Risk-based methods for reliability investments under performance based regulation

Elforsk rapport 13:62

Karin Alvehag

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Foreword

Performance-based regulations accompanied by quality regulations are gaining ground in the electricity distribution business. Quality regulations imply new financial risks for the network owner. Having poor reliability can reduce the allowed revenue for the network owner and compensations to affected customers may have to be paid. In Sweden a further development of the quality regulation is expected for the regulatory period that begins in 2016. Newly adopted regulations in Sweden also demand the network owners to perform risk analyses. Therefore, there is a need for enhanced risk-based methods for the network owners that take into account the financial risk of quality regulations. A deeper understanding of what effects different regulation designs have on the customers' reliability level is also desirable.

This report is a product of a post-doc project entitled “Profitable investments in power system reliability for future regulation designs” carried out by Karin Alvehag at the Department of Electric Power Systems, KTH. The project is within the Risk Analysis Program (Riskanalys 2011-2015) managed by Elforsk AB. The financial contributions to the research program come from more than fifteen companies, organizations and authorities. The project is a continuation of Karin Alvehag's PhD project that resulted in a doctoral thesis entitled “Risk-based methods for reliability investments in electric electric power distribution systems” in 2011. The doctoral project was financed by the previous Risk Analysis program within Elforsk (Riskanalys 2006-2010).

Some of the publications within the project are joint work together with Professor Lennart Söder, Johanna Rosenlind, and Fredrik Edström at KTH. Karin Alvehag was invited for a two months research visit to University of Cape Town to be a reviewer of a new developed risk-based method that was aimed to be applied by the transmission system operator ESKOM for reliability studies in planning and operations. Some publications within this project are therefore joint work together with Professor Trevor Gaunt, Ron Herman, Milton Edimu and Kehinde Awodele at the Department of Electrical Engineering, University of Cape Town.

The Risk Analysis program (Riskanalys 2011-2015) steering committee consists of the following members:
Horst Blüchert, The National Electrical Safety Board (chairman)
Kjell Oberger, Fortum Distribution AB
Håkan Jarer, Svenska Kraftnät
Eva Sundin, Vattenfall Eldistribution AB
Ola Ivarsson, E.ON Elnät Sverige AB
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Rémy Kolessar, The Swedish Energy Markets Inspectorate (Ei)
Susanne Olausson, Elforsk AB

Additional financial contributors to the program are:
Skellefteå Kraft Elnät AB
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Gävle Energi AB
Jönköping Energi Nät AB
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C4 Elnät AB
Borås Elnät AB

This project had a joint reference group together with two projects focusing on the regulation impact on the integration of distributed generation. Therefore some representatives in the reference group are experts in regulation while others have their expertise in distributed generation. Four reference group meetings have been held during the duration of this project.

The reference group consisted of the following members:
Fredrik Carlsson, Vattenfall
Anders Ekberg, Fortum
Peter Fritz, Sweco
Bengt Gustavsson, Swedish Energy Agency
Olle Hansson, Fortum (chairman)
Mats Johansson, Vattenfall
Rémy Kolessar, The Swedish Energy Markets Inspectorate (Ei)
Anders Larsson, Svenska Kraftnät
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Susanne Olausson, Elforsk
Susann Persson, Jämtkraft
Lennart Söder, KTH
Ulf Östrand, Ystad Energi

Summary

In the aftermath of the deregulated electricity markets, network ownership is privatized and the need for regulation of network owners has been accentuated by the natural monopoly status of these entities. In the reregulated markets there is therefore an increase interest for performance-based regulation combined with a quality regulation. The focus in this report is on the regulation for distribution system operators (DSOs), for which over 15 European countries already implemented a quality regulation.

Quality regulation has both a collective and a selective feature which aims to give incentives for adequate reliability both on customer and system level, respectively. The selective quality regulation ensures customers compensations when minimum guaranteed standards for electricity supply are not fulfilled; for example, when customers suffered many or long interruptions. The collective quality regulation applies, reward and penalty schemes aiming to establish a socioeconomic optimal system reliability level. In Sweden, customers receive compensations from the DSO for power interruptions above 12 hours. These costs the DSO are not allowed to cover in their revenue frame and it will therefore have a direct impact on their profit. The reward and penalty scheme in Sweden consists of a quality adjustment of the revenue frame and has also an impact on the DSO's profit. In other words, quality regulations imply new financial risks for the DSO. Especially when the reliability in a network is influenced by stochastic factors such as weather, environment and accidents.

This project intends to study the link between the technical risks and the financial risks. The technical risks cause power interruptions and depending on the quality regulation these interruptions imply financial risks for the DSO. A detailed risk-based method is applied to capture the DSO's financial risk. The effect of extreme outage events is considered by incorporating the effect of severe weather, estimating the full probability distribution of the cost for the DSO, and not only the cost for an “average year”, as well as adopting risk averse investment strategies.

Quality regulation designs have been tested in case studies to analyze what incentives to invest in reliability different regulations give the DSO. For example, the current Swedish design, Ei's proposal for the coming regulation period, SwedEnergy's proposal and the Norwegian design were tested. Questions asked are: Given a certain regulation, will socioeconomic investments also become profitable investments for the DSO? Does the quality regulation design affect how investments are prioritized? Will a DSO that takes decisions based on the cost for an “average year” (risk neutral) end up with the same decisions as a DSO that minimizes the costs during extreme years (risk averse)?

Case study results show that quality regulation designs have a significant impact on the reinvestments profitability. The chosen risk strategy (risk neutral/risk averse) may affect the investment decision. This fact is even more evident when the reward and penalty schemes include all interruption durations and not only durations between 3 minutes and 12 hours as is the

case in the current Swedish regulation. The reward and penalty is defined as a function of the customer interruption cost. How the customer interruption cost is estimated will therefore affect the incentive to the DSO. If aggregated index cost models are used, the choice of customer-based indices or load-based indices will have a direct impact on how the DSO prioritizes between customer sectors. But this is only important if national cost parameters are adopted as is the case in Sweden. For the tested quality regulation designs that instead apply sector-specific cost parameters the index type (customer- or load-based) will give identical results. Furthermore, the impact on the regulatory asset base is an important factor that affects if the DSO will find a reinvestment profitable or not. This is especially true under the current Swedish regulation that has a weak reward and penalty scheme.

Electric distribution components have long life times and how the quality regulation will develop in the future is uncertain. If an investment strategy in distribution system reliability is deemed to be beneficial or not for the DSO depends to a great extent on the assumptions made about the future development of the quality regulation. A method for how to take into account the regulatory uncertainty and identify robust investment strategies is presented. Different scenarios for quality regulation development are formulated in a case study. The case study results show that the regulatory uncertainty is a factor that has a large impact on the Net Present Value (NPV) of an investment strategy. Therefore, it becomes important to analyze the robustness of an investment strategy for possible future regulatory changes.

Examples from other countries show that DSOs today are adopting more advanced risk-based methods based on Monte Carlo simulations in order to include the effect of extreme years in their risk analysis but also to estimate the risk for power interruptions at different times during day, week or year. This reports ends with a discussion on how the method applied in the study can be simplified in order to be applicable to larger networks such as transmission networks.

Sammanfattning

I efterdyningarna av elmarknadens avreglering har ägandet av elnät privatiserats och behovet av reglering av elnätsföretag förstärks i och med deras naturliga monopolställning. På avreglerade marknader finns det därför ett ökat intresse för prestationsbaserad reglering (incitamentsreglering) kombinerad med en kvalitetsreglering för elnätsföretagen. Den här rapporten fokuserar på regleringen av distributionsnätsägare och för vilken över 15 EU länder redan har inrättat en kvalitetsreglering.

En kvalitetsreglering har både selektiva och kollektiva drag som syftar till att ge incitament för en tillräcklig tillförlitlighetsnivå på både kund- och systemnivå. Den selektiva kvalitetsregleringen ger den enskilda kunden rätt till ersättning när vissa minimumkrav på elleveransen inte uppfylls; tex när man har haft långa elavbrott eller många elavbrott. Den kollektiva kvalitetsregleringen använder belönings- och bestraffningssystem som ska verka för att uppnå ett samhällsekonomiskt optimum för medelkvaliteten på systemnivå. I Sverige får kunder avbrottsersättning från nätägaren för avbrott över 12 timmar. Dessa kostnader får nätägaren inte inkludera i sin intäktsram utan de har en direkt inverkan på deras vinst. Belönings- och bestraffningssystemet i den svenska regleringen innebär en kvalitetsjustering i intäktsramen som även den påverkar vinsten. Med andra ord innebär kvalitetsregleringen finansiella risker för nätägarna. Speciellt eftersom nätens tillförlitlighet påverkas av slumpmässiga faktorer så som väder, omgivning och olyckor.

Detta projekt avser att studera kopplingen mellan de tekniska riskerna och de finansiella riskerna. Tekniska risker kan orsaka elavbrott och beroende på kvalitetsregleringen så medför dessa elavbrott finansiella risker för nätägaren. Projektet använder en detaljerad riskanalysmetod för att fånga nätägarens finansiella risker. Inverkan av extrema år beaktas genom att inkludera effekten av oväder, ta hänsyn till hela fördelningen av nätägarens kostnad och inte bara kostnaden för ett ”medelår”, samt använda riskaversiva investeringsstrategier.

Olika kvalitetsregleringar har testas i fallstudier för att se vilka incitament de ger till nätägare att öka leveranssäkerheten. Bland annat har den nuvarande svenska regleringen, Ei:s förslag för nästa regleringsperiod, Svensk Energis förslag och den nuvarande norska regleringen testats. Frågor som studeras är: Givet en viss reglering, kommer samhällsekonomiskt lönsamma investeringar också vara förtagsekonomiskt lönsamma investeringar? Påverkar utformningen av kvalitetsregleringen vilka investeringar som prioriteras? Kommer en nätägare som fattar beslut enbart för att minska kostnaden under ett medelår (riskneutral) ta samma beslut som en nätägare som syftar till att minska kostnaderna under extrema år (riskaversiv)?

Resultaten visar att utformningen av regleringen har en stor inverkan på lönssamheten för en investering. Nätägarens val mellan en riskneural eller riskaversiv investeringsstrategi kan påverka investeringsbeslutet. Detta blir ännu mer tydligt när alla avbrottslängder inkluderas i belöning- och bestraffningssystemet och inte bara avbrottslängder mellan 3 minuter och 12

timmar som är fallet i den nuvarande svenska regleringen. Den ekonomiska belöningen eller bestraffningen är en funktion av kundernas avbrottskostnad. Hur denna kostnad beräknas kommer påverka nätägarens incitament att investera. Om aggregerade kostnadsmodeller används så blir valet mellan kundbaserade (SAIDI, SAIFI) eller lastbaserade (ILE, ILEffekt) tillförlitlighetsindex viktigt för hur nätägaren prioriterar mellan olika kundgrupper. I alla fall om man använder kostnadsparametrar på nationell nivå så som man gör i den nuvarande svenska regleringen. För de testade regleringar som istället använder olika kostnadsparametrar för varje kundsektor så kommer kundbaserade och lastbaserade index ge identiska resultat. Inverkan på kapitalbasen är också en viktig faktor som påverkar om en investering anses vara lönsam eller inte. Speciellt för den nuvarande svenska regleringen vars belöning- och bestraffningssystem ger svaga incitament.

Elnätskomponenter har lång livstid och hur kvalitetsregleringen kommer att utvecklas i framtiden är okänt. Om en investeringsstrategi anses vara lönsam eller inte beror också till stor del av vilka antaganden man gör om hur regleringen utvecklas i framtiden. En metod som tar hänsyn till osäkerheten på grund av regleringen presenteras. Metoden syftar till att identifiera robusta investeringsstrategier. Olika scenarier för hur kvalitetsregleringen kommer utvecklas har formulerats i en fallstudie. Resultaten visar att denna osäkerhet är en faktor som har stor inverkan på nuvärdet av en investering. Det blir därför viktigt att analysera hur robust en investeringsstrategis lönsamhet är för framtida förändringar.

Exempel från andra länder visar att nätägare idag tillämpar mer avancerade riskanalysmetoder baserade på Monte Carlo-simuleringar för att kunna inkludera effekten av extrema år men även för att uppskatta hur risken för elavbrott varierar under dagen, veckan eller olika perioder på året. Rapporten avslutas med en diskussion om hur metoden som använts i detta projekt skulle kunna förenklas för att vara möjlig att tillämpa på större elnät såsom transmissionsnät.

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Abbreviations

CAIDI – Customer Average Interruption Duration Index

CEER – Council of European Energy Regulators

CVaR – Conditional Value at Risk

DSO – Distribution System Operator

Ei – The Swedish Energy Markets Inspectorate

ENS – Energy Not Supplied

GS – Guaranteed Standard for worst-served customers

IEC – International Electrotechnical Commission

ILE – Icke Levererad Energi

ILEffekt – Icke Levererad Effekt

NPV – Net Present value

NRI – Network Reliability Index

PBR – Performance Based Regulation

PNS – Power Not Supplied

PQC – Premium Quality Contracts

RAB – Regulatory Asset Base

RPS – Reward and Penalty Scheme

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SRRTS – Swedish Rural Reliability Test System

SURTS – Swedish Urban Reliability Test System

TSO – Transmission System Operator

1 Introduction

Reliability of electric power supply is essential in modern society. In the deregulated electricity market there is a growing interest in performance-based regulation accompanied by quality regulation for electricity networks. In the EU:s 3rd Energy Liberalization Package [1] it says that: ”All regulators will have a role in monitoring compliance with and reviewing the past performance of network security and reliability rules and setting or approving standards and requirements for quality of service and supply”. According to CEER (Council of European Energy Regulators) this will probably lead to that more countries in the EU will apply quality regulations, where the network owner is rewarded (or penalized) when fulfilling (or not fulfilling) an adequate level of reliability to its customers [2].

Quality regulations imply new financial risks for the network owner and the design tends to become more complex with combinations of regulatory tools for improved reliability both on customer and system level. Poor reliability can thereby reduce the allowed revenue for the network owners and force them to pay compensations to affected customers. In Sweden a further development of the quality regulation is expected for the regulatory period that begins in 2016. The new quality regulation will have the objective to strive for a socioeconomic reliability level [3]. Since 2006 the Swedish regulations also demand that the network owners perform risk analyses [1]. Therefore, there is a need for enhanced risk-based methods for the network owners that take into account the financial risk of quality regulations. A deeper understanding of what effects different regulation designs have on the customers’ reliability level is also desirable.

1.1 Overall objective and project goals

With a more complex quality regulation the network owners need more advanced risk-based methods to evaluate how different network investments to improve reliability may affect their revenues and financial risks. This project develops risk-based methods assuming that the optimal investment decision is the one that minimizes the total reliability cost of an investment. The total reliability cost is not only the costs of providing reliability but also the incurred costs associated with interruptions such as quality regulation costs. The total reliability cost should not only include the impact of quality regulation but also other parts of the regulation that might have an impact on the incentive to invest such as the effect on the regulatory asset base.

The project aims to study the connection between the technical and financial risks. The technical risks may cause power interruptions that, depending on the quality regulation imply financial risks for the network owner. The methods also aim to help the network owner to estimate the risk for interruptions longer than 24 hours which from 2011 are forbidden by the Swedish quality regulation [2] unless the interruptions are caused by force

majeure situations. Furthermore, the project aims to analyze what incentives for network investments different regulation designs result in
The overall objective translates to four project goals:

I. **Investigate the impact of quality regulation design on investment decisions**
Analyses of the effect that different regulation designs have on the incentives for network investments are performed in case studies. This is done by comparing risk assessments from the perspective of society and the perspective of the network owner. The relationship in strength between the quality regulation on customer level (selective) and on system level (collective) is also studied. The project accounts for the whole effect of the network regulation which includes the impact an investment has on the regulatory asset base. The focus in the case studies is on reinvestments.

II. **Investigate the impact of different risk strategies when making reliability investment decisions**
Different network owners can have different attitudes towards risks and uncertainties. Network owners of larger networks may for example be more risk neutral (since a severe storm still only affects a part of their network), while owners of smaller networks may tend to be more risk averse. The network owner’s attitude towards risk and uncertainties will be summarized in the risk strategy that the owner uses when taking investment decisions. The impact of a risk neutral compared to a risk averse strategy is analyzed.

III. **Develop risk-based methods to account for both risks and uncertainties**
Both risks and uncertainties will affect the outcome of different investment decisions. Risk is defined as a measurable randomness that can be described by a probability distribution, in contrast to uncertainty that is randomness without a well-defined distribution [3]. The reliability of a component is stochastic and can vary. However, by using failure statistics the probability distribution of the failure rate can be estimated and the risk of power interruption can be simulated. On the contrary we have uncertainties where the probabilities are unknown, such as how the quality regulation design will be in the future. Except for the regulatory uncertainty, the development of other factors such as climate changes may affect the reliability in the future. With the proposed method it is possible to analyze the impact that future scenarios have on the DSO’s financial risk when adopting different investment strategies. For example, how robust an investment strategy is to changes in the quality regulation design can be investigated.

IV. **Develop more effective risk-based methods that are possible to apply on larger power systems**
To make the advanced risk-based methods more applicable on larger electricity networks the simulation times need to be shortened. This means that the proposed method need to be simplified but still be able to capture the most important features of the more advanced

methods. A simplification of an advanced risk-based method is presented and the effect on cutting simulation times is investigated.

The main focus in this study has been on distribution networks. Therefore, distribution system operator (DSO) is used for the network owner. To analyze the effects of regulatory policies on network investments representative test systems are needed. Two test distribution systems; the Swedish Rural Reliability Test System (SRRTS) and the Swedish Urban Reliability Test System (SURTS) [8]-[9], are used to study the impact of different regulatory policies. Even though the main focus is on distribution networks the simplified risk-based method, applicable for larger systems, can be applied on both distribution and transmission systems.

1.2 Publications

This report presents some unpublished material as well as a summary of the publications made within the project. Interested readers are recommended to read the following publications for further details:

Publication 1: Alvehag and Söder, "Quality regulation impact on investment decisions in distribution system reliability", presented at the 9th International Conference on the European Energy Market EEM12, Florence, Italy, May, 2012

Publication 2: Edimu, Alvehag, Gaunt, and Herman, "Performance of a Time-Dependent Probabilistic Approach for Bulk Network Reliability Assessment", Electric Power Systems Research, vol 104, 2013

Publication 3: Edström, Rosenlind, Alvehag, Hilber, and Söder, "Influence of Ambient Temperature on Transformer Overloading During Cold Load Pickup", IEEE Transactions on Power Delivery, vol 28, 2013

Publication 4: Alvehag, and Awodele, "Impact of reward and penalty scheme on the incentives for distribution system reliability", IEEE Transactions on Power Systems, vol PP (99), 2013

1.3 Scope

Consequences of power interruptions can relate to many different aspects such as environment and safety concerns. In this project, risk-based methods that consider the financial consequences of power interruptions for the DSO and society are developed. Net Present Value (NPV) calculations are carried out and the investment decision that minimizes the total reliability cost is assumed to be the optimal decision. The decision-making process in distribution system reliability can also be formulated as a multi-criteria decision problem. A multi-criteria problem considers not only the financial consequences when making decisions, but also other aspects that are difficult to attached a cost to, such as safety, environment and reputation impact. The methods developed in this project can be used to evaluate the financial impact in a multi-criteria problem.

In the current Swedish regulation both unannounced and announced interruptions are included. However, only the costs due unannounced (unplanned) sustained power interruptions are included when calculating the total reliability cost. Announced (planned) interruptions are within the DSO's control and it is assumed that these are planned optimally to minimize the financial penalties. Sustained power interruptions last for more than a few minutes which means that costs due to power quality problems, such as voltage sags and short interruptions, are outside the scope of this project.

In this project, regular maintenance actions are assumed to keep the failure rates constant. How a component's failure rate is affected by maintenance actions is not modeled in detail. Therefore, only reinvestment projects and not maintenance projects have been investigated in the case studies.

For the Swedish quality regulation used in the case study this report will use the formulated quality regulation in [4] and the transition period agreement (övergångsregeln) is not included.

1.4 Outline of the report

The report is structured as follows: Chapter 2 gives the necessary background for understanding the concepts used in this report. Chapter 3 presents the used risk-based method, test systems and considered investment projects. In Chapter 4 the impact of different Reward and Penalty Scheme (RPS) designs on investment decisions is investigated. The RPS is used in the collective quality regulation and its design includes aspects such as the choice of cost model for the reconstruction of customer interruption costs, RPS type (dead band, multi-year index, capped, continuous) and share factor. Also the impact of the choice of risk strategy and an investment's impact on the regulatory asset base are studied. Chapter 5 presents a risk-based method that also considers uncertainties by formulating future scenarios. Chapter 6 presents how the advanced risk-based method can be simplified to be applicable to larger power systems. Finally, in Chapter 7 conclusions are drawn.

2 Background

This chapter gives the background needed for understanding of the following chapters. The technical risks may cause power interruptions that depending on the quality regulation imply financial risks for the DSO. This chapter presents an overview of risk-based methods, the basics of quality regulation, customer interruption cost models and the current Swedish regulation.

2.1 Risk-based methods for reliability assessments of power systems

The international standards IEC defines the term risk to include both the probability and consequences of a specified event that can to harm [5]. In this project this event is power interruptions and the financial consequences of such for the DSO and society are estimated.

According to the Swedish Electricity Act [1] DSOs are obliged since 2006 to hand in risk analyses to the regulator. In 2010 the regulator published guidelines for how these analyses should be carried out [6]. The risk analyses should aim to identify the probability and consequence of power interruptions as well as prioritize between different investments or reinvestments to decrease the risk for power interruptions. In the aftermath of this new requirement the development of risk analysis methods has been intensified.

2.1.1 Using the total reliability cost as decision criteria

To prioritize between different investment and reinvestments aimed to improve reliability the decision maker need to set a decision criterion. The decision criterion is formulated as an optimization problem that can be of three general types [7]:

1. Optimize reliability subject to cost constraints
2. Optimize cost subject to reliability constraints
3. Optimize the total reliability cost including the cost to provide reliability and the incurred costs associated with interruptions.

A DSO with a fixed budget to spend on reliability improvement projects solves an optimization problem formulated as Type 1. In contrast, a DSO solving problems of Type 2 does not have a set budget. Instead, the total cost of approved projects is minimized until the reliability requirement is fulfilled. A DSO adopting Type 3 chooses the set of projects that minimizes the total reliability cost. The total reliability cost is not only the costs of providing reliability but also the incurred costs associated with power interruptions. For the DSO these associated costs are restoration costs and costs due to the quality regulation and for society the associated costs are customer interruption costs. Hence, in contrast to Type 1 and 2, Type 3 also includes costs implied by power interruptions.

To analyze the financial risk, net present value (NPV) analyses are widely used by DSOs [8]. The reason for this is that reliability investments in distribution networks have an impact far into the future and the cash flows for different project may be distributed differently over their lifetime. By translating the cash flows of each project to a NPV the projects become comparable. The total reliability cost defined for the investment's economic lifetime is therefore used when calculating the NPV.

In this project an optimal investment decision is assumed to minimize the NPV of the total reliability cost (Type 3). In Chapter 4 risk analyses are carried out from both the perspective of society and the DSO. Therefore, the total reliability cost of these two actors needs to be defined. The discounted total reliability costs for society $\boldsymbol{C}_{Tot}^{SOC}$ and the DSO $\boldsymbol{C}_{Tot}^{DSO}$ are in this project defined as:

Equation 1

$$\boldsymbol{C}_{Tot}^{DSO} = \sum_{\tau=1}^{T} \frac{\boldsymbol{C}_{I}(\tau) + \boldsymbol{C}_{M}(\tau) + \boldsymbol{C}_{R}(\tau) + \boldsymbol{C}_{Tot\,\mathrm{Re}g}(\tau) + \boldsymbol{C}_{RAB}(\tau)}{(1+\boldsymbol{r}_{DSO})^{\tau}}$$

$$\boldsymbol{C}_{Tot}^{SOC} = \sum_{\tau=1}^{T} \frac{\boldsymbol{C}_{I}(\tau) + \boldsymbol{C}_{M}(\tau) + \boldsymbol{C}_{R}(\tau) + \boldsymbol{cic}(\tau)}{(1+\boldsymbol{r}_{SOC})^{\tau}}$$

where,

$\boldsymbol{C}_{I}(\tau) =$ Investment cost for year τ

$\boldsymbol{C}_{M}(\tau) =$ Maintenance cost for year τ

$\boldsymbol{C}_{R}(\tau) =$ Restoration cost for year τ

$\boldsymbol{C}_{Tot\,\mathrm{Re}g}(\tau) = \boldsymbol{C}_{RPS}(\tau) + \boldsymbol{C}_{GS}(\tau) + \boldsymbol{C}_{PQC}(\tau)$, total regulation cost for year τ

$\boldsymbol{C}_{RPS}(\tau) =$ Regulation cost due to reward and penalty scheme (RPS)

$\boldsymbol{C}_{GS}(\tau) =$ Regulation cost due to guaranteed standards (GS)

$\boldsymbol{C}_{PQC}(\tau) =$ Regulation cost due to premium quality contracts (PQC)

$\boldsymbol{C}_{RAB}(\tau) =$ An investment's impact on the regulatory asset base (RAB)

$\boldsymbol{cic}(\tau) =$ Customer interruption cost for year τ

$\boldsymbol{T} =$ Calculation period (economic lifetime of the investment)

$\boldsymbol{r}_{DSO}, \boldsymbol{r}_{SOC} =$ Discount rate for the DSO and society, respectively

In Equation 1, the restoration cost $\boldsymbol{C}_{R}$ includes not only the cost of new parts needed to restore the failed component (if needed), but also the cost of the repair crew. The different parts of the total regulation cost $\boldsymbol{C}_{Tot\,\mathrm{Re}g}$ will be explained when introducing the concept of quality regulation in Section 2.2. An investment may also affect the regulatory asset base (RAB) $\boldsymbol{C}_{RAB}$. This is described further for the Swedish regulation in Section 2.2.4. For society a large part of the total reliability cost is the costs that the customers suffer due to power interruptions – the so-called customer interruption cost cic. Different ways to reconstruct customer interruption costs will be explained in Section 2.2.3.1.

The two actors use different discount rates r_{DSO} and r_{SOC} in their analysis. Except for the discount rates, there are two other differences between the analyses. Firstly, the effects of taxes are considered in the cost calculations for the DSO. Secondly, the DSO is assumed to depreciate the investment cost over a five year period. A five year depreciation period is only wise if the DSO makes a high enough profit. The scrap value of the investment is included in the analyses of both society and the DSO. The scrap value is the remaining value of the investment in the end of the calculation period. The technical lifetime is different depending on the project, but always longer than the calculation period. Linear devaluation of the network is used throughout the technical lifetime and the scrap value is calculated as the remaining part of the investment cost in the end of the calculation period.

Having the discounted total reliability cost the NPV of project n is defined as:

Equation 2

$$NPV^n = C_{Tot}^0 - C_{Tot}^n$$

where,

C_{Tot}^0 = discounted total reliability cost before (status quo)

C_{Tot}^n = discounted total reliability cost after a project n has been carried out

While some of the costs in Equation 1 are deterministic such as the investment cost, maintenance cost and the impact on the RAB, other costs that depend on the number and duration of power interruptions become stochastic. The stochastic costs are restoration cost, total regulation cost, and customer interruption cost. To estimate the benefits of an investment a risk assessment is needed that capture the risk of power interruptions before and after the investment. To fully capture the financial risks these methods need to be able to simulate the stochastic events of power interruptions and the following consequences. Different risk-based methods to estimate the risk of power interruptions exist and these are briefly reviewed in the following section.

2.1.2 The staircase of risk analysis

Risk-based methods can be categorized into three groups [9]: simplified risk analysis methods, standard risk analysis methods and model-based risk analysis methods. One example from each of the three groups: are brainstorming sessions, risk matrices and fault tree analysis, respectively [9]. The three groups represent an increasing complexity. The choice of method group is dependent on the purpose of the risk analysis, the required detail level and available data.

The risk analysis methods can also be divided into qualitative and quantitative methods. All risk analyses have important qualitative elements such as scope definition of the analysis, identification of risk factors and specification of the risk model. Qualitative methods are sufficient if the purpose is limited to identify the risk factors. However, more complex quantitative methods are required for numerical risk estimations to quantify the probability and consequences. In many cases the numerous data needed for quantitative methods are not available and qualitative methods are the only ones possible to apply.

The three groups with increasing complexity create the three first steps in the staircase of risk analysis shown in Figure 1. The added fourth step represents the research frontier that develop more advanced risk analysis methods based on mathematical models. Figure 1 is inspired by Klerdal & Holmberg's illustration of increasing knowledge in the field of risk analysis [10].

The applied risk-based method in this project is based on advanced mathematical models combined in a time-sequential Monte Carlo simulation. This approach will be explained in Section 3.1. The benefit of Monte Carlo is that not only the expected reliability can be estimated but also the outcome during more extreme years. Being able to capture the extreme events averse risk strategies can be applied. In contrast to a risk neutral decision maker that takes decisions based on expected values, a risk averse decision maker consider the costs of extreme events. The next section introduces the risk strategies applied in this project.

Due to the fact that advanced methods increase the computation time it becomes important to cut the simulation times in order to make the methods more applicable to larger systems. A suggestion on how to simplify the chosen method is discussed in Chapter 6.

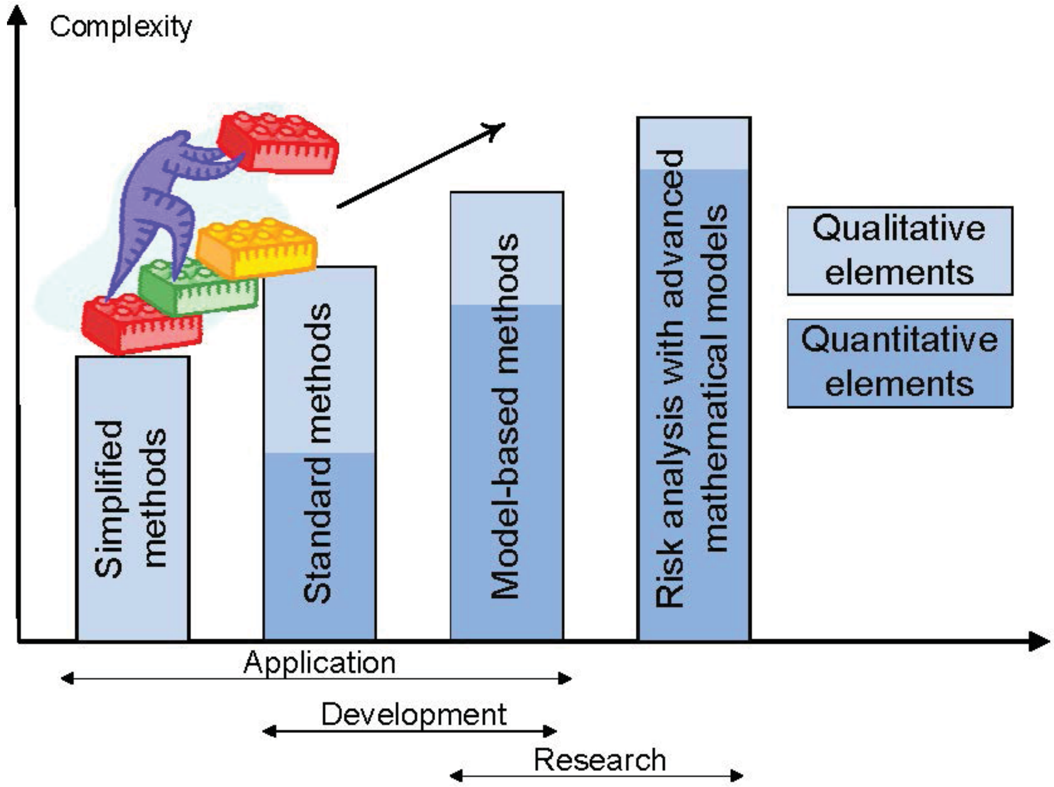

Figure 1: The staircase of risk analysis. Inspired by Holmberg's & Klerdal's compilation [10].

2.1.3 Risk strategies

Power systems are in most cases extremely reliable and power interruptions are rare events. Therefore, using expected values may be misleading since the "average year" never occurs. At least for rural networks with mainly overhead lines, the majority of years have a small number of power interruptions, while a few extreme years with major severe weather has geographically widespread blackouts.

A risk neutral decision maker takes decisions based on the expected total reliability cost. The expected total reliability cost is based on all years, but a year that produces this expected cost does not need to have ever occurred. Instead, the low-probability catastrophic events can be of higher concern for the decision maker than the more frequently occurring but less severe events. If this is the case the decision maker would prefer a risk averse strategy.

Extreme events are defined as low-probability and high consequences events. To be able to put more weight on the extreme events in the decision making process, two requirements need to be fulfilled. Firstly, you need a risk-based method that actually captures these events, so the extreme total reliability costs also are estimated. Secondly, you need a risk tools that focus on these extreme events in the decision-making process. In this project the risk averse strategy is formulated using a risk tool – Conditional Value at Risk (CVaR) - from the financial industry. CVaR takes the average of the total reliability cost during the most extreme years. CVaR is usually defined as the 1% or 5 % of the extreme costs [11]. In this project the extreme years are defined as the 5 % of the years with worst reliability and the CVaR is the expected total reliability cost for these years. The expected value and conditional value-at-risk value are illustrated in Figure 2.

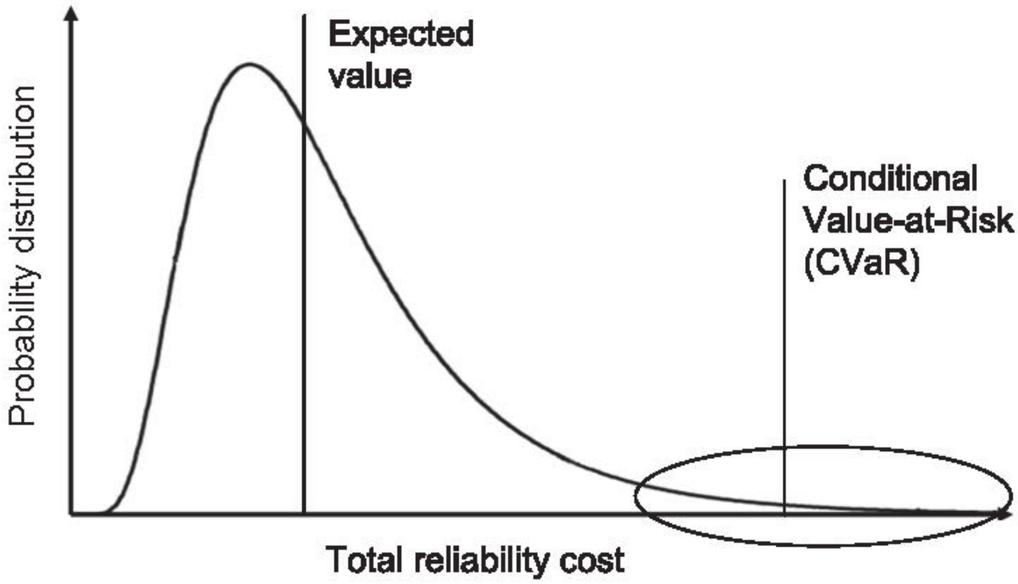

Figure 2: The expected total reliability cost used in a risk neutral strategy and the Conditional Value at Risk (CVaR) used in a risk averse strategy.

The risk strategy for a risk neutral and risk averse DSO are in this project defined as:

Equation 3

Risk neutral: $\max_{n} \mathrm{E}(\boldsymbol{NPV}) = \max_{n} \mathrm{E}(\boldsymbol{C}_{Tot}^{DSO,0}) - \mathrm{E}(\boldsymbol{C}_{Tot}^{DSO,n})$

Risk averse: $\max_{n} \mathrm{E}(\boldsymbol{NPV}) = \max_{n} \mathrm{CVaR}(\boldsymbol{C}_{Tot}^{DSO,0}) - \mathrm{CVaR}(\boldsymbol{C}_{Tot}^{DSO,n})$

Society is assumed to evaluate the projects based on the expected NPV corresponding to a risk neutral strategy. This is the most common approach in socioeconomic cost-benefit analysis [3].

2.2 Quality regulation designs

Significant changes in the form of liberalization and privatization have taken place in the electricity business. Many electricity markets in Europe have been deregulated resulting in the network owners being unbundled from power production [12]. In Sweden, network owners are unbundled both from power production and retail. After the re-regulation, retail and production are conducted on a competitive market. However, the network ownership of transmission and distribution networks constitutes natural monopolies since it is not socioeconomically defendable to have parallel networks serving the same customers. These natural monopolies need to be regulated.

Historically, cost-based regulation was used, allowing the DSOs, to charge for their actual costs plus a certain profit [13]. To motivate economic efficiency and to simulate competition in the natural monopoly of network ownership, the concept of performance-based regulation (PBR) was introduced [13]. In PBR, the DSOs are not always allowed to charge their customers for their actual costs. Profits are no longer guaranteed, but can be earned by cost savings. To prevent that cost savings in investments and maintenance result in a deterioration of reliability, many PBR regimes in Europe have been accompanied by quality regulations [14]. Quality regulations are relatively new and were firstly introduced in Italy 2000. Many European countries today apply quality regulation to reliability and the different regulations can be found in [14] [15]. This section introduces the concepts of quality regulation such as collective and selective quality regulation, customer interruption cost and the current Swedish regulation.

2.2.1 Definition of quality regulation

Quality regulation can be applied to different aspects such as reliability, customer service and voltage quality. This study looks on direct controls in the quality regulation that aim to provide incentives for an adequate level of reliability under a performance-based regulation by offering direct financial incentives to the DSOs [16]. By financial incentives, such as increased or decreased revenues and an obligation to pay compensation to customers that have suffered long power interruptions, the regulator tries to mimic the outcome of market-like conditions [16].

Quality regulation can be divided into collective and selective quality regulation, illustrated in Figure 3. Collective quality regulation consists of reward and penalty schemes (RPSs) and aims to control the average reliability on system level. Selective quality regulation consists of guaranteed standards for worst-served customers (GSs) and premium quality contracts (PQCs), and aims to control the reliability on customer level. The direct controls RPS, GS and PQC are functions of quality indicators on either system or customer level. Commonly, used indicators are shown in Figure 3. The quality indicators on system level are system reliability indices defined in Appendix A.

SYSTEM LEVEL	
Quality indicator	Direct control
SAIDI SAIFI ENS	Reward and penalty scheme (RPS)

CUSTOMER LEVEL	
Quality indicator	Direct control
Duration of interruption Number of interruptions	Guaranteed standard (GS) Premium quality contracts (PQC)

Figure 3: Direct controls adopted by the regulator in the collective (system level) and selective (customer level) quality regulation.

The sum of the costs due to the three direct controls in a quality regulation is the total regulation cost in Equation 1. Usually, the DSO is not allowed to transfer the costs due to RPS, GS and PQC to the customers by increased tariffs through adjustments in the DSO's future revenue. This means that the DSO's reliability performance will have a direct impact on its profit resulting in strong financial incentives for an adequate reliability level both on system and customer level. However, in some countries such as Norway the DSO is allowed to include a part of these costs in future revenues [17].

As discussed in [18], both GS and RPS are necessary. For example, only RPS may lead to that even though a DSO receives rewards for providing excellent system reliability, some areas may still have very poor reliability. A more thoroughly description of the theory behind quality regulations can be found in [19].

2.2.2 Guaranteed standards (GSs) and premium quality contracts (PQCs)

GS and PQC focus on reliability on customer level by setting standards for quality indicators such as maximum duration per interruption or maximum number of interruptions per year. The DSOs are penalized when not fulfilling these standards; commonly they have to pay compensation to the affected customers [16]. Often the compensation levels are different for different customer sectors and increase as the quality indicator exceeds the standard [14]. While a GS is formulated by the regulator, a PQC is a contract between the DSO and an individual customer. These contracts define the customer compensation if the performance standards agreed upon are not fulfilled. Usually, these contracts are signed with large users that have a need for high quality [14]. The experience with PQC is quite limited, but two countries that have adopted PQC are Italy and France [14].

2.2.3 Reward and penalty schemes (RPSs)

RPSs are currently being applied to distribution system reliability in 15 out of the 26 European countries considered in [15]. Compared to GS and PQC, RPS is the far most difficult tool to use. With the RPS the regulator aims to establish the socioeconomically optimal system reliability level [14]. To design an RPS the regulator must make an attempt to answer the question: what is an optimal reliability level and what is a fair price for the customers to pay for it?

The difficulty lies in the translation of the benefits of having continuous electricity supply into monetary terms. This is commonly assessed by approximating the consequences of unreliability, i.e. the costs due to power interruptions for customers. To assess these costs, referred to as customer interruption costs, customer surveys are commonly used. A quality regulation transfers some of the customer interruption costs to the DSO.

The customer interruption cost transferred to the DSO is defined in Equation 4. This penalty is defined as the difference of the costs at the actual reliability level (cic) and a target level ($\overline{cic}$). The target level is the reliability level at which DSO's total reliability cost is allowed to be coved by revenues. The regulator then implements penalties and rewards for DSOs when they fail to or succeed to meet these targets. A higher reliability level gives a higher profit for the DSO, and in this way the regulator tries to mimic the outcomes of market-like conditions.

Since the total reliability cost is used in this project a penalty is defined to be positive and a reward is defined to be negative. To achieve a socioeconomically optimal reliability level the target setting is irrelevant as shown in [19]. What is important is that the rewards/penalties are defined as function of the customer interruption costs.

Equation 4

$$\boldsymbol{C}_{\boldsymbol{RPS}}(\tau) = \boldsymbol{cic}(\tau) - \overline{\boldsymbol{cic}}(\tau)$$

where,

$\boldsymbol{cic}(\tau) =$ Customer interruption cost for year τ at the actual reliability level

$\overline{\boldsymbol{cic}}(\tau) =$ Customer interruption cost for year τ at the reliability target level

A rigorous derivation of optimal rewards/penalties together with assumptions that must be fulfilled can be found in [20]. In [20] it is concluded that optimal rewards/penalties should fulfill Equation 5.

The derivative $\frac{\partial \boldsymbol{C}_{\boldsymbol{RPS}}}{\partial \boldsymbol{R}}$ in Equation 5 is the slope of the types continuous, capped and dead band in Figure 4. This slope is referred to as *incentive rate* or *cost parameters* and is in many countries based on customer interruption costs, which is in line with Equation 5. However, a common simplification is to have a constant cost parameter for all levels of reliability. According to Equation 5 the cost parameter should equal the derivative of the customer interruption cost. How the customer interruption cost depends on reliability does not have to be linear corresponding to a constant slope. As can be seen in Equation 5, when integrating the derivative we get that the optimal reward and penalty scheme should be equal to the customer interruption cost minus an arbitrary constant. This constant is set to the customer interruption cost at the target level, which gives Equation 4. Sometimes, a share factor is employed which shares the rewards and penalties due to the RPS between the DSO and the customers. A share factor of less than 1 reduces the incentive rate of the RPS and such a regulation does not fulfill Equation 5.

Equation 5

$$\frac{\partial \boldsymbol{C}_{RPS}}{\partial \boldsymbol{R}} = \frac{\partial \boldsymbol{cic}}{\partial \boldsymbol{R}} \quad \Rightarrow \quad \boldsymbol{C}_{RPS}^{Optimal} = \boldsymbol{cic} - \boldsymbol{C}_1, \quad \text{for all reliability levels}$$

where,

$\boldsymbol{C}_{RPS} =$ Cost due to RPS (reward<0, penalty>0)

$\boldsymbol{cic} =$ Customer interruption cost

$\boldsymbol{R} =$ Reliability level

$\boldsymbol{C}_1 =$ Arbitrary constant, set to the cic at target level ($\overline{\boldsymbol{cic}}$)

Whether the regulator succeeds in formulating a quality regulation that leads to an adequate reliability level or not will depend on the regulator's ability to properly measure and reconstruct customer interruption costs. Regulators use different cost models with different levels of detail in the reconstruction. Examples of cost models used for reconstructing customer interruption costs are presented in [19]. Accurate customer interruption cost estimations have to be weighed against the drawbacks of a complex regulation. A complex regulation demands more data to be recorded and reported by the DSO to the regulator. To record all the required data, the DSOs may have to upgrade their equipment [21].

More simple cost models reconstruct customer interruption costs using system quality indicators. The system quality indices used in this project are System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Energy Not Supplied (ENS) and Power Not Supplied (PNS). These indices are defined in Appendix A.

The practical solution is to construct an RPS, as shown in Figure 4, for each used system quality indicator. *Minimum standards* is sometimes not defined as an RPS since it has a discrete relationship between quality and price [20], hence the brackets in Figure 4. Independent of how much the DSO under-performs to meet the target level, minimum standards give a constant penalty. This leaves the DSO with no incentives to perform better than the target and the resulting system reliability is thereby defined by the target level [20]. This study focuses on the types that have a continuous relationship between quality and price: *continuous*, *capped*, and *dead band*. When the slope of these schemes are based on the customer interruption cost data obtained from customer surveys the three types have better prerequisites to give incentives for achieving a socioeconomically optimal reliability level than minimum standards. Also combinations of the schemes exist such as a capped dead band scheme. The schemes can be symmetric as shown in Figure 4 or asymmetric around the target level [16].

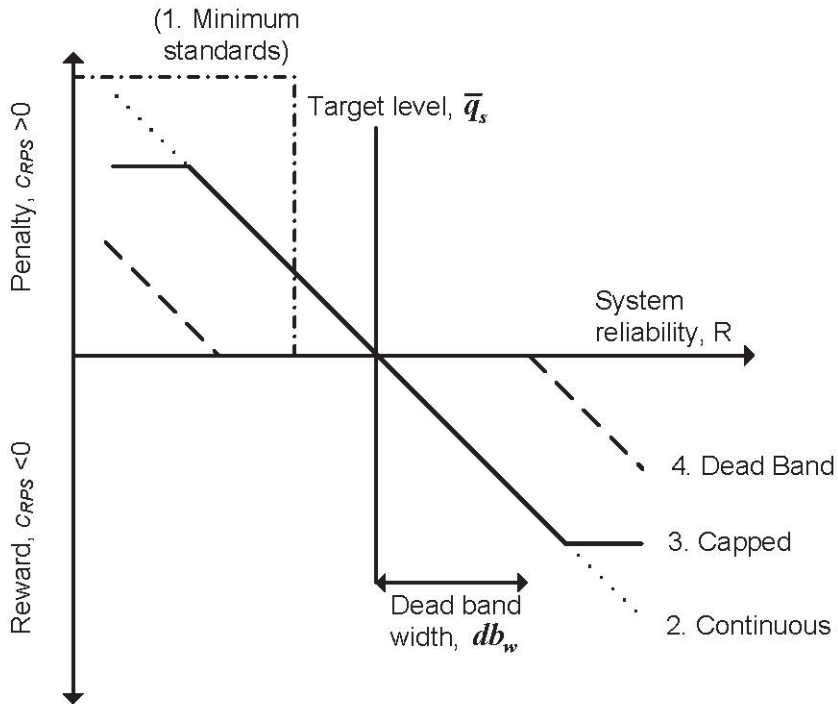

Figure 4: Different RPS types. The x-axis represents the system reliability measured by system quality indicators and the y-axis represents the financial incentives (reward/penalty).

The continuous scheme - Type 2 - has rewards/penalties that increase with the deviation from the set target level. The capped scheme - Type 3 - is similar to the continuous scheme. The difference is that maximum reward/penalty levels are set. Type 4 is the dead band scheme that has a “dead band” around the set target level within which the DSO's profit will be unaffected. Outside the dead band rewards/penalties increase as a continuous scheme. Types 2 to 4 in Figure 4 or combinations of these are the most common scheme types applied in European countries [15].

For cost models that use two indicators when reconstructing the customer interruption cost the cap can be defined on the sum of two indicators or on the individual indicators separately. However, the dead band is always defined on the indicators individually.

The slope in Figure 4 is the cost parameter that is multiplied with the system quality indicator. Different indicators have different cost parameters. The cost parameters for duration dependent indices (SAIDI, ENS) have the unit [SEK/kWh], while the unit for frequency indices (SAIFI, PNS) is [SEK/kW]. These cost parameters are based on customer damage functions and can be estimated on different levels. The following section is describing how this estimation is carried out.

In more detailed cost models information from each interruption such as duration and timing are used when reconstructing the customer interruption. The RPS is then defined for the annual customer interruption cost and depending on if the DSO is fulfilling the target or not it will receive a reward or a penalty. It is still possible to adopt PRS types as *dead band* and *capped*, however, this will now be applied directly on the annual customer interruption cost and not a quality system indicator.

The annual reliability level is highly dependent on stochastic factors such as weather and will thus vary from year to year. Using a dead band is one approach to decrease the variation of the DSO's financial risk and thereby avoid unnecessary tariff adjustments due to natural deviations from the target level. Using *multi-year system quality indicators* is another approach to achieve this. In Italy for example two-year rolling averages are applied [16].

2.2.3.1 Customer interruption costs and cost models applied by regulators in RPSs

The fact that customer interruption costs are functions of many different factors such as interruption duration, timing and customer sector, make them challenging to estimate. Due to this fact, not all regulators choose to use customer interruption costs as input when defining incentive rates [22].

For the regulators that base incentive rates on customer interruption costs, the first step is to collect customer interruption cost data by national surveys for different customer sectors. The customer sectors usually included are: residential, industrial, commercial, governmental and agricultural. Before the collected data can be used in an RPS they must be normalized by, for example, the annual peak demand. The Council of European Energy Regulators (CEER) has prepared guidelines for customer interruption data collection and normalization presented in [22]. Commonly, only the interruption costs for the worst case scenario, i.e. an interruption occurring at the worst time, are surveyed for a few interruption durations [22].

The second step is to use the collected data to construct *customer damage functions* for each customer sector that shows how the cost depends on outage duration [23]. Composite customer damage functions may also be derived. A composite customer damage function is defined as the aggregated interruption cost for a mixture of customer sectors in a region and is obtained by weighting the customer damage function for the different sectors [24]. The regulators can choose to base the cost parameters in the RPS on composite customer damage functions on national or area level. Alternatively, the regulator can use the customer damage functions for each customer sector combined with sector-specific quality system indicators.

The last step is to reconstruct the customer interruption costs. The cost models used by the regulator estimates the annual customer interruption costs in order to estimate the annual rewards/penalties defined by Equation 4. Many researchers have proposed various cost models with different number of outage and customer characteristics included. In [19] several cost models are described and compared. Roughly, the used cost models can be grouped into four categories with increasing detail level in the information used: national-, area-, sector- and outage-specific. The national-, area- and sector-specific models use system quality indices such as SAIDI, SAIFI, and ENS together with cost parameters aggregated on different detail level. The outage-specific model uses outage characteristics such as interruption duration and timing for each specific interruption to estimate the customer interruption cost.

A national-specific model using the system quality indicators SAIDI and SAIFI is applied in the Swedish quality regulation since 2012 [4]. The previous quality regulation in Norway adopted a sector-specific model based on ENS [25]. An area-specific cost model is used in Italy where the cost parameters are set depending on population density which results in different parameters for urban and rural areas [16]. The cost parameters also depend on the measured SAIDI indicator in the DSO's district area [16]. An outage-specific cost model is used in the current Norwegian quality regulation [21].

2.2.4 Swedish regulation and customer interruption cost surveys

The current quality regulation in Sweden has both a collective and a selective quality regulation.

The selective quality regulation consists of guaranteed standards referred to as the Gudrun Laws which ratify customers to get compensations for interruptions longer than 12 hours. The costs for the DSO due to paid customer compensations are not allowed to be covered by tariffs, hence the cost is not covered by the revenue frame. The selective quality regulation therefore give strong incentives since the compensations paid will have a direct impact on the DSO's profit. The compensations levels are dependent on the tariff the customer pays as well as on the interruption duration. Making the customer compensations dependent on tariff will result in that different customer sectors get different compensation levels.

According to the Electricity Act [26] the customer compensations in the Gudrun laws are defined as follows. Customer compensations for interruptions between 12 hours to 24 hours are 12,5 % of the customer's annual network tariff. If the interruption is longer than 24 hours the customer will receive additional compensation for every started 24 hour interruption period equaling 25 % of the annual network tariff. A minimal and a maximal compensation are defined as 2 % of the price base amount and 300 % of the customer's annual network tariff, respectively. The compensations are rounded upwards to the closest 100 SEK.

The collective quality regulation consists of an RPS which affects the DSO's revenue framework and will have a direct impact on their profit. Since 2012 Sweden has adopted an ex-ante tariff regulation for the period 2012-2015, which means that the tariffs are reviewed by the regulator before the regulatory period. The DSO will then know how much they can charge customers, conditional on that the assumptions which form the basis of determining the revenue framework are fulfilled. Ex-post regulation is conducted on actual accounts available after the regulation period. Even though network regulations can be either ex-ante or ex-post, the quality regulation is always based on actual performance, and hence applied ex-post.

In Figure 5 the flow chart for the revenue framework is shown for the current Swedish ex-ante regulation [27].The impact of the RPS is referred to as *Adjustment according to quality regulation* in Figure 5. According to the electricity act [28] the maximal quality adjustment is defined as the return on the regulatory asset base. This maximal adjustment is by the Swedish Energy Markets Inspectorate (Ei) approximated to be 25 % of the revenue frame [29]. A further cap on the quality adjustment has been introduced by Ei. The capped values of the quality adjustment are defined as +/-3 % of the DSO's annual revenue [4], which implies a lower cap than one defined by the electricity act. It is the total reward or penalty achieved by the sum of SAIDI and SAIFI that is capped.

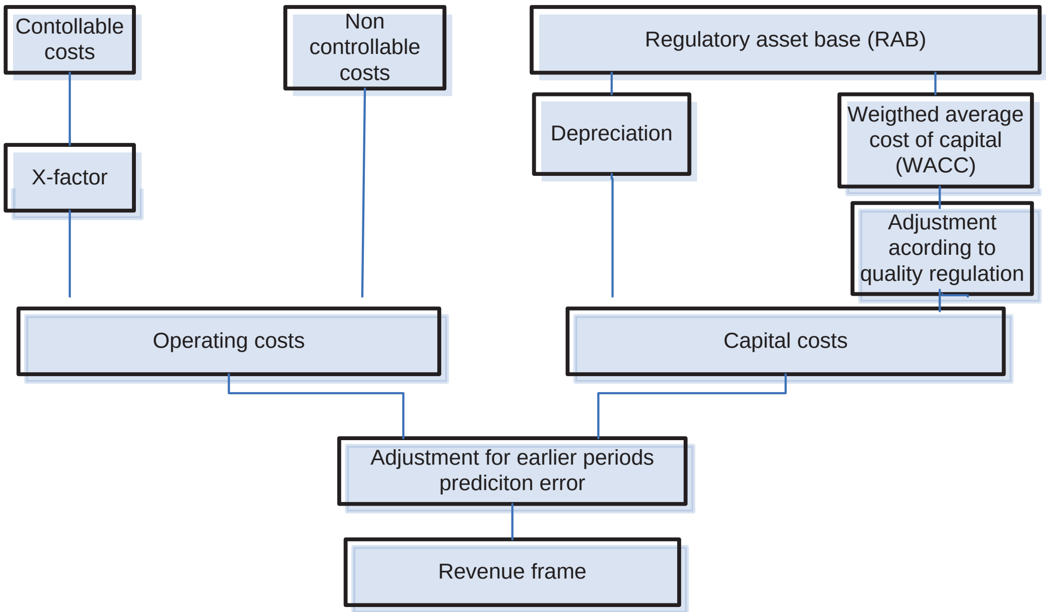

Figure 5: Flowchart of the revenue framework for the Swedish ex-ante tariff regulation. Adapted from [30].

For distribution networks a capped RPS type is applied together with a cost model that uses SAIDI and SAIFI combined with cost parameters on national level to reconstruct customer interruption costs (Equation 8). Also a share factor of 0.5 is applied. The share factor is motivated by that it divides the risk equally between the DSO and customers [4]. The RPS design is applied on both unannounced and announced interruptions between 3 minutes to 12 hours and described in [4]. The reason for excluding longer interruptions is to not double punish the DSO for interruptions above 12 hours both in the selective and in the collective regulation.

Year 2011 a transition period (övergångsperiod) was defined. The reason was that the newly adopted method for the calculation of the revenue framework gave unacceptable high revenues. This formulation of the transition period came after the report, presenting the quality regulation for 2012-2015, [4] was published. However, the change would come to have an effect on the quality regulation adjustment. Except for the share factor 0.5 that weakens the quality adjustment the transition period agreement lead to that the adjustment become even weaker. This report will use the formulated quality regulation in [4] and the transition period agreement is not included.

The cost parameters in the RPS are based on a customer interruption cost survey carried out by Svenska Elverksföreningen in 1994 [31] [4]. In [31] Svenska Elverksföreningen estimated the customer interruption cost, both in [SEK/kWh] and [SEK/kW], for different duration and customer sectors. The cost data was updated by SwedEnergy in 2003 by using a theoretical analysis, interviewing experts and comparisons with Norway [32]. It is these updated data, reported in [32], and adjusted to current price index, that is the basis for the national cost parameters used in the current RPS for the regulatory period 2012-2015. To calculate national-specific parameters the customer composition on national level between different sectors is needed. The customer composition is also based on the composition given in [31].

The most recent customer interruption cost survey was conducted by Gothenburg University between the years 2003-2005 [33]. But this study was not chosen to be used in the regulation. There are discussions on conducting a new customer interruption cost survey in Sweden. Hopefully, in the coming regulatory period 2016-2019 these updated customer interruption costs can be employed.

In this project cost data from the recent survey [33] was used since this study in contrast to the survey in [31] [4] covers all the five customer sectors: residential, industrial, commercial, agricultural, and governmental.

3 Chosen risk-based method, test systems and investment projects

This chapter presents the chosen risk-based method that is applied in the case studies in the following chapters when investigating the impact of quality regulations. The test systems and investment projects used in the case studies are also described.

3.1 The chosen risk-based method using Monte Carlo simulations

This section presents the motivation for the chosen risk-based method and gives a brief overview of the method. More details are given in [34].

3.1.1 Motivation

The motivation to use this model is mainly two-folded:

1. *Not only modeling an “average year” but also capture the effects of extreme years*

Investigating reliability statistics for Swedish rural distribution networks it is evident that reliability indices can vary a lot between years [35]. Even though the rural distribution networks in Sweden has gone through a radical change with huge investments in underground cables, there still remains overhead lines which make the networks vulnerable to severe weather. Severe weather conditions significantly affect the component failure rate and the restoration time in distribution systems [36]. Since quality regulation is always based on actual performance (ex-post) this will mean that yearly variations in system reliability become important for the DSO’s risk analysis when estimating their financial risk. If the variances of the indices are underestimated, the DSO is exposed to a higher financial risk than appears to be the case.

Commonly, analytical methods that use average values for the input parameters are applied to calculate NPV. Every year during the project’s lifetime is then assumed to be an average year. Power systems are extremely reliable and power interruptions are rare events. Most years have nearly no interruptions, while a few extreme years have stormy weather and several interruptions. Assuming every year to be an average year may be misleading since “the average year” does not even have to occur. Sensitivity analysis can be carried out in order to investigate how changes in the inputs affect NPV [37]. But this kind of analysis does not give any information on the probability of these changes. To be able to apply risk averse strategies the whole probability distribution of the total reliability cost, as shown in Figure 2, is needed.

2. *Capture time-dependencies in inputs for more accurate output assessments*

Severe weather is generally more common during certain seasons; consequently, weather-caused failures are not uniformly distributed over the year. This is evident in the component failures per month during the year for different components and countries presented in [38]. The seasonal patterns in severe weather will result in that the failure rate and the restoration time are becoming time-varying. Capturing this time dependency is important for accurate estimation of the ENS, which is usually estimated using time-varying load curves [16]. It has also been shown to be important for accurate assessments of customer interruption costs [39]. Results show that incorporating time dependencies will affect the total reliability cost for the DSO, sometimes in such an extent that the preferred project changes [40].

In Sweden a new law came into force in 2011 that prohibits interruptions to be longer than 24 hours. With the used risk-based method it is possible to calculate the probability of interruptions exceeding this duration. It is also possible to identify the load points that are at risk when planning for mobile generators. Case study results have shown that it is important to include the time-dependencies to capture the risk of not fulfilling the 24h-requirement. Not including time dependencies would result in an estimation of zero risk for interruption longer than 24 hour, while incorporating the dependencies results in an estimate on average one every third year [40]. These numbers are of course only applicable to the test system used in the study but it shows that the choice of risk model has a huge impact on the results.

3.1.2 Risk-based method based on Monte Carlo simulations

The used risk-based method in this project consists of five main parts shown in Figure 6. The method takes into account the fact that the total reliability cost for the DSO is stochastic and therefore can vary from year to year. The probability distribution of the total reliability cost is estimated using time sequential Monte Carlo simulations in Part III) Risk Estimation in Figure 6.

Detailed time-varying risk models are used in order to capture the time dependencies in inputs by modeling the effect of severe weather. To capture both the probability and consequences of interruptions three risk models are needed: a cost model, a load model and a reliability model. The cost model calculates the total reliability cost for either society or the DSO according to Equation 1. Since quality regulations may contain load indices such as ENS a load model that predicts the loss of load due to an interruption is also needed. Finally, the reliability model describes the failure and restoration processes of the components in a power system. Extreme events due to severe weather are captured by the reliability model. In the reliability model, the effect on overhead lines due to the stochastic nature of high winds and lightning is considered. In Sweden storms with high winds are more common during the winter months, while lightning is more common during the summer months [41]. This seasonal pattern is also captured in the model. The risk models are found in Part III) Risk Estimation in Figure 6.

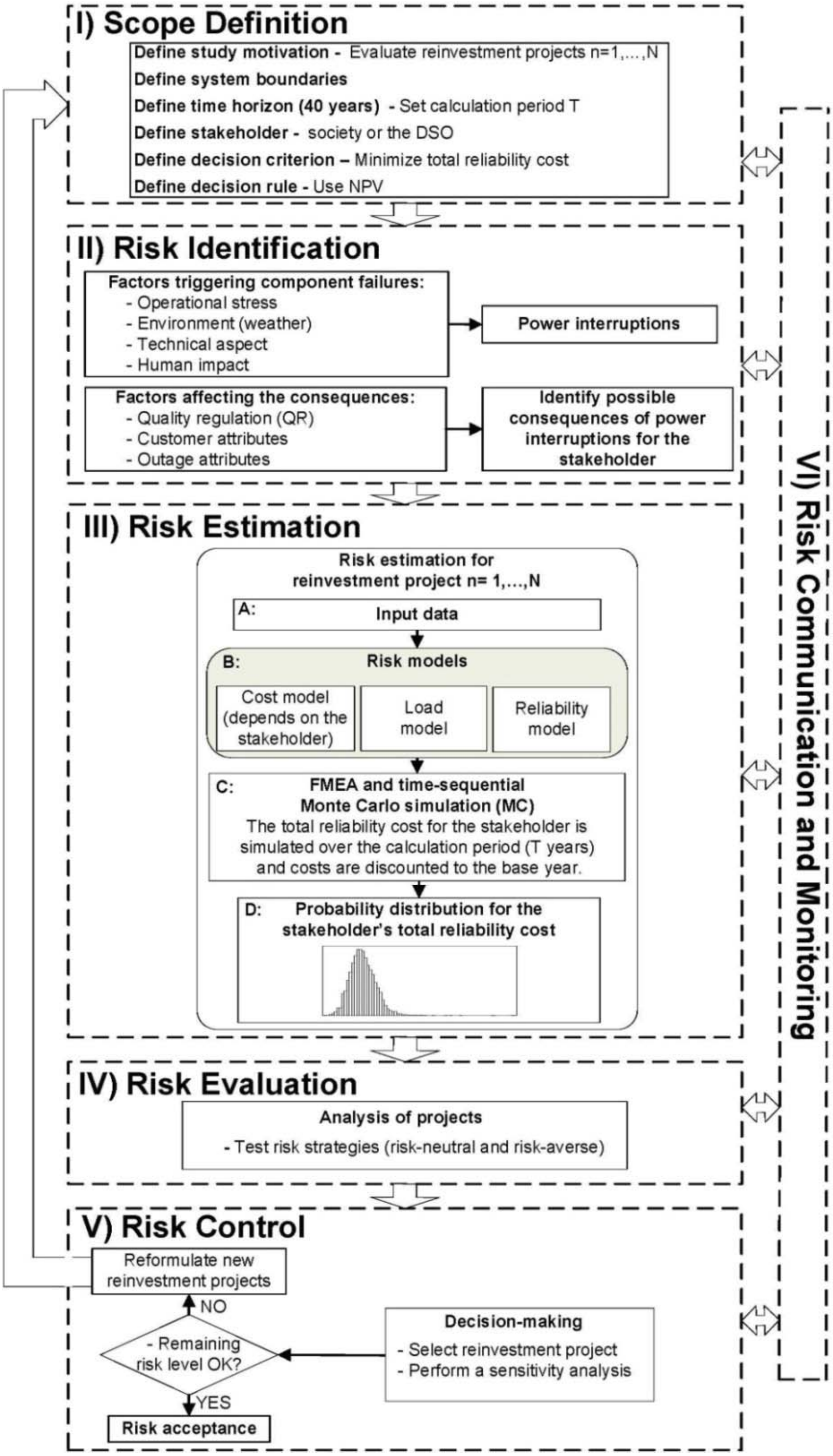

Figure 6: Chosen risk-based method. Described in detail in [34].

The drawback with Monte Carlo simulation approaches is that they are computational heavy compared to simple analytical methods. However, with faster computers, it is possible to use Monte Carlo simulations for large distribution systems. In [42], for example, Monte Carlo simulations were applied to an 11 kV distribution system of one of the largest DSOs in UK. A risk-based method is also used by the DSO in New York for the cable network in order to estimate the small probability of interruptions [43]. A risk-based method to model time dependencies in failures for large power systems is presented in Chapter 6. This method is developed for the transmission system operator ESKOM in South Africa for reliability studies in planning and operations.

The model parameters for the risk models are given in [34]. For the cost calculations, 2012-year's cost level was used and the calculation period (economic life time, *T)* was set to 40 years. The company tax in Sweden year 2012 is 26.3 %. DSO and society will have different discount rates in their NPV analysis. A discount rate of 4 % is recommended for socioeconomic studies in Sweden [44]. The discount rate for society is here based on that recommendation. For the DSO the real interest rate is set to different values in different studies, for example 5%, 6 % and 7% are used in [45], [37], and [46], respectively. In this study an inflation of 2 % was assumed and the discount rates (r_{DSO}, r_{SOC}) used for the DSO and society are set to 7% and 4 %, respectively.

3.2 Test systems

Two electrical medium voltage test distribution systems: the Swedish Urban Reliability Test System (SURTS) and the Swedish Rural Reliability Test System (SRRTS) are used in the case studies in Chapter 4 and in the publications within the project. The two test systems have been developed in a project within Elforsk [47]. The systems are also presented in [48]. For network data the reader is referred to [47].

Each test system provides a consistent set of data which enables reliability analysis and customer interruption cost assessments. To ensure the similarity of the test systems to Swedish networks in terms of load, component and customer data as well as network topology, industry representatives of major Swedish power distribution companies were an integral part of the development process.

Five different customer sectors are represented in the test systems: residential, commercial, industrial, agricultural (only in SRRTS), and governmental. The governmental sector provides government services and customers in this sector are for example schools, hospitals, etc. Each customer category has a set of different load curves to represent seasonal, daily, and hourly variations in load demand. Residential customers in urban and rural areas have also different energy consumptions. To further capture the variations in load, there are different load curves in different temperature intervals. The used time-varying load model extends this approach by also predicting the load during extreme temperatures outside the specified temperature interval.

Since 2008, when the networks were developed, the rural networks in Sweden have had investments in underground cables. The test system SRRTS might therefore need an update. As seen in Table 1, comparing with SAIDI and SAIFI for 2010 for all Swedish rural networks, the test system SRRTS has higher values. In Table 2 SAIDI and SAIFI values for the SURTS are compared with statistics. The main purpose of this study is to compare the impact of different quality regulations. It is the regulation impact, and not the test systems, that is evaluated, so the most important part is to use the same test systems for all tested regulations.

However, two updates have been done in this project compared to the networks presented in [47, 34]. Firstly, the identical loops in SURTS in turns of customer composition have been changed. Now there are some loops having more residential customer, industrial customers or commercial customers. Secondly, the restoration time for cables has been lowered to better be in line with the findings in [49]. The SAIDI and SAIFI values in the updated test systems are the ones given in Table 1 and Table 2 for SRRTS and SURTS. The number of customers per customer sector and the electricity consumption per customer as well as line lengths are given in Appendix C.

Table 1: SAIDI and SAIFI values in Ei statistics [35] compared with values for the test system SRRTS when all interruption durations are included.

	Year 2010	Average for 1998-2010	SRRTS
SAIDI [h]	1.8	6.0	5.0
SAIFI	1.5	1.6	1.7

Table 2: SAIDI and SAIFI values in Ei statistics [35] compared with values for the test system SURTS when all interruptions are included.

	Year 2010	Average for 1998-2010	SRRTS
SAIDI [h]	0.4	0.3	0.2
SAIFI	0.4	0.3	0.2

The test systems are implemented in Matlab, where Monte Carlo simulations are performed to assess reliability and customer interruption cost. A simplification made when implementing the test systems in order to limit the number of failure events was not to model the reclosing time. This simplification implies that only the sustained interruptions longer than three minutes are included in the Monte Carlo simulations.

3.2.1 The Swedish Urban Reliability Test System (SURTS)

SURTS is shown in Figure 7. SURTS has 96 load points, and ten identical loops each with approximately 1100 customers and 10 km feeder medium voltage cable.

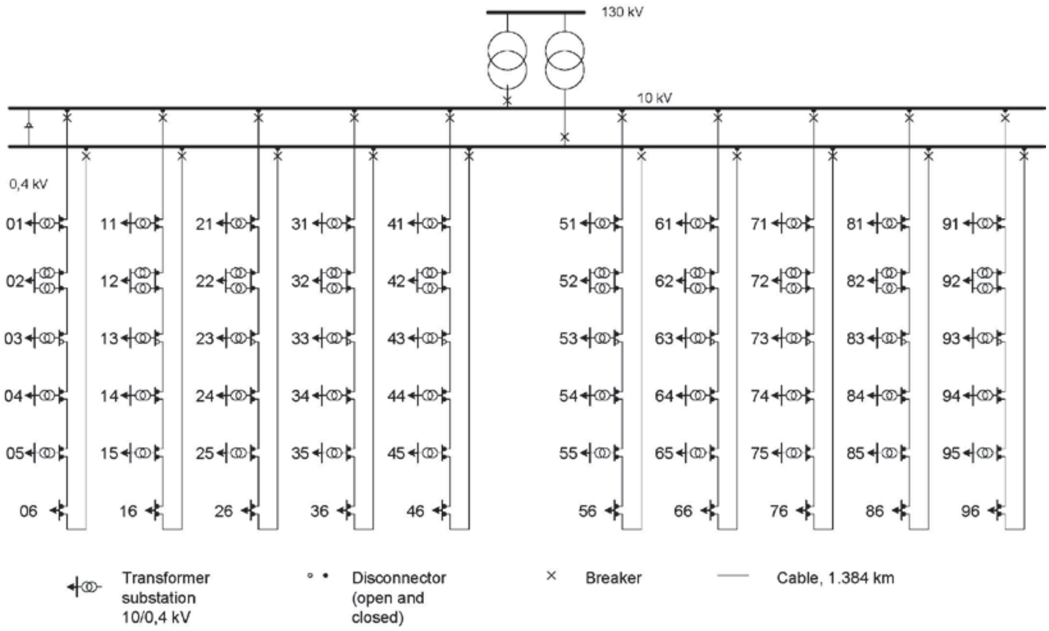

Figure 7: The SURTS consists of ten identical loops 1-10 (from left to right in the figure).

3.2.1 The Swedish Rural Reliability Test System (SRRTS)

SRRTS is shown in Figure 8. SRRTS consists of two modules: Module A and Module B. SRRTS has 44 load points, around 900 customers and consists of both overhead lines and cables with a total medium voltage line length of 92 km.

3.3 Reinvestment projects

This section introduces the selected reinvestment projects that are studied in the case studies in Chapter 4. Three projects for each test system are included.

3.3.1 SURTS

Investments in automation of three different loops in Figure 7 are studied for SURTS. There are different levels of automation which may result in a switching time from some seconds up to 5 minutes. The switching time in SURTS before the automation is 60 minutes. It is assumed that during the last decade the DSO has exchanged substations that needed to be replaced with substations that can smoothly be updated for automation of fault management. The additional investments then needed for automation is an indication and communication system which would result in that the switching

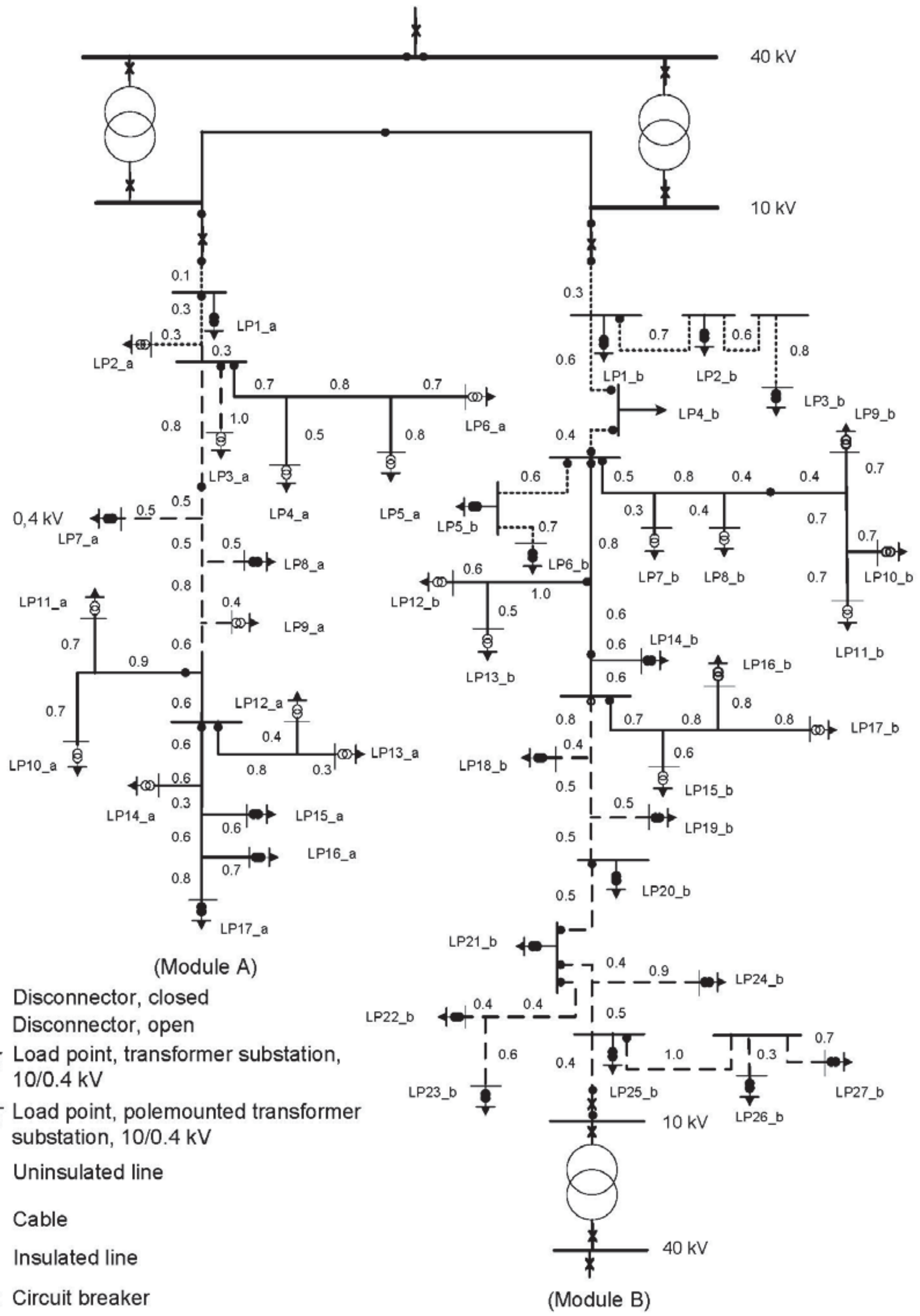

Figure 8: The SRRTS consisting of two modules: Module A and Module B.

time is decreased to 5 minutes. This is the time it takes for the personnel at the network management center to react. If investments to decrease the switching time to 5 minutes are profitable or not are studied in the case studies. The investment cost for such an investment is approximately 40 000 SEK per substation [50]. The total investment cost for each of the reinvestments 1 to 3 including six substations is therefore $C_I =$ 240 000 SEK.

The investment is assumed not to have an impact on the regulatory asset base ($C_{RAB} \approx 0$). To decrease the switching times to only seconds, the substations need to communicate directly and this requires other investments not considered here. Furthermore, the change in maintenance and restoration costs (C_M, C_R) due to the automation is assumed to be negligible. Hence, the considered reinvestments will be profitable if the investment cost is less than the decreased costs due to shorter interruptions. The DSO would like to start to improve only one loop based on the analysis results.

The loops included in the analysis are:

- **Reinvestment 1: Automation of loop 1**

Loop 1 supplies a residential area so the majority of customers are residential, but commercial and governmental customers are also in the customer mix. The customer composition is 95 % residential, 3 % commercial and 2% governmental customers. The total energy consumption for loop 1 is 17100 MWh. The energy consumption divided on the customer sectors: residential, commercial, and governmental is 70%, 25 % and 5 %, respectively.

- **Reinvestment 2: Automation of loop 6**

Loop 6 supplies a residential area and an industrial area. The customer composition is 93 % residential, 3 % industrial, 2 % commercial and 2 % governmental customers. The total energy consumption for loop 6 is 18700 MWh. The energy consumption divided on the customer sectors: residential, industrial, commercial and governmental is 50%, 33%, 13% and 4 %, respectively.

- **Reinvestment 3: Automation of loop 7**

Loop 7 supplies a residential area and a commercial center. The customer composition is 87 % residential, 10 % commercial and 3 % governmental customers. The total energy consumption for loop 7 is 17100 MWh. The energy consumption divided on the customer sectors: residential, commercial, and governmental is 42%, 53 % and 6 %, respectively.

Note that all three loops have approximately the same total load. However, loop 6 with industrial customer has a slightly higher load compared to the other two loops.

3.3.2 SRRTS

For the rural network SRRTS the three investigated reinvestments are: upgrade disconnectors to be remote controlled, or change the uninsulated overhead lines located in the critical part of the backbone of the modules to cables or insulated overhead lines. To compare the impact of the projects a status-quo alternative is also considered. The status-quo alternative is to keep the uninsulated lines and only do necessary reinvestments (changing of poles, etc).

- **Reinvestment 1: Replacing overhead uninsulated lines with cables**

In the critical part of the backbone of Modules A and B there are 2.6 km of uninsulated lines. Reinvestment 1 is to change the lines into cables. Since cables are around 15 % longer than overhead lines the cable length needed is 2.88 km.

- **Reinvestment 2: Installing remote controlled disconnectors**

Reinvestment 2 is to change 6 disconnectors at strategically points in the networks to be remotely controlled. Note that reinvestment 2 is compared with a “do nothing” alternative and not the status quo alternative since it does not directly affect the 2.6 km of uninsulated lines.

- **Reinvestment 3: Replacing overhead uninsulated lines with insulated overhead lines**

Reinvestment 3 is to change the critical part of 2.6 km uninsulated line located on the backbone of the network to insulated lines.

In Table 3 the technical lifetime, total investment cost and impact on the RAB for the status quo alternative and the three reinvestment projects are listed. The technical life time is used to calculate the scrap value of a reinvestment in the end of its economic lifetime (calculation period, $\boldsymbol{T}$). The effect on the regulatory asset base, $\boldsymbol{C}_{\boldsymbol{RAB}}(\tau)$, is derived in the same way as in [49].

Table 3: The technical lifetime, total investment cost and impact on the regulatory asset base (RAB).

	Technical lifetime [yr] [51]	Total investment cost, $\boldsymbol{C}_{\boldsymbol{I}}(\tau)$ [SEK]	Impact on RAB $\boldsymbol{C}_{\boldsymbol{RAB}}(\tau)$ [SEK]
Status quo	50	428 000	0
Reinvestment 1	55	1 436 000	291 00
Reinvestment 2	45	1 247 000	594 000
Reinvestment 3	50	853 000	0

The maintenance cost and restoration cost of an investment are defined in Equation 6 and Equation 7. The cost parameters for maintenance and restoration are listed for different type of components in Table 4 and Appendix

D, respectively. The cost parameters are mainly based on the EBR database. EBR provides standard costs for all types of different maintenance and repair work of distribution systems in Sweden. For the reparation costs the cost parameter data from one of the main Swedish DSOs have also been applied. The inspection interval for maintenance is set to 8 years. The maintenance cost for the disconnectors is assumed not to change when installing remote controlled disconnectors. Since it is the NPV that is calculated only the difference in total reliability cost and status quo alternative is needed. Therefore, the maintenance cost for components not included in the investment or status quo alternatives have no effect on the results. These costs will be the same before as after the investment and will therefore not influence the NVP.

Equation 6

$$\boldsymbol{C_M}(\tau) = \boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{yr}}(\tau)\ \boldsymbol{nr}_{\text{km}} + \boldsymbol{ins}(\tau)\ \boldsymbol{nr}_{\text{km}}(\boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{ins}} + \boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{act}})$$

where,

$\boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{yr}}(\tau) =$ Cost for annual maintenance for year τ [SEK/km]

$\boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{ins}} =$ Cost for inspection [SEK/km]

$\boldsymbol{c}_{\boldsymbol{M}}^{\boldsymbol{act}} =$ Cost for maintenance actions decided upon after inspection [SEK/km]

$\boldsymbol{nr}_{\text{km}} =$ Line length in the network [km]

$\boldsymbol{ins}(\tau) = 1$ if inspection year τ, 0 otherwise

Equation 7

$$\boldsymbol{C_R}(\tau) = \sum_{\boldsymbol{j}=1}^{\boldsymbol{nrF}(\tau)} \boldsymbol{C}_{\boldsymbol{R}}^{\boldsymbol{fix}}(\tau) + \boldsymbol{nr_p}\ \boldsymbol{c_{hour}}\ \boldsymbol{r_j}\ (\boldsymbol{t_j})$$

where,

$\boldsymbol{nr_F}(\tau) =$ Number of failures for year τ

$\boldsymbol{C}_{\boldsymbol{R}}^{\boldsymbol{fix}}(\tau) =$ Fixed restoration cost per failure for year τ [SEK]

$\boldsymbol{nr_p} =$ Number of persons reparing

$\boldsymbol{c_{hour}} =$ Cost of one working hour [SEK/h]

$\boldsymbol{r_j} =$ Restoration time of failure $\boldsymbol{j}$ described by the reliability model [h]

$\boldsymbol{t_j} =$ The timing of failure $\boldsymbol{j}$

Table 4: Maintenance costs for different component types

	Annual maintenance cost, c_M^{yr} [SEK/km]	Inspection cost, c_M^{ins} [SEK/km]	Action after inspection, c_M^{act} [SEK/km]
Uninsulated lines	1350	2700	16200
Insultated lines	950	2700	16200
Cables	0	2700	2030

3.4 Customer interruption costs and tested cost models

In total five different cost models are used to reconstruct the customer interruption cost used in the RPS. Four of these are aggregated index cost models and one is a detail outage-specific cost model. The customer interruption cost survey that been used in the case studies is the latest one carried out in Sweden presented in [33]. The main reason for choosing this study is because it is the newest study made that include all the five customer sectors: residential, commercial, industrial, agricultural, and governmental. Having the interruption cost for each customer sector, sector-specific cost parameters can be applied.

3.4.1 Tested cost models

This section defines the five different cost models tested that can be divided into aggregated models and outage-specific cost models. The tested cost models are referred to as C1 to C5.

Aggregated index cost models

Four aggregated cost models are presented here. The first two use customer-based indices such as SAIDI and SAIFI, while the other two use load-based indices such as ENS and PNS.

- C1: The current Swedish cost model for regulatory period 2012-2015

In this report only costs due to unannounced interruptions are included and this cost for year τ is defined in Equation 8 [4]. Since the method applied in this project calculates the total reliability cost, the cost due to RPS in Equation 8 is defined as positive which is opposite to the definition in [4].

Equation 8

$$C_{RPS}(\tau) = \left[cic(\tau) - \overline{cic}(\tau) \right] Sf = \left[(\text{SAIDI}\, P_E^N + \text{SAIFI}\, P_W^N)\frac{E_Y}{T_Y} - (\overline{\text{SAIDI}}\, P_E^N + \overline{\text{SAIFI}}\, P_W^N)\frac{E_Y}{T_Y} \right] Sf$$

where,

SAIDI, SAIFI = Indices [h,nr]

$\overline{\text{SAIDI}}$, $\overline{\text{SAIFI}}$ = Targets for SAIDI and SAIFI [h,nr]

P_E^N, P_W^N = Cost parameters on national level N in [SEK/kWh] and [SEK/kW], respectively

Sf = Share factor []

E_Y = Energy consumption for year τ for the test system [kWh]

T_Y = Number of hours per year (8760 h) [h]

- C2: Ei's proposal of a new cost model for regulatory period 2016-2019

Since year 2010, DSOs have reported interruptions per customer to Ei [52]. The customers are also divided into five different sectors. Before 2010 only the aggregated indices SAIDI and SAIFI values were reported to the regulator. The more detailed interruption data introduces the possibility to use a sector-specific cost model that takes into account that the customer interruption costs differ between customer sectors. Ei's proposal is to use the detailed statistics to calculate SAIDI and SAIFI per customer sector and then combine it with sector-specific cost parameters as defined in Equation 9.

Equation 9

$$C_{RPS}(\tau) = \left[cic(\tau) - \overline{cic}(\tau) \right] \bullet Sf = \sum_{S=1}^{nrS} \left[(\text{SAIDI}^S\, P_E^S + \text{SAIFI}^S\, P_W^S)\frac{E_Y^S}{T_Y} - (\overline{\text{SAIDI}}^S\, P_E^S + \overline{\text{SAIFI}}^S\, P_W^S)\frac{E_Y^S}{T_Y} \right] Sf$$

where,

SAIDI^S, SAIFI^S = Indices for each customer sector S [h,nr]

$\overline{\text{SAIDI}}^S$, $\overline{\text{SAIFI}}^S$ = Targets for SAIDI and SAIFI for each customer sector S [h,nr]

P_E^S, P_W^S = Cost parameters on sector level S in [SEK/kWh] and [SEK/kW], respectively

Sf = Share factor []

E_Y^S = Energy consumption for year τ for each customer sector S [kWh]

T_Y = Number of hours per year (8760 h) [h]

nrS = Number of customer sectors

- C3: SwedEnergy proposed cost model with national-specific cost parameters

SwedEnergy proposes that the cost model used for DSO should be the same as the one currently used on subtransmission level (regionnät). This cost model uses the load-based indices Energy Not Supplied (ENS) and Power Not Supplied (PNS) combined with national-specific cost parameters according to Equation 10.

Equation 10

$$C_{RPS}(\tau)=\left[cic(\tau)-\overline{cic}(\tau)\right]Sf=\left[(ENS\,\mathrm{P}_E^N+PNS\,\mathrm{P}_W^N)\ -\ (\overline{ENS}\,\mathrm{P}_E^N+\overline{PNS}\,\mathrm{P}_W^N)\right]Sf$$

where,

ENS, PNS = Indices [kWh,kW]

$\overline{ENS}$, $\overline{PNS}$ = Targets for ENS and PNS [kWh,kW]

P_E^N, P_W^N = Cost parameters on national level N in [SEK/kWh] and [SEK/kW], respectively

Sf = Share factor []

- C4: SwedEnergy proposed cost model but with sector-specific cost parameters

This cost model is similar to SwedEnergy's proposal but uses cost parameters on sector level. The cost due to RPS when adopting C4 is defined in Equation 11.

Equation 11

$$C_{RPS}(\tau)=\left[cic(\tau)-\overline{cic}(\tau)\right]Sf=\sum_{S=1}^{nrS}\left[(ENS^S\,\mathrm{P}_E^S+PNS^S\,\mathrm{P}_W^S)\ -\ (\overline{ENS^S}\,\mathrm{P}_E^S+\overline{PNS^S}\,\mathrm{P}_W^S)\right]Sf$$

where,

ENS^S, PNS^S = Indices for each customer sector S [kWh,kW]

$\overline{ENS^S}$, $\overline{PNS^S}$ = Targets for ENS and PNS for each customer sector S [kWh,kW]

P_E^S, P_W^S = Cost parameters on sector level S in [SEK/kWh] and [SEK/kW], respectively

Sf = Share factor []

nrS = Number of customer sectors

- C5: The current Norwegian outage-specific cost model

The last tested cost model is an outage-specific cost model which is currently adopted in Norway. The cost model takes into account customer sector, interruption duration and interruption timing when reconstructing the customer interruption cost. In contrast to the aggregated index cost models the target is set directly on the annual customer interruption cost. The cost model is defined in Equation 12. Since the cost is dependent on the characteristics of each interruption and the customer sector four summations become necessary. Remember that the customer composition is different in the different load points. Firstly, we need to sum the cost over the number of customers belonging to a certain sector in each load point. Secondly, we need to sum over the number of customer sectors in each load point. Thirdly, we need to sum over the number interruptions per year in each load point. Finally, we sum over all load points to get the total annual customer interruption cost in the system. The reference time is the outage scenario included in the survey, which usually is the worst possible time. In Sweden this is during winter.

Equation 12

$$C_{RPS}(\tau) = \left[cic(\tau) - \overline{cic}(\tau) \right] Sf$$

where,

$$cic(\tau) = \sum_{lp=1}^{nr_{LP}} \sum_{i=1}^{nr_I^{\tau}} \sum_{S=1}^{nr^S} \sum_{j=1}^{nr_C^S} f_h^S \; f_d^S \; f_m^S \; c_{ref}^S(r_i^{lp}) \; P_{ref,j}$$

f_h^S = Time-varying factor for hourly deviation from the reference time for sector S

f_d^S = Time-varying factor for day of week deviation from the reference time for sector S

f_m^S = Time-varying factor for monthly deviation from the reference time for sector S

c_{ref}^S = Customer damage function for sector S (in Figure 10) [SEK/kW]

r_i^{lp} = Interruption duration for load point lp due to interruption i [h]

$P_{ref,j}$ = Load at reference scenario for customer j [kW]

nr_{LP} = Number of load points

nr_I^{τ} = Number of interruptions during year τ for load point lp

nr^S = Number of customer sectors in load point lp

nr_C^S = Number of customers of customer sector S in load point lp

Only interruptions between 3 minutes and 12 hours are included when calculating the indices in the current Swedish cost model and the proposals by Ei and SwedEnergy. In contrast, the current Norwegian outage-specific cost model includes interruptions of all durations. In the case study the tested cost models are applied on interruptions between 3 minutes and 12 hours. However, to investigate the impact of the upper limit analyses are also made when all interruptions durations are included.

3.4.2 Customer interruption cost data

As stated in Chapter 2.2.3.1 the cost parameters are functions of customer damage functions. In Figure 9 a composite customer damage function (cdf) on national level is shown to illustrate how the cost parameters are estimated. The cost parameter with unit SEK/kW is the starting cost when having an interruption, i.e. the cost of an interruption of zero duration. The cost parameter with unit SEK/kWh is the slope of the customer damage function. As can be seen in Figure 9, the cost has different slopes depending on the interruption duration. Usually, the cost parameter [SEK/kWh] is set to the slope that is corresponds to the average interruption duration, which is given by the index CAIDI=SAIDI/SAIFI. For both test systems SURTS and SRRTS CAIDI is in the first interruption duration interval.

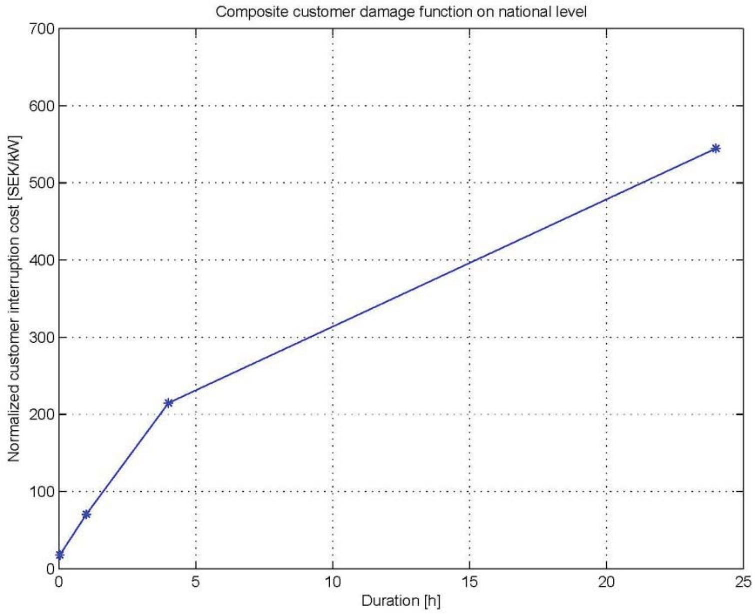

Figure 9: National customer damage function used for national-specific cost parameters based on the latest customer interruption cost survey [33].

The sector customer damage functions shown in Figure 10 can also be used to estimate sector-specific cost parameters in a similar way. The only difference is that the cost parameters are estimated on each sector customer damage function. Note that both axes in Figure 10 have a log scale. This is chosen since the cost for the residential sector is much lower than the cost for the other sectors and therefore difficult to see in the same plot if an ordinary scale is used. The national customer damage function in Figure 9 is estimated by weighting the sector customer damage functions based on the customer sectors' shares of the system's total energy consumption.

By using the customer damage functions in Figure 10 the cost parameters on sector level are estimated and given in Table 5. The national cost parameters are P_W^N = 18 SEK/kW and P_E^N = 48 SEK/kWh.

Table 5: Sector-specific cost parameters

	Residential	Industrial	Commercial	Agricultural	Governmental
P_W^S [SEK/kW]	0	15	57	3	3
P_E^S [SEK/kWh]	2	42	137	5	30

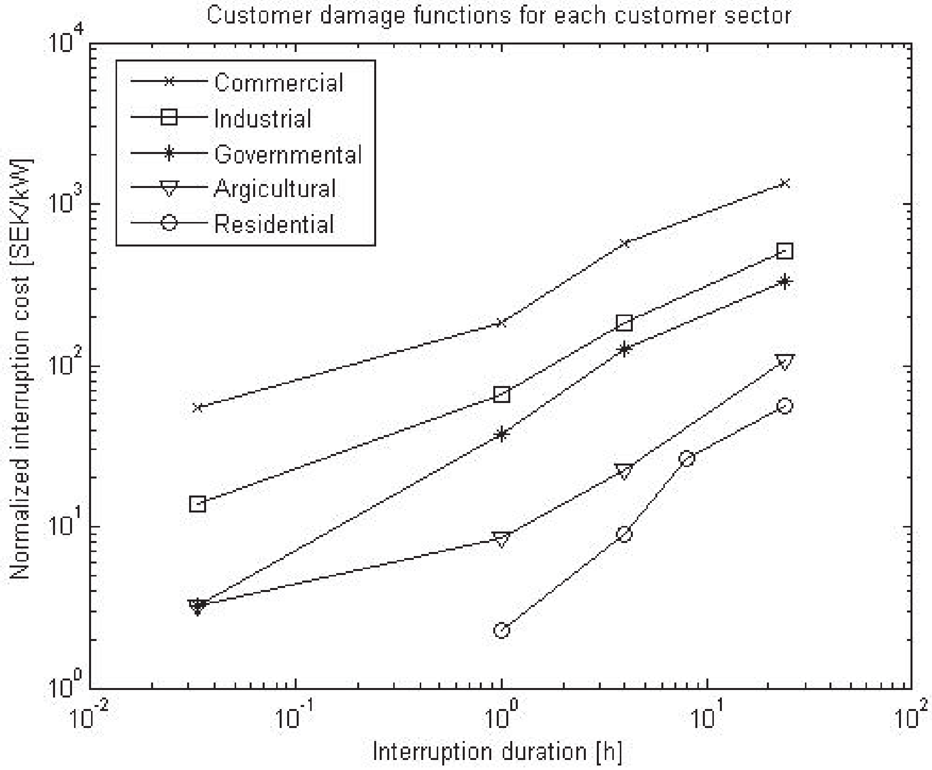

Figure 10: Customer damage functions for the worst case scenario for all customer sectors normalized by peak load.

For the outage-specific cost model the cost of an interruption for an affected customer is estimated using the sector customer damage function for each interruption and for the specific interruption's duration. This model does also take the timing of the interruption into consideration by using time-varying factors. The cost impact of the timing of an interruption was not investigated in [33]. Therefore, the time-varying factors used in Norway but rescaled to match the reference outage scenarios in the Swedish study are applied.

4 Impact of RPS design on investment decisions

This chapter investigates the impact of RPS design on investment decisions. The impact of the RPS design on the costs due to RPS was investigated in Publication 4 listed in the publication list in Section 1.2. In this chapter the impact that different RPS designs have on the total reliability cost is investigated.

Several aspects of the RPS design, such as cost model used for the reconstruction of customer interruption costs, RPS type (dead band, multi-year index, capped, continuous) and share factor are considered. Also, the impact of risk strategy chosen by the decision maker and an investment's impact on the regulatory asset base are included in the analysis. The relationship in strength between the quality regulation on customer level (selective) defined by guaranteed standards, and on system level (collective) defined by the RPS design is also studied. The guaranteed standards (GS) are the same in all designs and defined by the Gudrun laws.

The regulation is dynamic and will most certainly change between regulatory periods in the long term. By investigating if different RPS designs affect the investment decisions, the regulatory uncertainty due to changes in the RPS design can be examined.

The framework of the analysis is described Section 4.1. The framework is based on NPV analysis using the total cost of an investment. For the DSO the total cost is defined in Equation 1 in Chapter 2. It is the sum of the investment, maintenance, and reparation costs as well as the costs due to the regulation. The impact of regulation is here assumed to be the effect on the regulatory asset base due to the investment, reward/penalty due to the RPS and costs paid in customer compensations due to the Gudrun laws. The framework also includes a risk analysis from the society's perspective where the total cost is defined according to Equation 1 as the sum of the investment, maintenance, reparation and customer interruption costs. The analyses are carried out for the investment alternatives presented in Chapter 3 for SURTS and SRRTS in Section 4.2 and Section 4.3, respectively. The focus here is on the NPV defined in Equation 1 for different RPS design. In addition to the deterministic costs listed in Chapter 3, stochastic costs that depend on the annual reliability such as the costs due to RPS and GS, as well as restoration cost and customer interruption cost are included in the analysis. These costs will vary each year and this is captured in the Monte Carlo simulation. Finally in Section 4.4 the chapter is concluded with a summary of the findings.

4.1 Analysis framework

The analysis framework consists of two main parts. The first part is a risk analysis from the DSO's perspective. NPV analyses are performed with different RPS designs. The second part investigates if the regulation gives incentives to make socioeconomically beneficial investments also profitable for the DSO. This is carried out by comparing results for the DSO's risk analysis with results of a risk analysis performed from society's perspective on the same investment alternatives. The purposes of the two parts are explained in this section.

4.1.1 Profitable investments for the DSO under different RPS designs

Four questions are studied in the risk analysis performed from the DSO's perspective. The analysis is performed from the perspective of a risk neutral DSO as well as from the perspective of a risk averse DSO. The risk neutral DSO takes decisions based on the expected NPV, while the risk averse DSO takes decisions based on the NPV calculated using Conditional Value at Risk (CVaR). These two risk strategies are explained in Chapter 3.

- *What impact does the share factor have on the DSO's NPV analysis of different investment alternatives?*

Three cost models are tested - the current Swedish RPS design together with two proposals of future cost model designs. One proposal is from Ei and the other one is from SwedEnergy. For all three cost models a capped design with a share factor (Sf) of 0.5 is applied since it is the current set-up in the Swedish regulation defined in Equation 8.

Ei's proposal is to use a sector-specific cost model instead of a national-specific cost model. The same indices as today, SAIDI and SAIFI estimated based on interruptions between 3 min and 12 hours, will be used but instead these indices will be calculated on sector level and multiplied by a cost parameter for each sector. SwedEnergy's proposal is to adopt the same cost model on distribution networks as is currently used on subtransmission networks (regionnät). This national-specific cost model is based on the indices energy not supplied (ENS) and power not supplied (PNS) estimated for interruptions between 3 min and 12 hours. All tested cost models are described in detail in Chapter 3.

In total six RPS designs are tested in this part; three designs with a share factor of 0.5 and three designs with the share factor removed, i.e. set to 1:

- "SWE0": The current Swedish RPS design [0.5,cap,SAIDI,SAIFI,N]
- "EI0": Ei's proposal [0.5,cap,SAIFI,SAIFI,S]
- "SwedEnergy0": SwedEnergy's proposal [0.5,cap,ENS,PNS,N]
- "SWE1": The current Swedish RPS design, but with a share factor of 1 [1,cap,SAIDI,SAIFI,N]
- "EI1": Ei's proposal, but with a share factor of 1 [1,cap,SAIFI,SAIFI,S]
- "SwedEnergy1": SwedEnergy's proposal, but with a share factor of 1 [1,cap,ENS,PNS,N]

Where “0.5” or “1” is the value of the share factor, “cap” stands for a capped RPS type, and “N” and “S” implies cost parameters on national and sector level, respectively. The cost parameters P_W (SEK/kW) and P_E (SEK/kWh) on national and sector levels are based on the latest customer interruption cost survey and given in Chapter 3. The capped values are +/- 3 % of the DSO’s annual revenue accordingly to the set-up in the current Swedish regulation.

- *What impact does the RPS type have on the DSO’s NPV analysis of different investment alternatives?*

The RPS types that are included in the analysis are continuous, capped, dead band and multi-year indices. These types are described in Chapter 2. The different types are tested together with the current Swedish national-specific cost model using SAIDI and SAIFI for interruptions between 3 min to 12 hours.

The four tested RPS designs in this part of the analysis are labeled:

- “SWE2”: The current Swedish national-specific cost model with a share factor of 1 and a continuous RPS type [1,con,SAIDI,SAIFI,N]
- “SWE1”: The current Swedish national-specific cost model with q share factor of 1 and a capped RPS type [1,cap,SAIDI,SAIFI,N].
- “SWE3”: The current Swedish national-specific cost model with a share factor of 1 and a dead band for each of the indices SAIDI and SAIFI of +/- 3% [1,dead,SAIDI,SAIFI,N]
- “SWE4”: The current Swedish national-specific cost model with a share factor of 1 where three year rolling averages of the indices SAIDI and SAIFI are applied instead of annual indices [1,multi,SAIDI,SAIFI,N]. The multi-year approach is combined with a continuous RPS type.

- *How does the RPS type affect the DSO’s financial risk? Are unnecessary tariff changes reduced?*

The same RPS types as in the previous part of the analysis are also tested in this part. The impact of RPS type is evaluated based on how it limits the DSO’s financial risk during extreme years. The financial risk during the most extreme years is measured by conditional value at risk (CVaR) which is a tool used in the financial industry and explained in Chapter 2.

It is also desirable not to have too great variation in the annual costs since this can cause unnecessary tariff changes for customers. How the RPS type limits the standard deviation of the annual cost is therefore also examined.

- *What impact does the choice of cost model in the RPS have on the DSO's NPV analysis of different investment alternatives?*

In this section the impact of the choice of cost model is investigated. The cost model can, as explained in Chapter 2, be aggregated using index cost models (national-specific, area-specific or sector-specific models) or detailed using information such as outage timing and duration for each interruption (outage-specific cost models).

This main question can be broken down into sub questions. For aggregated cost models using system reliability indices in combination with cost parameters two sub questions are relevant: *How is the result affected by the choice of cost parameters on national or sector level? How is the result affected by the choice of customer-based or load-based indices?*

To investigate the impact of cost parameters and index type one more design is tested. This design is identical to SwedEnergy's proposal but with sector-specific cost parameters instead of national-specific cost parameters. The current Swedish cost model together with Ei's proposal are customer-based index models and SwedEnergy's proposal together with the new design are load-based index models with cost parameters on national and sector level, respectively.

Two other interesting sub question are: *Are aggregated cost models giving the same investment decisions as when using detailed outage-specific cost models in the RPS? Does it matter what interruptions are included in the RPS?*

All tested aggregated cost models use indices. The results of these aggregated models are compared to the results of an outage-specific cost model that include information on each specific interruption such as timing and duration as well as which customer sectors that were affected. The outage-specific cost model applied is the model applied in the current Norwegian quality regulation. In the current Swedish RPS design only interruptions between 3 minutes and 12 hours are included. To investigate the impact all interruptions are included to see the effect on the results of such a limitation. This test is performed for all cost models tested in this part of the analysis.

All cost models are tested together with a continuous RPS type and only interruption between 3 minutes to 12 hours are included. The five tested RPS designs in this part of the analysis are labeled:

- "SWE2": The current Swedish RPS design, but with a share factor of 1 and a continuous RPS type [1,con,SAIDI,SAIFI,N]
- "EI2": Ei's proposal, but with a share factor of 1 and a continuous RPS type [1,con,SAIFI,SAIFI,S]
- "SwedEnergy2": SwedEnergy's proposal, but with a share factor of 1 and a continuous RPS type [1,con,ENS,PNS,N]
- "SwedEnergy3": SwedEnergy's proposal, but with a share factor of 1, a continuous RPS type and sector-specific cost parameters [1,con,ENS,PNS,S]

- “NO”: Norwegian cost model with a share factor of 1, a continuous RPS type and including the effect of timing and duration of each interruption as well as customer sector [1,con,time,dur]

4.1.2 Comparisons with socioeconomically beneficial investments

This section investigates if investments profitable for the DSO also are socioeconomically beneficial.

- *Are investments profitable for the DSO also socioeconomically beneficial?*

The customer interruption cost included in the total cost for society is not affected by the RPS scheme type or share factor. The only aspect that affects the customer interruption cost in the socioeconomic analysis is the choice of cost model. The five cost models tested in the first part of the analysis are applied to test whether society would reach the same conclusion as the DSO, i.e. that the same investments are beneficial. The customer interruption cost to be included is the total customer interruption cost that the customers suffer due to interruptions. This means that all interruptions are included when reconstructing the customer interruption cost. For example, for the aggregated index cost models this mean that all interruptions are included in the calculation of the indices SAIDI, SAIDI, ENS, and PNS. This is an important difference compared to the DSO’s analysis where only interruptions between 3 min to 12 hours were included for the index calculations.

The five tested cost models in this part of the analysis are:

- “C1-SWE,N”: The current national-specific cost model used in Sweden [SAIDI,SAIFI,N]
- “C2-EI,S”: Ei’s proposal of cost model [SAIFI,SAIFI,S]
- “C3 - SwedEnergy,N”: SwedEnergy’s proposal of cost model [ENS,PNS,N]
- “C4 - SwedEnergy,S”: SwedEnergy’s proposal of cost model [ENS,PNS,S]
- “C5 – NO”: Norwegian cost model

There are two different viewpoints on how to reconstruct customer interruption costs for society. One viewpoint is that the same principle should be used when reconstructing the customer interruption costs as is used in the RPS. For example if the RPS is index-based using SAIDI and SAIFI on national level, the same indices should be used to reconstruct the customer interruption cost from society’s perspective.

The other viewpoint is that there is one correct way to calculate customer interruption costs. The customers experience costs due to interruptions based on each single interruption. Thus should the interruption cost be based on customer characteristics and interruption characteristics. This could mean customer sector, timing and duration of the interruption, but even more detailed reconstruction is also possible. According to this later viewpoint, “C5-NO”, is the most correct assessment of the customer interruption cost from society’s perspective of the ones investigated and should always be used in the analysis.

4.2 Results for SURTS

This section presents the results for the investments to improve the reliability in SURTS following the framework presented in section 4.1. The investigated reinvestments are to upgrade the substations of three different loops in the urban network with an indication and communication system for automation of fault management. The DSO would like to start to improve only one loop based on the analysis results. The customer composition in the different loops is different. Loop 1 supplies mainly residential area, loop 6 supplies a residential area and an industrial area and loop 7 supplies a residential area and a commercial center.

4.2.1 Profitable investments for the DSO under different RPS designs

In this section the four questions formulated in Section 4.1.1 are investigated for SURTS.

- *What impact does the share factor have on the DSO's NPV analysis of different investment alternatives?*

NPV results for the three reinvestments are shown in Figure 11 and Figure 12 for the current Swedish national-specific cost model (SWE0), the sector-specific cost model proposed by Ei (EI0) and national-specific cost model based on load indices proposed by SwedEnergy (SwedEnergy0). The cost models are combined with a capped RPS type and share factor of 0.5 and 1 in Figure 11 and Figure 12, respectively.

As shown in Figure 11, with a share factor of 0.5 only one of the reinvestment alternatives is profitable, and only given an RPS according to EI0, for a risk neutral DSO. However, when the share factor is removed (set to one) in Figure 12 the RPS incentive is stronger and all three reinvestments become profitable for the tested cost models. It can be concluded that the share factor has a great impact on the NPV results. Based on the findings in Figure 11 and Figure 12, the choice of cost model also has an impact if a reinvestment is concluded to be profitable or not. However, a more detail analysis of the impact of cost model is treated in the last part of this section.

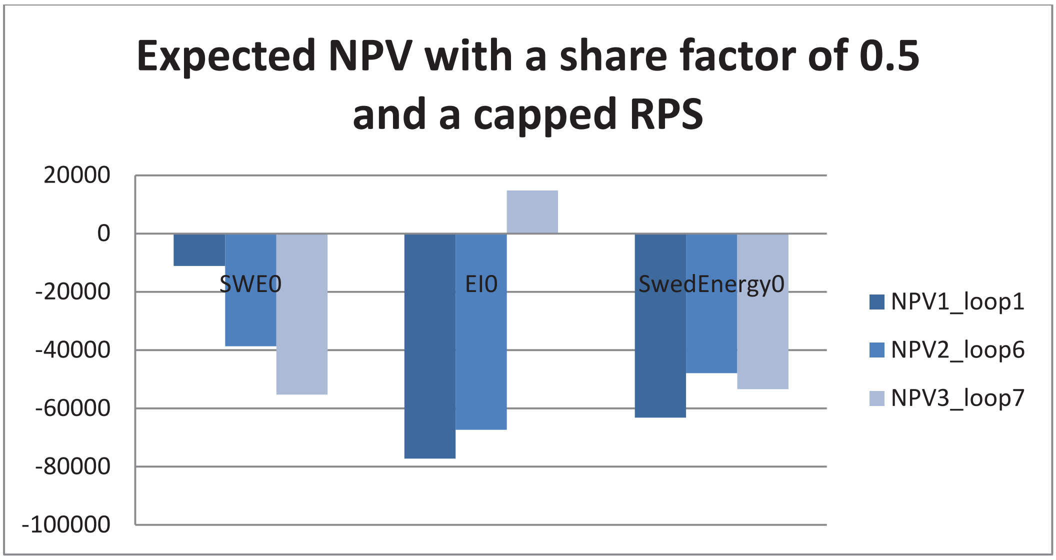

Figure 11: The expected NPV used by a risk neutral DSO when having a RPS with a share factor of 0.5 and a capped RPS type.

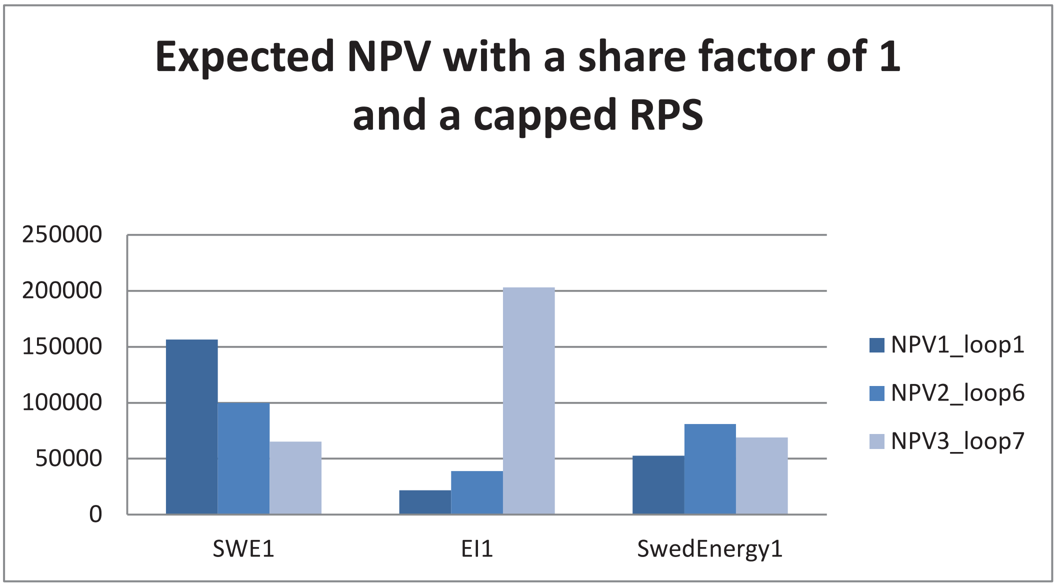

Figure 12: The expected NPV used by a risk neutral DSO when having a RPS with a share factor of 1 and a capped RPS.

The results for a risk averse DSO with are share factor of 0.5 and 1 are shown in Figure 13 and Figure 14, respectively. Firstly, with a share factor of 0.5 the NPV is in this case positive for at least one loop for each tested cost model. Hence, in contrast to a risk neutral DSO, the risk averse DSO would find reinvestments profitable even with a share factor of 0.5. Secondly, with a share factor of 1 all the reinvestment alternatives become profitable as was the case also for a risk neutral DSO. However, when comparing the results in Figure 12 and Figure 14, the prioritizing between the alternatives are not always the same for a risk neutral and a risk averse DSO. These results indicate that the investment decision is not only dependent on the share factor and cost model but also on the risk strategy applied.

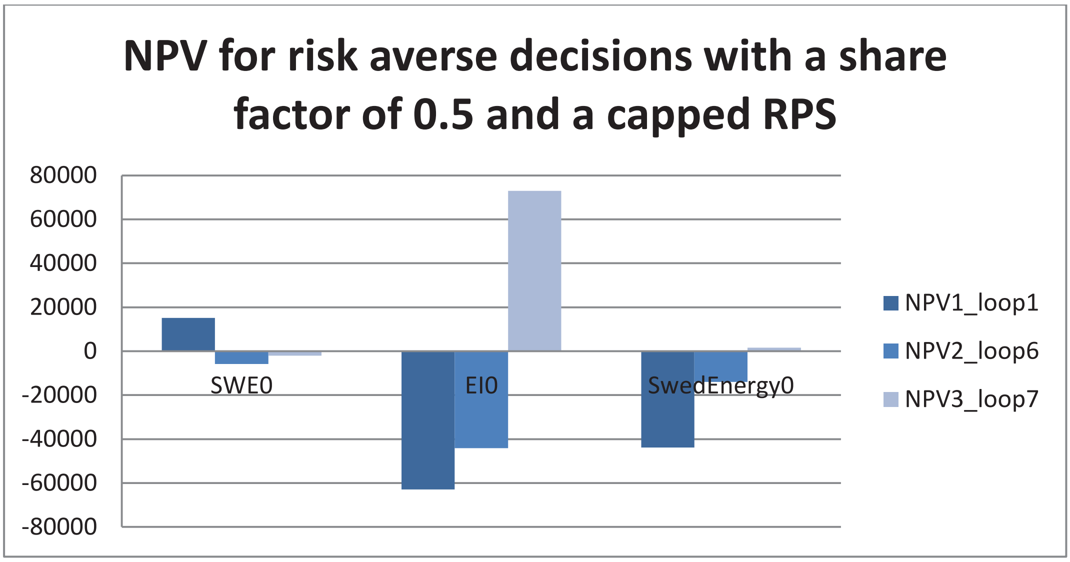

Figure 13: The NPV used by a risk averse DSO when applying a capped RPS type with a share factor of 0.5 is applied.

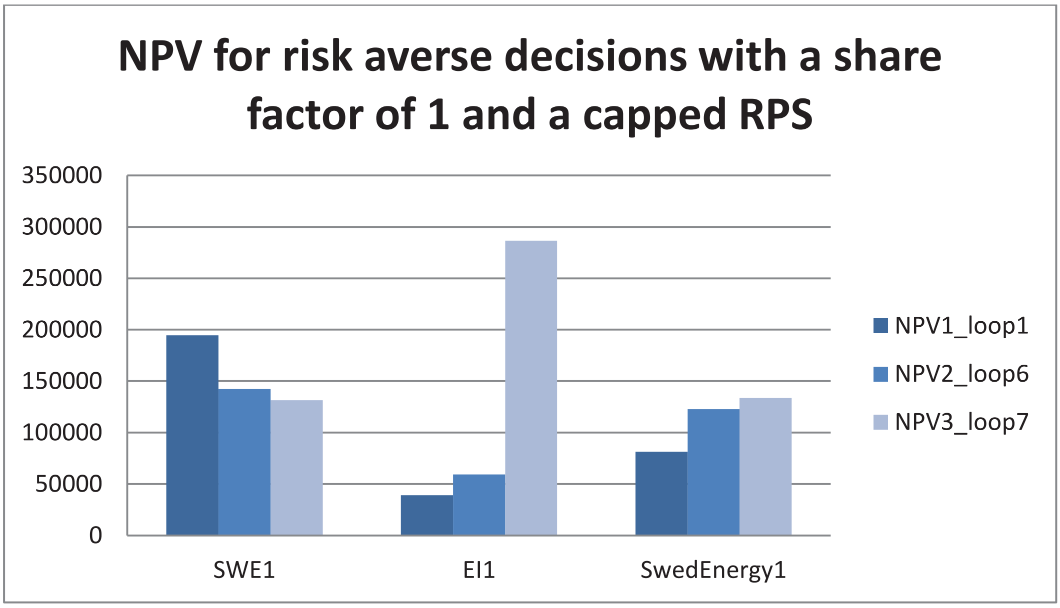

Figure 14: The NPV used by a risk averse DSO when applying a capped RPS type with a share factor of 1 is applied.

- *What impact does the RPS type have on the DSO's NPV analysis of different investment alternatives?*

As stated in Section 4.1.1, four RPS types are tested: continuous (con), capped (cap), dead band (dead) and multi-year indices (multi). Results for these different RPS types tested together with a share factor of 1 and the current Swedish national-specific cost model are shown in Figure 15.

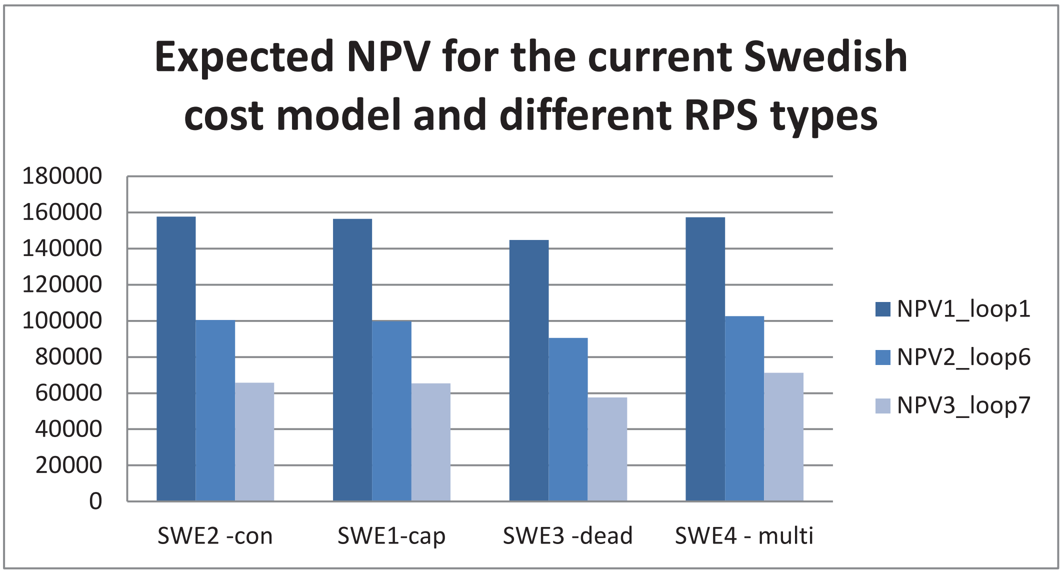

Figure 15: The expected NPV used by a risk neutral DSO when having the same cost model and different RPS types.

The same cost model has been used in all four cases which result in that loop 1 always will be the most profitable loop for automation. Interesting to note is that the RPS type does virtually not affect the incentive to invest; Figure 15 show that the expected NPV values are hardly affected by the choice of RPS type. The choice of RPS type is primarily targeted at limiting the DSO's financial risk and reducing the risk for customers of unnecessary tariff changes. Hence, it is a preferred result that the NPV is virtually unchanged.

Urban networks with cables does not have the extreme years that rural networks have, since only rural networks with their overhead lines are affected by severe weather. With no extreme years the effect of a capped RPS is expected to be small. Small variations in reliability between years would also mean that using annual indices or rolling three year averages would give the approximately the same result; hence the effect of a multi-year index approach become barely noticeable. The RPS type that has the largest effect on the expected NPV is the dead band. This RPS type removes the incentive around the target. In an urban network with small variation around the target this RPS type will therefore have the largest impact.

Results from a risk averse DSO are shown in Figure 16. The same investment decisions are made as by a risk neutral DSO. The difference in NPV values for reinvestment 2 (loop 6) and 3 (loop 7) are though decreased when applying a risk averse strategy.

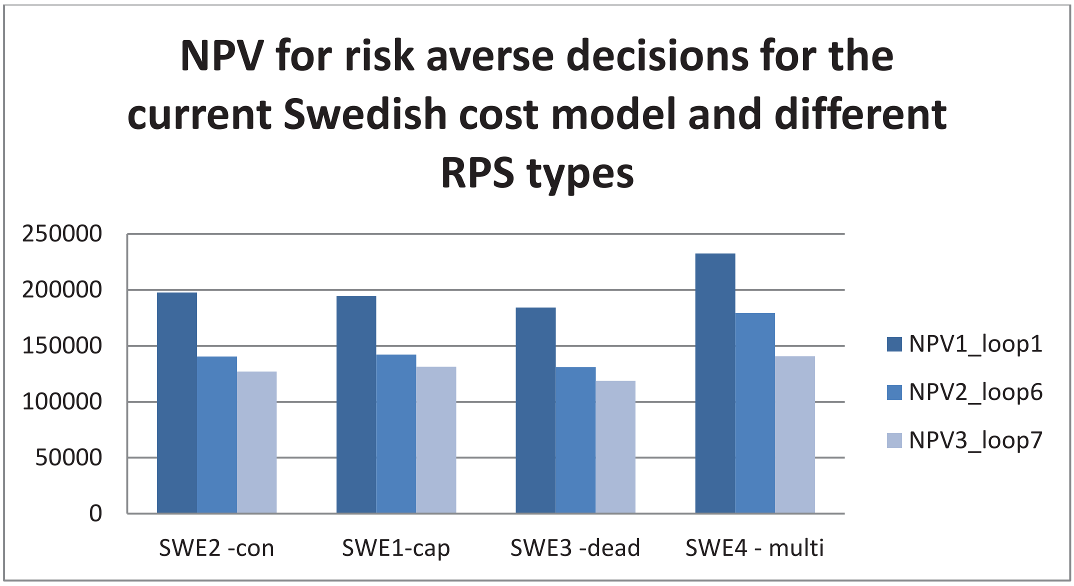

Figure 16: The NPV used by a risk averse DSO when having the same cost model and different RPS types.

- *How does the RPS type affect the DSO's financial risk? Are unnecessary tariff changes removed?*

How each of the four different RPS types (con, cap, dead, and multi) limit the DSO's financial risk during extreme years and also the variation in the annual costs are shown in Figure 17. The capped scheme aims to limit the DSO financial risk. To evaluate how well the RPS types limit the yearly financial risk Conditional Value at risk (CVaR) is used. The dead band and multi-year scheme aim to limit the unnecessary tariff changes. This is measured by using the standard deviation (std). As a reference a continuous RPS type is used to see how much CVaR and std are reduced by changing to a different RPS type such as capped, dead band and multi-year indices. In Figure 17 the results for the base case are shown, i.e. not for an investment alternative. Similar impact of the RPS type choice was obtained for all reinvestment alternatives.

Both the capped and dead band scheme have in this study no effect on limiting neither the financial risk nor the unnecessary tariff changes. However, the multi-year index approach decreases both the standard deviation and CVaR by around 30 %.

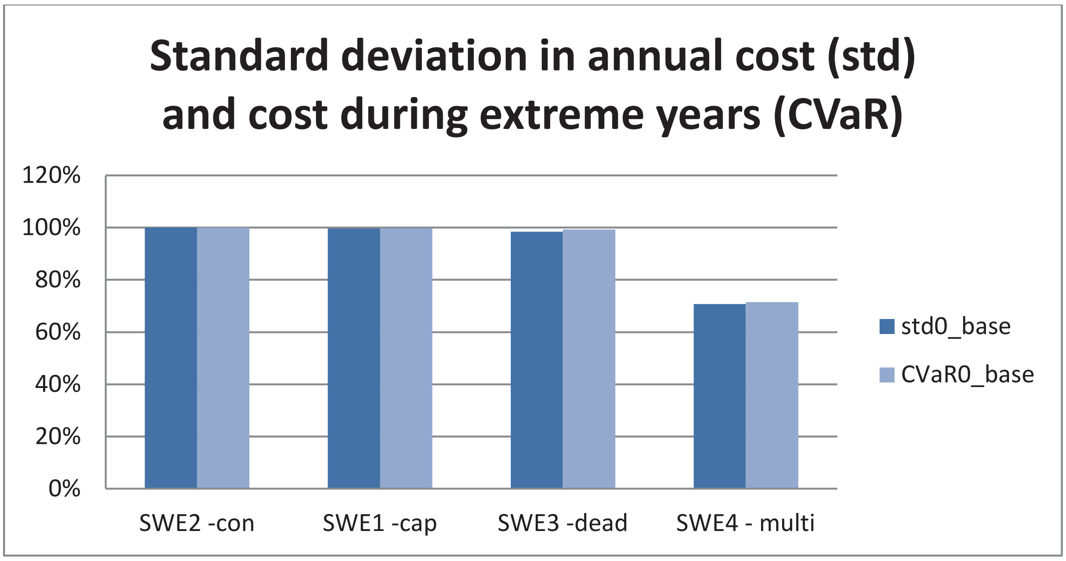

Figure 17: Impact of RPS types on limiting the financial risk during extreme years (CVaR) and unnecessary tariff changes.

- *What impact does the choice of cost model in the RPS have on the DSO's NPV analysis of different investment alternatives?*

The three cost models tested before (SWE, EI and SwedEnergy) are here applied with a continuous RPS type (SWE2, EI2, and SwedEnergy2). In addition two new cost models are tested – SwedEnergy3 and NO. The cost model SwedEnergy3 uses, as SwedEnergy2, the load-based indices ENS and PNS but together with sector-specific cost parameters instead of national-specific cost parameters. The cost model NO is the cost model applied in the current Norwegian quality regulation. This is a detailed model that considers the customer sector, as well as the outage duration and the timing when calculating in the customer interruption cost. A continuous RPS type is also applied for SweEnergy3 and NO.

The results for a risk neutral DSO and a risk averse DSO are shown in Figure 19 and Figure 20, respectively. An interesting result is that depending on the choice of cost model different loops will be prioritized. The national-specific cost model SWE2 uses the customer-based indices SAIDI and SAIFI which results in that loop 1 will be prioritized. Loop 1 has primarily residential customers and therefore the greatest number of customers. The sector-specific cost model EI1 also uses the customer-based indices SAIDI and SAIFI but will favor loop 7. This is due to the fact that the sector-specific cost model will take into account the customer composition at the specific loop. Loop 7 has many commercial customers which is the customer sector with the highest customer interruption cost per kW, see Section 3.4. Loop 6 also has high customer interruption costs due to its industrial customers. However, they are fewer and will therefore not be prioritized using customer-based indices. This is a direct consequence of how different cost models reconstruct customer interruption cost for different customer sectors. This fact is illustrated in [19] and shown in Figure 18. By comparing SAIDI/SAIDI with national ('N') and sector ('S') cost parameters the reconstruction of customer interruption cost become very different. As can be seen in Figure 18 national cost parameters prioritize the customer sector with the greatest number of customers which is the residential sector. With sector cost parameters the customer interruption cost for reach customer sector is taken into account which means that industrial and commercial customers are prioritized.

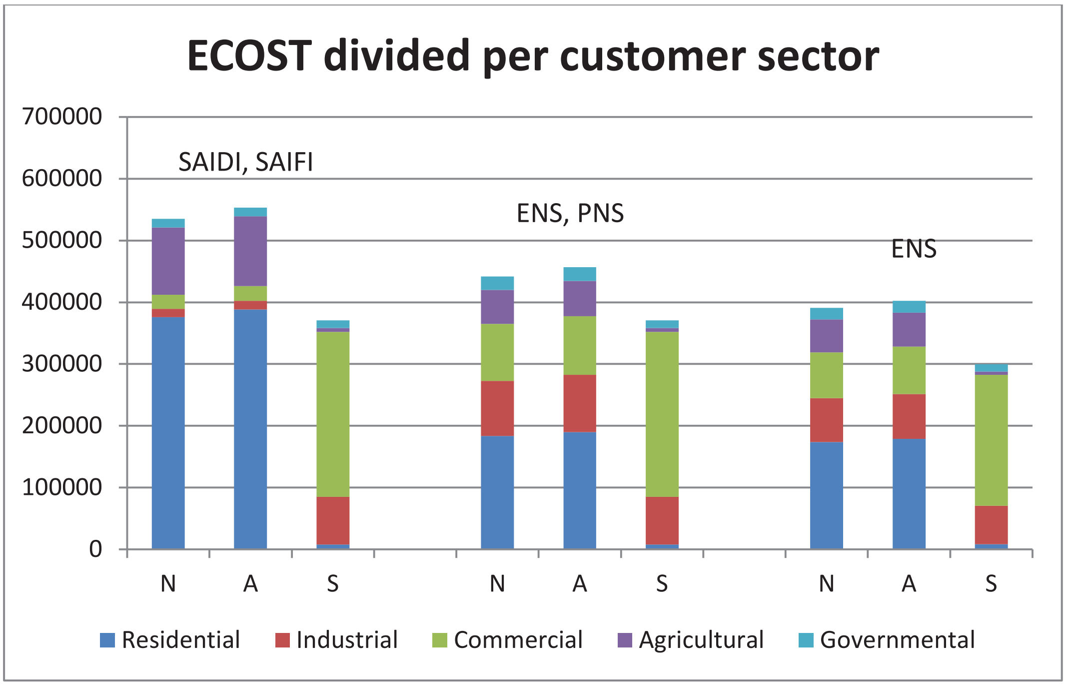

Figure 18: The Expected Customer Interruption Cost (ECOST) for the rural test system divided on customer sector for aggregated index cost models on national (N), area (A) and sector (S) levels [19] .

The national-specific cost model SwedEnergy2 uses the load-based indices ENS and PNS. The loops have approximately the same total load resulting in that the three loops are nearly equally prioritized. However, loop 7 with a high number of load heavy industrial customers is slightly prioritized over the other two loops.

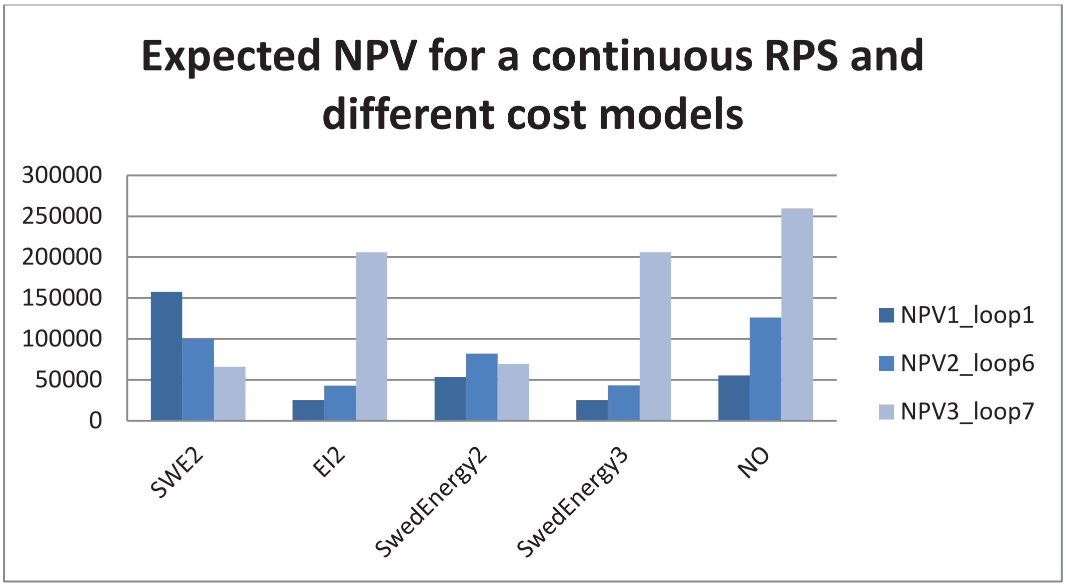

Figure 19: The expected NPV used by a risk neutral DSO when having the five different cost models. Customer-based (SWE2, EI2) and load-based (SwedEnergy2, SwedEnergy3) index models as well as outage-specific model (NO) are tested.

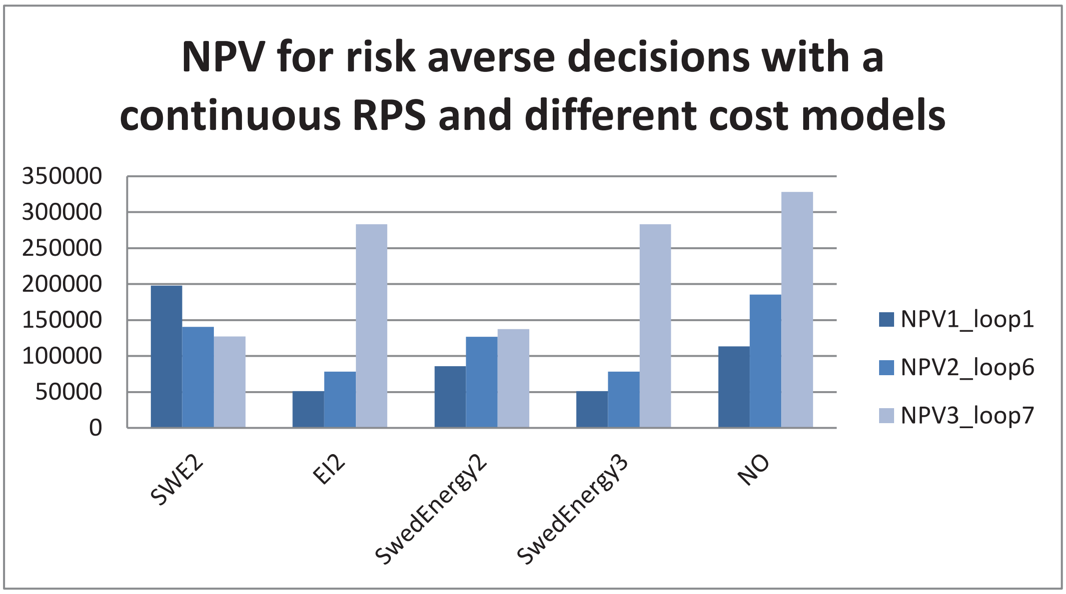

Figure 20: The NPV used by a risk averse DSO when having the five different cost models. Customer-based (SWE2, EI2) and load-based (SwedEnergy2, SwedEnergy3) index models as well as outage-specific model (NO) are tested.

Furthermore, four remarks can be made by studying the results in Figure 19 and Figure 20. Firstly, the choice of index type – customer-based or load-based indices – when having national cost parameters has such a large impact on the NPV results that it will affect the investment decision. This can be concluded by comparing the NPV values for SWE2 and SwedEnergy2. The remark holds both for a risk neutral DSO in Figure 19 and a risk averse DSO in Figure 20.

Secondly, the choice of cost parameters on national or sector level has a considerable effect on the results. The only difference between the customer-based models SWE2 and EI2 are that the cost parameters are defined on national and sector level, respectively. This is also the only difference between the load-based models SwedEnergy2 and SwedEnergy3. By comparing the results for the two pairs (SWE2,EI2) and (SwedEnergy2,SwedEnergy3) in either Figure 19 or Figure 20 it is evident that the cost parameter choice has a crucial impact on the investment decision.

Thirdly, the results in Figure 19 and Figure 20 both show that with sector-specific cost parameters, the NPV values for the customer-based model (EI2) and the load-based model (SwedEnergy3) are identical. The remark that customer-based and load-based models will give the same results when combined with sector-specific cost parameters is always true when using Approach 1 specified in Appendix B. This approach calculates the customer interruption cost per sector and load point and then sums to system level However, if only one load index is applied, the remark will not be true. An example of a one-index cost model is the cost model applied in the previous Norwegian quality regulation. The cost model used only ENS for each sector combined with sector-specific cost parameters. With such a model the cost due to the outage duration is accounted for but the effect of the number of interruption is lost. In SwedEnergy's proposed cost model this effect is captured with PNS and in Ei's cost model with SAIFI.

Finally, aggregated index cost models with sector-specific cost parameters give the same investment decisions as the outage-specific cost model. This can be seen by comparing the results of the four aggregated cost models with the result for the outage-specific cost model. The two aggregated cost models with sector-specific cost models, EI2 and SwedEnergy3, prioritize the reinvestments in the same order as the outage-specific cost model NO, although the incentives are smaller somewhat.

By comparing Figure 19 or Figure 20, the choice of risk strategy may have an effect on the choice of investment decision, as is the case for the cost model SwedEnergy2.

In Figure 21 the components of the expected NPV is shown for reinvestment 3. All reinvestment alternatives have the same investment cost and all loops are identical with regards to reliability. The changes in maintenance costs, repair costs and regulatory asset base due to automation of a loop are assume to be negligible. Furthermore, for the urban test system there will be no interruptions above 12 hours and the cost due to guaranteed standards – GS costs – are therefore zero in Figure 21.

As can be seen in Figure 21, the only contributor to the different NPV values for each investment in Figure 19 or Figure 20 is the costs due to RPS which is determined by the chosen cost model.

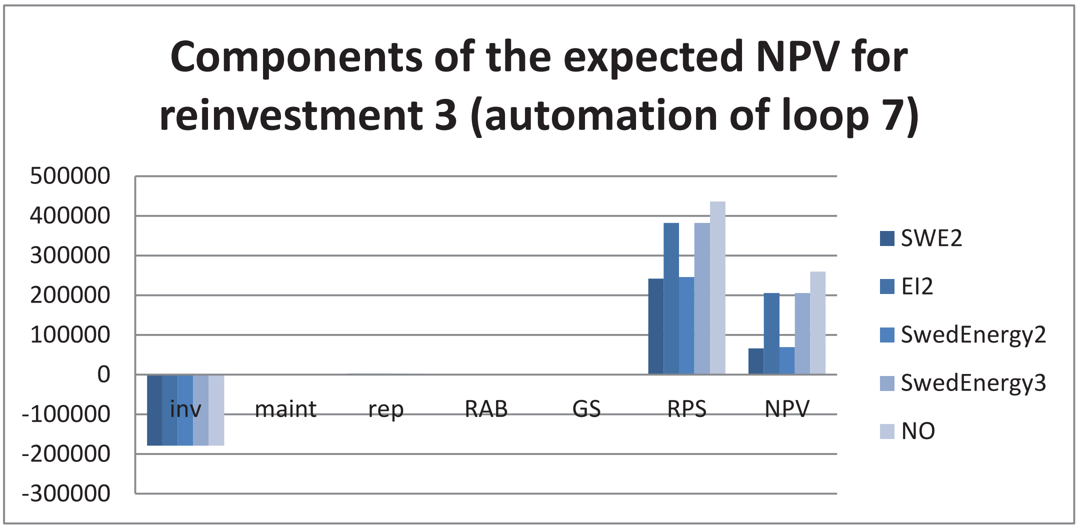

Figure 21: The components of the expected NPV for alternative 3 (automation of loop 7) when using five different costs models in the RPS.

Since no interruptions are longer above 12 hours in SURTS the limitation on which interruptions to include will have no effect on the results for the urban test system.

4.2.2 Comparisons with socioeconomically beneficial investments

This section compares the DSO's NPV analysis with the results of NPV analysis from society's perspective.

- *Are investments profitable for the DSO also socioeconomically beneficial?*

The five cost models that have been applied in the DSO's NPV analysis in the previous section are here applied in a socioeconomic analysis. The cost models C1 to C5 are applied in the RPS designs labeled SWE, EI, SwedEnergy and NO, respectively.

The expected NPV results are shown in Figure 22. As can be seen all reinvestment alternatives are beneficial from society's viewpoint. Comparing these results with the results for the DSO, the prioritizing of automation of the loops are the same. The two sector-specific cost models C2 and C3 give as stated before the identical results even though they use customer-based and load-based indices, respectively. The sector-specific models are also the models that give the same results as the more detail outage-specific cost model C5. Hence, with the second viewpoint on how to calculate customer interruption costs for society, the sector-based as well as the outage-specific cost models all give correct incentives to invest.

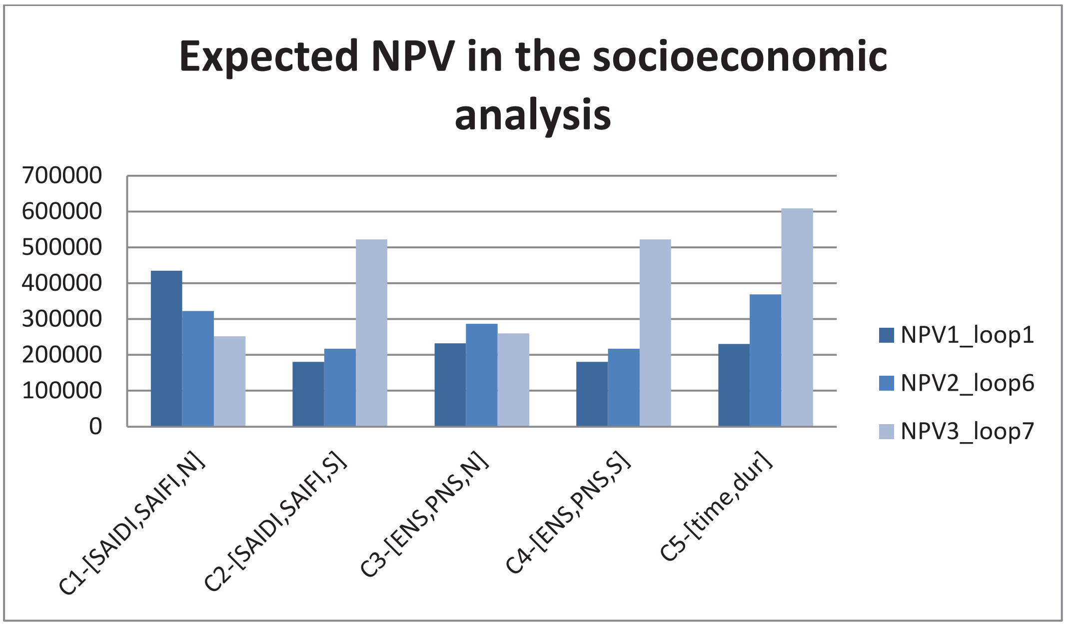

Figure 22: The expected NPV when the analysis is performed from society's perspective.

4.3 Results for SRRTS

This section presents the results for the investments to improve the reliability in SRRTS following the framework presented in section 4.1. The investigated reinvestments are to upgrade disconnectors to be remotely controlled, and whether to change the uninsulated overhead lines located in the critical part of the backbone of the modules to cables or insulated overhead lines.

4.3.1 Profitable investments for the DSO under different RPS designs

In this section the four questions formulated in Section 4.1.1 are investigated for SRRTS.

- *What impact does the share factor have on the DSO's NPV analysis of different investment alternatives?*

NPV results for the three reinvestments are shown in Figure 23 and Figure 24 for the current Swedish national-specific cost model (SWE0), the sector-specific cost model proposed by Ei (EI0) and national-specific cost model based on load indices proposed by SwedEnergy (SwedEnergy0). The cost models are combined with a capped RPS type and share factor of 0.5 and 1 in Figure 23 and Figure 24, respectively.

With a share factor of 0.5 in Figure 23 none of the reinvestment alternatives are profitable for a risk neutral DSO. However, when the share factor is removed (set to one) in Figure 24 the RPS incentive is stronger and reinvestment 2 (remote controlled disconnectors) become profitable for all the tested cost models. As for SRRTS, the share factor has a great impact on the NPV results.

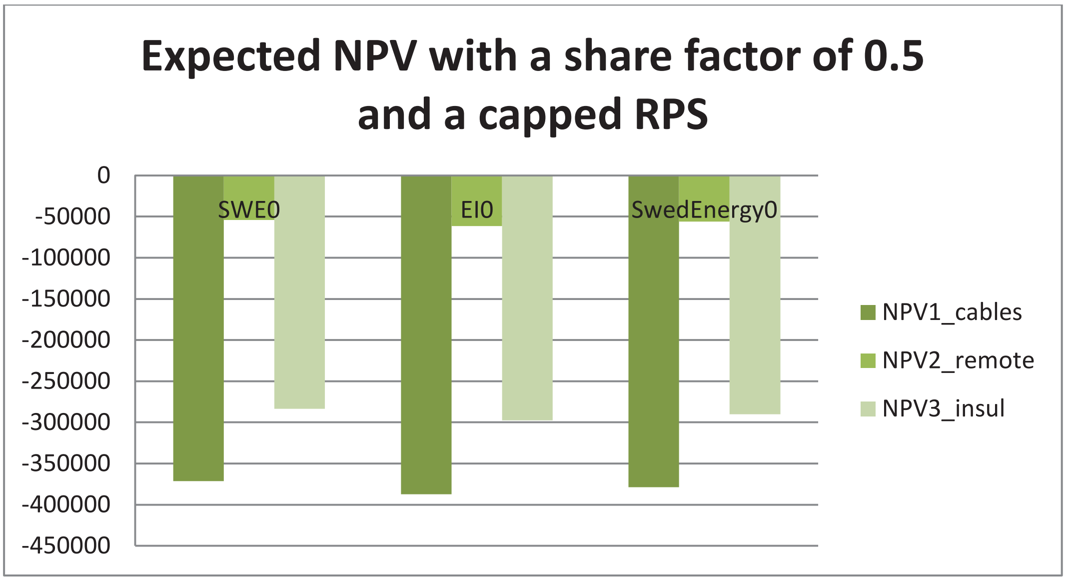

Figure 23: The expected NPV used by a risk neutral DSO when having a RPS with a share factor of 0.5 and a capped RPS type.

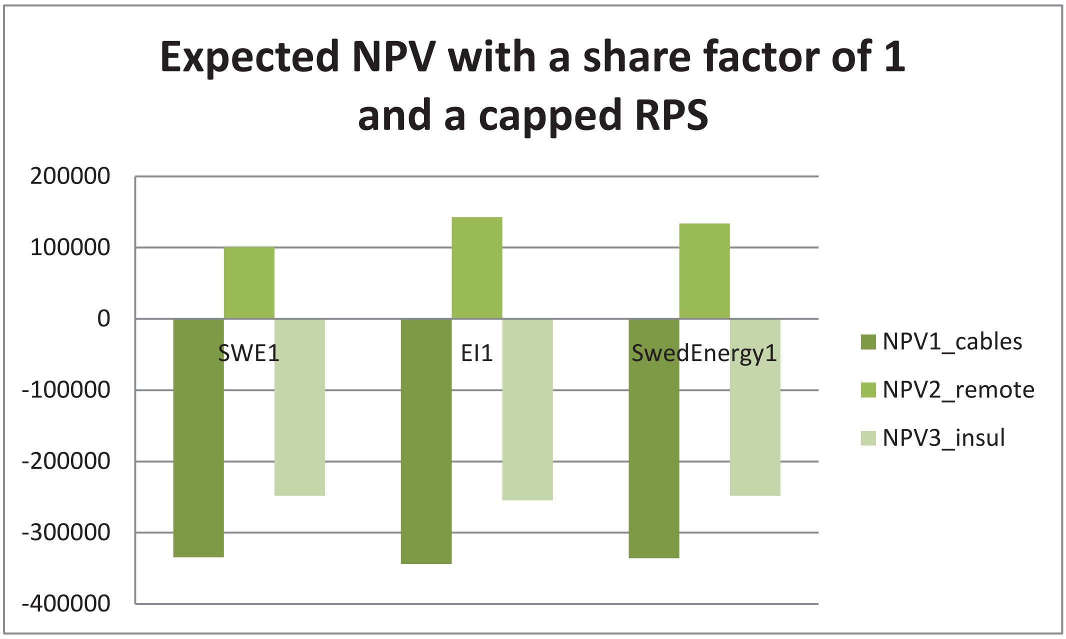

Figure 24: The expected NPV used by a risk neutral DSO when having a RPS with a share factor of 1 and a capped RPS.

In contrast to SURTS, the cost models give similar NPV results. The explanation for this is that all considered reinvestments for SRRTS affect more or less the reliability for all load points in the network. Therefore no investment favors a particular customer sector and the models will therefore give similar results.

The results for a risk averse DSO with are share factor of 0.5 and 1 are shown in Figure 25 and Figure 26, respectively. In contrast to a risk neutral DSO, a risk averse DSO see profit in reinvestment 2 even under a RPS with a share factor of 0.5. This implies that in order to lower the costs during the most extreme years, installation of remote controlled disconnectors is profitable. Hence, the investment decision becomes dependent on the risk strategy. Risk averse decisions are in this case study based on Conditional value at Risk (CVaR) instead of mean value. It is more likely that the NPV is positive when looking at CVaR. Therefore, a risk averse DSO is more likely to do investments in reliability than a risk neutral DSO.

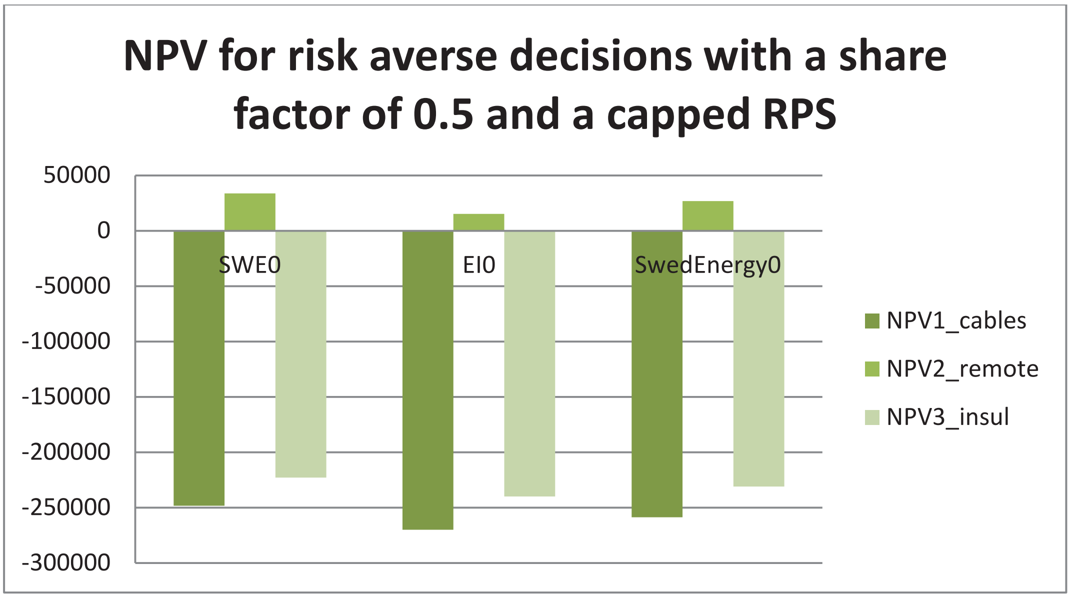

Figure 25: The NPV used by a risk averse DSO when applying a capped RPS type with a share factor of 0.5 is applied.

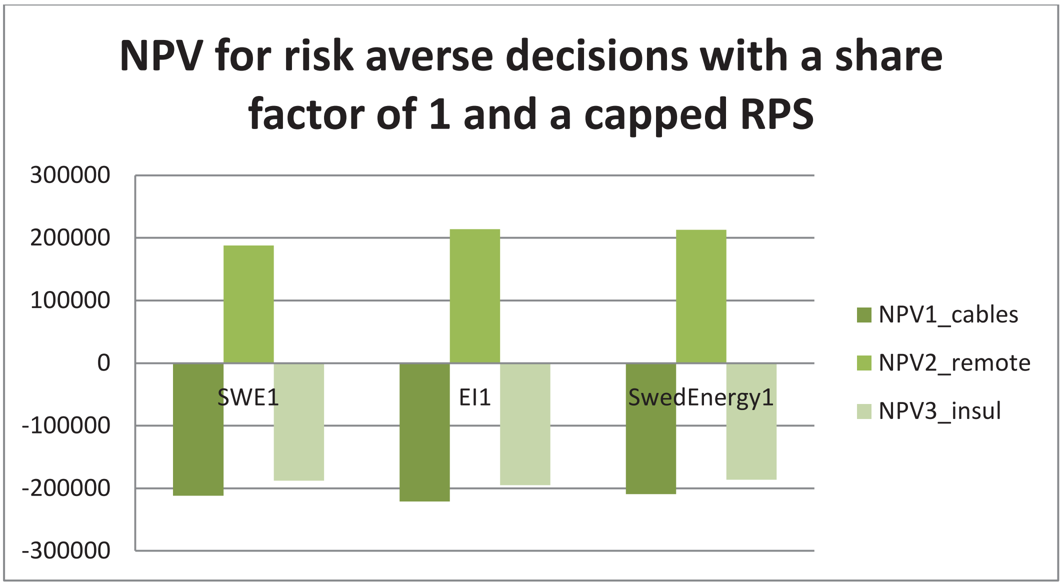

Figure 26: The NPV used by a risk averse DSO when applying a capped RPS type with a share factor of 1 is applied.

- *What impact does the RPS type have on the DSO's NPV analysis of different investment alternatives?*

As stated in Section 4.1.1, four RPS types are tested: continuous (con), capped (cap), dead band (dead) and multi-year indices (multi). Results for these different RPS types tested together with a share factor of 1 and the current Swedish national-specific cost model are shown in Figure 27.

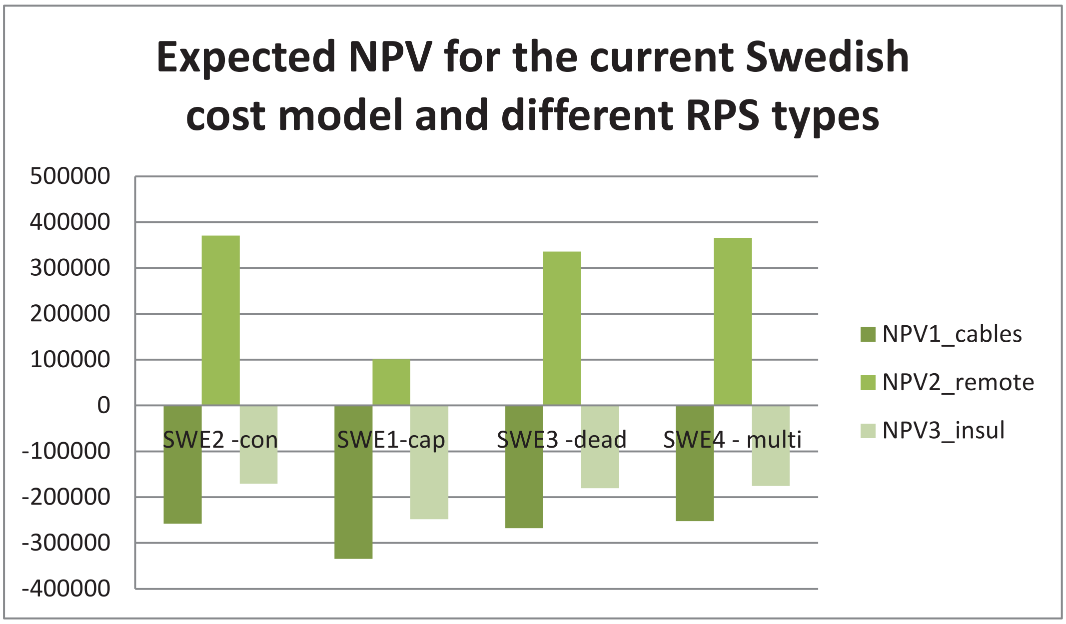

Figure 27: The expected NPV used by a risk neutral DSO when having the same cost model and different RPS types.

In contrast to the results for SURTS, the choice of RPS type has a considerable effect on the NPV values in Figure 27. Choosing a capped RPS decreases the incentive to invest for all three reinvestments. For example, the NPV value for reinvestment 2 (remotely controlled disconnectors) decreases from 370 000 SEK to around 100 000 SEK. Compared to the other two investments, reinvestment 2 is the investment that changes the shape of the probability distribution of SAIDI the most. Due to this fact the impact of a capped RPS is not as large for the other investments. A dead band and a multi-year approach hardly changes the NPV values for any of the considered investments. It can be concluded that the incentive to invest remains approximately the same under a dead band and a multi-year index RPS type. However, for a capped RPS type the incentive is reduced considerably.

Results for a risk averse DSO are shown in Figure 28. The same investment decisions are made as by a risk neutral DSO.

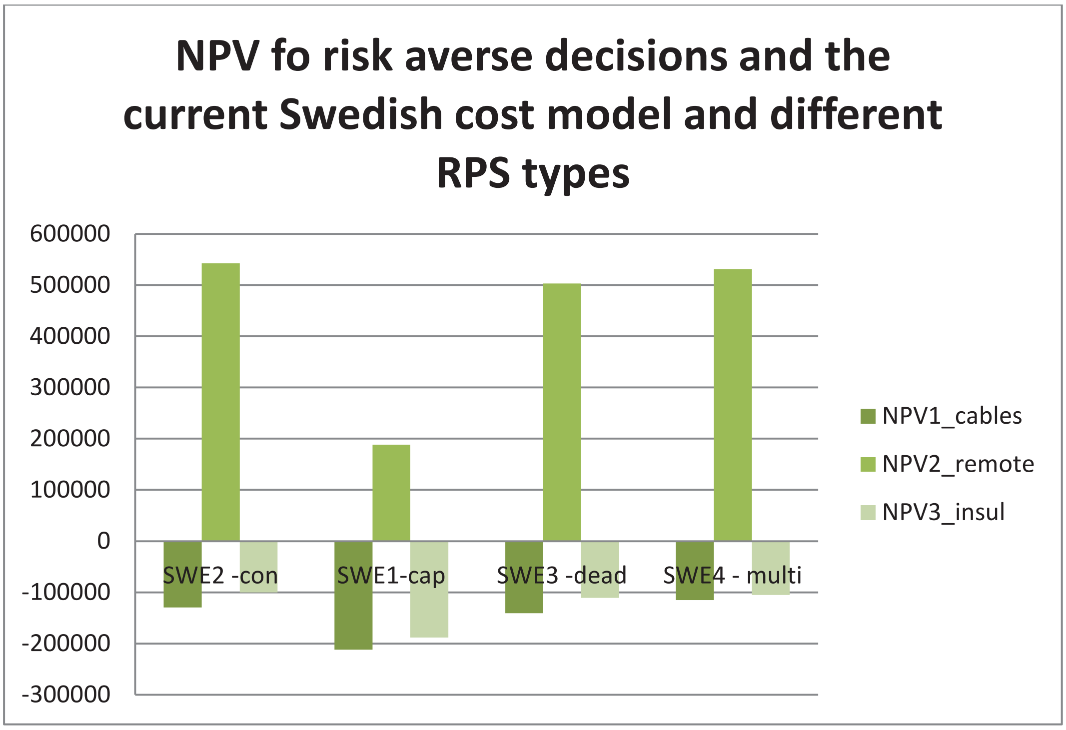

Figure 28: The NPV used by a risk averse DSO when having the same cost model and different RPS types.

- *How does the RPS type affect the DSO's financial risk? Are unnecessary tariff changes removed?*

How each of the four different RPS types (con, cap, dead, and multi) limit the DSO's financial risk during extreme years and also the variation in the annual costs are shown in Figure 29. The capped scheme aims to limits the DSO financial risk. To evaluate how well the RPS types limit the yearly financial risk

Conditional Value at risk (CVaR) is used. The dead band and multi-year scheme aim to limit the unnecessary tariff changes. This is measured by using the standard deviation (std). As a reference a continuous RPS type is used to see how much CVaR and std are reduced by changing to a different RPS type such as capped, dead band and multi-year indices. In Figure 29 the results for the base case, i.e. not for an investment alternative, are shown. Similar impact of the RPS type choice was obtained for all reinvestment alternatives.

A multi-year index scheme or a capped scheme is, compared to a dead band scheme, more effective in reducing the variation and limiting the DSO's financial risk. If the target is set on the average then in systems with large annual reliability variations it is unlikely with outcomes close to the target. Most of the years there are no storm resulting in nearly no interruptions, however during a few years storms cause very many and long interruptions. This reasoning would result in that is unlikely with outcomes within the dead band. A way to counter this fact is to increase the size of the dead band, but then much of the incentive to invest would disappear. The multi-year index approach average out the extremes (takes the mean of high and low values) and in this way decreases the variance.

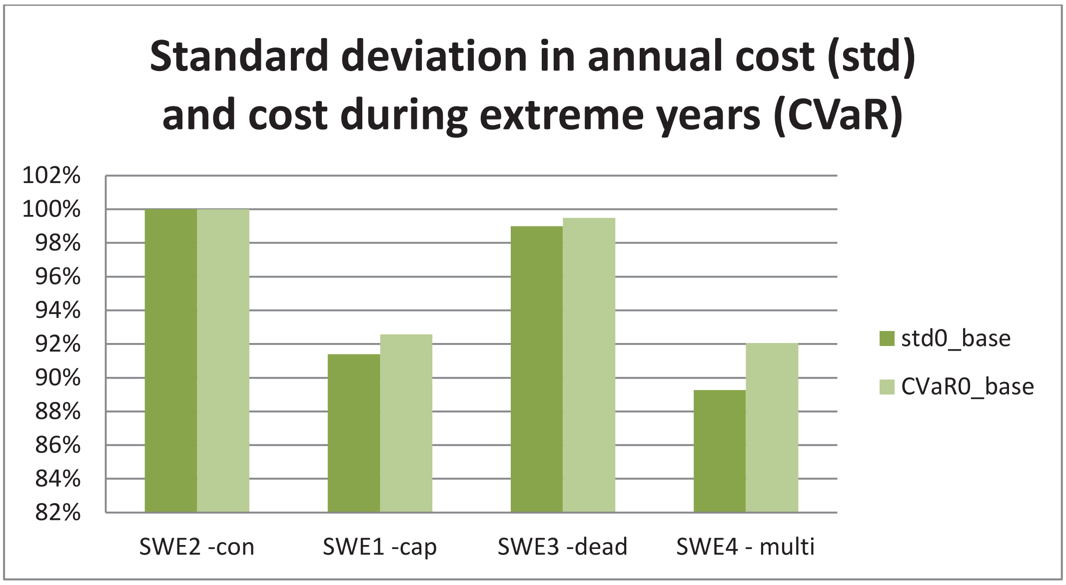

Figure 29: Impact of RPS types on limiting the financial risk during extreme years (CVaR) and unnecessary tariff changes.

- *What impact does the choice of cost model in the RPS have on the DSO's NPV analysis of different investment alternatives?*

The three cost models tested before (SWE,EI and SwedEnergy) are here applied with a continuous RPS type (SWE2, EI2, and SwedEnergy2). As for SURTS two additional cost models are tested – SwedEnergy3 and NO. The cost model SwedEnergy3 uses, as SwedEnergy2, the load-based indices ENS and PNS but together with sector-specific cost parameters instead of national-specific cost parameters. The cost model NO is the Norwegian outage-specific cost model including factors such as outage duration and timing. All five cost models are combined with a continuous RPS type.

The results for a risk neutral DSO and a risk averse DSO are shown in Figure 30 and Figure 31, respectively. The choice of cost model has no impact on the investment decision. The explanation for this is that the considered reinvestments affect almost all load points in the entire system resulting in that no particular customer sector is favored. Since the difference between the aggregated index cost models (SWE, SwedEnergy) is how they prioritize between different customers, they will all give similar results in this case study.

In contrast the outage-specific model NO produces NPV values higher than the other four cost models. The reason for this is that most of the interruptions in the rural network SRRTS are due to overhead line failures. These failures are not equally distributed over the year due to seasonal patterns in severe weather. In Sweden winter storms are more common than summer storms, resulting in longer interruptions during winter. During winter the customer interruption costs and loads are the highest. The customer interruption cost is also an increasing function of outage duration. The outage-specific cost model is the only model that considers the effect of both the timing and the duration of each specific outage. Since all reinvestments will mitigate the effect of overhead lines failures the extra value due to elimination of these long interruptions during a period with the highest customer interruption cost is only recognized in the outage-specific cost model.

The aggregated index cost models do not account for the duration of each interruption nor the timing. The cost parameters multiplied by the indices SAIDI and ENS, correspond to the cost of an interruption with an average duration calculated using CAIDI=SAIDI/SAIFI. It is for a duration equal to the CAIDI value that the cost parameter is determined on the customer damage function (cost parameter = cdf(CAIDI)). For the outage-specific cost model the value on the customer damage function is determined for each interruption duration. Different customer damage functions are also used for the different customer sectors. Thus, how the customer interruption cost of a specific customer sector relates to duration is captured.

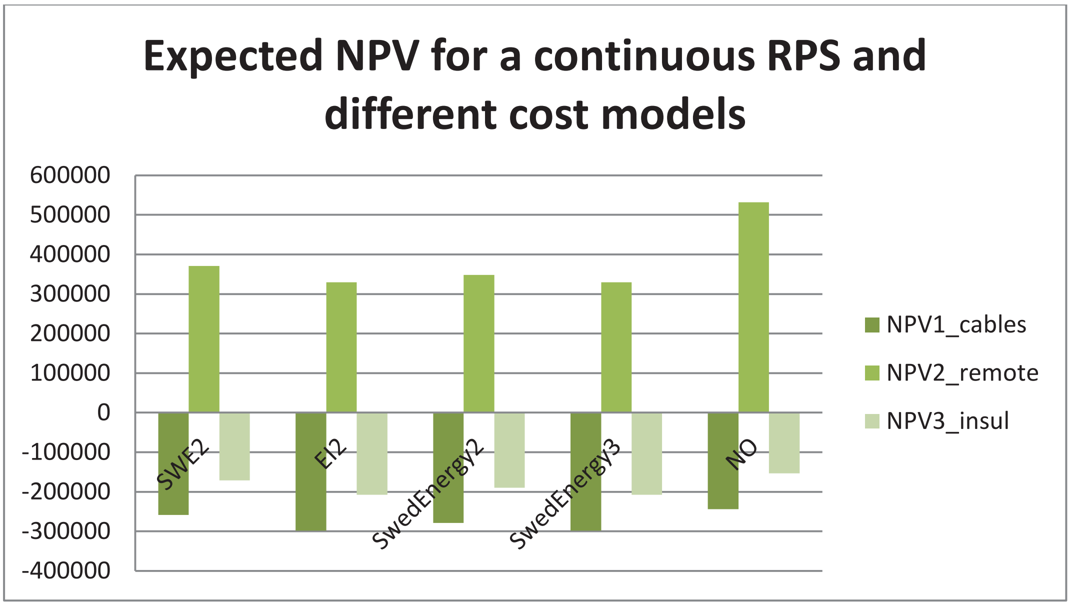

Figure 30: The expected NPV used by a risk neutral DSO when having the five different cost models. Customer-based (SWE2, EI2) and load-based (SwedEnergy2, SwedEnergy3) index models as well as outage-specific model (NO) are tested.

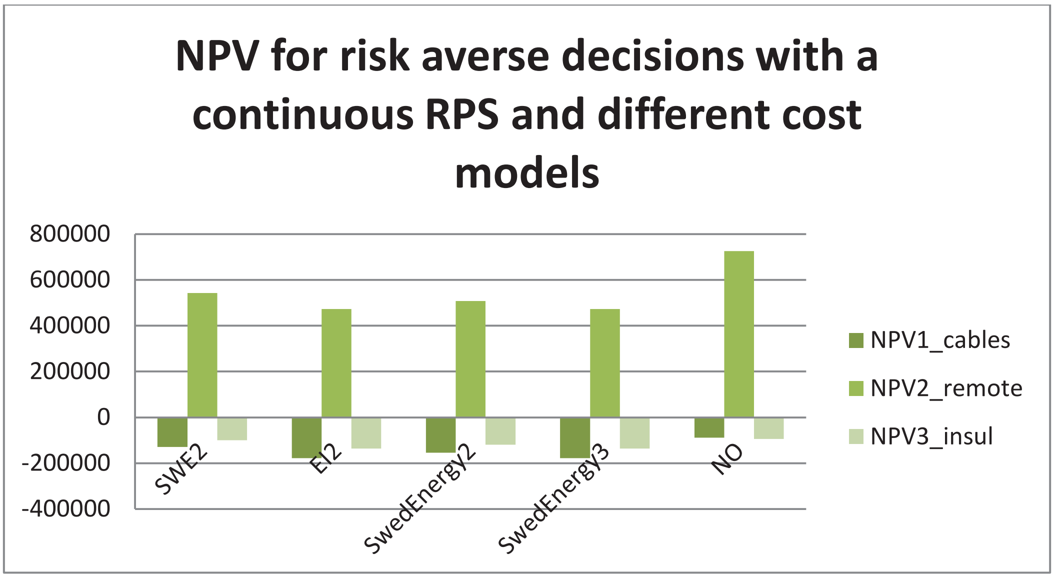

Figure 31: The NPV used by a risk averse DSO when having the five different cost models. Customer-based (SWE2, EI2) and load-based (SwedEnergy2, SwedEnergy3) index models as well as outage-specific model (NO) are tested.

Investments in cables would logically appear to be a risk averse strategy since cables eliminates the effect of widespread outages due to severe weather. However, as seen reinvestments in cables is not a profitable investment. Even though there are costs due to customer compensations for interruptions above 12 hours the incentive for a risk averse DSO is not large enough to make the investment profitable when the RPS only includes interruptions between 3 minutes and 12 hours. In Figure 32 the NPV results are shown for a risk averse DSO when all interruptions are included in the RPS. This is the current set-up in Norway where they apply a continuous RPS type with all interruptions included as well as customer compensations for interruptions above 12 hours.

According to the results shown in Figure 32 reinvestments in cables are now considered to be a profitable investment under the national-specific cost models and the outage-specific cost model. National-specific cost models give the highest NPV values for cables. This is due to that national cost parameters overestimate the customer interruption costs in rural areas. The customer compositions on national and on rural level are not the same. In rural areas many residential and agricultural customers are situated leading to that the actual cost parameters are lower than the national-specific cost parameters. When accounting for the customer composition in rural area using sector-specific cost parameters (EI2 and SwedEnergy2) the NPV values are again negative. However, when accounting for both the timing and duration of each interruption as well as customer sector reinvestments in cables will be slightly profitable. This can be seen in Figure 32 for the outage-specific cost model NO. These results demonstrate the importance in how the regulation defines which interruptions to include in RPS as well as the choice of cost model applied.

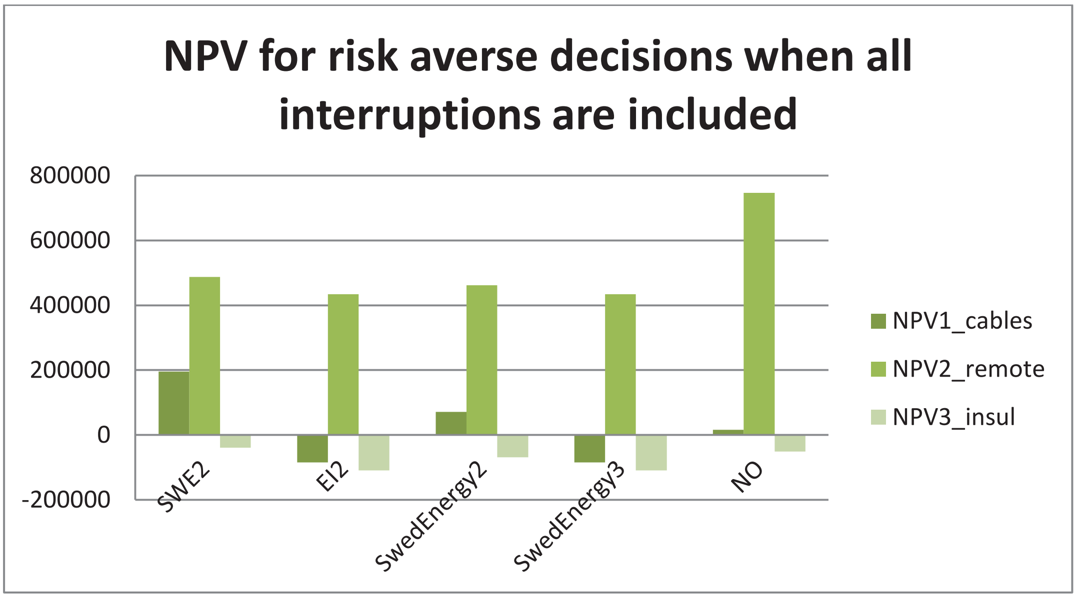

Figure 32: NPV for risk averse decisions with five different cost models and a continuous RPS when all interruptions are included and not only the interruptions between 3 min and 12h.

In Figure 33 the components of the expected NPV are shown for a RPS design using the current Swedish cost model and a capped RPS type with a share factor of 1 (SWE1). The reinvestments in cables and remote controlled disconnectors have more or less the same investment cost. However, they are not both profitable investments. An explanation for this is that one crucial factor for an investment to become profitable or not is how it affects the regulatory asset base (RAB). As can be seen in Figure 33 the reinvestments in remote controlled disconnectors will have a much larger impact on the RAB than reinvestments in cables. For reinvestments RAB will be updated with the differences in the norm values of the new and old components. Cables and the overhead lines that are replaced have similar norm values why the effect on RAB is small. However, if it was a new investment, the RAB adjustment would be different and the investment in cables may become profitable.

Study the incentives in Figure 33 given by guaranteed standards (GS) and RPS. Note that it is only for the reinvestments in cables and insulated lines that the incentives from GS exist. Reinvestments in remote controlled disconnectors have no impact on the interruptions above 12 hours and therefore there will be no profit made from decreased costs due to customer compensations. The results for cables and insulated lines show that with a share factor of 1 the incentives from RPS and GS are in approximately the same size. However, with the current Swedish RPS design adopting a share factor of 0.5 the incentives from GS are stronger compared to the incentives given by RPS.

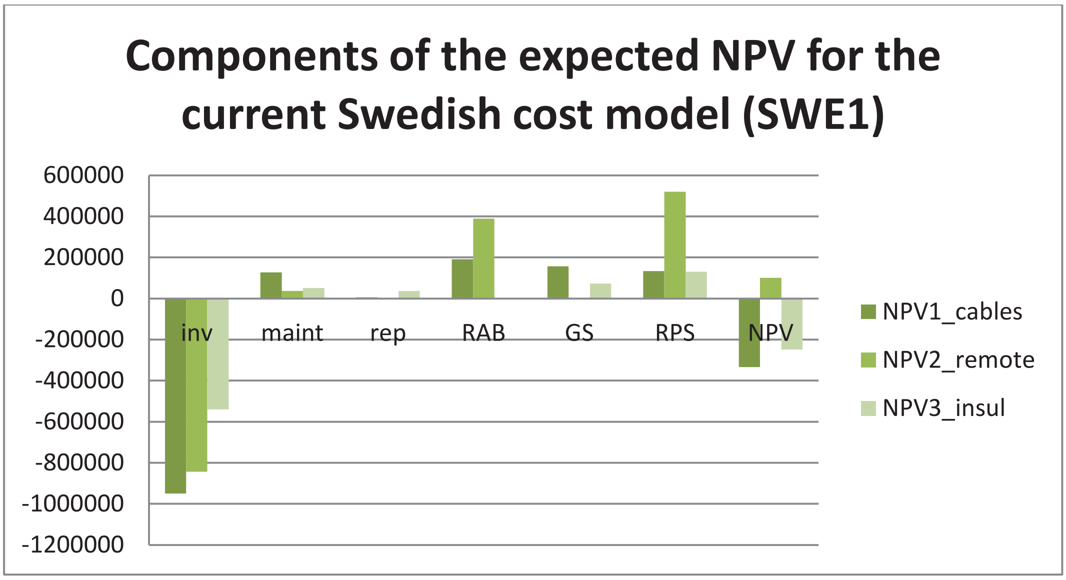

Figure 33: The components of the expected NPV for all reinvestments using SWE1 which is the current Swedish cost model (SAIDI, SAIFI, N) combined with a capped RPS and a share factor of 1.

4.3.2 Comparisons with socioeconomically beneficial investments

This section compares the DSO's NPV analysis with the results of NPV analysis from society's perspective.

- *Are investments profitable for the DSO also socioeconomically beneficial?*

The five cost models that have been applied in the DSO's NPV analysis in the previous section are here applied in a socioeconomic analysis. The cost models referred to as C1 to C5 are the ones applied in the RPS designs labeled SWE, EI, SwedEnergy and NO, respectively. The expected NPV results are shown in Figure 34. As can be seen the choice of cost model will have crucial effect on which reinvestment alternatives are considered beneficial or not.

For the DSO none of the reinvestments were profitable given the current Swedish regulation design with a share factor of 0.5 and a capped RPS type. However, a share factor of 1 resulted in that reinvestment 2 (remote controlled disconnectors) was considered to be profitable for all tested designs. For society three cost models give that both reinvestments 2 (remote controlled disconnectors) and reinvestment 3 (insulated lines) are considered to be beneficial. The three cost models are the national-specific cost models (C1-SAIDI,SAIFI,N and C3-ENS,PNS,N) and the outage-specific cost model (NO). For the sector-specific cost models (C2-SAIDI,SAIFI,S and C3-ENS, PNS,S) the NPV for reinvestment 3 is approximately zero (9000 SEK) and can be hard to detect in Figure 34. Note that these sector-specific models give the identical result, which is always the case for Approach 1 shown in Appendix B.

Interruptions with all durations are included in the socioeconomic analysis. Compare Figure 34 for society with Figure 35 for a risk neutral DSO regulated by a continuous RPS that include all interruption durations. Reasonably Figure 34 and Figure 35 should give similar investment decisions for society and a DSO for each cost model applied. However, this is not the case. Apart from different discount rates the main contributor fact to the different results for the two actors is the RAB. This fact indicates the importance of how the reinvestment affects the RAB in the DSO's NPV analysis. In Figure 33, we see that the RAB for the different reinvestments differ to a large extent. Even when having an outage-specific cost model and including all interruptions in the RPS the results between society and DSO do not correspond fully. To change uninsulated overhead lines to insulated is socioeconomically beneficial, however for the DSO this kind of reinvestment has a negligible impact on the RAB and will not be profitable.

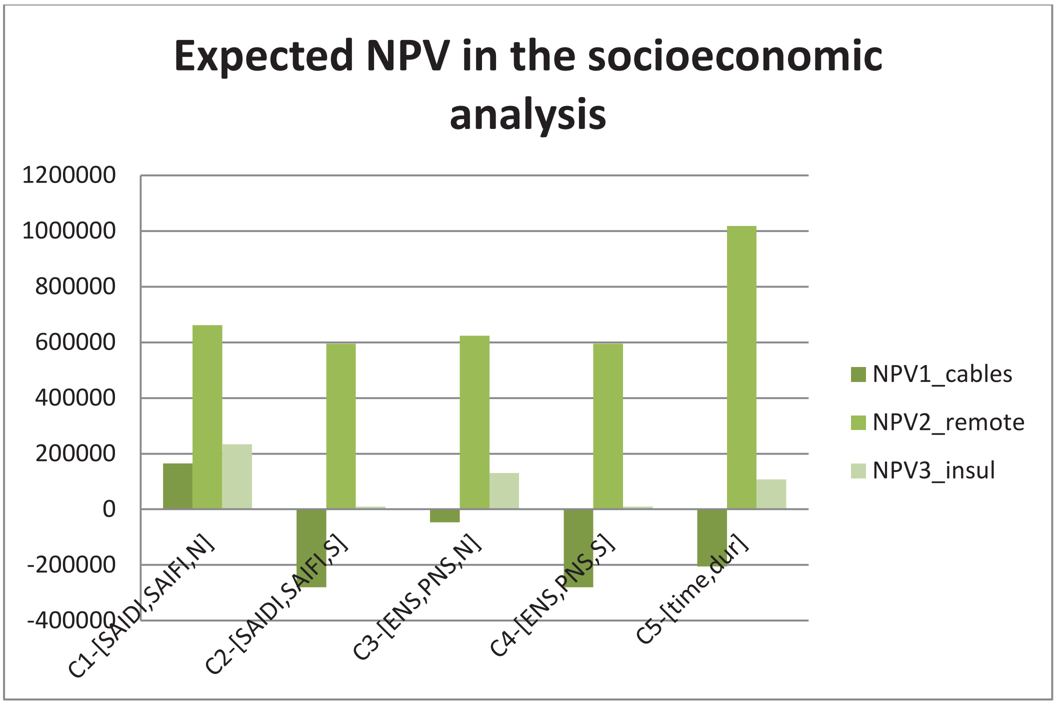

Figure 34: The expected NPV when the analysis is performed from society's perspective.

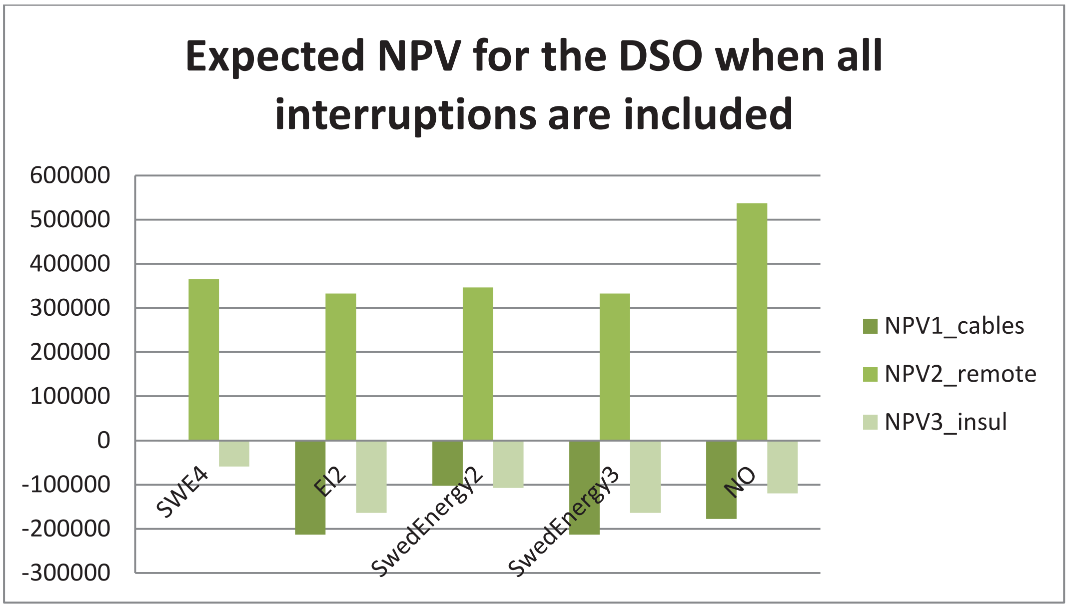

Figure 35: The expected NPV for the DSO when having a continuous RPS including all interruption durations.

4.4 Case study findings

The case studies presented in this chapter show that difference reinvestment projects are selected depending on the RPS design. The results are based on the NPV of the total cost, including capital and operation costs. This implies that the cost due to RPS is large in comparison to other costs. The RPS design therefore become important since it affects the outcome of investment decisions.

This section gives a summary of the findings in Chapter 4 which investigates the impact that several aspects have on the NPV analyses for DSO and society. Examples on investigated aspects are share factor, RPS type, cost model, effect on the regulatory asset base and choice of risk strategy. The strength relationship between the selective and collective quality regulation is also discussed.

- Choice of share factor

The results for both the urban test system (SURTS) and the rural test system (SRRTS) show that if the cost due to reward and penalty scheme (RPS) has a share factor of 0.5, a DSO may not profit from implementing a socioeconomically beneficial reinvestment project. Only one of all considered socioeconomically beneficial reinvestments become profitable for a DSO under the current Swedish regulation design that uses a share factor of 0.5 and a capped RPS type. Setting the share factor to 1 the current Swedish design still uses a capped RPS type. The share factor causes the RPS design to be capped twice. The share factor is motivated by that the risk should be divided equally between the customers and the DSO. However, by setting an adequate target for the RPS, this division of risk is arguably already implemented. Optimal rewards and penalties should be design to fulfill Equation 5. Using a share factor that deviates from 1 makes it impossible to fulfill Equation 5.

For SURTS, removing the share factor made all socioeconomically beneficial investments also profitable for the DSO. For SRRTS, it depends on the cost model used. Removing of the share factor when a more detailed sector-based cost model is applied made society and DSO both conclude that remote controlled disconnectors is a beneficial investment. However, using less detailed national-specific cost models also made investments in cables and insulted lines socioeconomically beneficial. For this example, which of the two viewpoints on how to calculate society's customer interruption cost one chooses to abide, different results are obtained. See 4.1.2 for a description of the two viewpoints.

- Choice of RPS type

The choice of RPS type did not have an impact on whether the reinvestments were considered profitable or not by the DSO for either of the two test systems. This is the desirable outcome since the choice of RPS type ideally should not distort average incentives. The choice of RPS type can though help with limiting the DSO's financial risk and unnecessary tariff changes.

A capped RPS type main purpose is to limit the DSO's financial risk measured by the so-called Conditional Value at Risk (CVaR). A dead band or a multi-year index RPS type aims to decrease the unnecessary tariff variations due to natural fluctuations in the reliability. This means decreasing the standard deviation (std) of the yearly cost. However, a capped RPS type also decreases the standard deviation since it cuts off extreme costs.

Extreme costs usually only occurs during extreme years in rural networks which are vulnerable to severe weather. The capped RPS type has therefore only an effect for SRRTS where it decreases the yearly financial risk during the most costly years and the standard deviation by around 10 %. The dead band RPS type shows the least promising results for both test systems; both concerning decreasing the standard variation as well as limiting the financial risk. The choice of dead band width is though a factor that may affect the results. Here plus/minus 3 % has been applied. A wide dead band would decrease the risks but also distort average incentives. Finally, the multi-year index RPS type shows to be the most effective RPS type in decreasing the standard deviation as well as limiting the financial risk for both the test systems. For the urban test system, SURTS, a multi-year approach decreased the financial risk and the standard deviation by 30 %. For the rural test system SRRTS the decrease was 10 %. In contrast to a capped RPS type a multi-year RPS type does not dilute the incentive to invest. While NPV values for SRRTS with a capped design was decreased by 70 % compared to when having a continuous RPS type, the NPV values with a multi-year RPS type was unchanged.

- Choice of cost model for reconstructing customer interruption costs in RPS

The choice of cost model was of great importance for SURTS where the different reinvestments favored difference customer sectors. For the SRRTS the reinvestments increased the reliability of mostly all load points and no certain customer sector was favored. Therefore the different cost models gave similar results. This indicates that the impact of the choice of cost model in RPS can be very different depending on the customer composition in the load points that different investments affect.

The cost model decides on how customer sectors are being prioritized. Two factors in the set-up of the cost model are important. Firstly, if it is a national-specific cost model using system reliability indices the choice of customer-based or load-based indices becomes important. With customer-based indices each customer, independent on which sector it belongs to, have the same weight. With load-based indices, customers with high load have a higher weight.

In the current Swedish cost model (SWE), customer-based indices are used together with national cost parameters. In Ei’s proposal (EI), customer-based indices should instead be used together with cost parameters on sector level. This change has a huge impact looking on the results for how different cable loops in SURTS are prioritized. Instead of prioritizing the loop with many residential customers, the loop with commercial customers is prioritized. The commercial customer sector is the sector with the highest customer interruption cost per kW and therefore this sector has high cost parameters. Using load-based indices with national cost parameters will prioritize the loop with most industrial customers. However, if load-based indices are combined with sector-specific cost parameter the results will be identical to Ei’s proposed cost model. This indicates that the cost parameters are even more important than the type of indices used.

- Choice of risk strategy

The results for both SURTS and SRRTS show that different reinvestment projects are chosen depending on which risk strategy the DSO chose to apply. Conventional investment analysis makes decisions based on the expected outcome which corresponds to assuming that the DSO is risk neutral. A risk averse DSO that aims to decrease the costs during the extreme years will invest more in reliability than a risk neutral DSO. Results show that using a risk averse strategy may clarify benefits or drawbacks with a reinvestment that is hard to discover by only looking at the expected NPV. The results of the risk averse strategy is affected by which interruptions that should be included in the RPS according to the regulation. For example, cables only become a profitable investment for a risk averse DSO when interruptions with all durations are included in the RPS, and not only interruptions between 3 minutes and 12 hours.

- Impact of regulatory asset base

The investments projects considered in the presented case studies are reinvestment projects. The effect on the regulatory asset base is found to be important if an investment will turn out to be profitable or not for a DSO. For some reinvestments the difference between the norm values of the old and new components are greater than for others and those will have the largest impact on the regulatory asset base. The effect of the RAB is one of the main facts why socioeconomically beneficial projects may not be profitable for the DSO.

- Strength relationship between the collective and selective quality regulation

Results from the case studies show that applying the current Swedish RPS design will give incentives on system level (from RPS) that is weaker than the incentives on customer level (from GS). If the share factor is set to one the incentives from the collective and selective quality regulations will be of approximately the same size.

5 Risk-based method including both risks and uncertainties

In the previous chapter the impact that different regulation designs have on the DSO's and society's NPV analysis have been studied. The NPV analysis is based on a risk analysis that includes the connection between technical and financial risks. Technical risks may lead to component failures and power interruptions, which under a certain quality regulation will imply financial risks for the DSO. However, it is not only the current risk situation that has an impact on the DSO's NPV analysis when evaluating the profitability of an investment. Lifetimes of distribution system components are very long and therefore reliability investment decisions are made in a very uncertain economic environment. This means that both the current risk situation as well as how the uncertainties for how these risk factors develop in the future will have an impact on the analysis.

Both risks and uncertainties will affect the outcome of different investment decisions. Risk is defined as a measurable randomness that can be described by a probability distribution, in contrast to uncertainty that is randomness without a well-defined distribution [53]. The reliability of a component is stochastic and can vary. However, by using failure statistics the probability distribution of the failure rate can be estimated and the risk of power interruption can be simulated. On the contrary we have uncertainties where the probabilities are unknown, such as the development of quality regulation design in the future. One way to include the effect of uncertainties is to formulate possible future scenarios for how the risk factor will develop. For these scenarios the robustness of investment strategies are analyzed.

This chapter presents an overview of the risk-based method developed the listed as Publication 1 in the publication list in Section 1.2. The developed risk-based method considers both risks and the regulatory uncertainty.

5.1 Motivation for developed risk-based method

Many investigations of the cost due to the RPS for a few possible designs have been performed [54] [55] [56] [57]. However, the quality regulation design is dynamic and will only be definitely fixed during a regulation period of 3-5 years. In fact the development of the regulatory model has been identified as a key factor in operations planning of a DSO [45].

5.2 Risk-based method considering both risks and uncertainties

A method that can be used to investigate how regulation parameter changes in the quality regulation affects the DSO's financial risk is presented in Publication 1. The proposed regulation impact method is based on NPV calculations of the total reliability cost and is an extension of the risk-based method proposed in [34]. Using the new method it is possible to analyze how robust an investment strategy is to changes in quality regulation design.

The proposed regulation impact method is illustrated in Figure 36 and consists of seven main parts which are described in this section.

Part I)-Scope definition

Scope definition includes the study motivation, system boundaries, time horizon, and decision rule. The study motivation is to evaluate different investment strategies in distribution system reliability. The time horizon is the calculation period used in the NPV analysis. System boundaries are defined by the considered distribution system. The applied decision rule is the expected Net Present Value (NPV) based on the total reliability cost.

Part II) -Risk identification

The factors that trigger power interruptions and affect the financial consequences for the DSO are identified. Historical reliability data are reviewed, such as the dominating failure causes.

Part III) -Define quality regulation

Firstly, the current quality regulation that the DSO is exposed to is defined. Secondly, the parameters that should be altered in the regulation impact study are decided and defined in different scenarios.

Part IV) -Risk estimation

Risk estimation estimates the probability of power interruptions and the resulting consequences. Given a regulation design a risk estimation corresponding to steps A-D in Figure 36 is carried out for each of the investment strategies.

Part V) -Risk evaluation

For each regulation scenario a risk evaluation is carried out where the risk estimation results for the investment strategies are compared.

Part VI) -Risk control

Risk control is decision-making. Based on the results from the risk evaluation and the risk attitude of the decision-maker an investment strategy is chosen and implemented. In the case study in Publication 1 the decision-maker is assumed to be risk neutral and the investment strategy that maximizes the expected NPV is selected.

Part VII) -Risk communication and monitoring

Risk communication and monitoring is a parallel activity that exchange information about risk between the parts as seen in Figure 36. Risk assessments cover different areas of expertise such as system analysis, component analysis, failure statistics and economics. For a successful risk assessment the involved parties must communicate. Monitoring and review should be carried out on a regularly basis to make sure that acceptable risk levels are obtained, and that the applied risk-based method and the input parameters are properly applied [5].

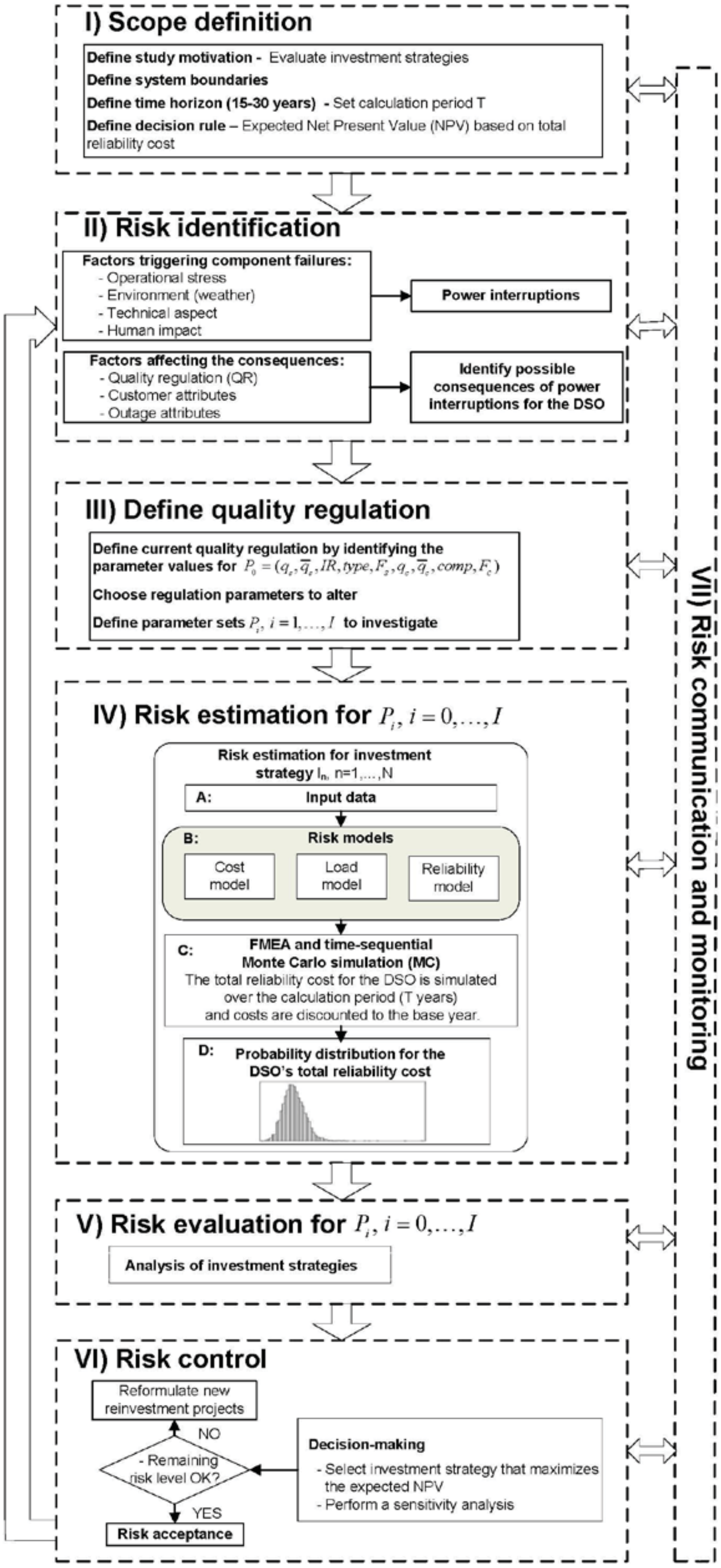

Figure 36: Regulation impact model.

5.3 Case study

The proposed regulation impact method is in Publication 1 applied in a case study to evaluate investment strategies to increase reliability of SRRTS. In the case study possible future parameter changes and their effect on the DSO's financial risk when adopting different investment strategies are investigated.

The purpose of the case study is to illustrate that the method can be used to analyze how robust an investment strategy is to changes in quality regulation design. The new method is applied to the current Swedish quality regulation. Possible future parameter changes and their effect on the DSO's financial risk when adopting different investment strategies are then investigated.

The investment strategies to change uninsulated overhead lines to cables or insulated overhead lines were included in the case study.

5.3.1 Future quality regulation scenarios

Four possible scenarios of quality regulation impact were included. The first scenario is the current Swedish quality regulation. The second scenario represents a stronger quality regulation on customer level regulated by GS. The third scenario represents a stronger quality regulation on system level regulated by RPS. Finally, the fourth scenario represents a stronger GS and a stronger RPS. It is assumed that customer interruption costs will double during the calculation period. This is the same assumption made by the Technical Research Center of Finland (VTT) when formulating the roadmap for distribution systems 2030 [45]. Since the incentive rate/cost parameter in RPS and the customer compensations in GS are related to customer interruption cost it is assumed that these will be twice as high.

5.3.2 Case study results

Changing overhead lines to underground cable is shown not to be beneficial for the DSO for three of four considered scenarios of future quality regulation designs. Changing the uninsulated lines into cables is only beneficial for the DSO if the quality regulation is stronger both on customer and system level as in scenario 4. To change the uninsulated lines into insulated lines is shown to be beneficial for the DSO for all the four investigated future quality regulation designs. Thus, for the considered case study the investments in insulated lines are a robust investment strategy for changes in quality regulation design.

Climate change is another key factor for rural distribution systems with overhead lines. Investigating the reliability in a power system exposed to different future climate changes would be interesting in combination with future quality regulation designs. More frequent severe weather would increase the relative benefits of underground cables. A method that can handle developments of several key factors in future scenarios is an area for further research.

6 Risk-based methods applied on larger scale power systems

More and more advanced risk-based methods are being used in the field of power system reliability [42], [43]. In Publication 3 listed in Section 1.2 graph theory is used to model the effect on different restoration actions to restore the power system after a blackout, a so-called cold load pickup. Other methods apply Monte Carlo simulations and it has been shown that even though these methods are computational heavy they can be applicable to larger systems. In [42], for example, Monte Carlo simulations were applied to an 11 kV distribution system of one of the largest DSOs in the UK.

There are also DSOs and Transmission System Operators (TSOs) that already apply or are about to apply more advanced risk-based methods for reliability analysis. This chapter presents a DSO that has been using an advanced risk-based method based on Monte Carlo simulations for several years. The chapter also discusses how the risk-based method presented in Section 3.1.2 can be simplified in order to be applicable to a larger system.

6.1 Advanced risk-based methods used on larger systems

An advanced risk-based method is used by Con Edison, a DSO in New York that supplies power to more than 3 million customers in New York City and Westchester County. As much as 85 % of the load in their service territory is supplied by underground low-voltage network systems. These underground cable systems are very meshed and therefore extremely reliable. In order to estimate the tiny probability of a power interruption Con Edison is forced to apply advanced risk-based methods. The methods are called the Network Reliability Index (NRI) program. The NRI program employs Monte Carlo simulations and models component failures as functions of age, transformers ranges, voltage levels and loadings. The NRI program is used for both planning and operational purposes. In planning, the program simulates a period of 20 years to evaluate the impact of different possible network configurations. In operation, the program provides the operator with real-time information of the current risk situation and gives a seven days-ahead prognosis.

6.2 Advanced risk-based method incorporating time dependencies

The risk-based method presented in Section 3.1.2 incorporates the time-dependencies in inputs as well as the effect of extreme events. The time-dependencies in inputs are due to the fact that time-varying external factors affect the network reliability. In the method presented the seasonal patterns of high wind events and lightning are considered. These severe weather events will result in that the power interruption failures not are distributed equally over the year. For example, high winds events are more common in winter when load and customer interruption costs are high. So we get an increased probability for interruptions when the consequences are the highest. This is what is referred to as time-dependencies in inputs.

Many models have been proposed that model how different weather phenomena affect the reliability of components [58] [59] [60] [41]. These models imply a significant effort when modeling both the severe weather and how it is affecting the failure rates. To capture the time-dependencies in inputs time sequential Monte Carlo simulations are also needed to simulate the up- and down states chronologically. An up state is when a component is working and a down state is when a component has failed and being repaired.

The method presented in Section 3.1.2 is such a method that uses time sequential Monte Carlo simulations. Compared to ordinary Monte Carlo simulations, time sequential Monte Carlo simulations are even more computationally heavy.

6.2.1 Simplification of risk-based methods based on time sequential Monte Carlo simulation

In Publication 2 a modeling approach is presented that still captures the time-dependencies without needing to model the actual severe weather event and its impact on the failure rate specifically. It does thus present a way to simplify the risk-based method in Section 3.1 while still capturing the time dependencies. The work was carried out during a research visit to University of Cape Town. The proposed modeling approach also cut simulation time by only sampling the down states (failure states) instead of sampling both up and down states. To capture the stochastic nature of the failures probability distributions are used. Time windows are used to describe the vulnerability of components for external risk factors affecting their failure rate.

Failure rates for components will be different in the different time windows. Reliability statistics are divided into the time periods defined by the time windows and reliability parameter such as failure rate and duration are estimated. For each component the number of failures in each time window is generated. The failures are then each randomly assigned a time of occurrence in the time window. The failure duration is then generated and under this period the component will be in the down state.

Depending on the geographical location of the considered network, different external risk factors cause time dependencies. In South Africa external risk factors causing transmission line failures are bird streamers, lightning, bush fire and pollution which have seasonal patterns both during the year but also during the day [61]. Weather data from South African Weather Service also show that lightning activity is more common on summer afternoons, while cold fronts are especially severe at night during winters [62]. The transmission system operator ESKOM[1] would like to get a more accurate estimate on the risk situation in different time periods. They intend to use the developed risk-based method both for planning as well as operation reliability studies on their transmission system.

The method is general and can be applied to any network –distribution as well as transmission network. Depending on the geographical location of the studied network, the present external factors causing the time dependencies in component failures need to be identified and failure statistics for different time periods must be collected.

The modeling approach has been tested on a bulk network for reliability assessments. It can be concluded that the presented approach gives the same estimated results as conventional Monte Carlo simulation approaches. The different is that the new proposed method significantly reduces the computation time compared with the conventional sequential Monte Carlo simulations.

[1] ESKOM is one of the biggest electricity utilities in the world. It is a state owned utility that owns the transmission grid and a large part of the distribution grids and generation.

7 Conclusions

The project aims to study the connection between the technical and financial risks for a distribution system operator (DSO). The technical risks may cause power interruptions that, depending on the quality regulation imply financial risks for the DSO. The objective of this project is two folded: The first objective is to develop risk-based methods for reliability investments under a performance-based regulation. The second objective is to investigate the impact that different regulations have on the incentives for the DSO to invest.

The direct controls in the quality regulation that imply financial risks for the DSO are reward and penalty schemes (RPS) and guaranteed standards (GS). RPS implies a quality adjustment on the DSO’s revenue frame and GS implies obligations to pay compensations to customer that have suffered long interruptions; compensation costs that many times not are allowed to be covered by revenues.

The share factor describes what fraction of the change in customer interruption costs due to an investment that is included in the RPS. In the current Swedish regulation a share factor of 0.5 is used together with a capped RPS type. Using a share factor of less of 1 dilutes the incentives for a DSO to invest in reliability. The case study in the report shows that a share factor of 0.5 can make socioeconomically beneficial investments not profitable for a DSO. Furthermore, in order to obtain a socioeconomically efficient RPS, a necessary but maybe not sufficient condition is that the share factor is 1. Results from the case studies also show that when having a share factor of 1 the collective and selective quality regulations become more equal in size.

The regulation should aim to limit the DSOs financial risk due to extreme situations and decrease unnecessary tariff variations for customers. Using multi-year indices is in the case study found to be better regarding these aims than using a capped or a dead band scheme.

Regarding uncertainties in the regulation, it is more likely that customer interruption costs will increase rather than decrease in the future. For example, in the road map for future distribution systems 2030 the Technical Research Center of Finland (VTT) assumes that the customer interruption costs will double. Arguably, this will lead to higher costs due to RPS and GS and thus that investments in reliability will become more profitable for DSOs and society. Also possible climate changes causing more severe weather in the future [63] will make investments in reliability more profitable. Thus, several uncertainties affect in the same direction. A method for how to include the regulatory uncertainty is presented by formulating possible future scenarios for how the regulation may develop. For these scenarios the robustness of investment strategies are analyzed.

More and more advanced risk-based methods are used in the field of power system reliability. One driving factor behind this development is plausibly the evolution of regulation. Regulation is becoming more complex, calling for more complex analysis methods in order to capture the financial risk the DSO is exposed to. Also the increasing computational capacity makes it possible to adopt more detailed and complex methods.

The risk-based method used for the case studies in this report is based on time-sequential Monte Carlo simulation. The method gives accurate and detailed results but is also computationally heavy. Therefore, as a part of the project a simplified method that can be used for larger networks has been developed in cooperation with University of Cape Town. The simplified method cuts calculation time while still preserves the overall structure that accounts for time-dependencies.

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Appendix A

This appendix defines the indices calculated on system level.

The notations used in the definitions are:

λ_i : Interruption frequency at load point $\boldsymbol{i}$

$\boldsymbol{N_i}$: Number of customers at load point $\boldsymbol{i}$

$\boldsymbol{U_i}$: Annual unavailability or outage time at load point $\boldsymbol{i}$

$\boldsymbol{P_i}$: Average load demand at load point $\boldsymbol{i}$

$\boldsymbol{nrLP}$: Number of load points in the considered system

Note that the four first definitions can be defined per load point and sector.

Customer-based reliability indices:

SAIFI - System Average Interruption Frequency Index $= \dfrac{\sum_{i=1}^{nrLP} \lambda_i N_i}{\sum_{i=1}^{nrLP} N_i}$

SAIDI - System Average Interruption Duration Index $= \dfrac{\sum_{i=1}^{nrLP} U_i N_i}{\sum_{i=1}^{nrLP} N_i}$

CAIDI - CustomerAverage Interruption Duration Index $= \dfrac{\sum_{i=1}^{nrLP} U_i N_i}{\sum_{i=1}^{nrLP} \lambda_i N_i}$

Load-based reliability indices:

ENS - Expected Energy Not Supplied $= \sum_{i=1}^{nrLP} P_i U_i$

PNS - Expected Power Not Supplied $= \sum_{i=1}^{nrLP} P_i \lambda_i$

The average annual interruption cost is defined as:

ECOST - Expected Customer Interruption Cost $= \mathrm{E}(cic(\tau))$

Appendix B

Using the definitions in Appendix A it can be shown that the sector-specific index cost model based on SAIDI and SAIFI give similar results as the sector-specific index cost model based on ENS and PNS. In this appendix we show that the customer interruption cost ($\boldsymbol{cic}(\tau)$) will at least be approximately be the same for the two different cost models.

Two different ways to calculate the customer interruption cost exist. If the customer interruption cost is calculated per load point and sector and then summed the results will be identical. However, if the customer interruption cost is calculated per sector (and not per load point) the results will identical only if the load and number of customers per sector and load point are identical. If the loads and number of customers per load point are similar the results will be similar.

Approach 1: Calculate $\boldsymbol{cic}(\tau)$ per load point and sector

$$\boldsymbol{cic}(\tau)=\sum_{S=1}^{nrS}\boldsymbol{cic}^{S}(\tau)=\sum_{S=1}^{nrS}\sum_{i=1}^{nrLP}\boldsymbol{cic}_i^{S}(\tau)=\underline{\underline{\sum_{S=1}^{nrS}\sum_{i=1}^{nrLP}\left(\mathrm{SAIDI}_i^S\,\boldsymbol{P}_i^S\,\boldsymbol{P}_E^S+\mathrm{SAIFI}_i^S\,\boldsymbol{P}_i^S\,\boldsymbol{P}_W^S\right)}}=$$

$$=\sum_{S=1}^{nrS}\sum_{i=1}^{nrLP}\left(\frac{\boldsymbol{U}_i^S\boldsymbol{N}_i^S}{\boldsymbol{N}_i^S}\boldsymbol{P}_i^S\,\boldsymbol{P}_E^S+\frac{\lambda_i^S\boldsymbol{N}_i^S}{\boldsymbol{N}_i^S}\boldsymbol{P}_i^S\,\boldsymbol{P}_W^S\right)=\sum_{S=1}^{nrS}\sum_{i=1}^{nrLP}\left(\boldsymbol{U}_i^S\boldsymbol{P}_i^S\,\boldsymbol{P}_E^S+\lambda_i^S\boldsymbol{P}_i^S\,\boldsymbol{P}_W^S\right)=$$

$$=\underline{\underline{\sum_{S=1}^{nrS}\sum_{i=1}^{nrLP}\left(\mathrm{ENS}_i^S\,\boldsymbol{P}_E^S+\mathrm{PNS}_i^S\,\boldsymbol{P}_W^S\right)}}$$

Approach 2: Calculate $\boldsymbol{cic}(\tau)$ per sector

$$\boldsymbol{cic}(\tau)=\sum_{S=1}^{nrS}\boldsymbol{cic}^{S}(\tau)=\sum_{S=1}^{nrS}\left(\mathrm{SAIDI}^S\,\boldsymbol{P}^S\,\boldsymbol{P}_E^S+\mathrm{SAIFI}^S\,\boldsymbol{P}^S\,\boldsymbol{P}_W^S\right)=$$

$$=\sum_{S=1}^{nrS}\left(\frac{\sum_{i=1}^{nrLP}\boldsymbol{U}_i^S\boldsymbol{N}_i^S}{\sum_{i=1}^{nrLP}\boldsymbol{N}_i^S}\sum_{i=1}^{nrLP}\boldsymbol{P}_i^S\boldsymbol{P}_E^S+\frac{\sum_{i=1}^{nrLP}\lambda_i^S\boldsymbol{N}_i^S}{\sum_{i=1}^{nrLP}\boldsymbol{N}_i^S}\sum_{i=1}^{nrLP}\boldsymbol{P}_i^S\boldsymbol{P}_W^S\right)$$

Assume that all $\boldsymbol{N}_i^S$ are similar and all $\boldsymbol{P}_i^S$ are similar, then

$$\frac{\sum_{i=1}^{nrLP} U_i^S N_i^S}{\sum_{i=1}^{nrLP} N_i^S} \sum_{i=1}^{nrLP} P_i^S \approx \sum_{i=1}^{nrLP} U_i^S P_i^S = \mathrm{ENS}^S$$

and

$$\frac{\sum_{i=1}^{nrLP} \lambda_i^S N_i^S}{\sum_{i=1}^{nrLP} N_i^S} \sum_{i=1}^{nrLP} P_i^S \approx \sum_{i=1}^{nrLP} \lambda_i^S P_i^S = \mathrm{PNS}^S$$

Appendix C

Number of customers for the test systems SRRTS and SURTS and annual electricity consumption per customer are given in Table 6. Line lengths for the two test systems are given in Table 7.

Table 6: Number of customer per sector for SRRTS and SURTS and electricity consumption per customer

	SRRTS	SURTS	
	Number of customers	Number of customers	Annual electricity consumption [MWh/cust]
Residential, urban	0	10799	6.82
Residential, rural	627	0	8.84
Industrial	38	180	119.72
Commercial	61	1016	72.60
Agricultural	187	0	9.15
Governmental	30	300	28.37

Table 7: Line lengths [km] for SRRTS and SURTS. OH is Overhead Lines

	SRRTS	SURTS
Uninsulated OH	26.1	0
Insultated OH	5.4	0
Cables	14.7	97

Appendix D

The fixed restoration cost per failure for different component types are given in Table 8.

Table 8: Fixed restoration cost per failure for different component types

Component	Fixed restoration cost per failure [SEK]
Transformer (40/10 kV or 130/10 kV)	200 000
Busbars (40 or 130 kV)	50 000
Busbars (10 kV)	25 000
Transformer substations	24 000
Polemounted transformers	12 000
Cable	61 000
Insulated lines	8400
Uninsultaed lines	2500
Breakers (MV)	30 000
Breaker (HV)	100 000

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