Evaluating the detail level of reliability analyses used in the investment planning at Fortum Distribution AB

Sabina Stenberg

KTH VETENSKAP OCH KONST

KTH Electrical Engineering

Master Thesis
Stockholm, Sweden 2009

XR-EE-ETK 2012:003

The department of Electromagnetic Engineering

Electrical Engineering

The Royal Institute of Technology, KTH

Examiner:

Patrik Hilber

April 2012

Acknowledgements

I would like to thank my supervisor at KTH, Carl Johan Wallnerström, for his constant support, no matter what the hour. I would like to thank my supervisor at Fortum Distribution AB, Olle Hansson, who knows exactly who to talk to and why.

This master thesis project is heavily based on interviews with people at Fortum Distribution AB. I have peeked over the shoulder of the power systems operators in the network control room, walked along the power lines with fitters in the field and spent entire days interrogating net planners, process managers and asset managers about the grid and the fault management. Throughout the project everyone I have met has been very helpful and eager to tell me about their job. I owe everyone a big thank you.

A very special thank you to Henrik Rinnemo, for voluntarily giving so much of his time to answering my questions, helping me solve problems and discussing the asset management at Fortum.

Another special thank you to Daniel Heidkamp who took his time to show me the actual electric grid, beyond the computer screens and network plans. Mats Estéen for letting me watch him work in the control center. Bo Andersson for spending a day with me talking about fault management. Ove Levein for explaining all about the Lesjöfors project to me, and many others for providing me with data and answering all of my many questions.

During the five months I've been at Fortum Distribution I have learned a lot, about the electric grid as well as the work at a DSO. This has been a sneak peek on the life as an electrical engineer, which has made me even more eager to start my career. In addition to all of this, I had a lot of fun!

Abstract

This master thesis project is a cooperation between Fortum Distribution AB and The Royal Institute of Technology (KTH).

When maintaining and operating a power distribution system, which is the task of Fortum Distribution AB, the aim is to always be able to deliver electric energy to the customers. A 100% reliability is however not a realistic goal since too high reliability would cost too much. The net planners at Fortum have to choose the most cost effective investments. Due to the complexity of the power system, grid analyses are expensive and simplifications have to be made.

In this master thesis it is examined if Fortum Distribution AB's methods for prioritizing between different reliability investments for the rural power distribution system are detailed enough to give the same result as more complex methods.

This is done by creating theoretical models of two 11 kV lines out of two different substations in a rural part of Fortum's grid.

The fault management process at Fortum Distribution AB is thoroughly described and implemented in the theoretical models of the two case lines. The time it takes to perform specific tasks in the fault management are listed for future reference.

A couple of investments for better reliability are applied to the case lines. The effect on reliability and cost efficiency of different investments allow for the investments to be prioritized after which are better to implement.

One of the case lines is in an area where reliability investments have already been performed. This line is chosen because the results from the analysis then can be compared to the real investments. To test and apply the result the other case study is performed on an area that has not yet been renovated. For this case line cost-efficient investments are recommended.

The conclusion of the analyses is that the detail level of the analyses made by Fortum Distribution AB most likely are sufficient for today's grid. However, because of the ongoing project to weather-secure the grid, changing overhead lines for underground cables is the number one priority. The analysis in this thesis could have reflected the effect of extreme weather better, but even so, the result shows such a significantly lower cost-efficiency for investing in cables that it might be favorable for Fortum Distribution AB to review the benefits of changing overhead lines for underground cables. In some cases other investments might be more beneficial.

List of tables

List of figures

English – Swedish dictionary

English	Swedish	Description
Professions		
Fitter	Montör	The person in the field, repairing and maintaining the grid
Net planner	Nätplanerare	The person planning investments in and reconstructions of the grid
Power systems operator	Driftoperatör	The person operating the grid from the control center, not to be confuse with Distribution System Operator which is the company delivering the electricity
Location		
Network control center	Driftcentral	The place where the grid is operated from
Components		
Aerial cable	Hängkabel	A cable hung on poles
Availability	Tillgänglighet	Percentage of the time when the system or component is working
Breaker	Brytare	Located in the substation, cuts the power automatically
Cable	Kabel	An underground feeder, if not otherwise stated
Fuse	Säkring	Protection device. Burns off and breaks the power if a short circuit fault occurs. Ground faults go unnoticed by the fuse
Line	Linje	One feeder out of a substation
Manual disconnector	Manuell frånskiljare	Power switches located here and there along the line that has to be manually opened and closed
Open point	Öppen punkt	At some places along the line there might be an open disconnector or breaker between the line and an adjacent line
Overhead line	Luftledning	Uninsulated line that will short circuit if the lines connect
Radial line	Radiell ledning	The radial lines are the branches sticking out of the main line
Remote controlled disconnector	Fjärrfrånskiljare	Power switch that can be operated from the control center
Secondary feeding	Sekundär matning	By closing the disconnector at the open point the customers can be supplied with electricity from the adjacent line instead of the default source
Secondary substation	Nätstation	Distributing the power from the medium voltage lines to the low voltage grid
Substation	Fördelnings-station	Distributing the power from the high voltage grid down to the lines on medium voltage
Unavailability	Otillgänglighet	Percentage of the time the system or component is failing
Economics		
Annuity method	Annuitetsmetod	A cost depreciated by the annuity method will be depreciated with the same amount every year
Capital base	Kapitalbas	The value of all assets in the company
Depreciation	Avskrivning	The cost of an asset is recorded as yearly depreciations
Energy Markets Inspectorate (EI)	Energimarknads inspektionen	The regulating authority for the DSOs
Life cycle cost analysis	Livscykel-kostnadsanalys	An analysis of the total costs and income of an investment (here) over its entire life length

Net present value method	Nuvärdes-metoden	Annual costs or income are re-calculated in today's value
Net tariffs	Nättariffer	What customers pay for the service of having electric energy delivered, separate from the cost of electricity production
Purchase value	Nuanskaffnings-värde	The cost of acquiring the assets if they were acquired today
Return on capital	Avkastning	The owners demand for cost of restricted capital
Revenue framework	Intäktsram	Restrictions on revenue from the EI
Swedish Energy Agency (STEM)	Energimyndigheten	
Fault Management		
Cable bus	Mätbuss	Advanced and expensive measurement equipment is kept in a bus to be able to use it on several locations
Fault notation	Kopplingssedel	A document for keeping record of all the switching of breakers and disconnector
Network plan	Nätschema	A drawing of how the secondary substations are connected and where the disconnectors are located
Residential grid	Fastighetsnät	Out of Fortum's area of responsibility
Sectioning	Sektionering	Isolating a fault with the disconnectors and connecting secondary feeding to the rest of the customers
Splicing a line	Skarva en ledning	Necessary for example when the line is broken off by a tree

Abbreviations and variables

AENS	**Average Energy Not Supplied**
CAIDI	Customer Average Interruption Duration Index
COMin	Customer outage minutes
DSO	Distribution System Operator
ENS	Energy Not Supplied
LV	Low voltage
MDT	Mean Down Time
MTTF	Mean Time to Failure
MV	Medium voltage
NPAM	Network Performance Assessment Model
OH line	Overhead line
PG	Power Grid (Computer tool)
r	Restoration time
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TSO	Transmission System Operator
λ	Failure rate

Contents

Sammanfattning

Denna svenska sammanfattning av examensarbetet riktar sig kanske främst till personer på Fortum eller den som annars har en inblick i arbetet på ett elnätsföretag.

Det här examensarbetet är ett samarbete mellan Fortum Distribution AB och KTH. Målet med examensarbetet är att undersöka om Fortum Distibution AB's metoder för att prioritera mellan olika investeringar för bättre tillförlitlighet på lokala landsbygdsnät ger samma resultat som mer komplexa metoder.

Projektet har genomförts genom att göra teoretiska modeller av två linjer i Fortums nät. Den ena, 102A Lesjöfors, är en linje där omfattande upprustningar redan genomförts. Där görs modellen av hur linjen såg ut innan den byggdes om för att sedan kunna jämföras mot verkligheten. Den andra linjen, 020E Charlottenberg, är en linje som är i behov av renovering. För denna linje kommer rekommendationer baserade på resultatet av denna studie att ges.

Indata till modellerna är felintensiteter för ett par olika komponenter och åtgärdstiderna för att återställa funktionen då ett avbrott inträffat. Komponenterna som beaktas är luftledningar, kablar, brytare, frånskiljare och lågspänningskomponenter (vars felintensitet aggregeras till en). Felintensiteterna uppskattas från historiska data över avbrott i området. Ett mål är att använda så lokala avbrottsdata som möjligt för att spegla de lokala variationerna av hur ofta fel inträffar. Åtgärdstiderna har uppskattats genom intervjuer med nätplanerare, driftoperatörer och montörer på Fortum och Infratek. Infratek är ett bolag som bygger och underhåller infrastruktur.

Linjen delas upp i olika segment efter var frånskiljarna sitter placerade, och kunderna som bor mellan samma två frånskiljare slås samman till en s.k. lastpunkt. För varje lastpunkt beräknas felintensitet och åtgärdstid för olika typer av felfall, som t.e.x. fel på luftledning. För varje lastpunkt beräknas det total antalet avbrott och den totala tiden då lastpunkten varit utan ström. Dessa multipliceras sedan med antalet kunder vid varje lastpunkt, och det totala antalet kundavbrott och kundavbrottstimmar används sedan för att beräkna SAIFI och SAIDI (se definition i avsnitt 2.1).

Ett antal olika investeringsscenarier undersöks för linjen. De olika investeringsalternativen är både vanliga typer av investeringar, så som kablifiering, men även lite nyare investeringar undersöks. Att sänka spänningen på en mindre radiell ledning till 1 kV och att installera en linjebrytare är exempel på sådana investeringar som ännu inte har användts speciellt mycket. Utöver dessa investeringar undersöktes även alternativet att uppgradera de manuella frånskiljarna till automatiska och att lägga till en möjlighet till sekundär matning.

Kablifiering var den investering som tidigare har utförts på den verkliga Lesjöforslinjen. En modell gjordes därför även av Lesjöforslinjen som den ser ut idag. På så vis kunde den i verkligheten genomförda investeringen jämföras mot de teoretiska investeringarna. Övriga investeringar beräknades genom att modifiera de befintliga modellerna för linjerna.

För investeringarna beräknas nya SAIFI och SAIDI, samt minskningen av kundavbrottsminuter. En LCC-analys görs av kostnader och inkomster från investeringarna under dess livslängd, som antas vara 40 år. I den totala kostnaden ingår investeringskostnad, underhållskostnader, kundavbrottsersättningar för långa avbrott och förändringar på intäktsramen via regleringen. Förändringarna på intäktsramen beror dels av en kvalitetsjustering baserat på hur mycket SAIFI och SAIDI har sänkts, dels på om kapitalbasen ändras genom investeringen.

Med de totala kostnaderna och sänkningen av kundavbrottsminuter tas nyckeltalen SEK/kundavbrottsminut och SEK/isolerad km ledning fram. Dessa nyckeltal används av Fortum i investeringsplaneringen. Investeringarna sorteras sedan efter kostnadseffektivitet. Slutsatserna av projektet kan sammanfattas i ett antal punker:

- Vädersäkring har högsta prioritet inom investeringsplaneringen på Fortum idag. Analyserna i detta examensarbete kunde ha speglat effekten av extremväder starkare. Trots detta är kostnadseffektiviteten för kablifiering så signifikant mycket lägre än för de andra investeringarna att det kan vara värt för Fortum att räkna på vinsterna med att kablifiera för att se om det kanske finns situationer där andra investeringar hade varit lönsammare.
- I Fortums analyser görs flera förenklingar, bl.a. att kablar är felfria. Beräkningarna i denna rapport har visat att kablar har mycket liten effekt på systemets tillförlitlighet och att denna förenkling nog kan anses vara acceptabel. Detta kan dock komma att förändras. Om kablifieringen av nätet fortsätter kommer en större och större del av det bestå av kabel. Detta gör att kablarnas felintensitet får en allt större procentuell betydelse. Det kan vara värt att fundera på hur detaljerade beräkningar man bör ha på sikt om luftledningsnäten byggs bort.
- Regleringen har en mycket stor påverkan på hur kostnadseffektiva investeringar blir. Det är därför fördelaktigt att ta med regleringens inverkan i beräkningarna för att kunna avgöra vilken investering som ger bäst resultat. Regleringen av elnätsföretagen har dock, och kan komma att, skifta och det är inte säkert att de regler som gäller idag även gäller nästa reglerperiod. Därför kan det även vara bra att välja investeringar vars lönsamhet inte rasar om en förändring av regleringen skulle ske, med tanke på att livslängden på investeringen beräknas vara 40 år.

1. Introduction

In this chapter the background and purpose of the project will be explained.

1.1. Background

The task of a distribution system operator (DSO) is to provide the service of delivering electric energy to its customers. When electric components fail and cause power outages the task of the distribution system operator cannot be fulfilled, which leads to dissatisfied customers and increased costs. It is therefore important to maintain and upgrade the electric grid in order to prevent power outages and to keep a suitable level of reliability in the system. The net planners at the DSO have to choose between different kinds of investments to lower the number and lengths of power outages, because it is not preferable to invest too much in increasing the reliability of the power supply either. In the end, the customers are the ones paying for the investments and the reliability must be in level with what they are willing to pay for. The net planners have to prioritize the most cost effective reliability investments.

Electric power systems are complex and intertwined, and can therefore be hard to analyze. They consist of a vast number of different components that affect each other. When making calculations of the grid, simplification is a must. The challenge is to find the level of complexity that is required to make good-enough analyses of the grid. The more complex the analysis is, the more expensive it gets. There is a trade-off between less costly analyses and better result. In this master thesis it is examined if Fortum Distribution AB's methods for prioritizing between different reliability investments are detailed enough to give the same result as more complex methods.

Even in the world of science and research, the models of the electric grid are still simplified images of the actual grid. The analyses contain many assumptions and estimations of the operation of the grid. The opportunity of having access to data and to people working with fault management on a daily basis has been used to describe and implement the fault management into the theoretical models.

1.2. Purpose

One of the main purposes of this master thesis project is to examine if more detailed methods of prioritizing different reliability investments would render recommendations of other investments than the ones implemented by Fortum.

A purpose of this thesis is also to describe the fault management at a DSO in detail and to implement it in a reliability analysis of a part of Fortum's grid.

The investments examined in this thesis are chosen to be investments that are new or in other ways interesting for Fortum to have evaluated.

In addition, observations made during the course of the project, that could be of use for either Fortum Distribution AB or KTH, will also be documented.

2. Reliability theory and incentives for improving the reliability

This chapter addresses the theory necessary for the project.

2.1. Reliability theory

A large part of Chapter 2 is based on Billinton's Reliability Evaluation of Power Systems [1].

In order to quantify the reliability of a system a stochastic model of the electric grid can be made, where the functionality of each component is described by a probability distribution. Availability, i.e. the probability that the component is operational at time *t* will depend on how often it fails, and the time it takes to repair it. The life length of a component is the time before the component fails for the first time. The expected value of the probability distribution of the life length will according to the law of large numbers go to the average of all lifetimes for *n* components of the same type as $n \to \infty$. The same is true for the probability distribution for repair time. This leads to a number of concepts as explained in Billinton's Reliability Evaluation of Power Systems [1, p. 21]:

$$MTTF = \frac{1}{n}\sum_{i=1}^{n} T_i \to E(T) \quad when\, n \to \infty \qquad \text{Eq. 1}$$

MTTF: Mean Time To Failure describes the average time before the component fails. The variable T_i describes the Time To Failure for component *i*. From this the failure rate can also be deduced:

$$\lambda = \frac{1}{MTTF} \qquad \text{Eq. 2}$$

λ: The *Failure Rate* describes how many times a year (for example) a component fails, counting only the time when the component is in operational mode. For power components this number is usually pretty small since the components of the grid usually last for many years. A km of power line, for example, can have a λ of approx. 0.1 failures / year, which means that MTTF is ten years.

MDT: Mean Down Time, or restoration time, indicates how long time the component is out of order when it fails. This is not always the same thing as the repair time, described by the MTTR (Mean Time To Repair). The fault has to be located before it can be repaired and the fitters must be available and have to drive to the place where the failing component is located. This value varies depending on what kind of fault it is, if it happens at night or in bad weather, if a lot of other faults are happening and so on. Many faults are restored within 3 to 4 hours [2].

$$\lambda = \frac{1}{MTTF} \approx \frac{1}{MTTF + MDT} \qquad \text{Eq. 3}$$

The Mean Down Time for components in the power distribution system is often very small compared with the time the components are in operation. Because of this the failure rate can be approximated by the inverse of the sum of the Mean Time To Failure and the Mean Down Time. This means that the failure rate can be approximated by the division of the total number of faults occurring during a time period over the length of the time period.

The availability, *A*, depends on both the Mean Down Time To Failure and the Mean Down Time:

$$A = \frac{MTTF}{MTTF+MDT} \qquad [hrs/year] \qquad \text{Eq. 4}$$

The time until a failure has occurred and been repaired can be said to be a cycle in a process that is repeated all the time if *MTTF* and MDT are assumed to be constant. MTTF + MDT will then describe the total time of one cycle and MTTF will describe the time that the component was in operation during the cycle.

The unavailability *U*, i.e. the probability that the component is down at time *t* is described by the time when it is not working relative to the total time for one cycle, which is the same thing as all the time when the component is not available(1-A):

$$U = \frac{MDT}{MTTF+MDT} = 1 - A \qquad [hrs/year] \qquad \text{Eq. 5}$$

To facilitate the calculations in electric grid analysis, it may be appropriate to make approximations when calculating the availability and unavailability. The mean time to failure is often much greater than the time it takes to restore the system operation. Even if a transformer would take up to 30 days to repair, this time is negligible compared to the 20-30 years it might had been running without any problems. Therefore, for the sake of simplicity, the impact of the restoration time on the total cycle time can be neglected when calculating unavailability:

$$U = \frac{MDT}{MTTF+MDT} \approx \frac{MDT}{MTTF} = \lambda r \qquad [hrs/year] \qquad \text{Eq. 6}$$

This leads to the conclusion that the availability of a component can be approximated by:

$$A = 1 - \lambda r \qquad \text{Eq. 7}$$

As with all approximations, this will lead to an error. In the analysis of power systems the uncertainty of input data however, is most of the time much greater (also because of the long operation times), which justifies the simplification.

2.1.1. System Calculations

When the availability of each component is produced the availability for the entire system can be calculated. In most electrical distribution systems on local level the customers are connected along a radial line, i.e. all components are in series. In some places it may be justified with a little more redundancy and those places might for example have two transformers next to each other, so that if one should fail the other can continue to deliver electricity. This is an example of a parallel system (see Figure 2).

Figure 1: A series system

In a series system, see Figure 1, every single component has to work for the system to work. Failure of one component will cause an outage for the entire system. The failure rate of the system will therefore be equal to the sum of the individual failure rates of the components, assuming that no two components fail at the same time.

$$\lambda_s \approx \sum_{i=1}^{n} \lambda_i \qquad \text{Eq. 8}$$

Similarly, the time of unavailability for the system is the sum of the unavailability of each component, because when a component was unavailable, so was the whole system.

$$U_s \approx \sum_{i=1}^{n} \lambda_i r_i \qquad \text{Eq. 9}$$

Example: A system with four components in series: λ_A= 0.1, λ_B= 0.09, λ_C= 0.11, λ_D= 0.08 and r_A=1 h, r_B=2 h, r_C=3 h, r_D=4 h, will be unavailable for almost an hour a year.

$$U_s = 0.1 * 1 + 0.09 * 2 + 0.11 * 3 + 0.08 * 4 = 0.93\ h/year \qquad \text{Eq. 10}$$

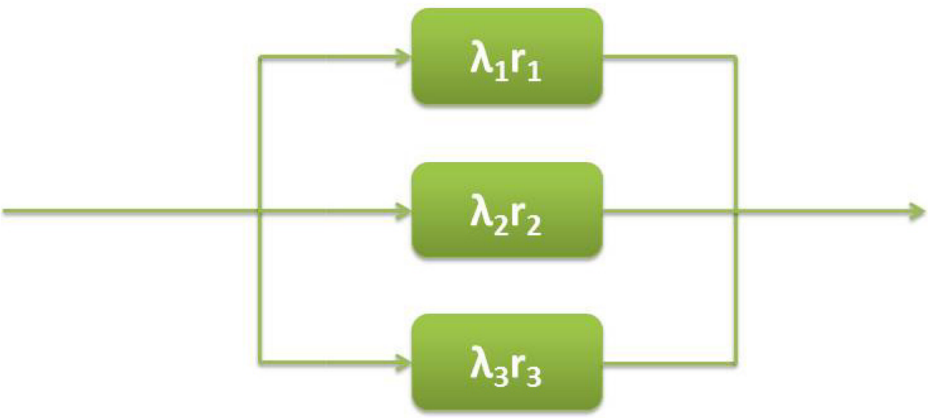

Figure 2: A parallel system

For a parallel system (see figure 2), however, all components must be out of order for the whole system to be out of order. This means that the probability of system unavailability is the product of the probability for the individual components' unavailability.

$$U_p = \prod_{i=1}^{n} \lambda_i r_i \qquad \text{Eq. 11}$$

The total failure rate can be derived:

$$\lambda_p = \frac{\prod_{i=1}^{n} \lambda_i * \sum_{i=1}^{n} r_i}{1+\sum_{i=1}^{n} \lambda_i r_i} \qquad \text{Eq. 12}$$

The same example system as in Eq. 10 will give the unavailability of 0.0019 hours, which is less than 7 seconds!

$$U_s = 0.1 * 1 * 0.09 * 2 * 0.11 * 3 * 0.08 * 4 = 0.0019\ h/year \qquad \text{Eq. 13}$$

In this master thesis project only series system will be concerned. The rural distribution lines are almost always built radially, but with one or more so called *normally open points* to adjacent lines. An open point is a connection to another line via for example an open disconnector. When something happens on the line the entire system will be blacked out, because it is a series system. The fault will however not spread to the adjacent line since the disconnector is opened. When a fitter reaches the location the fault can be isolated with disconnectors and the open disconnector closed. The customers that are not connected directly to the failing line segment can get the power back earlier than the rest through the adjacent line. The customers on the failing line segment have to wait the entire restoration time. *Line* is an important term in this thesis and refers to one feeder out of a substation. The entire line can be disconnected by the main breaker in the substation. Line in this context must not be confused with for example the term *overhead line*, which refers to a component (of any length).

2.1.2. Reliability Indices

To only use availability as a measure of the system is not quite enough to describe the significance of faults in a power distribution system. If a part of the system often fails, it is a problem, but if the number of subscribers who have an outage is not particularly numerous, it may be less of a problem than a single failure affecting multiple major load points. In order to compare different systems or different investments within one system, several customer-oriented system indices have been developed as described in [1, pp. 223-224]. The indices describe the unavailability of the system from different angles.

SAIFI: System Average Interruption Frequency Index describes how many faults a year that on average affect a customer.

$$SAIFI = \frac{\sum_i^n \lambda_i N_i}{\sum_i^n N_i} \qquad \left[\frac{faults}{year\ and\ customer}\right] \qquad \text{Eq. 14}$$

where N_i is the number of customers affected by fault *i* and λ_i is the failure rate for this specific fault. A shutdown of power line *x* in a system can for example lead to interruption of *y* number of customers. The failure rate of all possible faults that may occur in the system are multiplied by their impact and summed together to give the total number of *customer interruptions* during the year. By dividing the number of interruptions per year by the total number of customers in the network the average customer outage frequency is known.

SAIDI: System Average Interruption Duration Index describes, instead, on average how much time each customer has been disconnected during the year. The unit is hours / year and customer.

$$SAIDI = \frac{\sum_i^n (\lambda_i r_i N_i)}{\sum_i^n N_i} = \frac{\sum_i^n (U_i N_i)}{\sum_i^n N_i} \qquad \left[\frac{hours}{customer\ and\ year}\right] \qquad \text{Eq. 15}$$

SAIDI concerns the average unavailability. The unavailability for every fault is described by λ_i * r, i.e. how often this fault occurs, multiplied by how long it lasts. The unavailability of the fault is then multiplied by its impact, i.e. how many customers this particular case affects, just like for SAIFI. These numbers are summed up to produce the total so-called *customer outage hours*. Divided by the total number of customers the average yearly outage time per customer is obtained.

Customer outage minutes: A common value used within Fortum Distribution AB is the "customer outage minutes" (COM) where the customer outage hours have been re-calculated in minutes. The value is used among other things when deciding where reliability investments are needed and also to measure the effect of the investments.

CAIDI: Costumer Average Interruption Duration index. By dividing SAIDI by SAIFI the average length of each customer interruption is known. The unit is thus hours / failure.

$$CAIDI = \frac{SAIDI}{SAIFI} \qquad [hrs/failure] \qquad \text{Eq. 16}$$

Example: Different fault scenarios for an arbitrary electric system are shown in table 1. Depending on location in the system different amount of customers are affected of the outage.

Fault scenario	Failure rate	Mean Down Time	Affected customers
Failure of an 25 km overhead line	0.1 faults/km	3 hrs	30
Failure of transformer	0.01 faults	5 hrs	20
Failure of a 10 km cable	0.02 faults/km	4 hrs	10

Table 1: Example system

$$SAIFI = \frac{(0.1*25*30)+(0.01*20)+(0.02*10*10)}{60} = 1.3\ faults/year \quad \text{Eq. 17}$$

$$SAIDI = \frac{(0.1*25*30*3)+(0.01*20*5)+(0.02*10*10*4)}{60} = 3.9\ hours/year \quad \text{Eq. 18}$$

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{3.9}{1.3} = 3\ hours\ per\ outage \quad \text{Eq. 19}$$

ENS: Energy Not Supplied is a term used when estimating how much electricity that could have been delivered during the time of the outage if the system had been in operation. In the other indices customers are counted equally regardless of consumption, a large factory can be regarded as equal to a single-person household. This might lead to that the significance of an outage is overlooked. ENS is calculated by estimating an average power, L_a, for every affected load point, and then multiplying it by the unavailability of the specific fault. If this is then divided by the total number of customers, the obtained value is the AENS: Average Energy Not Supplied, i.e. how much more energy the average customer would have bought if no interruptions had occurred. The unit for ENS is kWh / year and for AENS the unit is kWh / year and customers.

$$ENS = \sum_i^n L_{a_i} U_i \qquad [kWh/year] \qquad \text{Eq. 20}$$

$$AENS = \frac{\sum_i^n L_{a_i} U_i}{\sum_i^n N_i} \qquad [kWh/year\ and\ customer] \qquad \text{Eq. 21}$$

The reason for having several different system indices is that different actors have different perspectives and approaches to interruptions. To the owner of a paper mill, it is essential to continuously have power since even a very short disconnection leads to a tedious and expensive start-up of the work again. Paper mill owners are therefore much more interested in SAIFI than SAIDI. In such networks, it can (at least according to the mill owner) be unfavourable to introduce a lot of protection components such as disconnectors which, even if they reduce outage time, will lead to an increase of SAIFI. This is due to the introduction of new components with their own failure rates and repair times into the system. To a food retailer, however, short outages cause no major problems, but the longer they are the more food could be lost. Therefore, the retailer is more interested in the SAIDI value.

In this project the system indices considered will be SAIFI and SAIDI. The customers on the case lines are almost all household customers with similar energy consumption and the SAIFI and SAIDI indices will therefore be enough to describe the reliability of the lines.

2.2. Incentives for investments

This master thesis report addresses the methods of choosing different investments for an enhanced reliability in the system. The reliability can however not be obtained at any cost. The cost of increased reliability must be reflected by the saved expenses due to unavailability of the system. Unavailability of the system leads to a number of costs, direct as well as indirect. When the system fails it must be repaired, which leads to direct repair costs. When the outages are longer than 12 hours the customers are entitled to compensation. The long outages are few, but the compensations are high and can therefore be very costly for the company. This is especially true for bigger disturbances, for example in case of a storm, where many customers can be out of power for a long time.

A distribution system operator (DSO), like Fortum Distribution AB, has a monopoly situation as the owners of the distribution network. This is because building more than one line to the customer's house is not economically feasible, which causes a natural monopoly. To ensure a fair and competitive situation a regulatory authority has been assigned the task to regulate the allowed revenue of the DSOs. Among other things, security of supply will affect the allowed revenue. This is further discussed in section 2.3.

Other costs are more indirect and harder to measure, like the goodwill of the DSO. If the customers experience reoccurring outages they will not be satisfied with their DSO, which will have negative consequences for the company. Fortum is a corporate group and dissatisfaction with one company can spill over on the rest in the group. In reality, the degree of reliability in a power grid can only be as high as the customers are willing to pay for and depends on what costs they have for outages. This is however out of the scope of this thesis, which will only concern the measureable parts of outage costs.

2.2.1. Repair costs

When an outage has occurred it generates several costs directly connected to the repair; cost for personnel working with the fault management, material used in the repairs and so on. The fault management in the field was earlier a part of Fortum Distribution AB, but has now been outsourced. Fortum is working on developing a list of costs of different repair jobs to be able to judge if the infrastructure service company is charging a reasonable amount for different jobs. This list (see table 2) has been used in the thesis to estimate the repair costs of the different kinds of faults [3].

Components	Cost of power back	Cost of remaining fault	Frequency of remaining faults
LV 0.4 kV	4 100	12 600	0.083
MV <24 kV Cable	16 100	50 400	0.1
MV <24 kV Other	7 800	19 100	0.05

Table 2: Costs of repair jobs on local network, not including Stockholm. All prices are in SEK[1], price level of 2011 and exclude VAT (VAT level is 25% and VAT is paid by the household customers).

The repairs are divided into categories depending on the failing component. In the top category concerns all low voltage faults. The second concerns cables on medium voltage and the third category includes, on medium voltage; overhead lines, disconnectors, breakers and transformers 20/0.4 kV and 10/0.4 kV.

The costs are divided into two categories as well. The cost of getting the power back to the customers is one. This category includes both permanent actions and temporary solutions, such as supplying the customers with electricity via a temporary cable over ground. When temporary solutions have been used, work still remains to be done. These costs fit into the second category, but are not always needed. The frequency of remaining faults can be seen in table 2 and describes that for example 10 % of the medium voltage cable faults will lead to a remaining fault. To calculate the average cost of every fault on MV cables the "Cost of remaining fault" is multiplied with the frequency of remaining faults and added to the "Cost of power back".

2.2.2. Cost of long outages

Long outages (>12h) are not included the regulatory model described in section 2.3, these are instead associated with direct costs. The customers have the right to compensation if they have had an outage longer than 12 hours. The size of the compensation depends on the customer's annual network tariff and is regulated in the Swedish law Ellagen (1997:857). Outages longer than 24 hours will not only increase the compensation to the customers, but are also associated with a functional requirement. It is illegal to have outages that long, which may in addition to the customer compensation also lead to legal costs. Exception to this rule might however be accepted if it can be shown that it is not reasonable that the DSO could have avoided the outage [4].

It is stated in the law [5] that for outages between 12 hours and 24 hours the amount of compensation will be 12.5% of the customer's yearly net tariff, unless it is lower than a minimum compensation amount. The minimum amount is calculated as 2% of a yearly set base amount and

[1] 1 Swedish krona ≈$7 ≈10 €

then rounded up to the nearest even 100 SEK. The base amount for 2011 was 44 000 SEK [6] which equals a minimum compensation of 900 SEK.

For an outage longer than 24 hours, every additional 24 hour period will be compensated by an additional 25% of the yearly customer net tariff. The maximum amount is however 300% of the net tariff [5]. To this amount the possible legal costs must be added since it is not legal to have outages longer than 24 hours. This requirement is however new and there is no data on average legal costs available.

The legal rules described in this section give strong incentive for the DSOs to avoid outages longer than 12 hours. Extreme weather situations where many customers are without power for several days can be devastating for a DSO, especially a small one.

2.3. Regulation of a Distribution System Operator

The Swedish electricity market was deregulated in 1996. However, due to the nature of electric power distribution systems, the infrastructures of the distribution systems are natural monopolies. This creates a need for supervision of the electric power distribution system tariff levels. The authority acting as regulator in Sweden is the "Energy Markets Inspectorate" (EI). The task of the EI is to ensure that the DSOs get fully compensated for the cost of distributing electricity and the cost of restricted capital, while also seeing that the costumers pay fair prices.

One of the incentives for investing in better reliability is the effect better security of supply has on the allowed revenue. In this chapter the regulation coming in 2012 is described.

2.3.1. Background

After the de-regulation of the electricity market the DSOs could be fully compensated for their costs regardless of efficiency and quality. To address this problem a new authority was formed in 1998: The Swedish Energy Agency (STEM). The task for STEM was, among other things, to create a better model of regulation. [7, p. 19] In 2003 the Network Performance Assessment Model (NPAM) was implemented. The idea of the NPAM was that the service of distributing electrical energy creates customer values and that the DSOs should be compensated in level with these values [8]. The NPAM used a fictive power distribution network to calculate the Network Performance Assessment, which is the total expected cost of operating a power distribution system. After the regulatory period, because this was an ex-ante model, the NPA was compared to the actual revenue of the DSOs. If the revenue was too high the DSO had to pay the customers back [9].

The NPAM met heavy opposition from the DSOs as many of them had to repay their customers each year. The amount of legal claims against the authority was growing every year. Because of this, and the fact that the EU requires an ex-ante regulation by 2012, the model was abandoned in 2009.

During the time since the fall of the NPAM the focus has been on preparing the new regulatory model that will come into force in 2012. The Energy Markets Inspectorate (the part of STEM handling the regulation was announced an authority in 2008) still controls the tariffs, but they are in some ways self-regulating. If the DSOs charge too much, the rules of regulation might be harder in the next period [10, p. 57].

2.3.2. Ex-ante model

In the new model a reasonable revenue framework for the DSOs will be determined *before* the regulatory period starts, a so called ex-ante regulation. The DSOs send a proposition to the regulator who decides if the suggested frame work is reasonable. The regulatory period is four years and the

Energy Markets Inspectorate (EI) might review a DSO's decision of a revenue framework during or after the period if it turns out that the decision was based on false data [11].

The method of evaluation of the proposed revenue framework is a template method where EI calculates the reasonable total costs and fair return on capital for a distribution system operator, taking objective prerequisites for the specific company into account. The template revenue is then compared to the suggested one. After the regulatory period the company's actual revenue is checked to make sure that the DSO has kept the revenue within the boundaries of the framework. If the actual revenue exceeds the predetermined levels, the framework will for the next regulatory period be reduced by the amount exceeding the framework. Similarly, if the revenue has been kept below the expected value the DSO has the right to an increased revenue framework. If the revenue has exceeded the framework by more than 5%, the framework will be additionally reduced by an overcharging fee [11].

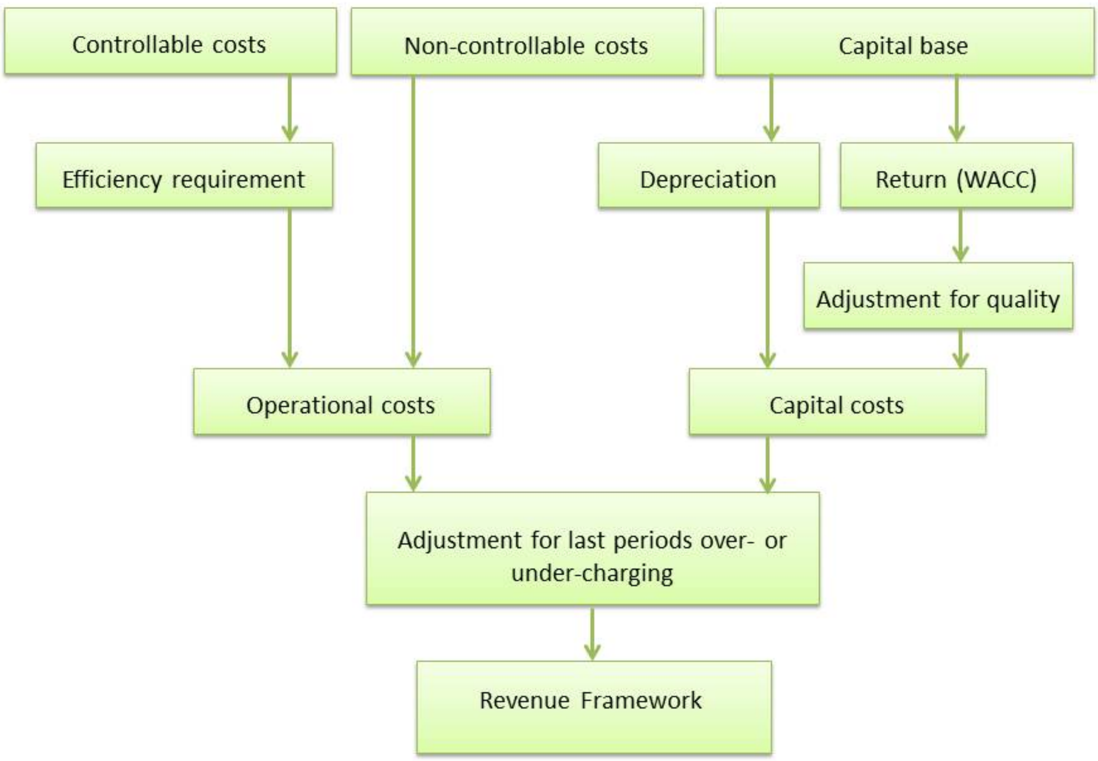

Figure 3: Flowchart of the ex-ante regulation. Translated from picture in Energy Markets Inspectorate 2009:09

The flowchart in figure 3 shows the parts that make up the framework for the revenue. The total costs for a DSO includes operational costs and capital costs.

2.3.3. Operational costs

Operational costs can be said to be any costs that are not capital costs, and are divided into controllable costs and non-controllable costs (see figure 3). The non-controllable costs are directly added to the revenue framework, since it is considered that the DSO can do nothing to affect these costs. This can be for example charges to superior grids. The controllable operational costs are for example costs of maintenance, administrative costs or cost of personnel. These costs are calculated from historical data from the company and are associated with an efficiency requirement [12]. The operational costs have to be lowered by 1% every year [11].

2.3.4. Capital costs

Capital costs are costs of acquisition of the capital base and the cost of restricted capital. The capital base includes all assets necessary to perform the service of delivering electrical energy. This is for example distribution lines, control equipment and electricity meters. To be able to measure the DSO's capital costs the value of the capital base must be determined. The DSO's calculate the value of the capital base and state this number in the proposition to the regulator. There are four different ways of calculating the capital base.

2.3.4.1 Assessment according to the norm value method

This is the method to be used primarily. It aims to evaluate the *purchase value* of the capital base. In other words, the DSOs calculate what it would cost them to obtain their entire capital base today. This way of regarding the grid as brand new has been questioned. EI did however try to ask the DSOs what the grids were worth today, which turned out to be too hard, if not impossible, to calculate. It was therefore decided to go with this method for the first regulatory period [11].

The evaluation of the capital base is done with norm values of different assets. EI has produced hundreds of norm values [13].

2.3.4.2 Assessment according to the acquisition cost

If there is no norm value of an asset in the capital base of a DSO, the asset can be valued with the acquisition cost. This means that the price of the asset when it was bought is re-calculated to today's value.

2.3.4.3 Assessment according to the book value

If the acquisition cost is not known the book value of the asset can be used to value it.

2.3.4.4 Assessment in exceptional cases

In some cases there are prerequisites that the DSOs would like the regulator to take into account, and the assessment of capital might be done differently. An example of this is the assessment of cables in the Stockholm city center. Fortum Distribution AB has applied for a different assessment method here, because of the much higher cost of installing cables in the center of a big city [11].

2.3.5. Quality adjustment

When the capital base is known, the cost of keeping it can be calculated. The capital costs consist of cost of acquiring the capital base, which is recorded as depreciation, and the demand of return that the shareholders have. It is the shareholders return on invested capital that gets adjusted according to the quality of the electrical energy.

Depending on the quality, which in this regulatory period will be measured only by the security of supply, deductions and additions to the return of capital will be made. The reliability in the system will be measured against historical data (2006-2009 in the first regulatory period) and if the DSO has improved the quality an addition to the return of capital can be made. If the reliability has declined, the return will decrease – creating incentives for better quality of the electricity supply.

Regional and local distribution systems will be measured differently. The regional grid will be measured in Energy Not Supplied, ENS (see section 2.1.2), and the local distribution systems will have their quality measured in SAIFI and SAIDI. This thesis concerns only the local distribution system and therefore only the quality regulation of those systems is described in this section.

SAIFI and SAIDI are divided into announced and unannounced outages. The planned outages, for maintenance and such activities should be announced in advance. The announced outages are not as costly or annoying for the customers. The planned outages must however be communicated to the customers well in advanced in order to count as an announced outage. For the unannounced outages the SAIFI and SAIDI are produced for outages longer than 3 minutes and shorter than 12 hours. Shorter outages are not considered to be interruptions of power supply, but more a quality issue of the same type as for example voltage instability or flicker. The unannounced outages longer than 12 hours are already subject to cost for the DSOs through direct outage compensations (see section 2.2.2). In order to not punish the DSOs twice, unannounced outages over 12 hours are not included in the regulation. SAIFI and SAIDI of announced outages are calculated for outages longer than 3 minutes. In this thesis only the disturbances, i.e. unannounced outages, have been regarded and the calculations will hence only include the unannounced SAIFI and SAIDI.

In order to scale the quality adjustment of return on capital the average yearly power and energy output in the grid is taken into account by valuing the cost of outage in SEK/kW and SEK/kWh. The costs have been estimated by the Energy markets Inspectorate and can be seen in table 3, which is collected from table 4 in [14].

	P_W SEK/kW	P_E SEK/kWh
Announced outage (AO)	4	38
Unannounced outage (UAO)	19	54

Table 3: Cost per kW and kWh for announced and unannounced outages.

Equation 26 is then used to calculate the quality adjustment, Q. The E_y in the formula stands for the annual average energy consumption in the area and T_y is the hours of a year. The quality adjustment is shared between the DSO and the customers by multiplying the adjustment with 0.5. The idea is that the cost of quality should be accounted to the DSO and the customers equally. The formula and explanations of the calculations can be found in [14, p. 27].

$$Q = 0.5 * \left\{\left[\left(\frac{SAIDI_{UAO,norm} - SAIDI_{UAO,actual}}{60}\right) * \left(\frac{E_y}{T_y}\right) * P_{E,UAO}\right] + \left[\left(SAIFI_{UAO,norm} - SAIFI_{UAO,actual}\right) * \left(\frac{E_y}{T_y}\right) * P_{W,UAO}\right] + \left[\left(\frac{SAIDI_{AO,norm} - SAIDI_{AO,actual}}{60}\right) * \left(\frac{E_y}{T_y}\right) * P_{E,AO}\right] + \left[\left(SAIFI_{AO,norm} - SAIFI_{AO,actual}\right) * \left(\frac{E_y}{T_y}\right) * P_{W,AO}\right]\right\} \quad \text{Eq. 22}$$

The announced and unannounced outage SAIFI and SAIDI for the current year are compared to the norm value that were calculated with the historical data. If the reliability is better now than compared to the norm value the result, and adjustment to return of capital, will be positive.

There are limits to how large the quality adjustment can be. In case of extreme weather during a year, the quality adjustment can be much too large for a small company to handle. In order to protect the companies from such events, the deduction can at most be 3% of the revenue framework or the entire return of capital [14, p. 32]. Too high security of supply is not economically justifiable either and hence an upper limit on the addition to the return of capital has been assigned. It is as well 3% of the revenue framework.

3. Fault management at Fortum

In this thesis theoretical models of two lines in the Fortum grid were made in order to be able to analyze the lines and examine the effect on reliability for different investment alternatives. The goal was to model the lines and the fault management at Fortum as close to reality as possible to give as true results as possible. The two case lines were analyzed with the reliability analysis methods described in section 2.1. In order to estimate the input data as accurately as possible it is crucial to understand how outages are dealt with at the DSO. Several interviews have been made with the Fortum personnel, such as process managers, net planners and fitters, to learn this. Study visits have been made, both to the *network control center* and out in the field with the *fitter*s. Section 3.3 and 3.2.2 is based mostly on interviews with Daniel Heidkamp [15]. All other sections are based on interviews with Bo Andersson [16] and Mats Estéen [2].

Figure 4 can be used to describe the fault management process at Fortum Distribution AB.

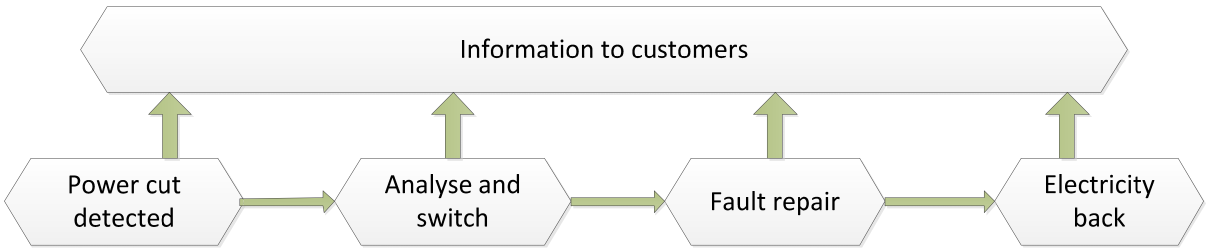

Figure 4: Fault Management Process at Fortum Distribution AB

3.1. Fault detection

If a fault occurs at medium voltage the breaker will detect the fault and break the power. This will be registered by the SCADA system and sent to the grid operators. Faults that occur on lower voltages will not be detected by the SCADA system and can therefore not be sent to the grid operator. In this case the information has to come from the customers.

3.1.1. Medium voltage fault detection

When the *power systems operator* receives the message from the SCADA system that an outage has occurred this is filed in the computer tool Succel by entering the name of the breaker that cut the power into the computer. This opens a so called "*fault notation*", a file where all the different switching of disconnectors and breakers will be noted. Succel is a DMS, which means Distribution Management System created to help system operators. Succel was created in the end of the 1990's as a way to enhance the information to the customers and to take better statistics.

3.1.2. Low voltage fault detection

If an outage occurs on lower voltage levels, the system has no way of knowing that it happened. The customers have to inform the DSO about the problem. They do this by calling to a call center that receives their call and sends a message to the network control center that an outage has occurred. The call operator tries to determine where the outage is, first through the phone number of the caller before the call is even answered. If the outage in this area is already known, through other customers, information is given to the customer. The customer will be asked to answer a couple of questions like; do the neighbors have power? Has the main fuse in the house gone? The customer is also informed that if the problem is in the customer's own building, and the Fortum fitters are sent out anyway, the customer will be charged with the costs. Fortum is not responsible for the customer's *residential grid*. The call operator also checks if the lack of power can be related to unpaid bills. If many customers are calling, the call center can make an announcement through media and on the phone waiting line so that the customers don't have to wait for the information.

When the power systems operator is given the message of an outage from the call center the errand is filed in Succel and a fitter is called.

3.2. Fault location

When the operator has opened the fault notation it is checked if there is any work being done on or around the line at the moment. This is because if there is, the workers could be hurt if the operator tries to turn the power back on. The people working close to the line are listed in the computer and the operator must read the list and make sure that no one is working on the line. If no one seems to be close to the line the system operator can try to put the power back on. Many outages occur because of faults that "fix themselves", for example tree branches that blow into the line and cause an outage. When the power is turned back on the branch is no longer on the line and everything works perfectly again. Another example could be moist that gets into the equipment and causes an electric short circuit. The arcing burns the moist away and when the power is turned back on, everything works again.

If the re-closing of the breaker only led to the breaker opening again, the problem has to be fixed. The operator then normally fetches the *network plan* of the area. If there are remote controlled disconnectors in the area they are now all opened and the breaker is then re-closed to see if the fault is on the first line segment. If not remote controlled disconnector number two is closed and this is continued until the breaker cuts the power once again. This means that the line segment where the fault is has been found. If possible the power systems operator now isolates the fault with the remote controlled disconnectors and then calls the fitter responsible for the area. The information on which fitter that is on duty and the phone number is found in the computer in a list that is continuously updated to show which fitter to call.

The fitters were earlier employed by Fortum, in the division "Fortum Service". This is now outsourced and the repairs and maintenance of the grid is done by companies like Infratek, Eltel and Relacom. In their contract with Forum it is stated how fast they must reach the area where there's an outage. Fitters in Värmland have 90 minutes to get to the place of the fault for example. In Bergslagen they have 120 minutes. The time to reach the fault does of course vary a lot, depending on where the fitter is, what time of the day it is and what the weather is like. An estimate of the general time is about 60 minutes, according to system operator Mats Estéen.

When the systems operator calls the fitter the power systems operator tells the fitter which disconnector to go to and open. In many cases the fitter also suggests which disconnector to start with. The fitters are often very accustomed to the parts of the grid where they work and have a lot of experience of where the faults normally occur.

3.2.1. Sectioning

If there are remote controlled disconnectors in the grid, the operator opens them all and then closes them one by one. But if the disconnectors are manual they have to be opened by the fitter. In this case it is important to figure out in which way to section the line to save as much time as possible. The remote controlled ones can easily and fast be opened and closed, but it takes a lot of time for the fitter to go back and forth along the line to open and close disconnectors. The normal procedure is to send the fitter to somewhere in the middle of the grid and open that disconnector. This will determine on which side of the middle the fault is located. Often the other side can then be fed from a secondary feeding. The first disconnector to be opened does not always have to be the one in the exact middle. If the line consists of for example one part of underground cables and then overhead lines one often start the sectioning on the part with overhead lines since they have a lot more problems than the cables. The decision where to start is based on the experience and knowledge of the operators and fitters.

Figure 5: A remote controlled disconnector.
The yellow box at the base of the pole is the control equipment. Photo: Sabina Stenberg

When the first disconnector is opened the fitter knows on which side the fault is and sections through the next couple of disconnector on that half of the line. At one point the power will go out again and then the segment of the line where the fault is located is found. The fitter will isolate the fault with disconnectors and the operator will close the breakers of any alternative feedings. Or, if there is an open disconnector to another line the fitter will go there and close it so that the other customers can get the power back. The sectioning work is often done in pairs to avoid that the fitter has to go back and forth in the grid. One fitter follows the other one, closing disconnectors behind the other.

3.2.2. Finding the fault

When the line segment where the fault is has been identified, the process of finding the exact location of the fault starts. The fitter always considers if there are different places where a fault is more likely. Is there a place that fails more often than others? Or, have trees in the area recently been cut down? Trees close to the lines are often left by the forest workers who fear to break the line when cutting these trees down [15]. These trees are now unprotected from the wind and much likelier than before to fall on the line. If there is no “obvious” place to start, the fitter starts by examining the overhead lines, if there are both cables and overhead lines on the line. The overhead lines will be checked by going by car as far as possible and when the line no longer can be seen from the road the fitter walks along it. The situation will of course be different if the fault happens during the night. Then the fitter will have to walk along the line while lightening it with a flashlight.

If the fault is not on the overhead lines, but likely on a cable, the *cable bus* is called to the place. The cable bus is a bus with measurement equipment for finding cable faults. Since this equipment is very expensive Infratek only has one cable bus and it is based in Örebro, a city located a couple of hours away from the areas examined in this thesis. It might therefore take some time until the cable bus can reach the area. The fault will be found by leading a lot of current into the line. The location of the fault is calculated by the equipment in the bus and the distance to the fault is showed in a display. The fitters will go to the distance showed and dig the cable up. If there is no cable bus available, or if the cable is very short, the fitters can use a simpler method. This method also means leading a lot of current into the line. When the current reaches the fault it will make a noise that can be heard by the fitters will be walking along the ground above the cable with a microphone. Once they hear the location of the fault they can dig the cable up.

3.3. Repairing the fault

The fault is then repaired. Common repairs are removing trees from the lines or splicing of lines or cables. Generally, the thicker the cable or overhead line, the more work it will take to splice the line. Non-insulated lines are the most vulnerable to all kinds of impact, a tree branch brushing on it might cause a short-circuit, but it is also a lot easier to repair if something happens.

Figure 6: Daniel Heidkamp at Infratek removes a tree from an overhead line. Picture Sabina Stenberg

It is worth noting, that even if some faults are quick to repair – like cutting down a tree that is leaning on an overhead line, the fault repair might still take time. Handling a chainsaw is not a one man job, someone else has to be there in case something goes wrong. When the fitters work in pairs this is of course not a problem.

3.4. Electricity back

When the fault is repaired and all customers have the power back, there is still some work to be done. The *fault notation* must be archived. This ends the errand and this is the measured outage end time in the statistics. When there is a lot to do the archiving of errands sometimes have to wait which leads to errors in the statistics. When archiving the errand, the operator answers questions on what caused the fault and what components were damaged and so on. The fault is also positioned in the computer tool PoDIS, where it later can be seen together with all other previous faults on the line. Other things the operator does after an outage is for example to stop the automatic phone messages about the outage and inform the media that the power is back on. It is also checked if there is still work to be done on the line, some customers may be fed by a temporary line because the original one is still broken. The work on the broken line is then ordered in another computer tool.

4. Reliability analysis of specific lines in Fortum's grid

4.1. Method

This project aims to examine if Fortum Distribution AB's methods for prioritizing between different reliability investments for the rural distribution grid are detailed enough to give the same result as more complex methods. This is done by in Excel creating theoretical models of two lines out of two different substations in the Swedish county of Värmland. The theoretical SAIFI and SAIDI for the lines will be calculated and consequently also the costs that depend on the reliability indices. Costs of repairs will also be added. These base cases will be compared to the outage statistics collected by Fortum to see if they correlate with the real lines (as far as the outage statistics can depict the real lines).

A couple of investments for better reliability will then be applied to the model lines, and the costs and reliability indices will once again be computed. The cost efficiency of the different investments allow for them to prioritized after which are better to perform.

One of the case lines is one in an area where reliability investments have already been performed. The model will be done according to the original structure of that line. This is because the results from the analysis then can be compared to the real investments to see if different detail levels give different priorities. To test and apply the result the other case study is performed on an area that has not yet been reconstructed.

On the already renovated line the results of the theoretical investments will show if more detailed methods would have led to recommendations of the same investments. On the other case line recommendations for reliability investments will be given.

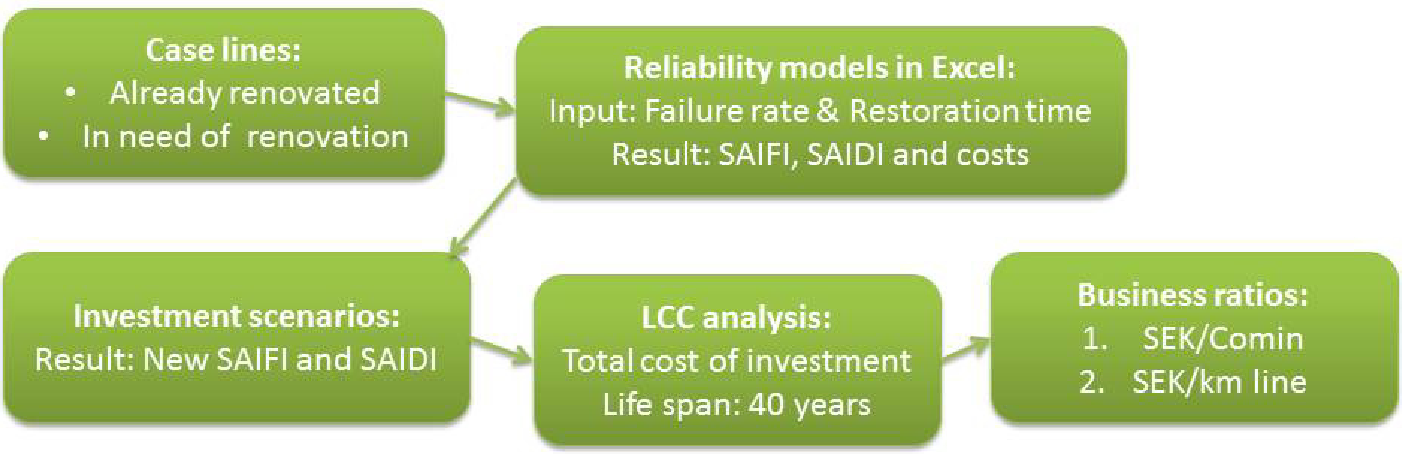

Figure 7: Schematic of the method used in the master thesis project

4.2. Case lines

The lines for the two case studies were chosen with help of the net planners at Fortum Distribution AB. With their knowledge and familiarity with the Fortum grid two lines fitting the requirements could be found; one line that had already been renovated and one that was in need of better reliability.

A summary of the properties of the case lines can be seen in table 4.

	Charlottenberg	Lesjöfors (before 2001)
OH lines	37 km	61 km
Cables	5 km	15 km
Total	42 km	76 km
Number of customers	312	303
SAIFI	8,2	5,0*
SAIDI (h)	5,5	13,4*

Table 4: Properties of the case lines. SAIFI and SAIDI from actual outage data.
* The SAIFI and SAIDI for 102A Lesjöfors are computed using outage data for 2001-2006. For 020E Charlottenberg data from 2001-2011 is used.

4.2.1. Line 102A in Lesjöfors

In the Bergslagen area lies the small town Lesjöfors. It has one substation (102) with 7 lines feeding the area. The 102B line covers the ten secondary substations in the northern urban area while 102C and 102D feeds the western and southern parts of the town, with 7 and 8 secondary substations respectively. The lines 102G and 102X both feed the factory "Lesjöfors Springs & Pressings". The rural areas south of the town are fed by 102E with 36 secondary substations. Line 102A is the biggest line and feeds the 53 secondary substations in rural parts north of the town. This line has undergone extensive reconstruction during the past years and is the line chosen for the first case study. **The model will be made after what the original line looked like.**

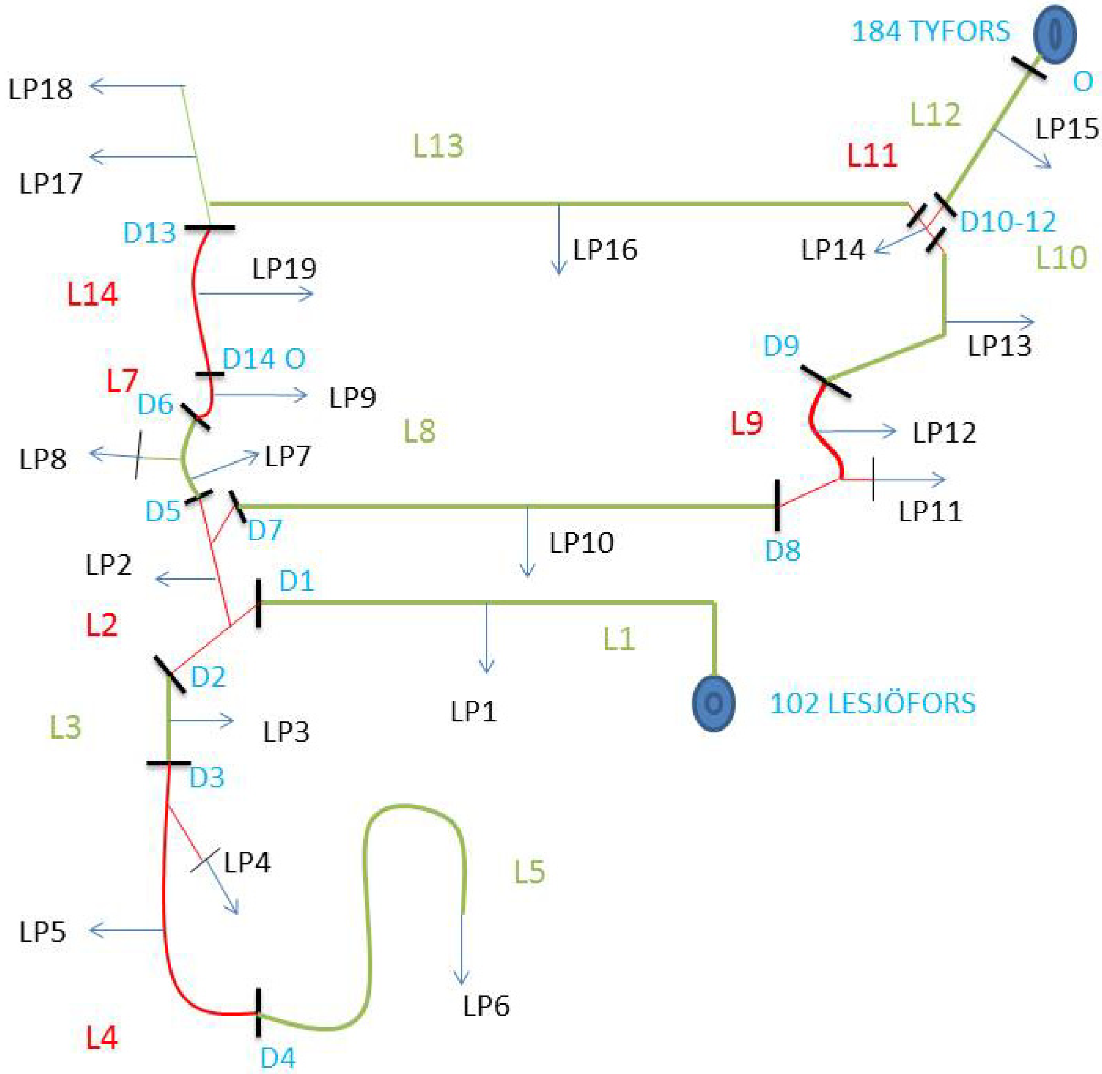

Figure 8: Image of the Lesjöfors line. Different line segments are shown in green and red. Disconnectors D1-D14 are marked on the map, so are also the two substations 102 Lesjöfors and 184 Tyfors.

Today the line supplies 303 customers distributed along more than 75 km of power lines. Before the year 2001 nearly the entire line consisted of overhead lines. The only longer piece of cable, the urban part excluded, was located on L4. This part was changed from overhead lines to underground cables during the 1990's. The rest of the line was made of overhead lines. This construction had some weaknesses. For instance, the first part of the line was a long overhead line (L1) along a lake. This part of the line was often damaged due to beavers that were cutting down trees close to the lake [17]. When this part had to be repaired, many customers were out of power since it happened close to the substation. Another area that possibly could have been built differently is the very long rounded line going south (L3-L5), this line could maybe instead have been electrified from the other way, straight from the substation.

The original line had 14 disconnectors on the main line that could be used to section the line in case of outages. A few of the disconnectors were fuse disconnectors that could disconnect the failing segment without causing an outage for the rest of the customers. The system had one open point to a secondary feeding at the substation 184 Tyfors located on the northeast part of the line. The northern part of the line formed a loop and had an open disconnector at the far west point (D14). This assured that the customers at the end of the northern part would not be cut off for long if a fault occurred, but could be supplied from the other direction. The customers on the southern part did not have this opportunity, they would all have a blackout until the fault was repaired if it happened on the south side.

This area suffered from many and long outages, but during the first decade of the 21th century a lot of work was done to improve the reliability of the line. The first improvement was to change 4.5 km of overhead line at L7 to an aerial cable. An aerial cable is hung on poles just like the overhead lines, but is much stronger and will not be short-circuited if a tree branch falls on it. This was done in 2001. The next investments were done on the lines just north of this line segment. In 2003 another 5 km of overhead lines, at L14, was changed for aerial cable. The same year 3.5 km underground cable was dug down at L3 and just over 1 km at L2. The biggest part of the renovation was made during 2006. Many projects of turning overhead lines into cables were carried out and since then the line consists of 73 km of cables and 18 km of overhead line. Of this 12 km are cables to new customers. (This does not add up to the original 76 km because cables are normally placed next to roads and therefore are longer than overhead lines feeding the same point [18], and the cables were not installed in the same topology as the overhead line.)

4.2.2. Line 020E in Charlottenberg

The second line to analyze was chosen to be line 020E in Charlottenberg. The town of 2000 people is situated right by the border to Norway in the Swedish county of Värmland. The town substation (020) has 13 outgoing lines of which three supply the urban area, five support important loads like the power station and the big border trade malls, and last four supply the rural areas around the town. Line 020E is one of the rural lines and supplies the eastern part, which consists of 44 secondary substations with a total of 312 customers, see figure 9.

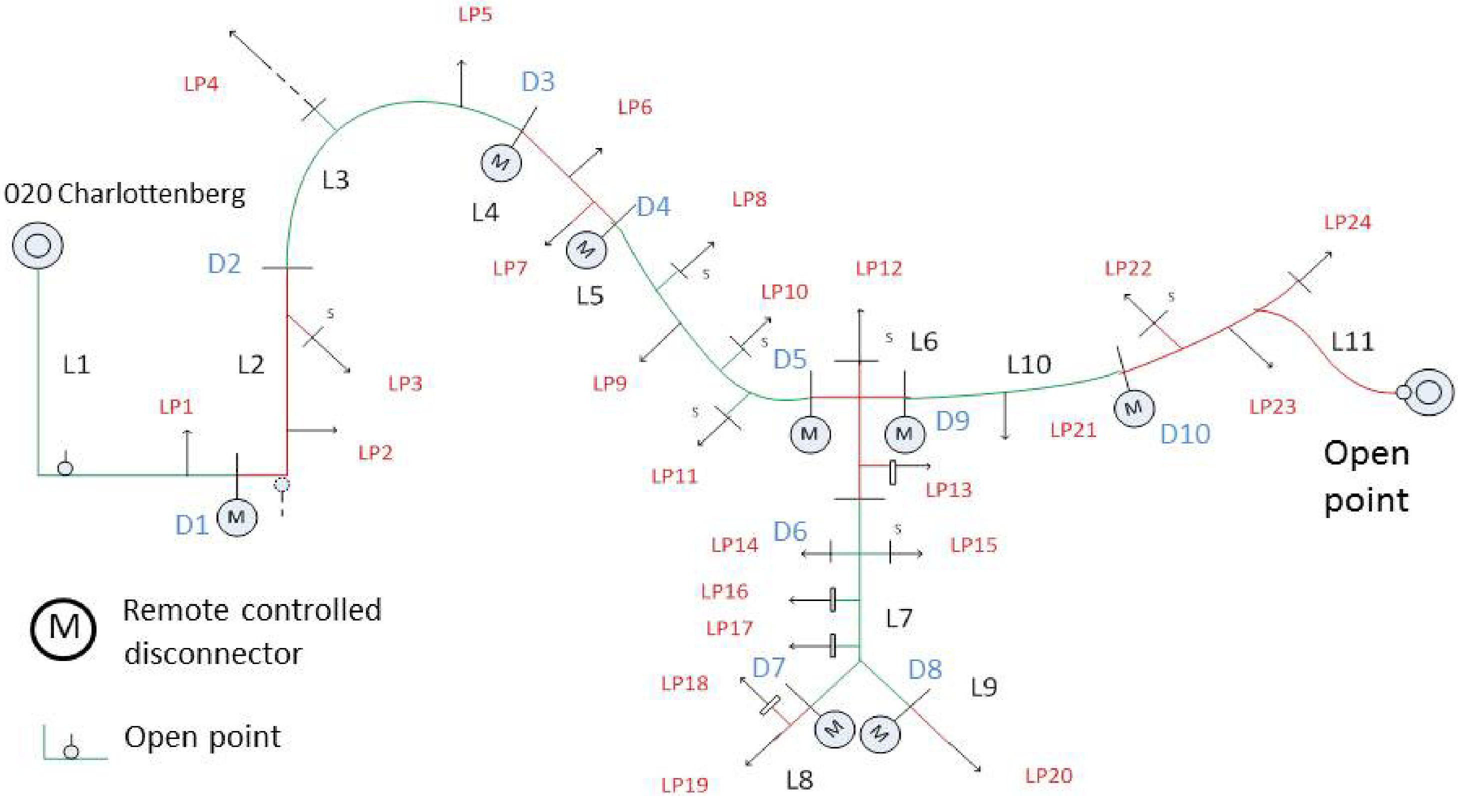

Figure 9: Image of the Charlottenberg line. The substation 020 Charlottenberg is located in the left part of the picture. The “M” stands for “motor” and these are the remote controlled disconnectors.

The 43 km long line has almost no underground cable, except for two radial lines to the two substations in the far north and two sea cables in Lake Räksjön. The main line goes straight east and connects with an open point at the substation *082 Järpforsen*, see figure 9. There is a more than 10 km long radial line going straight south from the middle of the line down towards Lake Fjällsjön. This part of the line has no connection to another line or substation and has therefore no possible secondary feeding. In case of blackout the 93 customers living at this part of the line are left without power until the line is fixed. There are two other open points on the line, both situated in the beginning of the line. One of the open points is to the line 020D and the other one to the line 020G, which are other lines out from substation 020, see figure 10. The latter open point has a remote controlled disconnector.

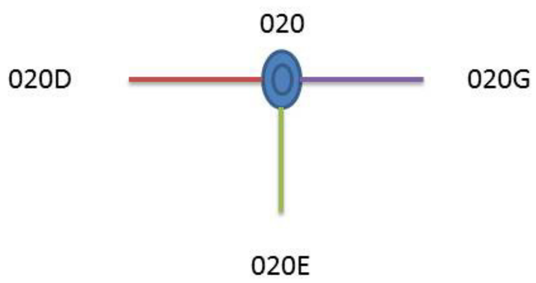

Figure 10: The substation 020 Charlottenberg and three of the outgoing lines

Along 020E there are eight remote controlled disconnectors that quickly can section the line, see figure 9. The main line has manual disconnectors at two places and many of the outgoing radial lines can be manually disconnected. Many of them are combined with a fuse.

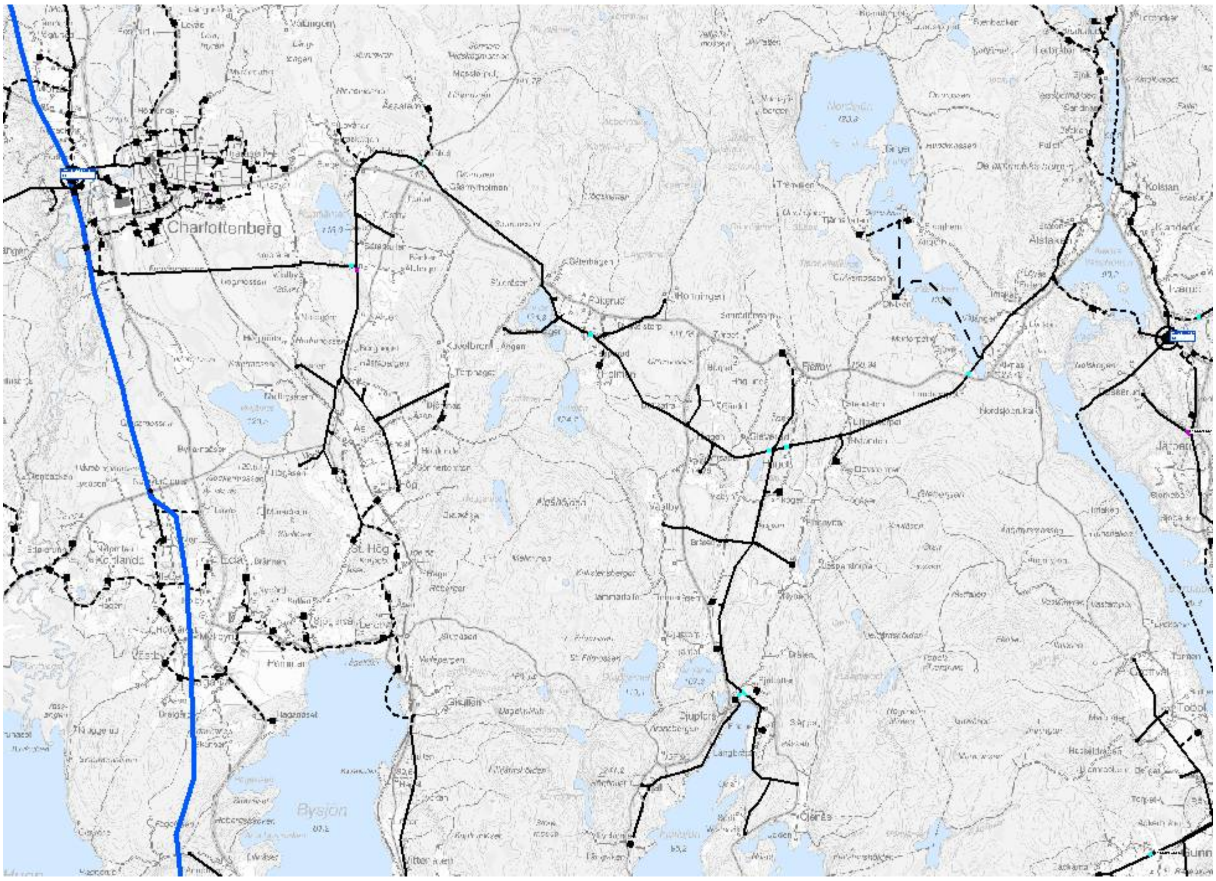

Figure 11: The Charlottenberg line. On the left is the Charlottenberg substation, The feeding from the blue high voltage line can also be seen. Image source: PG

The line has had many problems and Fortum is planning to reconstruct it. One of the problem areas for 020E is the long radial with no secondary feeding (L6-L9in figure 9). Many of the line's customers are without power if a fault occurs. Another issue is the amount of overhead line, a large part of the line goes through forest areas and is often blacked-out due to trees.

4.2.3. Lesjöfors today

The idea of this thesis is to make a model of the Lesjöfors line as it was designed before 2001 and calculate the reliability indices and the costs. Different investment scenarios are then applied to the model. The purpose is to determine if the investment alternative chosen by Fortum is the one that even more detailed reliability analyses would indicate as the best one. To be able to do this one of the investment scenarios is the Lesjöfors line in its current design.

This is the investment that was actually carried out on the Lesjöfors line. To measure its effect on reliability and its cost efficiency, a model of Lesjöfors as it is today is made. For the other investment scenarios the two models of the case lines only had to be modified accordingly to the investment that was being made. The actual reconstruction of the Lesjöfors line was so extensive that a new model had to be built.

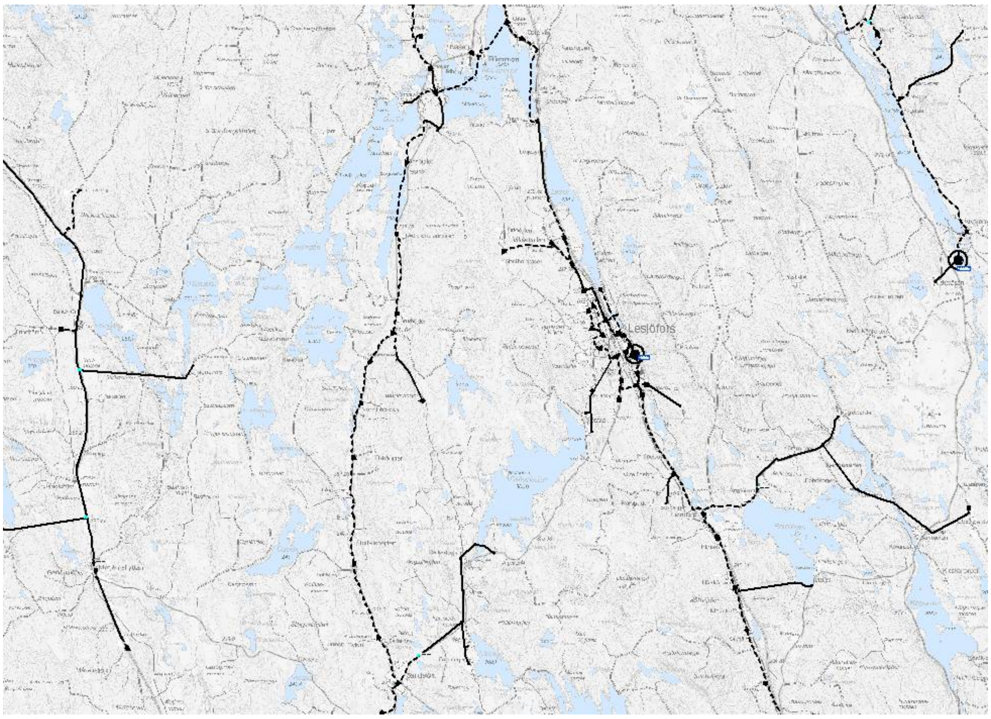

Figure 12: A part of the Lesjöfors grid in its current design

The model of the current grid topology on 102A Lesjöfors was made in basically the same way as the model of the original line. The components were listed and the line was divided into line segments according to where the main line disconnectors are located. An image of the current design of the Lesjöfors line can be seen in figure 13. As can be seen the line is divided into 14 line segments just like the original line. There are four radial lines for the current line as well as the original. The location of the sectioning equipment is however a bit different and the cables do not go exactly where the overhead lines went. The sectioning equipment has been located with the help of PG and the network plan for the current line, which was easier than for the original line where the equipment was positioned by the fitter. This lead to some inconsistencies, some places should logically have had a disconnector although it was not marked on the map. Because of this a few existing disconnectors have not been taken into account in the model because they were probably there on the original line as well, this in order to make the two cases as comparable as possible.

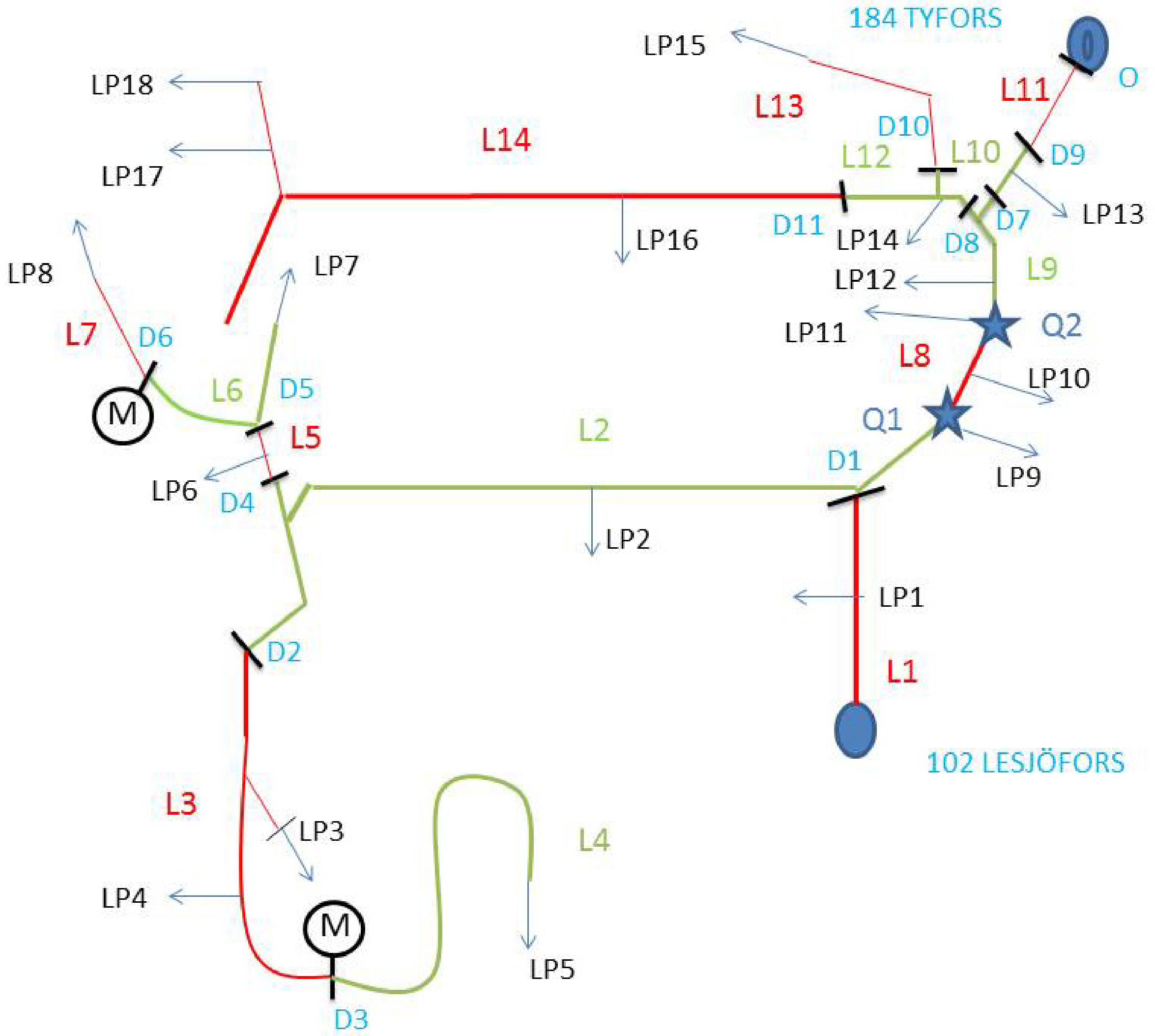

Figure 13: The Lesjöfors line in its current design, with line segments, disconnectors, load points and Quicksec (Q) marked in the map. Quicksec is a type of sectioning equipment.

Because the line segments were re-structured, the load points are not made up of the same secondary substations anymore. Now there are for example only 18 load points compared to the 19 of the original line. Some of the customers have been moved to other load points and some customers that were earlier fed by 184 Tyfors is now added to the 102A Lesjöfors line.

Only one of the disconnectors is a combined fuse disconnector, D10, which can disconnect the long overhead line to the substation 184 Tyfors. There are also two remotely controlled disconnectors on the line, D4 and D7. If the fault is on either L4 or L7 it can be found very quickly. **The remote sectioning is assumed to be done within the initial 3 minutes of the fault management**.

A new sectioning order had to be created now that the line is different. The sectioning order assumed in this project can be seen in appendix 2.

With the sectioning order the calculations of the restoration time of the power at every load point for every fault scenario was made. The rest of the input data was equal, the items that change were:

- Lengths of cables and overhead line
- number of customer per load point
- sectioning time

From the model the new total number of customer outages and customer outage hours were collected. After relating it to the number of customer at each load point the SAIDI and SAIFI of the current Lesjöfors line according to the model could be calculated. The results are then compared to the outage statistics for 2007 until today. The result can be seen in table 5.

Current 102A Lesjöfors	Model	Actual grid
SAIFI	3.41 ± 1.18	1.96
SAIDI [hours]	6.21 ± 2.19	6.12

Table 5: Reliability indices for the Lesjöfors line in its current design

4.3. The models

In this section it is described how the models of the case grids were made.

4.3.1. Listing components

The knowledge of the fault management process, see chapter 3, was used to create the models of the case lines. The first step in the process is to list all the important components along the line**.** It was decided that ***the components to be included in the model was; overhead lines, cables, disconnectors and breakers***. These components were chosen because they are the ones considered to be most important for the reliability and therefore are used in reliability analysis on research level. The components along the lines were identified in the computer tool Power Grid (PG). This computer tool is a GIS system that allows the user to, among many other things, study the topology of the grid and access information on different components. PG can also be used for net calculations and planning of reconstructions. In this project PG has been used to fetch information on for example the structure of the grid or the installation year of different components.

The data collected of the case lines were filed in Excel. Interesting details were for example length of overhead lines and cables and positions of sectioning equipment. Listing the components for the Lesjöfors line took some more work since this area had already been reconstructed and the data in PG concerned the current design of the grid. However, demolished lines and equipment can be shown in PG and the information could be listed for hand from this. The positions of the sectioning equipment were marked on a map by one of the fitters who had been working in the area during the period before the reconstruction [19].

	020E Charlottenberg	102A Lesjöfors (before 2001)
Number of breakers	1	1
Number of main line disconnectors	10	14
Number of radial disconnectors/fuses	15	4
Number of substations	44	53
Number of load point	24	19
Number of line segments	11	14

Table 6: Components on the case lines

The main lines were divided into segments depending on where the sectioning equipment was located. The Lesjöfors line was divided into 14 segments and had four radial lines going out from the main line and separated by sectioning equipment, see figure 8. The customers connected to the same segment or radial are affected the same way by outages on the line, and are therefore merged into one "load point". The 53 secondary substations on line 102A make up 19 load points.

The Charlottenberg line is divided into 11 segments and has 15 radial lines with sectioning equipment. The 44 secondary substations form 24 load points, see figure 9. Table 6 shows the number of different components along the lines.

4.3.2. Input data

One of the most important part of the project, the part that will affect the result the most, is the input data. This chapter is therefore written with the intent to thoroughly explain the origin of the data used in the project and the assumptions and simplifications that are made.

4.3.2.1 Outage statistics

The calculations of failure rates for the different components are built on the outage statistics kept by Fortum. The outage statistics are managed by Succel (see section 3.1.1.). A lot of information about the outages is kept in Succel and can be collected. Table 7 is an example of some of the data that can be listed. The information in Succel is in Swedish but has been translated here.

Date	Line	Voltage level	Cause	Damage	Customer	Customer hours
090723	020E	MV	Tree on street	OH LINE	311	464
090730	020E	MV	Tree, wind	OH LINE	98	391
090731	020E	LV	Tree, wind	OH LINE	11	69
090902	020E	LV	Unknown, fuse replaced	CABLE	7	5
090903	020E	MV	Tree, wind	OH LINE	98	141
091225	020E	MV	Tree, wind	OH LINE	28	51
100127	020E	MV	Snow(no tree)	OH LINE	28	50
100303	020E	MV	Component failure	OH LINE	12	14
100308	020E	LV	Component failure	CABLE	7	35

Table 7: Example of data from Succel

All outage data used to calculate the failure rates are on medium voltage level (except low voltage failure rate)**, longer than 3 minutes and shorter than 12 hours**. This is possible to filter in Succel. The reason for the outage length limitations is that this kind of data is used in the regulation of the DSO's, see section 2.3. SAIFI and SAIDI calculated from these outage data are used to adjust the revenue framework. These adjustments will be taken into account in this project and SAIFI and SAIDI produced by the model are therefore obtained in the same way as the ones in the regulation. The long outages (>12h) will be handled separately since the cost of these outages is much higher than for the shorter ones, see sections 2.2.2 and 4.4.

All extreme values in the data have been kept. When extreme weather situations occur it can have a great effect on SAIDI of that year. Storms are however a natural part of the weather over time. The outage data for the case lines are collected during several years and removing extreme values from the data might give a false value of what the real situation is like. None of the case line does however seem to have been hit badly by the biggest storms in the recent Swedish history, Per and Gudrun.

4.3.2.2 *Failure rates*

The failure rates of the components modeled in this thesis are listed in table 8.

Component/group of components	020E Charlottenberg	102A Lesjöfors
Overhead lines	**0.3**± 0.1	**0.08** ± 0.04
Cables	**0.02** ± 0.01	**0.02** ± 0.01
Breaker	0.001	0.001
Disconnector	0.05	0.05
Low voltage components	**0.08** ± 0.02	**0.05** ± 0.02

Table 8: Failure rates for the components in the project. Collected from outage statistics with the exception for breakers and disconnectors

A 95% confidence interval for the input failure rates has been calculated in accordance to equation (2.29) in [10] which reads:

$$\lambda \pm 1.96 * \frac{\lambda}{\sqrt{n}} \qquad \text{Eq. 23}$$

where n is the number of occurrences, in this case the number of outages. For this equation to be valid n has to be sufficiently large. The limit is n>15 according to [20, p. 184].

The calculations of the input fault rates to the models were made as follows.

Failure rate OH lines

	020E Charlottenberg	102A Lesjöfors
Time period	2005.01.01-2011.07.01	2001.01.01-2006.01.01
Number of years	6,5	5
Data origin	Outage data for L020E	Outage data L102A
Number of outages	66	22
Km overhead line	36.7	51.9
Fault rate	=66/36.7/6.5= =**0.3**± 0.1 faults/km and year	=22/51.9/5= =**0.08** ± 0.04 faults/km and year

Eq. 24: Failure rates of overhead lines

A main goal in the project has been to keep the input data as local as possible. This goes especially for the overhead line fault rate, since this value is the single most important for the resulting SAIFI and SAIDI of the models, see appendix 6. The same type of overhead line can have very differing fault rates depending on location. The terrain in the area is a far more important factor. If the line goes through forest with many trees growing close to it, the risk of outages increases. If the area also is very windy, the risk increases even more.

The overhead line fault rates were therefore the first to be calculated, to check if it was possible to use only the outage data from the actual lines. For the Charlottenberg line the time period chosen was 2005 – end of June 2011. This period was chosen because in this time no construction of underground cable (longer than 300 m) was done. Since the lengths of the lines are assumed to be directly proportional to the failure rate per km, it is very important to carefully measure the lengths of overhead lines and cables. This is another reason for keeping the data as local as possible, smaller areas allow for more precise length measurements. On the Lesjöfors line there had not been enough overhead line outages that a time period where there had been no construction of overhead lines could be chosen. Instead the time period 2001-2005 was chosen. In this time (see section 4.2) construction of the aerial cables was done on the north part of the Lesjöfors line and also some changing for underground cables on the south part. The work was done during 2001 and 2003. This changes the lengths of both cables and overhead lines, since the latter is demolished. However, since the area was kept small, the change in length could be computed and a mean cable length for 102A Lesjöfors could be calculated (see equation 31). In this time period there had been 22 outages due to overhead lines, which is enough to produce a statistically approved value according to theory of statistics, see equation 29.

	Overhead line [km]	Cable [km]
Before 2001	60.7	14.8
After 2001	55.1	19
After 2003	46.6	28.7

Table 9: Line lengths in Lesjöfors

The calculation of the mean lengths can be described with the (not-to-scale) figures 14 and 15.

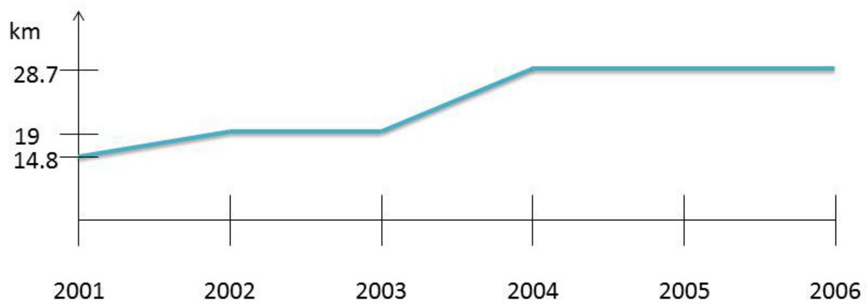

Figure 14: The change in cable length on 102A Lesjöfors during 2001-2006

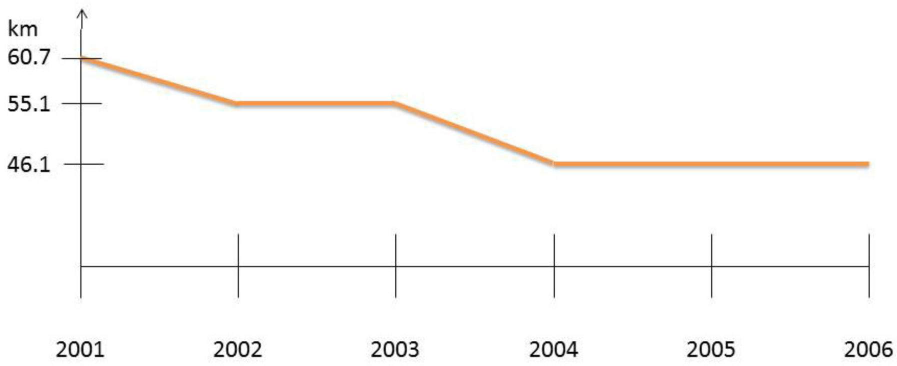

Figure 15: The change in overhead line lengths in Lesjöfors during 2001-2006

Calculation of the mean OH line length in the period 2001 to the end of 2005:

$$L_{OH} = \frac{\left(60.7 - \frac{60.7-55.1}{2}\right)*1 + 55.1*1 + \left(55.1 - \frac{55.1-46.6}{2}\right)*1 + 46.6*2}{5} = 51.91\ km \quad \text{Eq. 25}$$

Knowing the number of outages in a certain time period and the lengths of the overhead lines in the area the failure rate per km and year can be produced.

Fault rate cables

	020E Charlottenberg	102A Lesjöfors
Time period	2005.01.01-2011.07.01	2001.01.01-2006.01.01
Number of years	6.5	5
Data origin	14 substations around 020	10 substations around 102
Number of outages	67	20
Cable length	509.5 km	243.1 km
Fault rate	=67/6.5/509.5= =**0.02** ± 0.01 faults/km and year	=20/5/243.1= **0.02** ± 0.01 faults/km and year

Table 10: Failure rates of cables

When producing the fault rates for the cables the idea was to have at least as many outages of cables in the chosen time period as there were overhead line outages. Choosing the essentially same number of data points for the different failure rate calculations will give the same order of accuracy. For the cables, however, the outages on the specific lines are not as many as for the overhead lines. Cables have a smaller failure rate than overhead lines, there is also a lot more overhead line than cables in rural grids today. For the cable failure rate calculations either the time period or the geographical area for the statistics must be widened in order to cover more faults. Even when all the years available in the statistics are included for the case lines, the number of outages is not as many as the overhead line outages in the chosen time periods. Therefore the area of data collection was widened. The concession area where 020 Charlottenberg is located, 33 Arvika, was used when producing the value for the failure rate of cables on 020E. Fourteen substations (see Appendix 1) located around 020 were chosen (including 020). There had been 67 outages due to cables in this area, which corresponds to the number of overhead line outages along L020E during 2005-2011. When computing the value for 102A Lesjöfors ten substations in the area around the 102 substation was used (see Appendix 1). In this area there had been 20 cable failures.

Having larger areas for data collection complicates the measuring of line lengths. From PG a list of cables and overhead lines in the different concession areas can be extracted, a so called MV-report. The list contains among other things: lengths, types and installation years. This has however been found to not always be exact, especially the installation year (see discussion in Appendix 2). Zooming in on and measuring every line graphically in PG (which was done for the case lines) would however be too time consuming. Because of this the data in the MV report had to be trusted. The lengths of the cables in the area are summed and the increase of cable length during the time period is assumed to have equally big throughout the time period (i.e. not as carefully calculated as the Lesjöfors cable length increase).

	020E Charlottenberg	102A Lesjöfors
Area used	14 substations around 020	10 substations around 102
Cable length end of period	647.6 km	284.3 km
Length cable beginning of the period	371.5 km	201.8 km
Mean cable length	509.5 km	243.1 km

Table 11: Cable lengths in the areas around the substations

Calculation of the mean cable length

$$L_{C_{102}} = 201.8 + \frac{284.3-201.8}{2} = 243.1\ km \qquad \text{Eq. 26}$$

$$L_{C_{020}} = 371.5 + \frac{647.6-371.5}{2} = 509.5\ km \qquad \text{Eq. 27}$$

The substations that were used are listed in appendix 1.

Failure rate of breakers and disconnectors

	020E Charlottenberg	102A Lesjöfors
Breaker	**0.001** faults per component and year	**0.001** faults per component and year
Disconnector	**0.05** faults per component and year	**0.05** faults per component and year

Table 12: Failure rate of breakers and disconnectors

Data could not be collected in Succel for these components. If the data is scarce for cables, it is even worse for breakers and disconnectors. This could partly be because they are not as exposed to weather and wind as power lines are. Many breakers and disconnectors are located inside substations and are therefore more protected. They are also smaller, and the chances, for example, that a tree would hit them are therefore smaller compared to an overhead line.

Since data could not be collected from Succel in this case, reliability data earlier used in analyses of the electric grid of researchers at KTH were used [21, p. 158]. Lina Bertling (now professor at Chalmers) made her PhD at KTH and in her doctoral thesis a reliability analysis is made of the rural overhead line distribution system "Flymen", owned by the former Swedish DSO "Sydkraft". The outgoing lines from Flymen are basically of the same size as the case grids in this project and this is also a 10 kV system.

Faults on the low voltage grid

	020E Charlottenberg	102A Lesjöfors
Time period	2005.01.01-2011.07.01	2001.01.01-2006.01.01
Number of years	6.5	5
Data origin	Charlottenberg 020E, 020B, 020U	Lesjöfors 102A and 102E
Number of outages	60	21
Number of secondary substations	112	89
Fault rate	=60/6.5/112= =**0.08** ± 0.02 faults/sec substation and year	=21/5/89= =**0.05** ± 0.02 faults/sec substation and year

Table 13: Failure rate of low voltage faults

The faults on the low voltage grid are put together into one value. This is because **it is assumed that outages on low voltage grids do not spread to the medium voltage grid** because of protection equipment in the secondary substations [17]. **A simplification in the project is that it is assumed that every secondary substation has the same amount of low voltage faults a year**. This is probably not true since some secondary substations have a large low voltage distribution grid with a lot of overhead lines and others have just a few short underground cables. Since the low voltage faults do not affect many customers at the time and therefore have a limited effect on the reliability the simplification is assumed to be acceptable. The total number of outages on low voltage level is divided by the number of secondary substations. When calculating the low voltage failure rate for the Charlottenberg line three lines out from the substation is used, see table 13. This is because the low voltage faults on L020E Charlottenberg alone were too few. On all three lines 60 low voltage faults happen during the time period 2005.01.01 – 2011.07.01. The two extra lines were chosen to be rural lines that were fed from the same substation as 0202E Charlottenberg. The lines that feed the Charlottenberg town area were not used.

The procedure was the same in Lesjöfors. One other line had to be added in order to have a sufficient number of data points, L102E that supplies the southern part of the Lesjöfors area.

4.3.2.3 Fault restoration time

Another important variable in reliability analysis is the restoration time. The restoration time describes the time from a fault occurring until the power is back on again. This is, as explained in section 2.1 not equal to the repair time. The fault has to be discovered and found, and then repaired. The restoration time is varying between parts of the grids and between different kinds of failures. Because of the complexity, the restoration time is often assigned a mean value for all kinds of faults and for the time it takes to perform all tasks associated with restoring the power. As stated in [22] the use of mean values can however have significant disadvantages. ***In this project the restoration time has been divided into three parts; fault isolation time, fault location time and repair time***. The information on the time it takes to perform the different tasks in fault management was obtained during the study visits and interviews with the Fortum personnel. Almost all data are based on statements from the power systems operators and fitters. In order to model the sectioning time properly a simulation of sectioning was performed on the Charlottenberg line.

Task	Time
Discovering the fault	0.05 hrs
Reaching the first disconnector	1 hr
Time between two disconnectors	0.2 hrs
Sectioning with remote controlled disconnectors	0.167 hrs
Patrolling	4 km/hr
Fix cable time	3 hrs
Repair time for cables	4 hrs
Repair time for OH lines	3 hrs
Repair time for disconnectors	2 hrs
Repair time for breakers	1 hr

Table 14: Times of tasks in the fault management

Fault isolation time

This part of the restoration time describes the time from a fault's occurrence until the line has been sectioned and the customers on the lines where the fault did not occur have the power back. This includes several steps, like the power systems operator discovering the fault and calling a fitter or the time the fitter needs to get to the location of the fault. The greater part of this is however the manual sectioning. Depending on which line segment the fault is located, it will take more or less time to find and isolate. If the failing segment is right at the disconnector to first be opened, the fault will soon be isolated for example.

Lesjöfors

The fault isolation time will be very different depending on the sectioning equipment installed on the line. The Charlottenberg line has remote controlled disconnectors operated by the power systems operator or even automatically by the system. This shortens the fault isolation time drastically in comparison to the Lesjöfors line where all disconnectors have to be operated manually.

Discovering the fault
As explained in section 3.1 the SCADA system tells the power systems operator that a breaker has disconnected a failing line. The power systems operator will need a few minutes to for example go and get the net plan, try re-connecting the breaker and calling the fitters. This time is added to the total fault isolation time.

Discovering the fault [2]: 0.05 hrs

Fuses
At some places in the grid there are fuses that can disconnect the line behind it without the customers located before the fuse noticing it. The breaker will also not notice the fault and this means that the SCADA system will not send a message to the power systems operator. In this case the power systems operator is dependent on the blacked-out customers to inform the DSO about the outage.

The fuses can only break for the short-circuit faults, which are assumed to account for 60% of the faults. In the other cases the breaker will break and the SCADA system will notify the power systems operator.

A simplification that is made on the Lesjöfors line is that **it is assumed that the person calling the DSO is calling from the failing line segment**. This might give a slightly faster result on finding the fault. On 020E Charlottenberg most of the fuses are placed at radial lines, meaning that the person calling will always be calling from the failing segment.

The fitter reaches the first disconnector
The fitter has, according to the contract between the infrastructure service company and the DSO, a certain maximum time to get to the failing line after having received the call from the power system operator. This maximum time is 90 minutes in the Swedish county of Bergslagen, but one of the power systems operators was asked to estimate the *average* time it takes a fitter to reach and open the first disconnector as it often is performed faster than the maximum time.

First disconnector [2]: 1 hr

Sectioning
As discussed in section 3.2 the sectioning order on a line is decided by the power systems operator and depends on the power system operator's experience and knowledge. To find the likely order of sectioning on the original Lesjöfors line a power systems operator was asked to explain in what order the disconnectors were opened [2]. It must however be noted that the order of sectioning is often decided during the actual fault, and depends on the system operator. The order in which the

interviewed power system operator would have opened the disconnectors is described in the flow chart in figure 16.

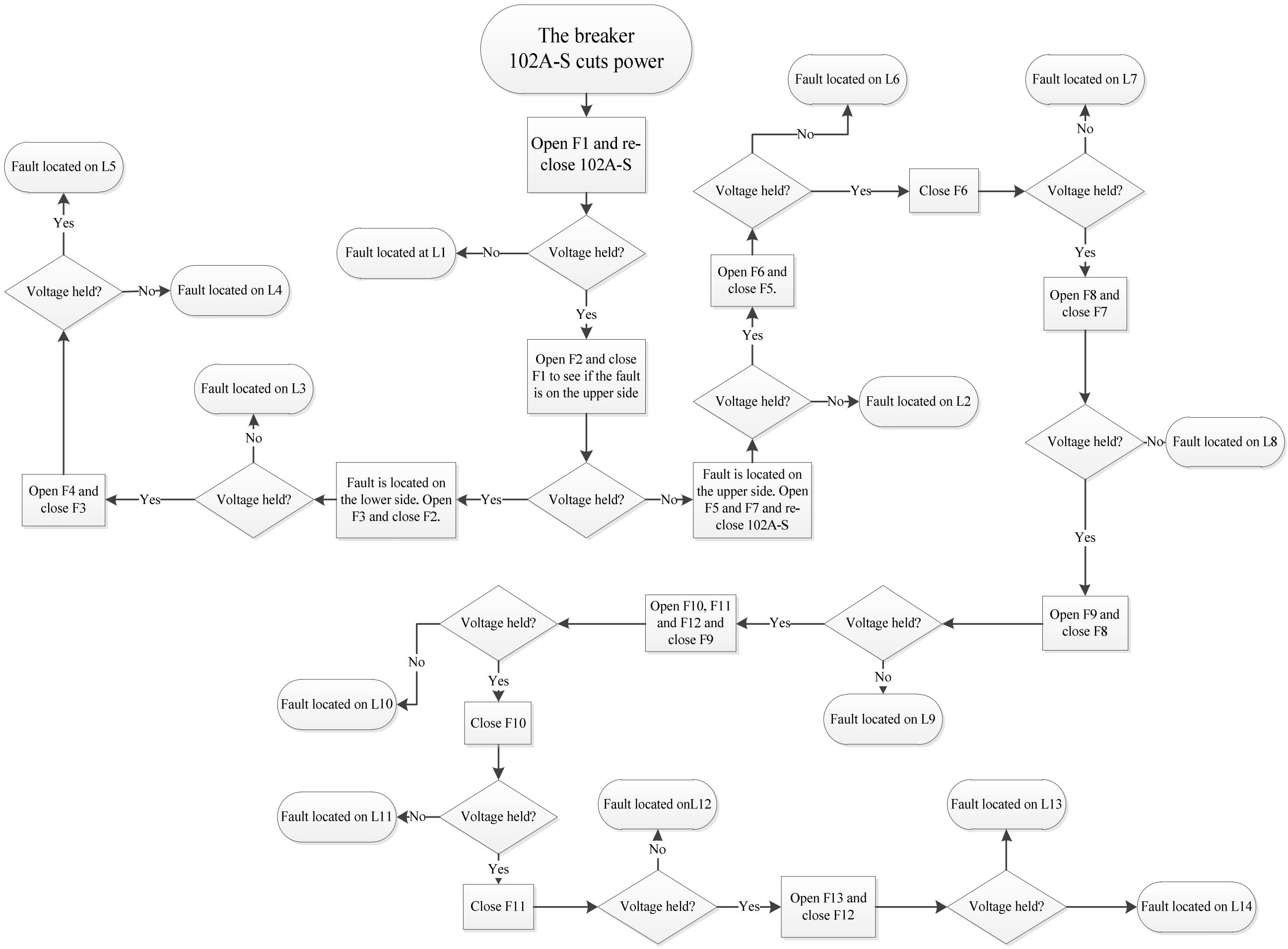

Figure 16: Sectioning order on the Lesjöfors line

The power systems operator explained that the first disconnector to be opened would be D1 in image 7. This is done to check if the fault is on the first line segment. Even though that disconnector is not in the middle it can be wise to start here since L1 is a risk area (see section 4.2). The next move would be to open disconnector 2 (D2) and close the first disconnector again. This would show if the fault is on the north or the south side, and depending on the result the rest of the line will be sectioned, either on the north or the south side.

Simulation of sectioning time

In order to examine just how long time the sectioning of a fault takes, a field test was performed with the help of one of the fitters working on the Fortum grid. The test was performed on the Charlottenberg line, even though this line has remote controlled disconnectors. The reason for doing so is that the line in Lesjöfors nowadays has cables for the most part and is therefore hard to simulate a sectioning on. Instead Charlottenberg was chosen and the result will then be applied on the model of the original Lesjöfors line with overhead lines.

The sectioning was initiated by going to the first disconnector on the line and “opening” it. This was done by parking the car as close as possible to it and the walking through the forest to the disconnector (in the case the disconnector was not located next to the road) and then allowing some time to pass. In this time the fitter would have called the control center and opened or closed the disconnector. The control center only had to be called when any line segment was going to be energized. The first disconnector was “opened”, and the first line segment was energized. Thereafter the fitter went to the second disconnector and opened it. This time the network control center did not have to be called since the segment was without power. When the second disconnector was opened we went back to the first one and closed it. This was then continued for all seven disconnectors that were in the simulation.

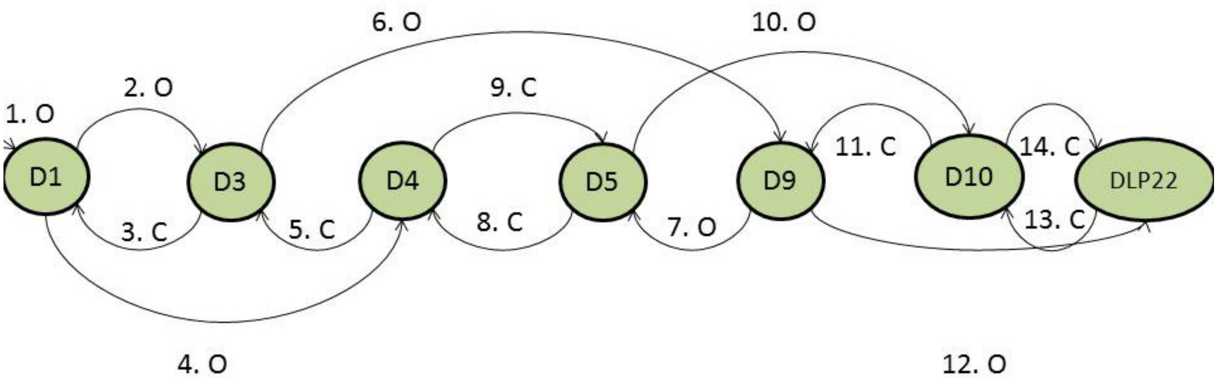

Figure 17: Order of sectioning during the simulation

Figure 17 shows the pattern of sectioning. The location of the different disconnectors can be seen in figure 9. The pattern follows the same basic rules of opening one disconnector and then going back to close the disconnector behind it, energizing only one segment at the time. One exception to this rule was made. The location of the disconnectors made it more convenient to open both D9 and D5 at the same time, thus saving time.

To estimate the time it takes to go from one disconnector to the next and open it, the value which will be used in the model, the total time of sectioning was divided by the number of trips between disconnectors. Since one has to go back and forth between the disconnectors, the seven disconnectors lead to 14 trips. The total time, 03:50 h, was hence divided by 14, producing the mean value of 12 minutes. In reality sectioning is often performed by two fitters working in a team to speed things up. One fitter then opens disconnectors and the other one closes them behind the other one. This method was not possible to simulate since only one car was at hand. The time estimates will however not be greatly influenced by this since the total time is divided by the number of trips. This experiment can hence be used both for single sectioning and sectioning in team.

The time between two disconnectors is affected by a number of things. If the fitter is used to the area there is no problem to find the disconnectors, but if not they can sometimes be hard to find. The fitter has got help from the operator who has the network plan to look at, but the disconnectors can sometimes be located inside the forest and hard to spot. Walking up to the disconnector through the forest will also take some time. Other times they are located by the roadside and very easy to get to. These disconnectors can of course be operated a lot quicker. Another variable is the connection to the network control center, sometimes more fitters are calling and there is a waiting line to speak to the operator.

Time between two disconnectors: 0.2 hrs

Isolation

When the failing line segment has been identified the fitter will isolate the fault and connect the secondary feeding. The isolation is often done by again opening the disconnector that was just closed, before the power went out. This is assumed to be done immediately. Sometimes however,

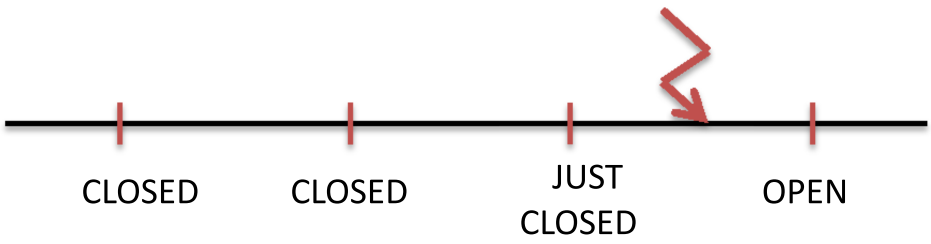

Figure 18: The fault can often be isolated by opening the disconnector that was just closed.

the fitter has to go somewhere and open another disconnector. This time is then added to the total fault isolation time, as is the time it takes to go to the secondary feeding point and give the power back to the other customers. This is assumed to be the same time as going between two disconnectors while sectioning.

Charlottenberg

The isolation of the fault on the 020E Charlottenberg line is much quicker because of the remote controlled disconnectors.

Discovering the fault and isolating it
The remote controlled disconnectors are so quick at sectioning that a fixed value is assigned to isolating the fault, independent of what segment of the line that is failing. In this part the time to discover the fault and register it in the computer etc. is also included.

Discovering the fault and isolating it [23]: 0.167 hrs

Local sectioning
Some disconnectors on the main line are manual and all disconnectors to the radial lines are manual. These disconnectors have to be opened by hand and **it is assumed that the fitter will always try to section the failing line segment with the manual disconnectors before starting to look for the fault (but after isolating the failing line segment). It is also assumed in the model that the fitter starts with the disconnector closest to the distribution station and goes out along the line**. The time to open the first manual disconnector will be equal to the time it takes the fitter to reach the area. The time to open the next manual disconnector is the same as the time between two disconnectors on the Lesjöfors line.

First manual disconnector [2]: 1 hrs

Next manual disconnectors[2]: 0.2 hrs

Fault location time
When the fault is isolated and the customers that can have the power back early do have the power back, the fitter starts looking for the fault at the failing line segment. This procedure will be the same for both the Lesjöfors line and the Charlottenberg line. Since the faults are most often on the overhead lines, the fitter will begin by examining those parts of the line segment. As described in section 3.2.2 this is done with the car in daylight and by walking next to the line at night, so called patrolling. A simplification in this project is that it is assumed that the fitter always patrols the line. This might give a slightly longer fault location time, but the alternative is found to be too complicated to model. (In appendix 6 a sensitivity analysis on the input data can be seen) The approximate time per km for the patrolling has been simulated by walking under the lines along a line corridor and clocking the time.

[2]Found through simulation

When modeling the fault location it must be taken into account that one cannot tell where the fault will be located, sometimes it will be found in the beginning of the line and sometimes in the end and so on. To compensate for this ***it is assumed that the fault is on average found after half the length of the overhead lines.***

Figure 19: The fitter sometimes have to walk along the line for long distances. Here a part of the 020E Charlottenberg line. Photo: Sabina Stenberg

When the fault is actually on a cable the fitter will still assume that it is on the overhead lines and search the entire line before "realizing" that it must be a failing cable. In this thesis ***it is assumed that the time to locate where on the cable the fault is, after the realization that it is in fact a cable fault, is fixed***. This is because when there is a fault on a cable the fitters have to wait for the cable bus, which then will make measurements on the cable and say somewhat exactly where the fault is. This ought to be independent of the length of the cable, which is also confirmed by the Infratek fitter Daniel Heidkamp.

The total time for patrolling a line segment will be calculated by multiplying the part of the faults caused by overhead lines with the time to find an overhead line fault and then add the same number for cables.

Patrolling time[3]: 4 km/hr

Fix cable time [15]: 3 hrs

Fault reparation
When the fault is found the reparation can begin. There are many different kinds of faults occurring in the grid. Some repairs will take ten minutes, e.g. cutting down a tree leaning on the line, others will be more time consuming. Sometimes spare parts must be fetched before the work can be started. It is therefore hard to give a specific number on the repair time. Nevertheless, one of the fitters was asked to estimate a value for the repair time of the four components included in the model [15]:

Repair time for cables: 4 hrs

Repair time for overhead lines: 3 hrs

Repair time for disconnectors: 2 hrs

Repair time for breakers: 1 hrs

4.3.3. Reliability analysis

The goal of the analysis is to produce the system reliability indices SAIFI and SAIDI for the model lines, i.e. the average number of outages for the average customer and the average length of these, see section 2.1. The base case will then be compared to the SAIFI and SAIDI of different investment scenarios and the most cost effective investment is deduced.

Every component in the case grids has been assigned its own reliability data; failure rate and restoration time. The unavailability, U, for every component can be calculated by multiplying its fault rate, λ, with the restoration time, r.

$$U_i = \lambda_i * r_i \qquad \text{Eq. 28}$$

The case lines in this project are examples of series systems. This means, see section 2.1, that every failure of a component will interrupt the function of the entire system. The customers at the load

[3] Found through simulation

points connected to the failing line segment have to wait the entire restoration time, but other load points might be able to get the power back sooner, thanks to sectioning equipment and secondary feeding possibilities.

The reliability analysis is made as follows. For every possible fault scenario the effect on every load point is calculated; number of faults per year, restoration time for this specific fault at this specific load point and the resulting yearly unavailability. The results are listed in a table. Table 15 shows a part of this table as an example of how the calculations are made. The table includes the values for the first three of 24 load points and the faults on the different line segments (including both cables and overhead lines). The other faults included in the model are faults on the disconnectors, breakers and low-voltage grid.

Load point	**LP 1**			**LP 2**			**LP 3**		
Failing component	**λ**	**r**	**U**	**λ**	**r**	**U**	**λ**	**r**	**U**
L1	1.146	**4.727**	5.416	1.146	0.167	0.191	1.146	0.167	0.191
L2	0.347	0.167	0.058	0.347	**4.523**	1.567	0.347	**4.523**	1.567
L3	0.318	0.167	0.053	0.318	*1.167*	0.371	0.318	*1.167*	0.371
L4	0.954	0.167	0.159	0.954	0.167	0.159	0.954	0.167	0.159
L5	0.895	0.167	0.149	0.895	0.167	0.149	0.895	0.167	0.149
L6	0.276	0.167	0.046	0.276	0.167	0.046	0.276	0.167	0.046
L7	0.897	0.167	0.149	0.897	0.167	0.149	0.897	0.167	0.149
L8	0.558	0.167	0.093	0.558	0.167	0.093	0.558	0.167	0.093
L9	0.722	0.167	0.120	0.722	0.167	0.120	0.722	0.167	0.120
L10	0.847	0.167	0.141	0.847	0.167	0.141	0.847	0.167	0.141
L11	1.070	0.167	0.178	1.070	0.167	0.178	1.070	0.167	0.178
Sum	**8.028**		**6.563**	**8.028**		**3.166**	**8.028**		**3.166**

Table 15: Table of the first three load point on the 020E Charlottenberg line and the impact of failing line segments on them. The bold numbers in the "r-column" are the complete restoration times. For the other line segment failures the load point is not impacted for the whole restoration time.

The fault rates for every fault scenario are added for every load point. The sum is the total amount of times load point *i* fails during a year. The "U" column holds the products of the fault rates and the restoration times and is also summed. The total unavailability *U* describes how many hours a year that load point *i* is without power. Different load points have different amount of consumers. This is taken into account by taking the total number of outages for load point *i* times its number of customers, which produces the column "Customers outages". This column is summed and the sum is divided by the total number of customers on the line to produce the SAIFI of the line. An example of the three first load points is shown in table 16 and the resulting SAIFI is calculated with equation 35.

Load point	Customers	Number of outages	Customer outages
LP 1	8	9.5	75.8
LP 2	6	9.5	56.8
LP 3	8	9.6	76.5
Sum	**22**		**209.1**

Table 16: Calculation of customer outages for the three first load points

$$SAIFI_{example} = \frac{209.1}{22} = 9.5 \; outages \; per \; customer \; and \; year \qquad \text{Eq. 29}$$

When calculating the average outage time per year and customer, SAIDI, the total outage time for load point *i* is multiplied with the amount of customers at that load point. An example can be seen in table 17 and calculation (eq. 36).

Load point	Customers	Unavailability [h]	Customer outage hours
LP 1	8	7.0	56.1
LP 2	6	3.7	22.4
LP 3	8	4.3	34.3
Sum	**22**		**112.9**

Table 17: Calculation of customer outage hours for the three first load points

$$SAIDI_{example} = \frac{112.9}{22} = 5.1 \; hours \; per \; customer \; and \; year \qquad \text{Eq. 30}$$

SAIDI and SAIFI of the model describe the condition of the line. If SAIFI is high it means that there are often outages here and some actions to lower the frequency of failures might be in place. If SAIDI is higher than usual it means that the part of the year when the line is unavailable is bigger than usual. SAIDI can be lowered either by shortening the outage time *or* by lowering SAIFI (i.e. lowering the number of outages that leads to an increased unavailability). The SAIFI and SAIDI in table 16 and 17 are just examples of how the calculations are made. The actual results will be higher because the faults on the rest of the components are added. It is however noteworthy that the if the customers on the Charlottenberg line are evenly distributed over the load points and if the load points are somewhat equally affected by failures of different lines – the SAIFI and SAIDI will be close to the numbers in the example. But load points with many customers or load points heavily affected by outages might also change these numbers considerably.

4.3.4. Calculation of costs

The cost of repair was calculated for the two lines as described in appendix 6.

Charlottenberg

Component	Cost per repair [SEK]	Failures per year	Yearly cost [SEK]
OH line	8 755	10.2	89 002
Cable	21 140	0.11	2 263
Disconnector	8 755	0.5	4 378
Breaker	8 755	0.001	9
LV components	5 150	3.6	18 676
Total cost			**114 328 SEK**

Table 18: Yearly cost of repair on the Charlottenberg line

Lesjöfors

Component	Cost per repair [SEK]	Failures per year	Yearly cost [SEK]
OH line	8 755	5.1	45 044
Cable	21 140	0.25	5 200
Disconnector	8 755	0.7	6 129
Breaker	8 755	0.001	9
LV components	5 150	9.1	46 739
Total cost			**103 120 SEK**

Table 19: Yearly cost of repair on the Lesjöfors line

4.3.5. Result of the models

When the reliability analysis is done on the two case lines the result can be listed.

4.3.5.1 *Reliability*

In appendix 9 are tables of the total number of annual faults and the total hours of unavailability for every load point. These are then related to the number of customer at the load point, and finally

SAIFI and SAIDI are calculated. The intervals are calculated by using the endpoints of the confidence intervals of the input fault rates to produce a lowest and a highest SAIFI and SAIDI.

020E Charlottenberg	SAIFI	SAIDI [h]
Model	10.05 ± 2.30	8.07 ± 1.83
Actual grid (Succel)	6.35	9.50

Table 20: Reliability indices of the model line and actual outage statistics for 020E Charlottenberg

This can now be compared to the outage statistics. The SAIFI and SAIDI indices have been calculated for the two actual case lines in the time periods that the fault rates for overhead lines were collected. These time periods were chosen because overhead line faults are the most important ones, and also the only data to be collected only on the specific lines.

102A Lesjöfors	SAIFI	SAIDI [h]
Model	5.27 ± 1.96	10.49 ± 3.86
Actual grid (Succel)	4.95	13.38

Table 21: Reliability indices of the model line and actual outage statistics for 102A Lesjöfors

4.3.5.2 Costs

The cost of reliability consists of repair cost, cost from the regulation and cost of long outages. The cost of repair for the base cases of the two lines can be seen in table 22 and the cost of long outages was calculated in section 4.4. The part of costs due to regulation will not be calculated for the base case. Instead the SAIFI and SAIDI of the base cases will be used as the norm costs when calculating the regulating costs for the investment scenarios, i.e. the change in SAIDI and SAIFI of the investment alternative relative to the base case will be input to the regulation costs.

	020E Charlottenberg	102A Lesjöfors
Repair costs	114 328 SEK	103 120 SEK
Long outages	2 826 SEK	3 964 SEK
Regulation	-*	-*
Total yearly cost	117 154 SEK	107 084 SEK

Table 22: Yearly costs on the case lines
***The regulation costs are not applicable here since it is the difference between investment alternative and the base case that gives this value.**

4.3.5.3 *Discussion of the model results*

The models of the grid that were created in this project are what the resulting conclusion and recommendations are based upon. Therefore it is of utmost importance that the models can reflect the reality well enough. The result of the models depends most strongly on the failure rates, restoration time and the order of sectioning (at least in Lesjöfors where the disconnectors are manual).

Failure rates

The key assumption in this project is that local data will produce a more accurate failure rate than average values of Fortum's entire electric grid. Therefore a goal has been to collect the input data for the failure rate as close to the case lines as possible. It is however assumed that the failure rate is constant over the entire line. This might be a setback for this model because, as earlier mentioned, the failure rate depends heavily on the terrain. The terrain can vary a lot locally, parts of the line can go through forest and other parts through fields, where the latter has a lot less risk of having trees falling it. An improvement to this model could be to use the local data for the components and then come up with a way to classify the failure rates depending on what terrain they are located in. This has not been done in this project because of limited time, but this could perhaps be input to another master thesis. This is further discussed in section 6.3.

Keeping the data local was also only possible for the overhead line faults. Failures of the other components in the project are so rare that the number of data points was not enough to produce a statistically approved value, see section (4.3.2.2). Therefore either the geographical area or the time period of data collection had to be broadened. This means that the failure rate values will be either not as local the overhead line failure rate or collected partly in a different time period, when reconstructions might have been made. The number of overhead line faults is what sets the requirement for the other faults as well. This means that if for example 30 failures due to overhead lines occurred on the case line, the area or time period must be widened until 30 cable failures have occurred when looking for the cable failure rate. The point of this is to keep the uncertainty of the different input data in the same range. (It might have been statistically enough to broaden the area or time period until 20 faults had occurred, but it was widened until 30 had occurred to have a value as accurate as the one for the overhead lines.) Keeping the data local led to uncertainties in the input data that makes the confidence interval of the result rather big. The resulting SAIFI and SAIDI have a confidence interval of more than ±20% for 020E Charlottenberg and over ±30% for 102A Lesjöfors. The Lesjöfors line model has a more uncertain result because it had less overhead line failures on the specific line than the Charlottenberg line had. Perhaps it had been better to widen also the area or time period for the overhead faults to obtain a more exact result. It is however hard to know if more data points from other lines in the area would have given a more exact result, or introduced data from problems that were not present on the case lines. Another problem with widening the area is that calculation of the lengths of the lines gets more complicated. If the data is very local the lengths of the lines can be manually calculated in PG. If not they have to be collected from a so called MV-report in PG which is not always very accurate. The lengths of the lines are assumed directly proportional to the failure rates, which is why it is important to measure them carefully.

Focusing on the overhead lines and adjusting the area and time period of the collection of data on the rest of the components to fit the accuracy of the overhead line calculation was probably not a bad idea. The overhead lines stand for the absolutely biggest part of the failures and the results are heavy dependent on the overhead line data. Therefore the focus has been to collect the just right data of this.

The breaker and disconnector faults were not possible to collect from Succel and had to be picked from another project. The data do however come from a similar system and the faults do not affect the results very much, and because of this it is assumed that the use of this data is acceptable.

Restoration times

In contrary to the failure rates, that are obtained through statistics, the data on the restoration time is almost completely based upon statements from the personnel working with fault management. The exception is the manual sectioning time that was simulated. The estimations of the average restoration times are probably very good, since the persons asked work with fault management of the electric grid every day. The average restoration time is however just an average. The actual restoration times are probably very fluctuating. Sometimes the faults are really easy to find and repair, if the fault happens during the day, in good weather and it is a tree leaning on the line, easy to spot and easy to cut down. Other times the faults can be a cracked insulator and happens in the middle of the night. It might very well take until daylight, or even longer, to find that fault. That the restoration times in this project describe the “normal” - when no problems occur- times is supported by the SAIFI and SAIDI of the outage statistics. The statistics show that compared to the models, the models tend to have a somewhat high SAIFI, whereas the SAIDI is lower than in the outage statistics. This could mean that the models of the case lines describe a theoretical best SAIDI- that could be obtained if everything went well. It could be useful to also try to improve the fault management as well as investing in technical solutions.

Electrical systems are complex and hard to model, and so is the operation of the electric grid. The fault management has been modeled in this project to obtain a reliability analysis closer to the reality. Even so, many assumptions had to be made. The sectioning order is however not performed in a pre-determined order, intuition and experience plays a big part in fault management, which is hard to model.

4.4. Long outages

The long outages (>12 h) will be handled separately in this project. This is because of the special circumstances of the long outages. They are rather rare, but when they occur they can lead to extensive costs, as explained in section 4.2. In that section it was also explained that the quality adjustment of revenue in the regulation was only dependent on the outages between three minutes and 12 hours. This is another reason for keeping the long outages outside of those models and model them separately.

Long outages are reported separately to the regulator and data on this is hence available, also including information on the individual compensation that was paid. In this project data of the long outages since 2008 was used. The aim here is still to keep the input data local, but because these outages are so very rare, seven concession areas in Värmland and the adjacent county Skaraborg had to be used to collect data. The numbers of medium voltage outages longer than 12 hours are listed in table 23 for every year along with the total amount of customer compensation that year.

Year	Number of outages >12 hours	Customer outages	Cost of outages (total)
2008	24	496	471 200 SEK
2009	2	54	23 016 SEK
2010	16	856	783 900 SEK
2011	9	193	173 700 SEK
Sum	**51**	**1599**	**1 451 816 SEK**

Table 23: Outage statistics for outages >12 hours in 7 concession areas in Fortum's grid.

Because outages over 12 hrs on medium voltage level only were caused by overhead lines the **only category for medium voltage is the failure rate of overhead line outages longer than 12 hours**.

In order to calculate the failure rate the total length of overhead line had to be computed. A lot of work has been done on the grid in recent years to change the overhead lines for cables. Underground cables have several advantages compared to overhead lines, especially in storms. Windy weather often causes large disturbances on the electric grid, trees falling on the lines for example. During the last decade two storms have greatly influenced the Swedish grid construction. The worst one, Gudrun, hit in 2005 and two years later little brother Per also took down many trees and power lines in a large part of Sweden. This led to a demand for more weather securing investments and an extensive program to change overhead lines for cables was initiated. Fortum has data on how many kilometers of cable that has been installed since 2006, see table 24.

Area	2008	2009	2010	Sum
Värmland/Skaraborg	470	290	330	**1090 km**
Gävleborg/Dalarna	220	110	150	**480 km**
Västkusten	80	100	70	**250 km**

Table 24: Kilometers of installed cable

The outage frequency data has been collected from the Värmland/Skaraborg area (in order to fit with the data of cable installation) so the top row is the one used in the calculations. The goal is to find an average length of overhead line by calculating today's length in Värmland/Skaraborg and then compensate for the reduction in overhead lines. The value of 2011 is not known and has been estimated as the average of the cable length increase of the three previous years.

$$Cable\ length\ increase\ 2011 = 363.3\ km \qquad \text{Eq. 31}$$

$$Total\ cable\ length\ increase\ since\ 2006 = 1453.3\ km \qquad \text{Eq. 32}$$

It must also be taken into account that when cables are installed, they are longer than the overhead lines that were removed. This is because cables are often placed along roads, whereas overhead lines can be built pretty much straight from the substation to the customer. The demolished overhead line can be assumed to have been 15% shorter than the cables [18]. This means that the 1453.3 km of cable have replaced 1671.3 km of overhead line in Värmland/Skaraborg. The total length of overhead line in the Värmland/Skaraborg area in 2011 can be seen in table 25.

Concession area	*OH 2011 (km)*
Bergslagen	407.7
Arvika	881.9
Karlstad	508.4
Nor-Segerstad	27.8
Nordvärmland	1065.0
Mariestad	984.4
Tiveds Energi	141.8
Sum (km)	**4017.0**

Table 25: Overhead line length

The mean overhead line length is calculated the same way as the average cable length in the area around the case lines when calculating the failure rate for cables (section 4.3.2).

$$Length\ of\ OH\ lines_{average} = 4017 + \frac{1671.3}{2} = 4852.7\ km \qquad \text{Eq. 33}$$

According to the theory in this thesis the failure rate for long outages on overhead lines will be described by the 51 long outages in the area divided by the line length and the number of years.

$$\lambda_{Long\ OH} = \frac{51}{4852.7*4} = 0.00263\ faults\ per\ km\ and\ year \qquad \text{Eq. 34}$$

In order to know what yearly costs the long outages will cause on the case lines the average cost of a long outage is deduced. The number of kilometers will then give the number of long outages a year, and hence the cost of them. The reason for using average cost per outage, instead of relating it to the number of customers, is because it is hard to know the number of customers that would be affected by a long outage on one of the case lines. The long medium voltage outages are calculated for the entire line and therefore an average cost per outage has been used.

$$Average\ cost\ of\ a\ long\ outage = \frac{Total\ cost\ of\ outages}{Number\ of\ outages} = \frac{1\,451\,816}{51} = 28\,467\ SEK \qquad \text{Eq. 35}$$

Cost due to long outages:

	020E Charlottenberg	102A Lesjöfors
Number of faults a year	36.7 km * 0.00263 faults/km = **0.096 faults per year**	51.9 km * 0.00263 faults/km = **0.14 faults per year**
Cost of long medium voltage outages	0.096 faults * 28 467 SEK/outage = **2745.0 SEK/year**	0.14 faults * 28 467 SEK/outage = **3885.7 SEK/year**

Table 26: Costs due to long outages on medium voltage level

According to this way of calculating, the cost of long outages will be 2750 SEK for the Charlottenberg line and 3900 SEK for the Lesjöfors line. In this analysis, however, the assumption is made that the long outages are dependent on the length of the line. It is not obvious that this is true. Long outages might depend more on other factors like not having enough personnel.

The low voltage long outages were dealt with a little bit differently. Since the low voltage faults have not been modeled per km line in this project, but rather per secondary substation, a failure rate per km line was not deduced. The low voltage faults concern only a few customers at the time, most often only one customer is affected. Because of this it was possible to calculate the long outage cost taking the customers into account. The long low voltage faults during the last 4 years were studied and the total cost and number of customers that had had a long outage were noted. The cost per customer was produced and the number of customer affected by a long outage was weighed to those who had not had a long outage on low voltage level. It was deduced that 0.23‰ of the customers in the same 7 concession areas used for the long medium voltage outages had had a long low voltage outage. The mean cost per customer outage was 1084 SEK, slightly above the minimum compensation level. The yearly cost per line can be produced knowing how many customers that live along the case lines.

	020E Charlottenberg	102A Lesjöfors
Customer compensation LV	80.7 SEK	78.4 SEK

Table 27: Costs due to long outages on low voltage level

None of the investment scenarios in this thesis will however change this cost estimation since none of them affect the low voltage faults.

In the medium voltage calculations in this section it is assumed that the long outages depend on the length of the overhead lines. This is probably not entirely true. More overhead line causes more faults, but the circumstances that make the outages longer than usual might depend on other things. Shortage of human resources is a commonly indicated cause in the data that have nothing to do with the length of the line. The time of the day also plays a big part in how long outages get. The faults are much harder to find during the night. During storms the reason for waiting can also be personal safety.

Another drawback of dividing the total amount of faults that lead to long outages by the length of all lines is that every line gets a very small fraction of a fault per year. The average cost of long outages per line then gets very small and is not giving enough incentives to invest in actions to prevent these outages. Most years there will not be a long outage on the line, but if it does happen one year the costs may be very large. Analyzing the long outages is preferably done with a wider perspective and not just looking at one line. The preventive actions must however be thoroughly integrated with the investment planning that is performed on one line at the time.

A better approach to this problem is discussed in section 6.3.2.

5. Investments

Different types of investment scenarios were carried out on the case lines. The decisions of what investments to do were taken together with the net planners at Fortum. The investment alternatives include some of the more common investments, like changing overhead lines for cables, but also new and untested investments. An example of the latter is reducing the voltage on minor radial lines to 1 kV in order to keep the fault from spreading, which is a new type of investment. The results in this thesis can give an indication of whether it is worth to keep investigating and perhaps implement this kind of reliability enhancing investment.

The investment alternatives examined in this project are:

- Changing overhead lines for underground cables
- 1 kV voltage reduction on radial lines
- Changing manual disconnectors to remote controlled ones
- Adding a secondary feeding possibility
- Line breakers

5.1. Investment planning at Fortum Distribution AB

In this section the methods of planning investments for better reliability at Fortum is described. This has been thoroughly studied in [24] and for this project interviews with the Asset Managers Ove Levein [17] and Roland Lennartsson [25] has been conducted.

Fortum has a list with the 100 lines in the grid in the most need of renovation. The lines are ordered after how many customer outage minutes they have [17]. The net planners pick a line from the top and decide what investments are adequate for this area. Overhead line faults are the most common ones and changing the lines for underground cable is therefore the number one priority when choosing investments [25]. The net planner studies the line with the most customer outage minutes and examines where on the line the most faults occur. When that line segment is identified the ground conditions in the area is analyzed to find out if changing for underground cable is possible. If this is not possible the second alternative is to have aerial cables or isolate the overhead lines [25].

Another investment that can be considered is for example installing remote controlled disconnectors at the base of radial lines. If a long line is feeding only a few customers, digging a cable might be a too costly way of assuring better reliability to them, but the problems on the radial line might affect the customers on the entire line. If a remote controlled disconnector is installed, the line can be quickly disconnected if it fails. The customers living on the radial line will have to wait for the line to be repaired, but the rest of them will soon have the power back.

The investments are evaluated and the improvement from the investment is estimated. If, for example, half of a long overhead line is exchanged for underground cable most of the faults, due to wind, threes and thunder for example, are eliminated. This means that the SAIDI can be estimated to drop to half of its original value. When Fortum calculates the benefits of making the investments it is assumed that cables have no failure rate [17]. This is because of the significantly lower failure rate. In the same way, if a radial line is isolated with a remotely controlled disconnector the faults behind the disconnector are assumed to only concern the customer behind that disconnector. This is because the remotely controlled disconnectors are so quick that the customers on the main line hardly notice that the power goes out.

As earlier discussed, simplifications are a must when analyzing the electric grid. The net planners know from experience that overhead lines are the uttermost important component for the reliability. It is therefore considered that assigning a fault value to cables does not contribute to the result enough to make up for the extra complexity of the analysis. It is the same case with for example considering the fact that some of the customers can get the power back from a secondary feeding or that the customers on the main line also have an outage before the remote controlled disconnectors have sectioned the line.

The net planners then insert the percentage reduction of SAIDI in a computer program (excel file) that calculates what reduction in customer outage hours this corresponds to and, based on the regulation, what savings can be made. The cost of investment is also given to the program that calculates if the project is profitable. The investments are measured in two business ratios: SEK per decreased customer outage minutes and SEK/km isolated line. By “isolated line” Fortum means the length of the line where faults can now be assumed to have been eliminated. If remote controlled disconnectors have been installed on radial lines, those lines are now isolated. Faults on these lines will not affect the main line customers.

$$Business\ ratio\ 1 = \frac{Total\ cost}{decreased\ customer\ outage\ minutes} \qquad \text{Eq. 36}$$

$$Business\ ratio\ 2 = \frac{Total\ cost}{km\ upgrade\ line} \qquad \text{Eq. 37}$$

The investment alternatives have to satisfy a certain level of both of these values. Investment alternatives outside of the borders need extra motivation if they are to be performed [18]. Chart 1 shows an example of the diagrams used for determining if an investment should be performed.

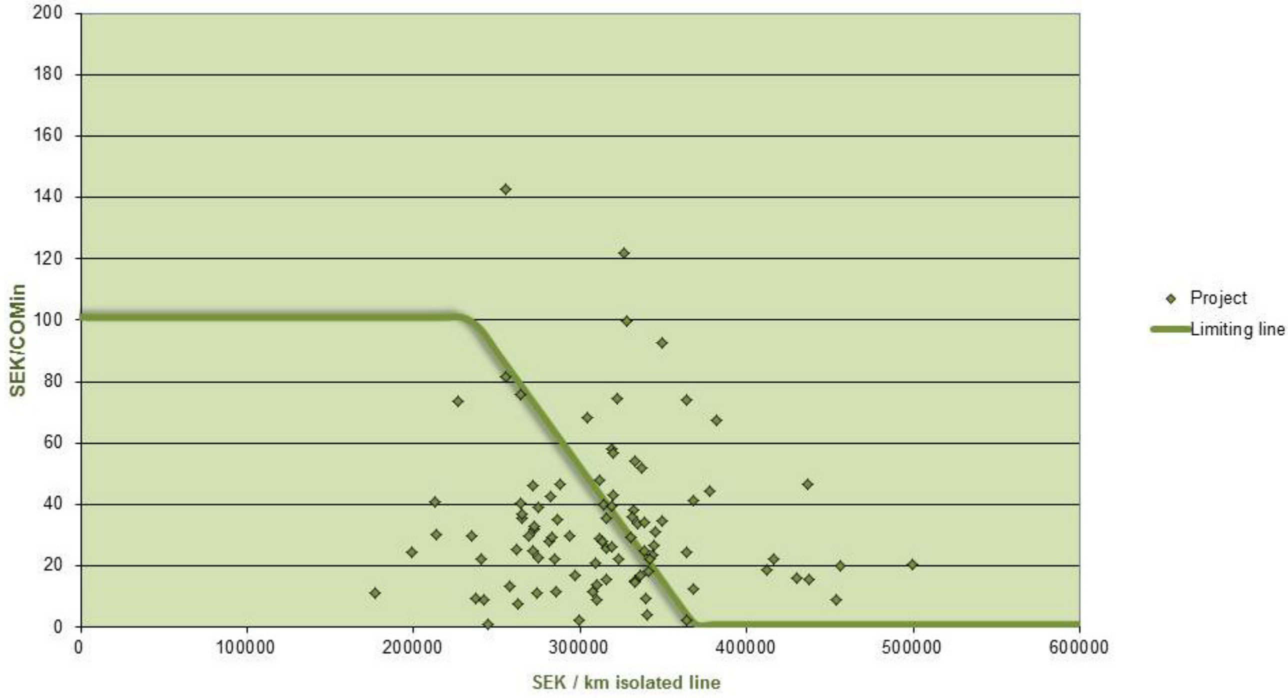

Figure 20: Example of a diagram used when determining if project will be performed. Projects under the limiting line will be performed and the projects above the limiting line will have to be motivated further.

When the cost and revenue of a project has been estimated the project is sent to the closest superior of the net planner for confirmation. Depending on size, i.e. investment cost, the project is either confirmed by the closest superior or forwarded higher in the organization.

Planning investments in the grid requires experience and knowledge of the grid. The net planners at Fortum know where the most faults occur and which investments are the most effective.

5.2. Calculation of the investments

The base cases of the case lines are changed according to the investments that are evaluated. Examples of what can be changed in the models are lengths of cables and overhead lines, switching time or how far the fault can spread. New values of SAIFI and SAIDI are calculated for every investment. SAIFI and SAIDI will be input to the calculation of the quality adjustment from the regulation. The decrease in customer outage minutes is input to one of the business values.

The different investment alternatives are compared with one another according to the same two business ratios that are used by Fortum Distribution AB (see section 2.3). A *life cycle cost analysis* (LCC) is performed for the different investment alternatives to determine which one is the most cost-effective, thus allowing for them to be prioritized. An LCC analysis considers the total costs and income of an asset over its entire life length. The life length for the investment alternatives in this thesis has been decided to be 40 years, the economic life length used by EI [26].

All costs and benefits for the investment alternatives are calculated and summed up to a total cost. The total cost consists of :

- **Investment cost**
  The actual cost of for example installing cables and demolishing old overhead line. A list of the costs and a description of the calculation of investment costs for every investment scenario can be seen in Appendix 4.
- **Changes to the revenue framework due to a Quality Adjustment**
  The improved reliability leads to a positive quality adjustment in the regulation that can be subtracted from the investment cost. The reliability is compared to a reference, the level of reliability before the regulatory period. After the regulatory period the reference level is reset and is set to the then current value. This means that the investment will be granted the Quality Adjustment for four years.
- **Repair cost/benefits**
  Adding or removing equipment or lines might affect the yearly repair costs. This item might be added to or subtracted from the investment costs depending on investment kind.
- **Customer Compensation**
  If the investments alternatives have an effect on outages >12 hrs the yearly amount of customer compensation might change. Note that for example adding more overhead lines might increase the risk of long outages, and this item can hence be both positive and negative.

- **Changes of the revenue framework by change of the value of the Capital Base**
  the DSO has a right to compensation for cost of capital according to the regulation. Changing the amount of equipment or lines will change the capital base and hence change the revenue framework. Adding more assets is favorable as it will increase the revenue framework. The value of the asset will be added to the revenue framework by the *annuity method* which means that the yearly value of the asset will be fixed, with compensation for the interest. The interest level is set by EI and the current value (Feb 2012) is 5.2% [11]. The costs used to calculate the Capital Base are the investment costs in Appendix 4. This is a simplification since EI uses norm values.

The costs and benefits are calculated over the 40 year life length of the investments. It must be considered that the value of money will not be as much in 40 years as today. If that money was at hand today it could also be invested in something that might give at better return than the current investment. To be able to produce a total cost for the entire life length of the investment the *net present value method* is used as explained in [10, p. 33] . The net present factor (NPF) of the costs is calculated by using the *discount interest* (z) at Fortum Distribution AB and assuming the inflation (i) to be 2%.

$$NPF = \left(\left(1 + \frac{z}{100}\right)\left(1 + \frac{i}{100}\right) - 1\right)^{-n} \qquad \text{Eq. 38}$$

where *n* is the number of years. All costs and incomes during the life length of the asset will be multiplied with net present factor and added together to produce the total net present value of the investment.

This cost is then divided by the number of decreased customer outage minutes the investment alternative leads to, in order to produce the business ratio SEK/decreased customer outage minutes. The second business ratio used by Fortum in investment planning (see section 2.3) is SEK/km isolated line. This business ratio will also be calculated for the investment alternatives where this is applicable. For some of the investments however, a length of isolated line cannot be deduced.

5.3. Investment alternatives

In this section the different investment alternatives that have been implemented on models of the case lines are described.

5.3.1. Changing for underground cables

This investment is the most common one, and the fact that changing the overhead lines for cables will reduce SAIFI and SAIDI is well known. It is however appropriate to include this type of investment into the project. One reason is to compare it to the other investments, which may not be as easy to evaluate. The result of, for example, the investment of adding a secondary feeding possibility can be evaluated by comparing how much better or worse it is compared to the cable investment alternative.

Changing for cables is the investment that was performed by Fortum on the actual Lesjöfors line and the current design of the line is described in section 4.2.3. The total investment cost for the restoration that was carried out on the Lesjöfors line is calculated in table 28, and is a little over 20 million SEK.

	Demolished OH	Installed cable	Demolished Substations	New Substations	Total Investment cost
Changed components	42.3 km	58.3 km	26	31	
Cost	762 235 SEK	17 475 390 SEK	92 040 SEK	2 108 000 SEK	**20 437 665 SEK**

Table 28: Investment cost for installing cables on the Lesjöfors line

From the investment cost the adjustment on the return of capital, the decrease of repair costs and the amount saved on customer compensation and the capital base will be subtracted. The adjustment of the return on capital depends on the change of SAIFI and SAIDI as described in section 2.3.5. The change for underground cables have improved the reliability and lowered SAIFI and SAIDI, which will lead to a positive quality adjustment and hence a bigger revenue framework. The quality adjustment is however assigned a negative value in table 29 since the positive quality adjustment can be subtracted from the investment cost. Since there are now more cables on the line, there will not be as many outages and the repair cost will be lowered. There will also be fewer long outages on medium level. The change in customer compensation is noted in table 29. Since installation of cables will be done along roads and not as straight as the overhead lines, the cables will be longer than the demolished overhead lines were. This means that the capital base is going to increase and so will the revenue framework. With the annuity method a yearly amount is calculated.

Changing to cables on 102A		
Customer outage minutes	-75 810	ΔCOM/year
Investment cost	20 437 665	SEK
Repair cost	-7 517	ΔSEK/year
Quality Adjustment	- 26592	ΔSEK/year
Customer compensation	-3 170	ΔSEK/year
Yearly Capital Base Value	-21 089	ΔSEK/year

Table 29: Result and costs for the investment alternative of changing overhead lines to cables on the Lesjöfors line

Charlottenberg

On the Charlottenberg line the line segments were examined separately in order to see where on the line cables would have the most effect. The line segments were reconstructed into cables in the model by adding the length of the overhead lines to the length of cables, with an additional 15% of the original overhead line length [18]. The investment costs can be seen in table 30 ordered by cost of investment.

Line	Length OH [m]	Installed cable [m]	Substations	Investment cost [SEK]
L3	1148	1320.2	4	842 884
L2	1778	2044.7	2	858 494
L6	1886	2168.9	2	897 698
L8	1954	2247.1	5	1 242 002
L9	2593	2981.95	4	1 367 419
L10	3059	3517.85	3	1 430 037
L1	4084	4696.6	1	1 589 032
L4	4227	4861.05	3	1 854 021
L7	4592	5280.8	5	2 199 596
L5	4149	5890.3	5	2 374 472
L11	6257	7195.55	10	3 336 691

Table 30: Investment cost for the different line segments on the Charlottenberg line

The cost and savings in SEK for every line segment was calculated and can be seen in table 31. The installation of cables and demolition of overhead line will lead to a decrease in repair costs and customer compensation for long outages. The enhanced reliability will lead to a positive quality adjustment in the regulation, and so will the fact that there is now more line installed along the line.

Line	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
L3	842 884	- 2 220	-1 927	-86	-12 100
L2	858 494	-3 439	-2 061	-133	-9 294
L6	897 698	-3 648	-3 819	-141	-9 585
L8	1 242 002	-3 779	-3 354	-146	-16 523
L9	1 367 419	-5 015	-3 979	-194	-15 994
L10	1 430 037	-5 916	-3 491	-229	-14 998
L1	1 589 032	-7 899	-4 411	-306	-13 257
L4	1 854 021	-8 175	-6 303	-316	-18 145
L7	2 199 596	-8 881	-12 143	-344	-23 632
L5	2 374 472	-7 547	-6 039	-311	-42 540
L11	3 336 691	-12 101	-14 003	-468	-39 377

Table 31: Costs of investments on the different line segments

5.3.2. 1 kV- voltage reduction

In order to lower the unavailability of the line, some of the medium voltage radial lines can have their voltage reduced with an 11/1 kV transformer at the base of the radial line. This is a new and relatively untested investment, which makes this a very interesting investment alternative to investigate.

On the customer side a 1/0.4 kV transformer has to be installed and an extra ground cable (PEN) needs to be installed between the stations. If this is done, **any faults on the radial line will affect only the customers living on that specific line**. This is because low voltage faults, as mentioned before, see section 4.3.2, will not spread to the superior grid. The fault protection equipment in the substation will disconnect the failing part. The down side of having low voltage lines, however, is trouble with keeping the voltage level fixed. If the line is feeding too many customers, the voltage will drop. A limit is set on 6 household customers [23]. Lower voltage does also mean more losses since the current is increased when the voltage is decreased. This is out of the scope of this thesis but should be taken into account when considering this type of investment.

This investment scenario is in reality only suitable on the Charlottenberg line. The Lesjöfors line does not, in contrary to the Charlottenberg line, have very many radial lines with a suitable number of customers. In Charlottenberg four radial lines fit the criteria for a voltage reduction investment, see table 32. The rest of the secondary substations are either located right on the main line, connected with a cable (which have so few faults that an investment is assumed to be unnecessary) or they have too many customers connected to them. However, just to try this new investment alternative, it was calculated for the Lesjöfors line as well. On line segment L5 the five secondary substations were divided into two radial lines, see table 33 and figure 8.

Load point	Number of customers	Length of OH line [m]
LP7 Nordsjöhaget	4	783
LP8 Rönningen	2	973
LP11 Björnsätra	6	389
LP14 Bråten fjäll and Åsen fjäll	6	875

Table 32: The load points on 020E Charlottenberg on which the 1 kV- investment are implemented

Load point	Number of customers	Length of OH line [m]
LP6 a	8	947
LP6 b	14	2393

Table 33: The load points on 102A Lesjöfors on which the 1 kV- investment are implemented

The investment cost for the voltage reduction will be the same for all six radial lines. The cost of the two transformers needed for the investment adds up to 55 100 SEK. The total cost then depends on how much that can be saved on the regulation and customer compensation. Since transformers are not taken into account in the model (due to their low fault rate), the repair cost will not be affected by this investment. In reality the installation of extra transformer might increase the repair costs somewhat.

Charlottenberg

Line	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
RLP7	55100	0	-880	-59	-1 204
RLP8	55100	0	-438	-73	-1 204
RLP11	55100	0	-181	-29	-1 204
RLP14	55100	0	-1450	-66	-1 204

Table 34: Costs of the 1 kV investments on the Charlottenberg line

Lesjöfors

Line	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
1 kV a	55100	0	-960	-179	-1 204
1 kV b	55100	0	-2135	-71	-1 204

Table 35: Costs of the 1 kV investments on the Lesjöfors line

5.3.3. Installation of remote controlled disconnectors

The disconnectors on the Lesjöfors line have to be opened manually by the fitter. Since the fitter have to reach the area before the sectioning can start, the manual sectioning is very time consuming. One investment scenario is therefore to upgrade manual disconnectors on the Lesjöfors line to remote controlled ones.

It was decided to not change all disconnectors into remote controlled ones, but to instead choose four strategically placed disconnectors to upgrade. Disconnectors D2, D5, D7 and D10 were chosen, see figure 8. The first three are located around L2 and remote control of these disconnectors enables the operator to determine whether the fault is on the south side (L3-L5), on the northwest side (L6-L7) or on the northeast side (L8-L14). This gives the fitters a good head start on where the fault is located. Disconnector D10 was also upgraded since the northeast part is so long. When the remotely controlled disconnectors are placed like this the fitters have to go to only one manual disconnector each and section from there to know on which line segment the fault is. The fault sectioning is described in appendix 3.

The investment cost of this investment alternative is not very high, compared to other kinds of investments. Upgrading four disconnectors to remote controlled ones costs just above 200 000 SEK. The investment will not lead to any difference in the repair costs (according to the information available) and since the sectioning equipment cannot help to avoid a long outage for all customers, only some, the customer compensation will not change. The total costs of this investment alternative can be seen in table 36.

Remote controlled disconnectors on 102 A		
Customer outage minutes	-85 205	ΔCOM/year
Investment cost	218 800	SEK
Repair cost	0	ΔSEK/year
Quality adjustment	-25 264	ΔSEK/year
Customer compensation	0	ΔSEK/year
Yearly capital base cost	-13 102	ΔSEK/year

Table 36: Costs and benefits of upgrading four manual disconnectors to remote controlled ones on the Lesjöfors line

5.3.4. Secondary feeding

This investment was performed on both 020E Charlottenberg and 102A Lesjöfors since they both had one long radial line with no secondary feeding. On both lines, the end of the radial lines were connected to the nearest adjacent line. On the Charlottenberg line the line segment L8 (see figure 9) was connected to the adjacent 255E Strand line and on the Lesjöfors line the line segment L5 was connected to another line out of the Lesjöfors substation, 102C, see figure 20.

The overhead lines are assumed to be drawn straight to the adjacent line, whereas the cables have to be installed along a road. The lengths of the new lines were measured in PG and can be seen in table 37.

	020E Charlottenberg	102A Lesjöfors
Overhead line	1569.1 m	3589.6 m
Cable	1720.4 m	4018.8 m

Table 37: Length of the lines installed to connect the case line with a secondary feeding possibility

When the reliability of the line is improved, the quality adjustment is positive and adds to the revenue framework (and will hence be negative in table 38 since it will be subtracted from the investment cost). The revenue framework will also be increased due to the fact that the capital base now is bigger. Adding more line will increase it and since no components are demolished in this investment alternative the change of the revenue framework is quite large.

The new line will however also bring its own failure rate into the equation and might cause blackouts itself. This depends on where the open disconnector is located. In this project it is assumed that the open point will be located where the new line meets the adjacent line. This is done so that the downsides of installing a new line will be caught in the model as well. As a test, it was also examined what the SEK/COMin ratio would be if instead *two* open remote controlled disconnectors were installed, one on each end of the new line. This way, faults on the connecting line would not affect the case line *or* the adjacent line.

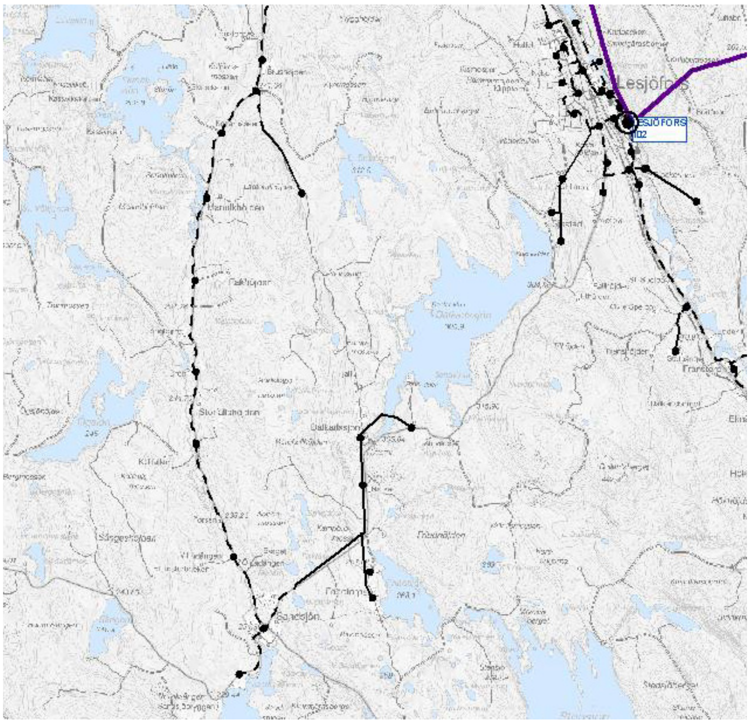

Figure 21: The south part of the Lesjöfors line can be connected to 102C Lesjöfors, a line out from the same substation

The increase in repair cost from adding more power line has been calculated, even in the case where the repair does not affect the customers (when there are two open disconnectors). This is because it would be unfair to not assign those costs to the case line. Adding more overhead line will also increase the risk of long outages, which is why the customer compensations increase. In this investment alternative the total costs are calculated by *adding* the repair cost and customer compensation cost to the investment cost. The investment will however lead to better overall outage statistics, so the quality adjustment is still positive (and hence negative in the table).

Charlottenberg	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
020E Cable	596 520	+717	-6 287	0	-35 721
020E OH	551 130	+3 787	-3 426	+117	-33 003
020E Cable 2 disc	676 920	+1 137	-6 600	0	-40 536
020E OH 2 disc	631 530	+4 207	-6 600	0	-37 818

Table 38: Costs of the investment to add a secondary of feeding on the 020E Charlottenberg

Lesjöfors	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
102A Cable	1 286 040	+1 402	-3 234	0	-77 011
102A OH	1 157 280	+2 664	- 903	+269	-69 301
102A Cable 2 disc	1 366 440	+1 840	-3 820	0	-81 826
102A OH 2 disc	1 237680	+3 102	-3 820	0	-74 116

Table 39: Costs of the investment to add a secondary of feeding on 102A Lesjöfors

5.3.5. Line breakers

All other investment alternatives in this project, except for the 1 kV investment, still mean that the line will disconnect all customers for every fault. In some cases the power can come back quickly for some customers, but everyone will still have an outage. Installing a line breaker somewhere in the middle of the line will assure that the customers closer to the substation do not have to have an outage if the fault happens behind the second breaker. This is, just like the 1 kV-investment, a fairly untested investment and it is therefore implemented on both the Lesjöfors line and the Charlottenberg line. The total costs for both lines can be seen in table 40.

Lesjöfors	Investment cost [SEK]	Repair costs [ΔSEK/year]	Quality adjustment [ΔSEK/year]	Customer compensation [ΔSEK/year]	Capital Base Value [ΔSEK/year]
102A Lesjöfors	200 000	0	-7 813	0	-10 438
020E Charlottenberg	200 00	0	-7 150	0	-8701

Table 40: Cost of the investment of adding a line breaker

5.4. Result of the investments

In this section the result of the investments are presented. Both the impact on SAIFI and SAIDI and on the business values is listed.

5.4.1. Result on the Lesjöfors line

The resulting SAIFI and SAIDI of the investments in Lesjöfors can be seen in table 41. This table is ordered after the investment alternative that resulted in the smallest SAIDI.

102A LESJÖFORS	SAIFI	SAIDI
Remote controlled disconnectors	5.27	5.81
Cables (today)	3.41	6.21
Line breaker	4.36	9.36
Sec feeding (OH 2 disc)	5.27	9.78
Sec feeding (cable 2 Disc)	5.27	9.78
Sec feeding (cable)	5.33	9.87
1 kV LP6 b	5.06	10.17
Sec feeding (OH)	5.57	10.22
1 kV LP6 a	5.18	10.34
Base case	5.27	10.49

Table 41: Resulting reliability indices for the Lesjöfors line

The resulting business ratios for the different investment scenarios in Lesjöfors are listed in table 42. The table is ordered according to the investments with the smallest SEK/COMin ratio. For some of the investments the second business ratio, SEK per km isolated line, is not applicable. This is the case for the remote controlled disconnectors for example. They cannot be said to isolate any part of the line, the benefits of this investment is rather to lower the overall restoration time. The investments for which the second business ratio is not applicable have been marked with NA (not applicable).

102A LESJÖFORS	Total cost [SEK]	Customer outage minutes [ΔCOMin]	Length isolated line [m]	Business ratio 1 [SEK/COMin]	Business ratio 2 [SEK/km isolated line]
Remote controlled disconnectors	-90 630	-85 205	NA	-1.1	NA
Line breaker	17 630	-20 561	11 925	0.9	1 000
1 kV LP6 b	28 531	-5 912	2 393	4.8	12 000
1 kV LP6 a	31 212	-2 686	947	11.6	33 000
Sec feeding (cable 2 Disc)	172 869	-12 884	NA	13.4	NA
Sec feeding (OH 2 disc)	176 446	-12 884	NA	13.7	NA
Sec feeding (cable)	159 149	-11 332	NA	14.0	NA
Sec feeding (OH)	175 173	-4 993	NA	35.1	NA
Cables (today)	19 886 669	-75 810	42 400	262.3	469 000

Table 42: Result for the Lesjöfors line. NA=Not applicable

In chart 1 the relation between cost and number of decreased customer outage minutes can be seen.

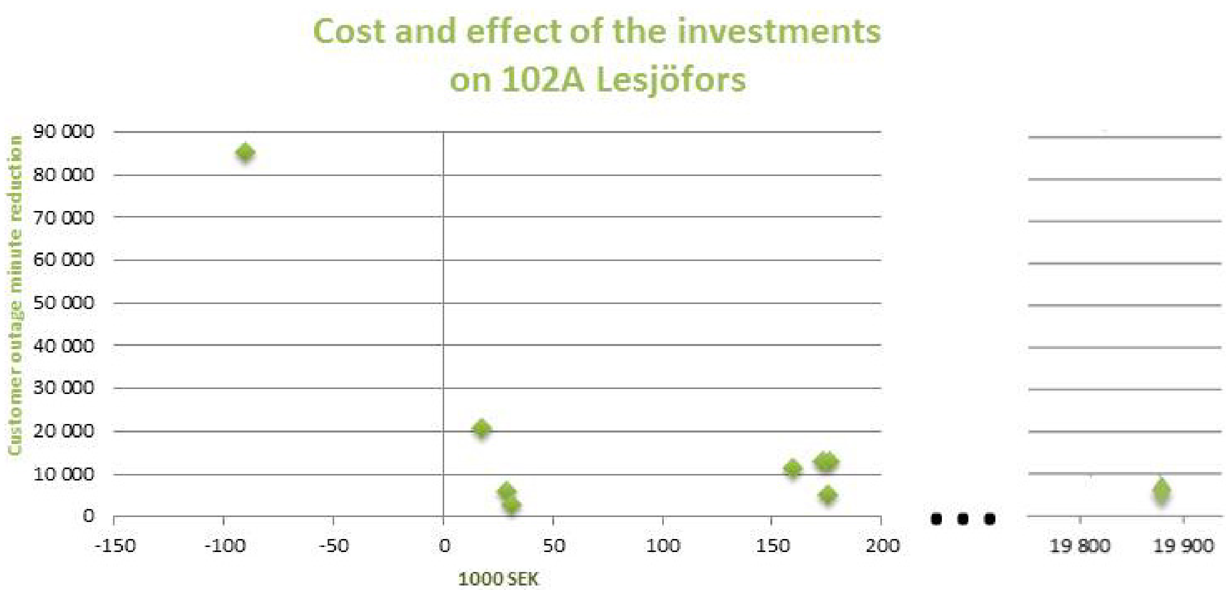

Chart 1: Cost and effect of the investments on 102A Lesjöfors

5.4.2. Result on the Charlottenberg line

The results on the reliability for 020E Charlottenberg can be seen in table 43.

	SAIFI	SAIDI [h]
Cables on 11	8.74	6.47
Cables on 7	8.96	6.67
Sec feeding (OH 2 disc)	10.05	7.1
Sec feeding (cable 2 Disc)	10.05	7.1
Sec feeding (cable)	10.09	7.13
Sec feeding (OH)	10.49	7.41
Cables on 4	8.98	7.52
Cables on 5	9.04	7.54
Cables on 6	9.70	7.63
Line breaker	8.14	7.69
Cables on 9	9.39	7.72
Cables on 8	9.56	7.75
Cables on 1	9.02	7.79
Cables on 10	9.28	7.83
Cables on 3	9.76	7.89
Cables on 2	9.68	7.9
Voltage reduction on RLP14	9.81	7.94
Voltage reduction on RLP7	9.83	8.02
Voltage reduction on RLP8	9.94	8.04
Voltage reduction on RLP11	10.01	8.06
Base case	10.05	8.07

Table 43: Reliability indices for the investments on the 020E Charlottenberg line.

	Total cost [SEK]	Customer outage minute decrease [COM]	Length isolated line [m]	Business ratio 1 [SEK/COMin]	Business ratio 2 [SEK/km isolated line]
Secondary feeding Cable	57 382	17 537	NA	3	NA
Secondary feeding Cable 2 disc	71 833	18 168	NA	4	NA
Line breaker	45 655	7 832	20 341	6	22 44
Secondary feeding OH 2 disc	111 813	18 168	NA	6	NA
Secondary feeding OH	109 509	12 294	NA	9	NA
1 kV RLP14	31 106	2 426	875	13	35 549
1 kV RLP7	33 282	993	783	34	42 506
Cables on L7	1 670 817	26 219	4 592	64	363 854
1 kV RLP8	34 681	500	973	69	35 643
Cables on L6	686 551	8 219	1 886	84	364 025
Cables on L11	3 004 120	29 940	6 257	100	480 122
Cables on L4	1 438 229	10 287	4 227	140	340 248
Cables on L8	928 210	5 966	1 954	156	475 031
Cables on L9	1 040 229	6 621	2 593	157	401 168
Cables on L5	1 609 217	9 943	4 149	162	387 857
1 kV RLP11	36 262	219	389	166	93 218
Cables on L3	623 404	3 386	1 148	184	543 035
Cables on L2	661 237	3 217	1 778	206	371 899
Cables on L1	1 256 461	5 316	4 084	236	307 655
Cables on L10	1 105 504	4 498	3 059	246	361 394

Table 44: Result of the investments on the Charlottenberg line. NA= Not Applicable

Table 44 is ordered after which investment is the most cost-effective one. In chart 2 the relation between cost and number of decreased customer outage minutes can be seen.

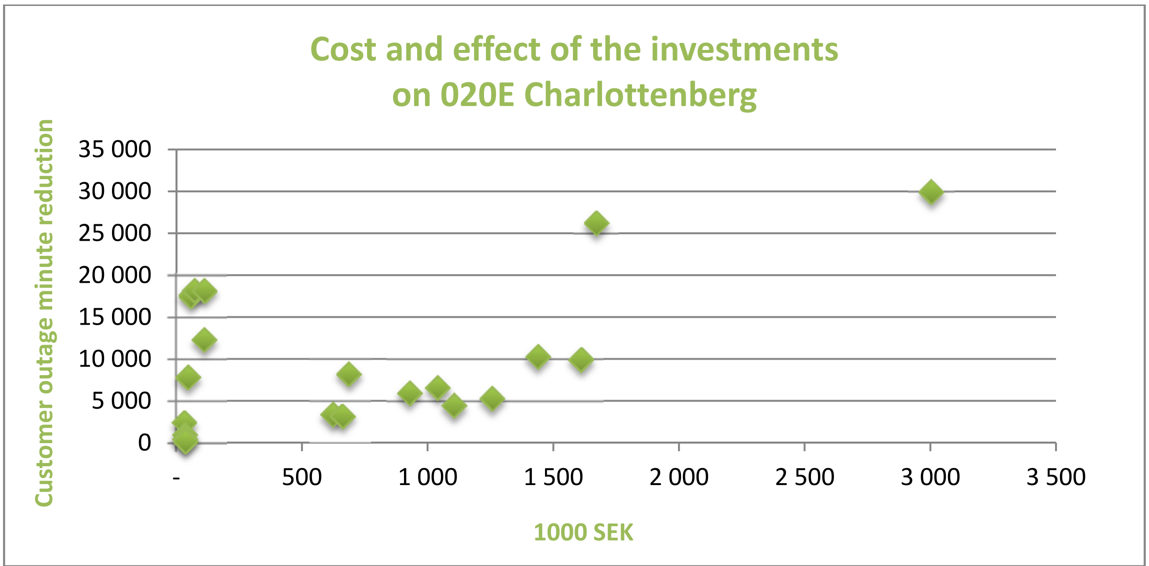

Chart 2: The cost and effects of the investments on 020E Charlottenberg

5.5. Recommendations for 020E Charlottenberg

The work in this master thesis project has rendered a couple of recommendations for reliability investments on L020E:

- The most cost-effective investment of the alternatives examined in this project is to add a secondary feeding possibility for the long radial in the middle of the main line. It seems to make little difference if this is done with overhead line, cables and whether one or two disconnectors are used.

- To install a line breaker on the middle of the line (where D5 is located in the model, see figure 9) is also as cost-effective as adding a secondary feeding. Both these investment alternatives do however depend heavily on the regulation of the DSO's and the results are calculated under the assumption that the rules of the regulation coming 2012 will be constant for 40 years.

- The 1 kV voltage reduction alternative would have the greatest effect when performed on load point 14 in the model, the radial line to Åsen fjäll and Bråten Fjäll. This investment alternative is not as dependent on the regulation as the others. When the change of revenue framework due to the capital base is not accounted for this alternative is the most cost-effective of all investment alternatives examined.

- If the intent is to weather-secure the line by changing the overhead lines for underground cables the most cost-effective area to do this would be at the base and middle of the long radial. (L6-L7 in figure 9)

- In general, the results for 020E Charlottenberg suggest that the big radial line towards Lake Fjällsjön (L6-L9 in figure 9) is where investments for enhanced reliability have the greatest effect.

6. Closure

This chapter holds a discussion of the result, a list of the conclusions that are drawn from the analyses and suggestions for future work.

6.1. Discussion

In this section the result of the thesis is discussed and particularly interesting aspects have been highlighted.

6.1.1. Result of the model compared to Fortum's investments

In the results in section 5.4 the investment alternatives can be seen, ordered after best effect on reliability in one table and cost-efficiency in the other. As can be seen, installing four remote controlled disconnectors on the Lesjöfors line would according to this method have had the largest effect on reliability as well as being the most cost-effective investment. The investment alternative that was chosen by Fortum is according to table 42 the least cost-effective and comes second in terms of lowering SAIDI (table 41). It seems that there would have been several investments that could have been chosen before changing the overhead lines on 102A Lesjöfors to underground cables. It must however be taken into account that the reconstruction of the Lesjöfors line was made during the ”Reliability Program”, which is a project to lower SAIDI in the Fortum grid by preventing long outages due to extreme weather. During this program weather-securing actions were prioritized above all other investments. If a storm hits and trees fall all over the line, the remote controlled disconnectors are of little use. Secondary feeding possibilities are not helping either in situations like those, since several adjacent lines often have an outage at the same time during a storm.

Among other things, this thesis has addressed the problem of quantifying the risk of long outages. From historical data a failure rate of long outages per km overhead line has been produced. As discussed in section 4.4 it is doubtful if the risk of long outages can be described as a per km line value. The extreme weather events are therefore not reflected strongly enough in the calculations in this project and weather-securing investment alternatives do perhaps not reach the priority they deserve. Under the assumptions that no extreme event happens, changing for underground cables is the least cost-effective investment according to the calculations made. This might however change radically if a storm occurs. If all 300 customers along one of the case lines in this project had an outage for five days during a rough storm, and if the compensation was 1800 SEK per customer and day (which is a low estimate) – then the total amount of customer compensation would be over 2.7 million SEK!

Weather-securing actions are hence of great importance and Fortum Distribution AB is prioritizing quality over cost when it comes to these kinds of investments. Considering the benefits of other investments as well can however be important. To justify the investment cost of 20 million SEK on the Lesjöfors line, a storm like the one in the numerical example has to hit the line every five years during the 40 year life span of the investment. It is questionable if a single line will be affected by great storms in the magnitude of Gudrun or Per that often. Especially the Lesjöfors line, as it is located in an area that is considered to have a lower risk for hard weather. To the cost of customer compensation other costs must be added, such as cost of repair and cost of extreme work situations during storms. The good-will of the company must also be taken into account when considering weather-securing investments. Even so, the results of this thesis show such a significant difference in cost-efficiency between cables and other investments that it might be favorable to review the benefits of weather-securing options. Cables may not be the number one option everywhere; in some cases other investments might be more beneficial.

6.1.2. Detail level of the analysis at Fortum Distribution AB

Today Fortum makes the simplification that cables are perfect when calculating the benefits and effects of different investments. This master thesis has shown that cables do indeed have a very small effect on the system performance, especially compared to overhead lines. The benefits of being able to do less complicated analyses are many, it does for example take less time and does not require as precise data. The simplification that cables are perfect must therefore be considered to be acceptable for today's conditions. As the weather-securing projects continue however, more and more overhead line will be changed for underground cable. This will lead to other kinds of problems than the ones the DSO's are faced with today. Cable faults will be more common, both in absolute and relative terms. A point will be reached when the simplifications that are valid today, have to be reconsidered. If the goal is to weather-secure the greater part of the grid, plans should be developed on how to handle investment planning when the configuration of the grid is changing. In the future, more detailed reliability analyses might be necessary.

6.1.3. Remote controlled disconnectors

Upgrading manual disconnectors to remote controlled disconnectors is an investment that is worth considering. In this analysis it is the only one that is a profitable investment, when good-will is disregarded. The calculation of the benefits of this investment does however have a setback. Because of lack of data the control equipment is not assigned its own failure rate, and is assumed to have the same failure rate as a manual disconnector. This does not correlate with the experience of the personnel at Fortum [23], [2]. The common opinion seems to be that the remote control of the disconnectors often malfunctions. This means that the reliability improvement will not be as large as estimated and the quality adjustment will be smaller. In addition the repair costs will increase. The benefits of remote controlled disconnectors seem to be high, but before this investment alternative is implemented on a large scale it should be investigated further. It would be beneficial if it could be assigned its own failure rate.

6.1.4. New types of investments

In this master thesis project a couple of the investment scenarios investigated were investments that are new or not very widely used. These are the 1 kV voltage reductions and the line breakers. These investment scenarios were implemented on both case lines to test the effect of them. The line breaker investment shows advantages in both reliability and cost-efficiency. The effect is more prominent on the Lesjöfors line. The 1 kV-reduction investment does not affect SAIFI or SAIDI very much, especially not on the Charlottenberg line where quick fault isolation is already at hand. But since the installation cost of these investment alternatives is low, the cost-efficiency of the investments is very good. For the Lesjöfors line it is one of the top choices based on cost-efficiency. The analysis in this thesis has shown that reducing the voltage on radial line to 1 kV or installing line breakers on the middle of the line are interesting investments that are worth investigating further. Another advantage with the 1 kV investment is that it does not seem to be as greatly affected of the regulation of the DSO's as other investments examined in this project.

6.1.5. Influence from the regulation

The evaluation of the investment alternatives analyzed in this master thesis project is strongly dependent on the authorities regulation of the DSO's. In the calculations it is assumed that the new ex-ante regulation starting 2012 will be the same for the investments full 40 year life length. This is however highly unlikely and the conditions will probably change. This affects the quality adjustment as well as the capital base value. The assumption made in this project is that; the quality adjustment is based on historical values today, the goal is for the DSO to improve the reliability compared to its own values of reliability for the time before the regulatory period. When the period is over and improvements have been rewarded for four years, the reference level is reset and the improved level is now the standard. It is however possible that the regulating authorities will develop general standard levels that every DSO will have to reach. Depending on those levels, the incentives for reliability investments may vary a lot.

Just like the rules of the quality adjustment, the methods of evaluating the capital base might change. As discussed in section 2.3.4 the current method, where the grid is always considered to be brand new, is questioned. The coming regulation gives very strong incentives to expand the grid and increase the capital base. Replacing old equipment with new is not nearly as profitable as installing more equipment. Some of the investment alternatives in this thesis are strongly dependent on the generous evaluation of the capital base. This goes especially for the alternatives of adding a secondary feeding. In appendix 5 a comparison of the total cost and SEK/COMin ratio of the investments for when the capital base is regarded and for when it is not is shown. As can be seen, the effect of the regulation is large. Upgrading to remote controlled disconnectors is no longer a profitable investment and the secondary feeding alternatives are no longer the most cost-effective on the Charlottenberg line. The analysis in this master thesis project shows the role of the prevailing regulation. The investment recommendations will change with changes in the regulation. Power system investments are however done with life spans of 40 years or longer in mind. The recommendations can therefore not change with the four year regulatory periods. When planning investments for the electric grid it might be wise to at one hand try to forecast the regulation, but also consider investments that have an acceptable SEK/COMin ratio even during periods of unfavorable regulation.

6.2. Conclusions

- **Weather-securing investment alternatives** are favored by Fortum Distribution AB at the moment. The analysis in this thesis does however show a significantly lower cost-efficiency for the investment of changing for underground cables compared to other investments. Even though extreme weather could have been reflected stronger in the analysis, this leads to the conclusion that it might be favorable for Fortum Distribution AB to review the benefits of changing to underground cables. It might not be the best solution for every line.

- **The detail level of the analyses** Fortum Distribution AB makes in the investment planning is most likely sufficient for today's electric grid. The extensive ongoing work to weather-secure the grid will however change the overall structure of it, which might change the conditions. As the proportion of cables increases, for example, the simplification that cables are perfect will become less acceptable.

- **Remote controlled disconnectors** seem to be the best investment alternative when weather-securing options are not prioritized the highest. This investment alternative outweighs the rest, both in terms of effect on reliability and cost-efficiency. The availability of the control equipment itself has however been questioned and further analyses on the reliability of remote controlled disconnectors would be favorable.

- **1 kV voltage reduction on radial lines and installation of line breakers,** investment alternatives that have not been studied so widely before, show promising results. The line breakers can have a large effect on the reliability of a line and it is also cost-effective compared with the other investment alternatives studied in this thesis. The 1 kV voltage reduction has limited effect on the overall reliability of the line, however, due to the cost-efficiency of the investment it might be a very good investment option. Both these investments are worth examining further.

- **The regulation of the DSO's** has a great effect on the cost-efficiency of the investment alternatives. The coming regulation for 2012-2015 gives strong incentives to expand the capital base. Investment alternatives like adding a secondary feeding possibility by building more lines are hence favored in this regulatory period, which is reflected in the result of this thesis. Alongside with forecasting the future regulation when planning investments, it can be favorable to consider investment alternatives that are not too dependent on the prevailing regulation.

- **The fault management at Fortum Distribution AB** has been described in this thesis and the resulting knowledge has been implemented in the reliability analyses of the case lines to obtain a detailed analysis. The average time of several tasks in the fault management has been developed and listed for future reference.

- **Fault rates** for several components on specific 11 kV rural distribution lines have been developed and can also be used as reference for analyses on similar lines.

6.3. Future work

The work in this master thesis project is merely begun. Many things can be done to continue and refine the work. A few examples are:

6.3.1. Terrain dependent failure rate

Keeping the input data for the failure rates local has been a main goal in this project. The failure rates can however be refined further. The failure rate was considered to be constant, but is probably varying along the line. A way to weigh the local failure rate according to what the surrounding terrain is like could be developed. Coefficients for different kinds of terrains could be produced by studying the proportion of faults occurring in different terrain.

6.3.2. Long outages

The risk of long outages has not nearly been studied enough in this thesis. When using models like this one to determine which reliability investment to choose, avoiding the risk and cost of long outages must be given more importance.

A better approach to this problem than calculating an "outages >12 hrs/km" failure rate might be to evaluate the risk of long outages and setting a limit for the situations that are unacceptable at all times. This can be done with a risk matrix. A risk matrix has the probability of an outcome on one axis and the consequence of it on the other axis. Risk is commonly defined as the product of probability and consequence.

Probability Consequence	1	2	3
1	1	2	3
2	2	4	6
3	3	6	9

Figure 22: Example of a risk matrix

In the example matrix in figure 22 the different risks can be seen depending on what the probability and consequence of the outcome "long outage" is. The risk of an event that has high probability but low consequences, like for example long outage on low voltage overhead line, is the same as for an event that has a high consequence but rarely happens, like for instance medium voltage cable faults. To these risk levels different actions can be assigned, like for example:

- Risk level 1-2: Low risk, no actions needed.

- Risk level 3-6: Medium risk, take actions to lower probability or consequence of event.
- Risk level 7-9: High risk, this risk is never accepted. Avoid at all costs.

This way of having a more quality based perspective on risk of long outages rather than trying to quantify it can give a more pragmatic way to deal with long outages.

References

[1] R. Billinton and R. N. Allan, Reliability Evaluation of Power Systems, Plenum Press, 2d Ed. 1994.

[2] M. Estéen, Interviewee, *Power systems operator.* [Interview]. 3 November 2011.

[3] M. Aldén, Interviewee, *Manager, Field Service Management.* [Interview]. 07 December 2011.

[4] Swedish law, *(2005:1110).*

[5] Swedish law, "Ellag (1997:857)".

[6] Statistiska Centralbyrån , Statistics Sweden, "Consumer Price Index for December 2011," 2012.

[7] Swedish Energy Agency, "Utvecklingen på elmarknaden - Energimyndighetens årsrapport," 1998.

[8] L. Bertling, B. M. Larsson and C. J. Wallnerström, "Review of the Swedish Network Performance Assessment Model," *Electric Power Systems Research,* 2008.

[9] M. B.-O. Larsson, "The Network Performance Assessment Model," Doctoral Thesis, KTH, 2005.

[10] C. J. Wallnerström, "On Incentives affecting Risk and Asset Management of Power Distribution," Doctoral Thesis, KTH, 2011.

[11] L. Boström, Interviewee, *Regulation and Strategies, Fortum Distribution AB.* [Interview]. 29 September 2011.

[12] Energy Markets Inspectorate, "Löpande kostnader i förhandsregleringen EI2010:06," 2010.

[13] Energy Markets Inspectorate, "Värdering av elnätsföretagens kapitalbas i förhandsregleringen R2010:07," 2010.

[14] Energy Markets Inspectorate, "Kvalitetsbedömning av elnät vid förhandsreglering R2010:08," 2010.

[15] D. Heidkamp, Interviewee, *Fitter at Infratek.* [Interview]. 9 November 2011.

[16] B. Andersson, Interviewee, *Process Manager, Process Development at Fortum Distribution AB.* [Interview]. 10 October 2011.

[17] O. Levein, Interviewee, *Asset Manager, Asset Managment and Design, Fortum Distribution AB.* [Interview]. 21 October 2011.

[18] K. Oberger, Interviewee, *Business Development and Documentation, Fortum Distribution AB.* [Interview]. 5 February 2012.

[19] O. Jansson, Interviewee, *Fitter at Infratek.* [Interview]. 02 11 2011.

[20] G. Blom, J. Enger, G. Englund, J. Grandell and L. Holst, Sannolikhetsteori och Statistikteori med Tillämpningar, Studentlitteratur, 2005.

[21] L. Bertling, "Reliability Centered Maintenance for Electric Power Distribution Systems," Doctoral Thesis, KTH, 2002.

[22] P. Hilber, C. J. Wallnerström, J. Rosenlind, J. Setréus and N. Schönborg, "Risk analysis for power systems - Overview and potential benefits," in *CIRED Workshop*, Lyon, 2010.

[23] H. Rinnemo, Interviewee, *Long Term Planning, Asset Management and Design, Fortum Distribution AB.* [Interview].

[24] C. J. Wallnerström, J. Hasselström, P. Bengtsson and L. Bertling, "Review of the risk management at a Distribution System Operator," in *PMAPS*, Rincón, 2008.

[25] R. Lennartsson, Interviewee, *Asset Manager, Asset Management and Design, Fortum Distribution AB.* [Interview]. 26 January 2012.

[26] Energy Markets Inspectorate, "Förhandsprövning av elnätstariffer 2010:24".

[27] L. Bergman, "The Nordic electricity market - continued success or emerging problems?," *Swedish economic policy review,* 9 2002.

[28] C. J. Wallnerström and L. Bertling, "Learning from experience of the prior Swedish Electrical Distribution System Regulation - Reference Material when Developing the Future Regulatory Incentives," in *Conference on innovative Smart Grid Technologies (ISGT) Europe 2010*, Göteborg, 2010.

[29] EBR cost catalogue, local networks, Swedenergy AB, 2010.

Appendix 1: Regulation of the DSOs

In this appendix section the history of regulation of the DSOs in Sweden will be addressed.

Background

The Swedish electricity market has undergone large-scale changes since the mid-90s. From being strictly regulated, dominated by state-owned utilities and protected from foreign competition through border tariffs, the electricity market is now deregulated and integrated with the other Nordic countries [27]. The deregulation, which came into force on 1 January 1996, aimed to make the electricity market more effective through competition [7, p. 8]. The generation and retailing of electricity was therefore separated from the transmission and distribution, being natural monopolies they cannot be subject of competition. The trade of electricity takes place at the Nordic power exchange market Nord Pool and in the form of bilateral agreements. Nord Pool Spot AS, the market for trade with physical electricity, is owned by the TSO's Svenska Kraftnät in Sweden, Statnett SF in Norway, the energy companies Energinet.dk in Denmark and Fingrid Oy in Finland. Nord Pool ASA is an exchange market for financial trade on the electricity market and is today owned by Nasdaq OMX. The physical market is divided into two parts. Elspot is the 24-hour market for short term trading of electricity. Since the consumption of power always has to be matched by equal power production, Elbas is the adjustment trading market where bids can be made up to one hour prior to delivery.

Two years after the deregulation, in 1998, a new authority was formed, called The Swedish Energy Agency (STEM). The task of the authority was, among other things, to supervise the net tariffs of the electric grid companies and develop a more effective model for regulation [7, p. 19]. For the time being the DSOs could get fully compensated for their costs of delivering electricity, regardless of efficiency and quality. An ineffective DSO could claim as much revenue as an effective one. To address the problem the Swedish Energy Agency initiated a project in 1998 to create a new regulatory model.

The Network Performance Assessment Model

This model was performance-based and was implemented in 2003. The idea was that the distribution of electricity creates costumer values and the DSOs are allowed compensation in the level of these costumer values [8]. It was an ex-post regulation, meaning that the net tariffs were controlled *after* every regulatory period. If the tariff levels were found to have been too high, part of the tariff had to be re-paid to the customer.

The model calculated the "Network Performance Assessment" (NPA) which is the total expected cost of operating a distribution system. This cost is then compared to the DSO's revenue to determine the debiting rate. (See equation 23) The debiting rate must not be higher than a certain value, or the DSO will be further investigated [28].

$$\boldsymbol{Debiting\ Rate} = \frac{\boldsymbol{Revenue}}{\boldsymbol{NPA}} \qquad \text{Eq. 39}$$

A debiting rate higher than 1 would imply that the DSO is overcharging the costumers. The NPA is calculated with

$$NPA = C_{Connect} + C_{Admin} + C_{Deliv} + C_{Service} - C_{Rel} \qquad \text{Eq. 40}$$

The NPAM took distribution system- and costumer data as input, along with the revenue and reliability indices, SAIFI and SAIDI. A radial reference network based on the distribution system- and costumer data was created to estimate the capital cost, C_{Radial}, of the actual distribution system. The fictive network often was very different from the actual network, but the objective was to create a reference grid that took the different objective conditions of the DSOs into account. Some of the DSOs can for instance have a majority of urban subscribers, whereas others have a more rural network. In urban areas the cables can be shared by many costumers and the conditions and costs of capital are different from those of the DSOs who have to install long lines to distant costumers. The most important objective prerequisites taken into account by the model are [9, p. 30]:

- Yearly energy consumption, from which the maximum power demand is estimated
- Customer density
- and, as mentioned, the location of the consumer

The network created is initially fully radial and does not take any redundancy into account. The actual networks however, often have component redundancy to lower the risk of system failure. To compensate for this, the model adds a certain spare capacity to the reference net. The cost of spare capacity, C_{Spare}, is determined by the costumer's will to pay. In a distribution system where the costumers are willing to pay more to avoid outages the level of investment costs can be higher [28] than in distribution systems where the customers do not find it as important. The total cost for capital and investments is called connection cost, $C_{Connect}$, and is part of the NPA-equation (see equation 24).

$$C_{Connect} = C_{Radial} + C_{Spare} \qquad \text{Eq. 41}$$

Next the cost of administration, C_{Admin}, cost of energy losses in the system, C_{Deliv}, and fees to superior grids and other service costs, $C_{Service}$, are added to the model. Finally the total cost can be adjusted with the so called "cost of reliability", C_{Rel}. To give the DSOs incentives to improve the availability of the system the NPA will be lowered if the reliability is unsatisfactory. See Equation 26. Cost of reliability is determined by calculating the cost of outages in the DSO's grid and comparing them to an expected outage cost. If the actual outage costs are lower than the expected cost, C_{Rel} will be zero and no reduction will be made. If the outage costs are higher than the expected value, C_{Rel} will be the difference between the costs. It will however never be higher than C_{Spare}.

$$C_{Rel} = \begin{cases} 0 & if\ C_{Outage} - C_{Expect} \leq 0 \\ C_{Outage} - C_{Expect} & if\ 0 \leq C_{Outage} - C_{Expect} \leq C_{Spare} \\ C_{Spare} & if\ C_{Outage} - C_{Expect} \geq C_{Spare} \end{cases} \qquad \text{Eq. 42}$$

Every year since the launch of the model in 2003 several DSOs had to re-pay their customers. The model aroused heavy opposition because the DSOs felt that the repayments were unjustified and every year the shareholders started legal processes against the regulator. In 2008 an agreement between the parties was made and the level of repayments was lowered. In 2009 the model was abandoned due to the criticism and the fact that the model is an ex-post model when the EU directive requires an ex-ante regulation by 2012.

Preparing the new regulation model

From the time of the fall of the Network Performance Assessment Model until the new regulation comes into force in 2012 the focus of the regulator has mostly been on preparing the new model. The tariff levels still have to be controlled, but are in some ways self-regulating since it is in the interest of the DSOs to keep the tariffs on reasonable levels in order to avoid harder rules of regulation in the new model [10, p. 57].

Appendix 2: Documentation issues

In the beginning of this project it was requested that any inconsistencies or errors found in the statistics or computer tools were noted. If there were any data that would have been useful in this project, but was not available, that could also be noted. During the past months a few points were gathered:

6.4. Errors in PG:

- On the Charlottenberg line, 020E, there is a disconnector that is listed as a fuse disconnector but is according to the operators a manual disconnector without fuse [2].
  L020E-F675 is listed as a fuse disconnector.

- It might be an error in PG, or there is a disconnector that is closed where it might be better to keep it open. The disconnector 102A-Fs268 (D9 on the model of "102A Lesjöfors today") is located at L102A-K564 on the Lesjöfors line. It can disconnect the 5 km long line to the secondary feeding from the substation 184 Tyfors. This disconnector is listed as closed. It would perhaps be better to keep it open, so that no faults on the 5 km overhead line would affect the customers.

6.5. Collection of statistics

Collection of statistics is a tradeoff between acquiring a lot of useful data and not having too heavy administrative work. The key is to collect only data that are useful, not collect anything twice and keeping it easy enough so that it really gets done. The statistics are useless if they are not collected correctly and therefore do not reflect the reality. From dialogues with fitters I also believe that one of the key things in collecting data is to communicate why the data are collected and what they are going to be used for. Taking statistics is an extra work task and if one does not know why it is important and what it will be used for, the errors in the statistics might increase.

The computer tools used in this thesis are PG, Succel and PoDIS. There might be other ways to collect the desired information, if that is the case the following can be disregarded. When an outage occurs it is managed in Succel by the operator. If the fault is on MV level the power system operator opens a *fault notation* (kopplingssedel) where all switching of disconnectors and breakers are noted. In the *fault notation* the number of affected customers and where the power was cut is also noted. *Fault notations* are made in order to have a record of which disconnectors that are opened and which that are closed so that the operators know where the power is on. I think that *fault notations* are excellent ways of also explaining what really happened during an outage. There is room on the *fault notation* where the operator can make notes if wished, but this seems to be rarely done and not very consistently. When doing analyses or investigating faults it would be helpful to have an explanation in the operator's own words on what happened. The outage data that are available in Succel "reports", where time, failing line, customer outage hours and so on are listed, also contains the cause of the outage. Here it is possible to see what the cause of the outage was, but it might still be useful to have a longer explanation in the *fault notation*. There is a point to this, if the categories in the "report" can be kept simple it will be easier to find a category for each fault, and less faults will be noted with "unknown". This will simplify the work with large number of data, that can be ordered into categories. If one wants to study individual outages in detail, one can read the *fault notation*. It can of course sometimes be too time consuming to write a more detailed explanation of what happened, for example during major disturbances. The short notation "major disturbance" does however speak for itself in a way.

In the *fault notation* it is also not clearly noted between which disconnectors the fault really was located, which can be hard to figure out. The fault is positioned in the computer tool PoDIS and it is possible to find where the fault was located by looking for the outage with the same date in PoDIS. But an idea could be to have that information in the fault notation as well, or a link between the two (if this is technically possible). It would be useful if one could click on the faults in PoDIS and choose to open the *fault notation*, and the perhaps the other way around: open PoDIS from the *fault notation* to see where the fault was.

Appendix 3: Substations for cable fault rate

The substations used for calculating the fault rate of cables in section 4.3.2 are shown in table A1.

	020E Charlottenberg	102A Lesjöfors
Substations	*020 Charlottenberg*	002 Baggetorp
	034 Edane	012 Brattfors
	082 Järpforsen	085 Kalhyttan
	115 Manskog	*102 Lesjöfors*
	132 Bergerud	123 Nykroppa
	133 Rexed	128 Persberg
	198 Töcksfors	172 Taberg
		247 Långban
	194 Vännacka	297 Skösselviken
	226 Åmotsfors	296 Gammelkroppa
	239 Jössefors	
	246 Koppum	
	255 Strand	
	262 Lenungshammar	
	282 Kroppstafors	

Table A1: Substations used for the cable calculations

Appendix 4: Sectioning on the Lesjöfors line of today

- The remote controlled disconnectors will be opened first and the breaker will be re-closed to see if the fault is on any of these line segments.
- Two fitters are sent to the area. One goes to D1 and the other one to Q1.
- Open D1
- Open Q1 and close D1 – is the fault on the north or south side?

➢ North: The power is now on, feeding L1-L4. The fitter goes to D10 and the breaker at 184 Tyfors (L7910) is closed by the operator.
  - If the fault is on the north side every load point on the south side will have the power back after 1.05 hours.
  - D8 is opened and D10 closed.
  - D9 is opened and D8 closed. This will show if the fault is on L8-L9 or L12-L14.
    - Fault on L8-L9: The power goes out. Open Q2 and re-close the L7910 breaker. If the power is still on the fault is on L8 or RLP11.
    - Fault on L12-L14: Power is still on. Open D11 and D12 and close D9.
    - Close D11. If the power goes out the fault is on L13, otherwise it is on L14.

➢ South: Power goes out. Open D5 and D2. D1 was closed before the fitter went on, this does not affect the customers since the power is already out.
  - Close D2 – Is the fault on the upper or lower side?
    - Lower: The power goes out. The fault is on L3 (L4 was already tested with the remote controlled disconnectors).
    - Upper: The power is still on. Open D6 and close D5.
    - If the power is still on the fault is on L6 (L7 was already tested), if not the fault is on L5.

- When the fault is found it is isolated just like in the previous models and any local sectioning is performed.

Appendix 5: Sectioning with remote controlled disconnectors on 102A Lesjöfors

When the breaker disconnects the line all four remotely controlled disconnectors are opened and the power is turn back on.

- If the breaker breaks again the fault is on L1 or L2. The fitter goes to D1 and opens it so see which one of the line segments that has failed. Within 1,167 hours a fault is located to L1 or L2.
- If the power did not go out again, D2 is closed – is the fault on the south side (L3-L5)?
    - If the power goes out the fault was in fact on L3-L5. The fitters are sent out and one of them goes to D3 and the other to D4. Within 1,167 hours a fault is located to be on either L3, L4 or L5.
    - If the power stays on the fault is not on the south side.

- Disconnector D5 is now closed to see if the fault is on L6 or L7.
    - If the power goes out the fault is on L6 or L7 and one of the fitter goes to D6 and opens it. The other fitter goes to D14, ready to close it if the fault is on L6, and L7 therefore can be fed through D14. Again, within 1,167 hours the failing line segment is identified.
    - If the power does not go out the fault was not on L6 or L7.

- Disconnector D7 is now closed to see if the fault is on L8-L10.
    - If the power goes out the fitters go to D8 and D9. Within 1,167 hour the fault is located to either L8, L9 or L10.
    - If the power stays on the fault was not on L8-L10.

- Disconnector D10 is now closed to see if the fault is on L11-14.
    - Unless the fault has “fixed itself” the power will go out. (Can be worth a try, many faults do fix themselves [16]) The fitters then go to D11-D12 (located at the same place) and D13. All are opened.
        - By opening D11 the operators can try to put the power on from 184 Tyfors to see if L12 is failing.
        - If not, D11 is closed again to see if the fault is on L11.
        - If not, D12 is closed to see if the power goes out- if it does the fault is on L13, if it does not the fault is on L14.
    - To identify the failing line segment will take 1,167 hours since D11 and D12 are located in the same place and the fitter does not have to move between them.

Appendix 6: Calculation of costs

This appendix section describes the costs and the calculations of the investment costs.

Cost of investments

In order to judge which investments that are the most cost effective, the prices of each item used in the investment and the work associated with it was listed using the EBR catalogue [29]. These can be seen in table A2.

Component and work	Cost (SEK)
Installation of cable (EBR: G146 21-26)	~300 000 SEK/km
Demolition of OH line (EBR: G126 01)	18 000 SEK/km
Installation of 24 kV* OH line (EBR: G109/G110 12-45)	~300 000 SEK/km
Installation of a disconnector (EBR: G161 12)	25 700 SEK
Upgrading of manual disconnectors to remote control (EBR: G161 21)	54 700 SEK
Installation a breaker [23]	200 000 SEK
Secondary substation cable (Seriesatellitstation EBR:152 28)	68 000 SEK (exc. transformer)
Secondary substation overhead line (EBR: G152 11	38 400 SEK
11/0.4 kV transformer 50-100 kVA (EBR: G159 25-26)	~35 000 SEK
11/1 kV transformer (EBR: G159 72)	31 200 SEK
1/0.4 kV transformer (EBR: G159 71)	23 900 SEK
Demolition of pole mounted secondary substation (EBR: 211 15)	3540 SEK

Table A2: cost of investments

*The 12 kV lines are in this category

Cost of changing overhead lines for underground cables

There are several different cables to choose from in the EBR catalogue, and the amount is therefore an approximate value of the cost of installing 1 km 12 kV underground cable. Most of the secondary substations on the overhead lines of 102A Lesjöfors were pole stations, meaning that they were mounted on the line poles and cannot be used for cable grid. The cost for new substations and their transformers have to be added. The overhead lines and their substations do also have to be demolished which leads to costs. **All possible rest values have been neglected in all investment alternatives.** The costs of this investment alternative can be seen in table A1.

$$Cost_{Cable} = installation\ of\ cable + demolision\ of\ overhead\ line + number\ of\ \sec substations * (cost\ of\ Seriesatellitstation + \frac{11}{0.4} kV\ transformer + cost\ of\ demolision\ of\ \sec substation) =$$

$$= x_{km\ cable} * 300\ 000 + x_{km\ OH} * 18\ 000 + x_{substation} * (68\ 000 + 35\ 000 + 3540)$$

$$= x_{km\ cable} * 300\ 000 + x_{km\ OH} * 18\ 000 + x_{substation} * 106\ 540\ SEK$$

Cost of voltage reduction to 1 kV

This investment alternative requires a 11/1 kV transformer, a 1/0.4 kV transformer and a grounding cable, as explained in section 5.3.2. The grounding cable is however almost always already installed and if some parts are missing it, the cost of installing one will be negligible [25].

$$Cost_{LV} = (31\ 200 + 23\ 900) * x_{Number\ of\ voltage\ reduced\ lines} =$$

$$= 55\ 100 * x_{Number\ of\ voltage\ reduced\ lines} \quad SEK$$

Cost of changing manual disconnectors for remote control

The cost of adding equipment to the manual disconnector in order to be able to operate it from the control center can be seen in table A1. The total cost will of course depend on the number of disconnectors that are changed to remote controlled ones.

$$Cost_{remote\ disc} = x_{disconnectors} * 54\ 700\ SEK$$

Cost of adding a secondary feeding possibility

This is done by building a connection to an adjacent line. In this project, the benefits and costs of doing that both with cable and with overhead line will be tried. The cost, and the result, will depend on the distance to the other line. Cables have better outage statistics, but will have to be longer than overhead line. The lines are then connected with an open disconnector, which will be remotely controlled.

$$Cost_{Connection} = Installing\ line * x_{km\ line} + disconnector + upgrading_{disconnector} =$$

$$= 300\ 000 * x_{km\ line} + 80\ 400\ SEK$$

Cost of installing a line breaker

The cost of installing a line breaker was estimated by Henrik Rinnemo to be about 200 000 SEK.

Appendix 7: Influence of regulation

Result of the investments when the change in the revenue framework due to changes in the capital base is not accounted for.

Lesjöfors	Total cost with Capital base [SEK]	Total cost without Capital Base	SEK/COMin	SEK/COMin No Capital Base	Change when regarding Capital Base
Remote controlled disconnectors	-90 630	-90 630	-1.1	1.5	-
Cables (today)	15 003 697	20 197 699	197.9	266.4	-26%
Line breaker	17 630	171 567	0.9	8.3	-90%
Sec feeding (OH)	175 173	1 197 251	35.1	239.8	-85%
Sec feeding (cable)	159 149	1 294 944	14.0	114.3	-87%
Sec feeding (cable 2 Disc)	172 869	1 379 671	13.4	107.1	-86%
Sec feeding (OH 2 disc)	176 446	1 269 532	13.7	98.5	-83%
1 kV LP6 a	31 212	48 964	11.6	18.2	-36%
1 kV LP6 b	28 531	46 283	4.8	7.8	-38%

Table A3: Influence on the regulation of the capital base on the Lesjöfors line

Charlottenberg	Total cost with Capital base [SEK]	Total Cost without Capital Base [SEK]	SEK/COMin With Capital base	SEK/COMin Without Capital Base	Change of SEK/COMin when regarding Capital Base
Cables on L1	1 256 461	1 451 978	236	273	-13%
Cables on L2	661 237	798 314	206	248	-17%
Cables on L3	623 404	801 858	184	237	-22%
Cables on L4	1 438 229	1 705 844	140	166	-16%
Cables on L5	1 609 217	2 236 614	162	225	-28%
Cables on L6	686 551	827 921	84	101	-17%
Cables on L7	1 670 817	2 019 353	64	77	-17%
Cables on L8	928 210	1 171 904	156	196	-21%
Cables on L9	1 040 229	1 276 111	157	193	-18%
Cables on L10	1 105 504	1 326 699	246	295	-17%
Cables on L11	1 256 461	1 451 978	42	48	-13%
Line breaker	45 655	173 980	6	22	-74%
1 kV RLP7	33 282	51 034	34	51	-35%
1 kV RLP8	34 681	52 433	69	105	-34%
1 kV RLP11	36 262	54 014	166	247	-36%
1 kV RLP14	31 106	48 857	13	20	-34%
Secondary feeding OH	109 509	596 252	9	49	-82%
Secondary feeding Cable	57 382	584 213	3	33	-90%
Secondary feeding OH 2 disc	111 813	669 564	6	37	-83%
Secondary feeding Cable 2 disc	71 833	669 670	4	37	-89%

Table A4: Influence on the regulation of the capital base on the Charlottenberg line

The two tables, A3 and A4, show the difference in *total cost* and *cost per reduced customer outage minute* when including vs. not including the capital base's change of the revenue framework in the calculations. The far right column shows the reduction of SEK/COMin in percent when adding the capital base evaluations to the calculations.

Appendix 8: Sensitivity Analysis

This appendix section shows the result of a sensitivity analysis of the input data to the models.

	020E Charlottenberg		102A Lesjöfors (original line)	
	Effect on SAIFI	**Effect on SAIDI**	**Effect on SAIFI**	**Effect on SAIDI**
Number of faults on OH line	+ 9.5 %	+ 8.1 %	+ 8.0 %	+ 7.4 %
Length of OH line	+ 8.2 %	+ 8.4 %	+ 8.0 %	+ 7.7 %
Repair time OH	0	+ 4.1 %	0	+ 1.4 %
Time for remote sectioning (And isolation of the fault, starting of secondary feeding)	0	+ 2.0 %	Not applicable	Not applicable
Time for the fitter to reach the area	0	+ 2.0 %	0	+ 4.8 %
Number of low voltage faults	+ 0.32 %	+ 1.7 %	+ 0.4 %	+ 0.7 %
Patrolling time	0	+ 1.2 %	0	+ 0.2 %
Sectioning time (Time to get from one disconnector to the next and opening it)	0	+ 0.5 %	0	+ 2.0 %
Number of faults on disconnectors	+ 0.1 %	+ 0.1 %	+ 1.1 %	+ 1.2 %
Number of faults on cables	+ 0.08 %	+ 0.1 %	+ 0.5 %	+ 0.6 %
Length of cables	+ 0.08 %	+ 0.1 %	+ 0.5 %	+ 0.6 %
Repair time disconnectors	0	+ 0.07 %	0	+ 0.3 %
Fixed part of the cable time	0	+ 0.03 %	0	+ 0.1 %
Repair time cables	0	+ 0.02 %	0	+ 0.2 %
Number of faults on the breaker	+ 0.01 %	+ 0.01 %	+ 0.002 %	+ 0.001 %
Repair time breakers	0	+ 0.01 %	0	+ 0.001 %

Table A5: Sensitivity analysis

Appendix 9: Tables for calculating the result of the models

The customer outages and customer outage hours for every load point on 102 Lesjöfors are shown in table A6.

Line	Loadpoint	Customers	U	U*customer	Outages	Outages* customers
L1	LP1	5	8.16	40.8	5.12	25.6
L2	LP2	17	7.72	131.3	5.12	87.1
L3	LP3	12	9.42	113.1	5.12	61.5
L4	LP4	1	11.19	11.2	5.03	5.0
	LP5	60	12.46	747.4	5.45	327.1
L5	LP6	22	13.17	289.8	5.22	114.8
L6	LP7	2	7.95	15.9	5.03	10.1
	LP8	11	8.80	96.8	5.07	55.8
L7	LP9	7	8.47	59.3	5.03	35.2
L8	LP10	54	9.54	515.4	5.17	279.1
L9	LP11	13	11.08	144.0	5.13	66.7
	LP12	7	10.73	75.1	5.07	35.5
L10	LP13	9	10.03	90.3	5.12	46.1
L11	LP14	21	8.91	187.1	5.17	108.6
L12	LP15	1	10.07	10.1	5.34	5.3
L13	LP16	31	11.70	362.7	5.66	175.5
	LP17	1	9.29	9.3	5.15	5.2
	LP18	23	9.29	213.7	5.15	118.6
L14	LP19	6	10.99	65.9	5.51	33.1
	∑customers=	**303**	**∑customers*U=**	**3179.1**	**∑customers*outages=**	**1595.7**

Table A6: Total customer outages and outage minutes on 102A Lesjöfors

The customer outages and customer outage hours for every load point on 020E Charlottenberg are shown in table A7.

Load point	Customers	U	Customer*U	Outages	Customer*outages
LP 1	8	7.19	57.5	9.86	78.9
LP 2	6	4.08	24.5	9.86	59.2
LP 3	8	4.63	37.0	9.95	79.6
LP 4	8	4.01	32.1	9.86	78.9
LP 5	24	4.34	104.1	10.03	240.7
LP 6	25	6.94	173.4	9.95	248.6
LP 7	4	7.03	28.1	9.95	39.8
LP 8	2	7.35	14.7	10.02	20.0
LP 9	6	7.04	42.2	9.95	59.7
LP 10	13	7.13	92.7	9.95	129.4
LP 11	6	7.05	42.3	9.93	59.6
LP 12	12	5.37	64.4	10.02	120.2
LP 13	3	4.89	14.7	9.87	29.6
LP 14	6	9.01	54.1	9.95	59.7
LP 15	9	8.79	79.1	9.94	89.5
LP 16	4	8.57	34.3	9.87	39.5
LP 17	4	8.56	34.2	9.86	39.5
LP 18	6	10.99	65.9	9.86	59.2
LP 19	32	11.55	369.5	10.11	323.5
LP 20	29	12.24	355.1	10.11	293.2
LP 21	11	6.20	68.2	10.03	110.3
LP 22	21	9.19	192.9	10.38	217.9
LP 23	45	8.50	382.7	10.28	462.4
LP 24	20	7.73	154.6	9.86	197.3
∑Customers=	312	∑Customers*U	2518.2	∑Customer*outage	3136.1

Table A7: Total customer outages and outage minutes on 020E Charlottenberg