Industrial Automation

Electricity Supply Reliability

Evaluation of Improvement Solutions for Existing Electricity Networks

Fredrik Roos

Department of Industrial Electrical Engineering and Automation
Lund University

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Department of Industrial Electrical Engineering and Automation
Faculty of Engineering
Lund University
Box 118
221 00 LUND
SWEDEN

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Abstract

Regulation of the electricity network business is continuously under development in many countries. This is a reaction of an increasingly electricity dependent society, which demands electricity supplies at acceptable quality levels and at reasonable tariffs. Thus, electric network companies are facing new requirements that change the conditions for exercising network activities. Generally, incentives are given to the network companies to maintain the present level of reliability in a cost-efficient way. In Norway, however, incentives are given to the network companies to plan, operate and maintain the networks in a socio-economically optimal way, taking into account the supply-interruption cost to the customers. Therefore, in Norway, electricity network companies strive to identify and implement the most cost-efficient reliability improvement projects, i.e., the projects that yield the greatest overall reduction in supply-interruption cost to the customers for the invested money.

In this thesis, implementations of reliability improvement solutions on a test system have been evaluated from a socio-economical point of view. For each of the alternative solutions implemented on the test system, the average annual supply-interruption cost to the customers supplied from the test system has been estimated. Furthermore, the maximum annual capital cost associated with the implementation of each solution has been estimated. Then, a reliability improvement solution is considered justified socio-economically if the capital cost associated with its implementation is less than the resulting reduction in the interruption cost to the customers.

The general conclusion from this thesis work is that the supply-interruption cost to the customers supplied from a test system can be reduced significantly by implementing reliability improvement solutions that are justified socio-economically. Even if the uncertainty of the input data is taken into account, it is obvious from the results that the interruption cost to the test system customers can be reduced to at least half the initial value.

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Lund, 9 November 2005
Fredrik Roos

Contents

Chapter 1

Introduction

1.1 Background and Motivation

Electricity plays an important role in economic development and growth. The fundamental dependence of today's society on electricity has raised increased demands for regulation that secures electricity supplies at acceptable quality levels and at reasonable tariffs. Regulation relating to electricity supply is continuously under development worldwide. The main objective of this process is to increase the cost-efficiency in the electricity network businesses for the benefit of the customers, while still maintaining acceptable quality levels. In Sweden (Larsson, 2003) and in Norway (Langset *et al.*, 2001), quality dependent revenue cap regulation has been introduced to achieve this objective. Ideally, electricity supply regulation should firstly decide upon a level of reliability that is optimal from a socio-economical point of view. Secondly, it should decide upon a reasonable allowed revenue for each network company corresponding to this reliability level. Finally, it should make the network companies meet the reliability requirements through some kind of penalization of requirement violation.

Consequently, electricity network companies are facing new requirements regarding reliability of supply. The challenge for electricity network companies is to meet these new requirements in an economically optimal way. In their efforts to improve the reliability of existing distribution networks in a cost-efficient way, electricity network companies are, among other things, considering network design and network automation opportunities.

This thesis work should be seen in the context of a socio-economic oriented regulation striving to minimize the sum of all costs in the society related to electricity supplies, including investment costs, costs of electrical losses, operation and maintenance costs and interruption costs.

1.2 Objective and Scope

Improvements in the reliability of supply require significant investments and therefore the most cost-efficient measures need to be identified. The objective of the work presented in this thesis is to evaluate the implementation of a number of reliability improvement *solutions* on an existing electricity network, from a socio-economical point of view. The majority of the evaluated solutions are related to distribution automation, i.e., solutions incorporating such functionality as automatic reclosing, automatic fault locating, automatic feeder sectionalizing, automatic feeder fault isolation and automatic upstream and downstream service restoration. However, improved dependability and security of feeder and transformer protection systems respectively, wide area protection, manual feeder sectionalizing and tree trimming have also been studied. The reliability improvement solutions that have been evaluated are either available for implementation today or are likely to be available for implementation in the near future.

For evaluation purposes, a test system has been specified. Each reliability improvement solution has been applied to the test system and for each solution applied, the average annual cost of *unplanned* interruptions to the test system customers has been estimated. Furthermore, the maximum annual capital cost associated with the implementation of each solution has been estimated. The evaluation was carried out by considering the sum of the costs above for each solution. A sensitivity analysis was performed in order to assess the robustness of the evaluation results against uncertainties in input data. In this thesis work, *sustained* as well as *momentary* interruptions are included in the interruption cost calculations.

1.3 Contributions

For a test system, it has been shown that:

- distribution automation significantly reduces the average annual interruption cost to the customers supplied from the test system
- distribution automation is justified socio-economically.

The main results of the thesis work are presented in Figure 1.1. It can be concluded from this figure that the supply-interruption cost to the customers supplied from the test system can be reduced significantly. In addition, the figure illustrates that cost-efficiency can be achieved by investing wisely in reliability improvement solutions.

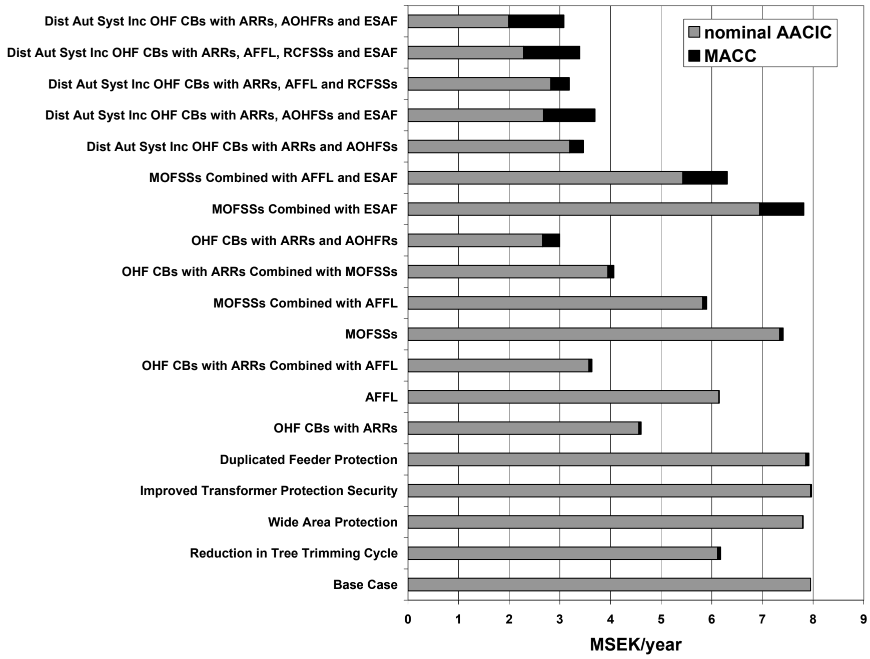

Figure 1.1: Sum of maximum annual capital cost (MACC) associated with the implementation of each reliability improvement solution on a test system and the corresponding average annual supply-interruption cost to the test system customers (AACIC).

1.4 Outline of the Thesis

In this section, the outline of the thesis is presented. The thesis consists of 10 chapters, which are briefly summarized below.

Chapter 1 provides the background, motivation, objective, scope and main contributions of the research work. In addition, it provides the outline of the thesis and a list of publications. The chapter concludes by clarifying the use of terminology in the thesis.

Chapter 2 reviews general aspects of interruptions, such as causes and characteristics of interruptions.

Chapter 3 clarifies what is meant by reliability of supply. Furthermore, it distinguishes reliability of supply from the reliability of a particular portion of the electricity supply system. The chapter concludes by introducing the concept of interruption cost considered in socio-economic studies and explains the main goal of the regulation of the electricity network business.

Chapter 4 presents the introductory work, in which incorrect protection operations were analyzed with respect to type and origin of the fault initiating the associated power system disturbance and with respect to type and cause of the incorrect protection operation.

Chapter 5 describes general features of the evaluated reliability improvement options.

Chapter 6 specifies the test system that forms the basis for the evaluation of a number of reliability improvement solutions.

Chapter 7 describes the procedure used when calculating the supply-interruption costs to the customers fed from the test system feeders. Furthermore, it presents the assumptions made in the calculations and the calculation results.

Chapter 8 explores the sensitivity of the calculated interruption costs with respect to variations in input parameter values.

Chapter 9 discusses the implementation details of the reliability improvement solutions under evaluation and it estimates the maximum annual capital cost associated with the implementation of each reliability improvement solution on the test system.

Chapter 10 evaluates the reliability improvement solutions from a socio-economical point of view taking the uncertainty of the input data into account. Furthermore, it suggests future research, which would complement the work presented in this thesis.

1.5 Publications

Parts of the work reported in this thesis have been published in the following papers:

Johannesson, T.; Roos, F. and Lindahl, S. Reliability of Protection Systems – Operational Experience 1976-2002, *8th International Conference on Developments in Power System Protection*, IEE, Vol. 1, pp. 303-306, April 5-8, 2004, Amsterdam, The Netherlands.

Roos, F. and Lindahl, S. Distribution System Component Failure Rates and Repair Times – An Overview, *Nordic Distribution and Asset Management Conference*, August 23-24, 2004, Espoo, Finland.

1.6 Terminology

To ensure the use of an internationally accepted terminology *The IEC Multilingual Dictionary, Sixth Edition, 2005* has been consulted. For terms that are not defined in this dictionary and in cases where the existing definition is not sufficiently clear or specific or when a term is not used in accordance with the existing IEC definition, definitions or explanations are provided in the thesis. Table 1.1 indicates where these definitions and explanations can be found in the thesis.

Conventions

The following conventions, as regards the use of vocabulary, have been adopted throughout the entire thesis.

The words fault and disturbance are used as short forms for power system fault and power system disturbance respectively. The term customer refers to end-user customer of electricity. Interruption is used as a short form for electricity service interruption to one or several customers. Since, in this thesis work, transient faults only occur on overhead feeders, wherever transient fault is mentioned, it refers to transient fault on an overhead feeder. Permanent feeder fault refers to the following types of feeder faults: overhead feeder permanent fault, underground cable internal fault and underground cable fault caused by excavation damage. By recloser should be read automatic overhead feeder recloser and by sectionalizer should be read automatic overhead feeder sectionalizer.

Table 1.1: Terminology that is defined or explained in the thesis.

Term	Defined in
automatic feeder fault locating	Section 5.6
automatic overhead feeder recloser	Section 5.7
automatic overhead feeder sectionalizer	Section 5.6
automatic reclosing	Section 5.5
average annual customer interruption cost (AACIC)	Section 7.1
distribution automation	Section 5.9
distribution automation system	Section 5.9
electricity service interruption	Section 2.1
emergency supply from adjacent feeders	Section 5.8
failure to operate of a protection system	Section 4.6
failure to reclose	Section 4.6
feeder sectionalizing	Section 5.7
interruption costs to customers	Section 3.3
interruption costs to utilities	Section 3.4
manually operated feeder sectionalizing switch	Section 5.7
maximum annual capital cost (MACC)	Section 9.2
missing protection operation	Section 4.6
missing reclosing	Section 4.6
momentary interruption	Section 2.4
non-selective fault clearance	Section 2.3
permanent forced outage duration	Section 2.1
planned interruption	Section 2.4
power system disturbance	Section 4.3
reliability indices	Section 3.2
reliability of supply	Section 3.1
spontaneous unwanted protection operation	Section 2.3
sustained interruption	Section 2.4
transient fault	Section 2.1
transient forced outage duration	Section 2.1
travel time	Section 2.1
underground cable fault caused by excavation damage	Section 2.1
underground cable internal fault	Section 2.1
unplanned interruption	Section 2.4
unwanted protection operation	Section 4.6
unwanted reclosing	Section 4.6
wide area protection	Section 5.2

Chapter 2

Electricity Service Interruptions

To fully appreciate the following chapters some basic knowledge of interruptions is required. This chapter provides a short resume on the topic. It deals with the root causes of interruptions and with interruption characterization.

2.1 Terminology Related to Interruptions

The definitions of terms given in this section reflect how these terms are used in this thesis. These definitions might differ somewhat from established definitions or established definitions do not exist.

Electricity Service Interruption

Interruption of electricity service to a customer involves a reduction in voltage magnitude to zero at the customer delivery point.

Transient Fault

A transient fault is a fault that disappears either by itself or by de-energization of the faulted circuit and it does not require any immediate repair work. The majority of the faults occurring on overhead feeders are transient faults. Common causes of transient faults are momentary tree contacts with conductor and flashovers initiated either by lightning or by conductors temporarily swinging together. In this thesis, it is assumed that in the event of a transient fault, reclosing of the associated circuit breaker or recloser is always successful, though it might not be successful on the first or second attempt.

Underground Cable Internal Fault

Underground cable internal faults are shunt faults on underground cables, which occur due to insulation failures. Insulation failures develop over time. Moisture, temperature and electrical stresses are all factors that contribute to degrade the dielectric strength of insulation. Common causes of electrical stresses are lightning and switching surges. Thus, these faults occur in the absence of mechanical damage. In this thesis, all underground cable faults, except for faults caused by excavation damage, are underground cable internal faults.

Underground Cable Fault Caused by Excavation Damage

One of the main fault causes in urban areas is excavation work in the streets causing damage to underground cables.

Permanent Forced Outage Duration

The permanent forced outage duration is defined as the average time it takes to restore the affected component to service without deliberate delays when the component outage occurrence has been automatically initiated due to a permanent fault on the component.

Transient Forced Outage Duration

The transient forced outage duration is defined as the average time it takes to restore the affected component to service without deliberate delays when the component outage occurrence has been automatically initiated due to a transient fault on the component.

Travel Time

By travel time is meant the average time period from the moment of the outage occurrence until the repair crew arrive at the trouble area with appropriate equipment. Thus, this time does *not* only include the actual travel time of the repair crew. However, no deliberate delays are included.

2.2 Causes of Interruptions

Interruptions are caused by either planned or unplanned opening operations of switching devices, disconnecting primary equipment from the network. Opening operations of switching devices are initiated either by the protection system or by humans. The protection system may operate incorrectly and opening operations initiated by humans may be inadvertent. When the protection system functions as intended, it detects faults and initiates opening operations of circuit breakers to isolate faulted parts from the healthy parts of the power system in a selective manner. Faults are caused by external factors, such as road traffic accidents, digging into buried cable, vegetation, animals and severe weather, and by equipment failure.

2.3 Incorrect Protection Operations

Incorrect protection operations initiate disturbances and may extend the consequences of faults. Unwanted protection operations initiate disturbances, while unwanted protection operations and failure to operate of protection systems may extend the consequences of faults.

Non-Selective Fault Clearance

Non-selective fault clearance means that a larger portion of the power system than necessary is disconnected in order to clear a fault. In case of a missing main protection operation, the corresponding backup protection will clear the fault. If the backup protection is remote, it operates non-selectively, which may result in an increased number of customers experiencing interruption. In addition, unwanted protection operations could result in non-selective fault clearance. Consequently, failure to operate of a protection system and unwanted protection operations may result in interruptions to customers who would not have been affected if the fault had been cleared selectively.

Spontaneous Unwanted Protection Operation

An unwanted protection operation that occurs in the absence of a power system fault is referred to as a spontaneous unwanted protection operation. Such unwanted protection operations initiate disturbances, which in turn may cause interruptions to customers.

2.4 Interruption Characteristics

Momentary and Sustained Interruptions

Sustained interruptions are long-duration interruptions lasting longer than a certain period, usually defined in the interval of 1-5 minutes. Interruptions with a shorter duration are termed momentary interruptions. Usually, only data on sustained interruptions is reported to the regulatory authority. Permanent faults on distribution circuits usually cause sustained interruptions to at least some customers. However, automatic fault isolation and automatic upstream and downstream service restoration reduces the number of customers that experience a sustained interruption. In the event of a transient fault on a distribution circuit, the customers on that circuit will only experience a momentary interruption if the circuit is reclosed after it has been interrupted to clear the fault. When reclosing is used on the overhead feeder circuit breakers, transient faults cause sustained interruptions only if they occur on fused laterals and if fuse saving is not used.

Planned and Unplanned Interruptions

A planned interruption occurs at a selected time less inconvenient for the customers and the customers have been notified beforehand of the interruption. On the other hand, if the occurrence time of the interruption has not been selected, then the interruption is unplanned. Unplanned interruption occurs, for example, due to fault clearing, unwanted operation of the protection system or due to inadvertent initiation of opening operation of a switching device by a human. Planned interruptions occur mainly for the purpose of construction, preventative maintenance or repair.

Chapter 3

Electricity Supply Reliability

In this chapter, it is clarified what is meant by reliability of supply. Furthermore, reliability of supply is distinguished from the reliability of a particular portion of the electricity supply system. The concept of interruption cost, which is considered in socio-economic studies, is introduced and the main goal of the regulation of the electricity network business is explained.

3.1 Reliability of Supply

The reliability of an electricity supply system reflects its ability to maintain service continuity. In this context, the service is to make electricity available for use to the end-user customers of the electricity supply system. When an electricity supply system fails to perform this task, there are customers that experience service interruptions, which means that these customers are de-energized. Reliability of electricity supply is primarily concerned with duration and frequency of such service interruptions. Thus, reliability of supply is a customer-oriented quantity that does not consider the origin of the causes of interruptions. The reliability of supply thus depends on the performance of generation, transmission and distribution. Availability is often used as one measure of reliability. Availability is defined as the percentage of time a customer is uninterrupted. Availability is considered as a subset of reliability as it only provides information about annual interruption duration, and not about interruption frequency.

3.2 Utility Reliability Performance Measurements

Reliability indices are statistics based on interruption data collected from a well-defined system. Each reliability index represents one particular aspect of the reliability of, for instance, a single feeder, a distribution system, or an entire utility network. Most reliability indices are concerned with duration and frequency of interruptions that are caused by component outages within the studied system. However, interruptions related to external events in bulk power generation and transmission might be included when assessing the reliability of a particular distribution system. This would provide incentives to reduce the sensitivity of the reliability of the distribution system to interruptions of HV supply to the distribution system, such as island operation. The reliability of a particular electricity network is improved by reducing the number and the duration of component outages and by mitigating the consequences of component outages. Electricity network reliability tracks the performance of a particular portion of the electricity supply chain. This is important for regulation purposes in order to identify the responsible for an interruption. Most commonly, reliability indices based on *sustained* interruptions are used by utilities and regulatory authorities to quantify the reliability level of a particular network. Definitions of distribution reliability indices and practical issues related to the calculation of these indices are given in (IEEE standard 1366-2003). The consequences of interruptions are measured in terms of energy not supplied and interruption costs.

3.3 Interruption Costs to Customers

Access to electricity supplies at reasonable cost and quality levels has become a basic condition for development, economical growth and welfare. The more developed societies are, the more vulnerable they are to electricity supply interruptions. This dependence on reliable electricity supplies implies that costs are associated with electricity supply interruptions. For companies, electricity supply interruption costs are strongly related to production losses and to costs involved in restoring production. In addition, interruptions may also cause property damages, both for companies and for private individuals. Wide-spread long-lasting blackouts put the vulnerable society to the test and involve extra expenses required to maintain tolerable living conditions. Then there is the aspect of inconvenience and suffering of which it is difficult to estimate the value.

In this thesis, the interruption cost to the customers is an estimated value of the economical losses for the customers that are exposed to electricity supply interruptions. The size of these economical losses depends largely on the composition of the customers that experience interruptions. In interruption cost surveys, customers are roughly divided into five categories: residential, agricultural, commercial, public sector and industrial customers. This customer categorization can of course be refined. The cost that each customer category relates to interruptions varies and consequently the willingness to pay for reliability improvements varies among the customer categories. Another factor that influences the costs incurred by the customers due to interruption of electricity supplies is whether the interruption has been notified or not. The network company can schedule the notified interruptions to occasions less inconvenient to the customers and the notification allows the customers to get prepared for the interruption.

It is a fact that our society is becoming increasingly dependent on electricity supplies as time elapses and therefore, the cost of supply interruptions also increases. Interruption cost rates estimated in 2003 for Swedish conditions are presented in (Elavbrottskostnader, 2004).

3.4 Interruption Costs to Utilities

Interruptions, of course, cost utilities money. These costs are related to

- service restoration (damaged equipment, labor)
- lost revenue
- legal liabilities such as damage claims from customers.

Note that interruption costs to utilities have not been taken into account in this study.

3.5 Planning and Operational Criteria

Today, the fundamental principle behind the planning for reliability in distribution systems resembles the (n-1)-criterion for transmission system operation: a distribution system should always be designed and operated in a way that allows for quick restoration of supply in the event of any single failure of equipment. How to define quick restoration of supply is in several countries left for the individual utilities to decide.

3.6 Regulations

Owning and operating electricity transmission and distribution systems are natural monopoly businesses. To prevent these businesses from taking advantage of their dominant market position, they are subject to regulation. Regulatory authorities are mandated to protect the interests of the society by setting rules for the electricity network companies. The electricity network regulatory methods applied differ between countries, however the main goal of the regulation is the same, i.e., to secure electricity supplies at acceptable levels of quality and at reasonable tariffs. The electricity network companies are obliged by their shareholders to maximize their profit by being cost-efficient. Cost-efficiency for electricity network companies usually means keeping costs as low as possible, while still meeting the requirements of the regulatory authorities. Thus, regulations should provide electric network companies with incentives to be cost-efficient in a way that benefits the society.

Chapter 4

Incorrect Protection Operations

Incorrect protection operations initiate disturbances and extend the consequences of faults. At the transmission level, incorrect protection operations play a significant role in the occurrence of cascading outages leading to blackouts. The results of two studies on incorrect protection operations that have affected the subtransmission system owned by Sydkraft AB[1] have been published. The first study (Svensson *et al.*, 1992) analyzed the incorrect protection operations that have been revealed at disturbances in the electric power system under study during the period 1976-1994. A recent study (Johannesson *et al.*, 2004) extended this period by eight years. Together, for the period 1976-2002, 391 power system disturbances with incorrect protection operation and 486 incorrect protection operations have been analyzed. The combined results of the two studies are presented in this chapter. Since incorrect protection operations may initiate or aggravate disturbances in power systems, these results can be used to improve the reliability of the electric power supply system in a cost-effective manner.

Investigating disturbances and incorrect protection operations is an essential part of the activities involved in keeping track of the performance of the protection systems. Furthermore, in order to be able to improve the reliability of the protection systems the causes of incorrect protection operations must be identified. It might appear straightforward to refer the causes of incorrect protection operations entirely to the protection equipment. However, several other aspects of the protection system have to be considered in order to identify the causes of incorrect protection operations.

[1] In September 2005, Sydkraft AB changed name to E.ON Sverige AB. Still, it is referred to Sydkraft AB several times in the thesis, when referring to the period before the name change.

4.1 System under Study

The power system under study has been owned by Sydkraft AB in Sweden and comprises 130, 50 and 40-kV subtransmission systems with a total length of some 5,500 circuit-kilometres and MV distribution systems with a total length of about 15,000 circuit-kilometres. Distance relays provide the main protection of 130-kV lines and directional residual overcurrent relays provide earth-fault protection in the effectively earthed 130-kV system. Non-directional phase overcurrent relays provide short-circuit protection of the 50- and 40-kV lines and the MV feeders. The 50- and 40-kV subtransmission systems and the MV distribution systems are non-effectively earthed and directional residual overcurrent relays provide main earth-fault protection of these lines and feeders.

The subtransmission system is connected to the interconnected transmission systems (400 and 220 kV) in Finland, Norway, Sweden and the eastern part of Denmark. The subtransmission system supplies power to the local distribution systems and to consumer plants usually at voltages ranging from 20 kV and below.

The 130-kV subtransmission system is meshed and the disconnection of a single 400- or 220-kV transmission line does not usually cause interruption of supply to customers. An incorrect protection operation in the subtransmission system may or may not cause interruptions to customers. Protective relays in the subtransmission systems provide back-up protection for the distribution systems and for the consumer plants. A failure to operate of a distribution feeder protection may cause an operation of a back-up relay in the subtransmission system. This in turn may increase the number of interrupted customers.

4.2 Sources of Information

Disturbance reports and special investigation reports produced for the system under study form the basis for the statistics presented in this chapter. For each disturbance that occurs on the electric power system under study, a *disturbance report* is produced. A special investigation is carried out when incorrect behavior of the fault clearance system is suspected to have appeared and this result in a *special investigation report*.

The special investigations rely on various recorded disturbance data, such as fault currents, fault clearance times, fault types and fault locations. In case the fault location is unknown, comparing calculated fault currents with measured fault currents, for various credible fault locations and fault characteristics, yields an estimate of the fault location. Once the assumed fault location is derived, the characteristics of the fault, i.e., the type of the fault and the fault impedance, might be obtained by inspection. On the other hand, if the characteristics and the location of the fault are known, calculated fault currents can be used to approximate those fault currents that the disturbance recorders did not capture.

Conclusions can then be drawn about the expected protection system behavior from recorded disturbance data, fault locations, characteristics of the fault, calculated disturbance quantities, relay coordination plan and relay calibration records.

Information about the true behavior of the protection system is obtained from event recordings, relay indications, inspections and functional tests. In addition, previously produced reports might facilitate the investigation. Note that only those incorrect protection operations that have been revealed at power system disturbances have been analysed.

4.3 Performance Index

Sydkraft has tracked the performance of the protection system for more than 50 years. Very early it was decided to use the percentage of power system disturbances with incorrect protection operation, PI, as defined by Equation 4.1 and the performance metric has not been changed.

$$PI = \frac{M_i}{M_c + M_i} \tag{4.1}$$

Here M_i is the number of power system disturbances with incorrect protection operation and M_c is the number of power system disturbances with correct protection operation. A power system disturbance is a sequence of unplanned circuit-breaker operations that is treated as one incident. It may involve more than one power system fault. A power system disturbance may involve an operation of a circuit breaker without any power system fault. The performance index, PI, is relevant for temporal tracking of the performance of a given protection system.

It has been realized that the performance index varies considerably from year to year. It is therefore advisable to use the average value over several years to reduce the random variations. Figure 4.1 shows the percentage of power system disturbances with incorrect protection operation year by year together with its ten-year moving average for the 130, 50 and 40 kV systems owned by Sydkraft AB.

The performance index was about 5% until the mid 1970's when it started to increase. The performance index has now settled at around 7%. Static electronic relays that were installed in the early 1970s had auxiliary power supply units with high power consumption and they dissipated much heat, which burned the insulation of conductors inside the relay case. The heat also caused rapid ageing of other relays mounted close to the relay.

Circuit local back-up protection was also introduced during this period. This increased the risk of unwanted protection operation. Digital relays have been introduced without any increase of the percentage of power system disturbances with incorrect protection operation.

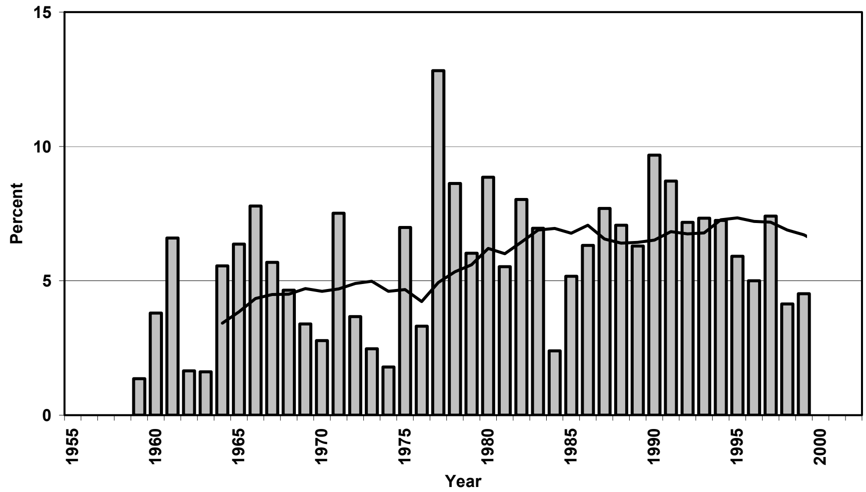

Figure 4.1: Percentage of power system disturbances with incorrect protection operation for each year during the period 1959-1999 together with its ten-year moving average. Courtesy of Sydkraft AB.

4.4 Type of Initiating Fault

Power system disturbances with incorrect protection operation are initiated either by a power system fault or by a spontaneous unwanted operation of a protective relay. Spontaneous unwanted operations of protective relays are referred to as non-system faults. Figure 4.2 shows that some 75% of the incorrect protection operations occurred when the associated power system disturbance was initiated by a power system fault, while some 25% of the incorrect protection operations occurred when the associated power system disturbance was initiated by a non-system fault.

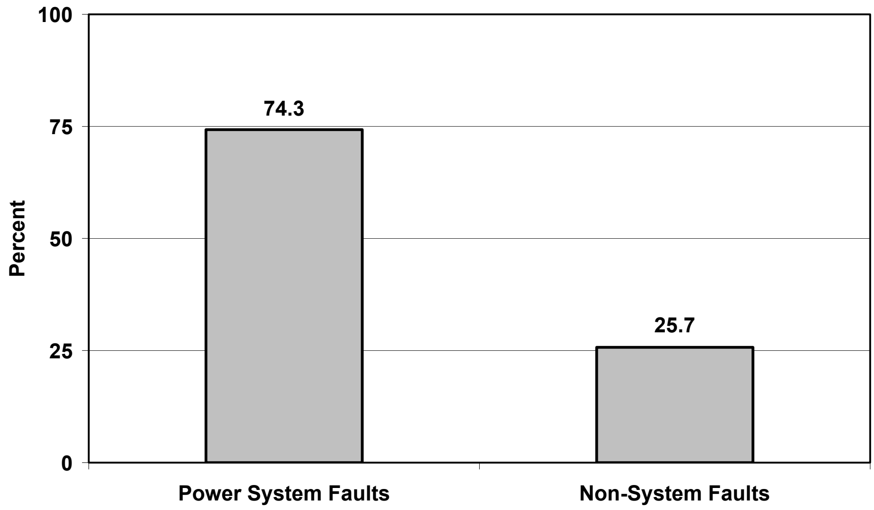

Figure 4.2: Distribution of incorrect protection operations on type of fault that initiated associated power system disturbance, 1976-2002. Courtesy of Sydkraft AB.

4.5 Origin of Power System Disturbance

The analysis includes incorrect protection operations that have occurred during power system disturbances that have affected the subtransmission system under study, i.e., when there has been at least one unplanned circuit breaker operation in any of the 130, 50 and 40 kV systems. The power system disturbance may originate from the transmission system (400 and 220 kV), the subtransmission system (130-40 kV), the distribution system (20-6 kV) or the consumer plants. Figure 4.3 shows the distribution of the incorrect protection operations on the origin of associated power system disturbance.

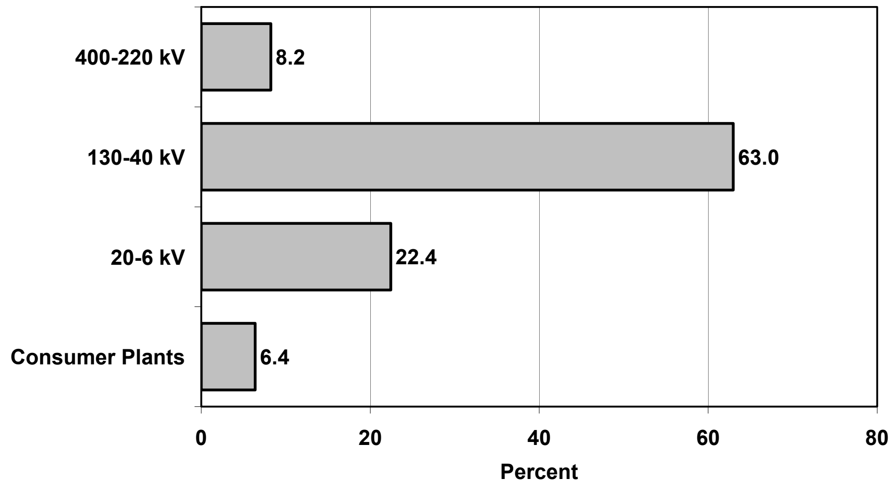

Figure 4.3: Distribution of incorrect protection operations on the origin of associated power system disturbance, 1976-2002. Courtesy of Sydkraft AB.

4.6 Type of Protection System Fault

Protection systems may malfunction in many ways. The following protection system fault types were considered in the study:

- unwanted operation
- missing operation
- unwanted operation of automatic reclosing equipment
- missing operation of automatic reclosing equipment
- missing relay indication.

Figure 4.4 shows the percentage of each fault type. An unwanted operation of a protective relay may occur when there is a power system fault outside the zone of the protection. Such an incorrect operation is called a *non-selective* operation. An unwanted operation may also occur when there is no power system fault. Such an incorrect operation is called a *spontaneous* unwanted operation. A protective relay may fail to operate when it should operate to clear a fault. Such an incorrect operation is called a failure to operate or a missing operation.

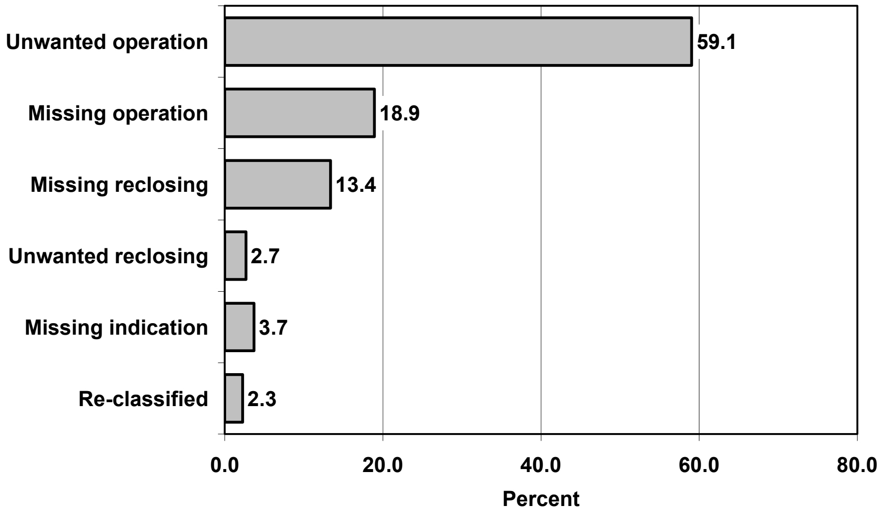

Figure 4.4: Distribution of incorrect protection operations on type of protection system fault, 1976-2002. Courtesy of Sydkraft AB.

Here, the protection system includes the automatic reclosing equipment, which may operate incorrectly. The automatic reclosing equipment may fail to operate when it is expected to operate. This is called a missing reclosing or a failure to reclose. The automatic reclosing equipment may also operate when it is not expected to operate, e.g., when a single-shot reclosing equipment initiates several reclosing attempts. Such an incorrect operation is called an unwanted reclosing.

Power system operators use relay indications (targets) to find out the reason for unplanned operations of circuit breakers and to decide on proper actions. Engineers responsible for the fault clearing process use relay indications to determine if the protection system has operated correctly or not. Sometimes the power system operators are misled by a missing indication and missing indications make the disturbance investigation more difficult.

Protection engineers are often focused on the dependability of protection systems. Therefore, they have introduced duplicated protective relays to avoid a complete failure to trip the associated circuit breakers even if one element in the protection system fails to operate. This has resulted in a decreasing security of the protection system, i.e., increased percentage of unwanted operations.

The analysis has revealed that the authors of the disturbance reports have sometimes misinterpreted the indications and classified the protection operation as incorrect. In such cases, the operation has been re-classified.

4.7 Cause of Incorrect Protection Operation

Figure 4.5 summarises the main result of this study and shows the causes of incorrect protection operation. The causes of the incorrect protection operation are:

Policy: The requirements, in the electrical safety regulations, on the protection system sometimes increase because of the introduction of new equipment, such as covered conductors. It may not be feasible to upgrade the protection system immediately to obtain selective clearance for all types of faults, such as high-resistance faults, intermittent earth faults and back-fed earth faults. The relay coordination engineers may then temporarily accept non-selective settings in order to delay investments in the protection system. Such policies have caused anticipated but undesirable operations.

Principle: The protection system operated incorrectly because the protection system was based on an improper principle. A disturbance analysis or a special field investigation revealed this fault after the power system disturbance. One example is directional earth fault current relays sensing capacitive residual current instead of resistive residual current. Another example of an improper principle is when non-directional relays have been installed to protect the parallel circuits feeding a consumer plant.

Design: The protection system did not operate as desired due to improper design or the drawings of the protection system were not correct.

Installation: A protective relay was not properly connected or the secondary wiring was not correct.

Settings: The protection system did not operate correctly because of improper setting values. This indicates that the fault calculations were incorrect or that the choice of setting values was improper.

Calibration: The protection system did not operate as desired because of incorrect calibration of protective relays. The relays were not calibrated in agreement with the relay coordination plan.

Switchings: The incorrect operation occurred during an operation of a switching device. A typical example is the energizing of a power transformer.

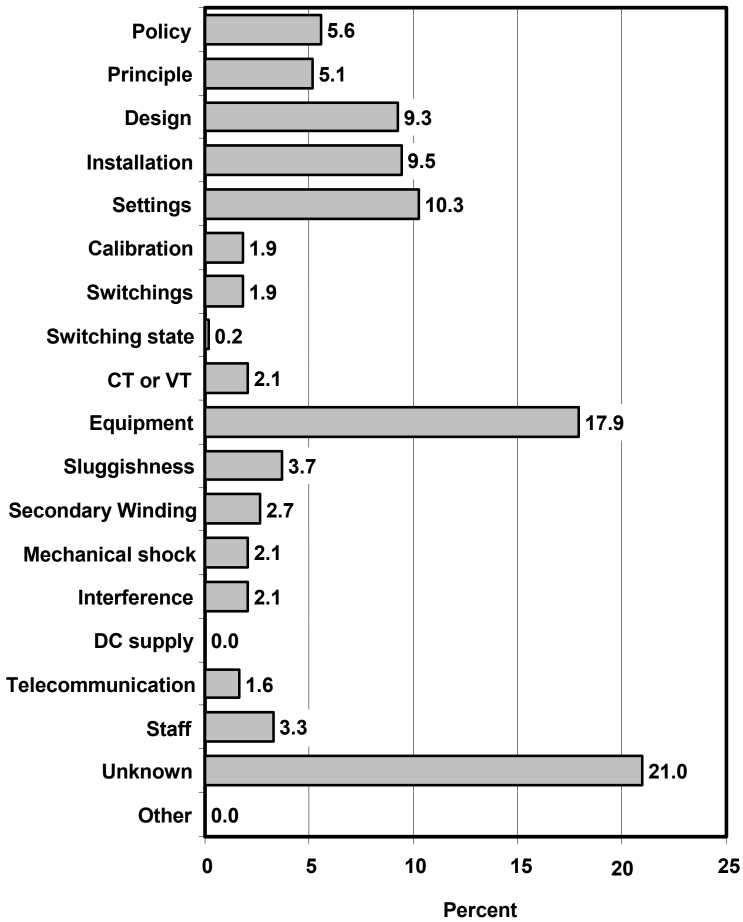

Figure 4.5: Distribution of incorrect protection operations on cause of incorrect protection operation, 1976-2002. Courtesy of Sydkraft AB.

Switching state: The incorrect operation of the protection system was caused by an abnormal switching state in the power system when the power system disturbance occurred.

CT or VT: A primary fault in the instrument transformers or a short circuit or an open circuit in the secondary winding of the instrument transformers caused the incorrect operation.

Equipment: A fault in the protection equipment caused the incorrect operation.

Sluggishness: An electromechanical relay that did not operate properly due to mechanical problems caused the incorrect operation.

Secondary wiring: There was a fault in the secondary wiring (e.g., the tripping circuits) of the protection system other than the current transformer or voltage transformer secondary circuits.

Mechanical shock: The incorrect operation occurred at the switching in of a shunt reactor or a transformer. The associated Buchholtz relays operated incorrectly due to a mechanical shock.

Interference: Insufficient electromagnetic compatibility (EMC) within the secondary circuits caused the incorrect operation.

DC supply: The incorrect operation was caused by the loss of DC auxiliary supply (battery circuits).

Telecommunication: A spurious (false) acceleration impulse generated somewhere in the telecommunication system caused the incorrect operation.

Staff: Operation or maintenance personnel were responsible for the incorrect operation of the protection system. One typical example is the failure to switch from resistive to capacitive current when a Petersen coil (arc-suppression coil) was taken out of service or connected to another system. Another example is the failure to restore the protection system properly after testing.

Unknown: The cause of the incorrect operation is said to be unknown if special investigations and additional tests fail to reveal the cause.

4.8 Summary of Results

This chapter presents the results of an extensive study on incorrect protection operations. The analysis indicates that the percentage of power system disturbances with incorrect protection operation is about 7%. Some 60% of the incorrect protection operations occurred during disturbances that originated from the subtransmission system. Some 25% of the incorrect protection operations occurred when there was no power system fault on the system. About 60% of the incorrect protection operations are unwanted operations. The cause of about 20% of the incorrect operations is unknown while the protection equipment has caused less than 20% of the incorrect operations.

4.9 Comparison of Results

Table 4.1 compares results presented in this thesis with corresponding results presented in (Kjølle *et al.*, 2005). Note that the results presented in (Kjølle *et al.*, 2005) cover data on incorrect protection operations at all voltage levels (1 – 420 kV).

Table 4.1: Incorrect protection operations distributed on three groups of fault causes.

Groups of fault causes	**Results presented in this thesis**	**Results presented in (Kjølle *et al.*, 2005)**
Human related causes	45%	40-50%
Technical causes (equipment)	34%	20-30%
Other and unknown causes	21%	A large portion

The results in (Kjølle *et al.*, 2005) are given as intervals since the distribution of incorrect protection operations on fault cause depends on type of protection, fault type and on voltage level.

4.10 Discussion

Once the causes of incorrect protection operations are known, it is possible to decide upon actions to take in order to improve the reliability of the protection systems. The fact that the causes of about 20% of the incorrect protection operations are unknown is therefore unsatisfactory. The large portion of unknown causes calls for a higher penetration of equipment supporting the disturbance investigations, such as disturbance recorders and event recorders. Furthermore, remote retrieval of relay settings, disturbance recorder data and relay indications significantly facilitate disturbance investigations. The experiences of an extensive program of installing disturbance recorders are reported in (Bakar, 2001). Finally, one cannot stress enough the importance of resetting the relay indications after a disturbance, so that the most current indications are considered in the investigations.

The fact that about 45% of the incorrect protection operations are caused by human related activities indicates that a better utilization of existing technology would improve the reliability of the protection systems. Probably, a higher degree of standardization would reduce the human impact on protection system reliability. For example, today each substation has its own unique features. In addition, training of personnel would probably have a positive effect on the reliability of the protection systems.

Chapter 5

Reliability Improvement Options

This chapter describes the general features of the evaluated *options* that either are, or will most likely in a near future, be available for achieving improved electricity supply reliability. These options are combined into a number of reliability improvement *solutions* that are suitable for implementation in existing power systems. Some of the options can be implemented alone, while others need to be combined in order to be effective. For example, *emergency supply from adjacent feeders* does not mitigate the consequences of feeder outages that occur due to permanent feeder faults, unless the feeders can be sectionalized. Furthermore, when combined, the options might interact with each other, thus prohibiting the full potential of each individual option. In this thesis work, both the effect of individual options and the aggregated effect of several options combined together on the reliability of supply have been studied.

Improving reliability of electricity supply is about reducing interruption frequency and duration. There are eight main approaches, which concern unplanned interruptions, to improving the reliability of supply:

1. By knowing the root causes of faults, it is possible to take actions that will prevent faults from occurring, such as performing tree trimming and installing animal guards and surge arresters.
2. Improving component performances by replacing existing components with comparable components that are less prone to failure, e.g., by replacing overhead networks with underground networks or by replacing aged components with new components.

3. Keeping existing components and instead improve component performance by taking preventative actions, such as introducing and executing inspection and maintenance plans.
4. Improving the performance of the protection system and training of personnel.
5. Employing network structures that are less sensitive to component outages, e.g., meshed networks.
6. Introducing permanent network solutions incorporating reclosers and fuses.
7. Introducing permanent network solutions incorporating such options as automatic reclosing, manual and automatic feeder sectionalizing, automatic feeder fault locating, remote monitoring and control capabilities and emergency supplies from adjacent feeders.
8. Employing temporary mobile supply restoration equipment, e.g., temporary cables and mobile generating units.

Approaches 1-3 are of a preventative nature, i.e., they prevent disturbances from occurring, while approaches 5-8 are of a mitigating nature, as they mitigate the consequences of those disturbances that do occur. Approaches 5 and 6 reduce the number of interrupted customers, while approaches 7 and 8 reduce the time required to restore service to the customers. Finally, approach 4 has both properties. It will prevent disturbances from occurring. In addition, improving the performance of the protection system will reduce the number of interrupted customers, while training of personnel will reduce the time required to restore service to the customers. Thus, the options chosen for implementation depend on the dominating root causes of the interruptions and on what aspect of reliability of supply that is to be improved.

The individual reliability improvement options, whose effects on the interruption costs to customers have been studied, are:

- reduction in tree trimming cycle (approach 1)
- wide area protection (approach 4)
- improved transformer protection security (approach 4)
- duplicated feeder protection (approach 4)

- automatic reclosing (approach 7)
- automatic feeder fault locating (approach 7)
- feeder sectionalizing by manually operated feeder sectionalizing switches (approach 7)
- overhead feeder sectionalizing by automatic overhead feeder reclosers (approach 6 and 7)
- emergency supply from adjacent feeders (approach 7)
- distribution automation systems, i.e., automatic isolation of faulted feeder section and automatic upstream and downstream service restoration (approach 7).

Thus, approach 7 dominates this study and approaches 2, 3, 5 and 8 are not studied at all. The majority of the reliability improvement options included in this study are related to distribution automation.

5.1 Reduction in Tree Trimming Cycle

Tree trimming is a conventional means of improving the reliability of supply and is a standard maintenance practice mandatory according to directives. It has been included in this study in order to compare it with other less frequently employed reliability improvement methods.

5.2 Wide Area Protection

The function of wide area protection is to detect abnormal power system operating conditions at the transmission voltage level (400-kV and 220-kV levels) and initiate appropriate actions to terminate those power system abnormalities. Thereby, the reliability of the HV electricity supply to distribution systems is improved. An alternative investment having a similar effect on the reliability of HV electricity supply to distribution systems would be to reinforce the transmission and subtransmission systems by constructing additional lines.

5.3 Improved Transformer Protection Security

Improving the transformer protection security is mainly about improving the security of the differential relay. The security for differential relays is calculated to 0.50 in (Kjølle *et al.*, 2005). One way to tackle this problem is to install differential relays that are able to distinguish internal fault conditions from other conditions that give rise to differential current.

5.4 Duplicated Feeder Protection

For the protection system, increased dependability is usually achieved at the cost of decreased security and there might be an optimal balance between dependability and security. Usually, unwanted protection operations resulting in a low level of security are the problem. Therefore, the challenge most often is to improve the security without deteriorating the dependability. It might be possible to achieve this by systematic use of new features offered by the numerical technology, such as self-monitoring. It has been shown (Aabø *et al.*, 2001) that a single numerical protection system has a higher level of security and the same level of dependability as a redundant numerical protection system.

5.5 Automatic Reclosing

Automatic reclosing is achieved by automatic reclosing relays or by reclosers. Automatic reclosing enable restoration of overhead feeders automatically after operation of associated feeder protection. Thus, automatic reclosing will be initiated even though the protection operation is a spontaneous unwanted protection operation. The number of reclosing attempts is adjustable. In the event the fault persists on the feeder at the end of the reclosing sequence, the feeder will be locked out. The majority of the faults occurring on overhead distribution systems are transient faults. In case a transient fault occurs on a feeder, customers connected to that feeder will only experience a momentary interruption if the device that de-energized the transient fault, either a circuit breaker or a recloser, is successfully reclosed to re-energize the circuit.

5.6 Fault Locating

There are various kinds of facilities available to assist the repair crew in finding fault locations much more quickly than by random feeder patrol.

A-frames, TDRs and Thumpers

Contrary to overhead feeders, visual inspection is not an option for fault locating on underground cables. Instead, three underground-cable fault-locating methods generally referred to as A-frame, Time Domain

Reflectometry (TDR) and high-voltage thumping are commonly used today to locate faults on underground cables. These methods have the following common characteristics:

- special fault-locating equipment is brought to the site, i.e., no permanent installations
- A-frame and high-voltage thumping involve walking along the path of the underground cable from the transmitter to the fault.

Together, the three methods accurately locate most underground cable faults.

Automatic Feeder Fault Locating

In this thesis, automatic fault locating refers to a functionality that is able to locate, with some accuracy, both transient and permanent feeder faults of all types before the faulted feeder is de-energized due to the fault. This functionality is either associated with the feeder protection installed in each feeder bay or realized by means of an central automatic fault locator installed in the substation. Note that the functionality is not yet commercially available for single phase-to-earth faults in a non-effectively earthed system.

Automatic Overhead Feeder Reclosers

In case of cascaded time-coordinated reclosers on an overhead feeder, by recognizing which of the reclosers along the feeder that have detected the fault and which recloser that has cleared the fault, it is possible to identify the faulted overhead feeder section.

Automatic Reclosing and Sectionalizing

In addition to automatic feeder fault locating, automatic identification of overhead feeder sections subject to permanent faults may be achieved by an arrangement combining automatic reclosing and automatic feeder sectionalizing. The sectionalizers are located on the load side of the switching device (circuit breaker or recloser) that de-energize the feeder. A counter in the sectionalizer keeps track of the number of de-energizations. At a preset number of de-energizations, an opening of the sectionalizer is initiated. The sectionalizers only operate when they are de-energized and thereby, they do not need to break or make fault current. Before the automatic sectionalizing procedure is started, the possibility of a transient overhead feeder fault is excluded by reclosing attempts. Then, starting downstream, sectionalizers isolate feeder sections consecutively with intermediate reclosing attempts. The faulted feeder section is isolated when a successful reclosing occurs.

Manual Reclosing and Sectionalizing

Manual reclosing and sectionalizing is an option for identification of faulted feeder section. The procedure is identical to that of the automatic counterpart, except for the fact that feeder sectionalizing and feeder circuit breaker reclosings are initiated manually. Usually, reclosers and sectionalizers can be manually operated as well.

5.7 Feeder Sectionalizing

Feeder sectionalizing provides the possibility to isolate faulty feeder sections from healthy feeder sections and can be achieved by installing various kinds of switching devices on the feeders. For instance, circuit breakers, reclosers, sectionalizers and disconnectors are such devices.

Feeder sectionalizing enables isolation of a permanent feeder fault in such a way that only the faulted feeder section is disconnected during localization and repair of the fault. If it would not be possible to sectionalize the distribution feeders, then a larger number of customers would experience interruption during the localization and repair phases of the restoration process. In addition, feeder sectionalizing plays a major role in some procedures that aim to identify the faulted feeder section when the fault is permanent.

When a permanent fault occurs on a radial feeder that is divided into sections, the faulted feeder section is identified by one of the techniques described in Section 5.6. Once the faulted feeder section is identified, it is also isolated, thus enabling restoration of the healthy feeder sections. Then, when as much as possible of the service to the interrupted customers has been restored, the fault is located more accurately and repaired.

Knowledge of which feeder section that is subject to the fault will limit the feeder distance to be more thoroughly examined, thus resulting in a reduction in the time required to accurately locate the fault. In addition, for underground cables, TDR locates faults more accurately when applied to a feeder section than when applied to the entire feeder, which means that instead of digging a 3-meter hole, it might be sufficient with a 1-meter hole to find the fault.

Manually Operated Feeder Sectionalizing Switches

The main purpose of manually operated feeder sectionalizing switches is to allow manual sectionalizing of feeders. They are usually implemented by disconnectors, which are designed to carry load current, however, when they are not equipped with interrupting chambers, they have limited current making and breaking capabilities. Therefore, they are normally only operated when the associated feeder is de-energized.

Automatic Overhead Feeder Reclosers

An automatic overhead feeder recloser, or just a recloser, is a self-contained pole-mounted overhead-feeder protection device with fault current making and breaking capability that incorporates overcurrent protection and automatic reclosing functionality. The main task of a recloser is to clear overhead feeder faults without causing service interruptions upstream of the recloser. Furthermore, when combined with downstream sectionnalizers, reclosers enable automatic isolation of faulted downstream feeder sections, when the faults are permanent, without causing upstream service interruptions.

5.8 Emergency Supply from Adjacent Feeders

Most distribution systems have an open ring structure, i.e. there are two alternative electrical paths to feed the customers, either from the same or from an adjacent primary substation. Once the faulted feeder section is isolated, closing normally opened tie switches will reconfigure the network and restore service to customers downstream of the isolated faulted feeder section.

5.9 Distribution Automation Systems

In this thesis, the concept of distribution automation includes the following functionalities:

- automatic operation of circuit breakers and disconnectors realizing such functionality as automatic reclosing, automatic isolation of faulted feeder section and automatic service restoration
- remote control capability of circuit breakers and disconnectors
- on-line distribution system monitoring (state of circuit breakers and disconnectors)

- automatic feeder fault locating.

A distribution automation system combines a number of the above distribution automation functionalities in order to achieve automatic isolation of the faulted feeder section, when a permanent fault occurs on the feeder, and to achieve automatic upstream and downstream service restoration. Thus, distribution automation systems require sectionalized feeders.

Chapter 6

Test System Specification

This chapter describes the test system that forms the basis for the evaluation of a number of reliability improvement solutions. These solutions constitute various combinations of the options described in Chapter 5. A general overview of the test system is provided in Section 6.1. Sections 6.2, 6.3 and 6.4 provide the parameter values used in the calculations of the average annual interruption costs to the test system customers. In Section 6.2, the credible contingencies resulting in interruptions to the test system customers and the process of restoration for these contingencies are described. The effects of the options on the reliability of the test system are treated in Section 6.3. The chapter ends by stating the interruption cost rates corresponding to the particular composition of the test system customers. The parameter values used in the calculations of the average annual interruption costs to the test system customers are summarized in Table 6.4.

6.1 General Overview

The test system, as shown in Figure 6.1, comprises an old-fashioned 130/20 kV distribution substation that is supplying a primary distribution system. The substation is old-fashioned in the sense that all protective relays are electro-mechanical. The distribution substation is supplied from a meshed 130 kV grid. The primary distribution system is radial and consists of 10 outgoing 20 kV feeders, F1-F10. Four feeders are underground cables, while the remaining six feeders are constructed with overhead bare conductors. The feeder details are given in Table 6.1. The underground cables serve customers in an urban area, while the overhead feeders serve customers in a heavily treed, high lightning, rural area. The distribution substation has two 40 MVA transformers, T1 and T2, which are both in service during normal operation. One transformer alone is capable of carrying the entire substation load, which has a maximum value of 50 MVA. There are three laterals per feeder serving the test system customers. The load is equally distributed among the 30 laterals, so that each lateral is serving a load demand that has an annual average value of 4/3 MW. The composition of customers is the same for each lateral. Each of the 10 feeder bays of the 20 kV busbar as well as each transformer bay is equipped with a circuit breaker. The feeder circuit breakers are remotely monitored and controlled from the operation control center. A disconnector makes it possible to sectionalize the 20 kV busbar.

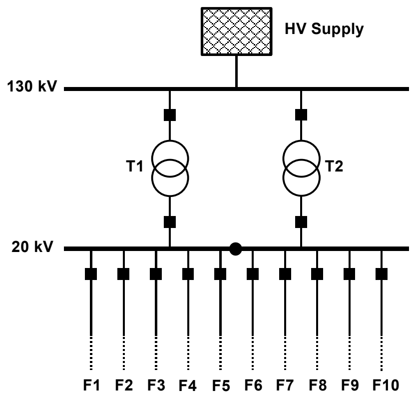

Figure 6.1: Structure of the test system.

Table 6.1: Feeder specification.

Feeder	Type	Length (km)
F1	Underground cable	4
F2	Overhead feeder	5
F3	Underground cable	7
F4	Underground cable	7
F5	Underground cable	8
F6	Overhead feeder	11
F7	Overhead feeder	15
F8	Overhead feeder	16
F9	Overhead feeder	23
F10	Overhead feeder	36

6.2 Credible Contingencies

Costs incurred by the customers fed from the test system feeders, due to unplanned interruptions, have been estimated as part of the evaluation of various reliability improvement solutions. The credible contingencies that have been taken into account in these calculations are:

- fault on feeder with correct feeder protection operation and correct reclosing relay operation
- fault on feeder with missing feeder protection operation
- spontaneous unwanted feeder protection operation with correct reclosing relay operation
- fault on feeder with correct feeder protection operation and missing reclosing relay operation
- spontaneous unwanted feeder protection operation with missing reclosing relay operation
- simultaneous outage of both distribution substation transformers due to a combination of one correct and one unwanted transformer protection operation
- loss of HV power supply to the distribution substation.

It is assumed that the probability of the following events is too low to be considered credible and therefore they have been neglected in the calculations:

- multiple power system faults occurring simultaneously on the system (Thus, for every single fault that occurs on the system, pre-fault operating conditions are always assumed normal.)
- missing operation of both main and backup protection
- simultaneous outage of both distribution substation transformers due to unwanted transformer protection operations
- missing transformer protection operation when there is an internal transformer fault or a fault located between the transformer and the busbar on the low voltage side
- busbar fault.

The following contingencies, which are related to the protection system, have been neglected as well, even though it would have been interesting to include them in the study. They have been left out of the study due to lack of knowledge of their frequency of occurrence:

- missing blocking signal of feeder protection in a blocking scheme for the busbar
- outage of DC auxiliary supply
- arc detectors tripping circuit breakers without overcurrent condition.

Since the lateral circuits have only been represented as average load demands when the interruption costs to the test system customers were calculated, faults on the lateral circuits have not been taken into account.

Faults on the Feeders

The faults occurring on the feeders of the test system are divided into transient and permanent faults. Permanent faults occur both on the overhead feeders and on the underground cables, while transient faults only occur on the overhead feeders. For the overhead feeders in the test system 80% of the faults are transient, leaving 20% of the faults to be permanent. The permanent faults occurring on the underground cables are divided into two categories: faults caused by excavation damages and all other faults referred to as internal faults. Most internal faults are due to insulation failures. The feeder failure rates are presented in Table 6.2.

In Sweden, there is a rule stating that reclosing of an overhead feeder circuit breaker without any action taken is only allowed within 90 seconds from the overhead feeder outage occurrence. In practice, this rule implies that overhead feeders must be inspected visually before manual reclosing of overhead feeder circuit breakers is performed. Since the travel time is 1 hour for transient faults and since the average time required for overhead feeder inspection is also 1 hour, the transient forced outage duration for the overhead feeders in the test system is equal to 2 hours. The permanent forced outage duration for the overhead feeders in the test system is equal to 5.5 hours, including 1 hour of travel time, 1 hour for visual feeder inspection, 1.5 hour for fault localization and 2 hours of repair time. Thus, even in the event of a permanent overhead feeder fault, visual overhead feeder inspection is performed. Furthermore, an unsuccessful manual overhead feeder circuit breaker reclosing attempt is made to exclude the possibility of a transient fault before starting to find the fault location.

Since visual inspection of underground cables is impossible, locating internal underground cable faults is performed by employing various techniques involving mobile fault-locating equipment such as cable radar (TDR) and high-voltage thumpers (see Section 5.6). For internal underground cable faults, getting the repair crew to the site with its test equipment is expected to take 2 hours, the fault locating procedure is expected to take 4 hours and the repair work is expected to take 3 hours. Thus, the permanent forced outage duration for the underground cables of the test system when the fault is internal is equal to 9 hours.

For underground cable faults caused by excavation damage, the fault location is of course known, at least to the operator of the excavator. However, it is assumed that the utility is immediately notified of the fault location. Thus, since no fault-locating equipment is needed on site, it is expected that it will take 1 hour for the repair crew to get to the fault location. The repair work for this kind of faults is expected to take 3 hours. Thus, the permanent forced outage duration for the underground cables of the test system when the fault is caused by excavation damage is equal to 4 hours.

Table 6.2: Test system feeder failure rates.

Type of fault	Failure rate
Overhead feeder transient faults	8 faults/(100 km, year)
Overhead feeder permanent faults	2 faults/(100 km, year)
Internal underground cable faults	0.2 faults/(100 km, year)
Underground cable faults caused by excavation	0.4 faults/(100 km, year)

Incorrect Feeder Protection Operations

The results that are presented in (Johannesson *et al.*, 2004) indicate that 7 % of the disturbances that occur in a power system involve incorrect protection operation, 20% of the incorrect protection operations are missing operations and 60% of the incorrect protection operations are unwanted operations. By applying these results to the test system, which experiences 10.8 feeder faults on average per year, a rough approximation of the number of missing feeder protection operations and of the number of spontaneous unwanted feeder protection operations that occur in the test system can be obtained. Thus, it is approximated that 0.15 missing feeder protection operations and 0.45 spontaneous unwanted feeder protection operations occur on average per year in the test system. The missing feeder protection operations are distributed among overhead feeder transient and permanent faults and underground cable internal and excavation faults in relation to the number of occurrences of each type of fault. For example, the average annual number of missing feeder protection operations when the feeder fault is transient is given by

$$\frac{\text{number of overhead feeder transient faults}}{\text{number of feeder faults}} \cdot 0.15$$

The spontaneous unwanted feeder protection operations are distributed equally among the 10 feeder bays, so that each feeder protection operates spontaneously 0.045 times on average per year.

In the event of a missing feeder protection operation, the travel time for the repair crew is 2 hours for all feeder faults, except for underground cable faults caused by excavation damage, for which the travel time is still 1 hour. Furthermore, upon arrival at the substation, the repair crew requires an average time of 30 minutes to identify the faulted feeder when the fault is either a permanent overhead feeder fault or an underground cable internal fault. Thus, the average restoration time of the healthy adjacent feeders after a missing feeder protection operation is 2.5 hours for permanent overhead feeder faults and for underground cable internal faults, 2 hours for transient faults and 1 hour for underground cable faults caused by excavation damage.

Automatic Reclosing

The evaluated automatic reclosing functionality initiates reclosing of overhead feeder circuit breakers and of automatic overhead feeder reclosers after operation of the associated feeder protection. Thereby automatic reclosing is initiated also after a spontaneous unwanted protection operation. An automatic reclosing sequence consists of, at the most, three reclosing attempts. The first reclosing attempt is instantaneous, the second attempt is initiated 30 seconds later and the third attempt is initiated after another 60 seconds.

In the event of a transient fault or of a spontaneous unwanted overhead feeder protection operation, an automatic reclosing sequence always successfully recloses the overhead feeder circuit breaker. However, the automatic reclosing relays in the distribution substation may fail to operate. Unwanted automatic reclosing relay operations never occur. In the event of a transient fault, the average time required for a successful automatic reclosure is 60 seconds, while the successful automatic reclosure is instantaneous in the event of a spontaneous unwanted overhead feeder protection operation. In the event of a permanent overhead feeder fault, the faulty feeder is locked-out after the third automatic reclosing attempt.

According to (Johannesson *et al.*, 2004), 7 % of the disturbances that occur in a power system involve incorrect protection operation and 13% of the incorrect protection operations are missing automatic reclosures. Since the feeders of the test system experience 10.8 faults on average per year, a rough approximation is that when the overhead feeder circuit breakers of the test system are equipped with automatic reclosing relays, 0.1 missing reclosing relay operations occur on average per year in the test system. These missing reclosing relay operations are distributed between overhead feeder circuit breaker trippings that are due to transient faults, to permanent faults and to spontaneous unwanted protection operations in relation to the average annual number of occurrences of each type of circuit breaker tripping. For example, the average annual number of missing reclosing relay operations, when the overhead feeder circuit breaker tripping de-energize a transient fault, is given by

$$\frac{\text{number of overhead feeder circuit breaker trippings de-energizing transient faults}}{\text{number of overhead feeder circuit breaker trippings}} \cdot 0.1$$

Manual Reclosing

Overhead feeders in the test system are always visually inspected before a manual reclosing attempt of an overhead feeder circuit breaker is made. Visual overhead feeder inspection with a subsequent manual overhead feeder circuit breaker reclosing attempt is performed on the test system when:

- an overhead feeder circuit breaker has been correctly tripped due to a fault (transient or permanent) and the overhead feeder circuit breakers are not equipped with automatic reclosing relays
- an overhead feeder circuit breaker has been correctly tripped due to a fault (transient or permanent) and a missing reclosing relay operation has occurred
- an overhead feeder circuit breaker has been correctly tripped due to a permanent fault and the associated automatic reclosing relay has locked out
- an overhead feeder circuit breaker has been incorrectly tripped due to a spontaneous unwanted overhead feeder protection operation and

the overhead feeders circuit breakers are not equipped with automatic reclosing relays

- an overhead feeder circuit breaker has been incorrectly tripped due to a spontaneous unwanted overhead feeder protection operation and the reclosing relay failed to operate.

Manual reclosing of an overhead feeder circuit breakers is always successful on the first attempt when it has been correctly tripped due to a transient fault or when it has been incorrectly tripped due to a spontaneous unwanted overhead feeder protection operation.

A manual reclosing attempt of an underground cable circuit breaker is always made after it has been tripped in order to exclude the possibility of a spontaneous unwanted underground cable protection operation. In the event of a spontaneous unwanted underground cable protection operation, the manual reclosing is always successful. The average underground cable outage duration when the underground cable outage is initiated by a spontaneous unwanted underground cable protection operation is equal to 5 minutes.

Missing Transformer Protection Operations

Due to the redundant nature of the transformer protection, missing transformer protection operation, when there is an internal transformer fault or a fault located between the transformer and the busbar on the low voltage side, has been considered unlikely to occur. The fact that transformer protection generally exhibits high dependability is confirmed in (Kjølle *et al.*, 2005) where Norwegian statistics for the period 1999-2003 are presented showing that transformer protection at 132 – 420 kV levels have a dependability equal to 0.985, i.e., 448 correct operations and 7 missing operations.

Simultaneous Outages of Both Transformers

Simultaneous outages of both distribution substation transformers of the test system occur when one transformer is taken out of service due to an internal fault on that transformer, while an outage of the other parallel transformer is caused by an unwanted transformer protection operation. Reference (Kjølle *et al.*, 2005) reports the results from a study of Norwegian fault statistics for the period 1999 – 2003. According to this study, the security of transformer protection at the 132 – 420 kV levels is equal to 0.643, i.e., 448 correct operations and 249 unwanted operations. Thus, about 1 out of 3 transformer protection operations are unwanted. This level of transformer protection security is adopted for the 130/20 kV power transformer protection of the test system. Each transformer of the test system experiences 0.02 internal faults on average per year. Since the probability of a missing transformer protection operation when there is an internal transformer fault is assumed negligible, these internal transformer faults are cleared selectively. Therefore, each transformer also experiences 0.01 outage occurrences on average per year that are caused by unwanted transformer protection operations. Furthermore, it is assumed that an unwanted transformer protection operation only occurs when there is a power system fault, either on the parallel transformer or on one of the feeders, F1-F10. Since the parallel transformer experiences 0.02 faults on average per year and the feeders experience 10.8 faults on average per year, there will be 0.00004 unwanted transformer protection operations on average per year that result in simultaneous outages of both distribution substation transformers of the test system. When a simultaneous outage of both distribution substation transformers has occurred as described above, the average outage duration for the healthy transformer is equal to 1 hour.

Loss of HV Power Supply to the Distribution Substation

The test system customers experience on average 0.2 interruptions per year caused by events occurring on the HV level, with an average interruption duration of 1.7 hours. Thus, the HV supply to the distribution substation is assumed unavailable 20 minutes per year on average.

6.3 Effects of Reliability Improvement Options

This section deals with the reliability improving effects that the evaluated options have on the test system.

Reduction in Tree Trimming Cycle

The current tree trimming program adopted by the owner of the test system allow tree trimming of the 20 kV overhead feeder corridors every eighth year. Reduction of the tree trimming cycle to half the time is expected to reduce the overhead feeder failure rate for permanent faults by 20% and the overhead feeder failure rate for transient faults by 30%.

Wide Area Protection

By installing wide area protection at the transmission level, the average number of interruptions per year caused by events occurring on the HV level is reduced by 20%, i.e., one out of five interruptions is avoided.

Improved Transformer Protection Security

By improving the transformer protection security, the number of unwanted transformer protection operations is reduced, such that 1 out of 4 instead of 1 out of 3 transformer protection operations is unwanted.

Duplicated Feeder Protection

By introducing duplicated feeder protection the average annual number of missing feeder protection operations occurring in the test system is reduced by 25%, while the average annual number of spontaneous unwanted feeder protection operations occurring in the test system is increased by 50%.

Overhead Feeder Circuit Breakers with Automatic Reclosing Relays

Successful automatic reclosing sequences of overhead feeder circuit breakers that have been tripped in order to de-energize transient faults reduce the transient forced outage duration for the overhead feeders in the test system from 2 hours to 60 seconds. Successful automatic reclosures of overhead feeder circuit breakers that have been tripped by spontaneous unwanted overhead feeder protection operations are instantaneous.

Automatic Fault Locating

Automatic fault locating provides fast determination of the distance to the fault with some accuracy. This enables the repair crew to be directed straight to the vicinity of the fault location. Thereby, the repair crew does not need to examine the entire feeder. Instead, the feeder distance that needs to be examined depends on the accuracy of the automatic fault locating. When automatic fault locating is combined with feeder sectionalizing, the accuracy is sufficient for determining the faulted feeder section. Furthermore, automatic fault locating will function as intended in the event of a missing feeder protection operation. Automatic fault locating improves the reliability of the test system by:

- reducing the average time required for visual inspection of faulted overhead feeders by 30 minutes
- reducing the average time required for locating a permanent overhead feeder fault by 1 hour

- reducing the average time required for locating an internal underground cable fault by 80 minutes (by 90 minutes if the underground cable can be sectionalized).

Note that in the event of a spontaneous unwanted overhead feeder protection operation, automatic fault locating will not reduce the average time required for visual inspection of the overhead feeder. Furthermore, in the test system, automatic fault locating is implemented by installing a central automatic fault locator providing the distance to the fault. However, in the event of a missing feeder protection operation, the faulty feeder needs to be manually identified.

Feeder Sectionalizing

Once a faulted feeder section is identified and isolated, the average time required for locating a permanent overhead feeder fault is reduced by 1 hour and the average time required for locating an internal underground cable fault is reduced by 1.5 hours.

In the cases where feeder sectionalizing is employed, each feeder is divided into 3 equally long sections. Since each feeder section directly serves 1/3 of the annual average feeder load demand, an outage of a feeder section always gives rise to energy not supplied. Thus, deliberate time delays in the process of restoration are unacceptable and are therefore not taken into account in the calculations.

Manual Fault Isolation and Restoration

Feeder sectionalizing is accomplished by installing various kinds of switches on the feeders, such as manually operated feeder sectionalizing switches, sectionalizers and reclosers. In the event of a permanent feeder fault, the faulted feeder section can be identified and isolated according to a procedure involving manual operation of these feeder-sectionalizing switches and of the feeder circuit breaker. This manual procedure is expected to take 30 minutes including restoration of the healthy parts of the feeder, i.e., either upstream or downstream restoration or both, before starting to locate and repair the fault. In this study, manually operated feeder sectionalizing switches and sectionalizers have no current-interrupting capability. Furthermore, the feeder sectionalizing switches are only remotely controlled when they are part of a distribution automation system.

Overhead Feeder Circuit Breakers with Automatic Reclosing Relays Combined with Automatic Overhead Feeder Sectionalizers

Coordinated operation of overhead feeder circuit breakers with automatic reclosing relays and automatic overhead feeder sectionalizers enable automatic isolation of overhead feeder sections subject to permanent faults according to the procedure described in Section 5.6. The benefits are similar to those for automatic fault locating, i.e., the repair crew is directed straight to the faulted section, and thereby, only the faulted section needs to be examined. An additional benefit is fast upstream service restoration. In the event of a permanent fault on the most downstream overhead feeder section, upstream service is expected to be restored in 3 minutes. In the event of a permanent fault on the middle overhead feeder section, upstream service is expected to be restored in 4 minutes. Finally, the most upstream overhead feeder section will be isolated in 5 minutes when it is subject to a permanent fault. The automatic sectionalizing procedure is automatically initiated after a preset number of unsuccessful overhead feeder circuit breaker reclosing attempts. However, in the event of either a missing overhead feeder protection operation or a failing reclosing relay, it will not be initiated. In both cases, the section subject to a permanent fault will instead be manually identified and isolated. In the event of a failing reclosing relay, the steps towards upstream (and downstream) restoration are as follows:

1. repair crew arrive at site (1 hour)
2. inspection of the entire disconnected overhead feeder (1 hour)
3. manual reclosing and sectionalizing in order to identify and isolate faulted overhead feeder section with subsequent manual upstream (and downstream) service restoration (30 minutes).

In the event of a failing overhead feeder protection, the steps towards upstream (and downstream) restoration are as follows:

1. repair crew arrive at the substation (2 hour)
2. identification of the faulted feeder (30 minutes)
3. manual identification and isolation of faulted overhead feeder section with subsequent manual upstream (and downstream) service restoration when the manual procedure is complicated by a malfunctioning feeder protection (1 hour).

Feeder Sectionalizing Combined with Emergency Supply from Adjacent Feeders

Feeder sectionalizing *without* emergency supply from adjacent feeders only enables upstream restoration, whereas feeder sectionalizing *with* emergency supply from adjacent feeders enables both upstream and downstream restoration. Emergency supply from adjacent feeders is applied once a feeder section subject to a permanent fault has been isolated.

6.4 Average Interruption Cost Rates

Table 6.3 presents interruption cost rates for the individual customer categories present in the test system. These cost rates are obtained from (Elavbrottskostnader, 2004) and are valid for unplanned interruptions with durations around 4 hours. For longer interruption durations, they will be greater. Furthermore, Table 6.3 displays the distribution of the annual average load demand on the customer categories, which motivates average interruption cost rates of 12 SEK/kW and 50 SEK/kWh for each lateral in the test system.

Table 6.3: Customer composition for each lateral in the test system and interruption cost rates for individual customer categories obtained from (Elavbrottskostnader, 2004).

Customer category	Interruption cost rate		Customer composition
	SEK/kW	SEK/kWh	
Residential	2	4	35%
Agricultural	10	35	5%
Commercial	34	169	10%
Small industry	15	60	50%

Table 6.4: Parameters that are associated with uncertainties and that are incorporated in the calculation of the average annual interruption costs to the test system customers for at least one reliability improvement solution.

Input parameter	Nominal value	Incorporated in solutions
Failure rate for 20 kV overhead feeder permanent faults	2 faults/(100 km, year)	1-19
Failure rate for 20 kV overhead feeder transient faults	8 faults/(100 km, year)	1-19

Failure rate for 20 kV underground cable internal faults	0.2 faults/(100 km, year)	1-19
Failure rate for 20 kV underground cable excavation faults	0.4 faults/(100 km, year)	1-19
Failure rate for 130/20 kV power transformer faults	2 faults/(100 transformers, year)	1-19
Interruption frequency of the 130 kV electricity supply to the distribution substation	0.2 interruptions/year	1-19
Average time required to travel to overhead feeders	1 hour	1-19
Average time required for visual inspection of overhead feeders	1 hour	1-19
Average time required to locate permanent faults on overhead feeders	1.5 hour	1-19
Average time required to repair permanent overhead feeder faults	2 hours	1-19
Average time required to travel to underground cables subject to internal faults	2 hours	1-19
Average time required to locate internal faults on underground cables	4 hours	1-19
Average time required to repair internal underground cable faults	3 hours	1-19
Average time required to travel to underground cables subject to excavation faults	1 hour	1-19
Average time required to repair underground cable excavation faults	3 hours	1-19
Average time required to identify the feeder subject to the permanent fault in the event of a missing feeder protection operation	30 minutes	1-19
Average transformer outage duration when the transformer outage is initiated by an unwanted transformer protection operation	1 hour	1-19

Average duration of interruption of the HV electricity supply to the distribution substation	1.7 hour	1-19
Average underground cable outage duration when the underground cable outage is initiated by a spontaneous unwanted underground cable protection operation	5 minutes	1-19
Percentage disturbances with incorrect protection operation	7 percent	1-19
Percentage of incorrect protection operations that are missing protection operations	20 percent	1-19
Percentage of incorrect protection operations that are missing automatic reclosing relay operations	13 percent	6, 8, 11-12, 15-19
Percentage of incorrect protection operations that are unwanted operations	60 percent	1-19
Transformer protection security	0.667	1-3, 5-19
interruption cost per kW (for customers)	12 SEK/kW	1-19
interruption cost per kWh (for customers)	50 SEK/kWh	1-19
Reduced failure rate for overhead feeder permanent faults	1.6 faults/(100 km, year)	2
Reduced failure rate for overhead feeder transient faults	5.6 faults/(100 km, year)	2
Reduction in interruption frequency of the HV electricity supply to the distribution substation	20 percent	3
Improved transformer protection security	0.75	4
Reduction in annual average number of missing feeder protection operations	25 percent	5
Increase in annual average number of spontaneous unwanted feeder protection operations	50 percent	5
Average time required for a successful automatic reclosure in the event of a transient overhead feeder fault	60 seconds	6, 8, 11-12, 15-19

Automatic reclosing relay lock out time in the event of a permanent overhead feeder fault	90 seconds	17-19
Reduction in average time required for visual inspection of overhead feeders (automatic fault locating or reclosers)	30 minutes	7-8, 10, 12, 14, 17-19
Reduction in average time required to locate permanent faults on overhead feeders (automatic fault locating or sectionalizing)	1 hour	7-19
Reduction in average time required to locate internal underground cable faults (automatic fault locating and not sectionalizing)	80 minutes	7-8
Reduction in average time required to locate internal underground cable faults (sectionalizing)	1.5 hour	9-19
Average time required to manually isolate the feeder section subject to a permanent fault when the faulted section does not need to be identified. This time also includes manual upstream and downstream restoration. (sectionalizing and automatic fault locating or excavation damage to underground cables)	10 minutes	9-19
Average time required to manually identify and isolate the feeder section subject to a permanent fault. This time also includes manual upstream and downstream restoration. (feeder sectionalizing and not automatic feeder fault locating)	30 minutes	9, 11-13, 15-16, 19

Average time required to manually identify and isolate the feeder section subject to a permanent fault when the manual procedure is complicated by a malfunctioning feeder protection. This time also includes manual upstream and downstream restoration. (feeder sectionalizing and not automatic feeder fault locating)	1 hour	9, 11-13, 15-16, 19
Time required for upstream service restoration when automatic isolation of overhead feeder sections subject to permanent faults is accomplished by means of coordinated operation of automatic reclosing relays and sectionalizers. (faults on most downstream overhead feeder sections)	3 minutes	15-16
Time required for upstream and downstream service restoration when automatic isolation of overhead feeder sections subject to permanent faults is accomplished by means of coordinated operation of automatic reclosing relays and sectionalizers. (faults on middle overhead feeder sections)	4 minutes	15-16
Time required for downstream service restoration when automatic isolation of overhead feeder sections subject to permanent faults is accomplished by means of coordinated operation of automatic reclosing relays and sectionalizers. (faults on most upstream overhead feeder sections)	5 minutes	16

Chapter 7

Interruption Cost Calculations

In this chapter, reliability improvement *solutions* are applied to the test system with the intention to improve the reliability of supply. The reliability improvement solutions are composed from the reliability improvement *options* described in Chapter 5. The interruption costs, incurred by the test system customers due to unplanned interruptions, when no reliability improvement solution has been applied and when each of the reliability improvement solutions has been applied, have been calculated. This chapter describes the calculation procedure employed and presents the results of the interruption cost calculations performed. The estimated average annual interruption costs to the test system customers for each reliability improvement solution are summarized in Table 7.1. The base case (Solution 1) represents the reliability of supply when none of the reliability improvement solutions is applied. In the following solutions (Solution 2-19), measures are taken to improve the reliability of supply.

Reliability improvement solutions need to be customized for each network in order to be cost-efficient. Problem areas experiencing remarkable poor reliability of supply and the most cost-efficient investment projects need to be identified. Cost-efficiency for electricity network companies usually means decreasing costs or maintaining costs at a low level, while still meeting the regulator's requirements. Note that the benefits of applying the reliability improvement solutions below to the test system might differ from the benefits of applying the same reliability improvement solutions to another system. This is because outage causes vary between utilities and even between areas for the same utility. The system dependency of the cost-efficiency of reliability improvement solutions becomes evident in (Brown, 2001). The first step in improving the reliability of supply in an area is to identify the causes of interruptions in that area. Thus, utilities have to analyze their systems rigorously in order to identify the most cost-efficient reliability improvement solutions.

7.1 Calculation Procedure

For each reliability improvement solution applied to the test system, the average annual customer interruption cost (AACIC) incurred by the test system customers due to unplanned interruptions is calculated as

$$\mathrm{AACIC} = \sum_i \sum_j \lambda_{ij} P_i \left[C_P + C_E T_{ij} \right] \tag{7.1}$$

where,

> λ_{ij} denotes the average annual number of interruptions experienced by the customers on lateral i due to contingency j
>
> P_i denotes the annual average load demand of the customers on lateral i
>
> C_P denotes the average interruption cost rate for interrupted power
>
> C_E denotes the average interruption cost rate for energy not supplied
>
> T_{ij} denotes the average interruption duration the customers on lateral i experience due to contingency j.

P_i, C_P, and C_E are constants and are equal to 4/3 MW, 12 SEK/kW and 50 SEK/kWh respectively, while λ_{ij} and T_{ij} depend on the reliability improvement solution applied to the test system. Furthermore, C_P is incorporated in the calculations because the interruption costs to customers generally are higher for frequent momentary interruptions than for rare sustained interruptions, even though the sums of customer interruption durations are equal for the two cases.

7.2 Assumptions

The following assumptions have been made in the interruption cost calculations:

- In the event of a spontaneous unwanted feeder protection operation, both manual and automatic reclosing are always successful on the first attempt
- In the event of a transient fault, both manual and automatic reclosing are always successful, though automatic reclosing may not be successful on the first attempt
- In the event of an unsuccessful automatic reclosing sequence, visual overhead feeder inspection with a subsequent unsuccessful manual reclosing attempt of the tripped overhead feeder circuit breaker or recloser is always performed before starting the fault locating procedure
- If a feeder protection has operated correctly on a permanent feeder fault, it will continue to operate correctly for that fault after reclosing of the circuit breaker
- If a feeder protection has failed to operate on a permanent feeder fault, it will continue to fail to operate for that fault
- If a reclosing relay has failed to operate, it will continue to do so
- Circuit breakers, reclosers, sectionalizers and remotely controlled sectionalizing switches are 100% reliable
- Remote monitoring and control facilities are 100% reliable
- Automatic fault locating is 100% reliable
- Once initiated, automatic sectionalizing is 100% reliable, i.e., it will successfully isolate feeder sections subject to permanent faults
- Once a faulted feeder section has been automatically isolated, automatic upstream and downstream restoration is 100% reliable
- Reclosers detect and clear all types of faults that occur on the test system feeders, i.e., not just faults that cause overcurrent conditions
- Cascaded time-coordinated reclosers on a feeder operate 100% in a selective manner
- Upstream and downstream restoration by closing feeder circuit breakers and normally opened tie switches, respectively, is initiated via

remote control from the operation control center, unless automatic upstream and downstream restoration is implemented

- Information on the state of circuit breakers, reclosers and sectionalizers is always available for the repair crew.

7.3 Calculation Results

In this section, the special features of each reliability improvement solution applied to the test system are described and the results of the interruption cost calculations performed according to the procedure described in Section 7.1 are presented. Nominal input parameter values from Table 6.4 have been used and the assumptions listed in Section 7.2 have been made in the calculations.

Solution 1 – Base Case

This solution is actually not a solution. Instead, the average annual interruption cost to the test system customers, without any of the reliability improvement solutions applied, is estimated. As described in Chapter 6, none of the following reliability improvement options is available in the test system:

- emergency supply from adjacent feeders
- possibility to sectionalize the feeders
- automatic reclosing of overhead feeder circuit breakers
- automatic feeder fault locating
- wide area protection at the transmission level.

Furthermore, typical transformer protection security and single feeder protection systems are assumed. The average annual interruption cost to the test system customers without any of the reliability improvement solution applied to the test system is calculated to 7.95 MSEK/year.

Solution 2 – Reduction in Tree Trimming Cycle

A failure rate for overhead feeder transient faults of 5.6 faults/(100 km, year) and a failure rate for overhead feeder permanent faults of 1.6 faults/(100 km, year) are achieved by reducing the tree trimming cycle to half the time. By applying this solution on the test system, the average annual interruption cost to the test system customers reduces to 6.11 MSEK/year.

Solution 3 – Wide Area Protection

Wide area protection at the transmission voltage level improves the interruption frequency of the 130 kV electricity supply to the distribution substation, such that instead of 0.2 interruptions/year, the distribution substation is expected to experience 0.16 interruptions/year. By installing wide area protection in the transmission system, the average annual interruption cost to the test system customers reduces to 7.80 MSEK/year.

Solution 4 – Improved Transformer Protection Security

By implementing this solution, we manage to reduce the number of unwanted transformer protection operations, so that instead of 1 out of 3 transformer protection operations, 1 out of 4 transformer protection operations is unwanted. This improvement in the transformer protection security has a negligible impact on the average annual interruption cost to the test system customers, which still amounts to 7.95 MSEK/year.

Solution 5 – Duplicated Feeder Protection

By duplicating the feeder protection, the feeder protection dependability is increased, while the feeder protection security is decreased. Thus, the average annual number of missing feeder protection operations occurring in the test system decreases from 0.15 to 0.11 missing feeder protection operations per year, while the average annual number of spontaneous unwanted feeder protection operations occurring in the test system increases from 0.45 to 0.68 spontaneous unwanted feeder protection operations per year. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 7.86 MSEK/year.

Solution 6 – Overhead Feeder Circuit Breakers with Automatic Reclosing Relays

Successful automatic reclosing sequences of overhead feeder circuit breakers reduce the transient forced outage duration for the overhead feeders in the test system from 2 hours to 60 seconds. Furthermore, automatic reclosing of overhead feeder circuit breakers that have been tripped by spontaneous unwanted overhead feeder protection operations instantaneously restores the associated overhead feeders to service. By introducing automatic reclosing relays in the distribution substation, the average annual interruption cost to the test system customers reduces to 4.56 MSEK/year.

Solution 7 – Automatic Feeder Fault Locating

Automatic feeder fault locating directs the repair crew to the vicinity of the fault location. Thereby, the average times required to locate permanent overhead feeder faults and to locate internal underground cable faults are reduced by 1 hour and 1.3 hours, respectively. Furthermore, automatic feeder fault locating reduces the average time required for visual inspection of overhead feeders by 30 minutes. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 6.14 MSEK/year.

Solution 8 – Overhead Feeder Circuit Breakers with Automatic Reclosing Relays Combined with Automatic Feeder Fault Locating

This solution combines Solution 6 and Solution 8. Automatically reclosing circuit breakers reduce the transient forced outage duration for the overhead feeders in the test system. Furthermore, automatic reclosing of overhead feeder circuit breakers that have been tripped by spontaneous unwanted overhead feeder protection operations instantaneously restores the associated overhead feeders to service. Automatic feeder fault location reduces the time required to locate permanent overhead feeder faults and internal underground cable faults. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 3.57 MSEK/year.

Solution 9 – Manually Operated Feeder Sectionalizing Switches

This solution enables manual identification and isolation of faulted feeder sections. Thereby, upstream service can be manually restored before a permanent fault is located and repaired. Furthermore, the time required to find the fault location is reduced. Once the faulted feeder section is isolated, the average times required to locate a permanent overhead feeder fault and an internal underground cable fault are reduced by 1 hour and 1.5 hours, respectively. Manual switching operations performed to isolate an underground cable fault caused by excavation damage and to restore upstream service are expected to take 10 minutes. By dividing each feeder into three equally long sections by means of manually operated feeder sectionalizing switches, where each feeder section directly serves 1/3 of the annual average feeder load demand, the average annual interruption cost to the test system customers reduces to 7.34 MSEK/year.

Solution 10 – Manually Operated Feeder Sectionalizing Switches Combined with Automatic Feeder Fault Locating

This solution combines Solution 7 and Solution 9. Automatic feeder fault locating directs the repair crew straight to the faulted feeder section. In the event of an overhead feeder fault, first visual inspection of the faulted section (30 minutes) is carried out followed by an attempt to reclose the circuit breaker that has been tripped due to the fault. If the reclosing attempt fails, then the faulted section is isolated and upstream restoration is performed (10 minutes) before the fault is located more accurately (30 minutes). In the case of an internal underground cable fault, upon arrival at the faulted section, the repair crew immediately isolates the faulted section and performs upstream restoration (10 minutes) before starting to locate the fault more accurately (2.5 hours). By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 5.82 MSEK/year.

Solution 11 –Overhead Feeder Circuit Breakers with Automatic Reclosing Relays Combined with Manually Operated Feeder Sectionalizing Switches

This solution combines Solution 6 and Solution 9. Visual inspections of overhead feeders, when the associated circuit breakers have been tripped either due to transient fault or by spontaneous unwanted overhead feeder protection operations, are avoided. Otherwise, the same benefits as in Solution 9 are obtained. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 3.95 MSEK/year.

Solution 12 – Overhead Feeder Circuit Breakers with Automatic Reclosing Relays Combined with Automatic Overhead Feeder Reclosers

In this solution, cascaded time-coordinated reclosers have been installed on the overhead feeders of the test system replacing the manually operated feeder sectionalizing switches in Solution 11. Thereby, all overhead feeder faults are cleared without affecting upstream customers. The substation overhead feeder protection and the pole-mounted reclosers operate 100% in a selective manner. Since the substation overhead feeder protection now only is the main protection for the most upstream overhead feeder section, the annual average number of feeder faults for which tripping of feeder circuit breakers is desired is changed from 10.8 faults per year to 3.7 faults per year. Then again, by applying the results that are presented in reference (Johannesson *et al.*, 2004) yields that 0.05 missing feeder protection operations and 0.03 missing reclosing relay operation occur on average per year in the test system. The missing feeder protection operations are distributed among overhead feeder transient and permanent faults and underground cable internal and excavation faults in a similar manner as that expressed in Chapter 6. For example, the average annual number of missing feeder protection operations when the feeder fault is an overhead feeder transient fault is given by

$$\frac{\text{number of desired overhead feeder circuit breaker tripps due to transient faults}}{\text{number of desired feeder circuit breaker tripps due to feeder faults}} \cdot 0.05$$

Similarly, the missing reclosing relay operations are distributed among overhead feeder circuit breaker trippings that de-energize transient faults, that de-energize permanent faults and that are initiated by spontaneous unwanted substation overhead feeder protection operations in a similar manner as that expressed in Chapter 6. The number of spontaneous unwanted feeder protection operations remains unchanged as compared to the base case (Solution 1), i.e., 0.045 spontaneous unwanted feeder protection operations on average per year and feeder bay. Notice that in this solution the manually operated underground cables sectionalizing switches remain as in Solution11. Since the repair crew always is notified of which device that has de-energized the overhead feeder fault, the repair crew can head directly to the faulted overhead feeder section. Thereby,

- the average time required for visual inspection of faulted overhead feeder is reduced by 30 minutes
- the average time required for locating a permanent overhead feeder fault is reduced by 1 hour.

Since reclosers provide automatic isolation of faulted overhead feeder section and no upstream restoration is necessary, the repair crew does not need to spend time on this matter. Furthermore, in the event of a transient fault, the expected time for successful reclosing of reclosers is equal to 60 seconds.

By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 2.66 MSEK/year.

Solution 13 – Manually Operated Feeder Sectionalizing Switches Combined with Emergency Supply from Adjacent Feeders

As compared to Solution 9, this solution offers the additional opportunity of manual downstream restoration. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 6.95 MSEK/year.

Solution 14 – Manually Operated Feeder Sectionalizing Switches Combined with Automatic Feeder Fault Locating and Emergency Supply from Adjacent Feeders

As compared to Solution 9, this solution offers the additional opportunity of manual downstream restoration. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 5.43 MSEK/year.

Solution 15 – Distribution Automation System Incorporating Overhead Feeder Circuit Breakers with Automatic Reclosing Relays and Automatic Overhead Feeder Sectionalizers

In this solution, automatic overhead feeder sectionalizers have been installed on the overhead feeders of the test system replacing the manually operated feeder sectionalizing switches in Solution 11. In addition, automatic isolation of overhead feeder sections subject to permanent faults and automatic upstream service restoration has been achieved through coordinated operation of the automatic reclosing relays and the sectionalizers. Thus, overhead feeder sections subject to permanent faults are automatically isolated according to the procedure described in Section 5.6. In the event of either a missing overhead feeder protection operation or a failing reclosing relay, the above automatic functionality will not be initiated (see Section 6.3). Note that in this solution the manually operated underground cable sectionalizing switches remain as in Solution 11. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 3.19 MSEK/year.

Solution 16 – Distribution Automation System Incorporating Overhead Feeder Circuit Breakers with Automatic Reclosing Relays, Automatic Overhead Feeder Sectionalizers and Emergency Supply from Adjacent Feeders

As compared to Solution 15, this solution offers the additional opportunity of automatic downstream restoration. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 2.67 MSEK/year.

Solution 17 – Distribution Automation System Incorporating Overhead Feeder Circuit Breakers with Automatic Reclosing Relays, Automatic Feeder Fault Locating and Remotely Controlled Feeder Sectionalizing Switches

In this solution, remotely controlled feeder sectionalizing switches have been installed both on the overhead feeders and on the underground cables. Furthermore, the same automatic functionality as in Solution 15 has been achieved through coordinated operation of the automatic reclosing relays, the central automatic feeder fault locator and the remotely controlled feeder sectionalizing switches. However, in this solution, it is also applied to the underground cables. For overhead feeders, automatic isolation of faulted sections and automatic upstream service restoration is automatically initiated when the associated reclosing relays have locked out. Then, when an overhead feeder fault persists after an unsuccessful circuit breaker reclosing sequence, isolation of faulted overhead feeder section and upstream service restoration is instantaneous. Similarly, for underground cables, automatic isolation of faulted sections and automatic upstream service restoration is also instantaneous. However, the automatic functionality on underground cables is initiated instantaneously when underground cable circuit breakers have been tripped due to underground cable faults.

The above automatic functionality will not be automatically initiated in the event of a missing reclosing relay operation, in the event of a missing feeder protection operation or in the event of a spontaneous unwanted underground cable protection operation. In the latter case, the underground cable circuit breakers will be successfully reclosed from the operation control center after an average time of 5 minutes. In the event of a missing feeder protection operation, automatic isolation will be initiated manually, if the fault persists after a manual reclosing attempt of the transformer circuit breakers on the secondary side. Then a second manual reclosing attempt of the transformer circuit breakers on the secondary side will restore healthy adjacent feeders and at the same time restore service upstream of the isolated faulted feeder section. The above does not apply to missing underground cable protection operations when the faults are caused by excavation damages, in which case the automatic isolation procedure will be initiated manually before reclosing of the transformer circuit breakers on the secondary side will restore healthy adjacent feeders and at the same time restore service upstream of the isolated faulted underground section. A missing reclosing relay operation, when the associated overhead feeder circuit breaker has been tripped due to a permanent fault, will be followed by:

1. an inspection of the faulted overhead feeder section that is indicated by the central automatic feeder fault locator (30 minutes)
2. an unsuccessful manual overhead feeder circuit breaker reclosing
3. an additional missing reclosing relay operation
4. manual isolation of faulted overhead feeder section with subsequent manual upstream service restoration (10 minutes)
5. repair (2 hours).

By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 2.82 MSEK/year.

Solution 18 – Distribution Automation System Incorporating Overhead Feeder Circuit Breakers with Automatic Reclosing Relays, Automatic Feeder Fault Locating, Remotely Controlled Feeder Sectionalizing Switches and Emergency Supply from Adjacent Feeders.

As compared to Solution 17, this solution offers the additional opportunity of automatic downstream restoration. By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 2.28 MSEK/year.

Solution 19 – Distribution Automation System Incorporating Overhead Feeder Circuit Breakers with Automatic Reclosing Relays, Automatic Overhead Feeder Reclosers and Emergency Supply from Adjacent Feeders

As compared to Solution 12, this solution offers the additional opportunity of automatic downstream restoration. Automatic isolation of faulted overhead feeder sections with subsequent automatic downstream restoration has been achieved through coordinated operation of the reclosing relays, the circuit breakers, the reclosers and the normally opened tie switches. Once the faulted overhead feeder section is automatically isolated, the automatic downstream service restoration is instantaneous.

Once an automatic reclosing relay, either at the substation or in a recloser, has looked out, the automatic isolation of the faulted overhead feeder section and the automatic downstream customer service restoration is instantaneous. However, the automatic isolation of faulted overhead feeder sections and the automatic downstream service restoration are not initiated in the event of a missing reclosing relay operation or in the event of a missing overhead feeder protection operation. A missing reclosing relay operation, when the associated overhead feeder circuit breaker has been tripped due to a permanent fault, will be followed by:

1. an inspection of the most upstream section of the disconnected overhead feeder (30 minutes)
2. an unsuccessful manual overhead feeder circuit breaker reclosing
3. an additional missing reclosing relay operation
4. manual isolation of the most upstream overhead feeder section with subsequent manual downstream service restoration (10 minutes).

In the event of a missing overhead feeder protection operation, when the fault is permanent, manual identification and isolation of faulted section is performed with subsequent manual upstream and downstream service restoration (60 minutes).

By implementing this solution on the test system, the average annual interruption cost to the test system customers reduces to 1.99 MSEK/year.

Table 7.1: Summary of constituent options and estimated average annual interruption costs to the test system customers (AACIC) for the reliability improvement solutions.

Solution number	Options	AACIC (MSEK/year)
2	Reduction in tree trimming cycle	6.11
3	Wide area protection	7.80
4	Improved transformer protection security	7.95
5	Duplicated feeder protection	7.86
6	Overhead feeder circuit breakers with automatic reclosing relays	4.56
7	Automatic feeder fault locating	6.14

8	Overhead feeder circuit breakers with automatic reclosing relays Automatic feeder fault locating	3.57
9	Feeder sectionalizing by manually operated sectionalizing switches	7.34
10	Automatic feeder fault locating Feeder sectionalizing by manually operated sectionalizing switches	5.82
11	Overhead feeder circuit breakers with automatic reclosing relays Feeder sectionalizing by manually operated sectionalizing switches	3.95
12	Overhead feeder circuit breakers with automatic reclosing relays Overhead feeder sectionalizing by automatic overhead feeder reclosers	2.66
13	Feeder sectionalizing by manually operated sectionalizing switches Emergency supply from adjacent feeders Central programmable unit that communicates with RTUs Integration with SCADA-system	6.95
14	Automatic feeder fault locating Feeder sectionalizing by manually operated sectionalizing switches Emergency supply from adjacent feeders Central programmable unit that communicates with RTUs Integration with SCADA-system	5.43
15	Overhead feeder circuit breakers with automatic reclosing relays Overhead feeder sectionalizing by automatic overhead feeder sectionalizers	3.19
16	Overhead feeder circuit breakers with automatic reclosing relays Overhead feeder sectionalizing by automatic overhead feeder sectionalizers Emergency supply from adjacent feeders	2.67

17	Overhead feeder circuit breakers with automatic reclosing relays Automatic feeder fault locating Automatic isolation of faulted feeder section from remote	2.82
18	Overhead feeder circuit breakers with automatic reclosing relays Automatic feeder fault locating Automatic isolation of faulted feeder section from remote Emergency supply from adjacent feeders	2.28
19	Overhead feeder circuit breakers with automatic reclosing relays Overhead feeder sectionalizing by automatic overhead feder reclosers Emergency supply from adjacent feeders	1.99

Chapter 8

Sensitivity Analysis

Estimates of average annual interruption costs to customers connected to the test system have been calculated for various reliability improvement solutions applied to the test system (see Figure 7.1). These calculations incorporate a number of input parameters (see Table 6.4). The exact values of these input parameters are usually not known, or do not even exist. Therefore, the input parameters were assigned nominal values that are qualified guesses based on operating experience acquired from statistical data. An overview of such published statistical data has been presented in (Roos *et al.*, 2004). Sensitivity analysis provides a systematic tool to examine the resulting uncertainties in the calculated average annual interruption costs to the test system customers. In addition, a sensitivity analysis indicates which of the input parameters are the most influential. Thus, a sensitivity analysis is necessary in order to assess the results. This chapter explores the sensitivities of the calculated average annual interruption costs to the test system customers with respect to variations of some selected input parameters around their nominal values.

8.1 Uncertainty of Input Parameter Values

The majority of the faults occurring on rural distribution systems are related to weather conditions, vegetation and animals. In more densely populated areas, excavation damages and traffic accidents are the dominating causes of faults. Thus, environmental conditions and population density have a significant impact on failure rates and this becomes obvious when studying fault statistics from different countries.

By observing one individual component, it will take a long time before a relevant statistical data set will be obtained. To reduce the observation time, a population of components needs to be observed. The bigger the observed population, the shorter the observation time required. However, by observing a population, average characteristics of the population are obtained, which will not represent the characteristics of an individual component. Nevertheless, the only rational way to obtain component reliability data is to observe a population of components. However, when applying such component reliability data in studies of a particular system, uncertainties in the outcome of the study will result. For instance, in distribution system reliability studies, the degree of uncertainty will depend on the size of the geographical area that the observed population covers. The uncertainties in power system reliability studies can be dealt with by different methods. For example, (Nahman *et al.*, 2003) proposes a method for quantifying the uncertainties of input and output data in distribution system performance analyses.

The network companies usually keep track of the interruption durations. However, the time each step in the restoration process takes, such as travel time, inspection time, fault locating time and repair time, are collected to a lesser extent. Therefore, these time parameters are subject to uncertainties.

The calculations of the average annual interruption costs to the test system customers are subjected to uncertainties associated with parameters that represent:

- travel times
- inspection times
- fault locating times
- fault repair times
- component outage durations
- probability of having component faults
- effects of reliability improvement options.

Going from system-oriented to customer-oriented reliability measures is not easy and their use for decision-making is even discouraged (Nahman *et al.*, 2003) due to the associated uncertainties. Still the use of such measures as EENS (expected energy not supplied) is a reasonable way to reflect the inconvenience of interruptions to customers in a socio-economic analysis. In this thesis work, EENS has been estimated based on products between interruption frequencies, interruption durations and interrupted power (see Section 7.1). Of course, the uncertainties in these products are greater than the uncertainties in each of the factors alone.

8.2 Range of Input Parameter Values

Input parameter values corresponding to 50 and 200% of the nominal parameter values were selected to reflect the range of the input parameter values within a particular power system. Figures 8.1 and 8.2 show that this is a realistic assumption for failure rates for overhead line faults. The ten-year moving average of the annual failure rates for overhead line faults that have occurred on the 130 kV system owned by Sydkraft AB (see Figure 8.1) suggests a nominal value of 2 faults/(100 km, year) for this parameter. During the period 1959-1991, the annual values only exceed 4 faults/(100 km, year) once, and they are never less than 1 fault/(100 km, year). A similar reasoning can be made for the annual failure rates for overhead line faults that have occurred on the 40 and 50 kV systems owned by Sydkraft AB (see Figure 8.2). Since similar statistics for other parameters are not available, the range the failure rate for permanent overhead line faults exhibits is extrapolated to all input parameters examined in the sensitivity analysis.

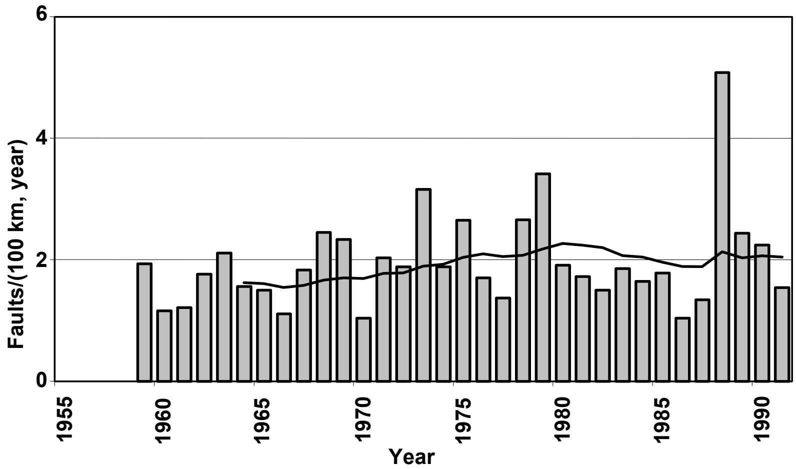

Figure 8.1: Annual failure rates for overhead line faults that have occurred on the 130 kV system owned by Sydkraft AB during the period 1959-1991. Courtesy of Sydkraft AB.

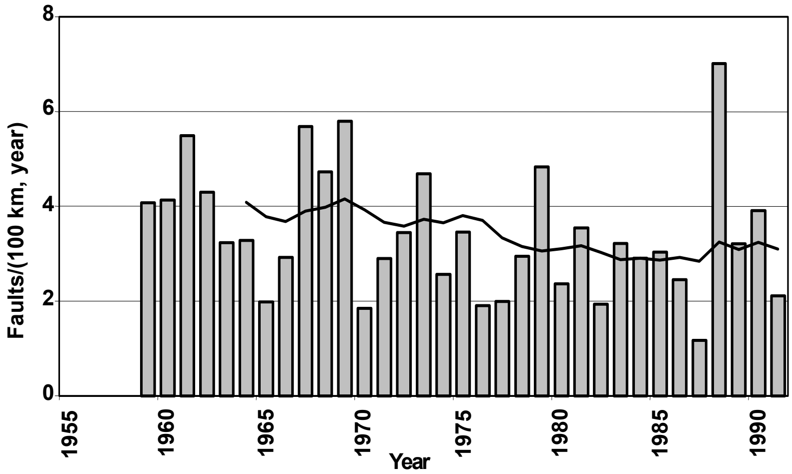

Figure 8.2: Annual failure rates for overhead line faults that have occurred on the 40 and 50 kV systems owned by Sydkraft AB during the period 1959-1991. Courtesy of Sydkraft AB.

8.3 Sensitivity Analysis Procedure

The sensitivity analysis has been carried out with respect to one input parameter at a time. This gives a good indication of the sensitivity of the average annual interruption costs to the test system customers with respect to parameter uncertainties, as long as there is no significant correlation between the parameters. Table 8.1 presents the parameters examined in the sensitivity analysis. These parameters were, one at a time, assigned values corresponding to 50 and 200% of their nominal values. The remaining parameters (see Table 6.4) were kept at their nominal values during the entire sensitivity analysis. In reality, some parameters are dependent and they will consequently vary together. However, this analysis still serves as a first approximation of the influence of the parameters, making it possible to rank their contribution to the uncertainties and thereby identify the key parameters.

Table 8.1: Input parameters examined in the sensitivity analysis. These parameters were assigned, one at a time, values corresponding to 50 and 200% of their nominal values. The sensitivity analysis resulted in one figure for each input parameter selected for variations in the sensitivity analysis.

Input parameter	Nominal value	Figure
Failure rate for 20 kV overhead feeder permanent faults	2 faults/(100 km, year)	8.3
Failure rate for 20 kV overhead feeder transient faults	8 faults/(100 km, year)	8.4
Failure rate for 20 kV underground cable internal faults	0.2 faults/(100 km, year)	8.5
Failure rate for 20 kV underground cable excavation faults	0.4 faults/(100 km, year)	8.6
Failure rate for 130/20 kV power transformer faults	2 faults/(100 transformers, year)	8.7
Interruption frequency of the 130 kV supply to the distribution substation	0.2 interruptions /year	8.8
Average time required to travel to overhead feeders	1 hour	8.9
Average time required for visual inspection of overhead feeders	1 hour	8.10
Average time required to locate permanent faults on overhead feeders	1.5 hour	8.11
Average time required to repair permanent overhead feeder faults	2 hour	8.12
Average time required to travel to under-ground cables subject to internal faults	2 hour	8.13
Average time required to locate internal faults on underground cables	4 hour	8.14

8.4 Results of Sensitivity Analysis

The sensitivity analysis has generated twelve diagrams (Figure 8.3 to Figure 8.14), one for each input parameter that was examined. The diagrams illustrate the uncertainties in the calculated average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. Table 7.1 provides the mapping between constituent reliability improvement options of each reliability improvement solution and solution numbers.

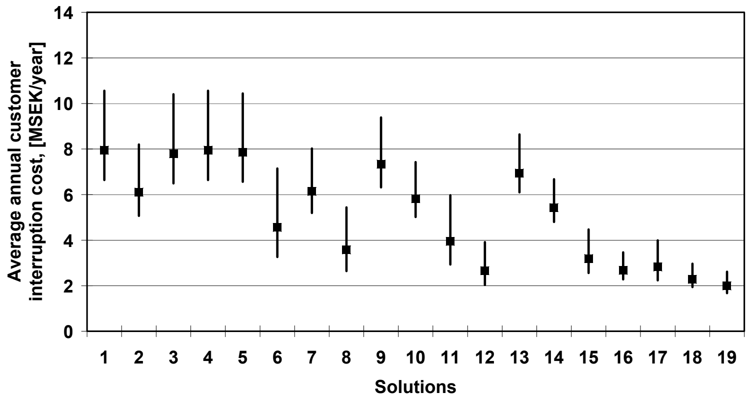

Figure 8.3: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *failure rate for overhead feeder permanent faults* has been varied between *1 fault/(100 km, year)*, the lower end-point of the high-low lines, and *4 faults/(100 km, year)*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

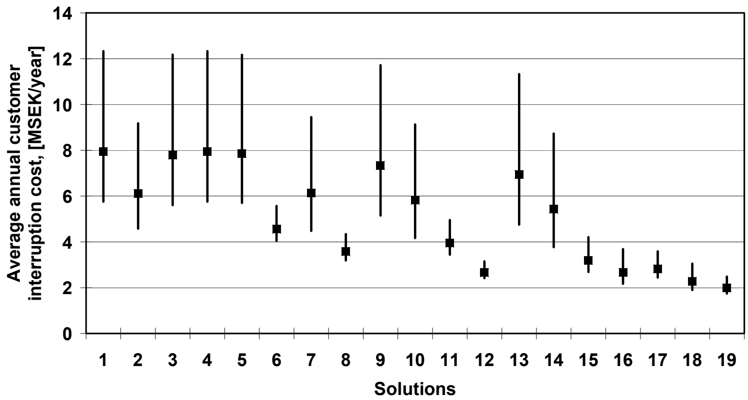

Figure 8.4: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *failure rate for overhead feeder transient faults* has been varied between *4 faults/(100 km, year)*, the lower end-point of the high-low lines, and *16 faults/(100 km, year)*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

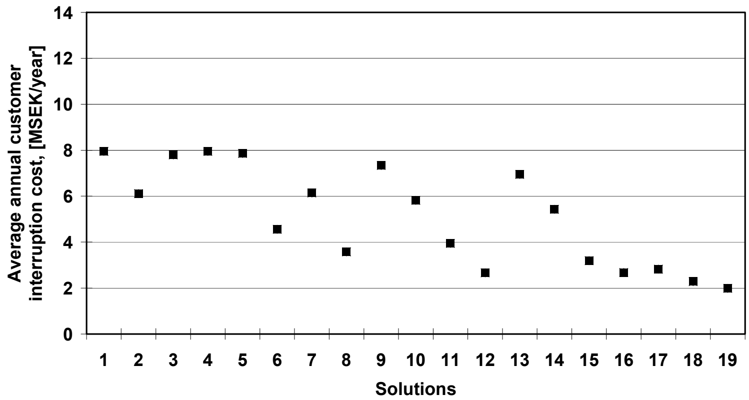

Figure 8.5: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *failure rate for underground cable internal faults* has been varied between *0.1 faults/(100 km, year)*, the lower end-point of the high-low lines, and *0.4 faults/(100 km, year)*, the upper end-point of the high-low lines. Here the lines are hidden by the squared markers that represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

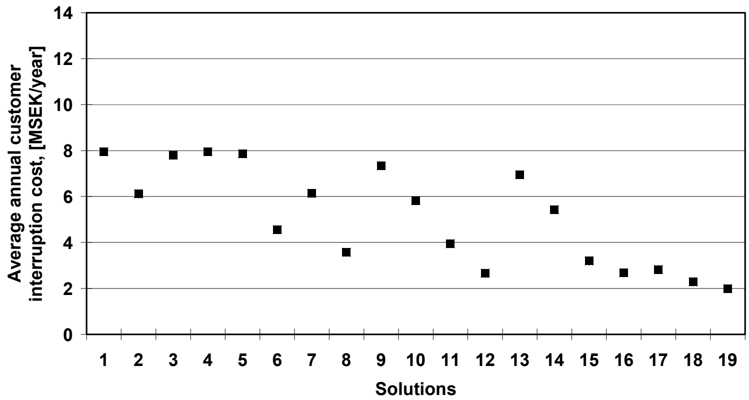

Figure 8.6: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *failure rate for underground cable excavation faults* has been varied between *0.2 faults/(100 km, year)*, the lower end-point of the high-low lines, and *0.8 faults/(100 km, year)*, the upper end-point of the high-low lines. Here the lines are hidden by the squared markers that represent the average annual interruption costs to test system customers corresponding to nominal input parameter values.

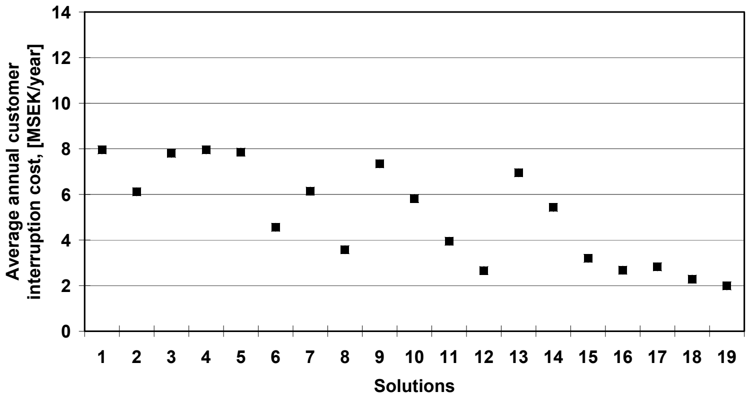

Figure 8.7: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *failure rate for 130/20 kV power transformer faults* has been varied between *1 fault/(100 transformers, year)*, the lower end-point of the high-low lines, and *4 faults/(100 transformers, year)*, the upper end-point of the high-low lines. Here the lines are hidden by the squared markers that represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

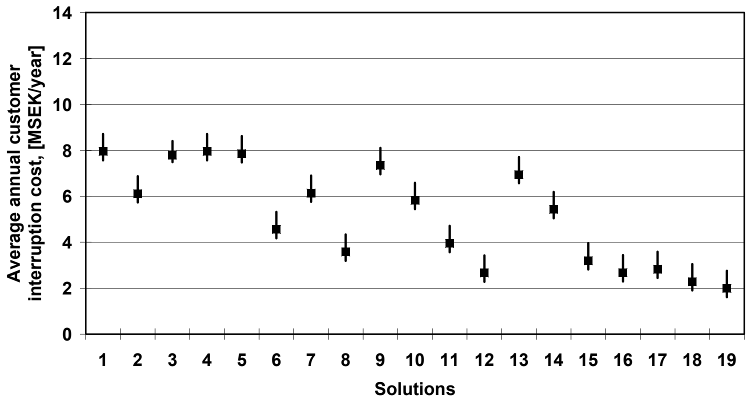

Figure 8.8: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *interruption frequency of the 130 kV electricity supply to the distribution substation* has been varied between *0.1 interruptions/year*, the lower end-point of the high-low lines, and *0.4 interruptions/year*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

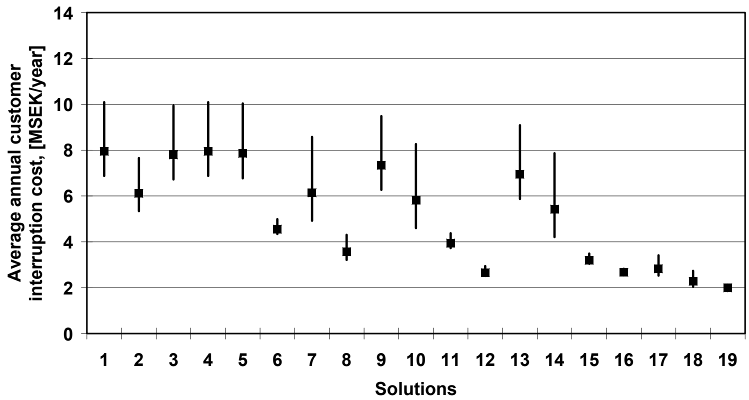

Figure 8.9: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required to travel to overhead feeders* has been varied between *0.5 hours*, the lower end-point of the high-low lines, and *2 hours*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

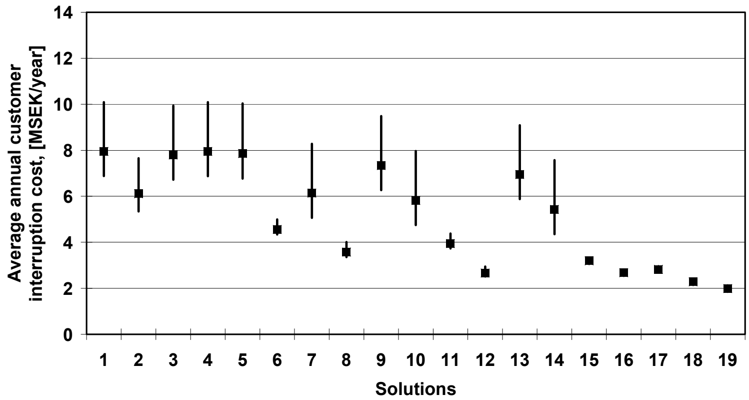

Figure 8.10: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required for visual inspection of overhead feeders* has been varied between *0.5 hours*, the lower end-point of the high-low lines, and *2 hours*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

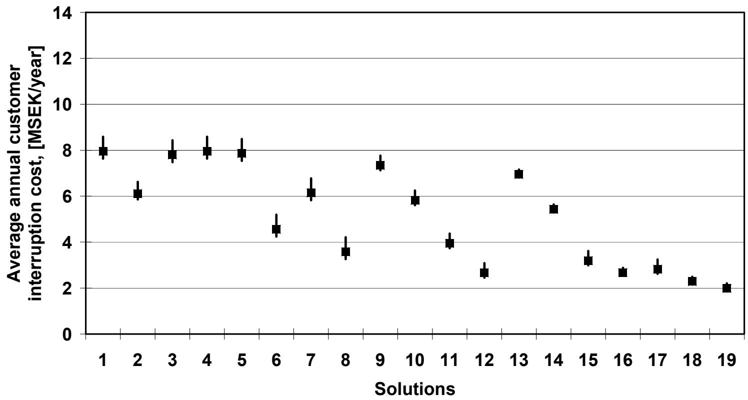

Figure 8.11: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required to locate permanent faults on overhead feeders* has been varied between *0.75 hours*, the lower end-point of the high-low lines, and *3 hours*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

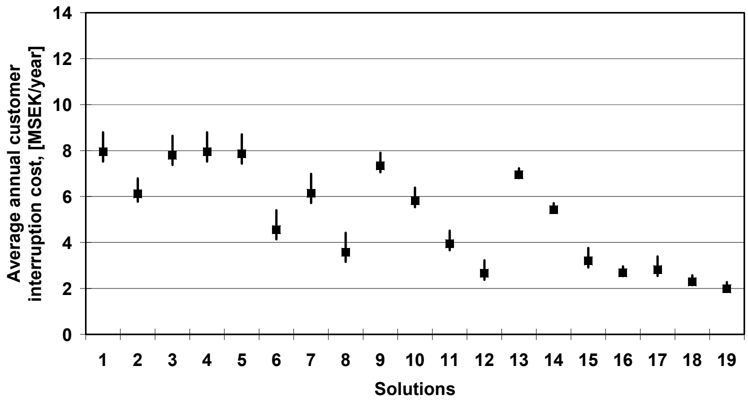

Figure 8.12: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required to repair permanent overhead feeder faults* has been varied between *1 hour*, the lower end-point of the high-low lines, and *4 hours*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

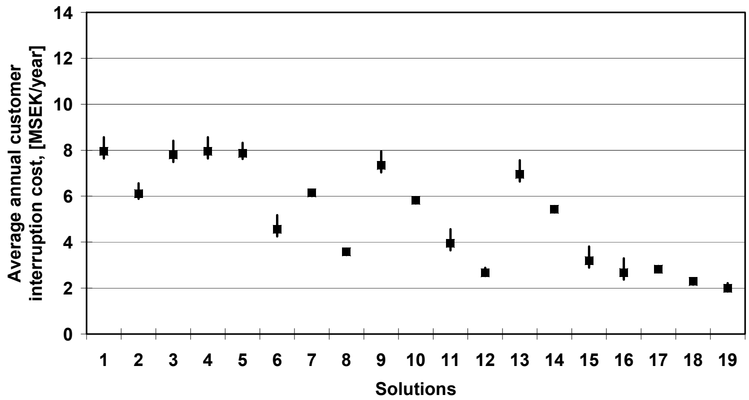

Figure 8.13: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required to travel to underground cables subject to internal faults* has been varied between *1 hour*, the lower end-point of the high-low lines, and *4 hours*, the upper end-point of the high-low lines. The squared markers represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

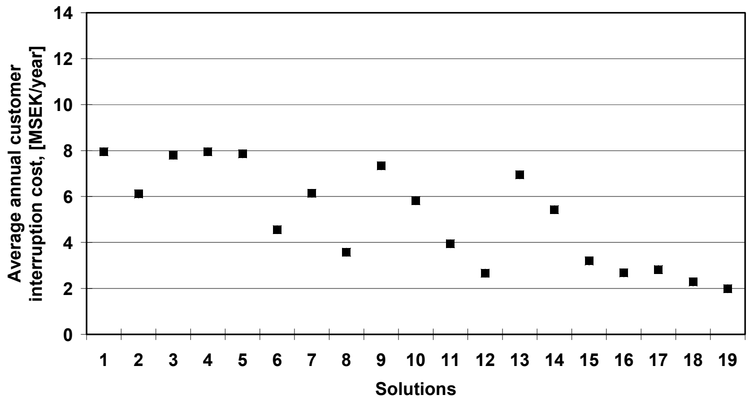

Figure 8.14: Variations in average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. The *average time required to locate internal faults on underground cables* has been varied between *2 hours*, the lower end-point of the high-low lines, and *8 hours*, the upper end-point of the high-low lines. Here the lines are hidden by the squared markers that represent the average annual interruption costs to the test system customers corresponding to nominal input parameter values.

8.5 Simultaneous Parameter Variations

Low and high value calculations of average annual interruption costs to the test system customers, when no reliability improvement solution has been applied (solution 1) and, when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied, have been carried out. In the low value calculations, each of the twelve parameters in Table 8.1 was simultaneously assigned a parameter value that corresponds to 50% of its nominal value. Similarly, in the high value calculations, each of the twelve parameters in Table 8.1 was simultaneously assigned a parameter value that corresponds to 200% of its nominal value. The input parameters are most likely to assume values close to their nominal values, thus giving rise to average annual interruption costs to the test system customers close to nominal values. The probability is negligible that each of the twelve parameters that were examined in the sensitivity analysis would simultaneously assume a value that exceeds 200% of its nominal value. Thus, as can be seen in Figure 8.15, the probability is negligible that the average annual interruption cost to the test system customers, when solution 12, 16, 17, 18 or 19 has been applied to the test system, would exceed the nominal value of the average annual interruption cost to the test system customers when no reliability improvement solution has been applied to the test system. Similarly, the probability is negligible that each of the twelve parameters examined in the sensitivity analysis would simultaneously assume a value that is less than 50% of its nominal value. Thus, as can be seen in Figure 8.15, the probability is negligible that the average annual interruption cost to the test system customers, when no reliability improvement solution has been applied to the test system, would be less than the nominal value of the average annual interruption cost to the test system customers when solution 12, 16, 17, 18 or 19 has been applied to the test system. All together, the above implies a negligible probability that the average annual interruption cost to the test system customers, when solution 12, 16, 17, 18 or 19 has been applied to the test system, would exceed the average annual interruption cost to the test system customers when no reliability improvement solution has been applied to the test system.

8.6 Conclusions of Sensitivity Analysis

A sensitivity analysis has been performed on twelve input parameters that are incorporated in the calculations of the average annual interruption costs to the test system customers. This sensitivity analysis has generated twelve diagrams (Figures 8.3-8.14), one for each input parameter that was examined. From these diagrams, four key parameters stand out as more important than the others:

- the failure rate for overhead feeder permanent faults
- the failure rate for overhead feeder transient faults
- the average time required to travel to overhead feeders
- the average time required for visual inspection of overhead feeders.

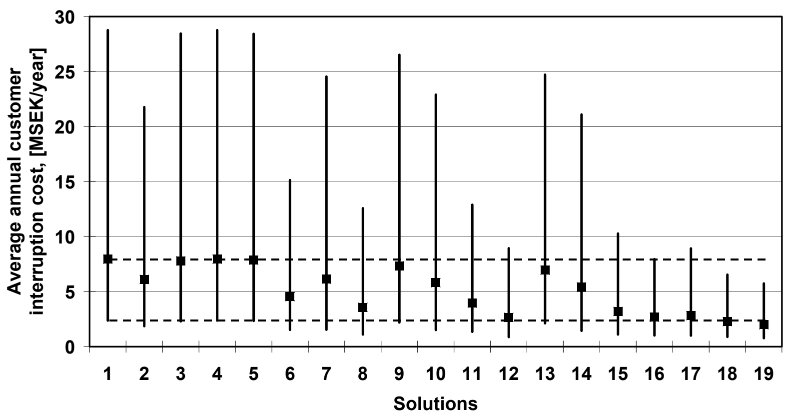

Figure 8.15: Low and high value calculations of average annual interruption costs to the test system customers when no reliability improvement solution has been applied (solution 1) and when each of the 18 evaluated reliability improvement solutions (solutions 2-19) has been applied. In the low value calculations, the twelve parameters in Table 8.1 were assigned, all of them at once, values corresponding to 50% of their nominal values, while they were assigned, all of them at once, values corresponding to 200% of their nominal values in the high value calculations. All other parameters were set at their nominal values.

Among the examined parameters, these four parameters have the greatest impact on the average annual interruption costs to the test system customers.

Furthermore, the following observations can be made from Figures 8.3-8.15.

- The average annual interruption costs to the test system customers for the highly automated reliability improvement solutions (solutions 12 and 15-19) are the least sensitive to input data uncertainties

- The average annual interruption cost to the test system customers, when no reliability improvement solution has been applied, is among the most sensitive to input data uncertainties
- Overhead feeder circuit breakers with automatic reclosing relays (solutions 6, 8, 11-12 and 15-19) make the average annual interruption costs to the test system customers less sensitive to uncertainties in failure rate for overhead feeder transient faults, in average time required to travel to overhead feeders and in average time required for visual inspection of overhead feeders
- All solutions are, of course, equally sensitive to uncertainties in the interruption frequency of the 130 kV electricity supply to the distribution substation
- The probability is negligible that the average annual interruption cost to the test system customers, when solution 12, 16, 17, 18 or 19 has been applied to the test system, would exceed the average annual interruption cost to the test system customers when no reliability improvement solution has been applied.

Chapter 9

Capital Cost Considerations

This chapter provides an estimation of maximum annual capital costs that are associated with the reliability improvement solutions treated in Chapter 7. Price information obtained from GE Consumer & Industrial (Electrical Distribution), RADIUS Sweden AB and the cost catalog (EBR, 2005) has been considered when maximum prices have been set. Note that the actual prices most likely are less than the maximum prices stated here. The actual prices, of course, depend upon negotiations, the size of the order and on the importance of the customer.

9.1 Maximum Prices

Table 9.1 and 9.2 present the maximum prices that form the basis for the estimation of maximum annual capital costs that are associated with the reliability improvement solutions in Chapter 7. The prices in Table 9.1 are based on information obtained from GE, RADIUS and (EBR, 2005), while the prices in Table 9.2 are based on estimates provided by an ABB representative.

The list prices of protection equipment quoted by GE were converted to Swedish crowns using a currency exchange rate of 9 SEK/$. Then, an installation and testing cost of 50% was added to the resulting prices in SEK before they were rounded to the nearest higher multiple of 10 kSEK. To the list prices quoted by RADIUS, an installation cost of 5 kSEK per unit was added (this does not apply to integration with SCADA-system), before they were rounded to the nearest higher multiple of 10 kSEK. The prices provided by the cost catalog (EBR, 2005) are averaged over a number of Swedish utilities and include installation costs. For tree trimming, the price obtained from the catalog was rounded upwards to 0.5 kSEK/(year, km), while for manually operated feeder sectionalizing switches and for interrupting chambers, the prices were rounded to the nearest higher multiple of 5 kSEK. The maximum prices stated in the catalog for construction of new 24 kV overhead feeders with bare conductors and 24-meter wide overhead feeder corridors were adopted without rounding. The same applies to the maximum prices stated in the catalog for construction of new 24 kV underground cables in suburban areas.

9.2 Maximum Annual Capital Cost of Options

The maximum annual capital cost, MACC, of a reliability improvement option is estimated as

$$\mathrm{MACC} = \frac{\mathrm{ICA}}{\text{depreciation period}} + \mathrm{AC} + \left(\mathrm{ICA{+}AC}\right) \cdot \frac{\text{interest rate}}{100} \tag{9.1}$$

where, ICA represents investment costs of assets and AC represents annual costs. The level of the interest rate should be reasonable, i.e., it should ensure cost of loans (external capital) to be covered and it should provide for a reasonable rate of return on internal capital. Below follows a description of the implementation of each reliability improvement option, which allows for an estimation of the maximum annual capital costs based on the maximum prices in Table 9.1 and 9.2. A depreciation period of 25 years and an annual interest rate of 10% are assumed. The maximum annual capital costs of the reliability improvement options that should be carried by the test system are summarized in Table 9.3.

Reduction in Tree Trimming Cycle

In the service area of the test system the current tree trimming program corresponds to a cost of 500 SEK/(year, km). A reduction in the tree trimming cycle to half the time, doubles the tree trimming cost per kilometer overhead feeder and year to 1000 SEK/(year, km). Since the test system contains 106 km of overhead feeders, the annual cost of reducing the tree trimming cycle to half the time is 53 kSEK/year. Thus, with ICA = 0 and AC = 0.05 MSEK/year, Equation 9.1 yields a MACC of 0.06 MSEK/year for this reliability improvement option.

Table 9.1: Estimates of maximum prices, including installation and functional testing, based on price information obtained from [1]GE, [2]RADIUS and [3](EBR, 2005).

Product or service	Maximum price
Tree trimming	0.5 kSEK/ (year,km)[3]
Digital transformer protective relay	80 kSEK[1]
Digital feeder protective relay	40 kSEK[1]
Digital feeder protective relay with automatic circuit breaker reclosing functionality	60 kSEK[1]
Digital feeder protective relay with automatic feeder fault locating functionality	70 kSEK[1]
Digital feeder protective relay with automatic reclosing and automatic feeder fault locating functionality	80 kSEK[1]
Manually operated feeder sectionalizing switch	25 kSEK[3]
Interrupting chamber for manually operated feeder sectionalizing switch	20 kSEK[3]
Constructing 20 kV overhead feeder	333 kSEK/ km[3]
Constructing 20 kV underground cable (suburban area)	508 kSEK/ km[3]
Equipment required to convert a manually operated feeder sectionalizing switch to a remotely controlled sectionalizing switch (actuator and RTU)	60 kSEK[2]
Equipment required to convert a manually operated feeder sectionalizing switch to a sectionalizer (actuator, measurement equipment sensing when the sectionalizer is de-energized, automatic sectionalizing functionality and RTU)	60 kSEK[2]
Equipment required to convert a manually operated feeder sectionalizing switch to a recloser (actuator, over-current protective relay with automatic reclosing functionality, pole-mounted current transformer and RTU)	80 kSEK[2]
Central programmable unit that communicates with RTUs (interface between RTUs and SCADA-system and implements ring closing)	40 kSEK[2]
Central unit that utilizes information from automatic feeder fault locating to initiate isolation of faulted feeder section and of subsequent closing of the feeder circuit breaker and of the ring	130 kSEK[2]

Integration with SCADA-system	300 kSEK[2]

Table 9.2: Estimates of maximum prices provided by an ABB representative.

Product or service	Maximum price
PMU (phasor measurement unit)	0.15 MSEK
Wide area protection central analysis unit	5 MSEK
Rental cost of communication channel between PMU and wide area protection central analysis unit	0.05 MSEK/ year
Installation cost of wide area protection system	1.5 MSEK
Central automatic fault locator (including installation)	0.1 MSEK

Wide Area Protection

The wide area protection system consists of 10 PMUs (Phasor Measurement Units), which are located at important nodes in the transmission system. The PMUs provide system-wide information to a central unit through a communication system utilizing 10 communication channels, one for each PMU. The central unit collects and processes the transmitted data and proposes remedial actions. Each PMU costs 150 kSEK, the cost of leasing each communication channel is 50 kSEK/year and the cost of the central analysis unit is 5 MSEK. The installation cost of the entire wide area protection system is 1.5 MSEK. Thus, with ICA = 8 MSEK and AC = 0.5 MSEK/year, Equation 9.1 yields a MACC of 1.67 MSEK/year for this reliability improvement option.

This investment is assumed to benefit 200 distribution systems and therefore it is not justified only by the effect it has on the reliability of supply to the customers of the test system. Thus, the annual capital cost that the test system should carry is obtained by dividing the annual capital cost of the investment by 200.

Improved Transformer Protection Security

Poor power transformer protection security is often due to saturated current transformers during external fault conditions (Kjølle *et al.*, 2001). To improve the security of the 130/20 kV power transformer protection in the test system, there are two alternative corrective measures to take, either to replace the current transformers or to replace the electro-mechanical power transformer protective relays. Since the current transformers on the high voltage side of the 130/20 kV power transformers of the test system are bushing current transformers, the latter alternative is considered more economically feasible. Thus, this option constitutes replacing the electro-mechanical power transformer protective relays with modern digital power transformer protection that will be less prone to operate due to current transformer saturation during external fault conditions. As a bonus, modern digital transformer protection is more secure for non-fault conditions giving rise to differential current, such as during power transformer energization. Replacement of the electro-mechanical protective relays for the protection of the two 130/20 kV power transformers of the test system with modern digital protection costs 160 kSEK. Thus, with ICA = 0.16 MSEK and AC = 0, Equation 9.1 yields a MACC of 0.02 MSEK/year for this reliability improvement option.

Duplicated Feeder Protection

In this option, modern digital feeder protective relays are installed in parallel with the existing electro-mechanical feeder protective relays. The cost of purchasing and installing ten new digital feeder protective relays is estimated at 400 kSEK. Thus, with ICA = 0.4 MSEK and AC = 0, Equation 9.1 yields a MACC of 0.06 MSEK/year for this reliability improvement option.

Overhead Feeder Circuit Breakers with Automatic Reclosing Relays

There are two main alternatives for implementing automatic reclosing of the overhead feeder circuit breakers in the test system. Either separate automatic reclosing relays are installed, which complement the existing electro-mechanical overhead feeder protective relays or, the existing overhead feeder protective relays are replaced with modern digital overhead feeder protection featuring automatic reclosing functionality. However, due to the electro-mechanical nature of the existing feeder protection, the latter alternative is considered more economically feasible. Thus, this option constitutes replacing the electro-mechanical overhead feeder protective relays with modern digital overhead feeder protection with automatic circuit breaker reclosing functionality at an estimated cost of 360 kSEK. Thus, with ICA = 0.36 MSEK and AC = 0, Equation 9.1 yields a MACC of 0.05 MSEK/year for this reliability improvement option.

Automatic Feeder Fault Locating

There are two alternative measures to take in order to introduce automatic feeder fault locating into the test system. Either the existing electro-mechanical feeder protection equipment are replaced with modern digital feeder protection equipment featuring automatic feeder fault locating functionality at an estimated cost of 700 kSEK, or a central automatic fault locator, which utilizes existing current and voltage transformers, is installed in the substation at an estimated cost of 100 kSEK. Clearly, the latter alternative is more economically feasible and for this alternative ICA = 0.1 MSEK and AC = 0. Equation 9.1 then yields a MACC of 0.01 MSEK/year.

Feeder Sectionalizing by Manually Operated Sectionalizing Switches

This option constitutes installation of two manually operated sectionalizing switches per feeder. The installation of manually operated feeder sectionalizing switches costs 25 kSEK/switch. Thus, with ten feeders ICA = 0.5 MSEK and AC = 0. Equation 9.1 then yields a MACC of 0.07 MSEK/year for this reliability improvement option.

Overhead Feeder Sectionalizing by Automatic Overhead Feeder Reclosers

This option constitutes the installation of two manually operated sectionalizing switches per feeder and of converting the switches that are installed on the overhead feeders to automatic overhead feeder reclosers. The following equipment are required to convert a manually operated sectionalizing switch to an automatic overhead feeder recloser:

- interrupting chamber
- actuator
- overcurrent protective relay with automatic reclosing functionality
- pole-mounted current transformer.

Furthermore, in order to be able to monitor the automatic overhead feeder reclosers from the operation control center, one RTU (remote terminal unit) per recloser, a central programmable unit that communicates with the RTUs and integration with SCADA-system is required. In addition to act as an interface between RTUs and the SCADA-system, the central programmable unit also implements ring closing. The installation of manually operated feeder sectionalizing switches costs 25 kSEK/switch, an interrupting chamber costs 20 kSEK, an actuator including overcurrent protective relay with automatic reclosing functionality, pole-mounted current transformer and

RTU costs 80 kSEK, a central programmable unit that communicates with the RTUs costs 40 kSEK and integration with SCADA-system costs 300 kSEK. Thus, with six overhead feeers and four underground cables ICA = 2.04 MSEK, AC = 0 and Equation 9.1 yields a MACC of 0.29 MSEK/year for this reliability improvement option.

Overhead Feeder Sectionalizing by Automatic Overhead Feeder Sectionalizers

This option constitutes the installation of two manually operated sectionalizing switches per overhead feeder and of converting the switches that are installed on the overhead feeders to automatic overhead feeder sectionalizers. The following equipment are required to convert a manually operated sectionalizing switch to an automatic overhead feeder sectionalizer:

- actuator
- measurement equipment sensing when the sectionalizer is de-energized
- automatic sectionalizing functionality.

Furthermore, in order to be able to monitor the automatic overhead feeder sectionalizers from the operation control center, one RTU (remote terminal unit) per sectionalizer, a central programmable unit that communicates with the RTUs and integration with SCADA-system is required. In addition to act as an interface between RTUs and the SCADA-system, the central programmable unit also initiates ring closing. The installation of manually operated feeder sectionalizing switches costs 25 kSEK/switch, an actuator including measurement equipment sensing when the sectionalizer is de-energized, automatic sectionalizing functionality and RTU costs 60 kSEK, a central programmable unit that communicates with the RTUs costs 40 kSEK and integration with SCADA-system costs 300 kSEK. Thus, with six overhead feeders and four underground cables ICA = 1.56 MSEK, AC = 0 and Equation 9.1 yields a MACC of 0.22 MSEK/year for this reliability improvement option.

Automatic Isolation of Faulted Feeder Section from Remote

This option constitutes the installation of two manually operated sectionalizing switches per feeder and of providing these switches with remote control facilities, so that they can be controlled from a central unit. The central unit initiates isolation of faulted feeder section based on information from automatic feeder fault locating. Once the faulted feeder section is isolated, it also initiates closing of the feeder circuit breaker and of the ring. An actuator with RTU is required to add remote control functionality to a manually operated sectionalizing switch. Furthermore, in order to be able to monitor the remotely controlled feeder sectionalizing switches from the operation control center, integration with SCADA-system is required. The installation of manually operated feeder sectionalizing switches costs 25 kSEK/switch, the central unit costs 130 kSEK, an actuator with RTU costs 60 kSEK and integration with SCADA-system costs 300 kSEK. Thus, with ten feeders ICA = 2.13 MSEK, AC = 0 and Equation 9.1 yields a MACC of 0.30 MSEK/year for this reliability improvement option.

Emergency Supply from Adjacent Feeders

In addition to feeder sectionalizing opportunities, emergency supply from adjacent feeders also requires normally opened tie switches and construction of tie feeders between adjacent feeders. Since the tie feeders are constructed between the feeders of the test system, five tie switches are required. Furthermore, the length of the tie feeders is assumed to correspond to 10% of the length of the feeders. The test system contains 106 km of overhead feeders and 26 km of underground cables. Thus, the test system needs to be extended with 13 km of new 20 kV feeders of which 10 km constitute overhead feeders and 3 km constitute underground cables. Since construction of new overhead feeders costs 333 kSEK/km and construction of new underground cables costs 508 kSEK/km, the total construction cost of the tie feeders between adjacent feeders in the test system amounts to 4.85 MSEK.

Furthermore, a remotely controllable tie switch requires the following equipment:

- manually operated sectionalizing switch
- interrupting chamber
- actuator
- RTU.

Thus, the cost of five remotely controllable tie switches amounts to 525 kSEK and the total construction cost of test system extension enabling emergency supply from adjacent feeders amounts to 5.38 MSEK. For this reliability improvement option ICA = 5.38 MSEK, AC = 0 and Equation 9.1 yields a MACC of 0.75 MSEK/year.

Table 9.3: The maximum annual capital costs of the reliability improvement options that should be carried by the test system.

Option	MACC (MSEK/year)
Reduction in tree trimming cycle	0.06
Wide area protection	0.01
Improved transformer protection security	0.02
Duplicated feeder protection	0.06
Overhead Feeder circuit breakers with automatic reclosing relays	0.05
Automatic feeder fault locating	0.01
Feeder sectionalizing by manually operated sectionalizing switches	0.07
Overhead feeder sectionalizing by automatic overhead feeder reclosers	0.29
Overhead feeder sectionalizing by automatic overhead feeder sectionalizers	0.22
Automatic isolation of faulted feeder section from remote	0.30
Emergency supply from adjacent feeders	0.75

9.3 Maximum Annual Capital Costs of Solutions

In Table 9.4 estimates of maximum annual capital costs for the reliability improvement solutions that are treated in Chapter 7 are presented in terms of the estimated maximum annual capital costs for their constituent options, which are obtained from Table 9.3. The estimated maximum annual capital costs for the reliability improvement solutions are summarized in Table 9.5.

Table 9.4: Estimates of maximum annual capital cost for reliability improvement solutions divided into the maximum annual capital costs of their constituent reliability improvement option.

Solution number	Options	MACC (MSEK/year)
2	Reduction in tree trimming cycle	0.06
3	Wide area protection	0.01

4	Improved transformer protection security	0.02
5	Duplicated feeder protection	0.06
6	Overhead feeder circuit breakers with automatic reclosing relays	0.05
7	Automatic feeder fault locating	0.01
8	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Automatic feeder fault locating	0.01
9	Feeder sectionalizing by manually operated sectionalizing switches	0.07
10	Automatic feeder fault locating	0.01
	Feeder sectionalizing by manually operated sectionalizing switches	0.07
11	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Feeder sectionalizing by manually operated sectionalizing switches	0.07
12	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Overhead feeder sectionalizing by automatic overhead feeder reclosers	0.29
13	Feeder sectionalizing by manually operated sectionalizing switches	0.07
	Emergency supply from adjacent feeders	0.75
	Central programmable unit that communicates with RTUs	0.01*
	Integration with SCADA-system	0.04*
14	Automatic feeder fault locating	0.01
	Feeder sectionalizing by manually operated sectionalizing switches	0.07
	Emergency supply from adjacent feeders	0.75
	Central programmable unit that communicates with RTUs	0.01*
	Integration with SCADA-system	0.04*
15	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Overhead feeder sectionalizing by automatic overhead feeder sectionalizers	0.22

16	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Overhead feeder sectionalizing by automatic overhead feeder sectionalizers	0.22
	Emergency supply from adjacent feeders	0.75
17	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Automatic feeder fault locating	0.01
	Automatic isolation of faulted feeder section from remote	0.30
18	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Automatic feeder fault locating	0.01
	Automatic isolation of faulted feeder section from remote	0.30
	Emergency supply from adjacent feeders	0.75
19	Overhead feeder circuit breakers with automatic reclosing relays	0.05
	Overhead feeder sectionalizing by automatic overhead feeder reclosers	0.29
	Emergency supply from adjacent feeders	0.75

*calculated based on maximum prices in Table 9.1

Table 9.5: Summary of estimated maximum annual capital costs for reliability improvement solutions.

Solution number	MACC (MSEK/year)
2	0.06
3	0.01
4	0.02
5	0.06
6	0.05
7	0.01
8	0.06
9	0.07
10	0.08
11	0.12
12	0.34
13	0.87
14	0.88

15	0.27
16	1.02
17	0.36
18	1.11
19	1.09

Chapter 10

Conclusions

Estimations of the benefits and costs of implementing various reliability improvement solutions on a test system have been made. Some of the solutions analyzed are commonly employed by network companies, while others are considered unconventional. A sensitivity analysis has been performed in order to explore the sensitivities of the calculated average annual interruption costs to the test system customers to uncertainties in input data.

10.1 Summary of Results

As regulators tend to relate allowed revenues to network reliability performances, electricity network companies, in order to maximize their profits, need to identify problem areas and implement the most cost-efficient reliability improvement solutions that will make these areas reach the reliability targets. For each reliability improvement solution analyzed in this thesis, Figure 10.1 shows the sum of average annual interruption cost to the test system customers based on nominal input parameter values and maximum annual capital cost.

10.2 Evaluation

In this thesis work, 18 solutions that improve the reliability of electricity supply have been evaluated, by applying the solutions to a test system. For each solution applied, the average annual interruption cost incurred by the test system customers due to unplanned interruptions and the maximum annual capital cost, have been estimated. The sum of these two costs was then used for evaluating the reliability improvement solutions. The evaluation was carried out by comparing, for each solution, the sum of the estimated interruption cost and the estimated capital cost with the estimated interruption cost when no reliability improvement solution has been applied to the test system.

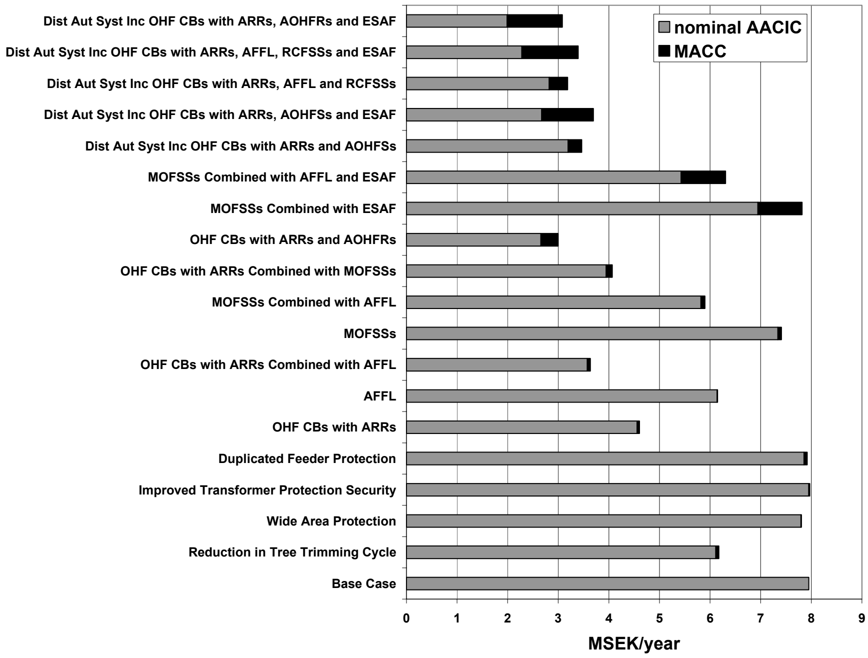

Figure 10.1: Sum of average annual interruption cost to the test system customers based on nominal input parameter values (nominal AACIC) and maximum annual capital cost (MACC), for each reliability improvement solution analyzed.

From Chapter 8 it is evident that the estimated average annual customer interruption cost when no reliability improvement solution has been applied to the test system is among the most sensitive to input data uncertainties. This implies that, if the true input parameter values are greater than their nominal values, then the interruption cost when no reliability improvement solution has been applied will increase by at least as much, in absolute terms, as when any of the solutions has been applied. Conversely, if the true input parameter values are less than their nominal values, then the interruption cost when no reliability improvement solution has been applied will decrease by at least as much, in absolute terms, as when any of the solutions has been applied. Thus, in case the true interruption costs are equal to or greater than their nominal values, Figure 10.1 shows clearly that any of the following solutions:

- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays, automatic overhead feeder reclosers and emergency supply from adjacent feeders (solution 19)
- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays and automatic overhead feeeder reclosers (solution 12)
- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays, automatic feeder fault locating, remotely controlled feeder sectionalizing switches and emergency supply from adjacent feeders (solution 18)
- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays, automatic feeder fault locating and remotely controlled feeder sectionalizing switches (solution 17)
- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays, automatic overhead feeder sectionalizers and emergency supply from adjacent feeders (solution 16)
- distribution automation system incorporating overhead feeder circuit breakers with automatic reclosing relays and automatic overhead feeder sectionalizers (solution 15)
- overhead feeder circuit breakers with automatic reclosing relays combined with automatic feeder fault locating (solution 8)

is justified, from a socio-economic point of view, for implementation on the test system.

For each reliability improvement solution applied to the test system, Figure 10.2 shows the sum of *low* average annual customer interruption cost and maximum annual capital cost. The low customer interruption costs have been obtained by assigning the twelve parameters in Table 8.1, all of them at once, values corresponding to 50% of their nominal values, while the remaining parameters in Table 6.4 are kept at their nominal values. Usually, the basic principle applies that the higher the level of reliability of supply, the more difficult it is to improve it further in a socio-economic manner. Despite this basic principle, it appears from Figure 10.3 that *most of* the solutions identified above as being justified socio-economically when the true interruption costs are equal to or greater than their nominal values, still are justified socio-economically when the true interruption costs are less than their nominal values. The exceptions are the solutions incorporating emergency supply from adjacent feeders, which seems to be a less attractive option in the latter case.

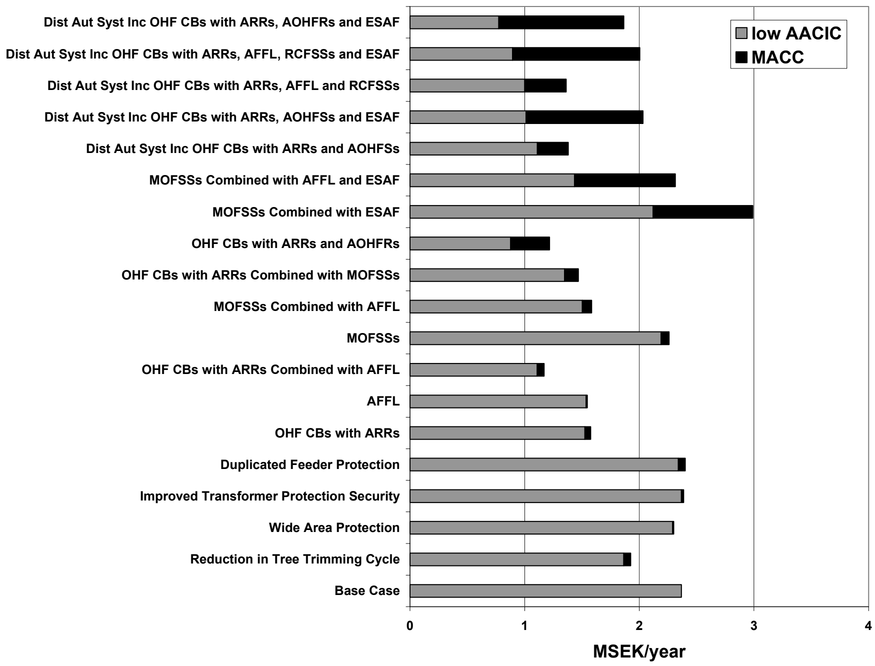

Figure 10.2: For each reliability improvement solution applied to the test system, the sum of low average annual interruption cost to the test system customers (AACIC) and maximum annual capital cost (MACC) compared to the low average annual interruption costs to the test system customers when no reliability improvement solution has been applied to the test system (Base Case).

Disregarding the uncertainties in the nominal interruption cost values, it can be seen from Figure 10.1 that, if the long-term reliability target for the test system is set to a customer interruption cost of 4 MSEK/year, then *overhead feeder circuit breakers with automatic reclosing relays combined with automatic feeder fault locating* (solution 8) might be the most cost-efficient choice for the owner of the test system. However, if instead the long-term reliability target is set to a customer interruption cost of 3 MSEK/year, then *overhead feeder* *circuit breakers with automatic reclosing relays and overhead feeder sectionalizing by automatic overhead feeder reclosers* (solution 12) might be a more cost-efficient choice.

Those reliability improvement solutions that are frequently employed by the network companies today, such as reduction in tree trimming cycle and automatic reclosing of overhead feeder circuit breakers, proved to be cost-efficient in improving the reliability of supply. However, if the reliability targets are set at a socio-economic optimal level, other solutions need to be considered for implementation on the test system.

At the distribution level (1-22 kV), incorrect protection operations are estimated to contribute to about 5% of ENS due to power system disturbances (Kjølle *et al.*, 2005). From Figures 10.1 and 10.2 it is evident that the reliability improvement solutions related to protection systems (solutions 4 and 5) have a minor effect on the interruption costs to the test system customers.

Wide area protection (solution 3) reduces the geographical area affected by a blackout. Blackouts are rare events, however, when they do occur, a large number of customers are simultaneously affected thereby creating bad publicity for the network companies. Therefore, wide area protection has a great value from a public relations point of view, which is not taken into account in this analysis.

Thus, to conclude, the best choice of reliability improvement solution for the owner of the test system depends on the reliability target. The reliability levels that result from implementation of solutions related to distribution automation seems to be justified socio-economically.

10.3 Future Work

This section brings up topics of future research work that would complement the work presented in this thesis.

Major Events

The reliability of an electricity supply system reflects its ability to perform its function under stated conditions. The function in this context is to supply electricity as economically as possible with an acceptable degree of service continuity. The stated conditions, i.e., the conditions for which the electricity supply system is designed, are discussed intensively. For example, it is discussed whether storms should be included in the reliability concept. In this thesis work, *minor events* corresponding to permanent forced outage durations of up to 9.5 hours have been included in the evaluation. *Major events* have been excluded since evaluated reliability improvement solutions have little effect on major events. Therefore, it would be interesting to also evaluate solutions that make electricity supplies less sensitive to adverse weather conditions.

On-Line Monitoring

A topic that has not been treated in this thesis is the use of equipment condition monitoring methods as a tool to maintain electricity distribution reliability, while reducing maintenance costs. When employed regularly and in a systematic manner, these methods can identify potential problems and if appropriate actions are taken, faults, and thereby unplanned service interruptions can be prevented. Generally, on-line monitoring converts unplanned interruptions to planned interruptions.

The developments in equipment condition monitoring follow the advances in sensor and computing technologies. Intelligent sensors can be used to detect incipient faults that will lead to component outages unless appropriate actions are taken. An interesting application of such sensors would be the detection of leakage current due to contamination on the surface of insulators. Early warnings would allow contaminated insulators to be cleaned before a flashover occurs.

Substation Data

A topic that is closely related to equipment condition monitoring is substation data monitoring and analysis. In modern substations equipped with numerical devices, a large amount of data is available, i.e., not only pure condition monitoring data. However, so far, very little effort has been made to provide systems that retrieve and analyze these data to extract relevant information. By analyzing the substation data, it might be possible to decide upon preventive measures that will improve the reliability of supply. Thus, the fundamental question would be what relevant information can be extracted from the substation data and how could it be used for preventing unplanned service interruptions.

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