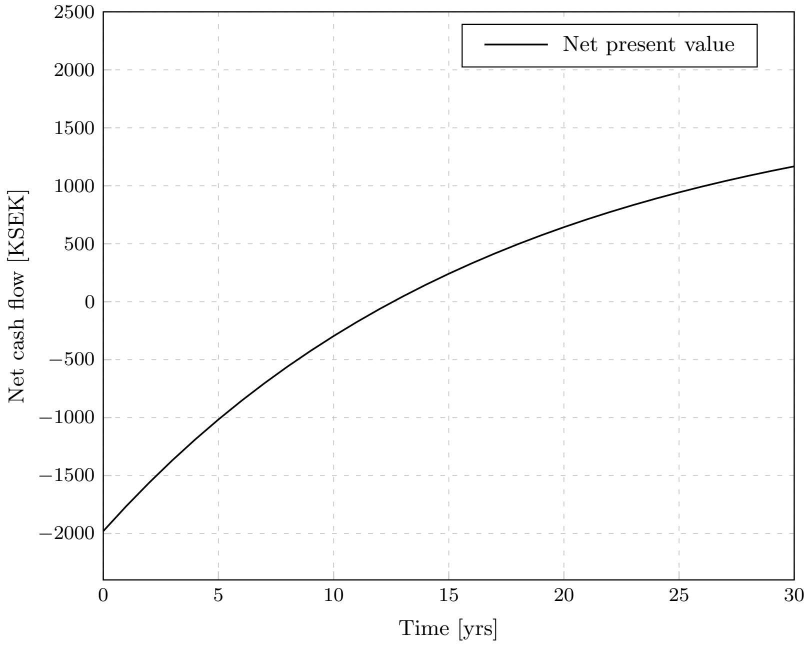


Figure 4.6: Net present value for Alternative 2 with 800 kVA substation using an average monthly power maximum.

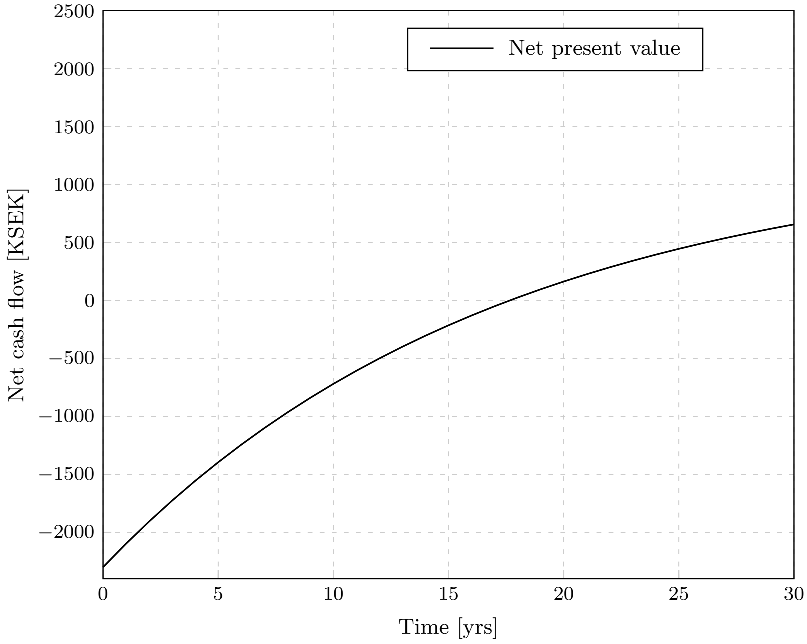


Figure 4.7: Net present value for Alternative 2 with 2 × 800 kVA substation using an average monthly power maximum.

4.5 Common Mode Failures

Table 4.25: The results when N-2 faults are included for Case 3 using the Markov modelling method.

	N-1 SAIDI	N-2 SAIDI	Difference	Difference
Without reserve generators	42.1 min	55.47 min	13.37 min	32 %

As can be seen in Table 4.25, there is an increase in SAIDI by 32 % if N-2 faults are included in the models. This increase is because of the high restoration time (118 hours) associated with a common mode cable fault since the section 2 can not supply all the substations in the loop. Since the maximum number of substations on each cable is modelled (Table 3.13, 11 substations in the first section, 10 substations in the second section and one substation on the reserve cable), the cable from distribution substation 2 in figure 3.3 does not have the capacity to provide electric power to all affected substations. If there are fewer substations on each cable, the second feeder would be able to provide power to all substations in case of a N-2 contingency and thereby SAIDI would be reduced. The maximum number of substations in each section in order to cope with a N-2 contingency and the result of this is presented in Table 4.26. The conclusion is that if there is a high occurrence of N-2 contingencies and it is important to keep SAIDI low, it is better to reduce the number of substations in each section to ensure that there is enough reserve capacity in each section case of a N-2 contingency. This is due to that the few available reserve generators to GENAB are seldomly utilised in the electric power system with loop configurations [36]. Reserve generators in Gothenburg are generally utilised during faults affecting secondary substations that are not configured as a loop and have no other path of reserve [36].

Table 4.26: Substation configuration ensuring that SAIDI is not increased with N-2 faults.

Substations in section 1	6
Substations in section 2	5
Substations on third leg	1
N-1 SAIDI	27.93 min
N-2 SAIDI	27.93 min

4.6 Sensitivity Analysis

In order to determine the influence of the input parameters in the models (presented in Table 4.1), such as failure rates and outage times, a sensitivity analysis was performed on the Markov models. It is especially important to include a sensitivity analysis when the uncertainty in the models is high, such as when probabilities and statistics are used [37]. Cases 1, 3, 4 and 6 from Section 3.1 were chosen as suitable systems to analyse. Case 1 was chosen since it is a common loop configuration used by GENAB. Case 3 is interesting since it utilises the reserve cable by adding a secondary substation. The reason that Case 4 was chosen is that it is similar to the system proposed in Section 3.8. A sensitivity analysis was performed on Case 6 due to the high number of components included. The systems were analysed for the City, Industry and Urban cases with the switching times being sourced from Table 4.1. The sensitivity analysis was performed using the brute force technique [37] and the input parameters were altered by ± 50 %, thereby determining their influence on SAIDI.

Table 4.27: The input parameters to the models

Faulty component	**Transition probability**	**Associated outage time**
Transformer	λ_T [faults/year]	r_T
Substation	λ_{Ss} [faults/year]	r_{Ss}
Cable	λ_C [faults/(year·km)]	r_{LDc}
Circuit breaker	λ_{CB} [faults/year]	r_{LDc}

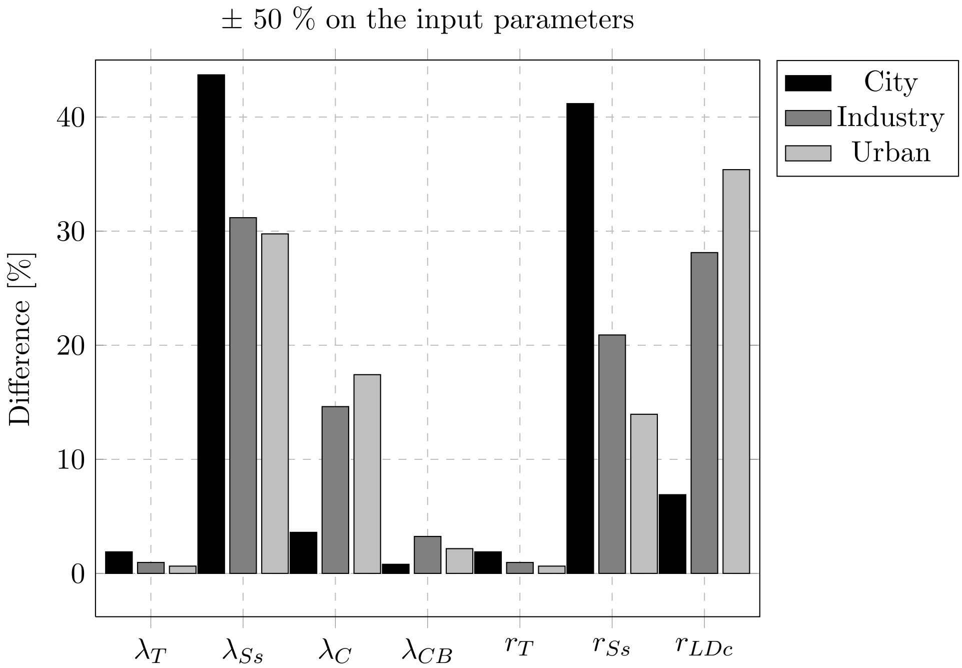


Figure 4.8: Identifying critical input parameters for Case 1 for the City, Industry and Urban area.

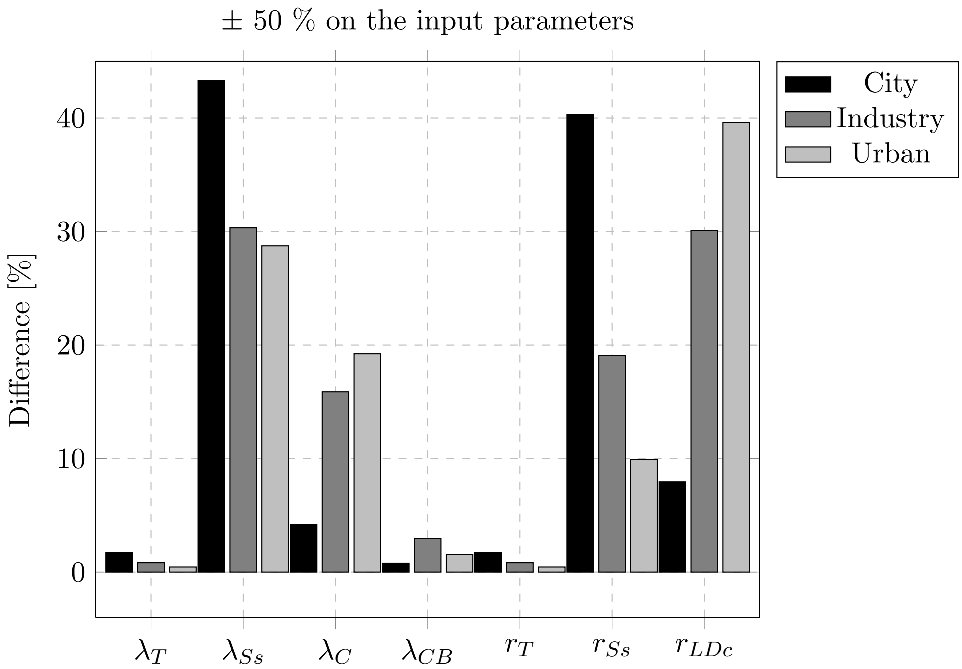


Figure 4.9: Identifying critical input parameters for Case 3 for the City, Industry and Urban area.

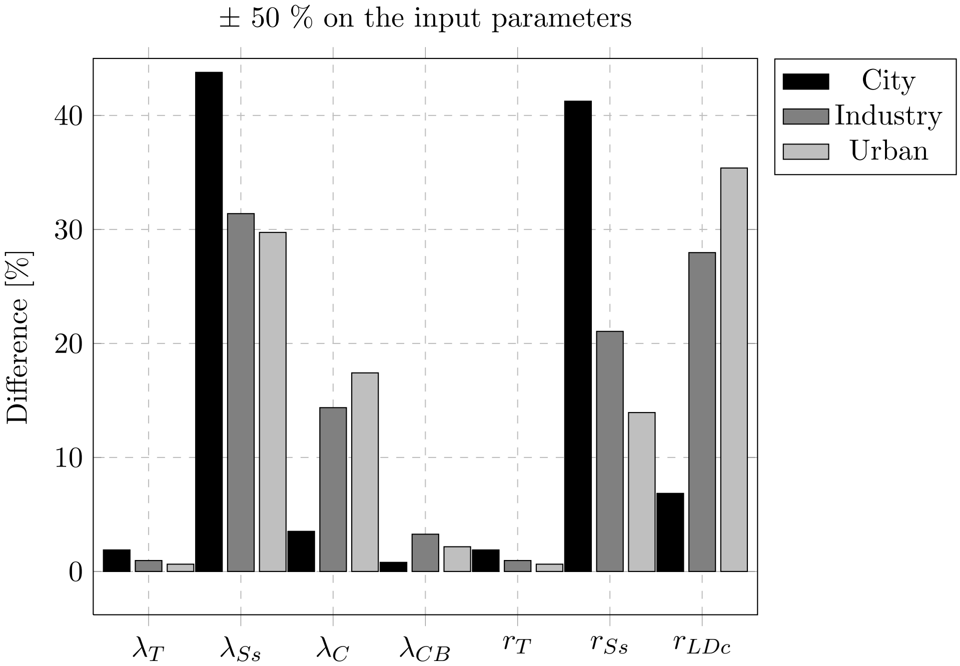


Figure 4.10: Identifying critical input parameters for Case 4 for the City, Industry and Urban area.

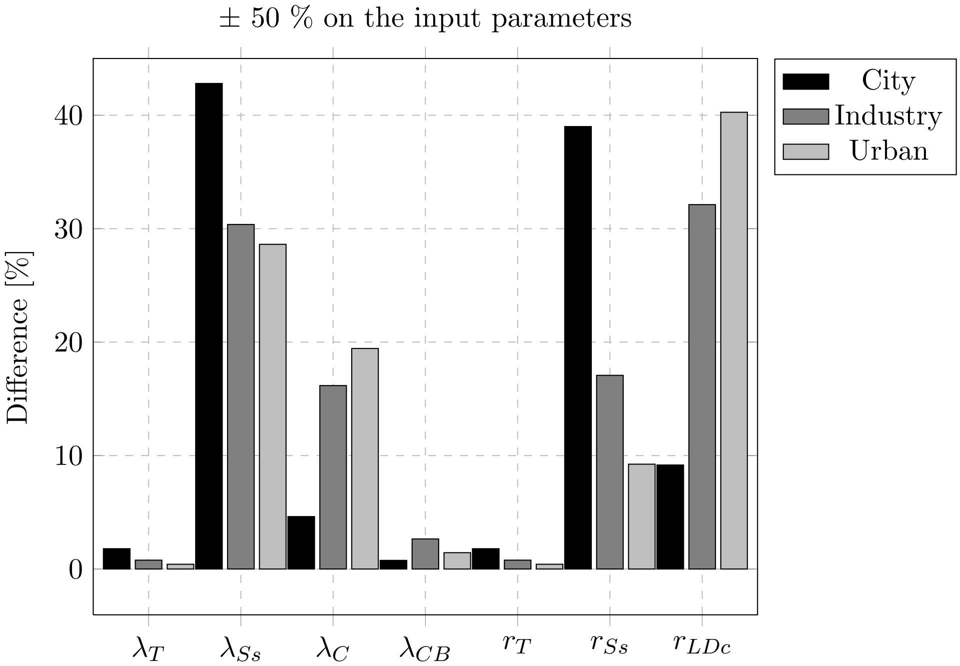


Figure 4.11: Identifying critical input parameters for Case 6 for the City, Industry and Urban area.

As seen in Figures 4.8-4.11, some parameters are more influential on the result than others. The difference in sensitivity between the City and Industry presented in Figure 4.8 shows that the switching time, r_{LDc}, has a strong influence on how much the input parameters influence the final outcome since the difference in the Industry and City models is switching time as well as number of connected customers per substation. The deviation between the Industry and Urban areas is smaller which supports the conclusion that it is the switching time that is the main difference between the City and Urban case and not the number of transformers per substation.

Figures 4.8-4.11 show that the substation failure rate, λ_{Ss} and the associated outage time, r_{Ss} have a major influence on SAIDI in the City areas. The substation failure rate is also a critical input parameters in the Industry areas but the switching time, r_{LDc}, is more influential than the substation outage time. In the Urban case it is the switching time, r_{LDc} and the substation failure rate λ_{Ss} that are the most critical and influential input parameters.

4.7 Discussion of Results

Apart from the sensitivity analysis, the results from Section 4.2-4.4 were also analysed and discussed with regard to their validity and significance.

4.7.1 Markov Modelling of Different Loop Configurations

Analysis of the results of the created Markov models presented in Table 4.7 shows correlation between the created mathematical Markov models for cases 1-6 and the simulated models in the NEPLAN simulation software. Since NEPLAN is proprietary software, it does not offer any way of knowing how the software does its calculations. Fuse failures are not modelled in the validation evaluation since NEPLAN does not support failures in the fuses. The probability of a fuse or disconnector failure is therefore included in the substation failure rate, λ_{Ss}. The absence of the modelling of fuses and disconnectors leads to less detail in the result. If fuses and disconnectors were included, the Markov models would become more complex to design with more states being needed to be added. The current Markov model for Case 6 is a 20×20 matrix and adding additional states would increase the complexity and time required for design.

The results in Figures 4.1a and 4.1c show that a large impact on SAIDI reduction is remote controlled disconnectors. The City area has very low variation in SAIDI even though the number of components and connected customers varies for the different cases. The Industry case in Figure 4.1c shows that using 2×800 kVA secondary substations impacts the customers less than single 800 kVA transformer secondary substations. The maximum number of stations presented in Table 3.13 are viable alternatives when planning new loops since the current and voltage drop limits are not reached. The six cases chosen for the Markov models are general and typical loop configurations in the Gothenburg area but do not represent all the available alternatives. If the models are to be used for applications in practice, they might need to be modified to represent the examined areas.

The results are highly influenced by the input parameters. It is therefore important to use accurate failure statistics and restoration times in order to get a useful result. If fault and restoration time statistics for the specific case are unavailable, it is possible to use industry standards, such as the ones presented in Table 4.23. Using industry standards gives the ability to compare different loop configurations but may not give a result that resembles reality. The benefit of using statistics from the analysed area is that the models can actually be used to find the specific impact on SAIDI that the loop configuration will have.

PM can be used to lower the frequency of failure [15] and the sensitivity analysis shows that the end result on SAIDI is highly influenced by failures within the substation. This is due to the fact that the restoration time is high for a failure within the substation as well as a relatively high failure frequency. By continuously maintaining the substations, a strong impact on SAIDI can be reduced.

4.7.2 Reserve Capacity With Respect to Load Variations Through Time

The results in Tables 4.9 and 4.13 show that it is possible and feasible to connect two sections of different loops with season varying loads, with a low probability of breaching the current limits of the cables. The times when the 270 A limit is breached is during switching operations with the cables acting in reserve to each other and the probability of this happening in the chosen loop is very low. The effect of adding a 800 kVA secondary substation to the chosen cable showed a 33 % increase in potential time that it would be breaching the 270 A limit. The probability of 0.28 % is still very small however and even smaller (0.09 %) if the median value is analysed instead of the mean. The case is chosen specifically due to the nature of the customer's loads and if the load profile of the customers changed, the case would have to be reevaluated.

The economical analysis shows that the option of adding a reserve cable is more costly than connecting two nearby loops together. The net present value shows that the investment of connecting the two loops paid off after 5 years for the scenario of adding a 800 kVA secondary substation or 7 years for a 2×800 kVA secondary substation. If a reserve cable is built it would take 12 years for the investment to pay off for the 800 kVA substation and 17 years for the additional 2×800 kVA substation, given that there is no change in income from new customers. If there is a change in income from the customers, e.g. the load goes up in the future, Alternative 2 is the most suitable choice. This is due to that Alternative 2 allows an increase of 135 A load on both cable C_A and cable C_B without affecting the reliability or current limits. Alternative 1 does not offer this increase in load without affecting the integrity of the cables' insulation. The investment and cost calculations are based on average costs as well as averaged income from customers. The chosen discount rate of 6 % also affects the outcome and only provides an estimate of the cost over the 30 years evaluated. The cost of the outages is also dependent on if the power outage for the customer lasts more than 12 hours. The outage cost increases significantly if the outage is longer than 12 hours since the customer has a right to be reimbursed. This should be included if a more detailed investment calculation is required.

Even though the probability of overloading a cable is low using the configuration in Alternative 1, the risk of overloading the cable still exists. The consequence of overloading the cable depends on the amplitude of the current as well as the time that the cable is exposed to the current. The dissipated power that needs to be cooled within the cable rises quadratically ($P = I^2R$) and current variations can therefore result in high temperature variations. The time is important since there is a thermal constant related to how quickly the temperature of the insulation material changes [27]. The ability for the cable to dissipate its power is also dependent on the temperature of the surrounding earth as well as the thickness of the insulation. A temperature that is over the maximum operating temperature of 90 °C will reduce the lifetime of the cable [25]. This is due to the Arrhenius relationship between temperature and lifetime for XLPE-cables, seen in Figure 2.2. These are all aspects that need to be taken into consideration when calculating the risk associated with Alternative 1.

A worst case scenario was found for Alternative 1 and the two substation scenarios. For the scenario of the 800 kVA substation, it was found that if the cable was overloaded with a current of 300 A for four consecutive hours, the final temperature would be 97.6 °C. For the 2 × 800 kVA substation scenario, the current would be 320 A. This current overload resulted in a final temperature of 103.2 °C. As described in Section 2.4, the temperature of the XLPE insulation is allowed to reach 105 °C for limited time emergencies without affecting the lifetime of the cable as long as the overload does not last longer than four hours. The worst case overload scenario found for the 2 × 800 kVA scenario showed that the cable would be very near the temperature limit during a current overload. Even though the temperature and time limit is not exceeded, it is very close to the limit. It would instead be safer to utilise the 800 kVA substation scenario where the temperature during the four hour current overload would be 97.6 °C which is lower than the 105 °C limit.

Chapter 5

Closure

This chapter draws conclusions as well as an introduction to potential future work and refinements of the proposed models.

5.1 Conclusions

The aim of this thesis project, described in Section 1.2, has been fulfilled by examining general and applicable loop configurations in the Gothenburg electric power system as well as proposing a number of dimensioning criteria for loop configurations. It can be concluded that the Markov models created for the different loop configurations and areas are feasible and accurate. The models are able to calculate the resulting SAIDI and implications for the customers for the different configurations and related input parameters. The sensitivity analysis in Section 4.6, shows that the input parameters have a varying influence on the end result. It is especially important to have accurate failure statistics and associated restore times for the components within the substations in order for the result to be accurate. Another conclusion from the results is the impact that the remote controlled load disconnectors have on the reduction of SAIDI for the examined cases and areas. Remote controlled disconnectors reduces SAIDI and lowers the variation in SAIDI between the different loop configurations.

The results in Section 4.4 show that there are two feasible alternatives to provide reserve capacity to the examined case. The most viable choice is influenced on how many customers that are to be connected as well as the needed level of reliability and reserve capacity. The number of customers connected and their power consumption impacts both the investment for the necessary installed electric power capacity but also the future monetary income to GENAB. More thorough investment calculations should be made if they are to be used as a basis for investments in practice. If *Alternative 1* is chosen, it is important to evaluate the potential rise above maximum temperature for the underground cables that the uncommon, temporary overloading would result in. If a 800 kVA substation is added the potential worst case overload temperature is 97.6 °C. This is lower than the 103.2 °C temperature that would be the result if a 2 × 800 substation had been utilised. Both of these overload temperatures are below the 105 °C limit but it would be result in lower risk to only add an additional 800 kVA substation instead of a 2×800 kVA substation.

Common mode faults that hinder the N-2 criteria from being fulfilled can be very problematic for the power system and can have a large influence on SAIDI if the outage time to the customer is high. Risk can be calculated as consequence times probability [18]. Even though the probability of a common mode fault is low relative to an independent fault, the consequence of a common mode fault can be very high. By lowering the number of substation per section, common mode faults can be handled without increasing SAIDI compared to single mode failures. This is a better design if the reserve cable and first section feeder cable lie in parallel in the same underground trench.

5.2 Future Work

This thesis presents and proposes Markov models for six cases with three different load profiles. Future work could include more detailed Markov models with more components and states as well as additional loop configurations. By making the models more detailed it is simpler to identify the critical components in the system. Identification of the critical components is important in order to achieve reliability centred maintenance [15]. Other future work could include incorporating small scale electricity generation such as local wind turbines or solar plants and their effect on the EPS reliability. This could be combined with possible distributed energy storage scenarios that might be able to act as a reserve power source and thereby reduce outage times. Since outage times and failure rates are important for an accurate result, future work could also include more detailed analysis of the failure rates and outage times.

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Appendix A

Markov Models for the Different Cases and Areas

The Markov models for the different areas and cases are presented in appendix A. Due to space limitations, the Markov matrices for cases 4-6 are not included. The specified states are included however.

A.1 Markov Models for Case 1

Markov Models for the City and Industry Areas for Case 1

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.

Table A.1: Markov matrix for Case 1 for the City and Industry areas.

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
0	$1 - \lambda_{00}$	$2(N + M)\lambda_T$	0	$\lambda_{C1} + N\lambda_{C2} + \lambda_{CB}$	$N\lambda_{Ss}$	$2(N + M)\lambda_{Fu}$	$\lambda_{C1} + (M - 1)\lambda_{C2} + \lambda_{CB}$	$M \cdot \lambda_{Ss}$
1	μ_T	$1 - \mu_T$	0	0	0	0	0	0
2	μ_{Ss}	0	$1 - \mu_{Ss}$	0	0	0	0	0
3	μ_{LDc}	0	0	$1 - \mu_{LDc}$	0	0	0	0
4	0	0	μ_{LDc}	0	$1 - \mu_{LDc}$	0	0	0
5	μ_{Fu}	0	0	0	0	$1 - \mu_{Fu}$	0	0
6	μ_{LDc}	0	0	0	0	0	$1 - \mu_{LDc}$	0
7	0	0	μ_{LDc}	0	0	0	0	$1 - \mu_{LDc}$

Markov Models for the Urban Area for Case 1

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.

Table A.2: Markov matrix for Case 1 for the Urban area

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
0	$1-\lambda_{00}$	$(N+M)\lambda_T$	0	$\lambda_{C1}+N\lambda_{C2}+\lambda_{CB}$	$N\lambda_{Ss}$	$(N+M)\lambda_{Fu}$	$\lambda_{C1}+(M-1)\lambda_{C2}+\lambda_{CB}$	$M\cdot\lambda_{Ss}$
1	μ_T	$1-\mu_T$	0	0	0	0	0	0
2	μ_{Ss}	0	$1-\mu_{Ss}$	0	0	0	0	0
3	μ_{LDc}	0	0	$1-\mu_{LDc}$	0	0	0	0
4	0	0	μ_{LDc}	0	1 - μ_{LDc}	0	0	0
5	μ_{Fu}	0	0	0	0	$1-\mu_{Fu}$	0	0
6	μ_{LDc}	0	0	0	0	0	$1-\mu_{LDc}$	0
7	0	0	μ_{LDc}	0	0	0	0	$1-\mu_{LDc}$

A.2 Markov Models for Case 2

Markov Models forr the City and Industry Areas for Case 2

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.

Table A.3: Markov matrix for Case 2 for the City and Industry areas.

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
0	$1-\lambda_{00}$	$2(N+M)\lambda_T$	0	$\lambda_{C1}+N\lambda_{C2}+\lambda_{CB}$	$N\lambda_{Ss}$	$2(N+M)\lambda_{Fu}$	$\lambda_{C1}+(M-1)\lambda_{C2}+\lambda_{CB}$	$M\cdot\lambda_{Ss}$
1	μ_T	$1-\mu_T$	0	0	0	0	0	0
2	μ_{Ss}	0	$1-\mu_{Ss}$	0	0	0	0	0
3	μ_{LDc}	0	0	$1-\mu_{LDc}$	0	0	0	0
4	0	0	μ_{LDc}	0	1 - μ_{LDc}	0	0	0
5	μ_{Fu}	0	0	0	0	$1-\mu_{Fu}$	0	0
6	μ_{LDc}	0	0	0	0	0	$1-\mu_{LDc}$	0
7	0	0	μ_{LDc}	0	0	0	0	$1-\mu_{LDc}$

Markov Models for the Urban Area for Case 2

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.

Table A.4: Markov matrix for Case 2 for the Urban area

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
0	$1-\lambda_{00}$	$(N+M)\lambda_T$	0	$\lambda_{C1}+N\lambda_{C2}+\lambda_{CB}$	$N\lambda_{Ss}$	$(N+M)\lambda_{Fu}$	$\lambda_{C1}+(M-1)\lambda_{C2}+\lambda_{CB}$	$M\cdot\lambda_{Ss}$
1	μ_T	$1-\mu_T$	0	0	0	0	0	0
2	μ_{Ss}	0	$1-\mu_{Ss}$	0	0	0	0	0
3	μ_{LDc}	0	0	$1-\mu_{LDc}$	0	0	0	0
4	0	0	μ_{LDc}	0	1 - μ_{LDc}	0	0	0
5	μ_{Fu}	0	0	0	0	$1-\mu_{Fu}$	0	0
6	μ_{LDc}	0	0	0	0	0	$1-\mu_{LDc}$	0
7	0	0	μ_{LDc}	0	0	0	0	$1-\mu_{LDc}$

A.3 Markov Models for Case 3

Markov Models for the City and Industry Areas for Case 3

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: The substation on the reserve cable is affected by cable fault.

Table A.5: Markov matrix for Case 3 for the City and Industry areas.

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
0	$1-\lambda_{00}$	$2(N+M)\lambda_T$	0	$\lambda_{C1}+N\lambda_{C2}+\lambda_{CB}$	$N\lambda_{Ss}$	$2(N+M)\lambda_{Fu}$	$\lambda_{C1}+(M-1)\lambda_{C2}+\lambda_{CB}$	$M\cdot\lambda_{Ss}$	$\lambda_{C1}+\lambda_{C2}+\lambda_{CB}$
1	μ_T	$1-\mu_T$	0	0	0	0	0	0	0
2	μ_{Ss}	0	$1-\mu_{Ss}$	0	0	0	0	0	0
3	μ_{LDc}	0	0	$1-\mu_{LDc}$	0	0	0	0	0
4	0	0	μ_{LDc}	0	1 - μ_{LDc}	0	0	0	0
5	μ_{Fu}	0	0	0	0	$1-\mu_{Fu}$	0	0	0
6	μ_{LDc}	0	0	0	0	0	$1-\mu_{LDc}$	0	0
7	0	0	μ_{LDc}	0	0	0	0	$1-\mu_{LDc}$	0
8	μ_{LDc}	0	0	0	0	0	0	0	$1-\mu_{LDc}$

Markov Models for the Urban Area for Case 3

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: The substation on the reserve cable is affected by cable fault.

Table A.6: Markov matrix for Case 3 for the Urban area

State	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
0	$1-\lambda_{00}$	$2(N+M)\lambda_T$	0	$\lambda_{C1}+N\lambda_{C2}+\lambda_{CB}$	$N\lambda_{Ss}$	$2(N+M)\lambda_{Fu}$	$\lambda_{C1}+(M-1)\lambda_{C2}+\lambda_{CB}$	$M\cdot\lambda_{Ss}$	$\lambda_{C1}+\lambda_{C2}+\lambda_{CB}$
1	μ_T	$1-\mu_T$	0	0	0	0	0	0	0
2	μ_{Ss}	0	$1-\mu_{Ss}$	0	0	0	0	0	0
3	μ_{LDc}	0	0	$1-\mu_{LDc}$	0	0	0	0	0
4	0	0	μ_{LDc}	0	1 - μ_{LDc}	0	0	0	0
5	μ_{Fu}	0	0	0	0	$1-\mu_{Fu}$	0	0	0
6	μ_{LDc}	0	0	0	0	0	$1-\mu_{LDc}$	0	0
7	0	0	μ_{LDc}	0	0	0	0	$1-\mu_{LDc}$	0
8	μ_{LDc}	0	0	0	0	0	0	0	$1-\mu_{LDc}$

A.4 Markov Models for Case 4

Markov Models for the City and Industry Areas for Case 4

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.

Markov Models for the Urban Area for Case 4

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.

- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: The substation on the reserve cable is affected by cable fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.

A.5 Markov Models for Case 5

A fault on the reserve cable does not affect the customers and therefore there is no need to specify a state for a fault on the reserve cable.

Markov Models for the City and Industry Areas for Case 5

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.

Markov Models for the Urban Area for Case 5

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.
- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: The substation on the reserve cable is affected by cable fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.

A.6 Markov Models for Case 6

Markov Models for the City and Industry Areas for Case 6

- 0: Normal operation
- 1: Half the substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: Half the substation is affected by a fuse fault.

- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.
- 12: All substations in section 5 and their customers are affected by a cable or circuit breaker fault.
- 13: All substations in section 5 are affected by a disconnector or busbar fault.
- 14: All substations in section 6 and their customers are affected by a cable or circuit breaker fault.
- 15: All substations in section 6 are affected by a disconnector or busbar fault.
- 16: All substations in section 7 and their customers are affected by a cable or circuit breaker fault.
- 17: All substations in section 7 are affected by a disconnector or busbar fault.
- 18: All substations in section 8 and their customers are affected by a cable or circuit breaker fault.
- 19: All substations in section 8 are affected by a disconnector or busbar fault.

Markov Models for the Urban Area for Case 6

- 0: Normal operation
- 1: One whole substation is affected by a transformer fault.
- 2: One whole substation and its customers are affected by a disconnector or busbar fault.
- 3: All substations in section 1 and their customers are affected by a cable or circuit breaker fault.
- 4: All substations in section 1 are affected by a disconnector or busbar fault.
- 5: One whole substation is affected by a fuse fault.

- 6: All substations in section 2 and their customers are affected by a cable or circuit breaker fault.
- 7: All substations in section 2 are affected by a disconnector or busbar fault.
- 8: The substation on the reserve cable is affected by cable fault.
- 8: All substations in section 3 and their customers are affected by a cable or circuit breaker fault.
- 9: All substations in section 3 are affected by a disconnector or busbar fault.
- 10: All substations in section 4 and their customers are affected by a cable or circuit breaker fault.
- 11: All substations in section 4 are affected by a disconnector or busbar fault.
- 12: All substations in section 5 and their customers are affected by a cable or circuit breaker fault.
- 13: All substations in section 5 are affected by a disconnector or busbar fault.
- 14: All substations in section 6 and their customers are affected by a cable or circuit breaker fault.
- 15: All substations in section 6 are affected by a disconnector or busbar fault.
- 16: All substations in section 7 and their customers are affected by a cable or circuit breaker fault.
- 17: All substations in section 7 are affected by a disconnector or busbar fault.
- 18: All substations in section 8 and their customers are affected by a cable or circuit breaker fault.
- 19: All substations in section 8 are affected by a disconnector or busbar fault.

Appendix B

Analysed 800 kVA and 1600 kVA Substations

Table B.1: Customers connected to substation Ss_6, the analysed 800 kVA substation.

ID	Fuse [A]	Annual consumption [kWh]
735999166203246235	160	40000
735999166203246907	200	221890
735999166204547232	750	746900
735999166203246938	16	6878
735999166203246846	125	268580
735999166203246853	50	25389
735999166203246242	250	179020
735999166203246891	50	20899
735999166203246877	50	14329
735999166203246822	50	15639
735999166204648694	50	69824
735999166203246433	16	224
735999166203246280	35	33870
735999166203246600	25	33
735999166203246327	50	62126
735999166203246303	160	37584
735999166203246617	160	12000
735999166203246297	35	57848
735999166203246310	125	166670
735999166300160113	35	31032
735999166203246273	63	780
735999166204765261	25	4707
735999166204550423	35	30710
735999166203246921	20	4469

Table B.2: Customers connected to substation Ss_2, the analysed 2×800 kVA substation.

ID	Fuse [A]	Annual consumption [kWh]
735999166204112317	250	471090
735999166204735127	16	14553
735999166203246259	500	172760
735999166204378249	20	38712
735999166204112300	500	825390
735999166203980979	25	20612
735999166204947575	360	276670
735999166204947674	125	96330
735999166204365003	20	9146
735999166203875381	63	23224
735999166203246990	160	145220
735999166203246976	100	116730
735999166204073274	35	44386
735999166204752254	16	6974
735999166204215261	16	5466