Reliability in Performance-Based Regulation

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Abstract

In reregulated and restructured electricity markets the production and retail of electricity is conducted on competitive markets, the transmission and distribution on the other hand can be considered as natural monopolies. The financial regulation of Distribution System Operators (DSOs) has in many countries, partly as a consequence of the restructuring in ownership, gone through a major switch in regulatory policy. From applying regulatory regimes where the DSOs were allowed to charge their customers according to their actual cost plus some profit, i.e. cost-based regulation, to regulatory models in which the DSOs performance are valued in order to set the allowable revenue, i.e. Performance-Based Regulation (PBR). In regulatory regimes that value performance, the direct link between cost and income is weakened or sometimes removed. This give the regulated DSOs strong cost cutting incentives and there is consequently a risk of system reliability deterioration due to postponed maintenance and investments in order to save costs. To balance this risk the PBR-framework is normally complemented with some kind of quality regulation (QR). How both the PBR and QR frameworks are constructed determines the incentive that the DSO will act on and will therefore influence the system reliability development.

This thesis links the areas of distribution system reliability and performance-based regulation. First, the key incentive features within PBR, that includes the quality of supply, are identified using qualitative measures that involve analyses of applied regulatory regimes, and general regulatory policies. This results in a qualitative comparison of applied PBR models. Further, the qualitative results are quantified and analysed further using time sequential Monte Carlo simulations (MCS). The MCS enables detailed analysis of regulatory features, parameter settings and financial risk assessments. In addition, the applied PBR-frameworks can be quantitatively compared. Finally, some focus have been put on the Swedish regulation and the tool developed for DSO regulation, the Network Performance Assessment Model (NPAM), what obstacles there might be and what consequences it might bring when in affect.
Abstract

*Keywords*: Performance-Based Regulation, Distribution System, Power System Reliability, Monte Carlo Simulations, Quality of Supply, Network Performance Assessment Model.
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Chapter 1

Introduction

The need for more efficient methods to regulate Distribution System Operators (DSOs) is a result of the significant restructuring of the electricity markets that has taken place during the last two decades. Many electricity markets all over the world are re-regulated, generation and retail of electricity is conducted in a competitive environment with market-based solutions, and a greater number of customers have access to a larger number of power producers. The competition in the power production has changed conditions for the former vertically integrated utilities dramatically. In some markets, like in the Nordic system for instance, retail and production is totally separated from transmission and distribution. So while the electricity is traded on the common Nordic market Nordpool, the grid activities can still be considered to be natural monopolies. However, the restructuring of the electricity market has lead to changes in the transmission and distribution grids’ ownership. Even though all DSOs are not profit maximising, the general trend is that the corporate ownership has changed due to extensive mergers and acquisitions of small community or municipality owned grids into large corporations, which has for many networks changed the fundamental corporate agendas. Mainly, the focus has somewhat switched from function towards profit.

DSOs conduct a monopoly activity, from a socio-economic point of view it is not feasible to connect the customers by more than one connection. To control the monopoly activity the authorities apply economic regulation onto the DSOs. The economic regulation has a dual purpose; it should not only protect the customers by keeping the DSOs from exploiting their monopoly situation, but also protect the regulated DSOs in such sense that they are enabled to attract investments thereby able to conduct good business. This is a delicate task given to the regulator and the methods that are used for DSO regulation varies significantly. The restructuring within ownership of the DSOs has increased the
need for more efficient methods to conduct DSO regulation and the international
trend within regulation of electric distribution is to promote efficiency through
incentives with regulatory measures [1]. This trend means a switch of focus,
from actual costs to the actual performance, i.e. Performance-Based regulation
(PBR). This is conducted in order to apply competitive conditions. The
performance is usually valued by economic efficiency and quality performance.
The purpose of including the quality of supply in the regulatory framework is to
mitigate the strong cost cutting incentives that can be the result of regulation
based on economic efficiency, which otherwise could lead to decreased
maintenance and investments.

The task of balancing the economic efficiency, the quality of supply, the
customers’ interests and at the same time keeping the grid business interesting to
investors is in no sense easy. How the regulatory framework is formulated and
applied determines the incentives that the regulated DSOs has to act on and will
therefore influence the future grid development. One of the most, if not the
most, important feature regarding incentives for the DSOs to act on, within the
PBR framework, is the regulation of the quality performance, henceforth called
quality regulation. Relevant questions regarding grid development are therefore:

- What incentives for grid investments and maintenance are the
  regulated DSOs given through the regulatory framework in general
  and the quality regulation in particular?

- Consequently, to what extent and how will this affect the future
  reliability and availability in the distribution systems?

This thesis will address these issues both from a general point of view and
specifically in form of an in-depth analysis of the main key incentive features.

1.1 Research background

When considering reliability in performance-based regulation, there are two
separate areas: methods for calculating and assessing the reliability in
distribution systems and methods to regulate DSOs based on their performance.
Reliability analysis is based on the stochastic nature of technical systems. PBR
on the other hand contains both technical as well as economical features,
reliability analysis can be one important part of the technical issues. This indicates on both great diversity as well as strong connections between the areas.

Previous research on reliability in technical power systems has been rather extensive, and methods for reliability analysis developed within other areas have been applied to power systems. Historically, the vast development has been within analytical reliability methods. Within power systems the focus has been on system adequacy, mainly including production units and transmission constraints. The reason for focusing on this area is mainly due to the economics at stake compared to interruptions within distribution systems. However, the main reason for customer interruptions is the distribution systems, and even though the methods suitable for calculating reliability within distribution systems are well developed, the applied research is somewhat limited due to the limited supply of recorded reliability data for typical distribution system components. Power systems are usually rather reliable and system failures are rather rare, which makes the average outage values rather misleading since the average year never occurs. One way to comprehend the annual variations in system performance, since analytical calculation becomes to extensive and complicated, is to use stochastic simulation models such as Monte Carlo simulation (MCS) methods. Since these simulation methods usually demand a significant amount of computer capacity, the development has been gradual. The analytical reliability assessment methods and the MCS method applied in this thesis can be found in [2] - [4] and [5] - [9] respectively.

The research on economic regulation has followed its development and implementation. The research within economic theory is quite extensive, [10] - [13] to name but a few. The power sector is neither the first nor the last sector to go through a restructuring process or the only sector that needs to be subjected to economic regulation. Various means for economic regulation has been applied in sectors that show some resemblance to the electric distribution sector. However, even though the profound ideas of the economic regulations are the same, no situation is the other alike, and the regulation of DSOs is somewhat unique in terms of capital costs, the customers’ willingness to pay and the limited potential of the conceivable substitutes. The research on economic regulation of DSOs in general and PBR in particular is now common and widely spread mainly due to the fact that many countries are applying or have plans to subject their DSOs to some kind of PBR. In this section, some selected geographical area in which PBR or some kind of competitive regulation has been applied are described in brief terms. Some of the sometimes extensive research activities related to each area are used as references. The research is usually such that the researchers/authors are active within the geographical areas
they are describing. The geographical areas not included here do not exclude usage of PBR, but published research from other areas is limited.

**South America.** The re-regulation within the electricity sector started in Chile in 1982 and other Latin American countries have followed. The main method, presented in research papers, for DSO regulation is yardstick competition where reference companies are developed in order to calculate the regulated DSOs’ price caps. Even though there’s usually no direct quality features in the models, the results have been decreased loss levels, increased supply coverage and lower tariffs thus more efficient and better performing DSOs. As it seems, Chile is the leading nation, where most research within the DSO regulation and yardstick competition has been conducted [14], [15].

**USA.** 39 of 50 states in the US have to some extend re-regulated their electricity market (2004) [16]. There is basically one regulatory authority for each state, as well as a Federal Energy Regulatory Commission (FERC), which makes it hard to be brief and specific concerning their use of PBR. In general it seems more common in the US that the performance of the DSOs is measured on individual customer level, i.e. electricity is considered to be a commodity like any other that the customers can order at a certain specified quality level, which means the individual reliability insurances based on performance-based rates are used. This has lead to more specified research on typical contracts, general regulatory framework terms and risk management within PBR [17], [18].

**Europe** has experienced extensive re-regulation of its electricity markets and in the backwaters of the re-regulation various kinds of performance-based regulation models have been developed and applied. The UK [19] - [21] was somewhat of a pioneer in applying performance-based price caps. Soon to follow was Norway [22] - [27] who applied DEA (Data Envelopment Analysis) benchmarking as efficiency indicator in its regulation, at first without quality features, but the CENS (cost of energy not supplied) was introduced for the second regulatory period. After that many European countries have introduced performance-based revenue or price caps such as the Netherlands [28] - [31], Sweden [32] - [37], Spain [38] - [42] and Finland [43] - [45] to name but a few. Quite extensive research on both each regulatory model as well as the fundamental theory on which the models are founded has been conducted.
1.2 Outline

Chapter 2 gives a basic description on reliability analysis in general and applied to power systems and electric distribution in particular. The methods described are both analytical as well as based on simulation such as Monte Carlo methods. The basic impact of the power protection system and its devices is briefly described. The deviations between the different approaches are illustrated in numerical examples.

Chapter 3 describes the general terms of DSO regulation including cost-based and performance-based methodologies. Within PBR there are basically two main areas; the efficiency regulation and the quality features in the regulation. Further, some basic ideas and methods for efficiency benchmarking are described, but the main contribution and the focus in this chapter is the generalised regulatory process and the key incentive features within PBR that constitute the foundation for the structure analysis methodology presented in chapter 4 and 5.

Chapter 4 describes four different PBR-model, Swedish, Norwegian, Spanish and the Dutch, with focus on the quality regulation. The chapter also presents a qualitative comparison of the described PBR-model based on the key incentive features presented in the previous chapter.

Chapter 5 holds a more in-depth analysis of reliability incentives in PBR in form of practical applications based on actual regulatory frameworks. The analysis is a comparative study based on chapter 3 and 4, using the methods and simulation model described in chapter 2. The main contributions of this thesis are presented in this chapter, which is the structured analysis approach of key incentive features and methods to analyse the impact different regulatory frameworks.

Chapter 6 concludes the analysis conducted in chapter 5 and describes possible impacts of the setting of the key incentive feature configuration. Moreover, how the results of this thesis can be used for future work on risk analysis and risk management within PBR is described.
1.3 **Main contributions**

The main contributions of the thesis constitutes within the way to structure the reliability and quality aspects of performance-based regulation. Listed as specified points they are:

I. An overview of performance-based regulation methods with focus on quality features and the regulation of the quality of supply.

II. A structured analysis of the processing and flow of information within the regulatory process of quality regulation.

III. Identification and analysis of the key incentive features within Performance-Based Regulation in general and within the quality regulation in particular.

IV. A qualitative and quantitative comparative analysis of applied and theoretical regulatory frameworks and general regulatory methodologies based on performance and quality of supply for DSO regulation.

V. An in-depth analysis of the long- and short-term implication that the Network Performance Assessment Model gives concerning future quality of supply for Swedish Distribution Systems Operators when used as a regulatory tool.

1.4 **List of publications**

Some of the results in this thesis have been published in the publications below.


Chapter 3 and 4 contains analyses similar to these published in [48] and [49], a similar quantitative comparison as the one in chapter 5 is published in [47]. Chapter 6 holds conclusions from all publications as well as some yet unpublished. The direction of the future work in chapter 6 is published in [46].
Chapter 2

Distribution System Reliability

In the context of power systems, distribution systems are usually considered the simplest kind of power systems, but none the less rather complex. Historically, the most attention, regarding reliability analysis, has been put into power generation rather than into distribution system reliability [2]. The main reason is the cost quantities associated with system failures. While outages in power generation can have great impact on a wide area as well as catastrophic environmental impact, outages in distribution systems has local impact. However, distribution system failures is the main cause for customer unavailability and due to increased sensitivity for the customers and switched focus within regulatory regimes the distribution system reliability is of more interest now than ever. This chapter describes basic methodologies for distribution system reliability applied in this thesis. The fundamental reliability theory used in the thesis can be found in [3], [4], section 2.1 – 2.2 and [2], section 2.31 – 2.3.3.

2.1 Reliability theory

The reliability of a component or a system of components refers to its ability to perform a required function, under given environmental and operational conditions and for a stated period of time [3]. This definition can be found in standards like [51], [52], it gives a broad aspect in terms of function but is also precise in stating the condition under which a certain reliability level can be expected. The characteristics of a system depends partly on its components, thus there are system and component reliability respectively.
2.1.1 System reliability

A system contains one or several subsystems of components, henceforth called items, interconnected so that the system is able to perform a number of required functions. The reliability of the system denotes the relationship between the systems required performance and its achieved performance. The probabilistic approach of the system’s reliability deals with the uncertainty of this relation. To prevent system failures, e.g. failures that prevents the system from performing any of its supposed functions, the potential failures should be identified. This can be performed using various methods such as; FMEA/FMECA (fault modes, effects and (critical) analysis), fault tree analysis, cause and effect diagrams, Bayesian belief networks, event tree analysis and reliability block diagrams [3]. In section 2.3.4, the FMEA method is used for system evaluation.

However, in order to use any of these methods the characteristics of the system’s items must be known. In systems where the item failures are considered to be uncorrelated, each component can be analysed separately. If the item failures are correlated, calculation on the system reliability becomes rather complex. It is therefore very common to simplify the calculations by assuming that the events are uncorrelated, and to compensate for this assumption by modifying the input data. In this thesis the failure events are considered uncorrelated.

2.1.2 Item reliability

To describe an item’s characteristics in terms of reliability there are several functions that can be used. The failure rate function, \( z(t) \) describes the components tendency to fail, failures per time unit, for \( t \geq 0 \). However, the instantaneous failure rate at the time \( t_0 \) for functional items rate is called \( \lambda = z (t_0) \), the corresponding instantaneous repair rate for faulted items is called \( \mu \) [52]. The basic difference between the two is that the failure rate is the item’s behaviour while it is functional, and the repair rate determines the item’s correction cycle length while it is faulted. Otherwise, the two functions are treated in similar fashion mathematically. This means that the function that will

\[^1\] A failure of an item is the termination of its ability to perform required performance.
be defined based on the failure rate for functional items have a corresponding function for faulted components.

The probability density function, \( f(t) \), denotes a component's tendency to fail when the time \( t \) has elapsed:

\[
f(t) = z(t) \exp\left(-\int_0^t z(x)\,dx\right) \quad \text{for } t > 0 \quad 2.1
\]

The item's distribution function, \( F(t) \), describes the probability that the item has failed when the time \( t \) has elapsed, thus:

\[
F(t) = \Pr(T \leq t) = \int_0^t f(x)\,dx \quad \text{for } t > 0 \quad 2.2
\]

\( T \) is the item's time to failure, the time when it actually fails. The reliability function, \( R(t) \), denotes the probability that the item has not failed at the time \( t \), thus:

\[
R(t) = 1 - F(t) = \Pr(T > t) = \exp\left(-\int_0^t z(x)\,dx\right) \quad \text{for } t > 0 \quad 2.3
\]

When using the probability density function and reliability function to describe the failure rate function it can be expressed as:

\[
z(t) = \frac{f(t)}{R(t)} = -\frac{R'(t)}{R(t)} = -\frac{d}{dt} \ln R(t) \quad 2.4
\]

The Mean Time To Failure (MTTF) of an item denotes its expected lifetime. For repairable items, that means its expected time to fail:
Chapter 2  Distribution System Reliability

\[
MTTF = E(T) = \int_{0}^{\infty} f(t)dt = \int_{0}^{\infty} R(t)dt \tag{2.5}
\]

For a set of output variables \( x = \{x_1, \ldots, x_n\} \), the mean value, \( \nu \), will correspond to the expected value and can be calculated according to [4]:

\[
\nu = \bar{x} = \frac{1}{n} \sum_{j=1}^{n} x_j = E(x) \tag{2.6}
\]

The variance, \( \tau^2 \), of the output set, \( x \), is:

\[
\tau(x)^2 = \frac{1}{n-1} \sum_{j=1}^{n} (x_j - \bar{x})^2 = \frac{\sum_{j=1}^{n} x_j^2 - \frac{1}{n} \left( \sum_{j=1}^{n} x_j \right)^2}{n-1} \tag{2.7}
\]

The standard deviation of \( x \) is \( \tau(x) \). Equation 2.6 and 2.7 are very useful when saving output data in reliability simulations when using large quantities of samples. Since only the sum of the output and the sum of the squared output have to saved, the memory usage is kept to a minimum.

2.2  Distribution functions

In order to comprehend an item’s stochastic behaviour concerning its uptime, functional, and downtime, faulted, the item’s probabilistic behaviour can be represented using a distribution function. The most commonly used probability distributions are; binomial and geometric, exponential, the gamma, Weibull, normal, the lognormal, Birnbaum-Saunders and inverse Gaussian distribution [3]. The distributions functions relevant for the simulations in this project are described in this chapter.
2.2.1 The exponential distribution

The exponential distribution is the most commonly used to describe items’ probability density within reliability analysis due to its mathematical simplicity and the failure rate is considered to be constant,

\[ z(t) = \lambda \quad 2.8 \]

With this assumption, items are as good as new, for \( t > 0 \), which is a good assumption for items in their functional lifetime, i.e. on the bottom of the bathtub curve [3]. The exponential distributed probability density function is:

\[
 f(t) = \begin{cases} 
 \lambda e^{-\lambda t} & \text{for } t > 0, \lambda > 0 \\
 0 & \text{otherwise} 
\end{cases} \quad 2.9
\]

Hence, the reliability function of the item is

\[
 R(t) = \Pr(T > t) = \int_{t}^{\infty} f(x)dx = e^{-\lambda t} \quad \text{for } t > 0 \quad 2.10
\]

\( T \) denotes the time to failure. The mean time to failure and the variance of \( T \) are:

\[
 MTTF = \int_{0}^{\infty} R(t) dt = \int_{0}^{\infty} e^{-\lambda t} dt = \frac{1}{\lambda} \quad 2.11
\]

\[
 \text{var}(T) = \frac{1}{\lambda^2} \quad 2.12
\]
2.2.2 The lognormal distribution

An item’s time to failure, $T$, is said to be lognormally distributed with the variance $\sigma^2$ and the mean value, $\mu$, if $W = \ln(T)$ is normally distributed. The lognormal distribution is common to use for repair time distributions. When considering the repair rate it is natural to assume the repair rate is initially increasing which would imply that the probability of finishing the repair in a short interval is increasing. However, the longer the repair is taking, the more likely it is that the repair will take long time, hence the repair rate decreases on the long-term perspective.

As mentioned before the lognormal distribution is based on the normal distribution (Gaussian), which has the probability density:

$$f(t) = \frac{1}{\sqrt{2\pi} \cdot \sigma} e^{-\frac{(t-\mu)^2}{2\sigma^2}} \quad \text{for} \ -\infty < t < \infty$$ \hspace{1cm} (2.13)

Where the random variable $T$ is said to be normally distributed with the mean value $\mu$ and the variance $\sigma^2$, $T \sim N(\mu, \sigma^2)$ where $N(0, 1)$ is called the standard normal distribution function. The probability density function for the standard normal distribution is

$$\phi(t) = \frac{1}{\sqrt{2\pi}} e^{-\frac{t^2}{2}} \quad \text{for} \ -\infty < t < \infty$$ \hspace{1cm} (2.14)

and the distribution function of $T \sim N(\mu, \sigma^2)$ can be written as

$$F(t) = \Pr(T \leq t) = \Phi\left(\frac{t - \mu}{\sigma}\right) \quad \text{for} \ -\infty < t < \infty$$ \hspace{1cm} (2.15)

where

$$\Phi(t) = \int_{-\infty}^{t} \phi(x) dx$$ \hspace{1cm} (2.16)
This means that the probability density function for the lognormal distribution is

\[
f(t) = \begin{cases} 
\frac{1}{\sqrt{2\pi} \tau t} e^{-\frac{(\ln t - \nu)^2}{2\tau^2}} & \text{for } t > 0 \\
0 & \text{otherwise}
\end{cases}
\]

2.17

The mean time to failure and the variance of \( T \) can be written as:

\[
MTTF = e^{\frac{\nu + \frac{\tau^2}{2}}{2}}
\]

2.18

\[
\text{var}(T) = e^{2\nu} \left( e^{2\tau^2} - e^{\tau^2} \right)
\]

2.19

The reliability function of an item that has a log-normally distribution time to failure is

\[
R(t) = \Phi\left( \frac{\nu - \ln t}{\tau} \right)
\]

2.20

This means that the failure rate function is

\[
z(t) = -\frac{d}{dt} \left( \ln \Phi\left( \frac{\nu - \ln t}{\tau} \right) \right) = \frac{\phi((\nu - \ln t)/\tau)/\tau}{\Phi((\nu - \ln t)/\tau)/\tau}
\]

2.21

As mentioned earlier, the log-normal distribution is commonly used for repair times, so also in this project. The item’s Mean Time To Repair (MTTR), defined analogously to the MTTF, when the repair time is assumed to be log-normally distributed:

\[
MTTR = e^{\nu(t_d) + \frac{\tau(t_d)^2}{2}}
\]

2.22
Where $n(t_d)$ and $\pi(t_d)$ is the item’s expected repair time and its standard deviation respectively, $t_d$ denotes the downtime.

An item’s availability, $A$, can be defined as the fraction of the time that the item is functional. The availability is calculated as:

\[
A = \frac{MTTF}{MTTF + MTTR}
\]  

2.3 Power system reliability

Reliability assessments of power systems require detailed knowledge about the function of system’s components. The reliability refers to its ability to transfer a required amount of power from the power producers to the users at a certain degree of continuity and quality for a stated period of time, which means that it refers to the design of the system. The complexity of power system reliability originates in the many factors that can affect the power system’s function. However, the primary focus when conducting reliability studies on power systems is either on the system’s adequacy or on the system’s security. While the adequacy refers to the system’s capacity in form of congestions, transfer limits and overloads due the loss of components and the negative events that could result as a consequence, the system security denotes the system’s ability to perform as designed and therefore refers to the state of the system.

There are basically two system levels within most power systems, i.e. transmission and distribution systems. While the transmission systems are designed for transferring large amounts of power over wide areas to distribution systems and customers consuming large quantities of power, the distribution systems are designed for local distribution to many small and medium sized consumers. The distribution systems are therefore most often constructed with either radial or looped feeders. Looped feeders are used in urban areas and the advantage is that each load point can be fed from at least two separate routes. Radial feeding systems are most often used in rural areas, where the distance between the customers makes looped feeders economically unfeasible. In certain areas, where special demands are set on the availability, double feeding can be used, which generally gives the system higher availability. However, even if the
distribution system is constructed looped or with double feeder, it is most often operated as if it was constructed with radial feeders. The extra routes can be used to supply load points that are interrupted during a components failure, at which time the first hand choice of supply route would be disconnected. This means that the components within these kinds of distributions system are dimensioned for aggregated capacities of more than it is exposed to under normal operating conditions. This means that that the system security is of much more relevant than the adequacy when doing reliability analysis of distribution systems [56]. Off course, the design practice varies from country to country, but the described practice is valid for the Nordic countries [61], as well as most European countries.

### 2.3.1 Protection system

Within all power systems there are protection devices, where the main purpose of the protection systems is to protect the system’s components, sectionalize the system and isolate the faulted component. This means that the kind of protection devices that are operating within the system influences how the distribution system responds when a certain component fails to operate. The protection system basically consists of relays that trigger the breakers that break the short circuit current and thereby prevent system equipment from being damaged, and enables the sections outside the affected area to operate as normal. However, there are also fuses and disconnecters involved in the process, i.e.:

- **Breakers**, used to break short circuit currents and operating currents. Breakers can be remotely operated and has generally no limit in the number of times it can operate.

- **Disconnecters**, used to isolate faults are of two kinds; those that can be operated with the power on and those that cannot. Disconnecters can not be operated for short circuits.

- **Fuses**, used to protect certain equipment, has to be manually replaced or reset when triggered.

There are generally two kinds of faults in the components in power systems that are considered when doing reliability analysis, i.e. passive and active faults.
Active faults are those that trigger the protection system such as ground faults and short circuits, the passive fault are such faults that don’t give rise to a short circuit current, for instance, a breaker that opens spontaneous.

2.3.2 Distribution system reliability

When considering the general construction of distribution systems, i.e. operation, the faults that can occur, the protection system together with the fact that the unavailability of each component is very low, the assumption that faults cannot occur simultaneously on serial components, only on parallel components seems logical. The method chosen to analyse the reliability of distribution system is based on how a failure in a component affects the state of the system. Therefore each component failure is analysed from all load points. This fundamental theory, applied in this chapter can among others be found in [2]. A test system, henceforth denoted test system 1, has been developed and is used to illustrate the general ideas for analysing distribution system reliability:

Figure 2.1. Test system 1
Fig. 2.1 illustrates the feeder system of a typical [61], [62] distribution system, the feeder is basically a 10 kV system that is fed at 40kV and has both 10 and 0.4 kV load points. The 0.4 kV systems connected to each of the 10/0.4 kV transformer are not shown for simplicity reasons. As shown in fig. 2.1 the feeder is constructed as a looped feeder, but under normal operating conditions the disconnector closest to load point 6 (LP6) on line 13 (L13) is open, which means that the system is operated as two radial feeders. The infeed transformation from 40 to 10 kV is equipped with two transformers, but in order to decrease the losses in the system only one is operating at the time, except during repairs or maintenance when the system is switched to the other transformer. The basic configuration of the protection system is so that each feeder is equipped with a breaker, B6 and B7, to protect bus bar 2 (BB2). There is also a secondary protection for each transformer in form of breaker 4 and 5 (B4 and B5). The protection for BB1 is constructed analogously in order to protect the 40 kV-system from being affected by faults occurring on the 10 kV-system. Not shown in the figure are the disconnecters placed on both sides of each line and breaker, which enables the isolation of lines, breakers and bus bars. Also not shown in the figure are the redundant bus bars that can be used instead of BB1 and BB2 by simple switching manoeuvres, these are assumed to be fully automated. There are fuses located on both sides of the 10/0.4 kV-transformers for protection and preventing transformer faults to affect the rest of the system.

In order to illustrate how the system is operated in case of component failure, some operating times must be defined:

- **SwT**  Switching time  The time it takes the operator to find and isolate the fault, by use of disconnectors.
- **RT**  Repair time  The time it takes to make the faulted component operational, by repairing it.
- **RpT**  Replacement time  If the repair time is expected to take too long time, the component can be replaced instead of repaired.
- **RcT**  Reclosing time  In order to detect whether the fault is temporary or permanent the breakers auto reclose. If the fault is cleared after the reclosing sequence the system can be operated as usual.

Below, some typical faults that can occur in a distribution system are listed together with how the faults are dealt with. This will increase the understanding
for the reliability analysis. One important assumption that should be emphasised is that T1 is normally in operation and T2 is the backup transformer.

1) **Permanent ground fault on L5.** The fault triggers the relay that operates B6. During the time SwT LP1 – LP7 are affected. When the fault has been located L5 can be isolated by opening its disconnectors and LP5 – LP7 can be fed by closing the disconnector on L13.

2) **Permanent ground fault on L12.** The fault triggers the relay that operates B7. During the switching time LP8 – LP12 are affected. The fault is isolated by opening the disconnectors on L12. LP8 – LP11 can now be fed through the ordinary supply route while LP12 is affected during the time it takes to repair (repair time, RT).

3) **Permanent short circuit fault on T7.** The fuse located over T7 is triggered and LP7 is affected during the repair time or the time it takes to replace (replace time, RpT) the transformer. Since the repair time for transformers are rather long, the most common way to deal with transformer faults is either to replace it or rely on a backup transformer.

4) **Permanent short circuit fault on T1.** The fault will trigger B2, the re-closing sequence of B2 will show the operator that the fault is permanent, LP1 – LP12 will be affected during the switching time that will transfer the infeed to T2.

5) **Temporary fault on L10.** The fault will trigger B7, but the re-closing sequence of B7 will show that the fault was temporary and when re-closed continue the operation. LP8 – LP12 will be affected during the re-closing time (RcT).

6) **Active fault on B6.** The short circuit of B6 will trigger B4, LP1 – LP12 are affected during the switching time, during which B6 is isolated and the disconnector on L13 is closed so that LP1 – LP7 can be fed through the alternative supply route.
7) **Passive fault on B6.** The passive fault in B6 result in the opening of B6, no protection devices are triggered, LP1 – LP7 are affected during the switching time, during which B6 is isolated and the disconnector on L13 is closed so that LP1 – LP7 can be fed through the alternative supply route.

If the faults of the components in a system are assumed to be independent, each load point’s reliability is a function of its minimal cut set [3] connected in series. Hence, the minimal cut set consists of all items that have influence on the load point’s availability. For instance, the availability in LP 3, in test system 1 depends on the set of components, \( K = \{B1, B2, B4, B6, B7, BB1, BB2, L1, \ldots, L7, T1, T4\} \), as displayed in figure 2.1. Since we assume that no simultaneous faults occur on components in series, since the probability off that happening is considered vanishingly small, the failure rate of LP3 can be calculated by adding the failure rates for permanent and temporary fault of the items affecting the load point, i.e.:

\[
\lambda_{LP3} = \sum_{i \in K} \lambda_i
\]  

Where \( K \) is the minimal cut set. Equation 2.24 is valid for single components but can also be used the other way around. For example, components for which several kinds of faults can occur, e.g. passive and active faults, the total failure intensity can be divided so the component is represented as two separate items.

The expected outage time of LP 3, \( U_{LP3} \), is the sum of each outage time that the events in the minimal cut set causes multiplied by their occurrence frequency, i.e.:

\[
U_{LP3} = \sum_{i \in K} U_i = \sum_{i \in K} \lambda_i \times cT_i
\]  

\( cT \) is the correction time, which is the expected RT, RpT, SwT or RcT, depending parameter settings and the system’s configuration, how the components are located relative the load point and type of fault.
Even though only the forced outages are considered in this project, the maintenance duration of T1 and T2 is so significant that faults occurring simultaneously of components in parallel, B2 – B5, should be considered. Also, when T1 or T2 are replaced after a fault, the replacement duration is so long that fault occurring in the same parallel components during that time should be considered. These particular events are included in the reliability analysis as separate items. The expected failure rates and repair times for these second order events are calculated as follows [2]. Assume that we have two parallel components, 1 and 2, with the failure rates \( \lambda_1 \) and \( \lambda_2 \) (f/yr), the repair times \( r_1 \) and \( r_2 \) (h), the annual maintenance outage rate \( \lambda_{m1} \) and \( \lambda_{m2} \) (yr\(^{-1}\)) and annual maintenance outage duration \( m_1, m_2 \) (h) respectively. Then the expected failure rate for 1 and 2, \( \lambda_{12} \), with the corresponding expected repair time, \( r_{12} \), are:

\[
\lambda_{12} = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{1 + \lambda_1 r_1 + \lambda_2 r_2}
\]

\[2.26\]

\[
r_{12} = \frac{r_1 r_2}{r_1 + r_2}
\]

\[2.27\]

The expected forced failure rate occurring while one of component 1 or 2 is maintained, \( \lambda_{m12} \), with the corresponding expected outage duration, \( r_{m12} \), are:

\[
\lambda_{m12} = \lambda_{m1} (\lambda_2 m_1) + \lambda_{m2} (\lambda_1 m_2)
\]

\[2.28\]

\[
r_{m12} = \frac{\lambda_{m1} (\lambda_2 m_1) \frac{m_1 r_2}{m_1 + r_2} + \lambda_{m2} (\lambda_1 m_2) \frac{m_2 r_1}{m_2 + r_1}}{\lambda_{m12}}
\]

\[2.29\]

### 2.3.3 System reliability performance indicators

System reliability indices indicate the system performance, or more precisely, the system’s shortcomings in form of undelivered energy, the average number of interruptions and the average outage duration. There are generally two types of indices that are used to indicate power system performance: Customer-weighted
and capacity-weighted. The indices relevant to this thesis are presented in equations 2.30 – 2.36. $U_j$ refers to the unavailability (h/yr), $\lambda_j$ the failure rate (f/yr), $N_j$ the number of customers and $P$ the average capacity demand (kW) in load point $j$.

\[
\text{System Average Interruption Duration Index} = \frac{\sum_{j \in M} U_j N_j}{\sum_{j \in M} N_j} \quad 2.30
\]

\[
\text{System Average Interruption Frequency Index} = \frac{\sum_{j \in M} \lambda_j N_j}{\sum_{i \in M} N_j} \quad 2.31
\]

\[
\text{Customer Average Interruption Duration Index} = \frac{\sum_{j \in M} U_j N_j}{\sum_{j \in M} \lambda_j N_j} \quad 2.32
\]

\[
\text{Customer Average Interruption Frequency Index} = \frac{\sum_{j \in M} \lambda_j N_j}{\sum_{j \in K} N_j} \quad 2.33
\]

\[
\text{Average System Interruption Duration Index} = \frac{\sum_{j \in M} U_j P_j}{\sum_{j \in M} P_j} \quad 2.34
\]

\[
\text{Average System Interruption Frequency Index} = \frac{\sum_{j \in M} \lambda_j P_j}{\sum_{j \in M} P_j} \quad 2.35
\]

\[
\text{Energy Not Supplied} = \sum_{j \in M} P_j U_j \quad 2.36
\]

$M$ is a set containing all of the system’s load points, $K$ is a set containing those load points that have been affected by at least one interruption.
2.3.4 Analytical system analysis

FMEA (failure modes, effects, and analysis), is a structured way to analyse a system. The technique is primarily qualitative, but can be quantified as in this case. The effects or consequences of individual component faults are systematically identified by analysing what happens if the fault occurs [57]. FMEA is a bottom-up approach that considers one fault mode at the time, which makes the method hard to apply to system containing large amounts of redundancy. It is a light-handed version of FMECA (failure modes, effects, and criticality analysis). In FMECA, the identified fault modes are ranked according to the risk associated with each fault mode. The FMEA method is one of the first systematic techniques for failure analysis and does not require any advanced analytical skills. However, it does require system understanding and knowledge about the constraints under which the system operates [3]. The approach applied in the thesis is described in figure 2.2, as shown in figure 2.2 the first steps are the same as in the stochastic simulation method, section 2.3.5, i.e. the events included in the two methods are the same. The events considered relevant here are basically in the first order events and the second order events, considered earlier in about the sub-station (section 2.3.2). The relevant failure modes are listed in a FMEA worksheet, the design of the worksheet is up to the user. One example of such worksheet is presented in the numerical examples in section 2.4.

1. Event identification

2. Event probability with corresponding duration times to reset the system, both partly and mainly (switching and repair).

3. Assign each event a consequence, i.e. which LPs are affected and for how long (annually).

4. Sum up the annual outage rate, \( \lambda_{LP} \), and outage duration, \( U_{LP} \), for each LP.

5. Calculate the expected system performance or cost of interruptions etc.

Monte Carlo simulation

\[ \text{Figure 2.2. FMEA flow chart} \]
2.3.5 Stochastic simulation models

The behaviour of a distribution system is stochastic, it is therefore necessary that the methods used to analyse the distribution system reliability respond well to this behaviour, i.e. probabilistic methods. In order to comprehend events or series of events that occur very seldom but can have severe impact on the system’s functions and can therefore cause great financial cost, methods such as Monte Carlo simulations (MCS) or Markov chains are preferable compared to analytical methods. However, Markov chains models have a tendency to become rather cumbersome [46] for large systems and are limited in such sense that the system’s items must have exponentially distributed failure and repair rates. MCS methods on the other hand are preferably used for large systems when analytical methods become too complicated and in situations when the output variance is of interest, for instance when performing risk evaluations.

The general concept of MCS methods is to use random numbers to generate the system’s possible states, this process is performed for a sufficient number of times in order comprehend the system’s stochastic behaviour sufficiently. In the MCS performed in this thesis the random numbers are used to simulate each event’s up and down time, i.e. the component’s time to failure, $T$, and time to correct the fault, $RT$, $RpT$, $SwT$ or $RcT$, the system’s down time. These events are assigned reliability distributions and input parameters. The reliability function, equation 2.10 and 2.20, of each events can then be used backwards to transform the random number into a time duration of a certain activity, e.g. $T$, $RT$, $RpT$, $SwT$ or $RcT$. The transformation process is displayed in figure 2.3.

![Figure 2.3. Sampling of $T$ or $cT$ based on random numbers](image)

The rather simple structure of distribution systems in terms of radial operation enables the use of the straightforward reliability assessment approach described in section 2.3.2 to be adopted into the MCS, figure 2.2. This is relevant since the effort to minimise the simulation time for each sample will decrease the total simulation time significantly, which enable better results to be generated. In this context, one sample refers to one isolated period with the length $T_0$. The
The simulation method used is called time sequential simulations [6]. The relevant fault events are represented in continuous time, these events the first order faults and some second order faults, described in section 2.3.2. Both temporary and permanent faults are relevant in the analyses since both outage frequency and duration are value in the interruption cost (IC) estimations. The different types of faults are included as separate events, equation 2.24. This representation, where second order faults are included as separate events and different types of fault can occur for each component it is essential that only one event can occur at the time. The events are therefore also considered to be uncorrelated. In the method applied, it is possible for fault events to overlap. If two events, that have impact on the same LPs, would overlap the effect would be that the events would be registered separately and thereby over estimate the outage duration as well as the frequency for the common LPs. However, the probability that this will happen is so small that the effects on the result due to this of mismatch in the time sequence is ignored. This is not a problem for overlapping events that have impact on different LPs. The fundamental MC-methodology originates for a technique developed by Billinton and Wang [5], it has however been further developed and significantly adjusted to fit the assigned tasks of this project. The MCS algorithm used in this thesis is described in the flow chart in figure 2.4 and is followed by a more detailed description. In figure 2.4, $T_0$ is the length of each sample in hours and $N$ is the number of predetermined samples. One simplification made in this MCS is that all the system’s components are assumed to be working in the beginning of each sample.
1. Start, $n = 1$

2. Generate $T$ for each event

3. Determine the event with the minimum $T$

4a. Generate $RT/RpT$ and $SwT$

4b. Generate $RcT$

5. Outages logged.

6. Assign new $T$ to the occurred event

7. $t > T_0$

8. Logging of reliability performance indicators and interruption costs for sample $n$

9. $n < N$

10. Data evaluation

Figure 2.4. MCS algorithm flow chart
where each step of the MCS algorithm can be described in more details as follows:

1. Simulation starts, \( n = 1 \).

2. Random numbers (0…1) for each event are generated, these are converted into times to failure, \( T \), based to the failure time distribution and the expected time to failure assigned to each event.

3. The event with the minimum \( T \) is determined.

4a. For events that include a permanently faulted component two correction times are needed, hence random numbers (0…1) are generated and converted into a RT or a RpT and a SwT. Whether the faulted component is repaired or replaced is set as input criterion for each component in the distribution system configuration.

4b. Events that include a temporary faulted component only one correction time is needed and consequently one random number (0…1) is generated and converted into a RcT according to predetermined RcT distribution.

5. The outage duration for each affected load point is recorded and added to the load point summation for simulated sample. Also, the number of outages for each LP is updated in order to record the interruption frequency for the simulated sample.

6. A new random number (0…1) is generated and converted into new \( T \) for the just occurred event. This \( T \) is added to the event’s previous \( T \) and its RT, RpT or RcT. The counted time up to the point system restoration is set to the total simulation time of the current sample.

7. If the total simulation time, \( t \), is less than the predetermined sample time, \( T_0 \), the procedure is repeated from step 2.
8. If not, the number of outages and total outage duration for each load point are recorded and sorted to enable evaluation of those indices that are of interest\(^2\).

9. If the number simulated samples, \(n\), is less than the predetermined number \(N\) for the required number of samples, the algorithm is repeated from step 2.

10. Data processing, the main data processing is conducted and evaluated.

The system complexity and purpose of the analysis determines how to choose the number of samples \(n\), and the sample time \(T_0\). In this thesis \(T_0\) was set to 8760 h and 3×8760 since it corresponds to the length of the regulatory period for quality in the analysed regimes. The number of samples required for an adequate result depends on the size of the system together with the component’s reliability, the more unlikely the components are to fail, the more samples are needed to comprehend the system behaviour [54]. Distribution system are to some extent what is known as duogen system [54], which means that of two conditions for each load point, connected or disconnected, one is very dominating. Consequently, the number of samples needed to receive a sufficiently accurate result when using simple sampling strategy is quite high. In order to decrease the number of samples one can use methods to reduce the variance such as stratified sampling and weighted sampling [6]. This will not however be included in this thesis.

### 2.4 Numerical examples

First, the basic reliability evaluation theory presented in section 2.3 will be presented in form of a FMEA process of the test system, which has been

\(^2\) The reason for processing data for each sample is that depending of what is evaluated combinations of indices and load point specific data is necessary, which makes system mean value and variance of interruption frequency and duration inadequate. Also, the evaluation might include index thresholds that requires more detailed data.
introduced in section 2.3.4. Then, the stochastic simulation model presented in section 2.3.5 will be applied to the same system which will illustrate how more information and features can be comprehended into the analysis when MCS are used.

2.4.1 Example 1

A basic FMEA process is applied to test system 1, this is presented in table 2.1. The basic structure is to list the fault that can occur in the system, how the protection system deals with these fault and the system impact of each fault, i.e. which kind of operation that affects each LP. Table 2.1 lists the relevant faults and their system impact.
Table 2.1. FMEA worksheet for test system 1.

<table>
<thead>
<tr>
<th>Event no.</th>
<th>Component</th>
<th>V (kV)</th>
<th>Event type</th>
<th>Protection</th>
<th>System impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Passive, Active</td>
<td>Permanent, Total</td>
<td>Triggered unit**</td>
</tr>
<tr>
<td>1</td>
<td>T1 or T2</td>
<td>40/10</td>
<td>T</td>
<td>P</td>
<td>B2/B3</td>
</tr>
<tr>
<td>2</td>
<td>T1 or T2</td>
<td>40/10</td>
<td>T</td>
<td>T</td>
<td>B2/B3</td>
</tr>
<tr>
<td>3</td>
<td>T3</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT3</td>
</tr>
<tr>
<td>4</td>
<td>T4</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT4</td>
</tr>
<tr>
<td>5</td>
<td>T5</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT5</td>
</tr>
<tr>
<td>6</td>
<td>T6</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT6</td>
</tr>
<tr>
<td>7</td>
<td>T7</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT7</td>
</tr>
<tr>
<td>8</td>
<td>T8</td>
<td>10/0.4</td>
<td>T</td>
<td>P</td>
<td>FT8</td>
</tr>
<tr>
<td>9</td>
<td>T1 + T2</td>
<td>25842</td>
<td>T</td>
<td>P</td>
<td>B2/B4</td>
</tr>
<tr>
<td>10</td>
<td>B2/B4 + T1/T2</td>
<td>40, 40/10</td>
<td>T</td>
<td>T</td>
<td>B1</td>
</tr>
<tr>
<td>11</td>
<td>B3/B5 + T1/T2</td>
<td>10, 40/10</td>
<td>T</td>
<td>P</td>
<td>B2/B4</td>
</tr>
<tr>
<td>12</td>
<td>T1 + T2</td>
<td>40/10</td>
<td>T</td>
<td>M</td>
<td>B2/B4</td>
</tr>
<tr>
<td>13</td>
<td>B2/B4 + T1/T2</td>
<td>40, 40/10</td>
<td>T</td>
<td>M</td>
<td>B1</td>
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<td>10, 40/10</td>
<td>T</td>
<td>M</td>
<td>B2/B4</td>
</tr>
<tr>
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<td>B1</td>
<td>40</td>
<td>T</td>
<td>P</td>
<td>-</td>
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<td>T</td>
<td>-</td>
</tr>
<tr>
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<td>T</td>
<td>P</td>
<td>B2/B3</td>
</tr>
<tr>
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<td>A</td>
<td>T</td>
<td>B1</td>
</tr>
<tr>
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<td>10</td>
<td>T</td>
<td>P</td>
<td>B4/B5</td>
</tr>
<tr>
<td>20</td>
<td>B4/B5</td>
<td>10</td>
<td>A</td>
<td>T</td>
<td>B2/B3</td>
</tr>
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<td>P</td>
<td>B4/B5</td>
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<td>T</td>
<td>B4/B5</td>
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<td>A</td>
<td>P</td>
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<td>T</td>
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<td>P</td>
<td>B1</td>
</tr>
<tr>
<td>29</td>
<td>BB2</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B4/B5</td>
</tr>
<tr>
<td>30</td>
<td>BB2</td>
<td>10</td>
<td>T</td>
<td>T</td>
<td>B4/B5</td>
</tr>
<tr>
<td>31</td>
<td>L1</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>32</td>
<td>L2</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>33</td>
<td>L3</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>34</td>
<td>L4</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>35</td>
<td>L5</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>36</td>
<td>L6</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B6</td>
</tr>
<tr>
<td>37</td>
<td>L7</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>38</td>
<td>L8</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>39</td>
<td>L9</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>40</td>
<td>L10</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>41</td>
<td>L11</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>42</td>
<td>L12</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
<tr>
<td>43</td>
<td>L13</td>
<td>10</td>
<td>T</td>
<td>P</td>
<td>B7</td>
</tr>
</tbody>
</table>
Those events in which it is irreverent whether the fault is passive or active, are specified as total.

The triggered unit can either be breakers (B) or transformer fuses (FT)

In order to analyse the failure modes we must have good estimations of the probability that each failure mode will occur, the estimated time of the operation needed to deal which the failure modes as well as data on maintenance intensity and duration of the maintenance. Here it is assumed that the components’ of test system 1 have the same reliability data as assumed for the test system in chapter 5, according to table 2.2 [60].

Table 2.2. Component reliability data of test system 1

<table>
<thead>
<tr>
<th>Component</th>
<th>$\lambda_{tot}$ [f/yr]</th>
<th>$\lambda_a$ [f/yr]</th>
<th>$\lambda_t$ [f/yr]</th>
<th>$\lambda_m$ [/yr]</th>
<th>RT [h]</th>
<th>RpT [h]</th>
<th>SwT [h]</th>
<th>RcT [h]</th>
<th>MT [h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer (70/10 kV)</td>
<td>0.015</td>
<td>0.0015</td>
<td>0.05</td>
<td>1</td>
<td>-</td>
<td>15</td>
<td>1</td>
<td>0.083</td>
<td>168</td>
</tr>
<tr>
<td>Transformer (10/0.4 kV)</td>
<td>0.015</td>
<td>0.015</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>10</td>
<td>3</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Breaker (70 kV)</td>
<td>0.002</td>
<td>0.0015</td>
<td>0.02</td>
<td>0.5</td>
<td>4</td>
<td>-</td>
<td>1</td>
<td>0.083</td>
<td>96</td>
</tr>
<tr>
<td>Breaker (10 kV)</td>
<td>0.006</td>
<td>0.004</td>
<td>0.06</td>
<td>1</td>
<td>4</td>
<td>-</td>
<td>1</td>
<td>0.083</td>
<td>72</td>
</tr>
<tr>
<td>Bus bar (70 kV)</td>
<td>0.001</td>
<td>0.001</td>
<td>0.01</td>
<td>0.5</td>
<td>2</td>
<td>-</td>
<td>1</td>
<td>0.083</td>
<td>1</td>
</tr>
<tr>
<td>Bus bar (10 kV)</td>
<td>0.001</td>
<td>0.001</td>
<td>0.01</td>
<td>1</td>
<td>2</td>
<td>-</td>
<td>1</td>
<td>0.083</td>
<td>1</td>
</tr>
<tr>
<td>Cable (10 kV)</td>
<td>0.04</td>
<td>0.04</td>
<td>-</td>
<td>-</td>
<td>30</td>
<td>-</td>
<td>3</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

- Data missing or considered irrelevant for the example

Where the designations of table 2.2 are;

$\lambda_{tot}$ Total failure rate [f/yr], passive and active, [f/yr, km] for cables.

$\lambda_a$ Active failure rate [f/yr], [f/yr, km] for cables.

$\lambda_t$ Temporary failure rate [f/yr], [f/yr, km] for cables.

$\lambda_m$ Maintenance rate [yr$^{-1}$].

MT Maintenance time [h]
Since the fault probability of the cables are denoted per km, the length of the cable must be known, these are presented in table 2.3.

### Table 2.3. Length of cables in test system 1.

<table>
<thead>
<tr>
<th>Cable length (km)</th>
<th>L1</th>
<th>L2</th>
<th>L3</th>
<th>L4</th>
<th>L5</th>
<th>L6</th>
<th>L7</th>
<th>L8</th>
<th>L9</th>
<th>L10</th>
<th>L11</th>
<th>L12</th>
<th>L13</th>
</tr>
</thead>
<tbody>
<tr>
<td>0,5</td>
<td>1,4</td>
<td>1,2</td>
<td>0,9</td>
<td>0,7</td>
<td>0,8</td>
<td>1,4</td>
<td>0,7</td>
<td>0,9</td>
<td>0,8</td>
<td>1,2</td>
<td>2</td>
<td>2</td>
<td></td>
</tr>
</tbody>
</table>

As described in section 2.3, the LP’s outage frequency, $\lambda$, and annual outage duration, $U$, can be added up. The LP’s outage frequency and duration can be found in table 2.4. The whole summation sheet can be found in appendix A.

### Table 2.4. LP outage frequency and duration for test system 1.

<table>
<thead>
<tr>
<th>LP</th>
<th>$\lambda$ [f/y]</th>
<th>$U$ [h/y]</th>
</tr>
</thead>
<tbody>
<tr>
<td>LP1</td>
<td>0.604</td>
<td>0.904</td>
</tr>
<tr>
<td>LP2</td>
<td>0.619</td>
<td>1.054</td>
</tr>
<tr>
<td>LP3</td>
<td>0.619</td>
<td>1.054</td>
</tr>
<tr>
<td>LP4</td>
<td>0.619</td>
<td>2.026</td>
</tr>
<tr>
<td>LP5</td>
<td>0.619</td>
<td>1.054</td>
</tr>
<tr>
<td>LP6</td>
<td>0.604</td>
<td>0.904</td>
</tr>
<tr>
<td>LP7</td>
<td>0.619</td>
<td>2.566</td>
</tr>
<tr>
<td>LP8</td>
<td>0.552</td>
<td>0.748</td>
</tr>
<tr>
<td>LP9</td>
<td>0.552</td>
<td>0.748</td>
</tr>
<tr>
<td>LP10</td>
<td>0.552</td>
<td>0.748</td>
</tr>
<tr>
<td>LP11</td>
<td>0.552</td>
<td>0.748</td>
</tr>
<tr>
<td>LP12</td>
<td>0.567</td>
<td>3.058</td>
</tr>
</tbody>
</table>

For a comparable result, the system reliability performance indicators presented in chapter 2.3.3 can be used, however in order to use these, there are some data on the LPs that have to be known. Table 2.6 presents the LP specific data.
Table 2.5. Load point data of test system 1

<table>
<thead>
<tr>
<th># of customers</th>
<th>Customer type</th>
<th>Average load [kW]</th>
<th>Peak load [kW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>LP1</td>
<td>2</td>
<td>Industrial</td>
<td>110</td>
</tr>
<tr>
<td>LP2</td>
<td>70</td>
<td>Residential</td>
<td>132</td>
</tr>
<tr>
<td>LP3</td>
<td>30</td>
<td>Commercial</td>
<td>61</td>
</tr>
<tr>
<td>LP4</td>
<td>10</td>
<td>Agriculture</td>
<td>46</td>
</tr>
<tr>
<td>LP5</td>
<td>75</td>
<td>Residential</td>
<td>121</td>
</tr>
<tr>
<td>LP6</td>
<td>1</td>
<td>Industrial</td>
<td>73</td>
</tr>
<tr>
<td>LP7</td>
<td>55</td>
<td>Residential</td>
<td>96</td>
</tr>
<tr>
<td>LP8</td>
<td>2</td>
<td>Industrial</td>
<td>110</td>
</tr>
<tr>
<td>LP9</td>
<td>4</td>
<td>Industrial</td>
<td>81</td>
</tr>
<tr>
<td>LP10</td>
<td>3</td>
<td>Industrial</td>
<td>99</td>
</tr>
<tr>
<td>LP11</td>
<td>3</td>
<td>Industrial</td>
<td>71</td>
</tr>
<tr>
<td>LP12</td>
<td>85</td>
<td>Residential</td>
<td>206</td>
</tr>
</tbody>
</table>

Hence, the result of the FMEA process is displayed in table 2.7:

Table 2.6. Result of FMEA process, example 1, test system 1

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>LP1</td>
<td>0.0053</td>
<td>0.0036</td>
<td>0.082</td>
<td>0.055</td>
</tr>
<tr>
<td>LP2</td>
<td>0.2169</td>
<td>0.1274</td>
<td>0.115</td>
<td>0.068</td>
</tr>
<tr>
<td>LP3</td>
<td>0.0930</td>
<td>0.0546</td>
<td>0.053</td>
<td>0.031</td>
</tr>
<tr>
<td>LP4</td>
<td>0.0596</td>
<td>0.0182</td>
<td>0.077</td>
<td>0.006</td>
</tr>
<tr>
<td>LP5</td>
<td>0.2324</td>
<td>0.1365</td>
<td>0.106</td>
<td>0.062</td>
</tr>
<tr>
<td>LP6</td>
<td>0.0027</td>
<td>0.0018</td>
<td>0.055</td>
<td>0.037</td>
</tr>
<tr>
<td>LP7</td>
<td>0.4150</td>
<td>0.1001</td>
<td>0.204</td>
<td>0.049</td>
</tr>
<tr>
<td>LP8</td>
<td>0.0044</td>
<td>0.0032</td>
<td>0.068</td>
<td>0.050</td>
</tr>
<tr>
<td>LP9</td>
<td>0.0088</td>
<td>0.0065</td>
<td>0.050</td>
<td>0.037</td>
</tr>
<tr>
<td>LP10</td>
<td>0.0066</td>
<td>0.0049</td>
<td>0.061</td>
<td>0.045</td>
</tr>
<tr>
<td>LP11</td>
<td>0.0066</td>
<td>0.0049</td>
<td>0.044</td>
<td>0.032</td>
</tr>
<tr>
<td>LP12</td>
<td>0.7644</td>
<td>0.1417</td>
<td>0.522</td>
<td>0.097</td>
</tr>
<tr>
<td>F1</td>
<td>0.7908</td>
<td>0.1612</td>
<td>0.746</td>
<td>0.262</td>
</tr>
<tr>
<td>F2</td>
<td>1.0239</td>
<td>0.4418</td>
<td>0.679</td>
<td>0.303</td>
</tr>
<tr>
<td>System</td>
<td>1.8156</td>
<td>0.6032</td>
<td>1.439</td>
<td>0.569</td>
</tr>
</tbody>
</table>
2.4.2 Example 2

Case 1. In order to apply the Monte Carlo simulation method described in section 2.3.5, onto test system 1, there are some additional data that have to be specified; distribution function for each event’s up and down time as well as their standard deviation\(^3\). The additional system data is displayed in Table 2.7.

**Table 2.7. Additional component and operating data for test system 1**

<table>
<thead>
<tr>
<th>Time to failure TTF</th>
<th>Repair time (RT)</th>
<th>Replace time (RpT)</th>
<th>Switching time (SwT)</th>
<th>Reclosing time (RcT)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Distribution function</td>
<td>Standard deviation ((\sigma))</td>
<td>Distribution function</td>
<td>Standard deviation ((\sigma))</td>
</tr>
<tr>
<td>Time to failure TTF</td>
<td>Exponential</td>
<td>-</td>
<td>Lognormal</td>
<td>6 h</td>
</tr>
<tr>
<td>Repair time (RT)</td>
<td>Cable</td>
<td>Lognormal</td>
<td>6 h</td>
<td>Bus bar</td>
</tr>
<tr>
<td>Replace time (RpT)</td>
<td>Transformer</td>
<td>Lognormal</td>
<td>1 h</td>
<td>Switching time (SwT)</td>
</tr>
</tbody>
</table>

Now, if we apply the MCS presented in chapter 2.3.5 onto test system 1, we are able to receive more results from the calculations. However, in order to verify the MCS model, three different parameter settings were used in the MCS and compared to the analytical results, i.e. FMEA analysis. The analytical results are considered to be the true values. One remark though, the simplifications regarding simultaneous faults have basically the same impact both methods. Table 2.8 shows the comparison of the results of FMEA and MCS.

\(^3\) The standard deviation is necessary if the operation time is not exponentially distributed, see chapter 2.2.2 for details.
### Table 2.8. Comparison of the analytical FMEA and the MCS model

<table>
<thead>
<tr>
<th></th>
<th>FMEA</th>
<th>MCS 1 (N = 10^6, T_0 = 1y)</th>
<th>MCS 2 (N = 10^5, T_0 = 1y)</th>
<th>MCS 3 (N = 10, T_0 = 10^6y)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LP1</td>
<td>0.604</td>
<td>0.904</td>
<td>0.603</td>
<td>0.905</td>
</tr>
<tr>
<td>LP2</td>
<td>0.619</td>
<td>1.054</td>
<td>0.618</td>
<td>1.049</td>
</tr>
<tr>
<td>LP3</td>
<td>0.619</td>
<td>1.054</td>
<td>0.618</td>
<td>1.056</td>
</tr>
<tr>
<td>LP4</td>
<td>0.619</td>
<td>2.026</td>
<td>0.618</td>
<td>2.023</td>
</tr>
<tr>
<td>LP5</td>
<td>0.619</td>
<td>1.054</td>
<td>0.618</td>
<td>1.052</td>
</tr>
<tr>
<td>LP6</td>
<td>0.604</td>
<td>0.904</td>
<td>0.603</td>
<td>0.905</td>
</tr>
<tr>
<td>LP7</td>
<td>0.619</td>
<td>2.566</td>
<td>0.618</td>
<td>2.563</td>
</tr>
<tr>
<td>LP8</td>
<td>0.552</td>
<td>0.748</td>
<td>0.551</td>
<td>0.749</td>
</tr>
<tr>
<td>LP9</td>
<td>0.552</td>
<td>0.748</td>
<td>0.551</td>
<td>0.749</td>
</tr>
<tr>
<td>LP10</td>
<td>0.552</td>
<td>0.748</td>
<td>0.551</td>
<td>0.749</td>
</tr>
<tr>
<td>LP11</td>
<td>0.552</td>
<td>0.748</td>
<td>0.551</td>
<td>0.749</td>
</tr>
<tr>
<td>LP12</td>
<td>0.567</td>
<td>3.058</td>
<td>0.566</td>
<td>3.064</td>
</tr>
</tbody>
</table>

In the first two cases, T_0 was set to 8760 h, 1 year, and the number of sample, N, was set to 10^6 and 10^5 respectively. MCS 1, generated results better in accordance to the FMEA results. This is quite natural since simple sampling technique is adopted, which requires large numbers of samples especially for duogen system, hence, the more samples the better results. One simplification in the MCS method is that all components are functional at the beginning of each sample, which should result in under estimations of both outage frequency and duration. To overcome this, MCS 3 was conducted where the simulation time T_0 was set to 10^6 years, and N was set to 10. And even though the results from MCS 3 are better congruous with the FMEA results than those from MCS 1, the reason is not due to the simplification mentioned earlier but more likely due to the fact that the total simulation time is longer. The maximum error of MCS 1 compared to the FMEA was rather small, ≤ 0.4 %, which means a sufficient accuracy for the analysis conducted in this thesis.

The additional information from the MCS compared to the information available through the analytically calculated results is significant. For instance, we can consider the annual reliability functions SAIDI, SAIFI and ENS as well as the probability for outage frequency for each LP, presented in figure 2.5 – 2.8. In figure 2.5 and 2.6 the risk of exceeding the expected value of SAIDI, ASIFI or ENS is only approximately 30 %. However, on the other hand, the expected value can be exceeded quite significantly. The figures also show that in approximately 50 % of all the years, there are no interruption at all.
Figure 2.4. Reliability functions for annual system SAIDI and ASIDI.

Figure 2.5. Reliability function for annual system ENS.
If considering the system reliability performance indicators simulated for each LP, the standard deviation of each indicator is much higher than the expected values shown in table 2.9. This confirms the statement earlier about power system being duogen and that the mean values can be very misleading since much information is missed. For instance, when performing risk analysis the mean values are of interest, but more important are those events that even
though occur very seldom can bring very high cost. Consequently, to comprehend the full picture the output distribution should be considered.

When considering changes in the system, such as investments, the impact can be analysed by using the MCS. First considering the original system, the output contribution for each LP is shown in table 2.9.

Table 2.9. Load point output for case 1 of test system 1

<table>
<thead>
<tr>
<th>Load point</th>
<th>SAIDI [h/y]</th>
<th>SAIFI [int/y]</th>
<th>ASIDI [h/y]</th>
<th>ASIFI [int/y]</th>
<th>ENS [kWh/y]</th>
</tr>
</thead>
<tbody>
<tr>
<td>LP1</td>
<td>0.0053</td>
<td>0.0097</td>
<td>0.0035</td>
<td>0.0046</td>
<td>0.0826</td>
</tr>
<tr>
<td>LP2</td>
<td>0.2160</td>
<td>0.4789</td>
<td>0.1273</td>
<td>0.1618</td>
<td>0.1149</td>
</tr>
<tr>
<td>LP3</td>
<td>0.0932</td>
<td>0.2143</td>
<td>0.0546</td>
<td>0.0694</td>
<td>0.0534</td>
</tr>
<tr>
<td>LP4</td>
<td>0.0595</td>
<td>0.1807</td>
<td>0.0182</td>
<td>0.0231</td>
<td>0.0772</td>
</tr>
<tr>
<td>LP5</td>
<td>0.2320</td>
<td>0.5174</td>
<td>0.1364</td>
<td>0.1735</td>
<td>0.1055</td>
</tr>
<tr>
<td>LP6</td>
<td>0.0027</td>
<td>0.0048</td>
<td>0.0018</td>
<td>0.0023</td>
<td>0.0548</td>
</tr>
<tr>
<td>LP7</td>
<td>0.4147</td>
<td>1.2061</td>
<td>0.1000</td>
<td>0.1272</td>
<td>0.2041</td>
</tr>
<tr>
<td>LP8</td>
<td>0.0044</td>
<td>0.0088</td>
<td>0.0032</td>
<td>0.0044</td>
<td>0.0683</td>
</tr>
<tr>
<td>LP9</td>
<td>0.0088</td>
<td>0.0176</td>
<td>0.0065</td>
<td>0.0087</td>
<td>0.0503</td>
</tr>
<tr>
<td>LP10</td>
<td>0.0066</td>
<td>0.0132</td>
<td>0.0049</td>
<td>0.0065</td>
<td>0.0614</td>
</tr>
<tr>
<td>LP11</td>
<td>0.0066</td>
<td>0.0132</td>
<td>0.0049</td>
<td>0.0065</td>
<td>0.0441</td>
</tr>
<tr>
<td>LP12</td>
<td>0.7660</td>
<td>2.1871</td>
<td>0.1415</td>
<td>0.1880</td>
<td>0.5234</td>
</tr>
</tbody>
</table>

Case 2. Now assume that the cables L8 – L12 would be doubled and the protection system would be upgraded in order to enable better selectivity so that fault on these cables would not influence the rest of the system unless both cables faulted simultaneously. The output contribution of each LP would be:
As expected the doubling of cable L8 – L13 did not substantially affect the LP’s indicators for outage frequency, however the outage duration indicators show a significant decrease for LP8 – LP12. The performance indicators for the whole system are displayed in table 2.11.

Table 2.11 shows that case 2 is a more robust system than case 1 since both the expected performance as well as its standard deviation have decreased. The greatest impact of doubling L8 – L13 is on the capacity weighted duration indicators; ASIDI and ENS. This can be explained by the fact that F2 holds less quantities of customers but more high consuming ones.
Chapter 3

Performance-Based Regulation

This chapter initially describes the general cost-based approach for regulation in short terms as a background to the development of more advanced regulatory regimes, i.e. PBR. Further, the two main parts of PBR are described in general; the efficiency benchmarking and the quality regulation. Also, a general step-wise process is described and applied to DSO regulation. Finally, the key quality incentive features within the efficiency benchmarking and the quality regulation are identified and analysed in terms of the impact each feature can have on the incentives on which the DSOs act regarding the system reliability.

3.1 Why regulate Distribution System Operators

If the market conditions are such that the best option from a socio-economic point of view is that only one company should supply a specific service or good, it is defined as a natural monopoly situation [23]. Under re-regulated market conditions retail and production of electric energy is traded on competitive markets. Electric distribution on the other hand is often considered as a natural monopoly since it is not economically feasible to build more than one distribution grid for each area. There is though a possible competition between grid upgrade, demand side management and/or distributed generation [16]. In order to avoid that the DSOs exploit their monopoly position they are under the supervision of a regulatory authority. Based on the laws in the electricity act the regulator sets terms for the economic regulation.

When classifying regulation models there are the typical cost-based methods, described in section 3.2, the strictly performance-based models where cost and income are totally separate and those in between, the so-called incentive-based
regulation models. In the latter, there is a link between cost and income since the capped price or revenue is most often initially based actual costs, but the direct connection is weakened by adjustments due to efficiency and quality. Henceforth, those normally classified as incentive-based models are here included in the performance-based models, these are described in section 3.3.

3.2 Cost-based regulation

Economic regulation is really a matter of information [29]. In order to make a fare judgement of the situation, the regulator must know what information that is relevant or the search for information can be time consuming and the amount of accessible of information can become too much to comprehend. The traditional approach to regulate DSOs has been conducted based on the their actual costs. The purpose of cost-based regulation is to limit the DSOs profit, it is applied so that the DSOs are able to charge according to their costs plus some extra in profit. The supervision is to determine whether the costs are justified or not. The reason for applying cost-based regulation is, since the DSOs know their costs better than regulator, that the regulator can by rather simple means oversee the situation. Examples of such regulations are Rate Of Return (ROR) regulation and Cost-Plus regulation. While Cost-Plus regulation can be applied both ex-ante\(^4\) and ex-post, ROR-regulation is applied ex-post. By applying the regulation ex-ante the DSOs have to justify their costs to greater extend than those subjected to ex-post ROR-regulation. This is the major difference between the two, Cost-Plus regulation motivates cost efficiency more than ROR-regulation do [22] since the DSOs have their costs more. Under normal conditions, the DSOs’ costs are not inspected in detail, when subjected to ROR-regulation. The regulator can however inspect some DSOs further if it seems justified. Regulation in which there is a direct link between the DSOs’ cost and income is usually considered as rather inefficient [22]. The general opinion is that DSOs subjected to ROR or Cost-Plus regulation have very small incentives to be economically efficient. Since it is actually rather difficult, and generally not their role, for the regulator to determine whether the investments conducted by the DSO are justified or not, the implication is to over-invest rather than the

\(^4\) Ex-ante, the regulation is conducted based on expected values, i.e. in advance. The opposite is called ex-post, i.e. the regulation is conducted on actual accounts.
opposite. These unsatisfactory conditions, together with customer demands have lead to the development stricter regulatory regimes that value cost efficiency, less focus on the DSOs’ cost and more attention on their actual performance [35].

3.3 Performance-Based Regulation

A typical incentive-based regulation scheme is the $RPI - X$ approach. The sequential year’s price or revenue cap is calculated through this formula:

$$R_t = (RPI_{t-1} - X_p - Y_t) \times R_{t-1}$$  \hspace{1cm} 3.1

$R$ can be either the price or the revenue, $RPI$ is the Retail Price Index, $X_p$ is the generic efficiency factor for the regulatory period $p$ and $Y_t$ is the individual efficiency factor for year $t$. The $X$-factor is set by the regulator for the entire regulatory period, usually 3 – 5 years. The $Y$-factor is determined through some kind of efficiency benchmark and is therefore based on the individual performance, chapter 3.3.1. Since the initial setting of the price/revenue cap is based on each DSO’s actual costs, the approach is considered cost-based. However, the longer the regulation is in effect the less will the capped price or revenue depend on the actual costs. Nevertheless, the initial setting is essential and therefore one of the biggest challenges when using this approach. The $RPI – X$ approach basically requires ex-ante regulation in order to be efficient [22].

Within the strict PBR methods, the connection between price and revenue is rather weak since the capped price or revenue instead is mainly based on the DSO’s performance. The general purpose of applying PBR is to motivate economic efficiency and to put the DSOs in a situation that resembles a competitive market. The means by which the performance is valued and the allowable price or revenue is set varies, but the use of reference models is one common way. The reference model is a theoretical copy of the actual network or the entire company, and it is used to value the optimal operation of the DSO. When compared to that of the actual network, the DSOs performance can be determined, this can be defined as yardstick competition where the reference
network/company is the yardstick\(^5\). The biggest challenge when constructing a reference model is to choose the input data so that the natural fluctuations between the regulated DSOs are comprehended objectively. Reference models are described further in chapters 3.3.2, 4.1.1 and 4.1.3. The general difference between cost-based and performance-based regulation schemes is illustrated in fig. 3.1 [35].

\[
\begin{align*}
\text{Cost-based regulation} & \quad \text{Tariff} = \text{Cost} + \text{Profit} \\
\text{Performance-based regulation} & \quad \text{Profit?} = \text{Tariff} - \text{Cost}
\end{align*}
\]

*Figure 3.1. Difference between Cost-Based and Performance-Base regulation schemes.*

The regulation is not supposed to be a one-way commitment and the regulators interests should be aimed towards both customers and the DSOs. The purpose of the PBR and the aim of the model used within the regulation can be described with the following seven points [19]:

\begin{itemize}
  \item[i] Give the regulated DSOs incentives to be economically efficient.
  
  \item[ii] Give the DSOs incentives to uphold a level of sufficient economic reliability, i.e. marginal benefit vs. marginal cost, fig. 3.4.
  
  \item[iii] Give efficient DSOs that are making wise grid investments the opportunity to make sufficient profits and thereby be able to attract external investors.
  
  \item[iv] Protect the customers from being overcharged.
\end{itemize}

\(^5\) The yardstick used in so-called yardstick competition can also be outputs from other companies, as conducted in DEA-analysis (section 3.3.1.1).
v Be fare in that sense that the regulation should be conducted on equal terms for the different DSOs.

vi The regulatory model should be cost-efficient to implement.

vii The rules within the regulation should be clear, fixed for periods longer than one year and the regulation should be based on factors that can be determined externally, i.e. transparency and stability.

One of the risks when introducing strong cost cutting incentives is that the system reliability will suffer due to postponed investments and expenditure savings on maintenance. To avoid this there are usually quality features within the regulatory framework. The stronger the cost cutting incentives are the more eminent it is to include the quality of supply as a performance feature or as a separate regulation. This connection is displayed in fig 3.2 [47].

![Figure 3.2. Cost cutting incentives vs. the virtual need for quality regulation](image)

Consequently, there are two parts of the DSOs’ performance the regulator has to value within the PBR framework; the economic efficiency and the quality of supply. The economic efficiency is usually determined in some kind of efficiency benchmark, and the quality of supply is usually regulated within the quality regulation.
3.3.1 Efficiency Benchmark

Benchmarking is used to measure a company’s efficiency by comparing it to that of others. A general description is: “Benchmarking is a continuous and systematic process of comparing one’s own efficiency concerning quality and working process with companies representing the best” [23]. One of the several applications of benchmarking is the regulators control of the regulated companies’ efficiency and their efficiency development. Some of the relevant benchmarking techniques for this project used for performance valuation within DSO regulation are described below.

3.3.1.1 Data Envelopment Analysis, DEA

A common method within DSO regulation used for efficiency benchmarking is data envelopment analysis (DEA). It is a nonlinear programming application where the objective is to maximise the ratio of weighted outputs to weighted inputs under the constraint that the weights are positive and that the efficiency score is less or equal to 1. The mathematical formulation is presented in equation 3.2 [55].

$$\text{max } \theta(u,v) = \frac{\sum_k u_j y_{jk}}{\sum_k v_i x_{ik}}$$

subjected to

$$\frac{\sum_j u_j y_{jk}}{\sum_i v_i x_{ik}} \leq 1$$

and

$$u_j, v_i \geq 0$$

$$\forall j = 1...n, i = 1...m, k = 1...K$$

Where the efficiency score for each company, $k = 1,...,K$, $y_{jk}$ is amount of output $j$ for unit $k$ and $x_{ik}$ the amount of unit $i$ for DSO $k$, $u_j$ and $v_i$ are the weights assigned to output $j$ and input $i$ respectively. $n$, $m$ and $K$ are the total number of outputs, inputs and units in the class respectively and $\varepsilon$ is a small positive constraint. Fig. 3.6 illustrates an example of a two-dimensional case, here two inputs and one output. The dots are unit included in the benchmark and the black dots and line connecting them the best performing units, the efficiency frontier.
Based on each unit’s performance relative the efficiency frontier an individual efficiency improvement factor can be assigned the units, i.e. the $Y$-factor.

There are two different approaches of DEA-benchmarking; constant and variable return of scale, CRS and VRS respectively. The difference between the two approaches is that VRS divides the units into classes in which the most efficient ones are determined. The purpose is to get better comparability within each class [23].

Typical inputs are; number of man-labour years, energy losses and various costs. The typical output variables are; delivered energy, number of customers served, quantity of grid components, etc.

The practical applications of DEA benchmarking in DSO regulation are many; Norway, Finland, Sweden\(^6\) and the Netherlands to name a few [23], the main reason why many countries use it is probably that DEA benchmarking is, compared to other benchmarking techniques, very flexible. The input and output

\(^6\) The Swedish regulator used DEA-benchmarking outside the regulation in 2002, the purpose was to test the technique and to put pressure on the DSOs by publishing their efficiency rating.
variables can easily be changed, it is rather easy to use and cost efficient to implement. The disadvantage is that in order determine an accurate efficiency frontier the number of DSO in each class much be sufficiently large, and the more input and output variables that are included the more units are required. This makes unique units 100% efficient since a comparison is not possible. The fact the DEA-benchmarking method does not indicate the cause of the inefficiency makes it somewhat a black box.

3.3.1.2 Reference network
Reference models are also used for efficiency benchmarking. The costs or performance of the reference company or grid are used as yardsticks, making the efficiency regulation resemble somewhat of a competitive market. The reference network built in the regulation model is based on the same objective prerequisites as the DSO. It is suppose to resemble an efficiently operated and built grid company. The DSO’s objective prerequisites represent those factors that the DSO is not able to influence, such location of customers, their demand, location of production units, geographical and demographical constraints, etc. The development of a reference network model for yardstick competition is often considered to be rather complicated due to the extensive simplifications that have to be made without losing the essence of the actual company or grids. The difficulty is to construct a model that can represents a great number varying units and that is robust towards deviating units and varying quality of in data.

If the reference network model is constructed robust and is able represent the reality with a sufficient degree of accuracy, it can be a good tool for not only pointing out general inefficiency but also the cause of inefficiency. Which makes the use of reference networks a more transparent method for efficiency benchmarking than DEA, for DSO regulation. Also, since the comparison is conducted towards a reference model based on the objective prerequisites, it is possible to remove the actual link between costs and income, making the incentives for cost reduction very strong.

The practice of using reference networks models for DSO regulation has been conducted in Latin America [15]. The models used there were constructed as reference companies based on the economic constraints for each DSO. However Sweden has from 2003 been using reference network model, the NPAM, which constructs a reference grid for each DSO and uses it as performance yardstick [32]. Spain have developed a reference network model that is in its implementation phase, it is also used as a tool for DSO regulation [39].
3.3.2 Quality regulation

As mentioned earlier, a well-known risk when implementing strong cost reductive incentives is that the quality of supply will decrease due to decreased maintenance and postponed investments. To mitigate this many regulators, applying PBR, include quality features within their regulatory framework.

3.3.2.1 Quality features

There are many features that can be included within the concept of quality of supply and different customer categories do not necessarily value the same features. For instance, voltage dips can be very costly for industrial customers while other categories hardly notice them. The quality of supply can be categorised as:

- **Commercial quality**, refers to how the DSOs answer to the customers’ demands regarding the customer service in general, metering, billing, handling of retailer swaps, etc.

- **Voltage quality**, which includes harmonics, deviation from nominal voltage, flicker and short interruptions\(^7\).

- **Continuity of supply**, which includes the number of long interruption, the total duration of long interruption and energy not supplied.

Many of the features regarded as voltage quality are regulated in ISO standards and are therefore not included in the regulation that affects the DSOs income. Further, even if there are regulators that have imbedded features so the DSOs’ the commercial quality affect their allowable revenue, those that have plans to do it and those that considers it, it is not that common. Henceforth the voltage and commercial quality will not included as features in the quality of supply, thus the continuity of supply is the only feature regarded in the quality regulation.

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\(^7\) The definition of a short interruption can vary depending on country but in most European countries the limit between a short and a long interruption is 3 minutes.
3.3.2.2 Implementation of quality regulation

The regulator can use different means to implement the quality feature into the regulatory process. Some approaches are listed below [20]:

i Comparative publications on quality performance of the regulated DSOs.

ii Income adjustments, revenue or price cap adjustments according to performed quality.

iii Economic penalties, remuneration to the affected customers or to the regulator.

The most common practice is a combination of bad publicity and economic consequence. Even if bad publicity is a rather powerful tool, without some kind of penalty backup the quality aspect becomes rather diffuse and the fact that the economic instrument is very versatile and adjustable, the task of enforcing a regulatory framework that creates the “right” incentives for the regulated DSOs falls more natural into place.

3.3.2.3 General scope of quality dependent revenues

By setting economic parameter on different quality features the regulator creates incentives for the DSOs to act on regarding how they deal with quality related issues. The challenge for the regulator is to set the parameter so that the implications of the regulation agree with the regulator’s long-term agenda regarding the best economically reliability. This is easier in theory than in practice, however the general concept is such that the DSOs should have incentives to increase their reliability as long as the marginal cost (MC) is less than the marginal benefit of the investment. This is illustrated in fig. 3.4.
The assumed cost function illustrated in fig. 3.4 is usually considered to have the characteristics that the return rate is high in systems with poor reliability and increases the higher the reliability becomes [33]. Translated into distribution systems investments; poor reliability would indicate a simple radial grid consisting of mainly overhead lines without any sophisticated protection and automation system. By rather simple means such as improving protection schemes and by adding components in order to increase the selectivity in the system the reliability would increase rather significantly. The next step might be to add lines in order to mesh the grid, adding overhead line would be more expensive relative the reliability increase than previous measures. If the desire is to increase the reliability even further, the next step might be to invest in underground cables, which is rather expensive but would also increase the reliability rather significantly. The improvement process can continue but the return relative the cost of further measures would decrease and a perfect working system would be enormously expensive, hence, not economically feasible.

To value the experienced benefit of certain quality levels the regulators usually rely on interruption cost surveys, which basically value the negative benefit due to lack of quality translated into costs. This is common practice, but the way the results are used and how the surveys are conducted differ for different
regulations, which has impact further down the line. The level of detail in the information from the survey and the level regarded in the regulation is central.

3.3.2.4 Quality regulation process
In this project, a general process describing the different steps within the quality regulation, has been identified and analysed. Here, the process describes the transformation of the actual interruptions into an output a financial output that may have an impact on a DSO’s capped income. Within the quality regulations considered in this project, the actual quality regulation is a financial adjustment that represent the valued discomfort experienced by the DSO’s customers due to interruptions. The process flowchart is displayed in fig. 3.5.

![Flowchart of the quality regulation process](image)

**Figure 3.5. Flowchart of the quality regulation process**

The steps of the flowchart can be described in more details as:

1. **Interruptions**, occur in the system, the input data for the regulation model is based on these interruptions.

2. **Filter.** There are regulatory filters in all regulation processes since the regulator is not able to comprehend all information assessable for the occurred incidents. The regulator controls the level of detail in the information that the DSOs are obliged to report regarding their quality of supply. Examples of the filters referred to here are; mean values or aggregated reliability performance indices as well as the choice of aggregation level, only including interruption longer than 3 minutes, etc.

3. **Valuation and reconstruction.** One of the regulators main tasks in quality regulation is to value the customers’ experienced benefit of
quality. Based on the reported data, from the DSOs, the regulator tries to reconstruct the actual costs that the customers have had due to the interruptions. This becomes the regulators view of the situation and the foundation on which it basis its regulatory decisions.

4. **Adjustment.** Since the valued cost of the interruptions is not automatically the same as the revenue adjustment due to possible constraints and adjustment limits, there must be an adjustment function. The characteristic of this transformation is one of the regulator’s means by which it can connect the system’s condition to certain incentives.

5. **Result.** The output of the process is a financial consequence in form of a revenue adjustment or tariff refunds etc.

The generic concept of this process can be applied to basically any kind of regulatory model since the challenges in economic regulation are the same, i.e. to use a limited amount of information and recreate the actual situation.

### 3.3.3 Key features in Performance-Based Regulation

All regulations create incentives. PBR promotes efficiency, the strong cost cutting incentives are usually balanced with a framework for quality regulation. The implications brought upon the DSOs, regarding the continuity of supply, when subjected to PBR with QR can be derived from some key incentive features within the regulatory framework. How the regulator chooses to or is forced to by law to handle these features have great impact on the quality related incentives and the future development regarding investments in and maintenance of the grids subjected to its regulation.⁸

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⁸ The incentive features within the regulation are however not the only issues that influence the DSOs’ decisions; political objective not include in the regulatory framework and goodwill objectives are examples of features that will influence the DSOs’ decisions but are hard to measure.
When considering the general regulatory framework there are three features that have been identified in this project as incentive creating features for quality of supply:

I. **Quality significance.** The quality dependent part of the total revenue determines the significance of the quality of supply. This could be considered the main quality feature, and the single most important feature in terms of economic incentives. If the quality dependent part of the revenue is small relative the total revenue, the issue becomes less important since the incentives are not strong enough for the DSOs to put an effort into it. On the other hand, the opposite situation can actually lead to over-investments, which in reality would imply that the customers are charged for better quality of supply than they are willing to pay for, or to a situation where poor performing DSOs are penalised to that extent that they are not able to recover.

II. **The regulators code of conduct.** The way the regulator implements the regulatory output sends signals to those subjected to the regulation. Whether the regulation is applied heavy- or light-handed influences, among other things, how strict the rules must be set and therefore also the DSOs attitude towards the regulation. Heavy-handed regulation is strictly applied and set high demands on output accuracy. In light-handed regulation, the regulatory model is used as a tool to sort out the poor performing DSO, which enables both the regulator and the DSOs to act more freely.

III. **Ex-ante or ex-post regulation.** Even if the quality regulation must be conducted on actual results, ex-post, the regulatory framework can be applied ex-ante. This is the most common approach since ex-ante regulation is considered more cost efficient to implement [22]. Whether the regulation is conducted ex-ante or ex-post is usually but not necessarily, connected to how strict the regulation is applied. Ex-ante regulation is regarded as heavy-handed and ex-post regulation as light-handed, but the fact that revenue or price caps set in advance can be regarded as rather final does not exclude the caps set ex-post are not enforced. The impact that this feature have on regulatory incentives is connected to the regulators code of conduct.
The quality regulation is the part where the regulator indicates to the DSOs which issues that are important. This is embedded in the fundamental outline of the framework for quality regulation. If considering the flowchart of the quality regulation process in figure 3.5, step 2 – 4 are essential. Within this project, nine features in the quality regulation framework have been identified and analysed:

i  *The factors considered in the quality regulation?* The duration is considered in most quality regulations. However, customers suffer in general more due to many rather short interruptions than to few long ones even if the total interruption duration is the same. The number of factors considered in the regulation reflects to some extend the level of detail within the regulation, and if both the interruption duration and frequency is considered in the quality regulation the reconstructed interruption cost is more likely to be accurate from a socio-economic point of view. This is a typical filter-feature, i.e. set in step 2.

ii  *Weighting of the reliability performance indicators.* As mentioned in chapter 2.3.3 the reliability performance indices used to indicate the system reliability performance can be either customer or capacity weighted. The weighting of the reliability performance indicators determines what impact interruptions, in different load points, have on the total performance. And which kind of indices that are used in the quality regulation determines which load points that should be prioritised, those containing large quantities of customers or those with high loads. Since industries usually are geographically separated from residential areas, commercial customers are often located in dense city areas together with hi-tech industries and agricultural customers are located in rural areas. The number of customers and the energy consumption in different parts of the grid does not automatically correspond and the variations in those quantities can be rather significant. This feature is first of all set in step 3, but step 2 of the regulatory process can have some influence.

iii  *Features that mitigate dominating incentives.* The effect of dominating or negative incentives can be mitigated by the use of different methods. For example, by using more than one aggregation level for interruptions, e.g. on customer and system level or by applying different remuneration/revenue cap reduction
schemes for the different aggregation levels, the risk of reliability performance segregation can to some extend be mitigated. Another method to mitigate dominating incentives is to use a combination of reliability indicators that are weighted differently, such as those weighted to the whole system in combination with such that are only weighted to the affected customers. This would indicate whether there are any significantly poor performing feeders in an otherwise good performing system. This feature is set in step 2 and 3.

iv  
*Level of detail in customer representation.* One of the many factors that determine the actual cost of an interruption is which categories of customers that are affected. For instance, industrial customers suffer in general higher cost due to an interruption than residential customers do. As a matter of fact, the IC of various customer categories differ very much [27], [63]. Therefore, the level of detail in customer representation within the regulation has impact on the DSOs’ considerations when valuing components, areas and grids. The categorisation within the regulation can be based on customer density, customer types or grid tariff. The customer type categorisation gives generally the best interruption cost representation. How many type of categories that are included influences the accuracy in representation. This feature is strongly connected to ii and, hence is set in step 2 and 3.

v  
*Including planned interruptions.* The customers generally experience unannounced interruptions as much more costly than announced interruptions [63]. However, just because the interruption is announced in advance does not exclude that there are costs related to it. By including the announced interruption the regulator can influence the DSOs to plan their interruptions as short as possible and during hours that are least costly to the customers. This means that the level of detail in reporting of planned interruptions determines whether the given incentives are correct or not. This feature can be set in step 2 or 3.

vi  
*Separating internal and external faults.* To the customers it is usually of no interest whether the interruptions that they have been affected by were caused in the distribution system or in the transmission system. However, the DSOs’ ability to influence the
upstream network can be limited and whether to include external fault or not is more a question of how the sub-transmission system operators and transmission system operators are regulated. If the interruptions caused in the upstream network are included in the DSO regulation, the DSOs will demand better quality of supply from the upstream operator, which can lead to long-term improvements in the quality of supply for the customers. This feature can be set in step 2 or 3.

vii Aggregation level. On what level in the system is the interruptions measured? This is a question of information quality versus quantity. The most correct valuation of the interruption costs should be if all interruptions are included, however since continuous measurement on customer level is not economically feasible, aggregation of information on customer level would mean that the interruptions to some extend would have to be estimated. To apply a higher aggregation level would enable higher quality of information but would not include all the interruptions. The legal aspect of this dilemma is interesting and the requirement on information accuracy tends to be linked to how strictly the regulation is applied. This is also a typical filter-feature, i.e. set in step 2.

viii Adjustment function characteristics. The characteristics of the adjustment function, step 4 in fig. 3.5, affect both the long- and short-term quality implications of the regulation. The adjustment function describes the connection between the state regulatory output. The short-term incentives are determined by the marginal changes in allowable revenue versus the investment cost and the long-term incentives are linked to the function’s general characteristics.

ix Length of quality regulatory period. The usual approach is to conduct quality regulation annually and set the parameters for the economic efficiency regulation in periods of 1 – 5 years. Quality regulation based on mean values for several years would make the DSO less sensitive to the yearly variations in quality performance, which can be quite significant. On the other hand, trends in quality development would be less obvious to the regulator and less tangible to the DSOs. This feature can be referred to either step 3 or 4.
This concludes the general descriptions or regulatory feature and methods. These general descriptions are put into context in the following chapter.
Chapter 4

Applied PBR

This chapter holds the general description of four applied performance-based regulations. The regulatory frameworks described here are chosen as typical frameworks of different key feature configuration, and are therefore meant to represent a greater number of PBR frameworks. At the end of the chapter, a qualitative comparison, based on the key incentive features in chapter 3, is presented. The comparison gives a foreseeable overview of the presented regulatory regimes, which is the essence of this chapter.

4.1 Swedish regulation

From the re-regulation of the Swedish electricity market in 1996 to the end of 2002, the Swedish DSOs were regulated based on their actual costs. The ROR regulation was conducted based on the DSOs annual financial accounts, but due to extensive mergers and acquisitions in connections with the restructuring of the power market, the financial accounts were more or less regarded as inadequate for economic regulation. The regulation conducted by the regulatory authority, the Swedish Energy Agency (STEM), was rather inefficient since much attention was put on legal technicalities and time-consuming investigations, determining whether certain costs were justified [32].

As from the beginning of 2003 the Swedish DSOs are regulated according to the Network Performance Assessment Model (NPAM). The regulation is conducted ex-post so the first regulatory results were made available in 2004. The Swedish electricity act, which to some extend has been developed and adjusted parallel to the development of the NPAM, states that: “The network tariffs shall be reasonable and based on objective criteria” [64]. The NPAM means a major
switch in regulatory policy, the regulation is meant to take the customer’s point of view, which is comprehended by valuing the customers’ benefit of power distribution [32]. Other aspects that are not considered to influence the experienced value of the service, such as grid history, geographical and demographical issues, are ignored in the valuation. The NPAM uses a reference network model that includes the regulators definition of DSOs’ objective prerequisites as input data. The objective prerequisites in the NPAM are the location, energy consumption/production, subscribed capacity\(^9\), voltage level and generated revenue of all customers, production units and feeding points.

The output is a ratio, called the debiting rate, between the DSO’s revenue and the Network Performance Assessment (NPA) calculated in the model. The debiting rate indicates how much the DSOs charge their customers relative the costs of the reference network. A debiting rate of more than one indicates that the DSO is over charging its customers\(^{10}\). The paradigm switch in regulatory regime also means a switch regarding who has the burden of proof. Now the DSOs have to justify why their revenue deviates from the reference value, the NPA.

The customer values used in the NPAM can be categorised into four areas; connection, connection reliability, delivery and grid administration [32], where:

- **Connection** refers to the physical feeding grid connecting a specific location, that has a certain demanded for electric energy.

- **Connection reliability**, due to the stochastic nature of technical systems the DSOs will add redundancy in the network in order to meet the customers demand for quality of supply. This item refers to the redundancy needed to meet these specifications.

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\(^9\) Only certain customers with capacity subscriptions.

\(^{10}\) When the Swedish DSOs were regulated based on the figures of 2003, DSOs with a debiting rate of 1.2 or more were reviewed. Reviewing is the first step in a series of action that STEM takes in its in-depth analysis before its verdict.
Delivery refers to the unavoidable losses that occur in power distribution. It is the energy losses in the reference grid that are considered, the actual losses are disregarded.

Grid administration refers to those values that are the result of having customers such as metering, billing and customer service.

Figure 4.1 displays the basic information flow in the NPAM. As shown in the figure, the regulation of economic efficiency of the NPAM includes the quality regulation, which influences the regulatory outcome.

Figure 4.1. Flow of information in the NPAM

Comment 1, the costs towards upstream network is considered as an objective prerequisite and therefore transferred through the model as a negative income. Also, the voluntary refunds some DSOs pay to customers affected by very long interruptions are deductible in the model.
A central issue in the NPAM is the *customer density*, which is the length of cables and overhead line per connected customer either in a limited area or the whole reference grid. The cost functions for grid establishment, the expected interruption cost template functions as well as the grid adjustment functions are customer density dependent.

To describe the NPAM properly, the economic efficiency regulation is described separate from the quality regulation.

### 4.1.1 Efficiency benchmark

Central in the NPAM is the reference network, it constitute the basis for the estimation of all capital costs and most operational costs as well as the expected interruption costs. The reference network, constructed based on the DSOs objective prerequisites, is a radial grid consisting of maximum four voltage levels and constructed with as few components as possible given the constraints of the input parameters. Voltage level 1 (0.4 kV) and 2 (10 kV) consists of cable networks, voltage levels 3 (40 kV) and 4 (130 kV) consists of overhead line networks. The reference grid is the sum of three separate steps in the construction process; *nominal grid*, *adjustment grid*, and *redundancy grid*. This process is displayed in fig 4.2

![Figure 4.2. Basic construction process of the reference network.](image)
In each part of the process there are several algorithms, constraints and template function working parallel in constructing a functional grid. Further details on this process and its ingredients can be found in [33].

Nominal grid is the foundation of the reference network. It is a radial grid constructed based on each DSOs’ objective prerequisites. The grid is constructed voltage level by voltage level beginning with the LV grids. The constraints on features such as voltage drop and length on cables and overhead lines, aggregated load on transformers, reactive power, thermal limitations and system losses set the model limits for each voltage level.

Adjustment grid, in order to consider geographical obstacles between connections such as buildings etc., the NPAM adjusts the length of each cable and overhead line in the nominal grid based on the customer density in which the cable or overhead line is located.

Redundancy grid, due to the stochastic behaviour in technical system in general and power systems in particular the nominal and adjustment grid is not sufficient to meet the customers’ demand for quality of supply. Due to this, redundancy is added in the reference grid. This is conducted in form of extra length and capacity of cable/overhead line and transformers respectively. The amount of extra capacity added is defined in customer density dependent template functions for the cable/overhead line and transformers of each voltage level. How these template functions were developed is described in section 4.1.2.

The valued performance of each DSO is calculated based on the costs that the DSO would have for building, operating and maintaining the reference network, the NPA_{max}. Assuming that the NPAM is used as a revenue cap regulation model, the NPA_{max} can be referred to as the DSO’s maximum allowable revenue. However, in order to comprehend the quality of supply into the regulation, the NPA_{max} is adjusted due to quality performance, explained in equation 4.2, this is the NPA_{actual}, which is used to calculate the debiting rate.

\[
\text{Debiting rate} = \frac{\text{Actual revenue}}{\text{NPA}_{\text{actual}}} \tag{4.1}
\]
The debiting rate is the business ratio used for the efficiency benchmark in the Swedish regulation since it indicates how each DSO charge compared to the yardstick, i.e. the reference grid.

### 4.1.2 Quality regulation

The output of the quality regulation in the NPAM is an adjustment of the maximum NPA or the maximum allowable revenue. The adjustment is based on the DSOs’ interruption cost, IC, valued based on the reported reliability performance indicators and what the documentation of the NPAM refers to as the DSOs’ expected IC, which actually is the IC threshold henceforth called $IC_{\text{min}}$.

$$\text{Quality adjustment} = IC_{\text{min}} - IC_{\text{valued}}$$  \hspace{1cm} 4.2

At present, 2005, there are two constraints regarding the quality adjustment, these are also illustrated in figure 4.3.

1. **Negative**, even if the expected IC is higher than the valued IC, the adjustment is not positive. The expected IC is defined as the IC that would be if the grid holds the optimal amount of redundancy. This means that a positive adjustment, $NPA_{\text{actual}}$ higher than $NPA_{\text{max}}$ would imply that the customers are charged for better quality than they are willing to pay for.

2. **Less or equal to the NPA corresponding to the redundancy grid**, $NPA_{\text{min}}$. The reference grid without the redundancy grid is supposed to represent a radial grid, which is regarded the type of grid that would have the worst quality level. Consequently, the minimum allowable revenue corresponds to the NPA of worst quality level.

As mentioned in section 4.1.1, the quality adjustment, which is negative or zero, is used to determine the $NPA_{\text{actual}}$.

$$NPA_{\text{actual}} = NPA_{\text{max}} - \text{Quality adjustment}$$  \hspace{1cm} 4.3
This means that the adjustment function describing the allowable revenue the following characteristics, showed in figure. 4.3.

![Quality adjustment function in the NPAM](image)

*Figure 4.3. Quality adjustment function in the NPAM.*

The DSOs’ IC\textsubscript{valued}, the real interruption cost according to the regulator, are calculated based on the system reliability performance indices, SAIDI and SAIFI, which the DSOs are obliged to report annually for announced and unannounced interruptions separately. The duration and frequency valuation in the NPAM is based on a customers’ IC survey, performed in 1994 and updated in 2003. To enable the usage of the results of the IC survey, the format has been modified. The Customers’ costs due to interruptions are represented as customer-density dependent cost-function of interrupted energy and capacity, for both announced and unannounced interruptions. Since both SAIDI and SAIFI are aggregated indices, the regulator has no idea which customers that actually have been affected by the interruptions and as a result, the IC valuation must be uniform in such sense that it does not consider customers category. The valued IC-functions that are currently used are displayed in figure 4.4.
Figure 4.4. Interruption cost valuation used in the NPAM [33].

The IC is calculated according to equation 4.4

\[
IC = \sum_{i} \sum_{a} \left[ \left( \text{SAIDI}_i \times C_{Eia} \times \frac{E_a}{8760} \right) + \left( \text{SAIFI}_i \times C_{Cia} \times \frac{E_a}{8760} \right) \right]
\]

4.4

\(C_E\) and \(C_C\) are the costs associated with energy and capacity in figure 4.4. \(E_a\) is the energy consumption in area \(a\), \(i\) indicates unannounced, 1, and announced, 2, interruptions and \(a\) are the different areas within the reference grid.

The estimations of the expected IC are the results of comprehensive reliability simulations performed on typical test reference grids by the originator of the NPAM, Mats B-O Larsson. The basic assumption that constitute the foundation for the quality feature in the NPAM is that the DSOs should uphold or strive towards the level of quality that the customers are willing to pay for. So in order determine the quality level that each DSO should strive towards the model have to determine the optimal level of redundancy in each DSO and how much IC that the interruptions cause in an optimal redundant grid. The mathematical
definitions for the method used to develop the template functions that determines these issues can be found in [32].

The approach was to perform MCS for each voltage level of the cables/overhead lines and transformers to calculate the IC of radial grid and compare the costs to those of alternative supply routes that would have prevented the interruption causing the costs. The simulation was performed so that the redundant supply routes were added gradually until no other modification would be economically feasible. This was performed for various kinds of grids and the result was the template functions for redundancy describing how much extra cable/overhead line length and transformer capacity that should be added for each voltage level depending on the customer density in order to meet the customers’ demands for quality of supply. The IC features used in the simulation were based on the IC functions displayed in fig. 4.4.

The results from these MCS were used to perform reliability analysis on an optimal redundant grid, and the result of that was transformed to a template function describing how much IC that each system component generates, cables, over head lines and transformers, depending on the delivered energy and customer density. In other words the scaling factor for the expected IC is the delivered energy. This is basically the case for most scaling features in the NPAM.

As a complement to the debiting rate, STEM also uses a quality index (QI) in its regulation to indicate poor performing DSOs quality wise.

\[
QI = \frac{2 \times IC_{\text{min}}}{IC_{\text{min}} + IC_{\text{valued}}} \tag{4.5}
\]

A QI of more than one indicates that the DSO has better quality than expected, less than one indicates the opposite.

### 4.2 Norwegian regulation

On the European level Norway is one of the pioneers in their early re-regulation of the electricity market, in 1991, and in their introduction of performance-based
regulation of DSOs, in 1997. From 1991 until 1996, the Norwegian Water Resources and Energy Directorate (NVE) used Cost-Plus regulation on the Norwegian DSOs. In 1997, NVE introduced incentive-based regulation where the economic efficiency and historical costs had impact on the capped revenue [26]. Even if the Norwegian DSO were obliged to report their interruption to NVE, the quality of supply was not considered at all in the regulation during the first period. The efficiency benchmark that affects the allowable revenue as a $Y$-factor, eq 3.1, was and still is performed using DEA benchmarking, described in chapter 3.3.1.1.

### 4.2.1 Efficiency benchmark

The regulation is conducted ex-ante, where the DSOs apply to set a certain tariff for the next-coming year. The initial cost-base for each DSO is set in the beginning of the regulatory period, but the only feature that is directly linked to the actual cost was that base set for the first regulatory period. The DEA model used for the economic efficiency benchmark is VRS, which means that the DSOs are divided into classes based on environmental factors. The input, output used in the benchmark as well as the environmental factors are presented in table 4.1 [26]:

*Table 4.1. Model parameters in Norwegian regulation.*

<table>
<thead>
<tr>
<th>Inputs</th>
<th>Outputs</th>
<th>Environmental factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of man labour years</td>
<td>Delivered energy</td>
<td>Network length</td>
</tr>
<tr>
<td>Net losses</td>
<td>Number of connected customers</td>
<td>Sea cable length</td>
</tr>
<tr>
<td>Net assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operation expenses</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The regulation is conducted in periods of 5 years, during this period the generic $X$-factor is fixed. This means that the DSOs know the expected efficiency
improvement that the regulator has on the business as a whole. The individual $X$-factors are determined through the efficiency benchmark.

During the first regulatory period, 1997 - 2001, the Norwegian DSOs were regulated solely based on their cost efficiency. The reason for this was to tune the cost efficiency parameters before introducing any form of quality regulation. However, as from 1995 the reporting of interruptions longer than 3 minutes has been mandatory, but no action on poor quality performing DSOs was taken at that point.

For the second regulatory period, 2002 – 2006, quality dependent revenue caps were introduced in form of adding the CENS arrangement, Compensation for Energy Not Supplied, to the previous economic efficiency regulation. The adding of the CENS arrangement meant that the allowable revenue was adjusted according to the DSOs quality performance.

### 4.2.2 Quality regulation

The quality regulation introduced for the second regulatory period was conducted according to the CENS-arrangement. When first implemented the customers were divided according into two categories, commercial/industrial and residential/agricultural. The costs of ENS were defined for announced and unannounced interruptions. Since implemented the customer representation has changed, it is currently, 2004, defined for five different customer categories. The cost of ENS used in the CENS-arrangement during 2004 are presented in table 4.2 [27], they are based on customer surveys conducted in 1989 – 1991, the results have been adjusted due to inflation.
Table 4.2. The cost of ENS used in the Norwegian quality regulation (2004)\(^{11}\).

<table>
<thead>
<tr>
<th>Customer type</th>
<th>Unannounced int. [euro/kWh], (C_{i \bar{c}})</th>
<th>Announced int. [euro/kWh], (C_{2 \bar{c}})</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Industrial</td>
<td>8.21</td>
<td>5.72</td>
</tr>
<tr>
<td>2. Commercial</td>
<td>12.31</td>
<td>8.46</td>
</tr>
<tr>
<td>3. Residential</td>
<td>1.00</td>
<td>0.87</td>
</tr>
<tr>
<td>4. Public</td>
<td>1.62</td>
<td>1.24</td>
</tr>
<tr>
<td>5. Large industrial</td>
<td>1.62</td>
<td>1.37</td>
</tr>
</tbody>
</table>

The actual CENS is calculated as:

\[
CENS = \sum_{i} \sum_{c} C_{i \bar{c}} \times ENS_{i \bar{c}} = \sum_{i} \sum_{c} C_{i \bar{c}} \times D_{i \bar{c}} \times \frac{E_{c}}{8760}
\]

Where \(i\) indicates whether the interruptions was announced or not and \(c\) the customer categories, 1 - 5 in table 4.2. \(D\) is the total interruption duration and \(E\) the energy consumption for each separate customer category.

Similar to the Swedish quality regulation, the allowable revenue is adjusted according to the difference between the expected CENS and the actual CENS [24]. One significant difference however is that there are no limits on the adjustment. This means that the Norwegian DSOs can be allowed to charge according to a tariff higher than the one set in the efficiency regulation, and also theoretically that the allowable revenue can be zero or lower.

---

\(^{11}\) 1 euro equals 8.04 NOK.
Since the regulation of economic efficiency is conducted ex-ante, which is not possible when regulating the quality, the DSOs’ CENS are estimated ex-ante and corrected ex-post. This means that one year’s quality has an impact on the subsequent year’s allowable revenue.

The DSOs’ estimated Energy Not Supplied (ENS) is calculated using a regression model that uses ENS data reported during the first regulatory period and adjusts it with respect to changes in delivered energy, grid expansions and weather conditions. A detailed description of the regression model can be found in [59].

### 4.3 Spanish Regulation

Spain started deregulating its electricity market in 1997. At first only high-consuming\(^{12}\) customers were able to choose electricity supplier. However, the re-regulation will take place gradually and by 2007 all customers will be able to choose electric energy supplier [41].

#### 4.3.1 Efficiency benchmark

The regulatory system of Spanish DSOs is quite unique in its kind. It is a centralized remuneration scheme. The Spanish National Energy Commission (CNE) differentiates the customers into six categories based on their voltage level. The customers within each category are charged according to a uniform distribution tariff, which is paid directly to CNE. Since the payment link between customers and DSO is removed, the efficiency benchmark is basically a matter of dividing the money paid by the customers between the DSOs.

Each DSO’s remuneration received from CNE for owning, operating and maintaining their grids are determined based on their previous remuneration, it is calculated according to equation 4.6.

\(^{12}\) Energy consumption greater than one GWh.
\[ R_{t+1} = R_t (1 + RPI - X) + L_t + Q_t + E_t \]

where;

- \( L_t \) Load growth compensation
- \( Q_t \) Quality of service incentive
- \( E_t \) Forecast errors compensation, adjustment for unseen events beyond management’s control, such as increased taxes, changes in environmental laws, natural disasters or restructuring costs [40]

A crucial issue with this kind of revenue cap, as in all \( RPI - X \) regulations, is to determine the remuneration in the starting year and according to the Spanish Electricity law 54/1997 the method for doing this should not only be based on objective, non-discriminatory and transparent criteria, but also consider the geographic and market characteristics of each distribution area [41].

Parallel to and independent of the Swedish development of the NPAM, Spain has developed reference network models for estimations of the initial revenue cap, the load growth, the quality of service incentives and the technical efficiency of the DSOs. The first proposal to the PECO model was presented in 1999, and the implementation was supposed to be conducted for the Spanish Tariff Revision 2004. The PECO-model is named after its originator Jesús Pascual Peco González.

Compared to the NPAM, the PECO model is more detailed and considers factors that are not included in the NPAM such as; geographical and typographical constraints, peak loads and can include the substations’ and transformer coordinates when it constructs the reference network. The minimum requirement of customers data is coordinates, subscribes capacity and annual energy consumption. The main features of the model are [39]:

1. The model can consider location of customers, transformers, substations and networks.

2. Settlements are determined automatically as far as street maps.
3. The model can consider forbidden zones map-orography if it’s given by the user.

4. Optimization of urban networks, considering street maps, and rural network, considering the orography etc, simultaneously.

5. The network components used in the model can easily be customized with the geographic interface.

6. The network is dimensioned by; minimizing the costs of investments, operation and maintenance and losses, which are subjected to capacity, voltage and reliability constraints when taken into account present and future demands.

7. Reliability assessment that considers the real process following a system failure; detection, locating and clearance of the fault as well as service restoration.

8. The reliability assessment computes the system’s cost of ENS, at customer level if necessary.

9. The results of the model are enabled for detailed display of power flow, reliability, system components and network topology.

The PECO model can actually be used for grid planning and operation optimization. It has three modes in order to comprehend the different agendas:

*Greenfield planning mode*, the actual grid is not considered. Given the location of LV, MV and HV customers together with the size and location of the transmission substations the model can; design an optimal distribution network or compute the replacement cost of an existing network. This is the feature is used within the regulation.

*Distribution network planning mode*, given the location of the substations and/or the MV/LV transformers, as well as the customers’ location and demand.
Optimization mode, given the topology of the LV and MV network the model can optimize the conductor sizing, losses and/or quality of supply. This feature is suitable for assessing MV network costs vs. quality of supply.

4.3.2 Quality regulation

The reliability constraints, point 6, in the reference model are used for network optimization in the efficiency benchmark or network planning. The actual quality regulation is conducted on two levels; system and customer level. On system level there are performance limits on ASIDI, ASIFI aggregated for each DSO as well as the 80 percentile limit of all areas within a company, table 4.3. These limits are not to be exceeded, should that happen, the DSO must propose a quality improvement plan, which has to be approved by the Regional Administration. Should the plan be delayed or if the DSO fails to carry it out, the DSO can be penalized. The DSO can be compensated with as much as half of the costs for implementing the improvement plan. The quality regulation on system level does not include the LV customers [41].

Table 4.3. System indices limits [41]

<table>
<thead>
<tr>
<th></th>
<th>ASIDI [h/y]</th>
<th>ASIDI 80% [h/y]</th>
<th>ASIFI [int/y]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urban</td>
<td>2</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>Semi-urban</td>
<td>4</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Rural concentrated</td>
<td>8</td>
<td>12</td>
<td>10</td>
</tr>
<tr>
<td>Rural dispersed</td>
<td>12</td>
<td>18</td>
<td>15</td>
</tr>
</tbody>
</table>

The quality regulation on customers level is also based on pre-determined interruption levels for interruption duration and frequency, table 4.4. If a customer suffers from more interruptions than pre-determined limits of interruption frequency and/or duration, the customer receives a remuneration of five times the energy price of the estimated ENS of the interruption exceeding the pre-determined limits [41]. If both limits are exceeded the remuneration most favourable for the customer is valid.
Table 4.4. Customer interruption limits for LV and MV customers [41]

<table>
<thead>
<tr>
<th></th>
<th>LV</th>
<th></th>
<th>MV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( \lambda ) [int/y]</td>
<td>( U ) [h/y]</td>
<td>( \lambda ) [int/y]</td>
</tr>
<tr>
<td>Urban</td>
<td>12</td>
<td>6</td>
<td>8</td>
</tr>
<tr>
<td>Semi-urban</td>
<td>15</td>
<td>10</td>
<td>12</td>
</tr>
<tr>
<td>Rural concentrated</td>
<td>18</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Rural dispersed</td>
<td>24</td>
<td>20</td>
<td>20</td>
</tr>
</tbody>
</table>

The remuneration is paid from the DSO directly to the customer. When including the quality regulation, the Spanish remuneration scheme can be illustrated as in fig. 4.5 [49].

Figure 4.5. Remuneration scheme in the Spanish regulation.
4.4 Dutch Regulation

Before 2000, the regulation of the Dutch DSOs was conducted according to a traditional cost-based regulation method. In 2001, the Dutch Office for Energy Regulation (DTe) introduced price caps on the distribution tariffs, and during this first regulatory period, 2002 – 2004, DTe regulated the DSOs solely based on their economic efficiency. DEA-benchmarking similar to the Norwegian approach was used to determine the $Y$-factors in an effort to uniform the DSOs’ economic efficiency.

4.4.1 Efficiency benchmark

As of 1 January 2005, DTe has introduced yardstick competition in form of quality dependent price caps. The reason for introducing efficiency before introducing the quality regulation is an attempt to level out the DGOs efficiency differences before starting to regulate on quality. During the second regulatory period, 2005 – 2007, the efficiency regulation of Dutch DSOs will be conducted using Total Factor Productivity (TFP). TFP-benchmarking is based on the same fundamental theory as DEA [28]. However, while DEA measures actual efficiency, TFP measures the change in efficiency or productivity. An estimation of the future productivity of the frontier shift sets the generic $X$-factor. The efficiency frontier consists of the DSOs that have achieved full efficiency during the first regulatory period, 2002 - 2004. The difference between the estimated and the actual efficiency improvement is brought on to the subsequent period, and in this way the DSOs performing better than average frontier shift will be more profitable than those performing worse than the efficiency frontier [28], thus a fictitious competitive market. The allowable revenue for DSO $i$ will be calculated using equation 4.8 [30].

\[
R_{i,j} = (1 + RPI_i - X + Y) \times R_{i,j-1} \tag{4.8}
\]

4.4.2 Quality regulation

The quality regulation is conducted ex-ante, where a quality factor ($q$-factor, $Y$) for the coming three-year period is calculated based on the quality performance of the two previous periods. Since the quality regulation is implemented in the beginning of the second regulatory period the quality factors for this period
cannot be set as they are to be set later on. This means that the way it is conducted will change for the next period in such sense that the data from the this period will then be available. The quality regulation includes all LV customers\textsuperscript{13}. Based on the total interruption time and the number of customer interruptions, together with the total number of customers, three customer weighted performance indicators are calculated; SAIDI, SAIFI and CAIDI. The $q$-factor is determined using the following formula\textsuperscript{14} [31]:

\[\sum_{k \in P_0} R_{i,k}^q + (\pi_{i,P_1} - \pi_{i,P_2}) = \sum_{k \in P_0} R_{i,T-1}^\prime \cdot (1 + Y_{i,P_0})^{k+1-T}\]

\[P_0 = \{T, \ldots, T+M-1\}\]
\[P_1 = \{T-M-1, \ldots, T-2\}\]
\[P_2 = \{T-2M-1, \ldots, T-M-2\}\]

$M$ is the length of the regulatory period that starts in year $T$. $i$ indicates the DSO and $P_0, \ldots, P_2$ the regulatory periods, where $P_0$ is the next period, $P_1$ the previous and $P_2$ the one before that. $R^q$ is the total revenue excluding the $q$-factor and $R^\prime$ is the total revenue when calculated based on the actual change in productivity. The total revenue is the product of average volume and the capped price. The quality performance ($\pi_i$ in equation 4.9) for DSO $i$ is determined as follows [31], The quality performance for $P_2$ is determined analogously\textsuperscript{15}:

\[\pi_{i,P_1} = \sum_{k \in P_1} N_{i,k} \cdot \varphi_{P_1} (\text{SAIDI}_{P_2} - \text{SAIDI}_{i,P_1}) + CV_{i,P_1}\]

\textsuperscript{13} Voltage level less or equal to 1kV.

\textsuperscript{14} The year $T-1$ is excluded from $P_0, \ldots, P_2$, this year is used as an accumulation/correction–year for which the price index is first calculated, and then weighted for $M$ years so that the price level of $T$ up to $T + M - 1$ can be used.

\textsuperscript{15} This is true if the quality performance of the period is assessable, which is not the case two periods before the first one, 2004 - 2005. How this is solved can be found in [31].
\( N_i \) is the total number of customers of DSO \( i \), CV is the compensation allowance, which is based on the interruption compensation for DSO \( i \) during period \( P_1 \), \( \varphi_{P1} \) is the evaluation of an interruption of a minute in period \( P_1 \) and determined as [31]:

\[
\varphi_{P1} = \frac{W_{P2}}{SAIDI_{P2}} \quad 4.11
\]

\( W_{P2} \) is the weighted interruption valuation for period \( P_2 \) determined as:

\[
W_{P2} = C^H\left(\overline{SAIFI}_{P2}, \overline{CAIDI}_{P2}\right)H + C^B\left(\overline{SAIFI}_{P2}, \overline{CAIDI}_{P2}\right)B \quad 4.12
\]

Where \( C^H(x,y) \), \( H \) and \( C^B(x,y) \), \( B \) are the interruption valuation function and the percentage of households and companies respectively.

The interruption valuation functions are specified as four different functions for commercial and residential customers separately. The function will not be included in this thesis, but can be found in [31]. Which function that is used depends on the input data, which is the outage duration and frequency indicators, SAIFI, and CAIDI. Fig. 4.6 illustrates the simplified characteristics of the functions.

![Diagram](image_url)

*Figure 4.6. Characteristics of \( C^H(x,y) \) and \( C^B(x,y) \).*
The basic layout of these functions is based on the interruption duration and frequency indicator thresholds, $\hat{D}$, $\hat{F}$ in figure 4.6 and table 4.5. The outage duration is the domination feature for poor performing DSOs, i.e. area 1 and 2, and the outage frequency for DSOs with good quality of supply, i.e. area 4. In areas 1 and 2 the output is negative, in area 3 it is zero and in area 4 it is positive. This means that the performance, equation 4.10, is positive in area 1 and 2, zero in 3 and negative in area 4. The general relationship in valuation of interruptions for commercial/industrial and residential is a factor of 7-8. The indicator thresholds are displayed in table 4.5 [31].

Table 4.5. Interruption valuation function indicator’s thresholds

<table>
<thead>
<tr>
<th></th>
<th>$C^H(F,D)$</th>
<th>$C^B(F,D)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\hat{F}$ [int/y]</td>
<td>0.12</td>
<td>0.08</td>
</tr>
<tr>
<td>$\hat{D}$ [h/y]</td>
<td>0.35</td>
<td>0.24</td>
</tr>
</tbody>
</table>

The maximum quality adjustment is set to ± 5% of the total revenue, which means that the adjustment is both floored and ceiled. The Dutch quality regulation is displayed in fig. 4.7.

Figure 4.7 Illustration of the Dutch quality of supply regulation.
As illustrated in figure 4.7 the q-factor for the coming period is positive since estimated quality level is better than the sufficient level.

## 4.5 Quantitative comparison

In order to receive a good overview of the differences in the regulations described in this chapter, the regulatory models are compared based on the key incentive features presented in chapter 3.3.3. Table 4.6 shows a qualitative comparison, which also makes a good foundation for a quantitative comparison. A qualitative comparison like this should be confirmed with a quantitative comparison. A previous qualitative benchmarking study, including different quality regulations, was performed by the Council of European Energy Regulators (CEER) [58], however the study had no distinct conclusions due to the lack of quantitative comparison, which made the different regulators definitions of reliability much harder to compare.
Table 4.6. Qualitative comparison of quality regulation models.

<table>
<thead>
<tr>
<th></th>
<th>Sweden</th>
<th>Norway</th>
<th>Spain</th>
<th>Holland</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Quality significance$^1$</td>
<td>High (~ 20%)</td>
<td>High (~ 10%)</td>
<td>Small (&lt; 5%)</td>
<td>Medium (≤ 10%)</td>
</tr>
<tr>
<td>II. Conduct code</td>
<td>Light-handed</td>
<td>Heavy-handed</td>
<td>Light-handed</td>
<td>Heavy-handed</td>
</tr>
<tr>
<td>III. Implementation$^2$</td>
<td>Ex-post</td>
<td>Ex-ante</td>
<td>Ex-ante</td>
<td>Ex-ante$^3$</td>
</tr>
<tr>
<td>i. Included factors</td>
<td>Duration and Frequency</td>
<td>Duration</td>
<td>Duration and Frequency</td>
<td>Duration and Frequency</td>
</tr>
<tr>
<td>ii. Weighting indicators</td>
<td>Customer</td>
<td>Capacity</td>
<td>Capacity</td>
<td>Customers</td>
</tr>
<tr>
<td>iii. Mitigating factors</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>iv. Customer representation</td>
<td>Density</td>
<td>Customer category</td>
<td>Density</td>
<td>Customer category</td>
</tr>
<tr>
<td>v. Including planned interruptions</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>vi. Separating internal and external faults</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>vii. Aggregation level</td>
<td>Customer lever</td>
<td>≥ 1 kV</td>
<td>Customer and system level</td>
<td>Customer level</td>
</tr>
<tr>
<td>viii. Adjustment function characteristics</td>
<td>Capped adjustment</td>
<td>Unrestricted</td>
<td>Entrance threshold</td>
<td>Capped adjustment</td>
</tr>
<tr>
<td>ix. Length of quality regulation period [Years]</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>3</td>
</tr>
</tbody>
</table>
Comments to table 4.6.

1) The level of significance that the quality of supply has on the total revenue is classified according to: less than 5 % is defined as small, between 5 and 10 % as medium and over 10 % is defined as high significance. The reason why the Dutch regulation is set to medium and not the Norwegian is the fact the Dutch quality rewards/penalties are set so that extreme cases becomes very rare, this is not the case in Norway where interruptions become quite costly to the DSOs.

2) As defined in section 3.3.3, the implementation refers to the regulatory regime as a total, no the quality regulation.

3) In the Dutch regulation the quality is estimated ex-ante, but since the estimation is conducted based on historical development, one might say that it is corrected ex-post.
Chapter 5

Reliability in PBR

This chapter links chapter 2, 3 and 4 together by the use of a test system on which some generally defined quality regulations are applied. By using MCS, described in chapter 2, to simulate the system reliability of the test system the quality regulations are evaluated and analysed. The generally defined quality regulations are based on the applied PBR models described in chapter 4. The main contribution of this chapter lay within the methodology by which the generally defined quality regulations are analysed. The system used for this analysis is a reliability test system (based on bus 4 of the RBTS [60]), which is also described in this chapter.

5.1 Analysing methodology

The method used to analyse and compare quality regulation is rather straightforward in its approach. It can be described with the following three steps: identification – simulation – analysis. The identification includes determining the key incentive features within each quality regulation model that is to be analysed. The simulation technique used has been described in section 2.3.5, however, in addition it must be stressed that in order to quantitatively compare various regulation models the results should come from the same simulations, or at least from simulation on the same system. The simulation output data can then be used for extensive analysis.

Based on the applied regulation model described chapter 4, some generic quality regulation models have been constructed. These are presented after the description of the test system that is used in this chapter. At the end of this
chapter there are a quantitative comparison and analysis of the generic quality regulations.

5.2 Reliability test system

The test system used for the bulk of the simulations performed in this project is based on bus 4 of the RBTS (Roy Billinton Test System) [60]. The system has been modified in order to correspond better to European conditions in general and Nordic conditions in particular [61]. The modifications are rather small; there are redundant bus bars, which are not displayed in fig. 5.1, and circuit breakers have been added on the primary side of the HV/MV transformers. Also the voltage levels have been altered to agree with typical Nordic grids. The test system used is displayed in fig. 5.1.
The system is a 7 feeder system containing 38 load points. It is fed at 40 kV and the main distribution is located at 10 kV. Residential and commercial customers are supplied at 0.4 kV and the industrial customers are fed at 10 kV. The 10 kV-system consists of underground cables and the 40 kV-system consists of overhead lines. There is only one supply point for the system. Both the 40 kV and the 10 kV-systems are meshed, however, while the 40 kV system is operated as a meshed network the 10 kV-system is operated as a radial network. The alternative supply routes in the 10 kV network, dotted lines in fig. 5.1, are normally open and switched to closed in case of faults. The standard operating procedures are described in chapter 2. The length of the cables as well as each
component type’s reliability data can be found in appendix B, originally from [60]. Henceforth, this system is called test system 2.

In test system 2 there are five different types of load points (LPs), the LP-types are specified in table 5.3 regarding number of customers, type of customers, the average and peak loads [60].

Table 5.3a. Load point type specification

<table>
<thead>
<tr>
<th>Type</th>
<th># of customers</th>
<th>Customer type</th>
<th>Average load [MW]</th>
<th>Peak load [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>220</td>
<td>Residential</td>
<td>0.5450</td>
<td>0.8869</td>
</tr>
<tr>
<td>2</td>
<td>200</td>
<td>Residential</td>
<td>0.5000</td>
<td>0.8137</td>
</tr>
<tr>
<td>3</td>
<td>10</td>
<td>Commercial</td>
<td>0.4150</td>
<td>0.6714</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>Industrial</td>
<td>1.0000</td>
<td>1.63</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>Industrial</td>
<td>1.5000</td>
<td>2.445</td>
</tr>
</tbody>
</table>

The load points are assigned the data displayed in table 5.3b.

Table 5.3b. Load point type specification (cont).

<table>
<thead>
<tr>
<th>Type</th>
<th>F1</th>
<th>F2</th>
<th>F3</th>
<th>F4</th>
<th>F5</th>
<th>F6</th>
<th>F7</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>LP1 - 4</td>
<td>-</td>
<td>LP11 - 13</td>
<td>LP18 - 21</td>
<td>-</td>
<td>-</td>
<td>LP32 - 35</td>
</tr>
<tr>
<td>2</td>
<td>LP5</td>
<td>-</td>
<td>LP14, 15</td>
<td>LP22, 23</td>
<td>-</td>
<td>-</td>
<td>LP36, 37</td>
</tr>
<tr>
<td>3</td>
<td>LP6, 7</td>
<td>-</td>
<td>LP16, 17</td>
<td>LP24, 25</td>
<td>-</td>
<td>-</td>
<td>LP38</td>
</tr>
<tr>
<td>4</td>
<td>-</td>
<td>LP8, 10</td>
<td>-</td>
<td>-</td>
<td>LP26 - 28</td>
<td>LP29, 30</td>
<td>-</td>
</tr>
<tr>
<td>5</td>
<td>-</td>
<td>LP 9</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>LP31</td>
<td>-</td>
</tr>
</tbody>
</table>

5.3 General regulatory quality regulation models

Based on the applied quality regulations described in chapter 4, some generic base cases for quality regulation have been defined. The definitions include; reliability performance indicators used, how the customers are represented and the adjustment function characteristics. Test system 2 is then simulated for two different lengths of regulatory periods and evaluated based on these generic cases. The base cases are defined in table 5.4. The reason for choosing these
features to alter in the qualitative comparison is first of all their general importance and the fact their impact is rather easy to illustrate.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|}
\hline
Case & Reliability indicator & Customer representation & Adjustment function \\
\hline
1 & SAIDI, SAIFI & Uniform & - \\
2 & SAIDI, SAIFI & Uniform & Ceiling and floor \\
3 & SAIDI, SAIFI & Customer type & - \\
4 & SAIDI, SAIFI & Customer type & Ceiling and floor \\
5 & ASIDI, ASIFI & Uniform & - \\
6 & ASIDI, ASIFI & Uniform & Ceiling and floor \\
7 & ASIDI, ASIFI & Customer type & - \\
8 & ASIDI, ASIFI & Customer type & Ceiling and floor \\
9 & ENS & Customer type & - \\
10 & Actual interruptions; $\lambda$, $U$ & Customer type & Remuneration threshold \\
\hline
\end{tabular}
\caption{General quality regulation models}
\end{table}

Compared to the applied cases in chapter 4 there are differences, however the fundamental strategy can be identified. Linking the applied cases to those presented in table 5.4; case 2 is similar to the Swedish quality regulation, case 9 similar to the Norwegian quality regulation and case 10 show resemblance to the Spanish remuneration scheme. The Dutch quality regulation on the other hand is harder to make into generic case, but case 4 would be the case that show most resemblance to the Dutch regulation.

In order to analyse comparable and relevant cases, all models in table 5.4 have significant impact on the total revenue, i.e. 5 – 20 % of what would be the revenue if it is calculated using the full-scale test data of the NPAM in table 5.6. To be able to compare the regulation methods, the relative interruption cost (IC) valuations are chosen so that a system average of one interruption during one hour generates the same IC for capacity weighted indicators for both energy and capacity individually regardless of whether the valuation used is uniform or category specified. The value of the customer specified IC is based on the Norwegian CENS-arrangement [27] and the report on which the valuation in the
NPAM is based on [63]. The relationship of energy vs. capacity in table 5.5 is also based on [63].

Table 5.5. ICs used in the generalized comparison

<table>
<thead>
<tr>
<th>Customer specific</th>
<th>Uniform</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>C_{SE}</td>
</tr>
<tr>
<td>[euro/kWh]</td>
<td>[euro/kW]</td>
</tr>
<tr>
<td>1) Residential</td>
<td>2</td>
</tr>
<tr>
<td>2) Commercial</td>
<td>14</td>
</tr>
<tr>
<td>3) Industrial</td>
<td>11</td>
</tr>
</tbody>
</table>

The calculation of the IC for the different cases is based on how the calculations are conducted in the applied models in chapter 4, i.e. equations 4.4 and 4.6. The IC with “unrestricted” quality adjustment is calculated according to eq. 5.1 - 5.3. Equation 5.1 is valid for cases that apply the uniform customer representation (1, 5) equation 5.2 is valid for cases that apply the specified representation (3, 7, 9) and 5.3 is used for case 7.

\[
IC = D_{tot} \times C_{UE} \times \frac{E_{tot}}{8760} + F_{tot} \times C_{UC} \times P_{Atot} \tag{5.1}
\]

\[
IC = \sum_i \left( D_i \times C_{SEi} \times \frac{E_i}{8760} \right) + \sum_i \left( F_i \times C_{SCI} \times P_{Ai} \right) \tag{5.2}
\]

\[
IC = \sum_i \left( ENS_i \times C_{SEi} \right) \tag{5.3}
\]
Where $D$ represents the duration index, SAIDI or ASIDI, and $F$ represent the frequency index, SAIFI or ASIFI. $C$ is the cost specified in table 5.5. $E$ and $P_A$ are the energy consumption and the average load respectively, table 5.3a, $i$ and $tot$ indicates LP $i$ and the total amount for the whole system.

The ICs for the restricted cases, i.e. case 2, 4, 6 and 8, are calculated as for the corresponding unrestricted cases, i.e. case 1, 3, 5, and 7 respectively. After that the output IC is determined using the algorithm displayed in fig. 5.2.

![Algorithm for determining the output IC for case 2, 4, 6, and 8.](image)

The floor and ceiling in the quality adjustment, $IC_{min}$ and $IC_{max}$ in fig. 5.2, are set based on the results from a full scale test of the NPAM [34], the purpose of this choice originates in the goal pay special attention to the NPAM in the analysis. Since the floor and ceiling of the quality adjustment in each reference network
are based on how the model constructs the grid and therefore unique, the median values of the full-scale test are used. The costs are specified in cents/kWh\textsuperscript{16}.

Table 5.6. Results of the NPAM’s full scale test.

<table>
<thead>
<tr>
<th>Feature</th>
<th>Cost</th>
<th>Fraction of the maximum NPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum NPA</td>
<td>0.964 cents/kWh</td>
<td>100 %</td>
</tr>
<tr>
<td>Minimum NPA</td>
<td>0.766 cents/kWh</td>
<td>79.3 %</td>
</tr>
<tr>
<td>Maximum adjustment</td>
<td>0.199 cents/kWh</td>
<td>20.7 %</td>
</tr>
<tr>
<td>IC\textsubscript{min}</td>
<td>0.069 cents/kWh</td>
<td>7.1 %</td>
</tr>
<tr>
<td>IC\textsubscript{max}</td>
<td>0.268 cents/kWh</td>
<td>27.8 %</td>
</tr>
</tbody>
</table>

These values can be used to calculate interruption times that correspond to the IC\textsubscript{min} and IC\textsubscript{max}. Assuming that the customers-density is 50 m/customer, 10 euros/kWh in fig. 4.5 for unannounced interruptions, and that the whole system would be affected by one single interruption. Using equation 4.3, IC\textsubscript{min} would then correspond to a 36 minute-interruption and IC\textsubscript{max} would correspond to a 92 minute interruption. Since the valuation used for the quantitative comparison, table 5.5, is lower than the average valuation used in the NPAM, the duration limits for IC\textsubscript{min} and IC\textsubscript{max} were kept and new IC-levels calculated:

\[ IC_{\text{min}} = 120\,000\,\text{euro} \]
\[ IC_{\text{max}} = 480\,000\,\text{euro} \]

Compared to the Dutch quality regulation, where the adjustment limit is 10 % [31], this is higher. Thus, when using table 5.6 and the calculated IC\textsubscript{min} to calculate what would be the maximum allowable revenue for test system 2, the threshold for a revenue adjustment is approximately 5 % and the maximum adjustment is 15-20 % for the generic cases, this is illustrated in fig. 5.3.

\textsuperscript{16} 9 SEK is approximately 1 euro (2005-04).
The remuneration thresholds for individual customers regarding outage frequency and duration, cases 10, are chosen based on the Spanish quality regulation for semi-urban areas, i.e. 15 interruptions or 10 hours for 0.4 kV customers and 12 interruption and 8 hour for 10 kV customers, table 4.4. The costs are calculated as the expected ENS of the interruptions exceeding any of the predetermined limits, for each load point. The algorithm explaining how the IC is determined for LP $i$ is displayed in fig. 5.4.
5.4 Simulation results

Test system 2, was simulated using the MCS-model described in chapter 2.3.4 and analysed based on the quality regulation cases and restrictions in chapter 5.3. The number of samples, \( N \), was set to \( 10^6 \) and the duration of each sample, \( T_0 \), was set, according to two scenarios, to 1 and 3 years, cf. table 4.6. Table 5.7 presents the reliability performance indicators table of the 1 and 3 year scenarios.
Table 5.7 Simulation result, reliability performance indicators of test system 2.

<table>
<thead>
<tr>
<th></th>
<th>1 year average</th>
<th>3 year average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$\nu$</td>
<td>$\tau$</td>
</tr>
<tr>
<td>SAIDI [h/y]</td>
<td>2.196</td>
<td>1.882</td>
</tr>
<tr>
<td>SAIFI [int/y]</td>
<td>0.777</td>
<td>0.549</td>
</tr>
<tr>
<td>ASIDI [h/y]</td>
<td>1.883</td>
<td>1.431</td>
</tr>
<tr>
<td>ASIFI [int/y]</td>
<td>0.699</td>
<td>0.500</td>
</tr>
<tr>
<td>ENS [MWh/y]</td>
<td>46.3</td>
<td>35.2</td>
</tr>
<tr>
<td>CAIDI [h/y]</td>
<td>3.508</td>
<td>3.505</td>
</tr>
<tr>
<td>CAIFI [int/y]</td>
<td>1.337</td>
<td>0.539</td>
</tr>
</tbody>
</table>

As expected, the average value for the system performance indicators is the same for the 1-year and the 3-year average, except for CAIDI and CAIFI. The expected IC, E(IC), and corresponding standards deviation for the quality regulation cases in table 5.3 are presented in table 5.8.

Table 5.8. Interruptions costs for test system 2.

<table>
<thead>
<tr>
<th>Case</th>
<th>1 year average</th>
<th>3 year average</th>
<th>$\tau$(IC)$_3$/\tau$(IC)$_1$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>E(IC) [10$^3$ Euro]</td>
<td>$\tau$(IC)</td>
<td>E(IC) [10$^3$ Euro]</td>
</tr>
<tr>
<td>Case 1</td>
<td>443</td>
<td>362</td>
<td>443</td>
</tr>
<tr>
<td>Case 2</td>
<td>252</td>
<td>195</td>
<td>293</td>
</tr>
<tr>
<td>Case 3</td>
<td>382</td>
<td>275</td>
<td>382</td>
</tr>
<tr>
<td>Case 4</td>
<td>231</td>
<td>179</td>
<td>253</td>
</tr>
<tr>
<td>Case 5</td>
<td>139</td>
<td>107</td>
<td>139</td>
</tr>
<tr>
<td>Case 6</td>
<td>51</td>
<td>79</td>
<td>35</td>
</tr>
<tr>
<td>Case 7</td>
<td>339</td>
<td>299</td>
<td>339</td>
</tr>
<tr>
<td>Case 8</td>
<td>188</td>
<td>185</td>
<td>212</td>
</tr>
<tr>
<td>Case 9</td>
<td>304</td>
<td>289</td>
<td>304</td>
</tr>
<tr>
<td>Case 10</td>
<td>129</td>
<td>182</td>
<td>52</td>
</tr>
</tbody>
</table>
What can be seen in table 5.8 is that $E(\text{IC})$ are the same and that the corresponding standard deviation has decreased with a factor of $(\sqrt{3})^{-1} \approx 0.577$ for the unrestricted cases, i.e. case 1, 3, 5, 7, 9, when comparing the 1- and 3-year averages. That the standard deviation decreases is not surprising since for longer sample periods each sample varies less from the expected value. The fact that the 3 year-average values gives 3 times more samples means that the variance, eq. 2.7, decreases one third and therefore decreases the standard deviation with a factor $(\sqrt{3})^{-1}$. The performance indicators, table 5.7, show the same indication. Moreover, $\tau(\text{IC})$ for the 1-year simulations is almost as high as $E(\text{IC})$, which indicates the expected outcome is rather uncertain and that the financial risk associated with these cases is significantly high. In order to illustrate the financial risk better, the IC reliability functions, survival functions, are displayed in figure 5.4 – 5.9 for case 1, 3, 5, 7, 9 and 10 respectively for both the 1- and the 3-year average.

![Figure 5.5. IC reliability functions for case 1.](image-url)
Figure 5.6. IC reliability functions for case 3.

Figure 5.7. IC reliability functions for case 5.

Figure 5.8. IC Reliability functions for case 7.
The reliability functions for case 1, 3, 4, 7 and 9 show the same characteristics, the risk of exceeding the expected IC is little less than 50 %, and there is a risk of approximately 10 % that the IC is double the expected value or more. The case associated with the lowest financial risk is case 5, the reason for this is combination of customer weighted indicators and customer specified valuation, the LPs with large quantities of customers are residential LPs, which has lowest IC valuation and those LPs with few customers connected have the highest individual valuation.

If comparing the IC reliability functions of case 7 and 9, the difference is rather small, approximately 10 %, case 9 seems less hazardous since the outage
frequency is included in case 7 but not in case 9. Including the interruption frequency has rather small impact on the IC outcome.

Case 10 shows the most significant difference of the 1- and 3-year average. When including such high thresholds as for this case the risk of being forced to pay customer remuneration is quite small. The risks are even smaller for the 3-year average.

The overall impression is that case 1, 3 and 7, bring significant risks of high quality adjustment due to poor quality performance. Case 1 seems to be the most hazardous relative case 3 and 7. The differences in cases 1, 3 and 7 can be explained in the combination of IC valuation and feeder significance. When using customer weighted indicators, the feeder containing large quantities of customers are the most important. When using capacity weighted indicators the feeders’ importance is rather even. However, since the probability of an interruption is higher in feeder containing more components, feeder 1, 3, 4, and 7, means the these will generate more IC. Fig. 5.10 and 5.11 shows the customer category and feeder significance regarding the IC for the case 1, 3, 5, 7, 9 and 10, the customer and capacity representation are included for comparison.

![Figure 5.11. Customer type IC significance for test system 2.](image)

The differences in customer type and feeder importance regarding the IC for the different cases is quite significant. If customer weighted indicators are used, case 1 and 5, it seem to be dominating factor regarding which feeders to prioritise. If capacity weighted indicators are used, the interruption valuation has impact on how the feeders are prioritised.

If we consider table 5.8 again, we can see that the expected value of the IC increases for case 2, 4 and 8, for the 3-year average compared to the 1-year average. These cases are such that the adjustment function is restricted with a threshold and a maximum revenue adjustment level. This can be explained by the fact the expected IC of the unrestricted cases 1, 3 and 7 that correspond to 2, 4, and 8 respectively, is higher than the minimum level needed to enable a revenue adjustment. The 3-year average is therefore more likely to exceed the threshold. Even if case 6 show the same tendency, the expected IC of case 5 is so close to the adjustment threshold that it is rather likely even for the 3-year average to be zero. Also, since probability of ending up within the adjustment area, the IC standard deviation of the restricted cases decreases for the 3-year average relative the 1-year average. Table 5.9 displays the probability of ending up in each area for case 2, 4, 6 and 8.
Table 5.9. Distribution of the outcome for the restricted cases.

<table>
<thead>
<tr>
<th></th>
<th>Case2</th>
<th>Case4</th>
<th>Case6</th>
<th>Case8</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 y</td>
<td>3 y</td>
<td>1 y</td>
<td>3 y</td>
</tr>
<tr>
<td>IC \leq \text{min}</td>
<td>20%</td>
<td>4%</td>
<td>18%</td>
<td>3%</td>
</tr>
<tr>
<td>min &lt; IC &lt; max</td>
<td>52%</td>
<td>75%</td>
<td>62%</td>
<td>88%</td>
</tr>
<tr>
<td>IC \geq \text{max}</td>
<td>28%</td>
<td>21%</td>
<td>20%</td>
<td>9%</td>
</tr>
</tbody>
</table>

The result presented in table 5.9 indicates that case 2 is the case that brings the highest financial risks, and that case 6 seen to be the less risky of the restricted cases. This aligns with the results from the unrestricted cases.
Chapter 6

Conclusions and future work

This chapter presents the conclusions of the project as well as suggestions for future work.

6.1 Conclusions

The purpose of this project is to analyse how the framework of PBR influence the incentives that the DSOs have to act on regarding their system reliability. The main effort has been to develop good and reliable methods to analyse PBR frameworks with focus on quality of supply. That process has consisted of two parts; identifying the key incentive features and analysing them mathematically. First, some conclusions of the methods applied to analyse the incentive features:

i In order to comprehend all aspects of the quality regulatory process methods that respond well to the stochastic behaviour of power systems and that are able to include the variations in annual reliability, methods such as Monte Carlo simulation methods are preferable.

ii One more advantage of using time sequential Monte Carlo simulations is that each sample can be analysed in detail. For instance, cases where an output is the result of many other outputs, the result can much easier be processed when using MCS then in other methods.

Second, some conclusions regarding the quality regulation process:
In order to get an adequate picture of the implications of a regulation framework and consequently be able to make the optimal financial decisions, constraints and opportunities of the whole regulatory process should be considered.

Whether the efficiency benchmark within the PBR framework is connected to the output of the quality regulation and vice versa is an important issue to consider analysing quality regulation.

Third, some conclusions based on the quantitative comparisons of key incentive features can be made:

The incentives given the regulated DSO are very much dependent on how the key incentive features are configured. Consequently, the financial risks for the DSOs associated with quality regulation due to the annual variations in system reliability vary significantly depending on how the key incentive features are configured.

Aggregated system reliability performance indices are suitable for determining overall system performance for uniform system. However, when applying aggregated indictors on systems with uneven performance the mean values are misleading. While customer weighted indicators tends to value areas containing large quantities of customers, capacity weighted indicators tends to value high consuming areas, which usually means a rather uniform valuation between different areas.

The effects of the indicator weighting can to some extend be mitigated depending on the usage of uniform or customer specified IC-valuations. When using capacity-weighted indicators the valuation between areas depends on the areas’ customer category configuration and how the categories are valued relatively each other. However, when using customer-weighted indictors it is the totally dominating factor, and the prioritisation becomes solely based on the number customers in each area.

Restrictions of the revenue or price cap adjustment, as those applied in the Swedish and Dutch regulations, should be set carefully. As selected in chapter 5 of this thesis approximately 50% of the
simulated years for these cases end up within the adjustment area, and would have strong short term incentive to strive towards the reliability target. The short-term implications for the other 50% as well as the long-term implications are harder to predict since the long run marginal cost must be considered which requires more information than has been presented for the test systems used in this thesis. However, the objective for the regulator when setting this kind of restrictions should be that the vast majority of the regulated DSOs should recognise the regulator’s agenda and strive towards the reliability target.

The length of the regulatory period affects the uncertainty in regulatory outcome, thus the financial risks associated with quality regulation due to the natural fluctuations in annual quality of supply. The usage of mean values for several years the deviation of the regulatory output from the expected IC decreases, hence the risks. In addition, setting the value for several years in advance creates stability for the regulated DSO. However, by using mean values trends become less obvious and there can be a risk of system reliability deterioration, which the regulator must be aware.

Finally, based on the analyses in this project some conclusions specifically directed to the Swedish regulation and the implementation of the NPAM regarding the incentives that the Swedish DSOs have to act on regarding their quality of supply.

The configuration of the key incentive features in the NPAM is such that high-density areas with large quantities of customers should be prioritised by the DSOs, regardless of energy consumption and customer type configuration, in order to decrease the risks and increase the regulatory outcome. This might lead to further segregation of the distribution quality for DSOs that operate several grids, urban vs. rural areas.

High valued interruptions make the boundaries between maximum and minimum allowable revenue tight. Due to this, the quality regulation runs the risk of becoming a digital risk feature that enables rather few DSOs to actually be affected by the regulatory implications.
That all DSOs are comparable when only considering their objective
prerequisites is one of the fundamental assumptions in the NPAM.
But, if we considering the strong incentives to prioritise urban areas,
the digital characteristic of the quality regulation feature together with
the fact that more than 50% [33] of the regulated DSOs in Sweden
have small incentives to strive towards the reliability target set in the
NPAM. The issue of comparability can be questioned, one can wonder
whether all DSOs are should be regulated using the same model.
Would the comparability issue fail the risk for further segregation in
quality of supply can be eminent.

6.2 Discussion and future work

Regarding the qualitative and quantitative comparison; how each regulator
chooses or is obliged to set the incentive key feature configuration depends on
many factor, some of which are not included in this thesis such as pricing issues,
ownership configuration, business culture, regulation history etc. Furthermore,
the regulation has been considered to be strictly applied, which is not the case in
reality, where the outcome can be the result of a compromise between the
regulator and the DSO. Moreover, when comparing different countries’ quality
regulations one should keep in mind the circumstances under which the DSOs
operate. For instance, the situation in the Netherlands is quite different from
situation in Sweden in terms of customer density and geographical aspects.
Sweden and Norway on the other hand are more comparable. Some areas in
Spain are comparable to Sweden and Norway and so on.

Since the quantitative analysis is conducted on a small test system, one should
be careful when translating the result onto normal systems, which usually are
much larger. However, the general conclusions are valid. Larger systems would
mean more complicated analyses and measures to simplify the simulation
models might be necessary. Furthermore, the usage of test systems enables well-
deﬁned component reliability data. In reality, the data available for actual
distribution systems is usually quite limited, which means that the simulation
models used for actual systems must either be simpliﬁed or extensive
assumptions about component reliability data would have to be made.

Regarding the NPAM, even though very much effort, nearly six years of
development work, have been put into the model there are some issues that
might need to be resolved regarding the quality of supply regulation. The regulatory authority, STEM, is as it seems aware of some of these issues, and even though the NPAM is presently used as it was constructed for, 2003 – 2004 are regarded as test years. Hence, the parameter settings of the model are by no means fixed. Also, even though the regulation is conducted by means of the NPAM, some issues that might need to be resolved depends on legislative issues outside the NPAM, for example, what system reliability data the DSOs must report to STEM and the level of detail in the data.

Suggestions for the future work within this project would be to broaden the area of interest. This includes analyses of actual distribution systems, their strategies for investments and their decision-making, when regarding the DSOs attitude towards financial risks. To enable this, there is a need to develop MCS-methods suitable reliability analysis of large distribution systems when input data might be limited. Furthermore, to enable sufficient risk analysis, there are requirements of instruments and method for evaluating financial risk within grid operations. These instruments should be developed in close cooperation with those making the decisions within the distribution business. The aim of these efforts would be to develop sufficient tools for analysing long-term analysis of regulatory impact as well as the financial impact of extraordinary and severe incidents in distribution systems together with the laws and regulations specially designed to handle these issues.
## Appendix A

Outage frequency and duration summation of LP1-7 for test system 1.

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Outage frequency and duration summation of LP8-12 for test system 1.
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Appendix B

Length of cables in test system 2 [60].

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Component reliability data for test system 2 [60].

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<th>( \lambda_s ) [f/yr]</th>
<th>( \lambda_p ) [f/yr]</th>
<th>( \lambda_t ) [f/yr]</th>
<th>RT [h]</th>
<th>RcT [h]</th>
<th>( \lambda_m ) [/yr]</th>
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- Not available
References


[34] L. Bertling, M. Larsson, C-J. Wallnerström, “Evaluation of the customer value of component redundancy in electrical distribution systems”, proceedings of IEEE St Petersburg PowerTech, St Petersburg, Russia, June, 2005


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