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A METHOD FOR THE PROBABILISTIC SECURITY ANALYSIS OF TRANSMISSION GRIDS

Doctoral Dissertation

Liisa Pottonen

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Department of Electrical and Communications Engineering
Power Systems and High Voltage Engineering

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Helsinki University of Technology
Department of Electrical and Communications Engineering
Power Systems and High Voltage Engineering

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Supervisor	Professor Matti Lehtonen
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Abstract

This thesis proposes a probabilistic method for evaluating transmission grid security after line shunt faults. The most efficient contributions to system reliability enhancement can be found in probabilistic methods applicable to real transmission grids. One aim of the research was also to get an estimate of the Finnish 400 kV transmission grid reliability.

The method developed in this thesis takes into account the effect of the following issues: frequency of line faults, fault location on the line, protection system, different substation structures, failure rates of substation components and the dynamic behaviour of the power system after different contingencies.

Mathematical modelling and computational methods were used in this research. Statistical analyses for the estimation of initiating events such as line faults were made. A failure mode and effect analysis was made for substation components using both the Finnish 400 kV device-failure database and expert judgments. Reliability analyses for substation post-fault operations were made with event and fault trees. Different event tree end states (fault duration and circuit breaker trips) were then simulated with a power system dynamic analysis program using a particular load flow and grid topology. The dynamic analysis results were classified as secure, alert, emergency and system breakdown. A special alert case 'partial system breakdown' was also classified. The event trees were then reanalysed, now focusing on the power system states rather than the substation consequences.

The method was applied to the Finnish transmission system and some quantitative estimates for grid reliability were obtained. Several grid-level importance measures (Fussell-Vesely, risk decrease factor, risk increase factor and sensitivity of parameters) for substation components and model parameters, as well as estimates of the total and partial system breakdown frequencies, were calculated. In this way, the relative importance of the substation components regarding the total and partial system breakdown was reached. Contributing factors to partial and total system breakdown after line faults were also found and ranked. On the basis of the results, some recommendations for improving the transmission grid reliability, in terms of maintenance planning and investments, were made.

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PREFACE

After I had attended the last examination for my licentiate degree in February 2002, I dropped in to Antero Arkkio's office in the Electromechanics laboratory and chatted with him for a while. Perhaps I was slightly frustrated with my life at that time or maybe I just felt like a new challenge. Antero suggested that I make a doctoral thesis. Well, I thought, this is a nice proposition. I then mentioned the idea to my boss at Fingrid, Jussi Jyrinsalo. He thought it sounded good and we started to search for a suitable topic. The subject was found later that year when I met Ritva Hirvonen, who was then working as a research manager at VTT (Technical research centre of Finland). VTT had some years earlier made a preliminary transmission grid reliability study for Fingrid plc. Ritva said that this topic warranted further research and would be suitable for a thesis.

After this things went ahead very quickly. Fingrid promised to finance the project and to give me all the technical information I needed. I started my student leave in September 2002 when I went to VTT. I performed the first part of this research there and stayed until the end of 2003. By the end of 2003 the situation at VTT had changed; Ritva Hirvonen had left to take up a position at the Energy Market authority. Matti Lehtonen had also left VTT to work as a full-time professor at TKK (Helsinki University of Technology). I then completed the research and finalized the thesis manuscript at TKK in 2004.

To conclude: this thesis is the result of a suggestion by a professor, financial and technical support from Fingrid, financial support from TEKES and research co-operation between Fingrid, VTT and TKK.

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The end of writing a thesis is the beginning of expressing gratitude to those who have contributed to it.

First of all I would like to express my deepest thanks to the two people who contributed most to the thesis. They are Research Professor Urho Pulkkinen and Senior Specialist Lauri Koivisto. Urho Pulkkinen guided me through the process from the very first ideas, taught me reliability thinking and discussed the modelling and many other issues with me. I have benefited immensely from his vast knowledge and enjoyed his supportive attitude. The other important person is my colleague and friend Lauri Koivisto, who knows everything worth knowing about the Finnish transmission system, who so willingly discussed and answered all the questions I posed, and was an interested commentator on my ideas and models.

I am very grateful to my supervisor Professor Matti Lehtonen for his guidance, encouragement and assistance. A tip of the hat goes to Professor Antero Arkkio, who put the idea of making a thesis into my head in the first place. Many thanks for his advice when it came to writing the thesis, too.

I wish to thank the members of the Fingrid project group, Leading Specialist Jarmo Elovaara, Senior Specialist Mikko Koskinen and Technology Manager Jussi Jyrinsalo, who have organised regular meetings and given a lot of constructive comments.

I also thank Dr. Ritva Hirvonen for suggesting the topic for this thesis and arranging a position for me at VTT. The topic was captivating, and I never lost my interest, even during the period when I had to work hard with the endless (so I felt) simulations.

I would like to thank my colleagues at VTT and TKK, who made my stays there a very positive experience. Special thanks go to the wine lottery group and enthusiastic orienteers at VTT, and the lunch group at TKK.

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Fingrid plc and the Technology Development Centre TEKES are greatly acknowledged for their financial support. I also want to thank Fingrid plc for providing the data that I needed for my models.

Finally, warm thanks go to my nearest and dearest, Kari and my sons Olli, Esa and Petri, for their encouragement and humour. Especial thanks go to Olli, who helped me with the huge software files and with some integrals.

Espoo, March 2005

Liisa Pottonen

CONTENTS

LIST OF ABBREVIATIONS AND SYMBOLS

AC	Alternating current
AR	Autoreclosing
BFR	Breaker failure relay
CB	Circuit breaker
CIGRE	International Council on Large Electric Systems
CT	Current transformer
D	Line differential relay
DC	Direct current
ET	Event tree
f	Frequency
$\hat{f}_{IE}$	Estimate of the annual frequency of initiating events per line kilometre
FMEA	Failure mode and effect analysis
FV	Fussell-Vesely importance measure. This is also known as the fractional contribution of basic event to risk.
HVDC	High Voltage Direct Current
IE	Initiating event
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IEV	International Electrotechnical Vocabulary
l	The length of the line in kilometres

MCB	Miniature circuit breaker
MCS	Minimal cut set
MTTR	Mean time to repair. In this thesis MTTR is used to denote the mean active repair time instead of the mean down time of the component.
NERC	North American Electric Reliability Council
Nordel	Nordel is an organisation for co-operation between the transmission system operators the Nordic countries, i.e. Denmark, Finland, Iceland, Norway and Sweden.
n-1 criterion	The n-1 criterion is a method of providing reliability to systems. According to this criterion, the system is sufficiently reliable if it is able to operate under any unplanned outage of a component due to a single cause. In a power system, the criterion means that the loss of any line, busbar, generator or transformer after a single power system fault will not cause overloading of the remaining components or other problems.
P	Probability
PLC	Power line carrier
POTT	Permissive overreach transfer tripping. Protection using telecommunication, with overreach protection at each section end and in which a signal is transmitted when a fault is detected by the overreach protection. Receipt of the signal at the other end permits the initiation of tripping by the local overreach protection (IEC 1995).
PSA	Probabilistic Safety Assessment
PSB	Partial system breakdown. A special alert or emergency state of a power system, when the extended fault duration has caused extra generator trips or permanent blocking of HVDC links.
pu	Per unit

PUTT	Permissive underreach transfer tripping. Protection using telecommunication, with underreach protection at each section end and in which a signal is transmitted when a fault is detected by the underreach protection. Receipt of the signal at the other end initiates tripping if other local permissive protection at the other end has detected the fault (IEC 1995).
q	Constant unavailability
RAR	Rapid automatic reclosing operation
RDF	Risk decrease factor
RIF	Risk increase factor
SB	System breakdown
SCADA	Supervisory Control and Data Acquisition System
SF6	Sulphur hexafluoride. This is a gas that has been used in high voltage circuit breakers and other switchgear.
Ti	Test interval
TSO	Transmission System Operator
UCTE	Union for the Coordination of Electricity Transmission. This is the association of transmission system operators in continental Europe.
VT	Voltage transformer
VTS	Voltage transformer supervision
Z-relay	Distance relay
λ	Failure rate
$\hat{\lambda}$	Failure rate estimate

1 INTRODUCTION

1.1 Background and motivation

The traditional way to plan and operate a power transmission system involves the deterministic n-1 criterion. In this method, the power system is operated in such a way that, after any single contingency, the system remains stable and a new operating point without overloading and voltage violations can be reached. Probabilities of different faults are traditionally not taken into account; instead all faults that may limit the transmission capacity are treated equally. This method can lead to conservative utilization of the grid. The liberalization of the electricity markets has called for using the transmission grid more efficiently than before. Also, it has become more difficult to get rights-of-way for building new transmission lines, which increases the pressure to transfer more power via the existing lines.

In the Finnish Electricity Market Act it is stated that “the electricity market authority orders one grid operator to be responsible for the technical operability and reliability of Finland's electricity system…” This is called "system responsibility". Thus the transmission system operator derives a motivation for the grid reliability analysis directly from the legislation.

The transmission system operators try to keep the security of the grid at as high a level as possible. The resources for that are always limited. Most benefit from the existing resources can be received if the decisions in investments, maintenance and operation prove to be correct. The most efficient contributions to the system reliability can be found by using the probabilistic methods.

The power systems are usually large, complex and, in many ways, non-linear systems. The post-fault phenomena in a power system are dynamic in nature and dependent on the grid connection and load flows in different parts of the grid. Thus the security analysis of a power system is a difficult task. The effects of an unreliable power system transmission can be widespread and affect millions of people, as was the case in the USA, Italy and Sweden in August and September 2003 (NERC 2004, UCTE 2004, and Svenska Kraftnät 2003).

The reliability and risk assessment tools have been widely used for many applications, for nuclear and conventional power plants, for example. There are several software tools for these purposes. So far no power system reliability analysis software package that would allow the user to simulate different substation structures in detail in a comprehensive power system reliability analysis has been introduced.

The organisation of the Nordic power system companies, Nordel, revised in 1992 its grid planning rules. The Nordic Grid Code 2004 includes the planning rules dated 1992 (Nordel, 2004). The probabilistic approach applied in the Grid Code accepts major system breakdowns after extreme faults. These planning rules have aroused the need to analyze grid security with probabilistic methods.

In 2000, the Finnish transmission system operator Fingrid plc, together with VTT (Technical Research Centre of Finland), searched for commercial reliability analysis computer programs that would both take into account the substation post-fault events and the impact of different substation structures on reliability and that would also be suitable for local solutions. There were some programs that had a substation model, but it was not suitable for the meshed transmission grid. After that, in 2002, Fingrid plc started a research project together with the Technical Research Centre of Finland. The aim of the project was to develop a probabilistic reliability analysis method for the grid security analysis. The probabilities of different faults, the post-fault events at the substations and the consequences of these faults for the power system at different load flows were inside the scope of this research. Helsinki University of Technology joined the project at 2004. This thesis is a part of this research project.

1.2 The research problem

Central to the research problem of this thesis is the estimation of transmission grid reliability in such a way that both post-fault substation events, i.e., the protection system and circuit breaker operations, and the power system dynamics are included.

The purpose is also to evaluate the applicability of the traditional reliability methods, such as failure mode and effect analysis, probabilistic safety assessment, event and fault trees, to power system reliability analysis.

1.3 Objectives of the study

The main objective of this research is to develop a probabilistic method for estimating the transmission grid reliability. The method should take into account the substation also. The protection systems and circuit breakers are situated at substations. Failure of these components can lead to a series of events that are usually not taken into account in transmission grid planning. The probabilistic and systematic analysis of these post-fault operations can give rise to indicators of reliability and thus help grid planning and operation. The aim was also to compare the effect of different busbar schemes and different substation components on reliability.

In order to use the research resources more efficiently by avoiding the development of new software, it was thought that the method developed should preferably use existing computer programs rather than require one that was purpose-made. In the market there are several computer programs for reliability analysis and for power system simulation.

One objective was to obtain an estimate of the Finnish 400 kV transmission grid reliability, too.

1.4 Scope of the research

Line faults are studied as they are the most common faults of the transmission grid. Busbar faults can be more severe, but they are rare compared to line faults. Security, not adequacy, is the power system issue of interest. The substation model includes only those components that isolate the faulted line after a fault, i.e., the protection system and circuit breakers.

The method is applied to the Finnish 400 kV grid; only one load flow is studied. In the load flow case used in the study, Sweden imports power to Finland via AC lines in the north. In this case, the voltage stability sets the limit for power transfer, so the case is not sensitive to the situation in Sweden and Norway. The dynamic behaviour during the export case is a more complicated issue. The limiting factor is the damping of interarea oscillations, which is a function of the Finnish load flow and also the generator connection and grid loading of southern Sweden and Norway.

The analysis finds out the frequency of different power system states (secure, alert, emergency and system breakdown) after line faults. Also, partial system breakdown (trip of extra generators or HVDC links due to extended fault duration), which is one alert case, is calculated. The importance measures are calculated only for total and partial system breakdowns. The complete reliability analysis of emergency and alert states would require a human reliability analysis, since the control centre personnel needs to act during these states. This is outside the scope of this thesis. The alert state in this research includes several different network configurations and consists of several event tree end branches. Some alert states are more critical than others. The complete, or even sufficient, analysis of the alert states in different load flow cases is a major task and would require a different study.

Only technical aspects, not economic are taken into account in this study. However, the results of this analysis can be used in decision making where economic issues are considered also. The system protection schemes are not studied.

The simulations already completed are sufficient for evaluating the suitability of this method for the power system post-fault reliability analysis. In order to get a full view of the power system security, the method should be applied to busbar faults also and the simulations should be made with different load flows.

1.5 Research methods

Mathematical modelling and computational methods are the tools used in this research. Reliability analysis for substation components and dynamic simulations for the power system are made. These two issues are then combined in order to meet the objectives of the study. A reliability model is created during this study. The model applies event and fault trees. The power system simulation model used in this study is the existing model of the Finnish grid and is made at Fingrid plc.

The basic idea was to get an overview of the grid reliability. In order to get the best benefit from the resources available, the use of existing computer programs was preferred instead of creating new software. The development of a method of grid reliability analysis using commercial computer programs was thought to be a good solution. Any substation structure can be analysed by using fault and event trees to the degree of accuracy found best by the user. This approach is laborious and requires a deep understanding of the grid, but it gives more flexibility, since any substation schemes and meshed and radial grids can be analysed. The substation reliability model was made with software Risk Spectrum (Relcon 2003). Power system dynamic simulations were made with PSS/E (Shaw PTI 2001).

Statistical analysis for the estimation of the reliability characteristics of grid components and initiating events such as line faults were made. Additionally, some other reliability engineering methods, such as failure mode and effect analysis, were used. The source data for these analyses was received from the database of the Finnish transmission system operator Fingrid plc; thus this is a case study of a transmission grid.

1.6 Scientific contribution

The main contribution of the study is a probabilistic method for transmission grid security analysis after line shunt faults. This method combines the failure analysis of the post-disturbance operations at the substations and the response of the power system to these failures. With this method, it is possible to estimate the probability of the system breakdown and other power system states.

This study differs from other studies in that it is applicable to transmission grids of real size, takes into account the power system dynamics after grid shunt faults and, additionally, develops a detailed substation model that includes all the components necessary for line fault isolation.

The method developed for substation post-fault operations uses event and fault trees and therefore inherently introduces the possibility of calculating different grid-level importance measures for substation components and for model parameters. With these component and parameter importance measures, the more and less effective ways of improving grid security can be found. They also help to find the contributing factors to system breakdown.

The method developed here takes into account the effect of the following issues on reliability:

- Frequency of line faults
- Fault location on the line
- Different substation structures
- Failure rates of substation components
- Dynamic behaviour of the power system after different contingencies
- Reach of the remote back-up distance protection

In the literature, the power system reliability analyses often concentrate on the grid dynamics and are made without a substation model or with a limited model. Even if the substation post-fault events are taken into account, the approach does not take into account all the relevant substation components. On the other hand, there are reliability analysis methods for substations only, even quite detailed ones, but they do not pay attention to the fact that a similar failure at different substations, or at the same substation but with a different load flow, can lead to completely different power system consequences.
The method developed here was applied to the Finnish transmission grid and some quantitative estimates for the grid reliability were received. The estimates of the partial and total system breakdown frequencies after line shunt faults were calculated. The estimates were calculated for a lightly loaded grid only,

which means that the results received are, to some extent, too optimistic. Also, different substation component importance measures in relation to system breakdown were calculated as well.

1.7 Outline of the thesis

After the introduction, Chapter 2 describes the reliability concepts used in this study. Both the special concepts used in power system reliability analysis and general reliability concepts are mentioned. Chapter 3 deals with the previous work with transmission system security and the reliability modelling of substations.

Chapter 4 presents the Finnish transmission system in general and those details that are needed in reliability modelling. The statistics of the Finnish 400 kV grid faults, which are used for identifying the initiating events for the reliability model, are described in Chapter 5.

Chapter 6 presents some aspects of the transmission system reliability modelling. It first describes the framework of the reliability modelling in general, after which it describes the model of this study. Finally, comments on a comprehensive reliability analysis of a power system are presented.

Chapters 7, 8 and 9 report the transmission system reliability model of this study. The substation model with event and fault trees is described in Chapter 7. After that, the failure model and effect analysis made in this study is described and, finally, some remarks on the common cause failures are made. Chapter 8 describes the dynamic simulations that are made according to the results of the substation model. It also presents the classification of the power system states. The way to combine the substation model and dynamic simulations is described in Chapter 9. This chapter describes the calculation of the frequency of post-fault power system states and different grid-level importance measures. It also gives some ways of creating indicators of system breakdown.

The model was used for analysing the security of the Finnish 400 kV transmission grid after line faults. The results received with the model are presented in Chapter 10.

Chapter 11 discusses the methodology, practical aspects, and miscellaneous issues of the model and proposes future work. Concluding remarks are presented in Chapter 12.

2 RELIABILITY CONCEPTS

Concepts like reliability, alert state of a power system or adequacy of a power system have been used with different meanings in the literature. There are also concepts like security, which have a different and specific meaning in the power system and in the protection of the power system. The aim of this chapter is to define the main concepts used in this research in an unambiguous way.

2.1 Reliability concepts in power system analysis

2.1.1 Power system reliability

In power systems, it is the term *reliability* that is widely used in the literature. The book written by Anderson (1999) about the power system protection and that by Anders (1990) about the probabilistic concepts in power systems use this term. The APM Task Force Report (1994), Beshir et al. (1999), Huang and Yishan (2002), Leite da Silva et al. (1993), Khan (1998), Miki et al. (1999), Rei et al. (2000), Xu et al. (2002) have used this term, too. In this thesis, the concept reliability is used as a general concept. There are two reasons for this. One is the fact that the literature uses this concept instead of the concept *dependability*. The other reason is the fact that, in this thesis, the protection has an important role. For power system protection, the general concept is reliability rather than dependability, both in the literature and in the standard (IEC 60050-448, 1995).

Maybe it is worth mentioning that some people prefer *dependability* as a general term describing reliability. IEC vocabulary standard IEV 191 for "Dependability and quality of service" uses *dependability* as a term of collective availability performance but points out that it is used only for general description in non-quantitative terms (IEC 1990).

Reliability

Reliability of a power system is a general term that refers to the probability of its satisfactory operation in the long term. According NERC, as quoted by IEEE/CIGRE (2004), the reliability of a bulk power electric system, "is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration and magnitude of adverse effects on consumer service." Reliability of power systems is divided into two different aspects: security and adequacy.

Security

Power system *security* is the ability of the power system to withstand sudden disturbances such as short circuits or non-anticipated loss of system components. *Security* refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. Thus it relates to robustness of the system in a context of imminent disturbances and depends on the power system operating condition before the disturbance and the contingent probability of disturbances. Security is a dynamic issue and it implies both the transition to the new operating point and the state of this new operating point. (IEEE/CIGRE 2004)

Adequacy

Power system *adequacy* is defined by the IEEE/CIGRE Joint Task Force (2003 p. 1393) as "the ability of the system to supply the aggregate electric power and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of the system components." Adequacy is therefore a steady state issue and deals both with generation and transmission capacity.

Reliability and security

The distinction between reliability and security is worth noticing. Reliability is a function of the time-average performance of a power system, in different loading situations, after different faults, during different outages. It can only be judged by consideration of the system's behaviour over an appreciable period of time. Security, on the other hand, is a time-varying attribute, which can be judged by studying the performance of the power system under a particular set of conditions. To be reliable, the power system must be secure most of the time (IEEE/CIGRE 2003).

2.2 Faults and disturbances in a power system

Power system fault is power system abnormality which involves, or is the result of, the failure of a primary system circuit or item of primary system plant, equipment or apparatus and which normally requires the immediate disconnection of the faulty circuit, plant, equipment or apparatus from the power system by the tripping of the appropriate circuit breakers. Power system faults can be shunt, series, and combination faults (IEC 1995, 48-13-02).

A shunt fault (short-circuit) is a fault that is characterized by the flow of current between two or more phases or between phase(s) and earth at the frequency of the associated power system (IEC 1995, 448-13-05).

In this study, the concept 'line fault' means such a shunt fault at the power line that it can be tripped by the distance relays. Therefore *line fault* is used as a synonym for *line shunt fault*. A shunt fault can be either a short circuit or an earth fault. In this study, the concept 'short circuit' means a multiphase shunt fault with or without connection to the earth. 'Earth fault' in this study means a shunt fault between one phase and the earth, which can be tripped by the distance relays. The line faults, where the fault impedance is less than about 50 Ω, can be detected and tripped by the distance relays. The concept 'high resistance earth fault' is an earth fault that cannot be tripped by the distance relays.

Line shunt faults, i.e., short circuits and earth faults on the line always create a disturbance in an effectively earthed grid. The power system state after the disturbance is dependent on the fault location and the power system state before the fault. Because the 400 kV grid in Finland is effectively earthed, the fault currents of earth faults can be high and the faults need to be tripped quickly.

2.2.1 Power system stability

Stability is an important part of the power system security analysis, and can be divided into three different parts: generator rotor angle stability, voltage stability and frequency stability. Power system stability is the ability of an electric power system, under a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance with most system variables bounded so that practically the entire system remains intact (IEEE/CIGRE 2003). Machowski, Bialek and Bumby (1997), Prabha Kundur (1994) and Carson W. Taylor (1994), for example, have written books about power system stability.

The rotor angle stability is the ability of synchronous generators in a power system to remain in synchronism. It can be divided into transient stability, which refers to stability after severe disturbances, and small signal stability, which refers to synchronism after small disturbances. If, after a fault, the generator angle increases suddenly because the active power cannot be transmitted to the grid or if the oscillations start to increase in amplitude, the generator has lost angle stability and is tripped. The angle stability after a fault means that the possible electromechanical oscillations after a fault are damped and a new load flow is reached.

Voltage instability after a disturbance occurs if the post-disturbance grid voltages are below or outside the accepted limits. The term *voltage collapse* is often used to refer to a system breakdown due to low voltages; more accurately, the term refers to the series of events that leads to a system breakdown or abnormally low voltages in a significant part of a power system. This may occur after a major transmission line or a big generator near the load area has tripped; this can lead to increased power transmission through remaining lines, which, in turn, increases the reactive power consumption. If the reactive power reserves are not sufficient for the new situation, the voltage values decrease, the remaining lines cannot transmit the power and a voltage collapse may occur. An example of a disturbance that almost caused a voltage collapse is presented in Hirvonen and Pottonen (1994).

The frequency stability is the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load (IEEE/GICRE 2003).

2.2.2 Power system states in a security analysis

A power system security analysis requires the analysis of the power system during and after the disturbance. The stability (rotor angle, voltage and frequency) needs to be studied. If the case is unstable, the result is a system breakdown. If, and only if, the stability is maintained after the disturbance, a steady-state analysis of the post-fault system conditions against the thermal and voltage violations is meaningful.

Stability and instability do not cover all the possible states of the power system. The power system states between the secure (normal) state and system breakdown are alert and emergency. These concepts are widely used in the literature and they are defined in the IEC dictionary, too (IEC 1990). The system state model with the states used in this study is presented in Figure 1.

Normal

The normal state here refers to the secure state of an electric power system, i.e., to a stable state that has the ability to withstand disturbances.

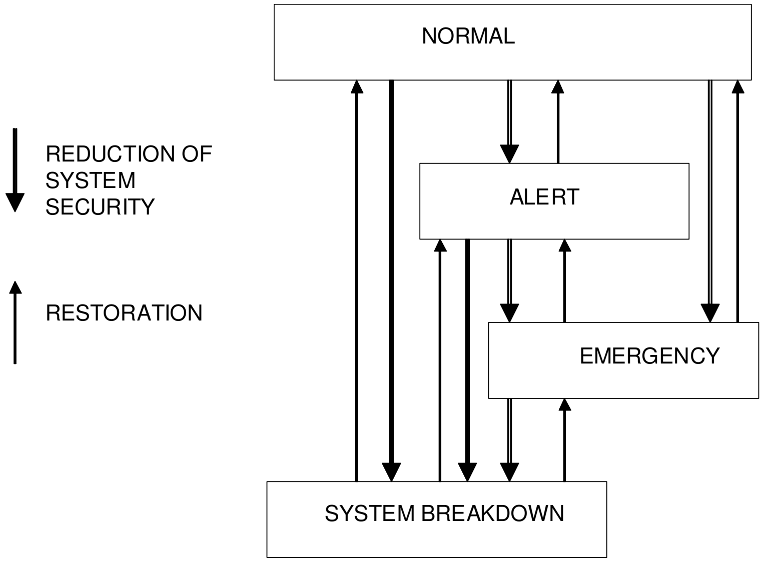


Figure 1 Power system states for the security analysis (Nordel 2002 p. 7)

Alert

An alert state of an electric power system is a state in which a credible event will result in loss of load, stresses of system components beyond their ratings, bus voltages and system frequency outside tolerances, cascading, voltage instability, or some other instability (IEC 1990, IEV-191-22-06). The system will remain stable and without any stresses beyond ratings as long as no fault occurs. The alert state would seem to be a normal state, but with no reserves available for disturbances.

But because a disturbance during an alert state would lead to problems, this state is not secure and it would require operator actions in order to become a secure state. The maximum allowed time for operator actions in the Nordel system is 15 minutes. This 15-minute rule is an agreement between the Nordel transmission system operators. According to the agreement, the system shall within 15 minutes resume operation within normal limits of transmission capacity and frequency deviation (Nordel, 2002). The operator actions may include gas-turbine starting, for example, and load shedding and the power control of a high voltage direct current (HVDC) link.

Emergency

An emergency state of an electric power system is a state in which some system components are stressed beyond their ratings, or some bus voltages or system frequencies are outside tolerances (IEC 1990, IEV-191-22-05). In this power system state, the grid operators shall act in such a way that the grid shall again reach a secure state. In this case, the maximum time for operator actions is also 15 minutes, according to Nordel requirements. But it may be possible that, in some situations, the control centre actions need to be made even faster in order to avoid a system breakdown.

System breakdown

System breakdown (SB) is a power system state in which the power system has collapsed. Often this is called a black out. This is a state in which the system has collapsed and operators start the system restoration. The breakdown can be caused due to rotor angle, voltage or frequency instability after the fault. It also can be caused by insufficient operator actions during an emergency state or after a fault that occurred during an alert state.

2.2.3 Reliability concepts in power system protection

Reliability of protection is defined as the probability that a protection can perform a required function under given conditions for a given time interval. In this context, the required function for protection is to operate when required to do so and not to operate when not required to do so (IEC 60050-448, 1995).

The reliability of protection is divided into two categories: security of protection, defined as the probability of protection from not having an unwanted operation under given conditions for a given time interval, and dependability of protection, defined as the probability of protection from not having a failure to operate under given conditions for a given time interval (IEC 1995). Thus security deals with unwanted erroneous trips, while dependability focuses on the problem of missing trips after grid faults.

2.3 General reliability concepts

A comprehensive presentation about system reliability issues can be found in, for example, Rausand and Høyland (2004), Høyland and Rausand (1994) and Henley and Kumamoto (1992). The most important definitions are listed in this chapter.

Availability

Availability is the ability of an item to perform its required function at a stated instant of time or over a stated period. There is a difference between availability at time instant t and long-term constant availability. The former is the probability that the item is functioning at time t, while the latter is the mean proportion of time the item is functioning.

Unavailability

The unavailability at time t is the probability that the item is not functioning at time t. The long-term constant unavailability is the mean proportion of time the item is not functioning.

Failure mode and effect analysis

Failure mode and effect analysis (FMEA) is a systematic technique for failure analysis. It involves reviewing the components of the system to identify failure modes and their effects. This method is used to identify the potential failure modes of each of the functional blocks of the system and to study the effects these failures might have on the system. FMEA can be used for designing and as a basis for more detailed reliability analyses and for maintenance planning. It can be simply qualitative, or can include the quantitative evaluation of different failures as well. The concept FMECA is also used. This encapsulates failure modes, effects, and criticality analysis.

Fault tree

A fault tree is a logical model that explains the failures of higher-level failure event as a logical function of those of a lower level. *Higher-level* in this context refers to the system, while *lower-level* refers to the subsystems and components. In a fault tree construction, the starting point is the specified system failure (top event). The system components are regarded as the basic events in a fault tree.

Event tree

The starting point in building an event tree is the initiating event, which is an accident or a disturbance. The event tree is a logic tree diagram that systematically describes the sequence of events, which most often are safety functions planned for preventing a catastrophe after an accident. The diagram starts with the initiating event and provides a systematic analysis of the different possible outcomes of the sequences. Event tree analysis can be quantitative, qualitative or both.

Minimal cut set

A cut set is a set of basic events whose simultaneous occurrence ensures that the top event occurs. A cut set is minimal if it cannot be reduced. Both a fault tree and event tree analysis produce a group of minimal cut sets.

Probabilistic safety assessment, PSA

Probabilistic safety assessment (PSA) is a method for evaluating the safety level in different processes. It was originally developed for the evaluation of the core damage of nuclear power stations.

Failure rate

Failure rate is denoted as failures per unit of time. Some authors prefer the concept hazard rate instead of failure rate.

Mean time to repair

Mean time to repair is the average amount of time required to repair a component. This time starts after the fault is detected.

A coherent system

A coherent system is such that

- if all the components are in a failed state, the system is in a failed state
- if all the components are functioning, the system is functioning
- when the system is in a failed state, no additional component failures will cause the system to function
- when the system is functioning, no component repair will cause the system to fail.

3 PREVIOUS WORK

The literature dealing with power system reliability can be divided according to the following issues: power system static and dynamic reliability, i.e., adequacy and security, and power system modelled with or without the substation. Figure 2 presents different research approaches for transmission system reliability studies classified according these differences. It is also possible to model the substation operations without the power system, as can be seen in Section 3.5.

	Substation model included	No substation model
Security studies	Chapter 3.4: Missing trips of the the protection	Chapter 3.3
	Chapter 3.2: Unwanted trips by the protection	
Adequacy studies	Chapter 3.1: Circuit breakers or protection	Many papers. Outside the scope of this research.

Figure 2 Different approaches for the power system reliability analysis

Some authors deal with power system reliability without a substation model. Substation events after a fault are assumed to be 100 % reliable and supposed only to change the grid topology. Some authors have a substation model included in the power system analysis, but different authors include different substation components in the model. Some authors deal merely with the substation reliability.

This thesis belongs to the category in which the substation model is included; both the missing trips by the protection failures and by the circuit breaker failures are included in this thesis.

3.1 Adequacy analyses of power system with a substation model

Jourda (1993) and Jourda and Allan (1996) present a dynamic methodology for substation availability evaluations, because “the substations are the most important features of the electrical networks, because they are nodes and because the protection systems are mainly located in the substations”. They use Markov models for substation components and study substation operations after disturbances, taking into account the protection and possible protection failures. The authors have created new indicators in order to compare different substation designs.

Many substation models do not allow the possibility of protection failures at all, but this approach is adequate for many purposes. The goal of the work by Xu et al. (2002) is to compare the effect of unplanned substation-originated outages to grid reliability. They use the average unavailability values of the substation components and study the effects of the failure of different substation components on the grid. The goal of the work of Medicherla et al. (1994), Karlsson et al. (1997) and Atanackovic et al. (1999) is to compare the effect of different substation configurations on substation reliability. Atanackovics et al. and Medicherla et al. use Markov models for substation components, Karlsson et al. calculate fault trees after having made an FMEA analysis. Power system adequacy analysis in which the circuit breaker trip at the substation is the main event is presented by Meeuwsen and Kling (1997). They have developed a computer program for analysing switching events at the substation, since the “faults at the substation can lead to line and generator tripping”. Software for substation reliability analysis presented by Goel and Shrestha (2002) includes the model for circuit breakers that trip after faults and change the grid topology. They calculate cut sets with a computer program after having made an FMEA for substation components.

3.2 Power system security and unwanted protection operations

A separate group consists of the power system security analyses with unwanted protection tripping. Many authors deal with the concept ‘hidden failures in power system protection’. Tamronglak et al. (1996), Koeunyi-Bae and Thorp (1999), Wang and Thorp (2001), Chen and Thorp (2002), Elizondo et al. (2001) and Yu and Singh (2002) present reliability studies that take into account the hidden failures in protection and power system cascaded outages due to these hidden failures.

Hidden failures are defined as "the incorrect operations that usually remain undetected until abnormal operating conditions are reached" (Wang and Thorp 2001) or "insecure or failed protection system that remains undetected until abnormal operating conditions are reached" (Bae and Thorp, 1999). Elizondo et al. (2001) define the hidden failure as "a permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove a circuit element(s) as a direct consequence of another switching event." It is worth noticing that a hidden failure is hidden under normal operating conditions, but activates with increasing line loading and causes an unwanted and unselective trip.

The probability of a hidden failure in these studies is a function of line loading. The authors analyse the cases where, in addition to a correct trip after a line fault, there exist also one or more unselective and unwanted trips. They analyse the power system adequacy after cascaded trips. Their focus is to find those areas of the power system that are most affected by hidden failures.

Some authors present methods to find power system vulnerability indices. Yu and Singh (2003) study the power system behaviour after hidden failures, taking into account also the power system security. They use swing equations for that. Yu and Singh mention that "it is necessary to incorporate dynamic reliability analysis in a vulnerability study as well", which is true, if we want a comprehensive hidden failure reliability analysis. Their method is applied to a test system with three generators, six lines and three load buses.

Another study of unwanted line trips by the protection is a power system security assessment by presented by Singh and Hiskens (2001). Their method uses the Lyapunov energy function method for dynamic analysis and it takes into account the possible protection operations that can contribute the voltage collapse, rotor swings and voltage dips. The dynamic simulation method proposed by the authors is fast and efficient. They present a protection model for a distance relay with circular characteristics. The protection operations are modelled with equations that are called *viability surfaces*, which are for unwanted unselective trips during the disturbance.

Anderson et al. (1997) propose a reliability model for redundant protection systems. They concentrate on protection dependability. If the relay fails to trip after a fault, the consequence may be the isolation of large sections of the power system by back-up protection. They use a Markov model and take into account common cause failures. Their model is very detailed and requires a considerable amount of outage data. The authors used the model and calculated their performance measures as a function of the relay test interval for a typical transmission system. As a result, they concluded that they had found a reasonable testing interval for the protection devices.

3.3 Power system security analyses without a substation model

If the security is studied with adequacy or alone, the grid model presented in the literature often is simple and may consist of only some nodes and some lines. In the simplest cases, the grid model includes only a very small number of nodes and lines. I got the impression that most sophisticated models developed are applied to the most simple grid model. Wu et al. (1988) present a study for power system steady-state and dynamic security. Their example consists of a double line with generators on one end and load on the other. Loparo and Abdel-Malek (1990) present a power system security study with a very simple grid model, but with a very detailed reliability model.

There have been many security analysis studies made without a substation model. Aboreshaid and Billinton (1999), Khan (1998), Rei et al. (2000), Leita da Silva et al. (1993), Huang et al. (2002), Beshir et al. (1999) and Shahidehpour et al. (1989) present a power system reliability analysis without a substation model. Correct trips after disturbances occur, but the interest is the power system state after those trips. This method inherently includes the simplification that both the protection and circuit breakers act 100 % reliably. This assumption, used by the authors mentioned above, is good for operation planning simulations, but has limited use as part of an overall approach to the reliability analysis of transmission grids.

Makarov and Hardiman (2003) present risk-based probability indices for transmission systems. They present a concept of a normalized risk index, which expresses the duration of system problems and is not dependent on the system size. Using this assumption, they calculate the normalized risk index for lines and buses. They want to find out areas that are affected more than the others by violations and are thus the most vulnerable parts of the system. This method gives information about the structure of the power system if the different substations and lines really are equal.

Berizzi et al. (2003) present a review of recent studies about power system security assessment. Authors describe several studies, most of which calculate different risk indices.

3.4 Power system security analysis with a substation model

Miki et al. (1999) have developed a hybrid model that includes power system dynamic simulations and event trees for protection system operation. The protection is included in the model because "the protection systems play an important role for preventing fault cascading". The protection system is modelled with a Markov model and the method is applied to a small model grid (19 nodes, 11 lines and 5 generators). The authors have made the extension from merely dynamic simulation to substation events. Since only the protection is modelled, the authors do not take into account the failures of the circuit breakers. Since the protection usually is duplicated, the protection is structurally more reliable than the circuit breakers.

3.5 Protection reliability analyses

Many authors deal with the reliability of protection as their main object and pay no or little attention to the consequences of protection failures to the power system. The APM Task Force (Allan et al., 1994) presents different methods (Markov models, event trees and Monte Carlo simulation) for power system protection analysis. They also point out that progress in modelling the effects of failures of the protection systems has been slower than developments in other areas or power system reliability studies. They conclude that estimating the likelihood of the instability due to protection system failures is not yet a mature technique, because the protection systems are complex and it is difficult to model the effects of protection malfunctions on power systems.

Transmission line protection system unreliability statistics are presented by Johannesson et al. (2004). This is an updated research of that by Svensson et al. (1992). Johannesson et al. present the fact that, in their case study, the percentage of power system disturbances with incorrect protection operations is about 7 % and that amount did not increase with the implementation of digital relays. In their statistics, the percentage of unwanted relay operation is 59.3 % and the percentage of missing operation is 19.3 %. The authors also present an extensive list of the causes of unwanted relay operations.

According to a NERC (North American Electric Reliability Council) study conducted from 1984 to 1988 as quoted by Tamronglak et al. (1996), the relative amount of those significant disturbances, where the protective relays are somehow involved, varied between 60 and 92 %. The authors do not report how often the protection problems were failure to trip and how often it was an unwanted unselective trip.

Pugh et al. (1997) present a reliability model that uses event trees for analysing modern protection systems, where the main protection, back-up protection, control, disturbance recorder and event register are integrated in one device. Event trees for differential and distance protection with the succeeding and failure probabilities are presented. This is a comparison of the effects that the telecommunication and the doubling of the main protection have on the overall protection reliability. The authors wanted to display that it is possible to develop the reliability models to evaluate the dependability of the protection systems.

The event tree method for protection reliability studies is presented by Ferreira et al. (1996). The authors present the planning of integrated protection in a National Grid Company in UK. The focus of the research is on protection security and dependability and the authors study a differential relay operation after a line fault. Current transformers, unit protection, trip relays, intertripping system and circuit breaker trip coils are included in the protection model. This approach is detailed and can be used for comparing some specific protection systems. Ferreira et al. (2001) have further compared the traditional protection and the modern protection system with functional integration by using event trees. The result of their study is that a judicious integration of functions leads to reliability gains.

Aabo et al. (2001) compare two different protection systems in a case study of the Norwegian grid, where unwanted trips are a problem. They use event trees and compare the traditional relays that are tested once in two years and modern relays with self-supervision functions. Their conclusion is that, since the modern relays have self-supervision, the maintenance procedures are reduced and this leads to reduction in works at the substation and reduces the possibility of human errors.

4 THE FINNISH TRANSMISSION SYSTEM

In this chapter, the Finnish 400 kV transmission grid is presented. The reliability practices and the substation schemes and protection system characteristics are briefly described.

4.1 The grid with connections to abroad

The Finnish transmission grid is presented in Figure 3. The total 400 kV line length is about 4300 km. The number of transmission lines is 39 and there are 26 substations with busbars at 400 kV level. In addition, there are five 400 kV substations without a busbar. This is a 400/110/20 kV transformer connected to the third branch of a 3-branch line.

The transmission grids of Finland, Sweden, Norway and the eastern part of Denmark are synchronously connected together and form the Nordel interconnected grid. The Finnish grid is connected to the Russian grid via a back-to-back HVDC link at Vyborg. This is only for the import of Russian power to Finland. Additionally, some Russian power stations are connected to the Finnish system instead of that of Russia.

Two 400 kV alternating current (AC) lines and one HVDC link connects the Finnish and Swedish grids together. The HVDC link Fenno-Skan is both for the import and the export of power and connects the southern parts of Finland and Sweden together.

4.2 Reliability practices

Nordel is the organisation of Nordic transmission system operators (TSOs). The members of Nordel are the TSOs of all Nordic countries, i.e., Sweden, Norway, Denmark, Finland and Iceland. The three main activity areas in Nordel are system planning, market development and system operation. Today there is an agreement between the Nordic TSOs about the operating code (Nordel, 2004). Nordel published in 2002 the report “Reliability Standards and System Operating Practices” (Nordel, 2002). In this, it is stated that the Nordic TSOs shall jointly maintain the coherent operation of the Nordic power system with a satisfactory level of security and quality (Nordel, 2002, p.6). The reliability criterion of Nordel is based on the n-1 criterion. The criterion implies that

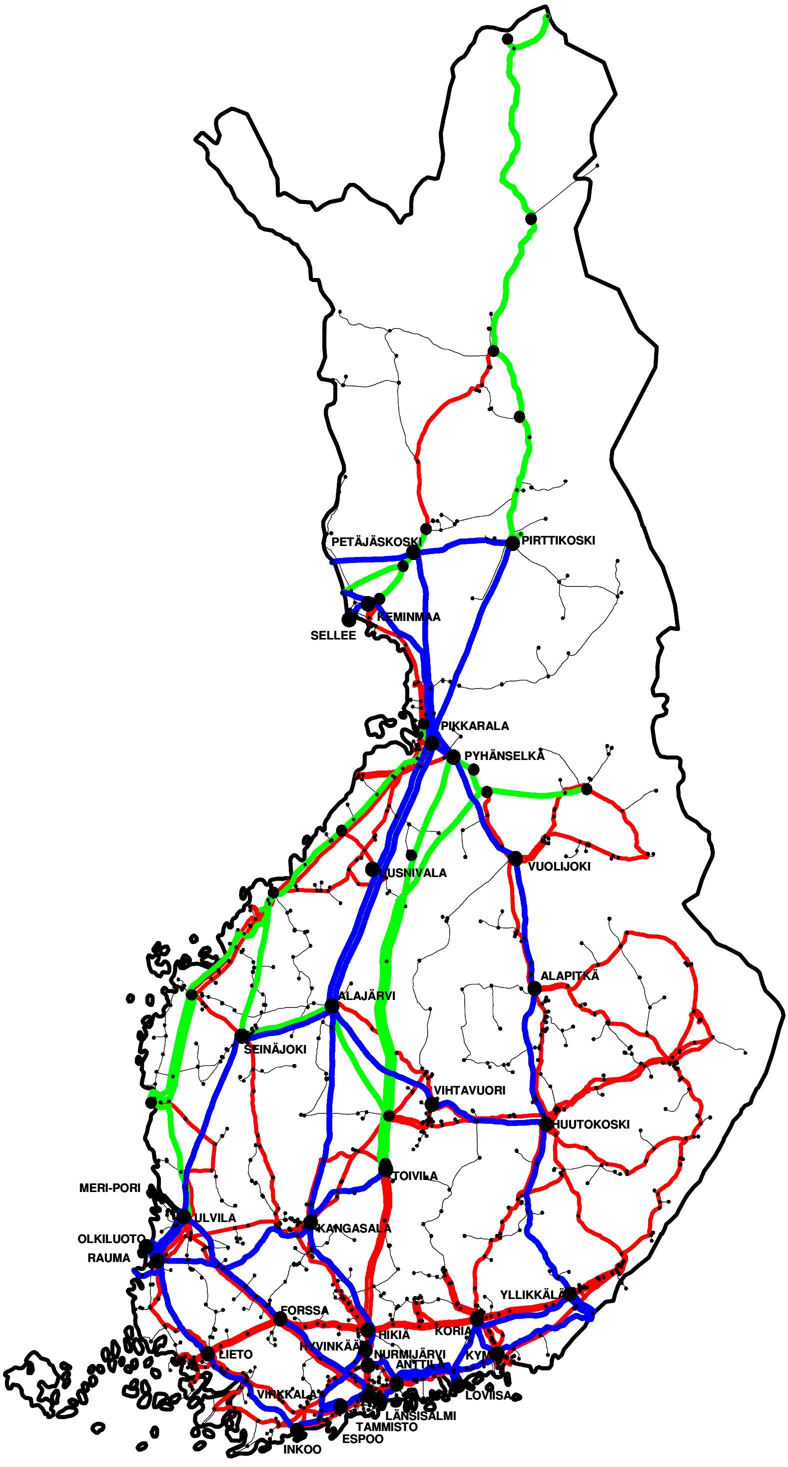


Figure 3 The Finnish transmission grid. 400 kV lines are blue, 220 kV lines green and 110 kV lines red.

- "Single faults shall not result in serious operational disturbances.
- There shall be an adequate disturbance reserve and transmission capacity to enable the Nordic power system to cope with clear design contingencies.
- The loss of a busbar must not lead to serious operational disturbances. Following a disturbance on the n-1 level, the system shall within 15 minutes resume operation within normal limits of transmission capacity and frequency deviation.
- System protection schemes are accepted as part of n-1 criterion, and are used to a variable degree in the various countries.
- Temporary n-0 principle is to a variable degree accepted regionally by each TSO under special operating conditions and when important lines are out for maintenance." (Nordel, 2002, pp. 6-7)

Nordel grid planning rules for the Nordic transmission system were revised in 1992. The basic idea of these rules is that more severe consequences are acceptable after less frequent combinations of faults and operation conditions. The allowed consequences after a fault that occurs when the grid is spontaneously weakened are to some extent more severe than consequences after a fault that occurs when the grid is intact or during planned maintenance. An example of this is that, after a single fault that affects a series component (e.g., a line), the acceptable consequence is stable operation if the grid is intact or if there is a planned maintenance outage. If the same fault were to occur when the grid is spontaneously weakened, the acceptable consequence would be "controlled operation, regional consequences". This means that a region in Nordel could have a system breakdown. The detailed list showing the classification of different faults and respective acceptable consequences following these can be found in the Nordel Grid Code (Nordel, 2004).

4.3 Busbar schemes

The Finnish 400 kV substations have two basic busbar schemes; these are described in this chapter. Both schemes have two main busbars. The main difference between these schemes is the number of circuit breakers per line end.

The busbar scheme with a single circuit breaker for a line end is presented in Figure 4. This scheme has two main busbars and one auxiliary. Usually each line or transformer bay is connected to one main busbar only, the bus coupler circuit breaker is closed and connects the main busbars together and the auxiliary busbar is dead. The bus coupler circuit breaker can be used for replacing the line or transformer circuit breaker with the bus coupler circuit breaker by utilizing the auxiliary busbar.

This busbar scheme is called *a single circuit breaker busbar scheme* in this study. Only one circuit breaker needs to be tripped after a line fault when the line end has this busbar scheme. A busbar fault leads to disconnection of all the lines connected to the faulted busbar.

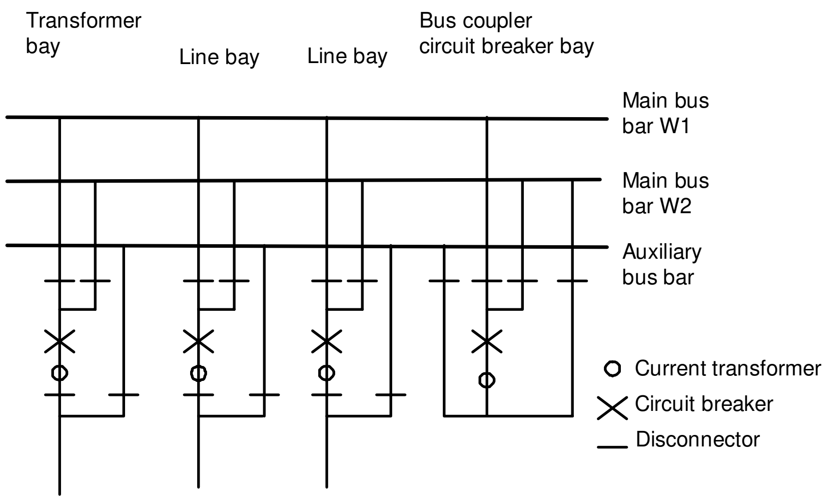


Figure 4 The substation scheme with two main busbars, one auxiliary busbar and one circuit breaker for each line end

The other common busbar scheme is presented in Figure 5. In this scheme, all line ends have two parallel bays, each equipped with a circuit breaker, a current transformer and disconnectors. All circuit breakers are normally closed. This busbar scheme is called *a double circuit breaker busbar scheme* in this study. After a line fault, two circuit breakers need to be tripped.

There are two 400 kV substations that have only one busbar. Since these substations have one circuit breaker for a line end, they are modelled basically in the same way as the substations with two busbars and one circuit breaker per line end. After a busbar fault, the faulted busbar and all lines are tripped.

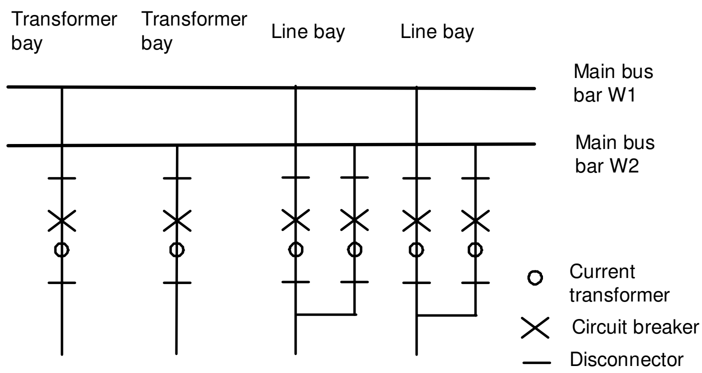


Figure 5 The substation scheme with two main busbars and two circuit breakers for each line end

The third branch of a 3-branch line has only one 400/110/20 kV transformer. The substation scheme of this kind of branch is presented in Figure 6.

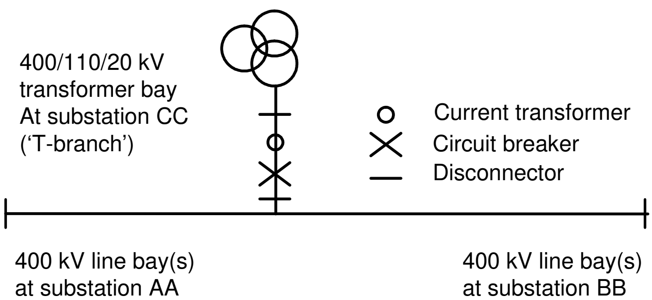
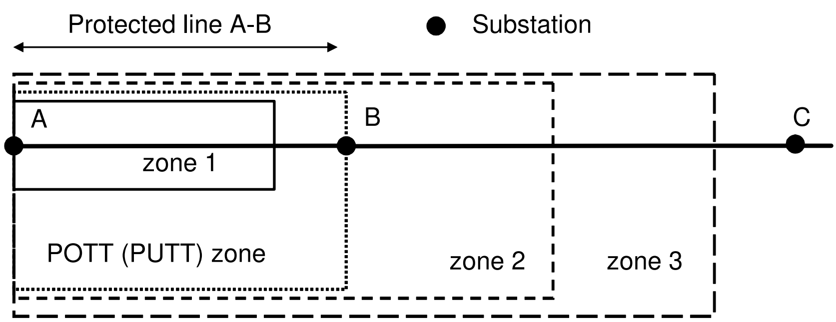


Figure 6 The substation scheme of the transformer branch of a 3-branch line

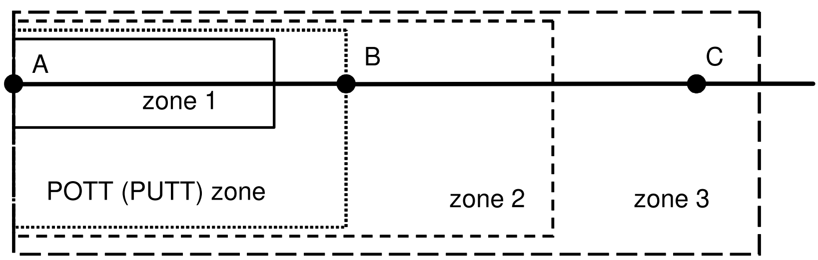
4.4 The line protection system

The Finnish 400 kV transmission line protection system always consists of two separate main protection relays. The two main relays are most often two different distance (Z) relays, which are equipped with the permissive overreach transfer trip scheme (POTT) or the permissive underreach transfer trip scheme (PUTT) in order to trip instantaneously faults, including those near the line ends. Both POTT and PUTT schemes need a telecommunication channel and thus are identical regarding the reliability of the protection. The line protection specification requires that the two distance relays of the same line end shall not be of similar type.

A simplified schematic representation of the zones of the distance protection is shown in Figure 7. Zone 1 covers about 80 % of the protected line, which in this case is the line between substations A and B. POTT and PUTT zones cover the whole protected line. Zones 2 and 3 of the distance relays located at substation A are the back-up protection systems for adjacent lines. Zone 2 covers the protected line completely and a section of the adjacent lines. Zone 3 covers the adjacent lines partly or completely. The trip signal of zones 2 and 3 is sent only after a delay, but zone 1 and POTT (PUTT) send a trip signal instantaneously. The reach of zones 2 and 3 is not constant. It depends on the characteristics of the relay and on the length of the protected line and adjacent lines and also on the amount of fault currents. In many cases, zone 3 cannot cover the whole length of the adjacent lines, since the fault current infeed from the other adjacent lines reduces the reach.



a) Zone 3 covers the adjacent line B-C partly



b) Zone 3 covers the adjacent line B-C completely

Figure 7 The protection zones of the distance protection for two different cases

The main protection relays are completely redundant, apart from the voltage transformer and the primary winding of the current transformer. The relays are situated in different relay cubicles, fed by different 220 V DC batteries and they receive the current measurement from different cores of the current transformer. The voltage transformer is common to both distance relays. In new installations with static or microprocessor relays, the miniature circuit breakers of the voltage measurement are separate, but the old installations with electromechanical distance relays have common miniature circuit breakers. If the miniature circuit breaker trips, the distance relays are incapable of sending a trip signal. This common component of electromechanical distance relays is included in the corresponding fault trees.

The static and microprocessor distance relays have a voltage transformer supervision, which detects the faults at the secondary circuit of the voltage measurement. This supervision prevents the distance relay trips, if it activates. The failure of the voltage transformer could lead to the activation of the voltage transformer supervision systems of both relays or it could trip both miniature circuit breakers. These occurrences would prevent the relay operation. However, the voltage transformer supervision operation and the trip of miniature circuit breaker send an alarm and are therefore immediately detected. After this alarm, both line protection systems are failed and the line is disconnected until the protection is repaired. These kinds of failures are not modelled. The probability of such occasions is small because it requires the simultaneous occurrence of two events. The duration of them is short because they send an alarm. No such failure has occurred. It is worth noticing that if the voltage transformer is failed in such a way that the voltage measurement is zero, but the voltage transformer supervision or the miniature circuit breakers are not operated, the correct operation of the protection during faults is not prevented. In this case, the problem might be the security of the protection, since the protection may trip if the load current exceeds the threshold limit of the relay.

Very short lines and some other special lines, such as series-compensated lines, are provided with one distance relay and one differential relay.

The relays send the trip signals to the relevant circuit breakers after a fault. The relays send a trip signal in less than 60 ms, the circuit breakers trip in about 40 ms. The instantaneous trip of a distance relay takes 50 ms at most. The permissive over- and underreach transfer trip scheme trips can take 60 ms due to the time required for the telecommunication signal. The delay of zone 2 of the distance relays is 400 ms and the delay for zone 3 is 1000 ms.

The breaker failure relay measures the current of the circuit breaker that has received a trip signal. If the current does not stop in a given time (200 ms in the Finnish 400 kV grid), the breaker failure relay trips all the circuit breakers connected to the same busbar as the faulted one and sends a trip signal to the distance relays at the remote end substation of the faulted line bay.

After instantaneous line trips there is one rapid autoreclosure and, if that fails, one delayed autoreclosure. The dead time of autoreclosing is different at different line ends. At one line end, called *master* in this study, the autoreclosing relay effects the autoreclosing first if the line is dead, i.e., if the measured line voltage is zero. At the other line end, called *follower*, the autoreclosing relay effects the autoreclosing after the master if the line voltage and busbar voltage are equal and in phase. After the delayed line trips, only delayed automatic reclosure is performed. The delayed trips are the trips by the zones 2 and 3 of the distance relays and the trips of the sensitive earth fault relays.

For high resistance earth faults there are sensitive earth fault current relays. They are definite time relays that can trip faults with zero sequence current. The sensitivity of the relays is sufficient for earth faults with 500 Ω or less fault resistance. The time delay of the relays is typically about 3 seconds.

4.4.1 Telecommunication systems for line protection

The protection system for 400 kV lines is always equipped with at least one telecommunication channel. The channel is realised with an analogue power line carrier (PLC), with radio link, with optic fibres or with a combination of these. When there is only one telecommunication channel, both distance relays at both substations use the same telecommunication channel. This means that, even though the two main relays are redundant, the protection system for faults near the line ends is not completely redundant as regards the instantaneous trip.

Two separate telecommunication channels are necessary when one main protection relay is a distance relay and the other is a differential relay. Also 3-branch lines and series-compensated lines are equipped with duplicated telecommunication channels. The two channels always have different routes and are redundant, apart from the 48 V DC supply for the telecommunication devices.

5 400 KV GRID FAULTS

The purpose of this chapter is to present the grid fault statistics of the Finnish 400 kV grid. Both the number of different grid faults and the causes of them are reported. As grid faults are the initiating events of the series of events in the substation reliability model, this chapter contains a fundamental part of the research. Only after we know which faults occur more probably than others, can we decide what kind of substation reliability model would be suitable.

5.1 Grid disturbance database

The statistics presented in this chapter is from the grid disturbance database of Fingrid plc. The data used in this research covers the period 1983-2002. The database has the following data for each disturbance: number, date and time, fault location, operator responsible for the fault location, grid owner, faulted component, shunt fault type (earth fault, short circuit, other), causes of fault, faulted phases, the relays that tripped, possible reconnections, fault class (line fault, busbar fault, other fault), nature of the fault (primary fault, secondary fault) and a field for all kinds of comments and discussions. The energy not supplied at a delivery point and the price of that energy is also recorded. The latter is the validation of financial costs of the disturbance to society, not the energy not invoiced.

The database is made for operation reliability analysis. The user can get predefined reports from the database and it is also possible to get different reports directly from the database. Some interpretation of the data was made in order to classify the faults correctly for this analysis. If the sensitive earth fault relay had tripped instead of the distance relay, the fault was interpreted as a high resistance earth fault.

5.2 400 kV line faults

5.2.1 Short circuits and earth faults on lines

There have been 48 line short circuits and 166 line earth faults in the 400 kV grid during the period 1983-2002. Only five short circuits were permanent; 21

faults were cleared by rapid automatic reclosing relays and 22 were cleared by delayed automatic reclosing relays. The causes of the permanent line short circuits were high wind, a fallen tower and a small aeroplane that cut the earth wires. The reason for the short circuits that were successfully cleared was most often lightning stroke, but a tree near the conductors and a forest fire were also responsible.

Table 1 Line-originated line trips in the Finnish 400 kV grid during the period 1983-2002

Cause	**Number of earth fault**	**Number of short circuit**	**Total number**
Lightning	127	38	165
Snow or ice	3	1	4
Spontaneous landslide	1		1
Forest fire		1	1
Storm or high wind	5	4	9
A tree or felling a tree	9	2	11
A failure of a tower or a part of a tower	6	1	7
Unknown	14		14
Vehicle	1	1	2
Total	166	48	214

Most earth faults (133) were successfully cleared by rapid or delayed autoreclosure relays. Twenty earth faults were permanent, 11 faults were manually reconnected after a time delay, which was more than 15 minutes, and 2 earth faults were reconnected manually after a time delay that was less than 15 minutes. The causes of permanent earth faults were a tower or tower-part failure, a tree, a vehicle that cut the guy wire of a tower, ice on phase wires or dew on earthing wires and earth slide due to a nearby dumping place causing one tower to move. Some faults remain unknown. Sometimes the automatic reclosure did not function after a lightning stroke, which caused the fault to be classified as permanent. The causes of non-permanent earth faults and short circuits with successful autoreclosure were lightning strokes, tree, ice on lines, high wind. Some fault causes remain unknown.

Even when there is only one cause of several line faults, all faults are calculated. Once a storm created three successive short circuits before the line was manually disconnected. All these three faults are included in Table 1, because they are line faults that needed to be tripped.

If we assume that the line fault frequency is constant per line unit length, and that the line shunt faults may be regarded as initiating events in the reliability analysis, we can calculate the estimate of the annual initiating event frequency $\hat{f}_{IE}$ When the line fault statistics and line lengths during different years are known, the estimate can be calculated with the following equation:

$$\hat{f}_{IE} = \frac{\sum_{M=1}^{M_{MAX}} F_M}{\sum_{M=1}^{M_{MAX}} l_M} \tag{1}$$

in which F_M is the number of line shunt faults during the year M and l_M the line length during the year M. Thus $\hat{f}_{IE}$ is equal to the total number of line faults divided by the total line kilometre years. During the period 1983-2002, the number of line shunt faults were 214; there were 72800 line kilometres altogether. Therefore the estimate for annual line fault frequency per kilometre is 2.9E-03. With the existing 4300 km of 400 kV lines, this estimate points to 12.5 line faults per annum.

5.2.2 High resistance earth faults

There have been ten high resistance earth faults during the years studied. The faults are presented in Table 2. Most of them were caused by single trees, one was caused by a forest fire and one by a tower insulator chain breaking; in one case, the cause remains unknown. Only on three occasions was the faulted line correctly tripped without any unwanted unselective trips.

The sensitive earth fault relays in the Finnish 400 kV grid measure only the current, not the voltage. The 400 kV grid is effectively earthed. Therefore, the zero-sequence voltage is small and the directional earth fault relays cannot be used, because the setting also needs to detect the earth faults, which have a fault resistance of 500 Ω. This limit is due to the electrical safety regulation.

For this reason, the selectivity is not always achieved by using sensitive earth fault relays.

Table 2 High resistance earth faults in the Finnish 400 kV grid during the period 1983-2002 and the corresponding correct and unselective line trips

<table>
<tr><th>Cause of the fault</th><th>Correct trips</th><th>Number of unselective trips</th><th>Comment</th></tr>
<tr><td>Unknown</td><td>Yes</td><td>0</td><td></td></tr>
<tr><td>A fallen tree</td><td>Yes</td><td>0</td><td></td></tr>
<tr><td>An insulator chain</td><td>Yes</td><td>0</td><td></td></tr>
<tr><td>A forest fire</td><td>Yes</td><td>1</td><td>There was a fire under the line. The adjacent non-faulted line tripped at one line end.</td></tr>
<tr><td>Tree 1</td><td>Yes</td><td>2</td><td rowspan="2">After the first fault, two healthy lines were tripped at one line end. The lines were reconnected. After three hours, the same tree caused a new earth fault. During this time four healthy lines tripped at one line end.</td></tr>
<tr><td>Tree 1</td><td>Yes</td><td>4</td></tr>
<tr><td>Tree 2</td><td>Only one line end</td><td>1</td><td rowspan="4">The tree caused four successive earth faults. The terminal strip of the trip coil of the circuit breaker was not connected at one line end of the faulted line. Thus the faulted line tripped at one line end only (1/2). There were also unselective line trips and trips of near-by generators.</td></tr>
<tr><td>Tree 2</td><td>Only one line end</td><td>2</td></tr>
<tr><td>Tree 2</td><td>Only one line end</td><td>1</td></tr>
<tr><td>Tree 2</td><td>Only one line end</td><td>5</td></tr>
</table>

5.3 Faults at the substations

During the period 1983-2002, there were six busbar trips. There is no automatic reclosing operation after a busbar protection trip. Three busbar trips were caused by the explosion of a current transformer in a line bay or in a main transformer bay. They were earth faults, which occurred in a substation with a single circuit breaker busbar scheme. One busbar trip was due to a human error during the substation connections after the explosion of a current transformer. The reason for this trip was the fact that the operation personnel had forgotten to set off the busbar protection before they started to connect the tripped lines to the healthy busbar.

Only two busbar faults had causes other than those relating to the current transformer explosion. They both occurred at the double circuit breaker substation and were correctly tripped. In one case, the earthing switch at the SF6-switchgear was closed, even though the position display showed the open position. In the other case, the cause of the busbar short circuit was probably ice. A busbar was tripped during foul weather when there were snowy icicles and a flash was seen. No marks were found afterwards, so the reason for this 2-phase short circuit remains unknown.

According to these statistics, busbar short circuits are rare. If we ignore the current transformer explosions, the frequency of busbar short circuits is such that there would be one short circuit and one earth fault in 17 years, if the number of busbars remained the same.

The number would be different if the current transformer explosions were taken into account. The analysis of current transformer explosions also requires a different approach because the initiating event can be a line fault, a busbar fault or a fault at the bay that combines two busbars. Also the possible protection operations are unforeseeable, as can be seen in Section 5.3.2, which analyses the possible consequences of the current transformer explosion.

5.3.1 Special busbar shunt faults

There is a substation fault, which is a special case. If the fault is situated at the bus coupler circuit breaker bay in a substation with a single circuit breaker busbar scheme, the result can be the trip of the whole substation, since the isolation of the fault requires the tripping of both busbars. This fault belongs to the group “other combinations of two faults with a common cause” in the Nordel grid planning rules. After this fault, the allowed consequence is “controlled operation, regional consequences” (Nordel, 2004).

There have been three earth faults at the bus coupler circuit breaker bay. They were caused by the explosion of a current transformer.

Usually the current transformer is situated on the line side of the circuit breaker as can be seen in Figure 4 and in Figure 5. Faults in the current transformer and also other faults between the current transformer and circuit breaker are special busbar faults, since tripping the busbar is not enough to disconnect the fault from the grid. The busbar protection trips the busbar, but this does not stop the fault current flowing via the line. Also the line has to be tripped. In order to do that, the busbar protection and/or breaker fail relays send the telecommunication signal to the line distance protection of the remote end substation. If the distance protection at the remote end substation has started, it trips the line circuit breaker after it has received the signal at the remote end substation, after which the fault is isolated. If such a fault occurs at the double circuit breaker substation, both the busbar and one line are tripped, i.e., the transmission capacity loss is more than that following a normal busbar fault. If this fault occurs at the substation with a single circuit breaker busbar scheme, the result is similar to a normal busbar fault.

5.3.2 An explosion of a current transformer

Nine times a current transformer has exploded during the 20-year period of the study. The reason was a flaw in design. All the transformers were manufactured by the same company and they were of a similar type. After the explosions, all current transformers of that type were removed from the grid. The explosions happened in the summer.

The consequences of the explosion of a line bay current transformer need not be the same. Possible consequences are line trip, busbar trip, an instantaneous substation trip by the busbar protection or the delayed substation trip by the remote end back-up protection. The explosion of a current transformer is a special kind of substation fault, since the consequences of the explosion can be anything between a line trip and the substation trip. The explosion a current transformer is not a controlled event and thus consequences other than the trip of the faulted bay are possible, even probable. The worst case would be if the secondary fault current were large enough to damage the busbar protection in such a way that it could not send a trip signal while, simultaneously, the line protection fails to measure a fault current. In this case, the fault would not be tripped at the faulted substation, but would be tripped by the distance relays at the remote end substations. The fault duration would be about 500 ms, which makes it a severe fault.

The trips and fault locations of the explosions of the current transformers are presented in Table 3.

Table 3 Explosions of the current transformers (CT) at the 400 kV substations during the period 1983-2002

CT location	**Num-ber**	**Tripped components and other comments**
Line bay	1	The trip of the faulted line. The current of the secondary winding of the CT was induced from the primary winding in the proportion of the CT ratio and the current direction was normal.
Line bay or 400/110 kV transfor mer bay	3	Busbar trip. Possible reasons: (1) if the secondary and primary coils of the CT have galvanic contact and thus the busbar protection measures a fault current towards the busbar. (2) The CT explodes in such a way that there is no current at the secondary side. The busbar protection measures differential current, since all the other current transformers measure the fault current.
Line bay	1	The busbar protection relay tripped all the circuit breakers connected to the same busbar as the faulted line.
Line bay	1	Both busbars tripped. The busbar protection measures a fault current towards both busbars due to an electric arc between the primary and secondary windings. The busbar protection relays of the both busbars at the single circuit breaker busbar scheme have a closely interconnected structure, which in certain cases enables the secondary fault current to access both relays. On this occasion, the current transformer was also on fire. Both busbars would not trip in double circuit breaker substations, where independent busbar protection systems exist for both busbars and there also exist separate current transformers for both circuit breakers.
Bus coupler CB bay	2	Both busbars tripped. The busbar protection acted correctly.
Bus coupler CB bay	1	The busbar protection tripped only the bus coupler circuit breaker. The primary fault current reached also the CT secondary windings, after which the miniature circuit breakers of the busbar protection DC circuit tripped and the busbar protection did not act after that. After the trip of the bus coupler CB the fault remained on one busbar only. The only line connected to the faulted busbar was tripped by the 2nd zone of the distance relay at the remote end substation.

		The fault duration was about 0.5 s.
All	9	

5.3.3 Line trip due to a short circuit or earth fault at the substation

There have been five substation-originated shunt faults that have led to a line trip. At a line bay, the reason for a 2-phase short circuit was the explosion of a capacitor voltage transformer of the line bay. In this case, the explosion of the voltage transformer disconnected the wire of the power line carrier transformer and this connected two phases together. Another time, a line voltage transformer exploded, causing an earth fault and the line to trip. A line was tripped once due to an electric arc in the bushing of a transformer. These faults belong to the protection zone of the line protection. However, the average frequency of these faults is not dependent on line length, but on the amount of components at the substation.

Once there was a substation earth fault and once a short circuit due to a human error. When the personnel closed a wrong disconnector, it caused an earth fault. Another time, a line circuit breaker was closed but the temporary earth remained on the line.

5.3.4 Miscellaneous line trips

As soon as somebody announced to the control centre that the conductor of a line has fallen, the line was disconnected. However, after the line was inspected, nothing exceptional was found. A transformer inrush current caused a line to trip once. At this time, the earth fault relays were not equipped with a filter for a 100 Hz component. One circuit breaker failure was such that one pole was open.

5.3.5 Line trips without a power system fault

Unwanted trips are not power system faults, but they cause a disturbance. For example, the protection system malfunctions, erroneous trip signals from the control centre, relay tests or spontaneous circuit breaker trips can be reasons for unwanted trips. Trips unwanted by the protection are classified as unwanted spontaneous trips and unwanted unselective trips.

Unwanted spontaneous line trips

Unwanted spontaneous trips are those that are independent of power system faults. This is why they are called spontaneous instead of unselective. A reason for an erroneous trip can, for example, be a human error during relay testing or a failure in the relay. The consequences of the spontaneous unwanted tripping depend on the number of components tripped, the operation principle of the power system (n-1, n-0), the loading of the grid and the possible occurrence of simultaneous faults. During the 20 years of the study, there were 29 unwanted spontaneous line trips. Almost half of them were unwanted trips during relay testing.

Table 4 Substation originated spontaneous unwanted line trips 1983-2002

Cause	**Number of spontaneous unwanted trips**
Substation secondary system planning	5
Circuit breaker	2
Relay failure	3
Human error in operation	3
Relay or disturbance recorder testing	14
Other	2
Total	29

Unwanted unselective line trips

Unwanted unselective trips are those that occur together with a power system fault. The consequences of the unselective unwanted trip depend on the same issues as those of the unwanted spontaneous trips and on the operation of the protection, which should trip the fault. If both the correct and the unselective trip or trips occur, there is a loss of several components, but the fault duration is not extended. If the correct tripping is missing, the consequence is a longer fault time and the loss of several components.

Table 5 Substation originated unselective line trips 1983-2002

Cause	**Number of unselective trips**
A hardware failure in a relay system	3
A high resistive earth fault with unselective trips, see Section 5.2.2.	6
Relay setting or configuration	1
Telecommunication	1
Error in the temporary relay system during a short circuit test	1
The terminal strip of the circuit breaker trip coil was not connected when a tree caused four successive high resistance earth faults	10
Total	22

5.4 Concluding remarks on grid faults

During the 20 years studied there were 214 line shunt faults and two busbar shunt faults. In this comparison, the explosions of current transformers are excluded. If the current transformer explosions are included, the number of substation faults is eleven. A current transformer explosion is a special fault case that cannot be treated as a normal busbar earth fault, since the consequences of the explosion are unforeseeable and the busbar and protection operations after the explosion depend on the details of the explosion.

The majority of the faults occur along the transmission lines. To get an overview of the reliability after power system faults, it is reasonable to first concentrate on line faults. The line faults that can be tripped by the distance relays are much more frequent than high resistance faults and they also have a greater effect on stability. Therefore, the reliability model was developed for those line faults that have enough fault current and can be tripped by distance relays.

The reliability analysis for high resistance earth faults, which may in some cases cause random unselective line trips, would require a different approach and cannot be made with the same model. Also, it has already been decided that the old sensitive earth fault relays will be replaced with modern relays in the near future. With the modern relays, it is possible to have a directional setting that uses the zero-sequence voltage and current measurements and can selectively detect and trip the earth faults, which have a fault resistance of about 150 Ω. This sensitivity is sufficient for most tree faults. Additionally, it is possible to have in the same relay another setting, which fulfils the requirements of the electrical safety regulation and detects the earth faults, which have a fault resistance of 500 Ω. With these changes, the selectivity of the high resistance earth fault protection will be improved. It is unnecessary to develop a reliability model for a system that will change in the near future.

The line faults that start with a failure of a current or voltage transformer of a line and create a shunt fault are not studied in this study. The analysis of the faults that start with a component failure at the line end resembles more the analysis of the substation faults, even though they would belong to the line protection zone. The frequency of this kind of initiating events is not dependent on the line length but on the number of components and the failure rate of different component types. Also, the possible consequences might be different from the line faults and therefore the same model is not valid for those faults.

6 CONSIDERATIONS OF POWER SYSTEM RELIABILITY ANALYSIS

This chapter presents some important aspects of a reliability analysis of a power system. First, a framework for a security analysis is presented. Then some observations about a comprehensive power system reliability analysis are made. Finally, the analysis performed in this study is briefly described.

6.1 A framework for transmission grid security analysis

Figure 8 gives an overview of the main aspects of the power system that need to be considered when performing an availability performance assessment for the transmission grid.

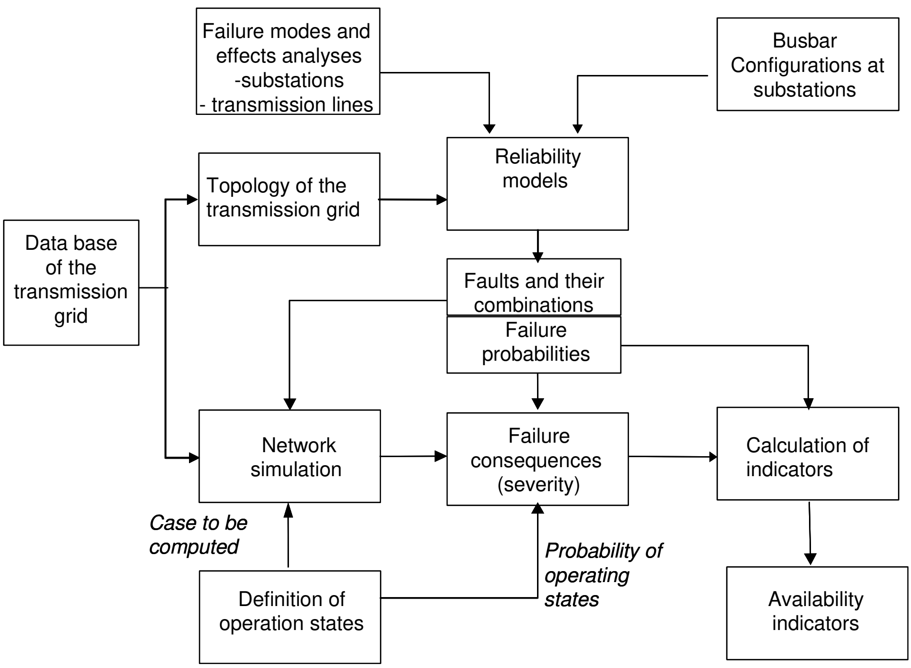


Figure 8 A block diagram for the power system availability analysis (Pulkkinen et al.)

The block diagram in Figure 8 presents the framework developed during the pre-project of the transmission grid reliability that was made at the Technical Research Centre of Finland (Pulkkinen et al., 2002). The aim of the pre-project was to develop a framework for electricity network availability assessment. A new approach was needed, because the existing software was designed for systems that have different protection philosophies and substation configurations from those in Finland.

The aim was a modular analysis package for transmission grid availability and risk analyses. The model recommended consists of four parts: a reliability model, use of a power system simulator to identify the severity of faults and their combinations, definition of availability performance indicators and probability distribution of operating states.

The recommended way of making the analyses is to use existing reliability methods. Fault tree analysis of the substations and dynamic simulation can both be realised with existing software. It is important that good analysis practices and proper interpretation of analysis results are made.

The model proposed includes the FMEA of the substations and transmission lines. The topology of the grid and the grid state are needed for power system simulation. Different substation configurations should be included in the model.

When the different faults are known and the load flow case is selected, the faults can be simulated. Dynamic power system simulations are necessary for finding out the consequences of the disturbance to the power system.

The effects of the faults to the power system are known only after the simulations are made. The severity of the faults can be ranked in different ways. Then a calculation of reliability indicators can be made. An indicator can be a probability of the system breakdown, for example, or a list of the faults that, together with certain substation operation failures, most probably lead to system breakdown.

6.2 The reliability model and analyses made

In this study, the framework presented in Figure 8 was the starting point. The focus of this study is on the reliability of the grid after power system faults, i.e., on security. Therefore some changes were made to the block diagram of the pre-project.

It is important to know the number of different initiating events and the causes of them. Therefore, the statistical analysis of grid faults was made in order to identify the different initiating events. As the most frequent initiating events were the line shunt faults, the model was developed for them.

The substation reliability model developed takes into account different busbar schemes and those primary and secondary components that are involved in fault clearing. The model developed here is for line faults only. A grid fault and the series of events at the substations after the fault are modelled. The substation reliability model produces the most probable substation consequences after the fault and their probabilities.

During the model development, some alterations were made to the original block diagram. The block diagram that describes the model used in this research is presented in Figure 9 and is described in detail in Chapter 7. The main structural difference between the block diagram developed in this study (Figure 9) and the block diagram that was the starting point (Figure 8) is the following:

The model developed during this research project uses the substation reliability model block in the following way. First, this block is used for analysing the protection and tripping operations at the substation after the line fault. This analysis produces the substation consequences that are used as inputs for power system dynamic simulation. After the simulations, the results (power system states) are analysed with the same substation reliability model. The results of the second analysis are the probability and importance values of the selected power system states.

Other differences between the block diagrams in Figure 8 and in Figure 9 describe the number of different analyses made and are not primary. During this research, only a limited number amount of analyses were made. Since the focus was the model development, it was enough to make a limited analysis with one load flow and one grid topology only. With these analyses, the applicability of the model developed can be evaluated. The dynamic simulations of the grid are very time consuming and so is the building of event and fault trees for the whole 400 kV grid. The differences between the comprehensive reliability analyses after grid faults and the analyses made in this study are listed here.

- One load flow and one grid topology was analysed instead of several load flows and grid connections
- Only line faults are analysed
- The power system states that were analysed in detail were system breakdown and partial system breakdown. Alert and emergency states were excluded at this stage. Here, the partial system breakdown is a special alert state, in which one or more extra generators or HVDC links are tripped due to extended fault duration. Importance measures were developed only for these two power system states.

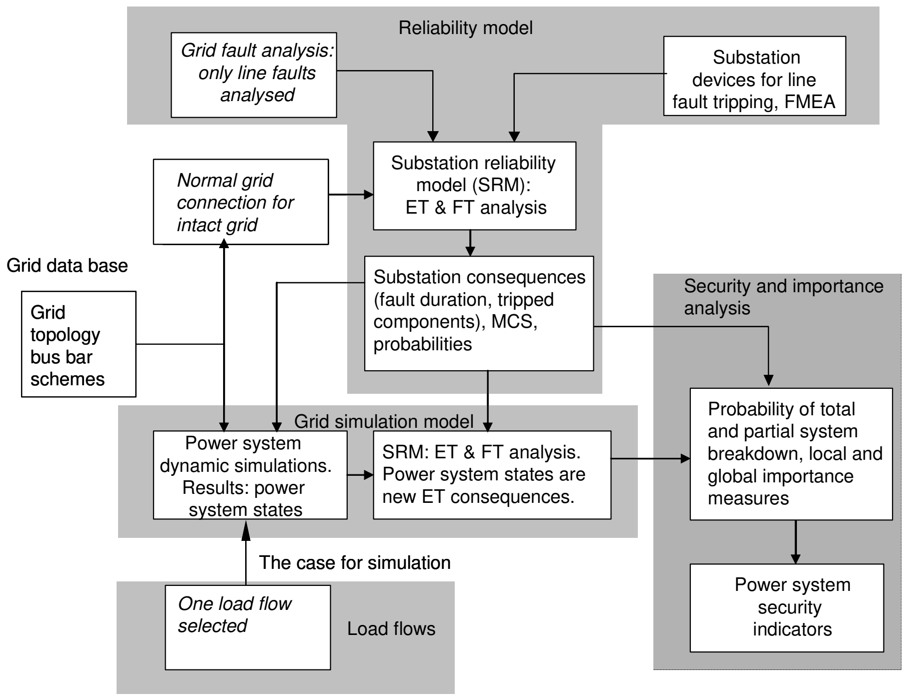


Figure 9 Block diagram for the power system security analysis of this study

6.3 A comprehensive reliability analysis

A complete reliability analysis of a power system should include issues other than the security after grid faults. At least, system problems, multiple faults and unwanted trips need to be considered. Also human actions during the alert and emergency states of a power system are worth attention.

System problems can lead to the loss of stability. A comprehensive power system reliability analysis covers those system problems that might be possible in the system under study. Both the causes and the probability of them are of interest. A variety of events can create system problems. Power system oscillations due to insufficient damping can cause problems, especially in a small system that exports power to a big system via a long AC line. A minor change in the system can start the oscillations; it is not necessarily a fault that starts the oscillations. A subsynchronous resonance of the turbogenerators near HVDC links or series-compensated lines can cause generator trips. Geomagnetically induced direct currents in closed transmission line loops can saturate the transformer and lead to transformer trips. The differential relay can trip the transformer due to the large magnetization current.

The analysis of special protection schemes is important, especially if the protection can create problems to the system if incorrectly activated. The special protection schemes are installed to prevent the system breakdowns. The unwanted operations of special protection schemes, as well as the failure of them to act when required should be analysed.

The occurrence of simultaneous grid faults, due to a common cause or independently should be analysed. A thunder storm or a high wind can cause several simultaneous faults. An explosion of a current transformer can lead to a line trip, a busbar trip or a trip of the whole substation. The system breakdown in southern Sweden and Eastern Denmark was caused by an n-3 fault, where a disconnector at a substation fell over double busbars some minutes after a generator was tripped due to a valve failure. The busbar fault was such that two different phases from the two busbars were short circuited through an electric arc (Svenska Kraftnät 2003).

Since there can be an infinite number of different faults, a selection of the cases for further analysis should be made. The substation faults can cause faults, where several components trip; therefore, the initiating event frequency and different consequences of them should be analysed.

The system breakdowns of Italy and USA in autumn 2003 were not caused merely by a single power system fault. The duration between the first fault and the final breakdown was 15 minutes or more (UCTP 2004, NERC 2003). During this time, the power transmission of some grid parts became overloaded, which is an emergency state. During this period, extra lines tripped due to overload and finally the system collapsed. Insufficient operator actions at the control centres during the alert or emergency state of a power system were the final causes of these breakdowns.

A comprehensive reliability analysis of the grid should include the control centre practices. The communication between neighbouring transmission system operators, the tools available at control centres for system monitoring and control, as well as the roles and responsibilities of the personnel, should be analysed.

Unwanted spontaneous and unselective trips caused by the relays should be included in the analysis and the effects of them should be simulated. Unwanted spontaneous trip of a single component is seldom a problem if the system is operated according to n-1 principle. Unwanted unselective trips can be disastrous and should be analysed.

7 RELIABILITY MODEL FOR SUBSTATIONS AND LINE FAULTS

This chapter describes the substation reliability analysis method developed for grid security analysis. First, the modelling principles and then the details of the model are presented.

7.1 General modelling principles

Substation risk modelling follows the principles of Probabilistic Safety Assessment, PSA (NUREG/CR-2300 1983). PSA is originally used for the safety analysis of nuclear power plants. In a so-called ‘level 1 PSA’, the accident starts with an initiating event, the continuation of which is then modelled with event and fault trees. This approach is suitable also for modelling the power system protection, since the method is developed for analysing the safety functions after an accident. This analysis of post-fault substation operations is therefore analogous to a nuclear power station PSA-analysis.

The purpose in this study was to combine reliability modelling and the dynamic analysis of the grid. Event and fault tree analysis is illustrative and the event trees, when correctly built, can give the necessary data for power system dynamic simulation. It also gives the probability of different failures at the substation, i.e., the probability of each of the consequences of the event tree.

Since different distance relay zones are used for faults at different parts of the line, one event tree for a line is not enough. According to Figure 10, one line can be modelled with three event trees.

Markov models would give additionally the duration of different component states. However, the duration of basic event states is not necessary for reliability estimation. Additionally, the definition of the Markov model states, and the calculation of them would be extremely laborious for a grid with 39 lines. A rough estimation of the number of states for each line fault analysis can be received by multiplication of 12 fault trees per line (on average) and about five different basic events per each fault tree. For one line, this makes about 60 basic events; for 39 lines, the number of basic events would be about 2340. The number of states in a Markov model with 2340 basic events is 2^{2340}. The system would have 2^{2340} states, the consequences of which would have to be analysed. It could be possible to eliminate those states that do not need any further analysis, but even that would be a laborious task.

The aim was to find a solution that can be used for a real grid and that would give results with a reasonable amount of work and pick out the essential issues that affect reliability. A PSA analysis instead of Markov models was chosen.

7.2 Identification of initiating events

Both qualitative and quantitative analyses were made for grid faults during the 20-year period studied. The causes of the faults and the number of them were analysed. The faults that occur most often are the line shunt faults. This is why the line faults are analysed in this study. The analysis of grid faults is presented in Chapter 5.

In this study, line faults are the initiating events of the event trees. More precisely, the initiating events are only those line faults that can be tripped by distance relays. High impedance earth faults that cannot be tripped by distance relays are not studied. They are infrequent. It is also useless to create a reliability model for such initiating event as the protection of them will improve significantly in the near future.

The distance protection of a line acts in different ways according to fault location along the line. The reach of zone 1 is about 80 % of the line length, which means that 20 % of the line at the remote end does not belong to the zone 1. Since an instantaneous trip is required after all line faults, the fault near the line ends needs to be tripped with a permissive over- or underreach transfer trip scheme, which needs a telecommunication channel. Therefore the distance relays at both line ends can trip at zone 1 the faults located in the middle of the line. About 60 % of the line length belongs to this section. The remaining 40 % is divided into two sections as shown in Figure 10.

The operation of a distance relay is about the same for 1-, 2- and 3-phase faults, i.e., the reaches of the zones are set to be similar. In this study, it is assumed that the zones are exactly the same and the probability of a failure in sending a trip signal is the same for 1-, 2- and 3-phase faults.

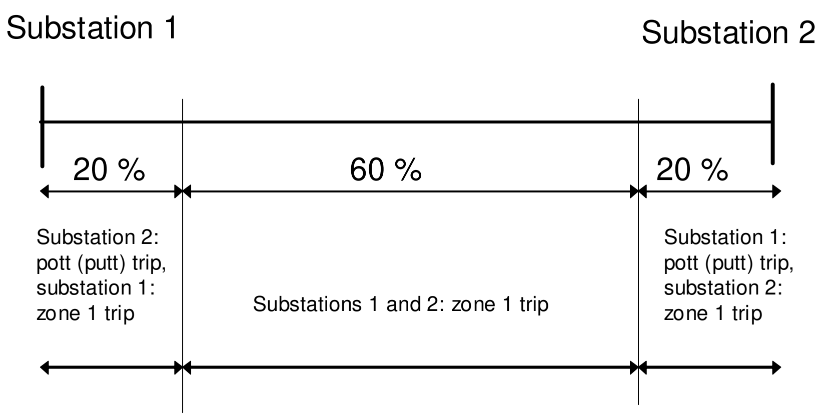


Figure 10 The zones of the distance protection along the line

7.3 The parts of the substation reliability model

There are three main components, the reliability of which is important when studying the power system functioning after a fault. The three components are

- The protection relay system, which includes the relays and the secondary circuits of the protection
- The circuit breakers that include the circuit breaker and the trip and close coils
- The telecommunication system between the relays.

After a fault in a power system, the protection system detects the fault and sends a trip signal to circuit breaker(s). Then the circuit breakers trip in order to isolate the fault, after which the power flow can continue in the healthy parts of the power system. The breaker fail protection and the remote back-up protection enter into action if the main protection does not function properly.

The event trees are created for substation events, taking into account the three main parts listed above.

7.4 Event trees

Here the event and fault trees are created and analysed by using a computer program called Risk Spectrum (Relcon AB 2003). This software package calculates the probabilities of the different events and it also analyses several importance measures.

In this model, each event tree branch always has one success and one failure path. With the success or failure branches of the main components listed in Section 7.3, we can create all the substation post-fault events. A location where one can create branches in an event tree is called as a function event in the program used. The input of the function events is calculated with fault trees; therefore the fault tree top gates are the inputs of the function events.

The aim was to make the event trees as simple as possible and to ensure that the analysis of event trees gives the necessary data for power system analysis. In order to reach this goal, some principles were established before and during the event tree construction.

The frequency, given the initiating event frequency, is calculated in event tree analysis for different substation consequences.

7.4.1 Principles for event tree construction

The basic structure of event trees is such that the function events of the main protection operations are put before the function events of the circuit breakers, which corresponds with the real-time sequence. The final functional events in all event trees are the automatic reclosing operations, first the master line end and then the follower line end, which also is a true order. The events of both line ends are put in the same event tree, while usually the operations of the master line end are before the operations of the follower line end. In the real world, the order of the trip signals of the main protection at the two line ends is arbitrary and the same yields for the circuit breakers trips. This does not matter. Since, basically, the event tree is a logical diagram, simultaneous events can be put in an arbitrary order. The line ends are the master and the follower. Master, in this context, means the line end that makes the autoreclosing first if the line is dead. The follower, on the other hand, makes the autoreclosure if the line voltage and busbar voltage are equal and in phase. The master has a shorter dead time than the follower before the autoreclosure.

The event tree branches are constructed in such a way that the analysis of them gives the different possible consequences that are necessary for power system analysis. In a power system dynamic analysis, one needs to know the fault duration and the sequence of circuit breaker trips. This principle leads to such a structure that the main protection system and the circuit breakers need to be in separate function events, since the consequence of the failure of the main protection is different from the failure of the stuck circuit breaker. If the main protection systems at one line end fail to send a trip signal, nothing at this substation stops the fault current flowing. If the circuit breaker fails to trip, the breaker failure relay can trip the other circuit breakers connected to the same busbar as the faulted circuit breaker.

A principle that prevents the event trees from being extremely complicated is the assumption that, if the circuit breaker is stuck, all the phases are stuck. This is a conservative assumption; it would be more probable that one phase of the circuit breaker would be stuck rather then all. But, if all the different possible failure modes (1- 2 and 3-phases) of each circuit breaker were taken into account, the number of event tree function events and branches would increase dramatically. However, the extra information received with this method would be secondary.

The same event tree analysis is valid for 1-, 2- and 3-phase faults, since we assume that the substation component operations after the fault are not dependent on the fault current phase and magnitude. The faults with zero sequence current have different remote back-up protection. The remote back-up protection is not modelled in event trees, but is taken into account when defining the power system states after the dynamic simulations.

If the distance relays fails to send a POTT or PUTT trip signal due to a failure of the telecommunication channel, the relays can send delayed zone 2 trip signals during the faults at the remote end of the line. Therefore, the event trees have a function event of a delayed zone 2 trip signal after the function event of a transfer trip scheme. The probability of the zone 2 and zone 1 trip signal failure is assumed to be the same, since all the components for both these trips are the same.

There are some fatal failures after which the failure branch always is the end branch. Such fatal failures are those where the fault current continues to flow at one line end, i.e., either the main protection relays fail to send a trip signal to circuit breakers or a breaker failure relay fails to trip the circuit breakers. From the power system point of view, there is no need to know if the trip succeeds at the other end if it has failed at one end. The failure is fatal enough and it is quite insignificant what would occur at the other line end. Additionally, a simultaneous ‘no-trip’ failure at both line ends would have the probability that is the product of probabilities of both line ends, a very small number.

The operations after the branch ‘no trip at one line end’ are not modelled in event trees, but taken into account later on. In reality, after such an incident, the remote end back-up protections of the adjacent lines can isolate the substation after a 1-second delay, if the 3rd zones of the back-up distance relays reach the fault and if the system has remained stable during the delay. The possible reach of the 3rd zones of the back-up relays and the stability are taken into account when defining the power system state after the power system analysis of substation consequences is made.

The substation post-fault operations of the line ends that are located in Sweden or in Russia are modelled on the assumption that the substation structures and failure rates are the same as in Finland.

The event trees of 3-branch lines are constructed in such a way that the protection operations of the third branch, which consists of the 400/110/20 kV transformer, are ignored. This branch has usually two distance relays and one circuit breaker. The scheme of this kind of substation is presented in Figure 8. If the tripping of this branch were to fail, the fault current infeed from the 110 kV grid would be small, due to the reactances of the transformer and 110 kV grid. This small current does not have any effect on the grid dynamic stability and therefore it is not necessary to take it into account when calculating the grid dynamics. Therefore, it is enough to model the operations of the other two line ends in the event trees.

7.4.2 Different event trees

The details of the event tree depend both on the substation schemes at line ends and on the fault location. The substation scheme has an effect on the number of circuit breakers that need to be tripped in order to isolate the fault. Three different fault protection systems are planned for three different fault locations, as can be seen in Figure 10. There are four different lines, when classified according to the number of circuit breakers. Therefore twelve different event tree constructions were made, as can be seen in Table 6.

Table 6 Different event trees for line fault analyses

<table>
<tr><th>Event tree</th><th>Line type</th><th>Fault location</th></tr>
<tr><td>ET 1</td><td rowspan="3">Both line ends have double circuit breaker busbars</td><td>Middle of the line</td></tr>
<tr><td>ET 2</td><td>Near the master line end</td></tr>
<tr><td>ET 3</td><td>Near the follower line end</td></tr>
<tr><td>ET 4a</td><td rowspan="2">The master line end has a double circuit breaker busbar scheme; the follower line end</td><td>Middle of the line</td></tr>
<tr><td>ET 5a</td><td>Near the master line end</td></tr>
</table>

ET 6a	has a single circuit breaker busbar scheme.	Near the follower line end
ET 4b	The follower line end has a double circuit breaker busbar scheme; the master line end has a single circuit breaker busbar scheme.	Middle of the line
ET 5b		Near the master line end
ET 6b		Near the follower line end
ET 7	Both line ends have single circuit breaker busbar schemes	Middle of the line
ET 8		Near the master line end
ET 9		Near the follower line end

Event trees 1, 2 and 3 are for the lines where both line ends have double circuit breaker busbars. These event trees have most branches and different possible substation consequences.

Event trees 4, 5 and 6 are for lines, where one line end has double circuit breakers and the other line end has single circuit breakers for each line end. These fault trees have some mutual symmetry, and they have an equal number of consequences. These event trees do not have a failure of two circuit breakers at the single circuit breaker line end, thus the number of consequences is smaller than in event trees 1, 2 and 3.

Event trees 7, 8 and 9 are the simplest, since they have the smallest number of circuit breakers and breaker failure relays.

7.4.3 One event tree in detail

In the following, one event tree is discussed in detail. This event tree is developed for a case with single circuit breakers at both line ends. The fault location is in the middle of the line and all the distance relays protecting the line measure the fault as being on zone 1; therefore the model does not contain any telecommunication channels. The number of the event tree presented here is ET7; this can be seen in Figure 11. The function events of the event tree are the following, starting from the initiating event:

1) The trip signal of the main protection relays of the master line end. The protection system at the master line end sends an instantaneous trip signal to the circuit breaker. If this fails, no other issues are checked.

2) The trip signal of the main protection relays of the follower line end. The protection system at follower line end sends an instantaneous trip signal to the circuit breaker. The failure branch of this is the end branch, since this failure is regarded as fatal.
3) The circuit breaker of the master line end trips. The failure of this branch leads to breaker failure protection.
4) The breaker failure protection of the master line end trips the relevant circuit breakers. If this fails, there is no trip at this substation and the failure branch is the end branch.
5) The circuit breaker of the follower line end trips. The failure of this branch leads to breaker failure protection.
6) The breaker failure protection of the follower line end trips the relevant circuit breakers. If this fails, there is no trip at this substation and the failure branch is the end branch.
7) The rapid automatic reclosing relays of the master line end make a successful automatic reclosing. If this fails, the follower does not try an autoreclosure.
8) The rapid automatic reclosing relays of the follower line end make a successful automatic reclosing. This can succeed only if the line has voltage and the voltages at the line and at the substation are in phase.

A description of each end branch and the consequences connected with the branches are presented in Table 7. A consequence of an event tree is a kind of label attached to each end branch. The consequences in this stage are substation consequences. It is worth noting that the same consequence can be caused due to different failure sequences. The substation consequences are independent of the load flow case because they depend only on the successes and failures at the substation components after the fault. The substation consequences include both the fault durations and the tripped components. The consequences are numbered. The numbers, descriptions and explanations of consequences are presented in Table 7 of event tree 7. The numbers and descriptions of all event trees are presented in the tables in Appendix A.

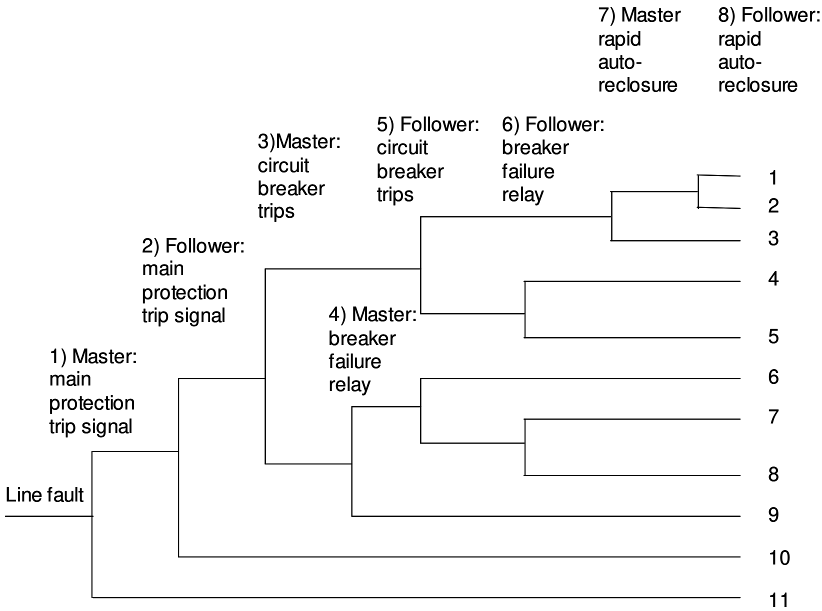


Figure 11 The event tree for the faults in the middle of the line for the lines with single circuit breaker busbar schemes at both line ends. (Event tree 7 is shown in Appendix A)

Table 7 Descriptions of the end braches of the event tree presented in Figure 11. RAR = rapid automatic reclosing, BFR = breaker failure relay.

End branch	**Substation consequence of the end branch: identification number, description of the consequence and explanation.**
1	7-00. Description: Master and follower: line trip 100 ms, autoreclosing. Explanation: Both the protection and circuit breakers succeed. The fault is isolated in 100 ms. Rapid automatic reclosure succeeds at both line ends. This is a planned n-1 fault and the grid will remain stable.
2	7-01. Description: Master: line trip 100 ms. Follower: line trip 100 ms. Rapid autoreclosing fails. Explanation: Both the protection and circuit breakers succeed. The fault is isolated in 100 ms. Rapid automatic reclosure succeeds at the master line end but fails at the follower line end. This is a planned n-1 fault, even though the line remains unconnected immediately after the fault. The grid will remain stable.

3	7-01. Description: Master: line trip 100 ms. Follower: line trip 100 ms. Rapid autoreclosing fails. Explanation: Both the protection and circuit breakers succeed. The fault is isolated in 100 ms. Rapid automatic reclosure fails at the master line end and therefore does not occur at the follower line end. This is a planned n-1 fault, even though the line remains unconnected immediately after the fault. The grid will remain stable.
4	7-11. Description: Master: line trip 100 ms (no RAR). Follower: one busbar trip (BFR 250 ms). Explanation: At the master line end, the protection and circuit breakers succeed to trip the fault. At the follower line end, the circuit breaker fails to trip, but the breaker fail protection succeeds to trip the busbar. There is no automatic reclosure after a busbar trip.
5	7-24. Description: Follower: no trip signal or no circuit breaker trip at the substation. Explanation: At the master line end, the protection and circuit breakers succeed to trip the fault in 100 ms. At the follower line end, the circuit breaker and breaker failure protection fail. Therefore, the fault current continues to flow from the follower line end.
6	7-10. Description: Master: one busbar trip (BFR 250 ms). Follower: line trip 100 ms (no RAR). Explanation: At the follower line end, the protection and circuit breakers succeed to trip the fault in 100 ms. At the master line end, the circuit breaker fails to trip but the breaker failure protection succeeds to trip the busbar 250 ms after the fault start. There is no automatic reclosure after a busbar trip.
7	7-12. Description: One busbar tripped at both substations by BFR after 250 ms. Explanation: The relays at both line ends send trip signals, the circuit breakers at both line ends fail to trip but both breaker failure protection systems succeed to trip the relevant busbars 250 ms after the fault start.
8	7-24. Description: Follower: no trip signal or no circuit breaker trip at the substation. Explanation: At both line ends, the circuit breakers fail to trip. The breaker failure protection succeeds to trip the busbar at the master line end but fails at the follower line end. Therefore the fault current continues to flow from the follower line end.

9	7-23. Description: Master: no trip signal or no circuit breaker trip at the substation. Explanation: At the master line end, the circuit breaker and breaker failure protection fail. Therefore the fault current continues to flow from the master line end.
10	7-24. Description: Follower: no trip signal or no circuit breaker trip at the substation. Explanation: The main protection at the master line end sends a trip signal, but the main protection at the follower line end fails to send a trip signal to the circuit breaker. Therefore the fault current continues to flow at the follower line end.
11	7-23. Description: Master: no trip signal or no circuit breaker trip at the substation. Explanation: The main protection at the master line fails to send a trip signal to the circuit breaker. Therefore the fault current continues to flow at the master line end.

7.4.4 Other event trees

If the line has extra circuit breakers compared to the line of event tree 7, extra function events are added to the event trees. This is the case if the line has double circuit breaker busbar schemes at one or both line ends.

For line faults near the line ends, the protection branches are three instead of the two presented in Figure 11. These are:

- The protection system at the line end near the fault sends an instantaneous (zone 1) trip signal
- The protection system at the other line end sends an instantaneous (POTT, PUTT) trip signal
- The protection system at the other line end sends a delayed trip signal.

All event tree structures created for different lines and different fault locations are presented in Appendix A, together with a list of all substation consequences of the end branches of different event trees.

7.5 Fault trees

The function events of the event trees need an input in order to calculate the branch probabilities. Fault tree top gates are used as inputs for event tree branches. The number of fault trees built during the study was about 460.

Fault trees consist of basic events and gates. The top gate of a fault tree corresponds to the event tree function event. Different fault trees made for different protection and trip functions are listed here:

- Two main protection relays fail to send a permissive overreach (underreach) trip signal to circuit breaker trip coils
- Circuit breaker fails to trip after it has received a trip signal to trip coils
- Breaker failure protection fails. The fault tree includes both the relays and the relevant circuit breakers. The failure of this fault tree occurs if one or more circuit breakers remains closed.
- Rapid autoreclosure fails at a line end that gives the voltage to a dead line (a master station). This fault tree includes relays and circuit breakers.
- Rapid autoreclosure fails at a line end that closes the circuit breaker only if the opposite end has made a successful autoreclosure (a follower line end). This fault tree includes relays and circuit breakers.

An example of a fault tree is given in Figure 12. The top gate of this fault tree is the failure of two main protection relays to send a trip signal to circuit breakers. Different fault trees of this study are presented in Appendix B. Fault trees are not presented graphically, but by listing the minimal cut sets and the probabilities of them.

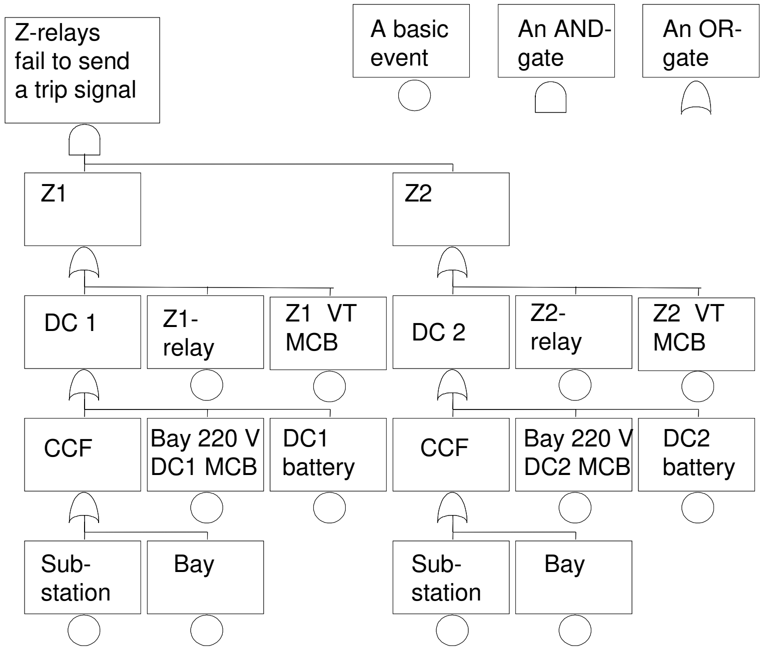


Figure 12 A fault tree, where the top gate is 'two main protection distance relays fail to send the zone 1 or zone 2 trip signal to circuit breaker trip coils.' Z = distance relay, MCB = miniature circuit breaker, VT = voltage transformer, DC = direct current, CCF = common cause failure.

7.5.1 Principles used in fault tree construction

Some assumptions were predefined before it was sensible to start to create the fault trees. The assumptions used in this model are listed in this chapter.

Usually the basic events in the fault trees are for a component, such as a certain relay or a certain circuit breaker, only. These basic events depend only on the component itself. Some basic events are for common components, the failure of which affects several fault trees. Such a basic event corresponds to, for example, the substation direct current system, which feeds the protection relays, circuit breaker trip and close coils. Another example of such a basic event is the substation pneumatic air system, which produces compressed air for air-blast circuit breakers.

Some devices send an alarm when there is a failure. It is supposed that this alarm is always sent successfully to the control centre, i.e., the alarm acts with 100 % reliability. Some devices that send an alarm are not modelled at all. An example of such a device is a DC rectifier that fails. After it has sent an alarm and during the repair, the batteries do not loose all their energy. Thus rectifier failures are not included in the model.

The cable ditch at the substation has several cables. There is a risk that something might damage all the cables in that ditch and prevent the transmission of the signals. The substation area is surrounded by a fence, so no one can excavate the cables accidentally. However, there is a common cause failure basic event for cables of each line bay.

A constant unavailability model is used for the telecommunication system reliability. This constant unavailability of the FMEA analysis is used for all other telecommunication channels except the power line carrier. The power line carrier unavailability is dependent also on the initiating event, thus the FMEA unavailability cannot be used directly. The power line carrier in the Finnish 400 kV grid is installed in two phases instead of three. During 1-phase faults, there is always a healthy phase available. The case is different for 2- and 3-phase faults. During 3-phase faults, all the phases carry the fault current and it is very probable that the telecommunication signal cannot pass the faulted line. In this case, the constant unavailability of the telecommunication is 1. During 2-phase faults, it is possible for the power line carrier to be on the healthy phase or on faulted phases. On average, one in three times the fault current is only on the faulted phases and the telecommunication fails. The constant unavailability of the power line carrier during a 2-phase fault $q_{2\text{-}ph}$ can therefore be calculated according to the following equation

$$q_{2-ph} = \frac{2}{3} q_{PLC} + \frac{1}{3} \tag{2}$$

where q_{PLC} is the constant unavailability of the power line carrier.

It is assumed that, if a relay succeeds to send a trip signal to the circuit breaker(s), it also sends a signal to the breaker failure relay. The breaker failure fault tree has both the relay and the circuit breakers connected to the same busbar as the faulted circuit breaker. However, in the model, the circuit breakers of the line and generator bays are included, since these bays feed large fault currents. The circuit breakers of the 400/100 kV transformers are excluded, since the fault current infeed from 110 kV grid to 400 kV is insignificant compared to the fault current at 400 kV grid. The breaker failure fault trees of those 400 kV substations that are connected to the 400 kV grid with a radial line and have no generators, are assumed to never fail.

After commissioning, the SF6 circuit breakers are provided with a blocking system that prevents the trip if the SF6-gas density in the circuit breaker is too low. If the circuit breaker trips with a low SF6-gas pressure, the circuit breaker can be broken. Fingrid plc removes the blocking system when the guarantee period is over. Therefore, most SF6 circuit breakers are not provided with this blocking system and this is not taken into account in the circuit breaker fault trees.

7.5.2 Basic event types

The Risk Spectrum reliability analysis code (Relcon 2003) uses different basic event types. These basic events of the software are used in this analysis as such.

Monitored components

The monitored, repairable basic event type is used for those components, which have a self-supervision property. The long-term constant unavailability of this basic event is calculated with the following equation (Relcon 2003 Theory Manual p.6, Høyland and Rausand 1994 p. 164):

$$q = \frac{\lambda}{\lambda + \frac{1}{MTTR}} \tag{3}$$

where λ is the constant failure rate and *MTTR* the repair time (mean time to repair.)

Tested components

Periodically tested components have a different basic event model. The long-term constant unavailability of tested components, when the repair time is taken into account is (Relcon 2003, Theory Manual p. 7):

$$q = 1 - \frac{1}{\lambda \cdot Ti}(1 - e^{-\lambda \bullet TI}) + (1 - e^{-\lambda Ti}) \cdot \frac{MTTR}{Ti} \tag{4}$$

where λ is the constant failure rate and *MTTR* is the repair time (mean time to repair) and *Ti* is test interval. The first part of the equation presents the average unavailability without taking into account the repair time and is presented in Høyland and Rausand (1994, p. 174). The second part is the unavailability contribution due to the repair. In the cases where the repair time is very short compared to the test interval, the second part is negligible.

Components with constant unavailability

The basic event with a constant unavailability has the unavailability value as its only parameter. It is the simplest model available. This model is used for telecommunication channels and for static and microprocessor relays.

Monitored and tested failures in one device

Static and microprocessor relays have two kinds of failures. A failure in the power supply unit of a relay is such that the self-supervision of the relay sends an alarm. An erroneous setting or configuration can be detected only during a test.

The fault tree program used does not have a model that includes both failure types in the same basic event. One possibility is to create two basic events for each relay. One basic event would be for monitored failures and the other would be for failures detected during testing. With this method, the number of minimal cut sets would be increased and the calculation of importance measures would give separate importance values for different faults of the same device, which would not be sensible.

The other possibility is to use one basic event with the constant unavailability for each relay. The latter choice is selected. The constant unavailability value is calculated with two basic events. One basic event has a failure rate calculated with those faults that send an alarm and the other uses a failure rate calculated according to those faults that can be detected during the testing only. The drawback of this method is that the importance of failure rate or testing interval cannot be calculated for those devices.

7.6 Failure mode and effect analysis, FMEA

The input data for fault tree analysis was received with failure mode and effect analysis. FMEA was used to identify different failure modes and their effects, causes and identification. This data was necessary for selecting the reliability models of components in the fault trees. The FMEA made is presented in Appendix C. The fault trees were made according to the failure mode and effect analysis and according to the substation structure.

The qualitative failure data of the substation components was received by specifications, substation diagrams and device failure database. Expert judgments of the specialists of the maintenance, planning and local operation were important sources for the FMEA. The FMEA data, as well as the structures modelled, are specific rather than universal. Different transmission companies may have different substation structures, different protection systems, different maintenance policies and they may have devices manufactured by different companies.

The quantitative results of the FMEA are received mostly from the device failure database of Fingrid plc. Some data are received from the supervisory control and data acquisition system (SCADA). The data used in this research cover the different periods depending on the respective cases. The quality of data was not constant, being better for some components than for others.

The device failure database of Fingrid plc has the following data: failure number, device location and ID, part of the device that has a failure, device type by manufacturer, manufacturing year, commissioning year, date and time of detection of failure, cause of failure, how the failure was detected, effect of failure, whether the device can be used during the failure, repair method, the urgency of the repair, repair time, repair duration, whether is the failure connected with a disturbance or not and a field for all kinds of comments. The database is made mainly for maintenance purposes. Some interpretation of the data was made in order to classify the failures correctly for this kind of analysis.

All the relays of the same class (microprocessor, static, mechanical) have the same FMEA data irrespective of the manufacturer. The same principle is applied for air-blast, minimum oil and SF6 circuit breakers, too.

The failure rate values for each component are calculated according to the Bayes theorem. The failure rate estimate $\hat{\lambda}$ is calculated according to the following equation:

$$\hat{\lambda} = \frac{0.5 + k}{T_{TOT}} \tag{5}$$

in which k is the number of failures detected during a certain time and T_{TOT} is the total number of component-years. This estimate is calculated by using a non-informative prior distribution (Høyland and Rausand, 1994; Lee, 1997)

If there have been many failures, the failure rate estimate approaches the classical estimate, which is the number of failures divided by the component-years. If there have been no failures and the number of component-years is small, the Bayes estimate might give too large a value. The estimate becomes better with the increasing number of components and years.

The parameter ‘mean time to repair’ is the mean active repair time for the components whose failure does not cause the changes in the grid connection. The repair duration of each failure is reported in the device failure database. These kinds of components are the ones that are doubled. For some single components, the 15 minutes value is used. This is due to the Nordel requirement that the operation be changed back to secure in 15 minutes following faults that change the grid state from secure to alert. If a single component like a circuit breaker is broken, the faulted circuit breaker is disconnected from the grid and possibly some alterations in the grid loading are made as well. This means that the faulted case duration is only 15 minutes, since the grid topology, and maybe the grid loading, are changed after that time. This is an approximation of the reality and a second-order matter in this model.

7.7 Common cause failures

The model does not contain common cause failures other than the substation and the bay. There are no other such issues that would lead to common cause failures that would have significance in the reliability model.
The basic event for the whole substation is in all fault trees of that substation. This basic event models a fire, for example, or a mechanical failure of the substation or at the building. All the secondary systems of the substation (relays, telecommunication devices, part of the cables connecting the bays to the secondary system) are in the building. It is worth noting that, if the substation is lost, the control centre has 15 minutes to adjust the power system connection and grid loading to be secure without the failed substation. If the line fault were to occur within 15 minutes, the case would have been correctly modelled. The same principle is valid for the basic event 'bay'.

A common cause failure due to maintenance or testing is one question that needs consideration. If the terminal strips of both circuit breaker trip coils are disconnected, the circuit breaker cannot trip, even though it would be undamaged. If all terminal strips were disconnected due to an error in maintenance or testing, this would be a common cause failure. If the maintenance of all similar devices at the substation were carried out simultaneously and reconnected simultaneously after the maintenance, a common cause failure could occur. However, the maintenance and inspection of the circuit breakers, relays and the telecommunication are made for one bay at a time. If an error is made at one bay, it is not likely that the same error would be made at the other bays, since maintenance and testing of them are separate events. The maintenance methods at the substation are such that this does not easily lead to common cause failures.

It is assumed that common cause failure mode can be neglected with duplicated main protection systems apart from the miniature circuit breakers of the electromechanical distance relays. Still the common cause failure issue of the two microprocessor relays by the same manufacturer is a tricky question. The specification allows two different relays from the same manufacturer, if they are not the same type. Modern microprocessor relays have software. Different relay models by the same manufacturer at the same line bay can fulfil the specification, but the relays can have the same software parts to some extent. It is possible that, in this case, there is a common cause failure possibility. This research is too optimistic in this respect, but because the relays are not completely similar, it might be too pessimistic to assume that they are similar. A common cause failure for two microprocessor relays by the same manufacturer would be the best way to model this, but finding a correct value for this would require more information than is available for the relay user.

The voltage transformer is common for both distance relays, but it is not modelled. The distance relays can trip during a fault when even the voltage measurement is lacking, therefore the failure of a voltage transformer does not necessarily prevent the trip. The voltage transformer supervision systems of both relays could operate during a voltage transformer failure and prevent a trip. The same could happen if miniature circuit breakers of both distance relays trip due to voltage-transformer failure. However, both these occurrences send an alarm and are detected, after which the line is disconnected. It is thought that both the probability of these occurrences is small and the duration of the failures is short; thus they are not modelled.

The current transformer primary is a common component for the two main protection relays. There have been several failures of current transformers. They all were explosions and created a substation fault. If there were a line fault during the explosion, there would be two simultaneous grid shunt faults, which is a completely different situation than is modelled in this study.

8 POWER SYSTEM SIMULATIONS

This chapter describes the dynamic simulations that were made in order to find the power system consequences of the substation failures after line faults. The software, load flow case, grid model, fault locations and the classification of simulation results are discussed.

8.1 Grid model and the load flow case

The grid simulations were made by using the Power System Simulator (PSS/E) program package by Shaw PTI (Shaw PTI, 2001). PSS/E is "a package of programs for studies of power system transmission network and generator performance both in steady state and dynamic conditions" (Shaw PTI, 2001, PSS/E Program Operation Manual, p. P-1). All transmission system operators of Nordel use this software; therefore the grid models and different load flow cases are available in PSS/E format.

The model used in this research has a detailed grid model of the Finnish grid. The load flow was received from Fingrid plc and has a sample from a day in January, 2003. The PSS/E load flow model includes all the generators bigger than 10 MW with their block transformers and 400 kV, 220 kV and 110 kV lines. The loads, which are connected to 20 kV and lower voltage level, are modelled as lumped loads at 110 kV substation nodes in order to create a correct load flow case. The grids of Sweden, Norway and Denmark are modelled as a reduced grid with big equivalent generators and equivalent lines. The HVDC link is modelled as a constant lumped active and reactive load.

The load flow

The load flow used in the simulations is a typical January load flow and the PSS/E model is created at Fingrid plc. The 400 kV grid is intact. Some characteristics of the load flow case are listed below:

- The load in Finland is 12240 MW, 1933 Mvar.
- The production in Finland is 10378 MW, 1029 Mvar, where hydro production is 1450 MW, nuclear production is 2749 MW and other thermal production is 6179 MW.
- Import from Sweden to Finland via northern 400 kV AC lines is 915 MW, -132 Mvar.

- Export to Sweden from Finland via Fenno-Skan HVDC link is 150 MW 80 Mvar.
- Import from Russia to Finland via 400 kV AC lines is 1098 MW, 24 Mvar. This includes both the Russian South Western Power Plant and the back to back HVDC link.
- Import from Norway to Finland via 220 kV AC lines is 66 MW, -26 Mvar.
- Transmission from northern Finland to Southern Finland is 834 MW, 20 Mvar.

8.2 Dynamic simulations

All those consequences of event trees were simulated where the power system state could not be directly concluded. There is no need to simulate the n-1 faults, since the grid is planned and operated according to the n-1 principle. The number of substation consequences to be analysed with dynamic simulations is about 1400. There are 39 lines and 25 - 55 different substation consequences for each line.

The substation consequence with number 23 of the event trees was such that no trip occurred at master line end. These cases were simulated in such a way that the line circuit breaker tripped after 100 ms in the follower line end. After a 1-second fault duration, the substation with the master line end was disconnected from the grid. This 1-second delay was chosen, because it is the delay of zone 3 of those distance relays that form the remote back-up protection of the faulted line. The same principle was used for consequences numbered as 24, where the trip does not occur at the follower line end.

8.2.1 Fault locations and durations

The line sections that require different event trees are presented in Figure 10. The fault location in a dynamic simulation was in the middle of each line section. The line sections that require telecommunication are 20 % of the line length and situated at the line ends. The fault location for them is 10 % from the line end. The fault location for the line section where the distance relays do not need a telecommunication channel is in the middle of the line. The fault locations for simulations are presented in Figure 13.

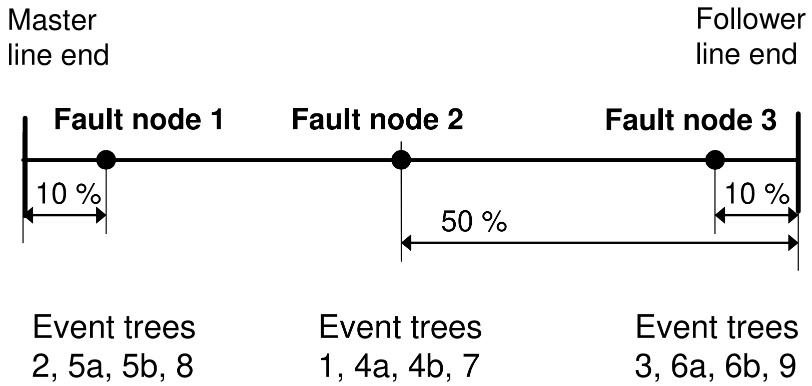


Figure 13 Fault node locations of a transmission line for dynamic simulations

The start of a dynamic simulation was always similar: first there is pre-fault simulation with a duration of one second, after which the fault is applied. Following that, the circuit breaker trips in a correct order are simulated. The fault durations vary according to the case, but every case is simulated from start to 20 seconds in order to see if the post-fault situation will be stable or not.

In the real world, there are some variations in fault durations, since different relays start and succeed in sending the trip signal in different times, so, too, do the circuit breakers. There also are variations in relay operations due to different fault locations. In this research, the fault duration times of the dynamic simulations were fixed and are presented in Figure 14, Figure 15, Figure 16 and Figure 17.

The instantaneous line trip duration is 100 ms, in which the relay operations are assumed to take 50 ms and the circuit breaker trip to take another 50 ms. This kind of trip can be either a zone 1 trip or permissive over- or underreach transfer trip scheme of the distance relays or a trip by the line differential relays. The fault duration of this trip is presented in Figure 14.

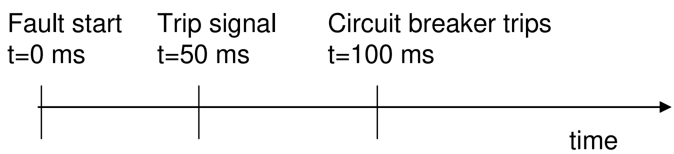


Figure 14 The duration of a line fault with a successful trip operation

The delayed zone 2 trip of the distance relays takes 450 ms. The relay sends the trip signal after 400 ms from the fault start; the circuit breaker operation takes 50 ms. The fault duration of this delayed trip is presented in Figure 15.

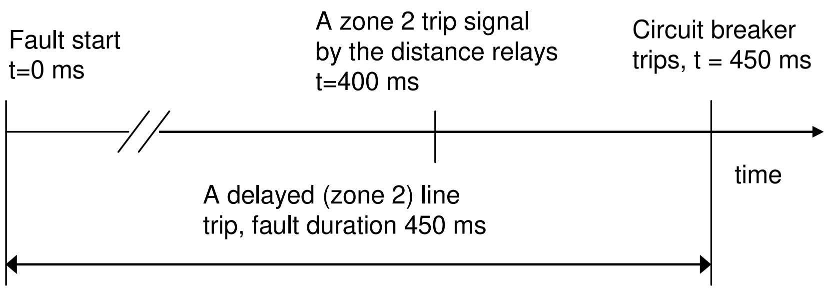


Figure 15 The duration of a line fault with a zone 2 trip of a distance relay

When the breaker failure protection relays trip the busbar after a circuit breaker failure, the fault duration is assumed to be 250 ms if the relay has sent an instantaneous trip signal. The duration of this fault is 600 ms if the relay has sent a zone 2 trip signal. The fault durations of these trips are presented in Figure 16 and in Figure 17.

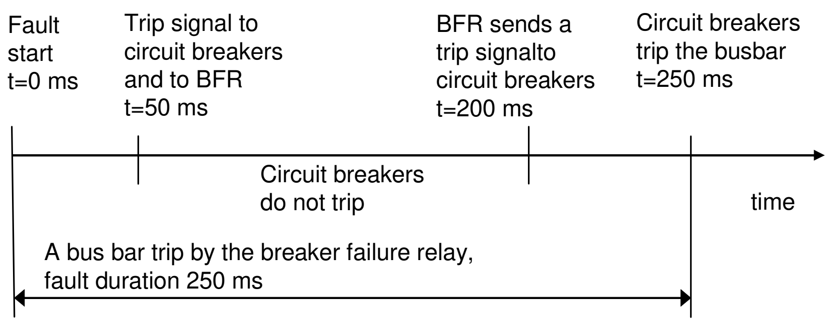


Figure 16 The duration of a line fault with an instantaneous trip signal, a circuit breaker failure and a breaker failure relay operation. BFR = breaker failure relay

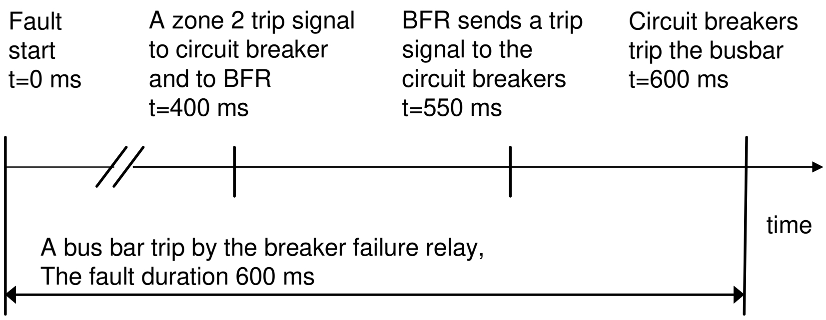


Figure 17 The duration of a line fault with a delayed trip signal, a circuit breaker failure and a breaker failure relay operation. BFR = breaker failure relay

It is assumed that when the circuit breaker fails to trip after a trip signal, all the phases remain closed. In the simulations, this means that the 3-phase fault continues until the breaker failure relay trips the busbar.

8.3 Analysis of grid simulation

8.3.1 Classification of simulation results

The results of the dynamic simulations were classified taking into account the stability, the voltage violations, and the thermal limits and also the reach of the remote back-up protection. All fault locations and substation consequences were simulated with 3-phase faults with zero fault impedance. The power system effects of a 2-phase shunt faults are very similar to those of 3-phase faults, but 3-phase faults are much quicker to simulate with PSS/E.

Stability

Angle stability was classified into the categories: stable and unstable. When the angle stability of the power system is lost in 20 seconds the result is a major disturbance. There is nothing the control centre operation personnel can do to prevent the case. Voltage- or frequency-stability problems did not occur in this load-flow situation.

Voltage violations

Voltage violations were checked, since it was possible that the voltages were beyond the limits without any stability problems. The upper voltage limit 420 kV was determined by insulation coordination and the lower voltage limit 370 kV by voltage instability and voltage quality. The simulations did not produce any voltage violations. This is due to the light loading of the grid as well as the series compensation at the lines between Finland and Sweden and between Northern and Southern Finland. The voltages were checked from the dynamic simulation results. The voltage dependency of the load models is included in the dynamic simulations. The model also has the reactive power limits of the generators and generator excitation controls.

Thermal limits

Thermal limits were checked at the winter outdoor temperature of minus 10 degrees Centigrade, which is a typical January temperature in Finland. No overloading of 400 kV branches was detected; there were some 110 kV lines that were overloaded after several 400 kV lines were tripped.

In the Finnish 400 kV system, it is most often the current transformer that sets the limits to the branch rating ratings. In those cases where there were are two parallel current transformers at double circuit breaker substations, it was assumed that the current in one parallel current transformer was not more than 60 % of the line total current. There are no measurements made on that subject, but 50 % -50 % would probably be too optimistic a value, since a very small difference between the impedances of the joints may cause different power flows for parallel routes.

The rate MVA values for line conductors, current transformers, disconnectors and series capacitors for a +30 degrees ambient temperature can be found in the specifications. The rate values for -10 degrees ambient temperature can be calculated by multiplying the +30 degrees rating value with a coefficient. The coefficients used in this study for converting the specified rating values into other ambient temperatures are presented in Table 8.

Table 8 The coefficients for converting the MVA rating values of certain components to different ambient temperatures

Component	**The coefficient for converting the MVA rating at +30 degrees ambient temperature into the rating at +10 degrees**	**The coefficient for converting the MVA rating at +30 degrees ambient temperature into the rating at -10 degrees**
Conductor	1.25	1.5
Current transformer	1.15	1.3

Series capacitor	1.0	1.0
Disconnector	1.0	1.0

If the +30 degrees rating of a branch is determined by a current transformer, a series capacitor or a disconnector, the rates at other temperatures are determined by this same component also. However, if it is the conductor that sets rating limits at +30 degrees, it happens sometimes that it is the current transformer limiting the branch rating at +10 or -10 degrees.

Remote back-up protection issues

The remote back-up protection should trip the fault if the trip does not occur at the substation. These consequences were numbered as 23 and 24 in the event trees. The remote back-up protection operations are ignored in the event tree. However, they are taken into account separately when analysing the event tree results. There is a remote back-up protection that consists of distance relays situated at the next substation on the reverse direction. If the 3rd zones of all the remote back-up distance relays reaches the fault and sends the trip signal, the fault is isolated after a 1-second delay. This leads to the disconnection of all the lines connected to that substation. But zone 3 of the remote back-up protection does not always reach the fault location; in this case the trip is not possible. This may happen when the remote back-up protection consists of electromechanical distance relays with circular zone characteristics or when the protected line is a long one.

8.3.2 Power system consequences

The power system states that will be used as consequences in the event trees are secure, alert, emergency and system breakdown. A special alert case, in which extra generators or HVDC links are tripped due to an exceptionally long fault duration, is also used.

The power system state after the line fault is studied and classified according to straightforward rules presented in this section. All the cases where the grid is not intact after the fault clearance are always classified in this study as ‘alert’ if there are no violations of voltage or thermal limits. In reality, this case can be either secure or alert. It is possible that, after some line trips at a certain grid loading, the grid would withstand another line or busbar trip, which would mean that it is secure. For the scope of this study, this simplification of the model is acceptable, since the main interest is to get an overview of the power system reliability and not study all the possible contingencies in detail. Getting an overall idea of the consequences of different contingencies requires many simulations, even with this degree of accuracy.

The power system states and their definitions are the following:

Secure

Secure was stable in dynamic simulations, no extra generators and HVDC links were tripped, no thermal nor voltage violations occurred. The fault tripped in 100 ms and the rapid autoreclosing succeeded.

Alert

Alert was a case that was stable and did not have any voltage or thermal rating violations in the dynamic simulations. One or several components could be tripped. A selective line trip without an autoreclosing was an alert case. A busbar trip and trips of extra generators were alert cases as well, if the voltages and thermal ratings were not violated.

For consequences 23 and 24, where the trip fails at one line end, the case was regarded as alert if the requirements of an alert case were fulfilled and if the remote back-up protection reach was sufficient to trip the substation. Substation consequences 23 and 24 are defined in Table 7.

An example of an alert state is the tripping of a busbar by the breaker failure relay at a double circuit breaker substation. The load flow case does not change after the fault is cleared, since all the lines and substations are in use after the trip. The only difference compared to the secure state before the fault is the fact that the faulted substation would lose all the lines connected to it if a busbar fault were to occur before the disconnected busbar is reconnected.

Emergency

Emergency was a stable case with several lines tripped. Voltages or thermal ratings or both were outside the limits. A trip of the faulted line only cannot lead to an emergency state due to the n-1 principle. A busbar trip, a substation trip and trips of extra generators could be emergency cases if the voltages or thermal ratings were violated.

For consequences 23 and 24 the case was regarded as emergency if the simulation results belonged to the emergency category and if the remote back-up protection reach was sufficient to trip the substation.

System breakdown

The system breakdown can be due to different causes. An unstable case in dynamic simulations was one reason of a system breakdown. Another possibility for a case to be classified as a system breakdown was such that zone

3 of the remote back-up protection did not reach to fault location in consequences 23 and 24. In this case, it did not matter if the dynamic simulation result was unstable or not. If there was no trip at the faulted line end and, additionally, if the remote back-up protection did not reach to the fault, nothing else would isolate the fault.

Partial system breakdown

An extra class, 'partial system breakdown', was calculated. It is a special case among the alert cases. The definition of a partial system breakdown is that it is either an alert or an emergency state where one or several extra generators or HVDC links trip due to the extended fault duration. It is worth noting that if a radial line between a generator and the grid is tripped, this is not regarded as an extra trip, since the generator acts as planned after such a fault.

Figures 18, 19 and 20 present the dynamic stability analysis results.

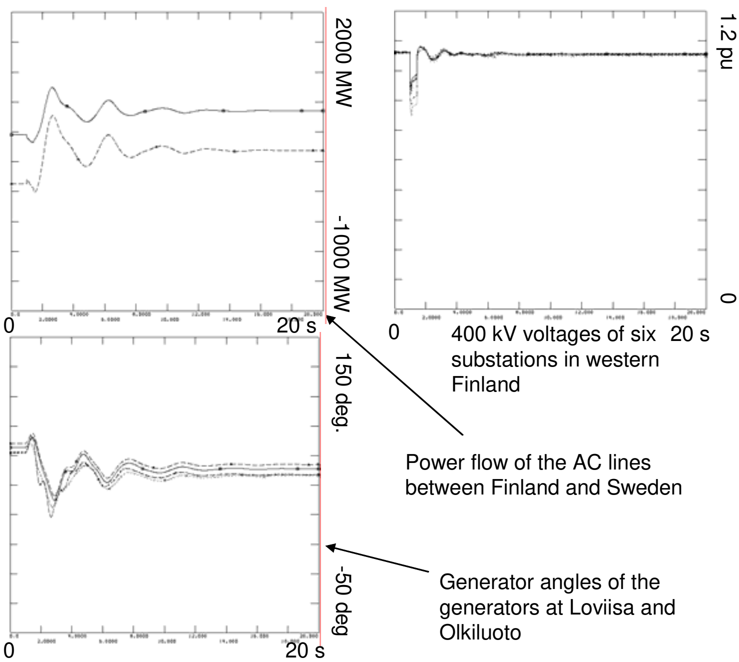


Figure 18 Dynamic simulation results of an alert and stable case

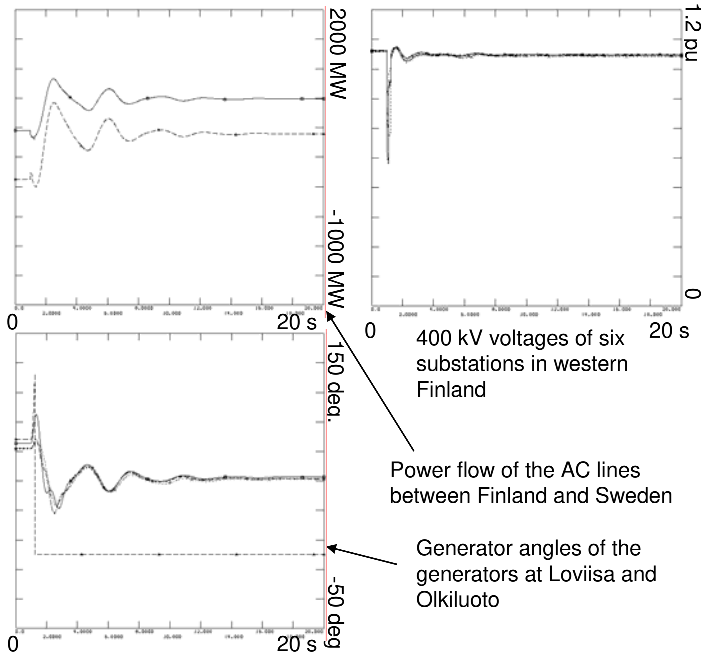


Figure 19 Dynamic simulation results of partial system breakdown

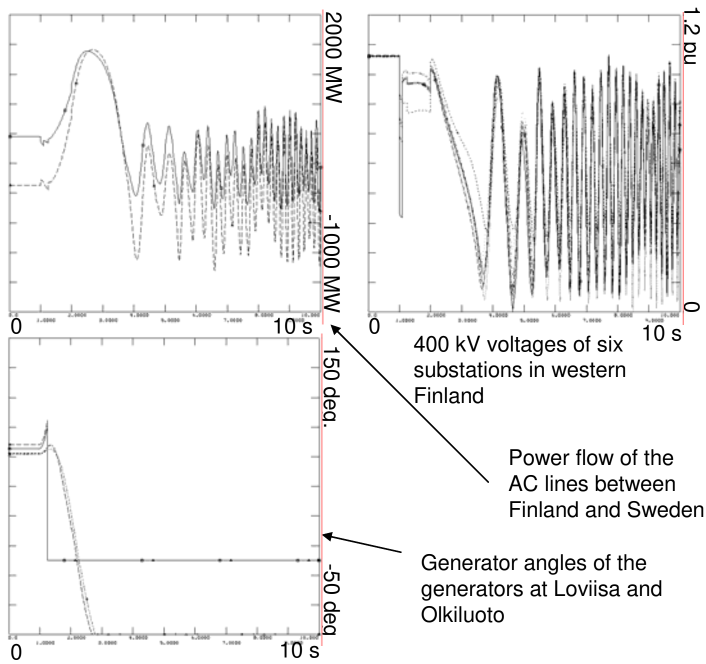


Figure 20 Dynamic simulation results of a system breakdown

9 COMBINATION OF RELIABILITY MODEL AND POWER SYSTEM SIMULATIONS

In this chapter, the combination of substation-model and power system simulations is described. Also, the importance measures of basic events for one line fault are presented and importance measures for the whole grid are proposed. In this chapter the equations for the system breakdown (SB) are presented, but a similar approach can be applied to all power system states. This chapter also includes a description of indices for the system breakdown.

9.1 The reliability analysis process

In this chapter, the process for one line as a part of the whole process is presented. The purpose is to illustrate how the modelling and analysis were made. Figure 21 presents the block diagram of the combination of the reliability model and dynamic simulations of the power system.

9.1.1 Line data and line analysis

When calculating the contribution of one line to the power system, the initiating event frequency needs to be calculated. All the event tree analyses are made in such a way that the initiating event has a certain frequency. The results of the event tree analysis are therefore frequencies rather than probabilities. In this study, the initiating events are the line faults and it is assumed that the annual line fault frequency per line length is constant. The initiating event frequency therefore depends on the line fault frequency and on the line section length. The average line fault frequency estimate is calculated from the statistics of 20 years of Fingrid plc; it includes both earth faults and short circuits. The calculation of the line fault estimate is presented in Section 5.2.1. Letting the average initiating event frequency be f_{IE} and the length of the line section of event tree M be l_M in kilometres, the frequency of the initiating event of event tree M is thus $f_{IE} \cdot l_M$.

The event trees needed for a certain line depend on the busbar structure of the substations at the line ends. Different event tree models are presented in detail in Section 7.4 and in Appendix A. The fault trees for each line depend on the protection system, substation structure and on the components at the substations. The fault tree construction is presented in detail in Section 7.5 and in Appendix B.

After the line event trees are built, they can be analysed. The results of these analyses are the frequencies of different substation consequences and the local importance measures.

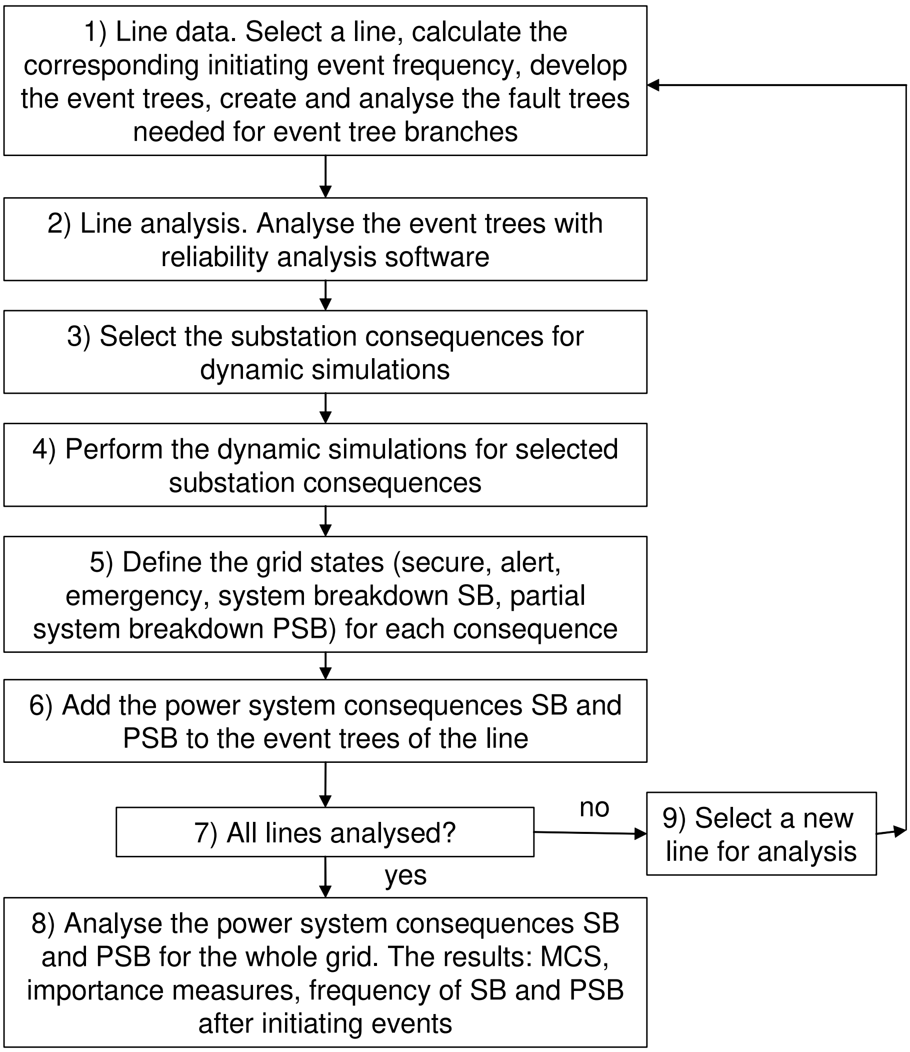


Figure 21 The block diagram of the power system reliability analysis after line faults

9.1.2 Dynamic simulations and the power system post-fault states

Those substation consequences are simulated where the post-fault state is not known in advance. The simulations, the grid model and the definition of the power system states after the fault are presented in detail in Chapter 8.

9.1.3 Power system consequences in the event trees

Figure 11 presents the substation consequences of an event tree 7. Those consequences are always the same and not dependent on the load flow or grid connection. The frequency of different consequences varies to some extent from line to line and is dependent on the components used at the line substations. The power system consequences, on the other hand, are dependent on the line. The substation failures at different lines lead to different power system consequences. The power system consequences are also a function of the load flow and grid topology. A substation consequence can in one load flow lead to an alert state and in some other load flow it can lead to a system breakdown. Therefore dynamic simulations are needed for defining the power system consequences at different grid connections and load flows.

Always when a substation consequence of a certain event tree leads to a system breakdown, the power system consequence SB for system breakdown and PSB for partial system breakdown are added to corresponding end branches of the event trees.

Figure 22 presents an example of an event tree with added power system consequence analysis results. In this case the power system state is a system breakdown if the follower or master line end trip is totally missing due to protection failure or due to the breaker failure protection failure.

After the power system consequences received from dynamic simulations are added to the end branches of the event trees of all lines, the consequence analysis of the system breakdown and partial system breakdown for the whole grid can be made.

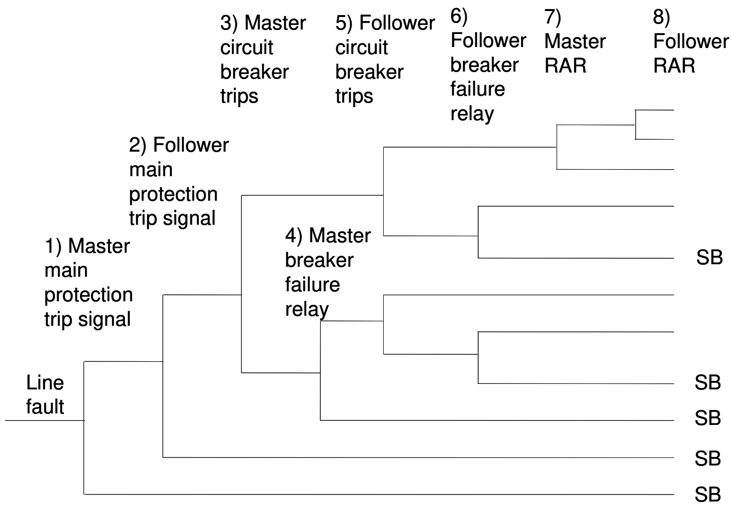


Figure 22 The event tree with power system consequences added to the end branches

9.2 Power system consequence analysis

The event trees are now analysed again, but the goal this time is to ascertain the grid-level frequency of system breakdown and partial system breakdown and the importance measures. The probability, minimal cut sets and importance measures can be calculated directly for power system consequences instead of substation consequences. The consequence analysis results are therefore at the grid level.

Notation

The frequency of the system breakdown after line shunt faults is denoted by *f(SB)*. The constant unavailability is denoted by *q*. The constant unavailability of a component *i* is denoted by *q(i)*. *P(SB|q(i)=1))* represents the conditional probability of SB, given that q(i) equals 1.

9.2.1 The frequency of power system breakdown

The frequency of the system breakdown after line shunt faults is a result of the analysis of all event trees. The frequency of the system breakdown *f(SB)* is the sum of the system breakdowns of each event tree.

$$f(SB) = \sum_{M=1}^{M_{MAX}} f(SB_M) \tag{6}$$

where the $f(SB_M)$ is the system breakdown frequency of an event tree M.

9.3 Importance measures

In this chapter the importance measures used in the consequence analysis are presented. The importance measures are those used for ranking the importance of different substation components. Different measures give different information about the components.

9.3.1 Fussell-Vesely importance

Fussell-Vesely's measure of importance *FV(i)* of a basic event *i* is the approximate conditional probability that at least one minimal cut set that contains component *i* is failed, given that the system is failed. A minimal cut set is failed when all the components in the minimal cut set are failed. Thus, the FV importance identifies the components that have the largest probability of being the cause of the system failure (Høyland and Rausand 2004, p. 194). This measure is also called the fractional contribution of basic event to risk (Mankamo et al., 1991). It is a positive number between 0 and 1. The equation of Fussell-Vesely importance for a system breakdown can be presented according to Høyland and Rausand (2004, p. 194) in the following way:

$$FV^{SB}(i) = \frac{P(D_i)}{P(C)} \tag{7}$$

where $P(D_i)$ is the probability that at least one minimal cut set that contains component *i* is failed, and *P(C)* is the probability that the system is failed.

9.3.2 Risk increase factor

Risk increase factor (RIF) is also called the risk achievement worth (RAW). Here we use the concept RIF. RIF is the ratio of the conditional system unreliability if component *i* is not present (or if component *i* is always failed) with the actual system unreliability. It presents a measure of the worth of component i in achieving the present level of system reliability and indicates the importance of maintaining the current level of reliability for the component (Høyland and Rausand, 2004, p. 191). For coherent systems the risk increase factor is always greater than 1. The *RIF* of a basic event i for a system breakdown SB is

$$RIF^{SB}(i) = \frac{P(SB|(q(i)=1))}{P(SB)} \tag{8}$$

in which $q(i)$ is the unavailability of basic event i (Relcon, 2003, Theory manual, p. 48). The risk increase factor can be calculated as a function of Fussell-Vesely importance. In this case, RIF is

$$RIF^{SB}(i) = \frac{1}{1-FV^{SB}(i)} \tag{9}$$

in which $FV^{SB}(i)$ is the Fussell-Vesely importance of the component i.

9.3.3 Risk decrease factor

Risk decrease factor RDF (also called as the risk reduction worth (RRW)) is the ratio of the actual system unreliability with the conditional system unreliability if component i is replaced by a perfect component (Høyland and Rausand, 2004, p. 191). The risk decrease factor identifies the basic event that would improve the system most if it were perfectly reliable. For coherent systems, the risk decrease factor is always greater than 1. The *RDF* of a basic event i for system breakdown SB is

$$RDF^{SB}(i) = \frac{P(SB)}{P(SB|(q(i)=0))} \tag{10}$$

in which $q(i)$ is the constant unavailability of basic event i (Relcon, 2003, Theory manual, p. 48).

9.3.4 Sensitivity of parameters

Parameters in the event tree model are, for example, the failure rate, test interval and constant unavailability. The sensitivity of a parameter indicates the rate of change of the consequence if the parameter changes. The sensitivity S_θ of any parameter θ for the system breakdown is calculated in the following way.

$$S_\theta = \frac{P(SB \mid \theta = 10 \cdot original\ value)}{P(SB \mid \theta = \frac{1}{10} \cdot original\ value)} \tag{11}$$

9.4 Analysis of the system with grid-level importance measures

After grid-level importance measures for all event trees have been calculated, they can be arranged so that the most important substation components contributing the system breakdown after the line short circuits can be recognised. The frequencies of system breakdown and partial system breakdown and the corresponding minimal cut sets are calculated. Also Fussell-Vesely importance, RDF and RIF measures and sensitivity of parameters are calculated. Chapter 10 describes the results of these calculations.

9.5 Summary of reliability indices

Different indicators can be calculated from the event tree results.

- The frequency of system breakdown after a fault at a line and frequency of system breakdown after all line faults.
- An index for the relative importance of each component in relation to system breakdown and partial system breakdown. This can be done by ranking the grid-level importance measures.
- Different probability values of each fault tree can be obtained.
- Local indices for each initiating event can be calculated from each event tree.

The indices, except the last one in the list above were calculated and some of them are presented in Chapter 10.

10 RESULTS

This chapter describes the results of the analyses made. The system breakdown and partial system breakdown frequencies, corresponding minimal cut sets and some importance measures for them are presented. The contributing factors to partial and total system breakdown are presented and some recommendations are made. It is worth noting that these results correspond to the intact grid and one grid loading only; it is only for those line shunt faults that can be tripped by the distance relays. More summaries of quantitative results are given in Appendix E for a system breakdown and in Appendix F for a partial system breakdown.

The estimate of the frequency due to failures at the substation after line shunt faults was made for partial and total system breakdown. They were made for a lightly loaded grid, which means that the values are, to some extent, too optimistic. The estimate is 1.37E-03 / years for the system breakdown and 1.12E-01 / years for the partial system breakdown. The corresponding time intervals between the successive breakdowns are 730 years and 9 years, respectively. The annual line shunt fault frequency estimate used in the analysis, i.e., 2.9E-03 faults / km, is calculated in Section 5.2.1.

10.1 System breakdown

There were two different series of events that led lead to a system breakdown. The most common cause was the failure to trip at the substation, after which the remote back-up protection reach was not sufficient to isolate the fault. The substation consequences that caused this system breakdown were numbered as 23 or 24 and are presented in Table 7. This kind of series of events caused a system breakdown after faults at 26 lines. The system remained dynamically stable, but was classified as a system breakdown due to the insufficient reach of the remote back-up distance relays.

The other, and significantly less frequent, cause that resulted in a system breakdown was extended fault duration near the generators. The extended fault duration was caused by the circuit breakers that failed to trip or by the failure of the telecommunication channel that caused the trip signal delay. The extended fault duration in these cases was either 250 ms or 450 ms. This was the case after faults at 6 lines. If a circuit breaker fails, the fault duration is 250 ms and several lines are tripped at single circuit breaker substations. If the telecommunication fails, the faulted line is tripped after 450 ms, which also can lead to loss of transient stability of the system.

Seven lines were such that there were no system breakdowns after the fault sequences studied.

Minimal cut sets

There were 13963 different minimal cut sets that led to a system breakdown. Figure 23 presents the components of the 100 most important minimal cut sets for the system breakdown. The frequency contributions of the cut sets are presented in Figure 24. Those 100 minimal cut sets represent 81.1 % of the whole system breakdown frequency. It appears that minimal cut sets consisting of two circuit breaker failures represent more than half of the minimal cut sets. Both causes of the breakdown are included.

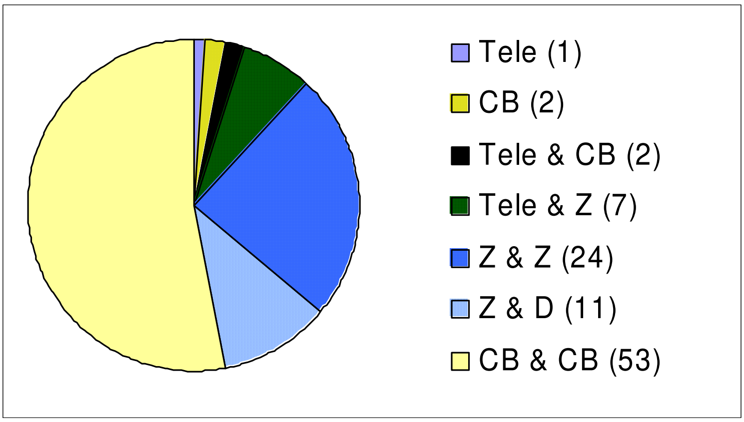


Figure 23 The components of the 100 most important minimal cut sets for a system breakdown

The minimal cut sets for the failure to trip at the substation always have two components. These components are either two circuit breakers at the single circuit breaker substation, two main protection relays or the telecommunication of the main protection 1 and the relay of the main protection 2.

At a few fault locations the power system went into system breakdown due to transient stability. The minimal cut sets that are most important at grid level have one basic event only; it is either one circuit breaker or one telecommunication channel. These components were the highest in the minimal cut set ranking list and are ranked high in all importance measure lists, too.

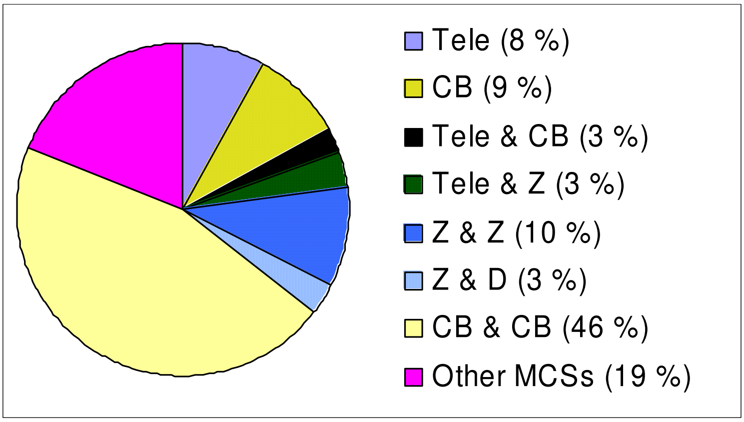


Figure 24 The frequency contributions of the 100 most important minimal cut sets for a system breakdown

Fussell-Vesely and risk decrease factors

Most important components according to grid-level Fussell-Vesely and RDF importance measures are presented in Figure 25. Only components with the FV-importance measure larger than 0.01 are presented.

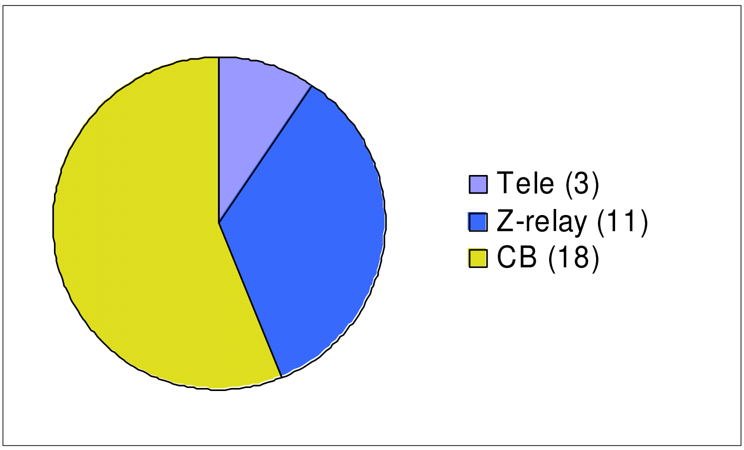


Figure 25 The 32 components that have the highest FV importance ranking for system breakdown

Among the most important components, there are 18 circuit breakers, 11 distance relays and 3 telecommunication channels. Most, but not all, circuit breakers are air-blast circuit breakers. It is worth noting that the remote back-up protection systems are not included in the importance measures, since they are not modelled in event trees. The most important components in Fussell-Vesely ranking are four air-blast circuit breakers. The FV measure of them varies between 0.11 and 0.13.

Risk increase factors

The most significant risk increase factors were different from Fussell-Vesely and risk decrease factors. The basic events for substations and bays had the highest RIF measure. This is natural, since the basic events for bays and substations are in all fault trees of that bay and that substation, respectively. Therefore they are in all function events of the event trees and their failure causes the system to fail. This is a structural property of the model.

In addition to this, all the voltage transformer miniature circuit breakers of electromechanical distance relays were ranked high in the list of grid-level RIF measures. The two electromechanical distance relays protecting the same line have a common miniature circuit breaker in the voltage transformer circuit. If the miniature circuit breaker trips, both relays are incapable of tripping the line.

Sensitivity of parameters for system breakdown

The ranking list of local parameter sensitivity shows that the circuit breaker testing interval and the failure rate of air-blast circuit breakers are the parameters that have the highest sensitivity values. This list also has ranked quite highly some unavailability values of the distance relays. The parameters that have a sensitivity value higher than 1.0 are listed in Appendix E.

10.2 Partial system breakdown

A delayed line trip takes longer than 100 ms. A delayed trip was the reason for a partial system breakdown because of faults at 21 lines. The consequence of the delayed line trip was the trip of near-by generators or the permanent blocking of near-by HVDC links. One reason for the delayed trip was the failure of the telecommunication signal, which caused the distance relays to trip at zone 2. This caused the fault duration to be about 450 ms. The most important minimal cut sets of this power system state had only one basic event; this was the power line carrier telecommunication channel.

Another cause of a delayed trip is the circuit breaker becoming stuck. A breaker failure relay trips the other circuit breakers connected to the same busbar as the faulted circuit breaker. In this case, the fault duration was 250 ms. This failure caused the partial system breakdown on many lines near the generators and HVDC links.

Minimal cut sets

There were 7603 different minimal cut sets that led to a partial system breakdown. 62 most frequent minimal cut sets covered 100 % of the partial system breakdown frequency. Among those cut sets there are 59 that have only one component and 3 that have two components. Figure 26 and Figure 27 present the contribution of these minimal cut sets to a partial system breakdown.

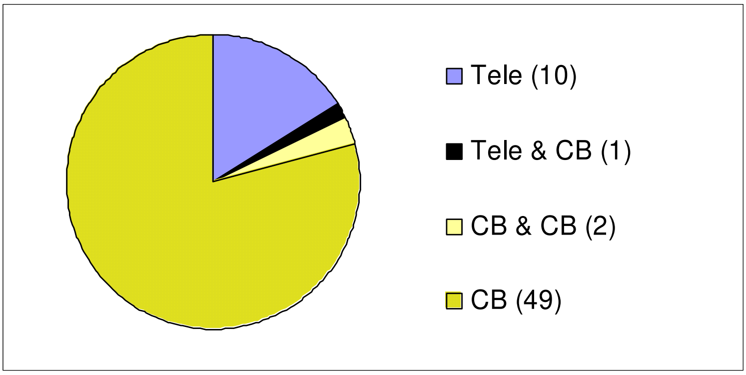


Figure 26 The components of the 62 most important minimal cut sets for a partial system breakdown

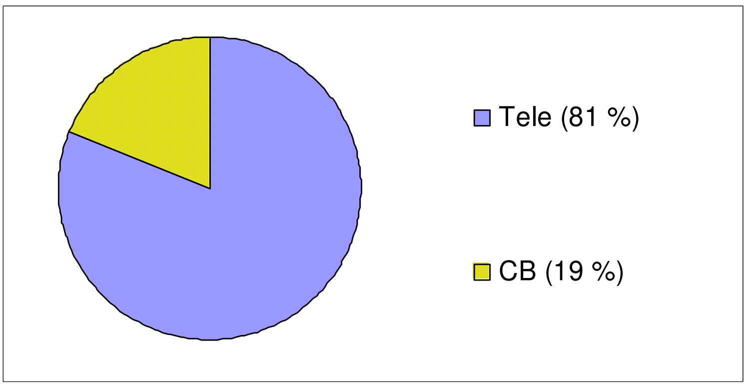


Figure 27 The frequency contributions of different types of the 62 most important minimal cut sets for a partial system breakdown

The most important minimal cut sets with one component have a telecommunication channel or a circuit breaker. The circuit breaker was often, but not always, an air-blast circuit breaker. Similarly, the telecommunication channel was often, but not always, a power line carrier. Naturally the components of these basic events were located near the generators or HVDC links.

Importance measures

Fussell-Vesely importance measures and RDF measures were identical to the list of minimal cut sets. The same circuit breakers and telecommunication channels that were ranked highest in the minimal cut set list were ranked high on the Fussell-Vesely and RDF lists, too. The reason is obvious: these components already have a high failure rate in the model. Figure 28 presents the 35 most important components according to the Fussell-Vesely and RDF ranking. Those 35 components have a FV measure value that is bigger than 0.001. The FV measure values of those four telecommunication channels that are ranked highest vary between 0.08 and 0.3.

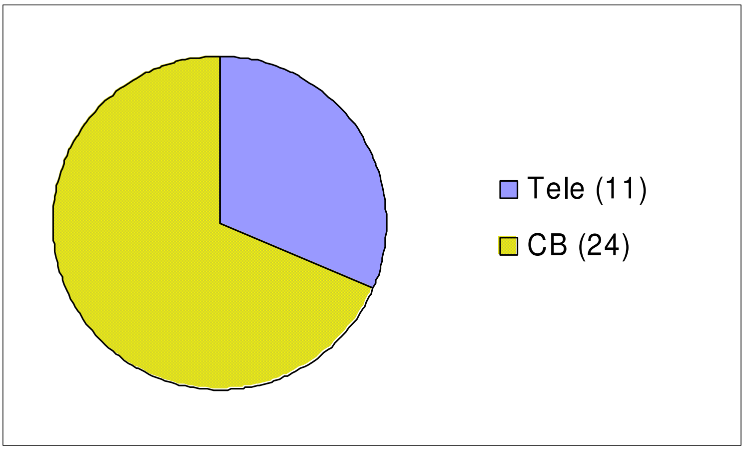


Figure 28 The 35 components that have the highest FV importance ranking

When ranking RIF measures, it was the circuit breakers, substations, line bays and miniature circuit breakers of the voltage transformers that were ranked high. Power line carrier telecommunication channels were not ranked very high in the RIF list.

10.2.1 Sensitivity of parameters

The ranking list of local parameter sensitivity shows that the power line carrier telecommunication constant unavailability has the highest sensitivity for the partial system breakdown. The circuit breaker test interval has the second largest sensitivity. Those parameters the sensitivity of which is larger than 1 are presented in Appendix F.

10.3 Comments and recommendations

The Fussell-Vesely importance is directly proportional to the unavailability of the component. Thus Fussell-Vesely importance measures can be used alone for identifying the potential components for safety improvement. Fussell-Vesely importance is comparable to the RDF measure. The RIF measure, on the other hand, is a weak function of the unavailability of the component and thus it sees the system from a different point of view. RIF does not represent the component itself but the defence of the rest of the installation against a failure of a component (Borst and Schoonakker, 2001).

Circuit breakers

The Fussell-Vesely grid-level importance measures show that the failure of a circuit breaker is in many fault locations the cause of a system breakdown. Many, but not all of these circuit breakers were air-blast circuit breakers. Some circuit breakers near big generators were ranked high in FV ranking lists, because the extended fault duration due to the stuck circuit breaker and the weakening of the grid after the breaker failure relay trip was enough to trip the generators and lead to system breakdown due to stability problems. Some circuit breaker failures near the generators caused partial system breakdowns. The parameter, the change of which most changed the system breakdown frequency, was in many fault locations the circuit breaker test interval. The test interval of the circuit breaker was also ranked high for the partial system breakdown.

Because the circuit breakers were often the main reason for grid problems, the circuit breaker test interval should not be lengthened. The test interval in this model was 1 year. This does not mean complete maintenance of the circuit breakers, but a check that the breaker trips after it has received a trip signal. Nowadays the relays are tested once a year and also the circuit breaker is checked during the test. If the relay test interval of the microprocessor relays is lengthened because of the self-supervision they have, the circuit breakers should still be checked once a year.

The air-blast circuit breakers should always be changed to SF6 circuit breakers when the substation is renovated. At the substations near the generators, the circuit breakers could be changed even without the substation renovation.

Some circuit breakers are ranked high in the Fussell-Vesely ranking for both system breakdown and partial system breakdown. Table 9 presents the ranking of those components.

Table 9 The ranking of the circuit breakers that have a high Fussell-Vesely ranking both for the system breakdown and the partial system breakdown. The substation identifications are not real due to confidentiality reasons.

Component	Ranking of FV and RDF measures for SB	Ranking of FV and RDF measures for PSB
25AC09 CB TRIP	8	5
26AC03 CB TRIP	9	38
25AC06 CB TRIP	13	15
20AC03 CB TRIP	22	24
22AC05 CB TRIP	25	30
18AC03 CB TRIP	34	8

Protection issues

The single components the failing of which most increases the risk of system breakdown are the miniature circuit breakers of the electromechanical distance relays. Always when the old relays are exchanged for new ones, both relays have their own miniature circuit breakers. Thus this safety problem will disappear in the future.

Because the power line carrier telecommunication channel fails almost always after 3-phase line faults and once in three 2-phase line faults, it would be good to duplicate the telecommunication at those lines where the power line carrier is the only telecommunication and at those that are located near generators. One power line carrier telecommunication channels had a high Fussell-Vesely ranking both for the system breakdown (ranking: 17) and for the partial system breakdown (ranking: 4).

The reach of the zone 3 of the distance relays is sufficient only on short lines. On many locations, it is not possible to lengthen the reach to all fault locations of the adjacent lines. It is worth noting that a lengthening of the reach can increase the risk of unwanted trips.

A good way to improve the reliability of duplicated protection systems would be to change the specifications in such a way that the main protection relays were obtained from different manufacturers. Then the common cause failure possibility due to the same software code in the duplicated relays would disappear.

High resistance earth faults

In Section 5.2.2, the line faults with a high resistance were described. Even though they are infrequent, they have caused unselective line trips. The selectivity of the protection for high resistance earth faults can be improved by changing the settings from definite time to inverse time. This requires that the old electromechanical earth fault relays are replaced with modern microprocessor relays, which have both definite time and inverse time settings. The old electromechanical relays have only a definite time setting. This will be realised as the remaining electromechanical relays are replaced with modern relays within the next few years. The number of high resistance faults can also be reduced with other measures, such as tree felling at regular intervals on the transmission line right-of-ways. This may not be the case with high current faults.

10.4 Other results

Slightly different conclusions can be drawn from the results of the substation reliability model alone, without a consideration of the power system impacts. The relays that cause the failures at the substation more often are the static distance relays compared to electromechanical or microprocessor relays. The same comparison between the circuit breakers gives the result that air-blast circuit breakers fail more often than minimum oil and SF6 circuit breakers. Here it is worth remembering that the blocking of SF6 circuit breakers due to low gas pressure is not used.

When the circuit breakers are ignored, and only the different protection systems for the line faults near the line ends are compared, different details can be seen. The impact of the telecommunication unavailability value and the duplication of the telecommunication channels can be compared. In this comparison, it is assumed that the line fault distribution along the line is uniform. The result of one comparison between three different protection systems is presented in Table 10. In this comparison the best solution is two distance relays with duplicated telecommunication channels. The second best solution is the one distance relay and one differential relay. The system with the lowest reliability is the protection system with the two distance relays that use a common telecommunication channels. The ranking of the three solutions remains the same with two different telecommunication unavailability values. The minimal cut set that covers 99 % of the unavailability of solution (3) in Table 10 has only one basic event: telecommunication channel. The details of the comparison are presented by Pottonen et al. (2004a, 2004b).

Table 10 Constant unavailability values for three different protection systems with two different unavailability values of the telecommunication channel. Z = distance relay, D = differential relay.

Unavailability q of the tele-communication channel	Unavailability of a protection system with two Z–relays and two tele-communication channels	Unavailability of a protection system with one D-relay and one Z-relay, two telecommunication channels	Unavailability of a protection system with two Z- relays and one tele-communication channel
q = 1.2E-02	q = 7.5E-05	q = 1.3E-04	q = 2.4E-03
q = 1.0E-03	q = 1.6E-05	q = 3.9E-05	q = 2.1E-04

In addition some qualitative results were achieved during the modelling process. The FMEA process gave an overview of the different ways of keeping the component-failure statistics. The failure statistics of the primary components, such as circuit breakers, were more detailed than the statistics of the secondary components, such as the relays. The relay failure databases had quite detailed descriptions of the relay failures, but lacked the information about component years. The number of component years had to be estimated from other sources. During the modelling, an incorrectly made duplication of the telecommunication channel was found and corrected. The telecommunication channels A and B were in the same optic cable at one substation.

10.5 Concluding remarks

The results received with the analysis of the transmission grid give an overview of the different series of events that lead to system problems. They also present the relative importance of different components as a reason for a system breakdown or a partial system breakdown.

Also the modelling process gave some valuable information about the grid that can be used in asset management.

11 DISCUSSION

The aim of the project was to create a modelling method for the transmission grid reliability. The model was made for line faults only, since they are the most common initiating events. There exist other initiating events, which might contribute more to power system breakdown frequency than line shunt faults. However, this study deals only with line shunt faults.

The other aim was to estimate the reliability of the Finnish 400 kV grid. The model was made for this grid and the estimates for partial and total system breakdown were calculated. Some importance measures and more and less likely contributing factors to system breakdown were also received. The fact that the model can be applied to a grid of real size, gives results at component level and ranks the component importance is a practical achievement. It is easier to create accurate and detailed models for reduced grids, but these models often have more academic than practical value.

The calculated estimates after line faults for partial and total system breakdown were one in 9 years and one in 730 years, respectively. When considering these figures one has to remember that this is only for failures of the substation operations after line shunt faults, not for all possible initiating events and substation operation failures. It is also important to remember the properties of a probabilistic approach. The probability indicates the degree of uncertainty and a result like ‘once in 9 years’ needs to be understood as a rational belief based on a certain case and certain assumptions instead of a scientific fact that can be proved. This probability model connects the evidence of the component reliability to the transmission system breakdown probability in a rational way.

The model gives information about the upper-level (the transmission grid) reliability by using the reliability of the lower-level components. There is no data available on the system breakdown but there is a lot about the failures of different components. The grid-level failure is a function of the structural function of the system and the reliability of the system components. The important results derived from this approach are failure sequences that contribute to the system breakdown, the importance values and ranking of different components and the indicators for the system breakdown. Thus the real result is the knowledge of the system characteristics, not the exact numerical values.

Methodology

The scientific contribution of the model is the evaluation of the applicability of the probabilistic safety assessment for power system security estimation. The power system is a highly non-linear system, in which similar failure sequences in different locations and at different grid loading levels can lead to different system states. Thus the dynamic simulations of the substation failures are an essential part of this study. When combining the PSA-type of approach for substation post-fault events with grid simulations one can get the importance measures for different power system post-fault states. In this model, the substation component importance measures are calculated for total and partial system breakdown of the whole grid.

When the reliability of the meshed grid is under discussion, it is the system state that is more important than the unavailability of a single substation component, a bay or a line. This is due to the fact that, according to the n-1 criterion, the transmission system can at any time lose a component without any problems to the consumers. In this respect, the study differs from the previous studies, where either the power system security is studied without a detailed substation model or the substation is studied without considering the effects of substation operation failures on the power system. It also differs from the security study of Miki (1999), which had a limited substation model where the protection, but not the circuit breakers, was included. The results of this study show that the circuit breaker operation failures are one of the important reasons that lead to system breakdowns.

The FMEA analysis of the substation components was made. The FMEA made in this study was both qualitative and quantitative. It is a necessary part of a reliability analysis and also a good way to document device-failure statistics and expert judgements. Here the FMEA was conducted by using the specific data of the Finnish 400 kV transmission grid. Thus the failure data are suitable for the case analysed. Different transmission system operators may have different maintenance policies, different substation structures and also equipment from different manufacturers. Also the ages of the line and substation equipment can be different at different transmission grids. It is therefore better to use the specific FMEA data instead of general data.

In some cases, the component failure statistics are not available and therefore the quantitative modelling seems to be impossible. That is not necessarily the case, however. It is possible to use the data received with expert judgments and get information of structural properties of the system from diagrams and pictures. In this way, one can also find important failure combinations. There also exist methods for estimating the structural importance of the components. These methods do not need any failure data. Some measures are presented by Myötyri (2003).

This analysis method enables risk-informed grid asset management, since it gives the connection between the system breakdown risk and a single component at the substation. It brings the quantitative element into reliability analysis and helps to rank the substation components at different substations.

Practical aspects

The model is detailed enough to give information about the impact of different substation components to grid security. The model can be built by using different reliability and power system dynamic software.

The correctness of the results received depends on the structure of the model, i.e., how well it represents the reality. It also depends on the quality of the fault and failure statistics available. If the component failure statistics are made for purposes other than reliability analysis, they need to be interpreted. In this research, the failure statistics were made mostly for maintenance purposes. It was therefore necessary to read every failure report and conclude from them whether the failure reported is a failure in this model. For example, if a circuit breaker has a 'major failure' it can be a major failure as far as the maintenance engineers are concerned, but it does not necessarily prevent the circuit breaker trip. On the other hand, if a trip coil of a circuit breaker is disconnected, it is not necessarily reported at all in the circuit breaker failure database, but it definitely prevents the circuit breaker trip.

Despite the uncertainties of the model and the component failure data, the method proposed can suggest ways of improving the maintenance and the transmission grid. It also can be used during the planning stage of a new substation. Different busbar schemes and protection systems can be compared from the reliability point of view. As the method lists the relative importance of substation components and helps to identify the weaknesses of the system, it can help those concerned to focus the maintenance operations and thus it can bring risk-informed thinking into the asset management of the power system. The method makes it possible to identify beneficial changes that do not deteriorate the system reliability.

The drawback of the model proposed is that building the reliability model for substations, and also the use of it for different load flow cases, requires a lot of work and therefore is expensive. But after the model has been built, the information received with it can be beneficial. Also creating the model gives rise to knowledge of the system, so the model is not a black-box model. One needs to understand the details of the model in order to interpret the results correctly. In this respect, the model is not different from other power system simulation software.

Other issues

The model was made for 2-phase short circuits. To some extent the results are also valid for 3- and 1-phase line shunt faults. The event tree model is similar for 1-, 2- and 3-phase faults in all other aspects, but the power line carrier telecommunication unavailability changes drastically with the phases involved in the fault. This is due to the fact the PLC system is installed on 2 phases and the carrier signal most probably fails to travel on the faulted line.

The power system simulation results are made for 3-phase faults. The results are valid also for 2-phase faults, since the fault currents are about the same magnitude. All the cases that were stable for 3-phase faults would be stable also during 2- and 1-phase faults. But if the transient stability is lost during a 3-phase fault, it might not always be the case with 1-phase faults. Therefore, a few faults that were unstable with 3-phase faults were simulated with 1-phase faults in order to compare the difference in the power system state due to the fault type. The fault locations were near big generators. The transient stability was lost in most simulations in a way similar to that with 3-phase faults. One can conclude that, even though the model and the results are tuned for 2-phase faults, they are to some extent valid also for other line shunt faults.

When evaluating the system breakdown and partial system breakdown results, one has to remember that this dynamic simulation model did not include all the possible causes for a generator trip, which in many cases is the main contributing factor of a system breakdown. The model trips a generator if it loses the synchronous operation. In reality, a generator can trip due to low voltages even though it is dynamically stable. This means that it may be possible that some generators may trip during a near-by short circuit even though they are dynamically stable. Power stations are complicated systems and modelling of all possible causes for a trip is simply not possible. Tripping of a single contactor can sometimes be enough for a generator trip.

Future work

A substation reliability model for busbar faults should also be made. The busbar faults are less frequent, but they are more severe. The model for ordinary busbar shunt faults can be created in a way similar to that in which the substation model for line shunt faults was made. A slightly different approach is suitable for explosions of current transformers, since the consequences of the current transformer explosions are partly unforeseeable and partly dependent on the busbar scheme and the location of the current transformer. The initiating event frequency for substation faults depends more on the devices at the substation and so the initiating event analysis should take into account the number of devices, not only the faults that have occurred.

The method can be used for analysing how often the power system ends up in different states (secure, alert, emergency, major disturbance) during a year. This requires that different load flows are simulated and the duration of them is estimated. A comprehensive analysis requires that the different ambient temperatures and different initiating event frequencies are taken into account in different load flow analysis cases. There are more line shunt faults due to lightning strokes in the summer than in the winter.

The model proposed here is too complicated for multiple faults. A simpler method would be more applicable for analysing different combinations of several faults.

By analysing different power system operating conditions, it might be possible to define a quantitative value for the acceptable risk level for normal and exceptional operating conditions.

One way to use the model would be to estimate how often the grid ends up in different power system states during a certain moment with given load flow, grid connection, initiating event frequency and weather forecast (the probability of lightning, ambient temperature). This analysis can be useful during the planning stage of line or busbar outage, for example. The risk of power system breakdown at different load flows can be compared.

Based on the statistics, an analysis of the high resistance earth faults and their effect on the reliability of the power system would be needed. Even though the fault current during these faults is smaller than in other line shunt faults, the possible unselective line trips can weaken the grid significantly and cause stability and thermal problems. However, the sensitive earth fault relays will, within the next few years, be changed into inverse time relays, thus improving the selectivity of the protection. Because the selectivity will be improved in the near future, there is no need to analyse these faults with the existing protection system; however, an analysis would be useful after the changes are made.

This study includes basically exceptional fault durations of 250 ms, 450 ms, 600 ms and 1000 ms. The effect of these fault durations combined with a possible weakening of the grid during a load flow case where Finland exports power to Sweden would certainly be worth researching. In this case, it is the damping of electromechanical oscillations that are critical. Also, the new nuclear power station of 1600 MW will change the grid; the effect this will have needs to be researched.

12 CONCLUDING REMARKS

This study deals with transmission system reliability. More precisely, it proposes a reliability model for a power system in which the reliability of substation operations after line shunt faults and the impact of possible failures of the operations on the power system dynamics are both taken into account. The reliability evaluation was made for a real 400 kV transmission grid with one grid connection and load flow case.

The main contribution of the study is a probabilistic method for transmission grid security analysis after line shunt faults. This method enables the estimation of the probability of the system breakdown and other power system states. The method developed for substation post-fault operations uses event and fault trees and therefore inherently gives rise to the possibility of calculating different importance measures for substation components and for parameters of the model. Importance measures can be used as tools for evaluating the importance of different grid components in several ways. With these importance measures, the more and less effective ways for improving grid security can be found.

The method proposed is applicable to real transmission grids. Every line and every substation bay with the line protection primary and secondary components are included in the model. The basic functions in the substation operations after line faults are modelled, yet some simplifications and assumptions were made. The predefinitions and assumptions of the model were made bearing in mind the applicability of the method for the grids of real size. Fundamental to the modelling process was the fact that the basic phenomena and reliability problems were of interest, rather than every (local) detail.

The method developed here takes into account the effect of the following issues in the matter of security:

- Frequency of line faults
- Fault location at the line
- Different substation structures
- Failure rates of the substation components
- Dynamic behaviour of the power system after different contingencies
- Reach of the remote back-up distance protection

The mechanisms that lead to power system breakdown are different at different parts of the grid. This is why quantitative analysis is required in order to correctly estimate the contribution of different fault locations and different grid components to the system breakdown.

The method developed was applied to the Finnish transmission system and some quantitative estimates for the grid reliability were received. Several importance measures for substation components and model parameters, as well as estimates of the total and partial system breakdown frequency due to failures at the substation after line shunt faults, were calculated. The factors contributing to partial and total system breakdown were found. Based on the results, some recommendations for improving the reliability were made.

When a transmission system operator has a tool that can really estimate quantitatively the reliability of the grid after grid faults, it can be used for several different purposes. It is possible, for example, to calculate the probability of a system breakdown during a planned outage with different grid connections and with different grid loadings and then decide the connection and maximum grid loading for that outage. It is possible to compare different substation structures when planning a new substation. In addition, different reliability indices can be calculated for a certain period. The aim was to get a practical, rather than a purely theoretical, model and it succeeded. In this way, this study differs from many other studies where a method is developed but is used only for a reduced grid model.

For society, the probabilistic approach of grid planning and operation can produce benefits, since it enables a more efficient utilization of the grid without reducing the reliability.

This study is a reliability analysis of a transmission grid in which some system issues were predefined, after which the system was analysed. In this way, an understanding of the system security after line faults was gained. One has to bear in mind that this research does not give a comprehensive view of all possible transmission system risks, because not all initiating events are modelled. Nevertheless, the method used in this research can also be used for risk, as well as reliability, analysis.

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APPENDIX A – EVENT TREES FOR SUBSTATION MODEL

Event trees for lines with a double circuit breaker busbar scheme at both ends of the line

Event tree 1 is for faults in the middle of the line. The fault tree is presented in Figure 1 and the corresponding substation consequences are presented in Table 1.

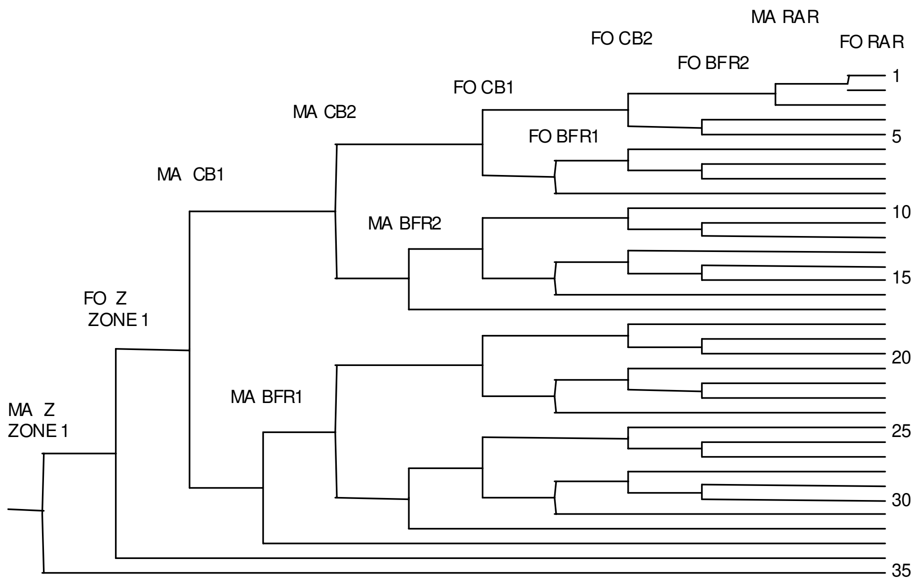

Figure 1 Event tree 1 (ET 1) for a line with a double circuit breaker busbar scheme at both line ends. The fault location is in the middle of the line. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay.

Table 1 The substation consequences of event tree 1

	The identification number and description of the substation consequence of the end branch
1	1-00 Master and follower: line trip, automatic reclosing
2	1-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails
3	1-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails
4	1-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	1-24 Follower: no trip signal or no CB trip at the substation

6	1-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
7	1-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms
8	1-24 Follower: no trip signal or no CB trip at the substation
9	1-24 Follower: no trip signal or no CB trip at the substation
10	1-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
11	1-12 One busbar tripped at both substations by BFR after 250 ms
12	1-24 Follower: no trip signal or no CB trip at the substation
13	1-12 One busbar tripped at both substations by BFR after 250 ms
14	1-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	1-24 Follower: no trip signal or no CB trip at the substation
16	1-24 Follower: no trip signal or no CB trip at the substation
17	1-23 Master: no trip signal or no CB trip at the substation
18	1-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
19	1-12 One busbar tripped at both substations by BFR after 250 ms
20	1-24 Follower: no trip signal or no CB trip at the substation
21	1-12 One busbar tripped at both substations by BFR after 250 ms
22	1-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
23	1-24 Follower: no trip signal or no CB trip at the substation
24	1-24 Follower: no trip signal or no CB trip at the substation
25	1-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms.
26	1-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
27	1-24 Follower: no trip signal or no CB trip at the substation
28	1-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
29	1-59 Both substations tripped by BFR after 250 ms
30	1-24 Follower: no trip signal or no CB trip at the substation
31	1-24 Follower: no trip signal or no CB trip at the substation
32	1-23 Master: no trip signal or no CB trip at the substation
33	1-23 Master: no trip signal or no CB trip at the substation
34	1-24 Follower: no trip signal or no CB trip at the substation
35	1-23 Master: no trip signal or no CB trip at the substation

Event tree 2 is for faults near the master line end. The fault tree is presented in Figure 2 and the corresponding substation consequences are presented in Table 2.

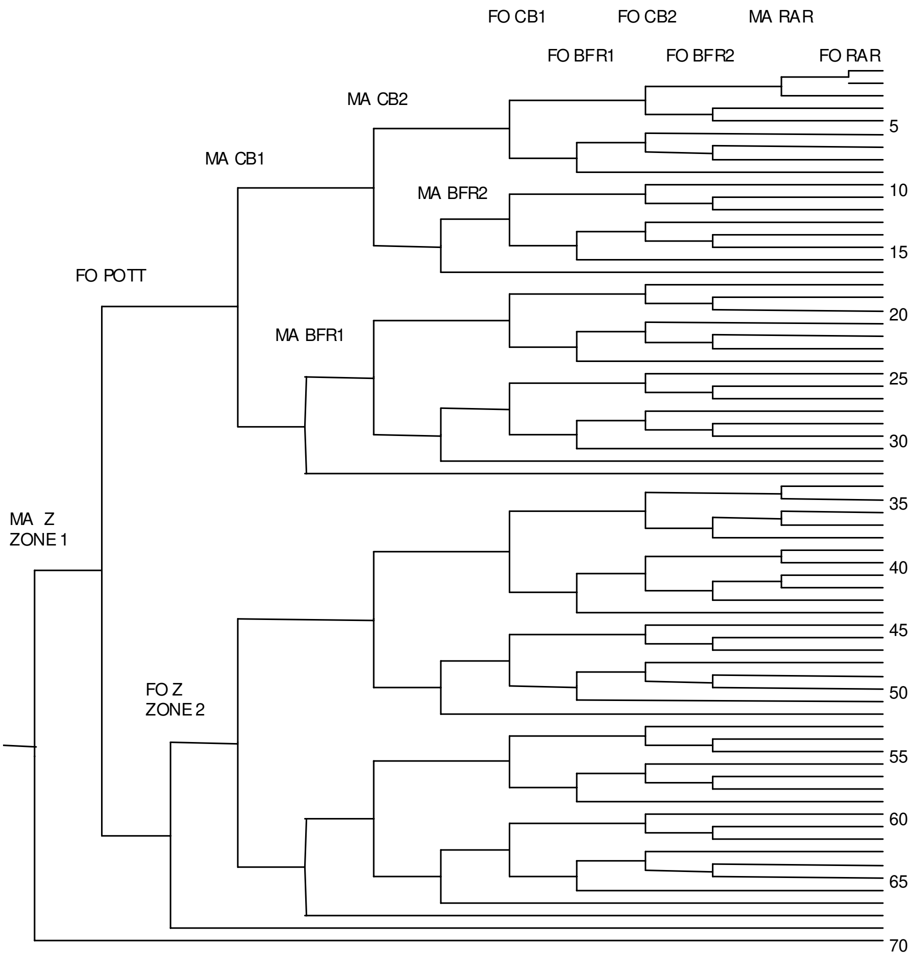

Figure 2 Event tree 2 (ET 2) for a line with a double circuit breaker busbar scheme at both line ends. The fault location is near the master line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 2 The substation consequences of event tree 2

	The identification number and description of the substation consequence of the end branch
1	2-00 Master and follower: line trip, automatic reclosing.
2	2-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	2-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	2-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	2-24 Follower: no trip signal or no CB trip at the substation
6	2-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
7	2-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms

8	2-24 Follower: no trip signal or no CB trip at the substation
9	2-24 Follower: no trip signal or no CB trip at the substation
10	2-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
11	2-12 One busbar tripped at both substations by BFR after 250 ms
12	2-24 Follower: no trip signal or no CB trip at the substation
13	2-12 One busbar tripped at both substations by BFR after 250 ms
14	2-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	2-24 Follower: no trip signal or no CB trip at the substation
16	2-24 Follower: no trip signal or no CB trip at the substation
17	2-23 Master: no trip signal or no CB trip at the substation
18	2-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
19	2-12 One busbar tripped at both substations by BFR after 250 ms
20	2-24 Follower: no trip signal or no CB trip at the substation
21	2-12 One busbar tripped at both substations by BFR after 250 ms
22	2-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
23	2-24 Follower: no trip signal or no CB trip at the substation
24	2-24 Follower: no trip signal or no CB trip at the substation
25	2-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms.
26	2-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
27	2-24 Follower: no trip signal or no CB trip at the substation
28	2-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
29	2-59 Both substations tripped by BFR after 250 ms
30	2-24 Follower: no trip signal or no CB trip at the substation
31	2-24 Follower: no trip signal or no CB trip at the substation
32	2-23 Master: no trip signal or no CB trip at the substation
33	2-23 Master: no trip signal or no CB trip at the substation
34	2-04 Master: line trip 100 ms, RAR 500 ms, line trip 550 ms. Follower: line trip 450 ms.
35	2-05 Master: line trip 100 ms, RAR fails. Follower: line trip 450 ms.
36	2-15 Master: line trip 100 ms, RAR 500 ms, line trip 600 ms. Follower: one busbar trips, BFR 600 ms.
37	2-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips, BFR 600 ms.
38	2-24 Follower: no trip signal or no CB trip at the substation
39	2-15 Master: line trip 100 ms, RAR 500 ms, line trip 600 ms. Follower: one busbar trips, BFR 600 ms
40	2-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips, BFR 600 ms.
41	2-43 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: two busbars trip, BFR 600 ms.
42	2-44 Master: line trip 100 ms. Follower: two busbars trip, BFR 600 ms.
43	2-24 Follower: no trip signal or no CB trip at the substation
44	2-24 Follower: no trip signal or no CB trip at the substation
45	2-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms
46	2-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
47	2-24 Follower: no trip signal or no CB trip at the substation

48	2-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
49	2-48 Master: one busbar trips, BFR 250 ms. Master: two busbars trip, BFR 600 ms.
50	2-24 Follower: no trip signal or no CB trip at the substation
51	2-24 Follower: no trip signal or no CB trip at the substation
52	2-23 Master: no trip signal or no CB trip at the substation
53	2-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms.
54	2-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
55	2-24 Follower: no trip signal or no CB trip at the substation
56	2-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
57	2-48 Master: one busbar trips, BFR 250 ms. Master: two busbars trip, BFR 600 ms.
58	2-24 Follower: no trip signal or no CB trip at the substation
59	2-24 Follower: no trip signal or no CB trip at the substation
60	2-34 Master: two busbars trip, BFR 250 ms. Follower: line trip 450 ms
61	2-46 Master: two busbars trip, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
62	2-24 Follower: no trip signal or no CB trip at the substation
63	2-46 Master: two busbars trip, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
64	2-60 Master: two busbars trip, BFR 250 ms. Follower: two busbars trip, BFR 600 ms.
65	2-24 Follower: no trip signal or no CB trip at the substation
66	2-24 Follower: no trip signal or no CB trip at the substation
67	2-23 Master: no trip signal or no CB trip at the substation
68	2-23 Master: no trip signal or no CB trip at the substation
69	2-24 Follower: no trip signal or no CB trip at the substation
70	2-23 Master: no trip signal or no CB trip at the substation

Event tree 3 is for faults near the follower line end. This fault tree is presented in Figure 3 and the corresponding substation consequences are presented in Table 3.

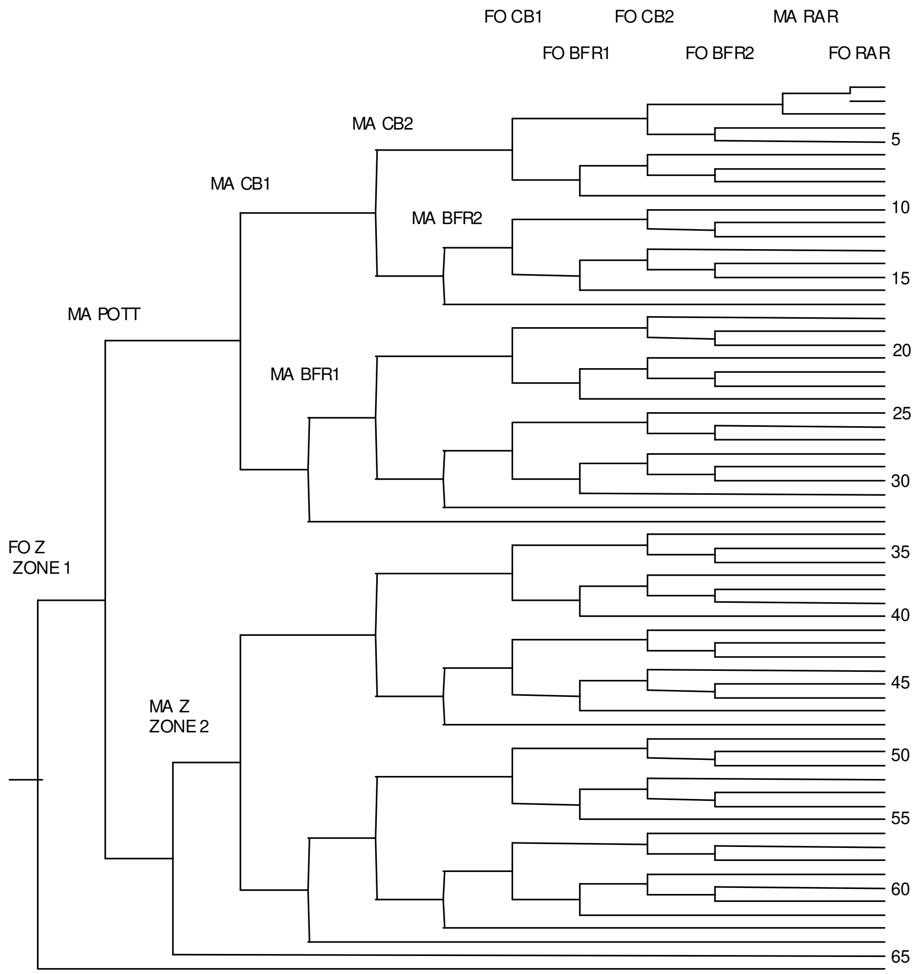

Figure 3 Event tree 3 (ET 3) for a line with a double circuit breaker busbar scheme at both line ends. The fault location is near the follower line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 3 The substation consequences of event tree 3

	The identification number and description of the substation consequence of the end branch
1	3-00 Master and follower: line trip, automatic reclosing.
2	3-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	3-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	3-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	3-24 Follower: no trip signal or no CB trip at the substation
6	3-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.

7	3-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms
8	3-24 Follower: no trip signal or no CB trip at the substation
9	3-24 Follower: no trip signal or no CB trip at the substation
10	3-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
11	3-12 One busbar tripped at both substations by BFR after 250 ms
12	3-24 Follower: no trip signal or no CB trip at the substation
13	3-12 One busbar tripped at both substations by BFR after 250 ms
14	3-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	3-24 Follower: no trip signal or no CB trip at the substation
16	3-24 Follower: no trip signal or no CB trip at the substation
17	3-23 Master: no trip signal or no CB trip at the substation
18	2-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
19	3-12 One busbar tripped at both substations by BFR after 250 ms
20	3-24 Follower: no trip signal or no CB trip at the substation
21	3-12 One busbar tripped at both substations by BFR after 250 ms
22	3-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
23	3-24 Follower: no trip signal or no CB trip at the substation
24	3-24 Follower: no trip signal or no CB trip at the substation
25	3-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms.
26	3-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
27	3-24 Follower: no trip signal or no CB trip at the substation
28	3-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
29	3-59 Both substations tripped by BFR after 250 ms
30	3-24 Follower: no trip signal or no CB trip at the substation
31	3-24 Follower: no trip signal or no CB trip at the substation
32	3-23 Master: no trip signal or no CB trip at the substation
33	3-23 Master: no trip signal or no CB trip at the substation
34	3-06 Master: line trip 450 ms. Follower: line trip 100 ms.
35	3-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
36	3-24 Follower: no trip signal or no CB trip at the substation
37	3-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
38	3-35 Master: line trip 450 ms. Follower: two busbars trip, BFR 250 ms.
39	3-24 Follower: no trip signal or no CB trip at the substation
40	3-24 Follower: no trip signal or no CB trip at the substation
41	3-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
42	3-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
43	3-24 Follower: no trip signal or no CB trip at the substation
44	3-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
45	3-37 Master: one busbar trips, BFR 600 ms. Follower: two busbars trip, BFR 250 ms.
46	3-24 Follower: no trip signal or no CB trip at the substation
47	3-24 Follower: no trip signal or no CB trip at the substation
48	3-23 Master: no trip signal or no CB trip at the substation
49	3-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
50	3-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.

51	3-24 Follower: no trip signal or no CB trip at the substation
52	3-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
53	3-37 Master: one busbar trips, BFR 600 ms. Follower: two busbars trip, BFR 250 ms.
54	3-24 Follower: no trip signal or no CB trip at the substation
55	3-24 Follower: no trip signal or no CB trip at the substation
56	3-45 Master: two busbars trip, BFR 600 ms. Follower: line trip 100 ms.
57	3-39 Master: two busbars trip, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
58	3-24 Follower: no trip signal or no CB trip at the substation
59	3-39 Master: two busbars trip, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
60	3-61 Master: two busbars trip, BFR 600 ms. Follower: two busbars trip, BFR 250 ms.
61	3-24 Follower: no trip signal or no CB trip at the substation
62	3-24 Follower: no trip signal or no CB trip at the substation
63	3-23 Master: no trip signal or no CB trip at the substation
64	3-23 Master: no trip signal or no CB trip at the substation
65	3-23 Master: no trip signal or no CB trip at the substation
66	3-24 Follower: no trip signal or no CB trip at the substation

Event trees for lines with a double circuit breaker busbar scheme at the master line end and a single circuit breaker busbar scheme at the follower line end

Event tree 4a is for faults in the middle of the line. The fault tree is presented in Figure 4 and the corresponding substation consequences are presented in Table 4.

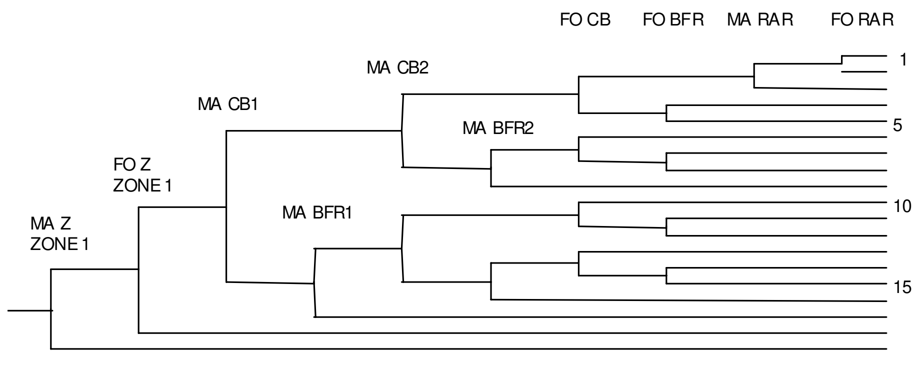

Figure 4 Event tree 4a (ET 4a) for a line with a double circuit breaker busbar scheme at the master line end and a single busbar scheme at the follower line end. The fault location is in the middle of the line. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay

Table 4 The substation consequences of event tree 4a

	The identification number and description of the substation consequence of the end branch
1	4a-00 Master and Follower: line trip, automatic reclosing.
2	4a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	4a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	4a-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	4a-24 Follower: no trip signal or no CB trip at the substation
6	4a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
7	4a-12 One busbar tripped at both substations by BFR after 250 ms.
8	4a-24 Follower: no trip signal or no CB trip at the substation
9	4a-23 Master: no trip signal or no CB trip at the substation
10	4a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
11	4a-12 One busbar tripped at both substations by BFR after 250 ms.
12	4a-24 Follower: no trip signal or no CB trip at the substation
13	4a-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms
14	4a-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms).
15	4a-24 Follower: no trip signal or no CB trip at the substation
16	4a-23 Master: no trip signal or no CB trip at the substation
17	4a-23 Master: no trip signal or no CB trip at the substation
18	4a-24 Follower: no trip signal or no CB trip at the substation
19	4a-23 Master: no trip signal or no CB trip at the substation

Event tree 5a is for faults near the master line end. This fault tree is presented in Figure 5 and the corresponding substation consequences are presented in Table 5.

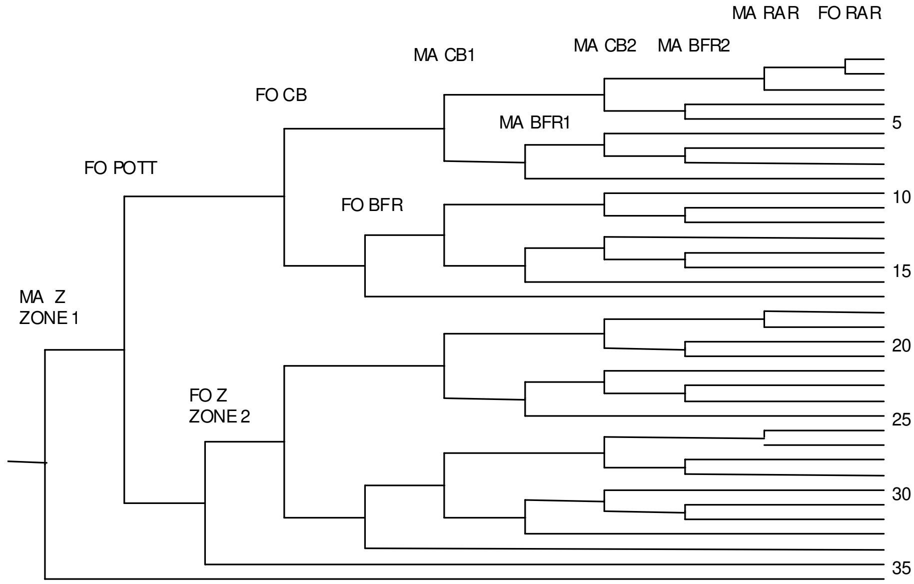

Figure 5 Event tree 5a (ET 5a) for a line with a double circuit breaker busbar scheme at the master line end and a single busbar scheme at the follower line end. The fault location is near the master line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 5 The substation consequences of event tree 5a

	The identification number and description of the substation consequence of the end branch
1	5a-00 Master and Follower: line trip, automatic reclosing.
2	5a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	5a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	5a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
5	5a-23 Master: no trip signal or no CB trip at the substation
6	5a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
7	5a-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms.
8	5a-23 Master: no trip signal or no CB trip at the substation
9	5a-23 Master: no trip signal or no CB trip at the substation
10	5a-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
11	5a-12 One busbar tripped at both substations by BFR after 250 ms
12	5a-23 Master: no trip signal or no CB trip at the substation
13	5a-12 One busbar tripped at both substations by BFR after 250 ms
14	5a-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms)
15	5a-23 Master: no trip signal or no CB trip at the substation
16	5a-23 Master: no trip signal or no CB trip at the substation
17	5a-24 Follower: no trip signal or no CB trip at the substation

18	5a-04 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: line trip 450 ms.
19	5a-05 Master: line trip 100 ms, RAR fails. Follower: line trip 450 ms.
20	5a-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms.
21	5a-23 Master: no trip signal or no CB trip at the substation
22	5a-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms.
23	5a-35 Follower: two busbars trip, BFR 250 ms. Master: line trip 450 ms.
24	5a-23 Master: no trip signal or no CB trip at the substation
25	5a-23 Master: no trip signal or no CB trip at the substation
26	5a-15 Master: line trip 100 ms, RAR 500 ms, line trip 600 ms. Follower: one busbar trips, BFR 600 ms.
27	5a-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips, BFR 600 ms.
28	5a-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
29	5a-23 Master: no trip signal or no CB trip at the substation
30	5a-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
31	5a-46 Master: two busbars trip, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
32	5a-23 Master: no trip signal or no CB trip at the substation
33	5a-23 Master: no trip signal or no CB trip at the substation
34	5a-24 Follower: no trip signal or no CB trip at the substation
35	5a-24 Follower: no trip signal or no CB trip at the substation
36	5a-23 Master: no trip signal or no CB trip at the substation

Event tree 6a is for faults near the follower line end. This fault tree is presented in Figure 6 and the corresponding substation consequences are presented in Table 6.

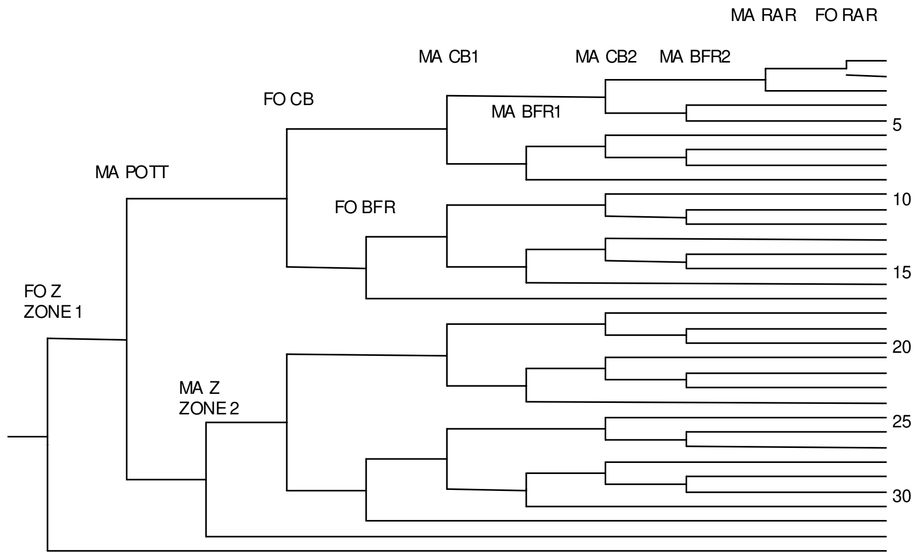

Figure 6 Event tree 6a (ET 6a) for a line with a double circuit breaker busbar scheme at the master line end and a single busbar scheme at the follower line end. The fault location is near the follower line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 6 The substation consequences of event tree 6a

	The identification number and description of the substation consequence of the end branch
1	6a-00 Master and Follower: line trip, automatic reclosing.
2	6a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	6a-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	6a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
5	6a-23 Master: no trip signal or no CB trip at the substation
6	6a-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
7	6a-13 Master: two busbars trip, BFR 250 ms. Follower: line trip 100 ms.
8	6a-23 Master: no trip signal or no CB trip at the substation
9	6a-23 Master: no trip signal or no CB trip at the substation
10	6a-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
11	6a-12 One busbar tripped at both substations by BFR after 250 ms
12	6a-23 Master: no trip signal or no CB trip at the substation
13	6a-12 One busbar tripped at both substations by BFR after 250 ms
14	6a-33 Master: two busbars trip, follower: one busbar trips (BFR 250 ms).
15	6a-23 Master: no trip signal or no CB trip at the substation
16	6a-23 Master: no trip signal or no CB trip at the substation
17	6a-24 Follower: no trip signal or no CB trip at the substation
18	6a-06 Master: line trip 450 ms. Follower: line trip 100 ms.

19	6a-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
20	6a-23 Master: no trip signal or no CB trip at the substation
21	6a-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
22	6a-45 Master: two busbars trip, BFR 600 ms. Follower: line trip 100 ms
23	6a-23 Master: no trip signal or no CB trip at the substation
24	6a-23 Master: no trip signal or no CB trip at the substation
25	6a-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
26	6a-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
27	6a-23 Master: no trip signal or no CB trip at the substation
28	6a-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
29	6a-39 Master: two busbars trip, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
30	6a-23 Master: no trip signal or no CB trip at the substation
31	6a-23 Master: no trip signal or no CB trip at the substation
32	6a-24 Follower: no trip signal or no CB trip at the substation
33	6a-23 Master: no trip signal or no CB trip at the substation
34	6a-24 Follower: no trip signal or no CB trip at the substation

Event trees for lines with a single circuit breaker busbar scheme at the master line end and a double circuit breaker busbar scheme at the follower line end

Event tree 4b is for faults in the middle of the line. This fault tree is presented in Figure 7 and the corresponding substation consequences are presented in Table 7.

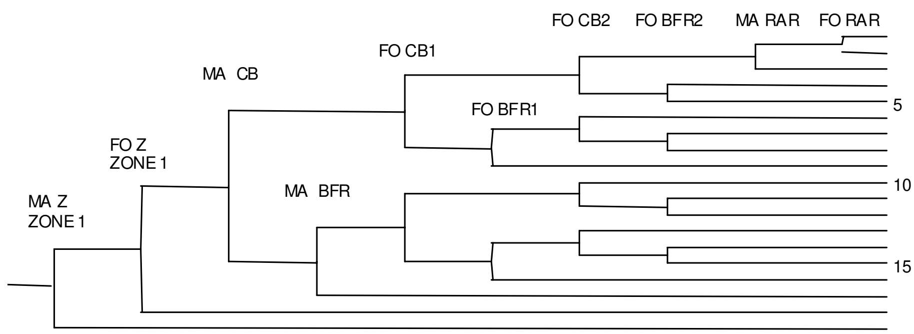

Figure 7 Event tree 4b (ET 4b) for a line with a single circuit breaker busbar scheme at the master line end and a double circuit breaker busbar scheme at the follower line end. The fault location is in the middle of the line. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay.

Table 7 The substation consequences of event tree 4b

	The identification number and description of the substation consequence of the end branch
1	4b-00 Master and Follower: line trip, automatic reclosing.
2	4b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	4b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	4b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	4b-24 Follower: no trip signal or no CB trip at the substation
6	4b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
7	4b-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms.
8	4b-24 Follower: no trip signal or no CB trip at the substation
9	4b-24 Follower: no trip signal or no CB trip at the substation
10	4b-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
11	4b-12 One busbar tripped at both substations by BFR after 250 ms
12	4b-24 Follower: no trip signal or no CB trip at the substation
13	4b-12 One busbar tripped at both substations by BFR after 250 ms
14	4b-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	4b-24 Follower: no trip signal or no CB trip at the substation
16	4b-24 Follower: no trip signal or no CB trip at the substation
17	4b-23 Master: no trip signal or no CB trip at the substation
18	4b-24 Follower: no trip signal or no CB trip at the substation
19	4b-23 Master: no trip signal or no CB trip at the substation

Event tree 5b is for faults near the master line end. The fault tree is presented in Figure 8 and the corresponding substation consequences are presented in Table 8.

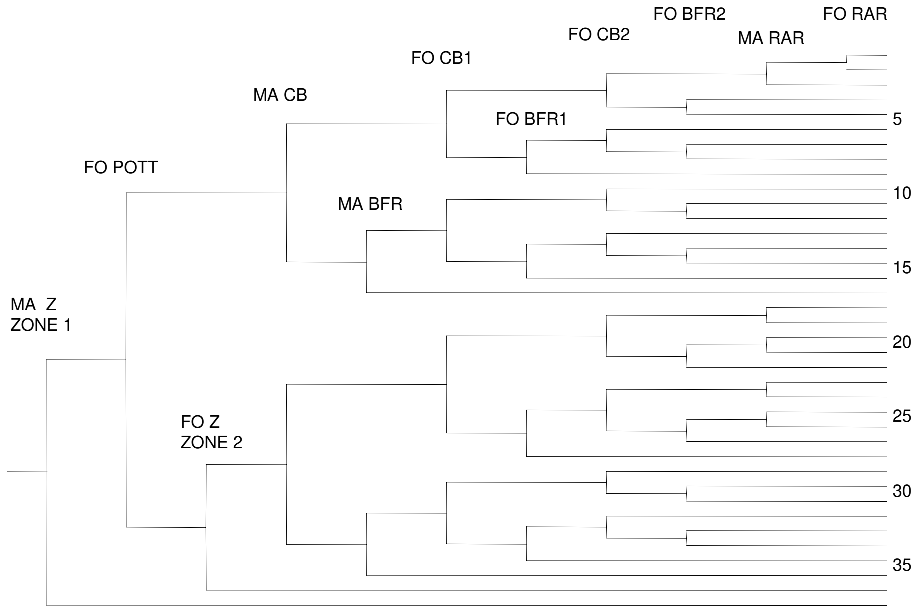

Figure 8 Event tree 5b (ET 5b) for a line with a single circuit breaker busbar scheme at the master line end and a double circuit breaker busbar scheme at the follower line end. The fault location is near the master line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 8 The substation consequences of event tree 2

	The identification number and description of the substation consequence of the end branch
1	5b-00 Master and Follower: line trip, automatic reclosing.
2	5b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	5b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	5b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	5b-24 Follower: no trip signal or no CB trip at the substation
6	5b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
7	5b-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms.
8	5b-24 Follower: no trip signal or no CB trip at the substation
9	5b-24 Follower: no trip signal or no CB trip at the substation
10	5b-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
11	5b-12 One busbar tripped at both substations by BFR after 250 ms
12	5b-24 Follower: no trip signal or no CB trip at the substation
13	5b-12 One busbar tripped at both substations by BFR after 250 ms
14	5b-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	5b-24 Follower: no trip signal or no CB trip at the substation
16	5b-24 Follower: no trip signal or no CB trip at the substation

17	5b-23 Master: no trip signal or no CB trip at the substation
18	5b-04 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: line trip 450 ms.
19	5b-05 Master: line trip 100 ms, RAR fails. Follower: line trip 450 ms.
20	5b-15 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: one busbar trips (BFR 600 ms).
21	5b-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips, BFR 600 ms.
22	5b-24 Follower: no trip signal or no CB trip at the substation
23	5b-15 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: one busbar trips (BFR 600 ms).
24	5b-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips, BFR 600 ms.
25	5b-43 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: two busbars trip, BFR 600 ms.
26	5b-44 Master: line trip 100 ms. Follower: two busbars trip, BFR 600 ms.
27	5b-24 Follower: no trip signal or no CB trip at the substation
28	5b-24 Follower: no trip signal or no CB trip at the substation
29	5b-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms.
30	5b-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
31	5b-24 Follower: no trip signal or no CB trip at the substation
32	5b-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
33	5b-48 Master: one busbar trips, BFR 250 ms. Master: two busbars trip, BFR 600 ms.
34	5b-24 Follower: no trip signal or no CB trip at the substation
35	5b-24 Follower: no trip signal or no CB trip at the substation
36	5b-23 Master: no trip signal or no CB trip at the substation
37	5b-24 Follower: no trip signal or no CB trip at the substation
38	5b-23 Master: no trip signal or no CB trip at the substation

Event tree 6b is for faults near the follower line end. This fault tree is presented in Figure 9 and the corresponding substation consequences are presented in Table 9.

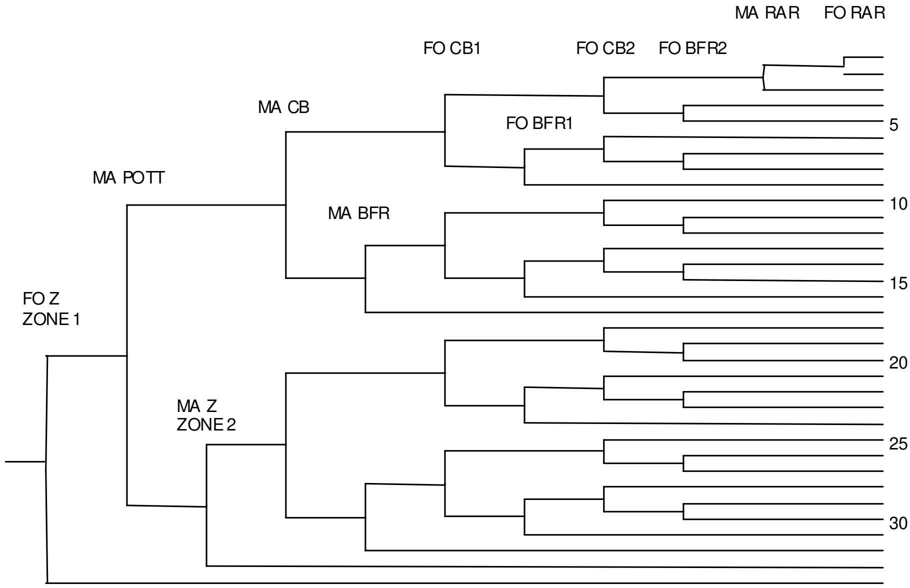

Figure 9 Event tree 6b (ET 6b) for a line a single circuit breaker busbar scheme at the master line end and a double circuit breaker busbar scheme at the follower line end. The fault location is near the follower line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 9 The substation consequences of event tree 6b

	The identification number and description of the substation consequence of the end branch
1	6b-00 Master and follower: line trip, automatic reclosing.
2	6b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	6b-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	6b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	6b-24 Follower: no trip signal or no CB trip at the substation
6	6b-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
7	6b-14 Master: line trip 100 ms. Follower: two busbars trip, BFR 250 ms.
8	6b-24 Follower: no trip signal or no CB trip at the substation
9	6b-24 Follower: no trip signal or no CB trip at the substation
10	6b-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms.
11	6b-12 One busbar tripped at both substations by BFR after 250 ms.
12	6b-24 Follower: no trip signal or no CB trip at the substation
13	6b-12 One busbar tripped at both substations by BFR after 250 ms.
14	6b-32 Master: one busbar trips, follower: two busbars trip (BFR 250 ms)
15	6b-24 Follower: no trip signal or no CB trip at the substation
16	6b-24 Follower: no trip signal or no CB trip at the substation
17	6b-23 Master: no trip signal or no CB trip at the substation

18	6b-06 Master: line trip 450 ms. Follower: line trip 100 ms.
19	6b-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
20	6b-24 Follower: no trip signal or no CB trip at the substation
21	6b-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
22	6b-35 Master: line trip 450 ms. Follower: two busbars trip (BFR 250 ms).
23	6b-24 Follower: no trip signal or no CB trip at the substation
24	6b-24 Follower: no trip signal or no CB trip at the substation
25	6b-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
26	6b-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
27	6b-24 Follower: no trip signal or no CB trip at the substation
28	6b-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
29	6b-37 Master: one busbar trips, BFR 600 ms. Follower: two busbars trip, BFR 250 ms.
30	6b-24 Follower: no trip signal or no CB trip at the substation
31	6b-24 Follower: no trip signal or no CB trip at the substation
32	6b-23 Master: no trip signal or no CB trip at the substation
33	6b-23 Master: no trip signal or no CB trip at the substation
34	6b-24 Follower: no trip signal or no CB trip at the substation

Event trees for lines with single circuit breaker busbar schemes at both ends of the line

Event tree 7 is for faults in the middle of the line. This fault tree is presented in Figure 10 and the corresponding substation consequences are presented in Table 10.

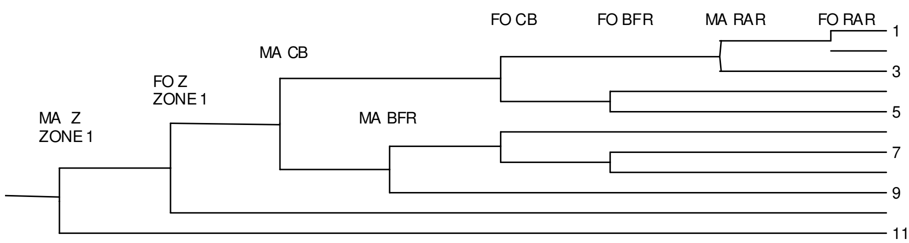

Figure 10 Event tree 7 (ET 7) for a line with a single circuit breaker busbar scheme at both ends of the line. The fault location is in the middle of the line. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay.

Table 10 The substation consequences of event tree 7

	The identification number and description of the substation consequence of the end branch
1	7-00 Master and follower: line trip, automatic reclosing.
2	7-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	7-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	7-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	7-24 Follower: no trip signal or no CB trip at the substation
6	7-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
7	7-12 One busbar tripped at both substations by BFR after 250 ms
8	7-24 Follower: no trip signal or no CB trip at the substation
9	7-23 Master: no trip signal or no CB trip at the substation
10	7-24 Follower: no trip signal or no CB trip at the substation
11	7-23 Master: no trip signal or no CB trip at the substation

Event tree 8 is for faults near the master line end. The fault tree is presented in Figure 11 and the corresponding substation consequences are presented in Table 11.

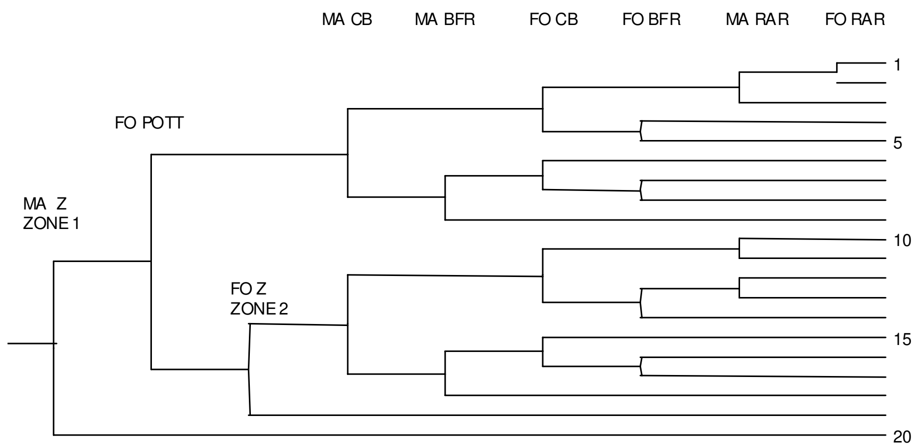

Figure 11 Event tree 8 (ET 8) for a line with a single circuit breaker busbar schemes at both ends of the line. The fault location is near the master line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 11 The substation consequences of event tree 8

	The identification number and description of the substation consequence of the end branch
1	8-00 Master and follower: line trip, automatic reclosing.
2	8-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	8-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	8-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	8-24 Follower: no trip signal or no CB trip at the substation
6	8-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
7	8-12 One busbar tripped at both substations by BFR after 250 ms
8	8-24 Follower: no trip signal or no CB trip at the substation
9	8-23 Master: no trip signal or no CB trip at the substation
10	8-04 Master: line trip 100 ms, RAR 500 ms, trip 600 ms. Follower: line trip 450 ms.
11	8-05 Master: line trip 100 ms, RAR fails. Follower: line trip 450 ms.
12	8-15 Master: line trip 100 ms, RAR 500 ms, line trip 600 ms. Follower: one busbar trips, BFR 600 ms.
13	8-25 Master: line trip 100 ms, RAR fails. Follower: one busbar trips BFR 600 ms.
14	8-24 Follower: no trip signal or no CB trip at the substation
15	8-21 Master: one busbar trips, BFR 250 ms. Follower: line trip 450 ms.
16	8-50 Master: one busbar trips, BFR 250 ms. Follower: one busbar trips, BFR 600 ms.
17	8-24 Follower: no trip signal or no CB trip at the substation
18	8-23 Master: no trip signal or no CB trip at the substation
19	8-24 Follower: no trip signal or no CB trip at the substation
20	8-23 Master: no trip signal or no CB trip at the substation

Event tree 9 is for faults near the follower line end. This fault tree is presented in Figure 12 and the corresponding substation consequences are presented in Table 12.

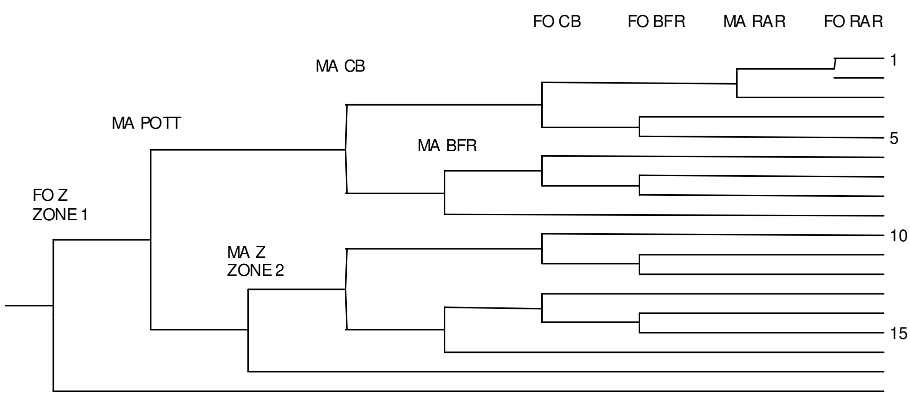

Figure 12 Event tree 9 (ET 9) for a line with a single circuit breaker busbar scheme at both ends of the line. The fault location is near the follower line end. MA = master line end, FO = follower line end, CB = circuit breaker, BFR = breaker failure relay, RAR = rapid automatic reclosing, Z = distance relay, POTT = permissive overreach transfer trip scheme.

Table 12 The substation consequences of event tree 6b

	The identification number and description of the substation consequence of the end branch
1	9-00 Master and follower: line trip, automatic reclosing.
2	9-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
3	9-01 Master: line trip 100 ms. Follower: line trip 100 ms. RAR fails.
4	9-11 Master: line trip 100 ms. Follower: one busbar trips, BFR 250 ms.
5	9-24 Follower: no trip signal or no CB trip at the substation
6	9-10 Master: one busbar trips, BFR 250 ms. Follower: line trip 100 ms
7	9-12 One busbar tripped at both substations by BFR after 250 ms
8	9-24 Follower: no trip signal or no CB trip at the substation
9	9-23 Master: no trip signal or no CB trip at the substation
10	9-06 Master: line trip 450 ms. Follower: line trip 100 ms.
11	9-22 Master: line trip 450 ms. Follower: one busbar trips, BFR 250 ms.
12	9-24 Follower: no trip signal or no CB trip at the substation
13	9-17 Master: one busbar trips, BFR 600 ms. Follower: line trip 100 ms.
14	9-51 Master: one busbar trips, BFR 600 ms. Follower: one busbar trips, BFR 250 ms.
15	9-24 Follower: no trip signal or no CB trip at the substation
16	9-23 Master: no trip signal or no CB trip at the substation
17	9-23 Master: no trip signal or no CB trip at the substation
18	9-24 Follower: no trip signal or no CB trip at the substation

APPENDIX B – MINIMAL CUT SETS OF THE FAULT TREES

The fault trees are presented as a list of minimal cut sets. If the minimal cut set list is brief, it is presented completely. If there are more than 20 minimal cut sets, only the most important cut sets are presented. In all cases at least 99 % of the cut sets are presented.

In the tables, ID is the identification at the substation where the protection is located, ID2 is the identification for the substation at the remote line end, id is the identification for the bay at the substation where the protection is located and id2 and id3 are the identification for the other bays.

Fault trees for the main protection when the fault is located within zone 1 of the distance relay

These fault trees are inputs in the event tree branches labelled MA Z ZONE 1, FO Z ZONE 1, MA Z ZONE 2 and FO Z ZONE 2.

Table 1 Minimal cut sets for the fault trees with two microprocessor distance relays for each line end. Top event probability q = 1.093E-05.

No.	Prob.	%	Event	Event
1	1.09E-05	99.62	IDACid Z1 PRO	IDACid Z2 PRO
2	1.13E-08	0.1	IDACid DC1 MCB 1	IDACid Z2 PRO
3	1.13E-08	0.1	IDACid DC2 MCB 1	IDACid Z1 PRO
4	6.53E-09	0.06	IDACid Z1 VT MCB	IDACid Z2 PRO
5	6.53E-09	0.06	IDACid Z1 PRO	IDACid Z2 VT MCB
6	1.90E-09	0.02	ID DC2 220 1	IDACid Z1 PRO
7	1.90E-09	0.02	ID DC1 220 1	IDACid Z2 PRO
8	1.83E-09	0.02	ID SUBSTATION	
9	7.25E-10	0.01	IDACid BAY	
10	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
11	6.77E-12	0	IDACid DC1 MCB 1	IDACid Z2 VT MCB
12	6.77E-12	0	IDACid DC2 MCB 1	IDACid Z1 VT MCB
13	3.92E-12	0	IDACid Z1 VT MCB	IDACid Z2 VT MCB
14	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
15	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
16	1.14E-12	0	ID DC2 220 1	IDACid Z1 VT MCB
17	1.14E-12	0	ID DC1 220 1	IDACid Z2 VT MCB
18	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 2 Minimal cut sets for the fault trees with one microprocessor distance relay and one electromechanical distance relay for each line end. Top event probability q = 1.10E-05.

No.	Prob.	%	Event	Event
1	1.09E-05	99.62	IDACid Z1 MEC	IDACid Z2 PRO
2	1.13E-08	0.1	IDACid DC2 MCB 1	IDACid Z1 MEC
3	1.13E-08	0.1	IDACid DC1 MCB 1	IDACid Z2 PRO
4	6.55E-09	0.06	IDACid Z1 MEC	IDACid Z2 VT MCB
5	6.53E-09	0.06	IDACid Z1 VT MCB	IDACid Z2 PRO
6	1.91E-09	0.02	ID DC2 220 1	IDACid Z1 MEC
7	1.90E-09	0.02	ID DC1 220 1	IDACid Z2 PRO
8	1.83E-09	0.02	ID SUBSTATION	
9	7.25E-10	0.01	IDACid BAY	
10	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
11	6.77E-12	0	IDACid DC2 MCB 1	IDACid Z1 VT MCB
12	6.77E-12	0	IDACid DC1 MCB 1	IDACid Z2 VT MCB
13	3.92E-12	0	IDACid Z1 VT MCB	IDACid Z2 VT MCB
14	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
15	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
16	1.14E-12	0	ID DC1 220 1	IDACid Z2 VT MCB
17	1.14E-12	0	ID DC2 220 1	IDACid Z1 VT MCB
18	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 3 Minimal cut sets for the fault trees with two electromechanical distance relays per line end. Top event probability q = 1.30E-05..

No.	Prob.	%	Event	Event
1	1.10E-05	84.51	IDACid Z1 MEC	IDACid Z2 MEC
2	1.98E-06	15.27	IDACid Z VT MCB	
3	1.13E-08	0.09	IDACid DC2 MCB 1	IDACid Z1 MEC
4	1.13E-08	0.09	IDACid DC1 MCB 1	IDACid Z2 MEC
5	1.91E-09	0.01	ID DC2 220 1	IDACid Z1 MEC
6	1.91E-09	0.01	ID DC1 220 1	IDACid Z2 MEC
7	1.83E-09	0.01	ID SUBSTATION	
8	7.25E-10	0.01	IDACid BAY	
9	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
10	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
11	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
12	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 4 Minimal cut sets of the fault trees with one microprocessor distance relay and one static distance relay per line end. Top event probability q = 2.36E-05.

No.	Prob.	%	Event	Event
1	2.35E-05	99.73	IDACid Z1 PRO	IDACid Z2 STA
2	2.44E-08	0.1	IDACid DC1 MCB 1	IDACid Z2 STA
3	1.41E-08	0.06	IDACid Z1 VT MCB	IDACid Z2 STA
4	1.13E-08	0.05	IDACid DC2 MCB 1	IDACid Z1 PRO
5	6.53E-09	0.03	IDACid Z1 PRO	IDACid Z2 VT MCB
6	4.11E-09	0.02	ID DC1 220 1	IDACid Z2 STA
7	1.90E-09	0.01	ID DC2 220 1	IDACid Z1 PRO
8	1.83E-09	0.01	ID SUBSTATION	
9	7.25E-10	0	IDACid BAY	
10	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
11	6.77E-12	0	IDACid DC1 MCB 1	IDACid Z2 VT MCB
12	6.77E-12	0	IDACid DC2 MCB 1	IDACid Z1 VT MCB
13	3.92E-12	0	IDACid Z1 VT MCB	IDACid Z2 VT MCB
14	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
15	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
16	1.14E-12	0	ID DC1 220 1	IDACid Z2 VT MCB
17	1.14E-12	0	ID DC2 220 1	IDACid Z1 VT MCB
18	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 5 Minimal cut sets for the fault trees with a microprocessor differential relay and microprocessor distance relay per line end. The line is a 3-branch line where the third branch is a 400/110 kV transformer. In this protection system it is enough if two of the three telecommunication channels between the three differential relays are functioning. All the telecommunication channels between the differential relays use fibre optics. Top event probability q = 3.69E-05. Here we exclude all transformer branch operations except the line differential relay, since all three differential relays at all line ends are needed for tripping operations at the two normal line ends. The transformer branch tripping operations can be neglected due to the reasons given in Section 7.4.1.

No	Prob.	%	Event	Event	Event
1	1.19E-05	32.08	IDACid D PRO	IDACid Z2 PRO	
2	1.19E-05	32.08	IDACid Z2 PRO	ID2id2 D PRO	
3	1.19E-05	32.08	IDACid Z2 PRO	ID3ACid3 D PRO	
4	4.75E-07	1.29	IDACid Z2 PRO	TELE 1A	TELE 2A
5	4.75E-07	1.29	IDACid Z2 PRO	TELE 3A	TELE 1A
6	4.75E-07	1.29	IDACid Z2 PRO	TELE 3A	TELE 2A
7	1.23E-08	0.03	IDACid D PRO	IDACid DC2 MCB 1	

Minimal cut sets numbered from 8 to 82 are not listed

Table 6 Minimal cut sets for the fault trees with one microprocessor differential and one microprocessor distance relay per line end. Top event probability q = 4.01E-05. The telecommunication channel of the differential relays is a combination of a radio link and optical fibre.

No.	Prob.	%	Event	Event
1	1.65E-05	41.11	IDACid Z2 PRO	TELE B
2	1.19E-05	29.51	IDACid Z2 PRO	IDAC06 D PRO
3	1.19E-05	29.51	IDACid Z2 PRO	ID2ACid2 D PRO
4	1.71E-08	0.04	IDACid DC2 MCB 1	TELE B
5	1.23E-08	0.03	IDACid DC2 MCB 1	IDAC06 D PRO
6	1.23E-08	0.03	IDACid DC2 MCB 1	ID2ACid2 D PRO
7	1.13E-08	0.03	IDACid Z2 PRO	ID2ACid2 DC1 MCB 1
8	1.13E-08	0.03	IDACid DC1 MCB 1	IDACid Z2 PRO
9	9.90E-09	0.02	IDACid Z2 VT MCB	TELE B
10	7.11E-09	0.02	IDACid Z2 VT MCB	IDAC06 D PRO
11	7.11E-09	0.02	IDACid Z2 VT MCB	ID2ACid2 D PRO
12	2.88E-09	0.01	ID DC2 220 1	TELE B
13	2.41E-09	0.01	ID DC 48 V 1	IDACid Z2 PRO
14	2.41E-09	0.01	IDACid Z2 PRO	ID2 DC 48 V 1
15	2.07E-09	0.01	ID DC2 220 1	IDAC06 D PRO
16	2.07E-09	0.01	ID DC2 220 1	ID2ACid2 D PRO
Minimal cut sets numbered from 17 to 50 are not listed				

Table 7 Minimal cut sets for the fault trees with two static distance relays per line end. Top event probability q = 5.09E-05.

No.	Prob.	%	Event	Event
1	5.08E-05	99.83	IDid Z1 STA	IDid Z2 STA
2	2.44E-08	0.05	IDid DC2 MCB 1	IDid Z1 STA
3	2.44E-08	0.05	IDid DC1 MCB 1	IDid Z2 STA
4	1.41E-08	0.03	IDid Z1 MCB VT	IDid Z2 STA
5	1.41E-08	0.03	IDid Z1 STA	IDid Z2 MCB VT
6	4.11E-09	0.01	ID DC1 220 1	IDid Z2 STA
7	4.11E-09	0.01	ID DC2 220 1	IDid Z1 STA
8	1.83E-09	0	ID SUBSTATION	
9	7.25E-10	0	IDid BAY	
10	7.25E-10	0	IDid BAY	
11	1.17E-11	0	IDid DC1 MCB 1	IDid DC2 MCB 1
12	6.77E-12	0	IDid DC1 MCB 1	IDid Z2 MCB VT
13	6.77E-12	0	IDid DC2 MCB 1	IDid Z1 MCB VT
14	3.92E-12	0	IDid Z1 MCB VT	IDid Z2 MCB VT
15	1.97E-12	0	ID DC2 220 1	IDid DC1 MCB 1
16	1.97E-12	0	ID DC1 220 1	IDid DC2 MCB 1

17	1.14E-12	0	ID DC2 220 1	IDid Z1 MCB VT
18	1.14E-12	0	ID DC1 220 1	IDid Z2 MCB VT
19	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 8 Minimal cut sets for the fault trees with one microprocessor differential relay and one microprocessor distance relay per line end. Top event probability q = 6.31E-05. The telecommunication channel of the differential relays consists of an optical fibre.

No	**Prob.**	**%**	**Event**	**Event**
1	3,96E-05	62,74	TELE B	IDACid Z2 PRO
2	1,19E-05	18,77	ID2ACid2 D PRO	IDACid Z2 PRO
3	1,19E-05	18,77	IDACid D PRO	IDACid Z2 PRO
4	4,10E-08	0,07	TELE B	IDACid DC2 MCB 1
5	2,38E-08	0,04	TELE B	IDACid Z2 VT MCB
6	1,23E-08	0,02	ID2ACid2 D PRO	IDACid DC2 MCB 1
7	1,23E-08	0,02	IDACid D PRO	IDACid DC2 MCB 1
8	1,13E-08	0,02	IDACid DC1 MCB 1	IDACid Z2 PRO
9	1,13E-08	0,02	ID2ACid2 DC1 MCB 1	IDACid Z2 PRO
10	7,11E-09	0,01	ID2ACid2 D PRO	IDACid Z2 VT MCB
11	7,11E-09	0,01	IDACid D PRO	IDACid Z2 VT MCB
12	6,91E-09	0,01	TELE B	ID DC2 220 1
Minimal cut sets numbered from 13 to 55 are not listed				

Table 9 Minimal cut sets for the fault trees with one microprocessor differential relay and one static distance relay per line end. Top event Prob. q = 1.17E-04. The telecommunication channel of the differential relays consists of a radio link.

No.	Prob.	%	Event	Event
1	6.63E-05	56.63	IDACid Z2 STA	TELE A
2	2.56E-05	21.86	IDACid Z2 STA	ID2ACid2 D PRO
3	2.56E-05	21.86	IDACid D PRO	IDACid Z2 STA
4	3.18E-08	0.03	IDACid DC2 MCB 1	TELE A
5	2.44E-08	0.02	IDACid DC1 MCB 1	IDACid Z2 STA
6	2.44E-08	0.02	IDACid Z2 STA	ID2ACid2 DC1 MCB 1
7	1.84E-08	0.02	IDACid Z2 VT MCB	TELE A
8	1.23E-08	0.01	IDACid D PRO	IDACid DC2 MCB 1
9	1.23E-08	0.01	IDACid DC2 MCB 1	ID2ACid2 D PRO
10	7.11E-09	0.01	IDACid Z2 VT MCB	ID2ACid2 D PRO
11	7.11E-09	0.01	IDACid D PRO	IDACid Z2 VT MCB
Minimal cut sets numbered from 12 to 54 are not listed				

Fault trees for the main protection when the fault is located in the permissive overreach zone

These fault trees are inputs in the event tree branches labelled MA Z POTT and FO Z POTT.

Table 10 Minimal cut sets for the fault trees with two microprocessor distance relays per line end and two telecommunication channels. Top event probability q= 1.35E-04. The telecommunication channels A and B each consist of a combination of a radio link and optical fibre .

No.	Prob.	%	Event	Event
1	2.50E-05	18.48	TELE A	TELE B
2	1.65E-05	12.2	IDACid Z1 PRO	TELE B
3	1.65E-05	12.2	TELE A	ID2ACid2 Z2 PRO
4	1.65E-05	12.2	TELE B	ID2ACid2 Z1 PRO
5	1.65E-05	12.2	IDACid Z2 PRO	TELE A
6	1.09E-05	8.05	IDACid Z1 PRO	IDACid Z2 PRO
7	1.09E-05	8.05	IDACid Z2 PRO	ID2ACid2 Z1 PRO
8	1.09E-05	8.05	IDACid Z1 PRO	ID2ACid2 Z2 PRO
9	1.09E-05	8.05	ID2ACid2 Z1 PRO	ID2ACid2 Z2 PRO
Minimal cut sets numbered from 10 to 88 are not listed				

Table 11 Minimal cut sets for the fault trees with one microprocessor differential relay and one microprocessor distance relay for each line end. The telecommunication channels A and B each consist of a combination of a radio link and optical fibre. Top event probability q= 1.42E-04.

No.	Prob.	%	Event	Event
1	2.50E-05	17.62	TELE A	TELE B
2	1.80E-05	12.65	TELE A	ID2ACid2 D PRO
3	1.80E-05	12.65	TELE A	IDAC06 D PRO
4	1.65E-05	11.63	TELE B	ID2ACid2 Z2 PRO
5	1.65E-05	11.63	IDACid Z2 PRO	TELE B
6	1.19E-05	8.35	IDACid Z2 PRO	ID2ACid2 D PRO
7	1.19E-05	8.35	IDAC06 D PRO	ID2ACid2 Z2 PRO
8	1.19E-05	8.35	ID2ACid2 D PRO	ID2ACid2 Z2 PRO
9	1.19E-05	8.35	IDACid Z2 PRO	IDAC06 D PRO
Minimal cut sets numbered from 10 to 78 are not listed				

Table 12 Minimal cut sets for the fault trees with one microprocessor differential relay and one microprocessor distance relay for each line end. The telecommunication channel of the differential relay consists of an optical fibre and the telecommunication channel of the distance relays is a combination of optical fibre and a radio link. Top event probability q= 2.22E-04.

No.	Prob.	%	Event	Event
1	6.00E-05	26.99	TELE A	TELE B
2	3.96E-05	17.81	TELE B	IDACid Z2 PRO
3	3.96E-05	17.81	TELE B	ID2ACid2 Z2 PRO
4	1.80E-05	8.08	TELE A	IDACid D PRO
5	1.80E-05	8.08	TELE A	ID2ACid2 D PRO
6	1.19E-05	5.33	IDACid Z2 PRO	ID2ACid2 D PRO
7	1.19E-05	5.33	IDACid D PRO	IDACid Z2 PRO
8	1.19E-05	5.33	IDACid D PRO	ID2ACid2 Z2 PRO
9	1.19E-05	5.33	ID2ACid2 D PRO	ID2ACid2 Z2 PRO
Minimal cut sets numbered from 10 to 80 are not listed				

Table 13 Minimal cut sets for the fault trees with a microprocessor differential relay and microprocessor distance relay for each line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. In this protection system it is enough if two of the three telecommunication channels between the three differential relays are functioning. All the telecommunication channels between the differential relays consist of optical fibre. The telecommunication channel of the distance relays consists of the series connection of an optical fibre and the combination of an optical fibre and radio link. Top event probability q= 2.63E-04. Here we exclude all transformer branch operations except the line differential relay, since all three differential relays at all line ends are needed for tripping operations at the two normal line ends. The transformer branch tripping operations can be neglected due to the reasons given in Section 7.4.1.

No.	Prob.	%	Event	Event	Event
1	4.31E-05	16.33	TELE 1B	ID3ACid3 D PRO	
2	4.31E-05	16.33	IDACid D PRO	TELE 1B	
3	4.31E-05	16.33	TELE 1B	ID2ACid2 D PRO	
4	1.80E-05	6.8	TELE 2B	ID2ACid2 D PRO	
5	1.80E-05	6.8	IDACid D PRO	TELE 2B	
6	1.80E-05	6.8	TELE 2B	ID3ACid3 D PRO	
7	1.19E-05	4.49	IDACid D PRO	IDACid Z2 PRO	
8	1.19E-05	4.49	IDACid D PRO	ID2ACid2 Z2 PRO	
9	1.19E-05	4.49	IDACid Z2 PRO	ID2ACid2 D PRO	
10	1.19E-05	4.49	ID2ACid2 Z2 PRO	ID3ACid3 D PRO	
11	1.19E-05	4.49	IDACid Z2 PRO	ID3ACid3 D PRO	
12	1.19E-05	4.49	ID2ACid2 D PRO	ID2ACid2 Z2 PRO	

13	1.73E-06	0.65	TELE 3A	TELE 1B	TELE 1A
14	1.73E-06	0.65	TELE 3A	TELE 2A	TELE 1B
15	1.73E-06	0.65	TELE 1A	TELE 1B	TELE 2A
16	7.29E-07	0.28	ID DC 48 V 1		
17	7.29E-07	0.28	ID2 DC 48 V 1		
18	7.29E-07	0.28	ID3 DC 48 V 1		
Minimal cut sets numbered from 19 to 158 are not listed					

Table 14 Minimal cut sets for the fault trees with one microprocessor differential relay and one static distance relay for each line end. The telecommunication channel of the differential relay consists of a radio link and the telecommunication channel of the distance relays is a radio link. Top event probability q= 3.85E-04.

No.	**Prob.**	**%**	**Event**	**Event**
1	8.65E-05	22.45	TELE A	TELE B
2	6.63E-05	17.21	TELE A	ID2ACid2 Z2 STA
3	6.63E-05	17.21	IDACid Z2 STA	TELE A
4	3.34E-05	8.67	TELE B	ID2ACid2 D PRO
5	3.34E-05	8.67	IDACid D PRO	TELE B
6	2.56E-05	6.64	IDACid Z2 STA	ID2ACid2 D PRO
7	2.56E-05	6.64	IDACid D PRO	IDACid Z2 STA
8	2.56E-05	6.64	ID2Acid2 D PRO	ID2ACid2 Z2 STA
9	2.56E-05	6.64	IDACid D PRO	ID2ACid2 Z2 STA
Minimal cut sets numbered from 10 to 34 are not listed				

Table 15 Minimal cut sets for the fault trees with a microprocessor distance relay and an electomechanical distance relay for each line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. There are telecommunication channels A and B between the line ends and the transformer substation. This makes two parallel telecommunication channels (A and B). Both of these channels consist of two (1 and 2) telecommunication channels in series. The telecommunication channel A1 is an optical fibre, A2 is a radio link,B1 and B2 are both combinations of an optical fibre and a radio link. Top event probability q= 4.60E-04.

No.	Prob.	%	Event	Event
1	6.00E-05	13.04	TELE 1B	TELE 2A
2	6.00E-05	13.04	TELE 2A	TELE 2B
3	4.65E-05	10.1	TELE 1A	TELE 2B
4	4.65E-05	10.1	TELE 1A	TELE 1B
5	3.97E-05	8.63	ID2ACid2 Z2 MEC	TELE 2A
6	3.96E-05	8.6	IDACid Z2 PRO	TELE 2A
7	3.08E-05	6.69	TELE 1A	ID2ACid2 Z2 MEC
8	3.07E-05	6.67	IDACid Z2 PRO	TELE 1A

9	1.66E-05	3.6	TELE 1B	ID2ACid2 Z1 MEC
10	1.66E-05	3.6	ID2ACid2 Z1 MEC	TELE 2B
11	1.65E-05	3.58	IDACid Z1 PRO	TELE 1B
12	1.65E-05	3.58	IDACid Z1 PRO	TELE 2B
13	1.10E-05	2.38	ID2ACid2 Z1 MEC	ID2ACid2 Z2 MEC
14	1.09E-05	2.37	IDACid Z2 PRO	ID2ACid2 Z1 MEC
15	1.09E-05	2.37	IDACid Z1 PRO	ID2ACid2 Z2 MEC
16	1.09E-05	2.37	IDACid Z1 PRO	IDACid Z2 PRO
Minimal cut sets numbered from 17 to 88 are not listed				

Table 16 Minimal cut sets for the fault trees with a microprocessor distance relay and a static distance relay for each line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. There are telecommunication channels A and B between the line ends and the transformer substation. This makes two parallel telecommunication channels (A and B). Both of these channels consist of two (1 and 2) telecommunication channels in series. Telecommunication channel A1 is a combination of optical fibre and a radio link, A2 is a radio link, B1 and B2 are both combinations of an optical fibre and a radio link. Top event probability q= 4.99E-04.

No	**Prob.**	**%**	**Event**	**Event**
1	6.63E-05	13.29	ID2ACid2 Z2 STA	TELE 2A
2	5.08E-05	10.19	IDACid Z1 STA	ID2ACid2 Z2 STA
3	4.65E-05	9.32	TELE 2A	TELE 2B
4	4.65E-05	9.32	TELE 1B	TELE 2A
5	3.57E-05	7.14	TELE 1A	ID2ACid2 Z2 STA
6	3.57E-05	7.14	IDACid Z1 STA	TELE 2B
7	3.57E-05	7.14	TELE 1B	IDACid Z1 STA
8	3.07E-05	6.15	IDACid Z2 PRO	TELE 2A
9	2.50E-05	5.01	TELE 1A	TELE 2B
10	2.50E-05	5.01	TELE 1A	TELE 1B
11	2.35E-05	4.71	ID2ACid2 Z1 PRO	ID2ACid2 Z2 STA
12	2.35E-05	4.71	IDACid Z1 STA	IDACid Z2 PRO
13	1.65E-05	3.31	TELE 1A	IDACid Z2 PRO
14	1.65E-05	3.31	TELE 1B	ID2ACid2 Z1 PRO
15	1.65E-05	3.31	ID2ACid2 Z1 PRO	TELE 2B
16	1.09E-05	2.18	IDACid Z2 PRO	ID2ACid2 Z1 PRO
Minimal cut sets numbered from 17 to 107 are not listed				

Table 17 Minimal cut sets for the fault trees with two electromechanical distance relays for each line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. There are telecommunication channels A and B between the line ends and the transformer substation. This makes two parallel telecommunication channels (A and B). Both of these channels consist of two (1 and 2) telecommunication channels in series. Telecommunication channel A1 is an optical fibre, A2 is a combination of an optic fibre and a radio link, B1 is an optical fibre and B2 is a combination of an optical fibre and a radio link. Top event probability q= 5.55E-04.

No	**Prob.**	**%**	**Event**	**Event**
1	1.44E-04	25.94	TELE 1A	TELE 1B
2	6.00E-05	10.81	TELE 2A	TELE 1B
3	6.00E-05	10.81	TELE 2B	TELE 1A
4	3.97E-05	7.16	ID2ACid2 Z1 MEC	TELE 1B
5	3.97E-05	7.16	IDACid Z1 MEC	TELE 1B
6	3.97E-05	7.16	IDACid Z2 MEC	TELE 1A
7	3.97E-05	7.16	ID2ACid2 Z2 MEC	TELE 1A
8	2.50E-05	4.5	TELE 2A	TELE 2B
9	1.66E-05	2.98	IDACid Z2 MEC	TELE 2A
10	1.66E-05	2.98	TELE 2B	ID2ACid2 Z1 MEC
11	1.66E-05	2.98	TELE 2A	ID2ACid2 Z2 MEC
12	1.66E-05	2.98	IDACid Z1 MEC	TELE 2B
13	1.10E-05	1.97	ID2ACid2 Z1 MEC	ID2ACid2 Z2 MEC
14	1.10E-05	1.97	IDACid Z1 MEC	ID2ACid2 Z2 MEC
15	1.10E-05	1.97	IDACid Z2 MEC	ID2ACid2 Z1 MEC
16	1.10E-05	1.97	IDACid Z1 MEC	IDACid Z2 MEC
Minimal cut sets numbered from 17 to 72 are not listed				

Table 18 Minimal cut sets for the fault trees with two microprocessor distance relays for each line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. There are telecommunication channels A and B between the line ends and the transformer substation. This makes two parallel telecommunication channels (A and B). Both of these channels consist of two (1 and 2) telecommunication channels in series. The telecommunication channel A1 is an optical fibre, A2 is an optical fibre, B1 is an optical fibre and B2 is a radio link. Top event probability q= 8.39E-04.

No.	**Prob.**	**%**	**Event**	**Event**
1	1.44E-04	17.16	TELE 2A	TELE 2B
2	1.44E-04	17.16	TELE 1A	TELE 2B
3	1.12E-04	13.3	TELE 1B	TELE 2A
4	1.12E-04	13.3	TELE 1A	TELE 1B
5	3.96E-05	4.72	IDACid Z1 PRO	TELE 2B

6	3.96E-05	4.72	TELE 1A	IDACid Z2 PRO
7	3.96E-05	4.72	IDACid Z2 PRO	TELE 2A
8	3.96E-05	4.72	TELE 2B	ID2ACid2 Z1 PRO
9	3.96E-05	4.72	TELE 1A	ID2ACid2 Z2 PRO
10	3.96E-05	4.72	TELE 2A	ID2ACid2 Z2 PRO
11	3.07E-05	3.66	TELE 1B	ID2ACid2 Z1 PRO
12	3.07E-05	3.66	TELE 1B	IDACid Z1 PRO
13	1.09E-05	1.3	ID2ACid2 Z1 PRO	ID2ACid2 Z2 PRO
14	1.09E-05	1.3	IDACid Z1 PRO	ID2ACid2 Z2 PRO
15	1.09E-05	1.3	IDACid Z2 PRO	ID2ACid2 Z1 PRO
16	1.09E-05	1.3	IDACid Z1 PRO	IDACid Z2 PRO
Minimal cut sets numbered from 17 to 108 are not listed				

Table 19 Minimal cut sets for the fault trees with two static distance relays for one line end and one microprocessor and one electromechanical distance relay at the other line end. The line is a 3-branch line, where the third branch is a 400/110 kV transformer. There are telecommunication channels A and B between the line ends and the transformer substation. This makes two parallel telecommunication channels (A and B). Both of these channels consist of two (1 and 2) telecommunication channels in series. The telecommunication channel A1 is an optical fibre, A2 is an optical fibre, B1 is an optical fibre and B2 is a combination of an optical fibre and a radio link. Top event probability q= 9.27E-04.

No.	**Prob.**	**%**	**Event**	**Event**
1	1.44E-04	15.54	TELE 1A	TELE 2B
2	1.44E-04	15.54	TELE 2A	TELE 2B
3	8.56E-05	9.23	TELE 2A	ID2ACid2 Z2 STA
4	8.56E-05	9.23	TELE 2B	ID2ACid2 Z1 STA
5	8.56E-05	9.23	TELE 1A	ID2ACid2 Z2 STA
6	6.00E-05	6.48	TELE 1A	TELE 1B
7	6.00E-05	6.48	TELE 1B	TELE 2A
8	5.08E-05	5.49	ID2ACid2 Z1 STA	ID2ACid2 Z2 STA
9	3.97E-05	4.29	IDACid Z1 MEC	TELE 2B
10	3.96E-05	4.27	IDACid Z2 PRO	TELE 1A
11	3.96E-05	4.27	IDACid Z2 PRO	TELE 2A
12	3.57E-05	3.85	TELE 1B	ID2ACid2 Z1 STA
13	2.36E-05	2.55	IDACid Z1 MEC	ID2ACid2 Z2 STA
14	2.35E-05	2.54	IDACid Z2 PRO	ID2ACid2 Z1 STA
15	1.66E-05	1.79	IDACid Z1 MEC	TELE 1B
Minimal cut sets numbered from 16 to 107 are not listed				

Table 20 Minimal cut sets for the fault trees with two electromechanical distance relays for each line end and one telecommunication channel. Top event probability q= 5.03E-03. The telecommunication channel is a combination of a radio link and an optical fibre .

No.	Prob.	%	Event	Event
1	5.00E-03	99.5	TELE	
2	1.10E-05	0.22	ID2Acid2 Z1 MEC	ID2ACid2 Z2 MEC
3	1.09E-05	0.22	IDACid Z1 PRO	IDACid Z2 PRO
4	1.98E-06	0.04	ID2ACid2 Z VT MCB	
Minimal cut sets numbered from 5 to 27 are not listed				

Table 21 Minimal cut sets for the fault trees with twomicroprocessor distance relays for each line end and two telecommunication channels. Top event probability q= 6.66E-03. The telecommunication channel A is a power line carrier, the telecommunication channel B is a combination of a power line carrier and an optical fibre.

No.	Prob.	%	Event	Event
1	4.38E-03	65.77	TELE A	TELE B
2	1.11E-03	16.69	TELE A	IDACid Z2 PRO
3	1.11E-03	16.69	TELE A	ID2ACid2 Z2 PRO
Minimal cut sets numbered from 4 to 41 are not listed				

Table 22 Minimal cut sets for the fault trees with twomicroprocessor distance relays for each line end and one telecommunication channel. Top event probability q= 9.32E-03. The telecommunication channel is a radio link.

No.	Prob.	%	Event	Event
1	9.30E-03	99.75	TELE	
Minimal cut sets numbered from 2 to 40 are not listed				

Table 23 Minimal cut sets for the fault trees with two microprocessor distance relays for one line end, two electromechanical distance relays at the other line end and one telecommunication channel. Top event probability q= 9.32E-03. The telecommunication channel is a radio link.

No.	Prob.	%	Event	Event
1	9.30E-03	99.73	TELE	
Minimal cut sets numbered from 2 to 34 are not listed				

Table 24 Minimal cut sets for the fault trees with two distance relays(any type) for each line end and one telecommunication channel. Top event probability q= 1.20E-02. The telecommunication channel is an optical fibre.

No.	Prob.	%	Event	Event
1	1.20E-02	99.79	TELE	

Table 25 Minimal cut sets for the fault trees with two distance relays(any type) for each line end and one telecommunication channel. Top event probability q= 3.37E-01. The telecommunication channel is a power line carrier.

No.	Prob.	%	Event	Event
1	3.37E-01	99.99	TELE	

Fault trees for the tripping of circuit breakers

These fault trees are inputs in the event tree branches labelled as MA CB and and FO CB.

Table 26 Minimal cut sets for a fault tree using SF6 circuit breakers for tripping. Top event probability q = 1.40E-03.

No.	Prob.	%	Event	Event
1	1.40E-03	99.99	IDACid CB TRIP	
2	8.70E-08	0.01	IDACid CB TRIP COIL1	IDACid CB TRIP COIL2
3	1.83E-09	0	ID SUBSTATION	
4	1.01E-09	0	IDACid CB TRIP COIL2	IDACid DC1 MCB 1
5	1.01E-09	0	IDACid CB TRIP COIL1	IDACid DC2 MCB 1
6	7.25E-10	0	IDACid BAY	
7	1.70E-10	0	ID DC1 220 1	IDACid CB TRIP COIL2
8	1.70E-10	0	ID DC2 220 1	IDACid CB TRIP COIL1
9	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
10	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
11	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
12	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 27 The minimal cut sets of a fault tree with minimum oil circuit breakers for tripping. Top event probability q = 2.45E-03.

No	Prob.	%	Event	Event
1	2.45E-03	100	IDACid CB TRIP	
2	8.70E-08	0	IDACid CB TRIP COIL1	IDACid CB TRIP COIL2
3	1.83E-09	0	ID SUBSTATION	
4	1.01E-09	0	IDACid CB TRIP COIL2	IDACid DC1 MCB 1
5	1.01E-09	0	IDACid CB TRIP COIL1	IDACid DC2 MCB 1
6	7.25E-10	0	IDACid BAY	
7	1.70E-10	0	ID DC1 220 1	IDACid CB TRIP COIL2
8	1.70E-10	0	ID DC2 220 1	IDACid CB TRIP COIL1
9	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
10	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
11	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
12	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Table 28 Minimal cut sets for a fault tree using air-blast circuit breakers for tripping. Top event probability q = 8.45E-03.

No	Prob.	%	Event	Event
1	8.45E-03	100	IDACid CB TRIP	
2	8.70E-08	0	IDACid CB TRIP COIL1	IDACid CB TRIP COIL2
3	1.83E-09	0	ID SUBSTATION	
4	1.01E-09	0	IDACid CB TRIP COIL1	IDACid DC2 MCB 1
5	1.01E-09	0	IDACid CB TRIP COIL2	IDACid DC1 MCB 1
6	7.25E-10	0	IDACid BAY	
7	1.70E-10	0	ID DC1 220 1	IDACid CB TRIP COIL2
8	1.70E-10	0	ID DC2 220 1	IDACid CB TRIP COIL1
9	1.17E-11	0	IDACid DC1 MCB 1	IDACid DC2 MCB 1
10	1.97E-12	0	ID DC2 220 1	IDACid DC1 MCB 1
11	1.97E-12	0	ID DC1 220 1	IDACid DC2 MCB 1
12	3.32E-13	0	ID DC1 220 1	ID DC2 220 1

Fault trees for the breaker failure protection

These fault trees are inputs in the event tree branches labelled MA BFR and FO BFR.

Table 29 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one SF6 circuit breaker. Top event probability q = 1.98E-03.

No.	Prob.	%	Event
1	1.40E-03	70.54	IDACid2 CB TRIP
2	5.13E-04	25.87	IDACid BFR STA
3	6.63E-05	3.34	IDACid BFR TS REC 1
Minimal cut sets numbered from 4 to 15 are not listed			

Table 30 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one minimum oil circuit breaker. Top event probability q = 3.03E-03.

No.	Prob.	%	Event
1	2.45E-03	80.74	IDACid2 CB TRIP
2	5.13E-04	16.93	IDACid BFR STA
3	6.63E-05	2.19	IDACid BFR TS REC 1
Minimal cut sets numbered from 4 to 15 are not listed			

Table 31 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip two SF6 circuit breakers. Top event probability q = 3.38E-03.

No.	Prob.	%	Event
1	1.40E-03	41.4	IDACid2 CB TRIP
2	1.40E-03	41.4	IDACid3 CB TRIP
3	5.13E-04	15.18	IDACid BFR STA
4	6.63E-05	1.96	IDACid BFR TS REC 1
Minimal cut sets numbered from 5-23 are not listed			

Table 32 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one SF6 circuit breaker and one minimum oil circuit breaker. Top event probability q = 4.42E-03.

No.	Prob.	%	Event
1	2.45E-03	55.29	IDACid2 CB TRIP
2	1.40E-03	31.62	IDACid3 CB TRIP
3	5.13E-04	11.6	IDACid BFR STA

4	6.63E-05	1.5	IDACid BFR TS REC 1
Minimal cut sets numbered from 5-23 are not listed			

Table 33 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip three SF6 circuit breakers. Top event probability q = 4.77E-03.

No.	**Prob.**	**%**	**Event**
1	1.40E-03	29.31	IDACid2 CB TRIP
2	1.40E-03	29.31	IDACid3 CB TRIP
3	1.40E-03	29.31	IDACid4 CB TRIP
4	5.13E-04	10.75	IDACid BFR STA
5	6.63E-05	1.39	IDACid BFR TS REC 1
Minimal cut sets numbered from 6-31 are not listed			

Table 34 Minimal cut sets for a fault tree for breaker failure protection. In this case the protection needs to trip two minimum oil circuit breakers. Top event probability q = 5.47E-03.

No.	**Prob.**	**%**	**Event**
1	1	2.45E-03	IDACid2 CB TRIP
2	2	2.45E-03	IDACid3 CB TRIP
3	3	5.13E-04	IDACid BFR STA
4	4	6.63E-05	IDACid BFR TS REC 1
Minimal cut sets numbered from 5-23 are not listed			

Table 35 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip four SF6 circuit breakers. Top event probability q = 6.17E-03.

No.	**Prob.**	**%**	**Event**
1	1.40E-03	22.69	IDACid2 CB TRIP
2	1.40E-03	22.69	IDACid3 CB TRIP
3	1.40E-03	22.69	IDACid4 CB TRIP
4	1.40E-03	22.69	IDACid5 CB TRIP
5	5.13E-04	8.32	IDACid BFR STA
Minimal cut sets numbered from 6-39 are not listed			

Table 36 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one SF6 circuit breaker and two minimum oil circuit breakers. Top event probability q = 6.86E-03.

No.	**Prob.**	**%**	**Event**
1	2.45E-03	35.66	IDACid2 CB TRIP
2	2.45E-03	35.66	IDACid3 CB TRIP

3	1.40E-03	20.39	IDACid4 CB TRIP
4	5.13E-04	7.48	IDACid BFR STA
Minimal cut sets numbered from 5-31 are not listed			

Table 37 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip three minimum oil circuit breakers. Top event probability q = 7.90E-03.

No.	Prob.	%	Event
1	2.45E-03	30.96	IDACid2 CB TRIP
2	2.45E-03	30.96	IDACid3 CB TRIP
3	2.45E-03	30.96	IDACid4 CB TRIP
4	5.13E-04	6.49	IDACid BFR STA
Minimal cut sets numbered from 5-31 are not listed			

Table 38 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip four SF6 circuit breakers and one minimum oil circuit breaker. Top event probability q = 8.60E-03.

No.	Prob.	%	Event
1	2.45E-03	28.46	IDACid2 CB TRIP
2	1.40E-03	16.27	IDACid3 CB TRIP
3	1.40E-03	16.27	IDACid4 CB TRIP
4	1.40E-03	16.27	IDACid5 CB TRIP
5	1.40E-03	16.27	IDACid BFR STA
Minimal cut sets numbered from 7-47 are not listed			

Table 39 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one air-blast circuit breaker. Top event probability q = 9.03E-03.

No.	Prob.	%	Event
1	8.45E-03	93.58	IDACid2 CB TRIP
2	5.13E-04	5.68	IDACid BFR STA
3	6.63E-05	0.73	IDACid BFR TS REC 1
MCS numbered from 4 to 15 are not listed			

Table 40 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip three SF6 circuit breakers and two air-blast circuit breakers. Top event probability q = 9.64E-03.

No.	Prob.	%	Event
1	2.45E-03	25.38	IDACid2 CB TRIP
2	2.45E-03	25.38	IDACid3 CB TRIP
3	1.40E-03	14.52	IDACid4 CB TRIP

4	1.40E-03	14.52	IDACid5 CB TRIP
5	1.40E-03	14.52	IDACid6 CB TRIP
6	5.13E-04	5.32	IDACid BFR STA
Minimal cut sets numbered from 7-47 are not listed			

Table 41 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip one SF6 circuit breaker and one air-blast circuit breaker. Top event probability q = 1.04E-02.

No.	**Prob.**	**%**	**Event**
1	8.45E-03	81.13	IDACid2 CB TRIP
2	1.40E-03	13.43	IDACid3 CB TRIP
3	5.13E-04	4.92	IDACid BFR STA
4	6.63E-05	0.64	IDACid BFR TS REC 1
Minimal cut sets numbered from 5-23 are not listed			

Table 42 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip two air-blast circuit breakers. Top event probability q = 1.74E-02.

No.	**Prob.**	**%**	**Event**
1	8.45E-03	48.55	IDACid2 CB TRIP
2	8.45E-03	48.55	IDACid3 CB TRIP
3	5.13E-04	2.95	IDACid BFR STA
4	6.63E-05	0.38	IDACid BFR TS REC 1
Minimal cut sets numbered from 5-23 are not listed			

Table 43 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip two air-blast circuit breakers and one SF6 circuit breaker. Top event probability q = 1.88E-02.

No.	**Prob.**	**%**	**Event**
1	8.45E-03	45	IDACid2 CB TRIP
2	8.45E-03	45	IDACid3 CB TRIP
3	1.40E-03	7.45	IDACid4 CB TRIP
4	5.13E-04	2.73	IDACid BFR STA
Minimal cut sets numbered from 5-31 are not listed			

Table 44 Minimal cut sets of a fault tree for breaker failure protection. In this case the protection needs to trip three air-blast circuit breakers. Top event probability q = 2.57E-02.

No.	**Prob.**	**%**	**Event**
1	8.45E-03	32.87	IDACid2 CB TRIP
2	8.45E-03	32.87	IDACid3 CB TRIP

3	8.45E-03	32.87	IDACid4 CB TRIP
4	5.13E-04	2	IDACid BFR STA
Minimal cut sets numbered from 5-31 are not listed			

Fault trees for the autoreclosing

These fault trees are inputs in the event tree branches MA RAR and FO RAR.

Table 45 The minimal cut sets for a fault tree covering the autoreclosing system of a master line end. The autoreclosing relay and synchronism check device are integrated microprocessor relays and the circuit breaker is the minimum oil type. Top event probability q = 1.03E-02

No.	Prob.	%	Event	Event
1	7.46E-03	72.31	IDACid CB CLOSE	
2	1.14E-03	11.05	IDACid SC STA	
3	1.02E-03	9.88	IDACid AR MEC 2	
4	6.50E-04	6.3	IDACid AR OFF	
5	6.50E-05	0.63	IDACid AR1 SIGN	
6	3.42E-06	0.03	IDACid DC1 MCB 1	
7	2.11E-06	0.02	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
8	1.98E-06	0.02	IDACid BUS U MEASURE	
9	5.76E-07	0.01	ID DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
11	1.83E-09	0	ID SUBSTATION	
12	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 46 The minimal cut sets for a fault tree covering the autoreclosing system of a master line end. The autoreclosing relay and synchronism check device are electromechanical and the circuit breaker is the minimum oil type. Top event probability q = 1.11E-02.

No.	Prob.	%	Event	Event
1	7.46E-03	67.49	IDACid CB CLOSE	
2	1.89E-03	17.04	IDACid SC MEC 2	
3	1.02E-03	9.22	IDACid AR MEC 2	
4	6.50E-04	5.88	IDACid AR OFF	
5	6.50E-05	0.59	IDACid AR1 SIGN	
6	3.42E-06	0.03	IDACid DC1 MCB 1	
7	2.11E-06	0.02	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
8	1.98E-06	0.02	IDACid BUS U MEASURE	
9	5.76E-07	0.01	IDACid DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG

11	1.83E-09	0	IDACid SUBSTATION	
12	8.36E-10	0	IDACid DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 47 The minimal cut sets for a fault tree covering the autoreclosing system of a master line end. The autoreclosing relay and synchronism check device are electromechanical and the circuit breaker is of the air-blast type. Top event probability q = 1.35E-02.

No.	Prob.	%	Event	Event
1	9.93E-03	73.44	IDACid CB CLOSE	
2	1.89E-03	13.93	IDACid SC MEC 2	
3	1.02E-03	7.54	IDACid AR MEC 2	
4	6.50E-04	4.8	IDACid AR OFF	
5	6.50E-05	0.48	IDACid AR1 SIGN	
6	6.60E-06	0.05	ID AIR PRESSURE AR	
7	3.42E-06	0.03	IDACid DC1 MCB 1	
8	2.11E-06	0.02	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
9	1.98E-06	0.01	IDACid BUS U MEASURE	
10	5.76E-07	0	ID DC1 220 1	
11	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
12	1.83E-09	0	ID SUBSTATION	
13	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
14	7.25E-10	0	IDACid BAY	

Table 48 The minimal cut sets for a fault tree dealing with the autoreclosing system of a master line end. The autoreclosing relay and synchronism check device are integrated microprocessor relays and the circuit breaker is of the SF6 type. Top event probability q = 1.90E-02.

No.	Prob.	%	Event	Event
1	1.29E-02	67.82	IDACid AR / SC PRO	
2	5.48E-03	28.81	IDACid CB CLOSE	
3	6.50E-04	3.42	IDACid AR OFF	
4	6.50E-05	0.34	IDACid AR1 SIGN	
5	3.42E-06	0.02	IDACid DC1 MCB 1	
6	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
7	1.98E-06	0.01	IDACid BUS U MEASURE	
8	1.98E-06	0.01	IDACid LIN U MEAS FO	
9	5.76E-07	0	ID DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
11	1.83E-09	0	ID SUBSTATION	

12	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 49 The minimal cut sets of a fault tree for the autoreclosing system of a master line end. The autoreclosing system consists of an electromechanical autoreclcosing relay and a microprocessor synchronism check device. The circuit breaker is of the air-blast type. Top event probability q = 2.04E-02.

No.	Prob.	%	Event	Event
1	9.93E-03	48.65	IDACid CB CLOSE	
2	8.86E-03	43.39	IDACid SC PRO	
3	1.02E-03	4.99	IDACid AR MEC 2	
4	6.50E-04	3.18	IDACid AR OFF	
5	6.50E-05	0.32	IDACid AR1 SIGN	
6	6.60E-06	0.03	ID AIR PRESSURE AR	
7	3.42E-06	0.02	IDACid DC1 MCB 1	
8	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
9	1.98E-06	0.01	IDACid BUS U MEASURE	
10	5.76E-07	0	ID DC1 220 1	
11	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
12	1.83E-09	0	ID SUBSTATION	
13	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
14	7.25E-10	0	IDACid BAY	

Table 50 The minimal cut sets for a fault tree covering the autoreclosing system of a master line end. The autoreclosing relay and synchronism check device are integrated microprocessor relays and the circuit breaker is of the air-blast type. Top event probability q = 2.34E-02

No	Prob.	%	Event	Event
1	1.29E-02	55.08	IDACid AR & SC PRO	
2	9.93E-03	42.42	IDACid CB CLOSE	
3	6.50E-04	2.77	IDACid AR OFF	
4	6.50E-05	0.28	IDACid AR1 SIGN	
5	6.60E-06	0.03	ID AIR PRESSURE AR	
6	3.42E-06	0.01	IDACid DC1 MCB 1	
7	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
8	1.98E-06	0.01	IDACid BUS U MEASURE	
9	5.76E-07	0	ID DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
11	1.83E-09	0	ID SUBSTATION	

12	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 51 The minimal cut sets of a fault tree for the autoreclosing system of a master line end. The autoreclosing system consists of a static autoreclcosing relay and a static synchronism check device. The circuit breaker is of the SF6 type. Top event probability q = 2.57E-02.

No.	**Prob.**	**%**	**Event**	**Event**
1	1.85E-02	71.99	IDACid AR STA	
2	5.48E-03	21.33	IDACid CB CLOSE	
3	1.14E-03	4.44	IDACid SC STA	
4	6.50E-04	2.53	IDACid AR OFF	
5	6.50E-05	0.25	IDACid AR1 SIGN	
6	3.42E-06	0.01	IDACid DC1 MCB 1	
7	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
8	1.98E-06	0.01	IDACid BUS U MEASURE	
9	5.76E-07	0	ID DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
11	1.83E-09	0	ID SUBSTATION	
12	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 52 The minimal cut sets of a fault tree for the autoreclosing system of a master line end. The autoreclosing system consists of a static autoreclcosing relay and a static synchronism check device. The circuit breaker is of minimum oil type. Top event probability q = 2.76E-02.

No.	**Prob.**	**%**	**Event**	**Event**
1	1.85E-02	66.93	IDACid AR STA	
2	7.46E-03	27	IDACid CB CLOSE	
3	1.14E-03	4.12	IDACid SC STA	
4	6.50E-04	2.35	IDACid AR OFF	
5	6.50E-05	0.24	IDACid AR1 SIGN	
6	3.42E-06	0.01	IDACid DC1 MCB 1	
7	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
8	1.98E-06	0.01	IDACid BUS U MEASURE	
9	5.76E-07	0	ID DC1 220 1	
10	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
11	1.83E-09	0	ID SUBSTATION	

12	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
13	7.25E-10	0	IDACid BAY	

Table 53 The minimal cut sets of a fault tree for the autoreclosing system of a follower line end. The autoreclosing system consists of a static autoreclcosing relay and a static synchronism check device. The circuit breaker is of the air-blast type. Top event probability q = 3.01E-02.

No.	**Prob.**	**%**	**Event**	**Event**
1	1.85E-02	61.53	IDACid AR STA	
2	9.93E-03	33.04	IDACid CB CIDSE	
3	1.14E-03	3.79	IDACid SC STA	
4	6.50E-04	2.16	IDACid AR OFF	
5	6.50E-05	0.22	IDACid AR1 SIGN	
6	6.60E-06	0.02	ID AIR PRESSURE AR	
7	3.42E-06	0.01	IDACid DC1 MCB 1	
8	2.11E-06	0.01	IDACid Z1 AR1 SIG	IDACid Z2 AR1 SIG
9	1.98E-06	0.01	IDACid BUS U MEASURE	
10	1.98E-06	0.01	IDACid LIN U MEAS FO	
11	5.76E-07	0	ID DC1 220 1	
12	4.96E-09	0	IDACid DC2 MCB 1	IDACid Z1 AR1 SIG
13	1.83E-09	0	ID SUBSTATION	
14	8.36E-10	0	ID DC2 220 1	IDACid Z1 AR1 SIG
15	7.25E-10	0	IDACid BAY	

APPENDIX C – FAILURE MODE AND EFFECT ANALYSIS

Table 1 Substation, a basic event for a common cause failure. Identification of the basic event: ID SUBSTATION, where ID is the identification of the substation.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
The whole substation: control building, common cables.	All the control commands, measurements and alarms of the substation	Fire due to overload of a device	The protection systems of the substation do not function	A failure of control, protection and alarm systems	Fire alarm.	$\hat{\lambda}$ = 6.3E-05 MTTR = 2.9E-05
		Manufacturing or installation failure of cables	Cable failure -> earth fault, short circuit -> signal transfer is prevented	A failure of control, protection and alarm systems	DC earth fault alarm	
		A truck drives to the control building. A meteorite or an air plane falls.	Mechanical failure of devices prevents substation operations	A failure of control, protection and alarm systems		

Table 2 Bay, a basic event for a common cause failure. Identification of the basic event: IDACid BAY, where ID is the identification of the substation and id is the identification of the bay. This basic event shall be included in all fault trees, which includes at least one component of that bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
Cables of one bay, which connects the circuit breakers, instrument transformers etc to substation control and protection.	Controls, measurements and other information between the building devices (relays) and the switchyard devices (circuit breakers, instrument transformers)	Frost	Frost damages the cables or causes the insulation to fray due to cable move-ment. -> earth fault, short circuit	Controls commands and alarms fail. Circuit breaker does not trip or close, current and voltage measurements fail.	Alarm after a cable failure. DC earth fault alarm or DC MCB trips or Z MCB trips or busbar protection differential relay sends an alarm or the main transformer (400/110/20 kV) trips.	$\hat{\lambda}$ = 2.5E-05 MTTR: 2.9E-05
		Water in the cable ditch	Mechanical failures due to water freezing and melting -> a cable suf-fers an earth fault or short circuit			
		Fire	A fire caused by overload or an external reason -> a cable faces an earth fault or a short circuit			
		Manufactur-ing or in-stallation failure	Manufacturing defect or a careless installation causes an earth fault or a short circuit			

Table 3 220 V DC voltage supply. IDENTIFICATION: ID DC1 220 V 1 or ID DC2 220 V 1, where ID is the identification of the substation. ID DC1 220 V 1 is used for distance relay 1, breaker failure relay, circuit breaker trip coil 1, circuit breaker closing coil and rapid automatic reclosing relays. ID DC2 220 V 1 is used for distance relay 2, differential relay, and circuit breaker trip coil 2.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
Substation 220 V DC voltage batteries. This includes the batteries, miniature circuit breakers and direct current conductors.	Direct voltage that feeds the relays and circuit breaker trip coils and tele-communication 48 V DC supply.	Manufacturing , installation failure or ageing	DC short circuit	Relays do not function, circuit breaker trip coil does not receive a trip command	An alarm for a DC fuse or an alarm for battery low voltage. Monitored component.	$\hat{\lambda}$ = 6.4E-04 MTTR = 9.0E-04

Table 4 Miniature circuit breaker (MCB) for the 220 V DC voltage supply for the bay. IDENTIFICATION: IDACid DC1 MCB 1 or IDACid DC2 MVB 1, where ID is the identification of the substation, id is the identification of the bay. Usually IDACid DC1 MCB 1 is used in the fault trees that contain the basic event ID DC1 220 V 1 and the basic event IDACid DC2 MCB 1 is used in the fault trees that contain the basic event ID DC2 220 V 1. The only exception to this rule are the fault trees for the breaker failure relays, which do not use the miniature circuit breakers for the bays but the miniature circuit breakers for the busbar protection relays. At the substations with two circuit breakers and two bays for a line end, there is only one MCB for DC batteries 1 and 2.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
220 V DC miniature circuit breaker protecting the DC 1 or DC 2 supply circuits of a bay	Short circuit protection for the DC supply circuits	Mechanical failure, ageing	Short circuit leads to a MCB trip	Relay does not function, CB does not receive a trip signal to trip coil 1, and CB does not close.	Alarm: MCB tripped	$\hat{\lambda}$ = 5.7E-03 MTTR = 6.0E-04
		Human error	The DC circuit is disconnected	Relay does not function, CB does not receive a trip signal to trip coil 1, and CB does not close.	If the DC circuit is open, the failure is detected by a test if there are only electro-mechanical relays in the bay: Static and microprocessor relays send an alarm during a DC supply failure.	Not included in the model.

Table 5 Miniature circuit breaker for the 220 V DC voltage supply for the breaker failure relay. IDENTIFICATION: ID DC1 BPR MCB 1, where ID is the identification of the substation. This basic event is used in the fault trees for the breaker failure relays.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
Miniature circuit breakers for the busbar protection relay, which is supplied from the 220 V DC batteries. This is used when the initiating event is not an explosion of a current transformer.	MCB of the busbar protection and breaker failure protection. It detects faults in the DC supply of those relays.	Human error during installation, ageing, manufacturing failure.	DC short circuit, MCB trips without a fault	Breaker failure relay does not function	Alarm	$\hat{\lambda}$ = 4.2E-03 MTTR = 6.0E-04

Table 6 48 V DC voltage supply for the telecommunication devices. IDENTIFICATION: ID DC 48 V 1, where ID is the identification of the substation. This basic event is used in the fault trees for the protection that uses the telecommunication.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
The 48 V DC supply for the protection telecommuni-cation system components. This includes the 48 V DC system and its parts: 220/48 V DC/DC-converters, MCB, and the 48 V DC circuitry (the 48 V cables between the terminal devices and DC/DC converters). The cables are usually not doubled.	Distance relays permissive overreach and underreach transfer trip and differential relays need protection tele-communicatio n terminal devices. These devices are supplied by 48 V DC battery.	Manufacturing failure, installation failure, ageing	Mechanical failures in the devices	Those protection systems that need tele-communicatio n channel between stations do not function.	Alarm. Either a part of the 48 V system fails and sends an alarm or the entire 48 V system fails and the substation remote terminal unit sends an alarm.	$\hat{\lambda}$ = 8.1E-04 MTTR = 9.0E-04
		Human error, ageing,	The DC circuit is disconnected		Alarm (terminal devices send an alarm)	
		Overload	Voltage is too low		Alarm indicating a low DC voltage	
		Telecommunicati on device cubicle that includes DC/DC converters and terminal devices	Fire, shock		Alarm	

Table 7 Substation pneumatic system at the substation for the air-blast circuit breakers. IDENTIFICATION: ID AIR PRESSURE AR, where ID is the identification of the substation. This basic event is used in the fault trees, where the air-blast circuit breakers need to reclose after a trip.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
Pneumatic system of the substation for the CB trip function	The system creates the compressed air for the circuit breakers. CB trip function.	Ageing, manufacturing failure	Valves of the circuit breaker leak and the pneumatic system of the substation fails.	The pneumatic system cannot give CBs the pneumatic they need. Since the CBs have individual PI tanks, they can trip once but then the pneumatic tank would be empty. After one trip a CB cannot reclose if the air is not replenished.	Alarm. The following actions in this order after the valves start to leak: 1) Alarm, 2) CB closing is blocked 3) CB tripping is blocked. After there is not any compressed air left, the CBs remain closed or close.	This is not used in the fault trees since the CBs can trip once even if the substation pneumatic system has failed.
Pneumatic system of the substation for the CB reclosing function	The system creates the compressed air for the circuit breakers. CB trip function.	Ageing, manufacturing failure	Valves of the pneumatic system leak, mechanical damage in the pneumatic system.	Not a single CB at the substation can reclose after tripping. An assumption: tripping has emptied the compressed air tank of the CB and since the substation pneumatic system tank has failed, the CB cannot close any more.	Alarm. The following actions in this order after the valves start to leak: 1) Alarm, 2) CB closing is blocked 3) CB tripping is blocked. After there is not any compressed air left, the CBs remain closed or close.	$\hat{\lambda}$ = 1.1E-02 MTTR = 6.0E-04

Table 8 The trip function of the air-blast circuit breakers. IDENTIFICATIONS: IDACid CB TRIP, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Air-blast circuit breaker	Trip after it has received a trip signal during a fault	Ageing	A valve failure, where the compressed air leaks from the circuit breaker	CB does not trip on command	Alarm	This is not taken into account. The faults detected by the tests dominate the unavailability of the air-blast circuit breakers. Therefore this fault does not have significance. The same constant unavailability is received with and without this basic event.
Air-blast circuit breaker	Trip during a fault	Ageing, manufacturing failure	A mechanical failure in the circuit breaker	CB does not trip on command	Test. An additional manual trip command, which is not taken into account in the model.	$\hat{\lambda}$ = 1.7E-02 MTTR = 2.9E-05 *Ti* = 1

Table 9 The trip function of the minimum oil and SF6-circuit breakers. IDENTIFICATIONS: IDACid CB TRIP, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti* (year)**
Minimum oil circuit breaker	Trip during a fault	Ageing, manufacturing failure	A mechanical failure in the CB.	Circuit breaker does not trip on command	Test (also manual command, which is not taken into account in the model).	$\hat{\lambda}$ = 4.9E-03 MTTR = 2.9E-05 *Ti* = 1
SF6 circuit breaker	Trip during a fault	Ageing, manufacturing failure	A mechanical failure in the CB.	CB does not trip on command	Test (also manual command, which is not taken into account in the model).	$\hat{\lambda}$ = 2.8E-03 MTTR = 2.9E-05 *Ti* = 1

Table 10 Trip coils in all types of circuit breakers. IDENTIFICATIONS: IDACid CB TRIP COIL 1 or IDACid CB TRIP COIL 2, where ID is the identification of the substation and id is the identification of the bay. This basic event is used in the fault trees, where the circuit breakers trip.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Circuit breaker	Trip during a fault	Terminal strip of the trip coil 1 is disconnected	Human error	Circuit breaker does not receive a trip signal to trip coil 1	Test. An additional manual command, which is not taken into account in the model.	$\hat{\lambda}$ = 5.9 E-04 MTTR = 2.9E-05 *Ti* = 1
Circuit breaker	Trip during a fault	Terminal strip of the trip coil 1 is disconnected	Human error	Circuit breaker does not receive a trip signal to trip coil 2	Test	$\hat{\lambda}$ = 5.9 E-04 MTTR = 2.9E-05 *Ti* = 1

Table 11 The reclosing function of the air-blast circuit breakers. IDENTIFICATIONS: IDACid CB CLOSE, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Air-blast circuit breakers	Close at automatic reclosing action	Manufacturing failure, ageing	A valve failure in which the compressed air leaks from the circuit breaker.	CB does not close on command	Alarm	This is not taken into account. It is detected by an alarm and the faults detected by tests dominate the unavailability of the circuit breakers
Air-blast circuit breakers	Close at automatic reclosing action	Human error, ageing, manufacturing failure	CB mechanical failure, terminal strips disconnected.	CB does not close on command. CB does not receive a signal to the coil for closing the CB.	Test. An additional manual command.	$\hat{\lambda}$ = 2.0E-02 MTTR = 2.9E-05 *Ti* = 1

Table 12 The reclosing function of the minimum oil and SF6-circuit breakers. IDENTIFICATIONS: IDACid CB CLOSE, where ID is the identification of the substation and id is the identification of the bay. This basic event is used in the fault trees, where the minimum oil circuit breaker recloses.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year)** **MTTR (year)** ***Ti* (year)**
Minimum oil circuit breakers	Close at automatic reclosing action	Manufacturing failure, ageing	Failure of the spring charger.	CB does not close on command	Alarm	This is not taken into account. These faults do not have significance compared to faults detected by tests.
Minimum oil circuit breakers	Close at automatic reclosing action	Human error, ageing, manufacturing failure	Circuit breaker mechanical failure, terminal strips disconnected.	CB does not close on command. CB does not receive a signal to the coil for closing the CB.	Test. An additional manual command.	$\hat{\lambda}$ = 1.5E-02 MTTR = 2.9E-05 *Ti* = 1
SF6 circuit breakers, reclosing after the trip	Close at automatic reclosing action	Manufacturing failure, ageing	Failure of the spring charger	Circuit breaker does not close on command	Alarm	This is not taken into account. These faults do not have significance compared to faults detected by tests.
SF6 circuit breakers	Close at automatic reclosing action	Human error, ageing, manufacturing failure	CB mechanical failure, terminal strips of the close coil are not connected	CB does not close on command. CB does not receive a signal to the coil for closing the CB.	Test. An additional manual command.	$\hat{\lambda}$ = 1.1E-02 MTTR = 2.9E-05 *Ti* = 1

Table 13 Electromechanical distance relays. IDENTIFICATIONS: IDACid Z1 MEC 2 and IDACid Z2 MEC 2, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Voltage measurement circuits	The voltage value to the relay.	Human error, ageing	Measuring circuit disconnected, loose junction	The relay trips if the load current exceeds the threshold value (e.g. 0.2*IN)	Unwanted trip.	It is no relevant in this study, since the relay trips correctly during faults.
Electromechanical distance relays	Send an instantaneous trip signal during faults on the protected line	Dirt, ageing	Trip signal delayed due to dirt	No instantaneous trip signal	Test	$\hat{\lambda}$ = 6.5E-03 MTTR = 1.0E-02 *Ti* = 1
		Dirt, ageing	Zone 1 reach decreases			
		Human error	Current measurement circuit of the relay is disconnected			
		Human error	Terminal strips of the relay or of the relay cubicle are disconnected			
		Human error	Erroneous setting or configuration			
		Ageing, manufacturing error,	Internal contact of the relay is loose and prevents the signal transfer			

Table 14 Static distance relays. IDENTIFICATIONS: IDACid Z1 STA and IDACid Z2 STA, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Static distance relay	Send an instantaneous trip signal during faults on the protected line (zone 1 and POTT trips)	Ageing of the relay components.	Zone 1 reach is reduced	The relay does not send an instantaneous trip signal	Test	$\hat{\lambda}$ = 1.4E-02 MTTR = 1.0E-02 *Ti* = 1
		Human error	Current measurement circuit of the relay is disconnected			
		Human error	Terminal strips of the relay or of the relay cubicle are disconnected			
		Human error	Erroneous setting or configuration			
		Ageing	The spring of the card joints becomes loose and the signal transfer is prevented.			
		Ageing of the components in the relay power supply	The relay loses the power supply it needs.	The relay does not send a trip signal.	Alarm	$\hat{\lambda}$ = 2.7E-03 MTTR = 1.0E-02
Voltage measurement circuit	Voltage measurement to the relay	Human error	Voltage measurement circuit disconnected. The trip signal transfer to the CB is prevented by the voltage transformer supervision	No trip signal to the circuit breaker		

Table 15 Microprocessor distance relay. IDENTIFICATIONS: IDACid Z1 PRO and IDACid Z2 PRO, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti* (year)**
Processor distance relay	Send an instantaneous trip signal during faults on the protected line (zone 1 and POTT trips)	A software error	No trip signal.	No trip signal.	Test	$\hat{\lambda}$ = 5.2E-03 MTTR = 2.0E-02 *Ti* = 1
		Human error	Current measurement circuit of the relay is disconnected			
		Human error	Terminal strips of the relay or of the relay cubicle are disconnected			
		Human error	Erroneous setting or configuration			
		Ageing	The spring of the card joints is loose, the signal transfer is prevented.			
		Ageing of the components in the relay power supply.	Relay loses the power supply	No trip signal	Alarm	$\hat{\lambda}$ = 3.0E-02 MTTR = 1.0E-02
Voltage measurement circuit	Voltage value to the relay.	Human error: voltage measurement circuit disconnected	No trip signal (voltage transformer supervision)			

Table 16 Instrument transformers

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Voltage trans-former (VT) for the electro-mechanical distance relays	Voltage measure-ment for the distance relay.	Manufa cturing error, ageing	Voltage transformer fails (e.g. an explosion)	No trip signal.	Alarm. If the VT explodes, the alarm is too late.	VT failure is a separate initiating event (an extra busbar or line fault), which means that the grid has to withstand two simultaneous faults. In this case it is not sensible to analyse in detail the sequence of events after one fault only. Besides, a VT failure alone does not necessarily prevent the trip after line faults. The case is different if the VT fails and the MCBs for the VT trip or if the VT fails and the voltage transformer supervision of the relays operates. In these cases the distance relays can not trip the line. These are not included in the model, nor are simultaneous grid faults..
Current trans-former	Current measure-ment for the relays	Manufa cturing error	Current transformer explodes	Substati on or line shunt fault	Alarm. If the VT explodes, the alarm is too late.	Not included in the model, since this is a separate initiating event, the consequences of which are unforeseeable, as can be seen in 5.3.2.

Table 17 Miniature circuit breakers (MCB) for the voltage measurement. IDENTIFICATIONS: IDACid Z MCB VT for electromechanical distance relays, IDACid Z1 MCB VT and IDACid Z2 MCB VT for static and microprocessor distance relays. ID is the identification of the substation and id is the identification of the bay. This basic event is used in the fault trees, where a distance relays sends a trip signal.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
MCB for an electro-mechanical distance relay	Prevent a trip during the short circuits of the voltage measurement circuit	Ageing (materials deteriorate over time)	Isolation failures in the relay -> internal short circuits of the relay -> MCB VT trips	No trip signal to circuit breakers. (Busbar VT & old installation: both relays use the same MCB, line VT and/or new installation: one MCB per relay.	Alarm	$\hat{\lambda}$ = 3.3E-03 MTTR = 6.0E-04
		Human error, mechanical failure	MCB VT trips due to a short circuit (both relays usually have a common MCB)			
MCB of a static distance relay	Inform about the short circuits at the voltage measurement circuit	Human error: short circuit	MCB VT trips due to a short circuit (each relay usually has a MCB)			
MCB of a Processor distance relay	Inform about the short circuits at the voltage measurement circuit	Human error: -> short circuit	MCB VT trips due to a short circuit (each relay usually has an MCB)			

Table 18 Microprocessor differential relay for a line. IDENTIFICATIONS: IDACid D, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year) MTTR (year)**
Processor differential relay for a line	Send a trip signal during faults on the protected line.	Ageing of the components in the relay power supply.	The relay loses the power supply it needs.	The relay does not send a trip signal.	Alarm	$\hat{\lambda}$ = 2.9E-02 MTTR = 2.0E-02
		A software error	No trip signal.	No trip signal.	Test	$\hat{\lambda}$ = 5.8E-03 MTTR = 2.0E-02 *Ti* = 1
		Ageing of the relay components.	Settings are altered.			
		Human error	Terminal strips of the relay or the relay cubicle are disconnected			
		Human error	Wrong setting or configuration			
		Ageing, the spring of the card joints becomes loose	The signal transfer is prevented.			

Table 19 Static breaker failure relay (BFR). IDENTIFICATION: IDACid BFR STA where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti* (year)**
Static breaker failure relay	Sends a trip signal to other circuit breakers connected to the same busbar as the faulted circuit breaker. Also sends a trip signal to the remote end distance relays if the fault current has not stopped in the predefined time (200 ms).	Ageing of the components of the relay power supply.	The relay loses the power supply it needs.	No trip signal	Alarm by self supervision of the relay	$\hat{\lambda}$ = 2.9E-03 MTTR = 1.0E-02
		Human error	Current measurement circuit of the relay is disconnected	No trip signal	The busbar protection relay sends an alarm	
		Ageing of the relay components.	Settings are changed	No trip signal	Test	$\hat{\lambda}$ = 9.5E-04 MTTR = 1.0E-02 *Ti* = 1
		Ageing. The spring of the card joint becomes loose.	The signal transfer is prevented			
		Human error	Erroneous settings or configuration.			

Table 20 Terminal strips of the breaker failure relay are disconnected. IDENTIFICATION: IDACid BFR TS REC 1, where ID is the identification of the substation and id is the identification of the bay.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti* (year)**
Terminal strips of the breaker failure relay	To transmit a trip signal from the distance or differential relays to the breaker failure relay. After receiving this signal the breaker failure relay starts to measure the current of the circuit breaker that needs to trip.	Human error	The signal transfer is prevented, therefore the start signal from the distance relay to the BFR is not transferred.	No trip signal to the relevant circuit breakears	Test	$\hat{\lambda}$ = 1.3E-03 MTTR = 1.0E-02 *Ti* = 1

Table 21 Telecommunication channels for the distance and differential relays. IDENTIFICATION: IDid&IDid TELE A or IDid&IDid TELE B, where the IDid-parts are the identifications of the substation and the bay at different line ends. This basic event is used in the fault trees, where relays need a telecommunication channel. This basic event also includes also the terminal devices between the relays and the telecommunication system.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**Unavailability *q***
Optical fibre (OF)	Signal transfer	Manufacturing, installation or mechanical failure, or a human error	A failure of the optical fibre, a joint or terminal device. A human error in the software of the grid of the network provider	The signal transfer is prevented. No instantaneous trip signal from the distance relays. No trip signal by the differential relays.	An immediate signal. An alarm after 20 seconds.	q = 1.2E-02
Radio link (RL)		Fog, manufacturing or installing failure or a human error	Fog or mechanical failure. A human error in the software of the grid of the network provider			q = 9.3E-03
Analogue power line carrier (PLC)		Frost, manufacturing or installing failures	Corona caused by the frost			q = 6.1E-03
OF and RL in series		As See OF and RL	See optical fibre and microwave			q = 5.0E-03
OF and PLC in series		As OF and PLC	See optical fibre and PLC			q = 1.3E-02

Table 22 The test switch of the telecommunication channel. IDENTIFICATION: IDid&IDid TELE A TEST or IDid&IDid TELE B TEST, where the first IDid identifies the substation and the bay at one line end and the second IDid identifies the substation and the bay at the other line end. This basic event is used in fault trees, where a distance relay or a differential relay needs a telecommunication channel.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\hat{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Telecommunication link test switch is at TEST position during normal operation	To prevent trips during testing and maintenance.	Human error	Test switch is at ON position after the test.	The signal transfer is prevented	There is an alarm when the testing or maintenance of the telecommunication channel starts. This alarm will be on until the test switch is set to the normal position. However, there will not be any more alarms and it is possible that the test engineer forgets to switch the test switch to its normal position after the work and nobody pays attention to the old alarm any more. In this study this switch is treated as a tested component	$\hat{\lambda}$ = 7.4E-04 MTTR = 2.9E-05 *Ti* = 1

Table 23 Electromechanical relays for the automatic reclosing system. IDENTIFICATION: IDACid AR MEC 2 and IDACid SC MEC 2, where ID is the identification of the substation and id is the identification of the bay. AR is for automatic reclosing and SC is for the synchronism check function.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\tilde{\lambda}$ (1/year)** **MTTR (year)** ***Ti* (year)**
Electro-mechanical autoreclosing relay	To send a close signal to circuit breakers after a fault	Ageing, dirt	Automatic reclosing is delayed due to dirt and fails.	Automatic reclosing fails.	Test	$\hat{\lambda}$ = 2.0E-03 MTTR = 1.0E-02 Ti = 1
Electro-mechanical synchronism check relay	To check the voltage conditions before the Automatic reclosing.	Ageing, dirt	Setting values are changed due to dirt.	Automatic reclosing fails.	Test	$\hat{\lambda}$ = 3.7E-03 MTTR = 1.0E-02 Ti = 1

Table 24 Static automatic reclosing relay and synchronism check relay. IDENTIFICATION: IDACid AR STA and IDACid SC STA, where ID is the identification of the substation and id is the identification of the bay. AR is for automatic reclosing and SC is for the synchronism check function.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	$\tilde{\lambda}$ **(1/year)** **MTTR (year)** ***Ti*** **(year)**
Static automatic reclosing relay AR	To send a close signal to circuit breakers after a fault	Ageing of the components of the relay power supply.	Relay loses the power supply it needs.	Automatic reclosing fails.	Alarm	$\hat{\lambda}$ = 3.6E-02 MTTR = 1.0E-02
		Ageing of the relay components.	Settings are changed.	Automatic reclosing fails.	Test	$\hat{\lambda}$ = 3.6E-02 MTTR = 1.0E-02 *Ti* = 1
		Ageing. The spring of the card joint becomes loose.	The signal transfer is prevented			
		Human error	Erroneous settings or configuration.			
Static synchronism check relay	To check the voltage conditions before the Automatic reclosing .	Ageing of the components of the relay power supply.	The relay loses the power supply it needs.	Automatic reclosing fails.	Alarm,	$\hat{\lambda}$ = 2.2E-03 MTTR = 1.0E-02
		Ageing of the relay components.	Settings are changed	Automatic reclosing fails.	Test	$\hat{\lambda}$ = 2.2E-03 MTTR = 1.0E-02 *Ti* = 1
		Ageing. The spring of the card joint becomes loose.	Signal transfer is prevented			
		Human error	Erroneous settings or configuration.			

Table 25 Microprocessor relays for the synchronism check (SC) alone and for the automatic reclosing with the synchronism check function (AR&SC). IDENTIFICATION: IDACid AR&SC and IDACid SC PRO, where ID is the identification of the substation and id is the identification of the bay. AR&SC is for the combined automatic reclosing and synchronism check relay and SC is for synchronism check only.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year)** **MTTR (year)** ***Ti* (year)**
Micro-processor synchronism check relay.	To check the voltage conditions before automatic reclosing.	Ageing of the components of the relay power supply.	The relay loses the power supply it needs.	Automatic reclosing fails	Alarm	$\hat{\lambda}$ = 3.4E-03 MTTR = 1.0E-02
		Human error	Erroneous settings or configuration	Automatic reclosing fails	Test	$\hat{\lambda}$ = 1.7E-02 MTTR = 1.0E-02 *Ti* = 1
Microproc-essor relays, combined automatic reclosing and synchronism check relay.	To send a close signal to circuit breakers after a fault if the voltages are correct.	Ageing of the components of the relay power supply.	The relay loses the power supply it needs.	Automatic reclosing fails	Alarm	$\hat{\lambda}$ = 2.4E-02 MTTR = 1.0E-02
		Human error	Erroneous settings or configuration	Automatic reclosing fails	Test	$\hat{\lambda}$ = 2.4E-02 MTTR = 1.0E-02 *Ti* = 1
		Human error	A software error			
		Ageing of the components	Settings are changed			
		Ageing. The spring of the card joint becomes loose.	The signal transfer is prevented			

Table 26 Automatic reclosing (AR) system, the components that send an alarm. IDENTIFICATION: ID W1 U MEASURE, IDACid LIN U MEAS FO, where ID is the identification of the substation and id is the identification of the bay. ID W1 U MEASURE is for busbar voltage measurement and is used in all autoreclosing fault trees. IDACid LIN U MEAS FO is for line voltage measurement and is used in the autoreclosing fault trees for the follower line end only.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year) MTTR (year)**
Busbar voltage measurement for the automatic re-closing system. This is used in both the master and follower line ends.	To send a close signal to circuit breakers after a fault if the busbar voltage is correct and the line is dead.	Busbar voltage measurement circuit has an earth fault or miniature circuit breakers of the VT trip	SC relay blocks the AR-relay.	AR fails	Alarm	$\hat{\lambda}$ = 3.3E-03 MTTR = 6.0E-04
Line voltage measurement for the automatic re-closing system of the follower line end	To send a close signal to circuit breakers after a fault if the busbar and line voltages are correct	Line voltage measurement circuit has an earth fault or miniature circuit breakers of the VT trip	SC relay blocks the AR-relay. The bay that is a ‘follower’ cannot make an automatic reclosing action.	AR fails	Alarm	$\hat{\lambda}$ = 3.3E-03 MTTR = 6.0E-04

Table 27 Automatic reclosing (AR) system, the tested components. IDENTIFICATION: IDACid Z1 AR SIG, IDACid AR1 SIGN and IDACid AR OFF. ID is the identification of the substation and id is the identification of the bay. : IDACid Z1 AR SIG is for a start signal from the trip relay, IDACid AR1 SIGN is for signal transfers between the circuit breaker and autoreclosing relays and between the synchronism check relays and autoreclosing relays. IDACid AR OFF is for the switch which turns AR off when needed.

Item	**Function**	**Cause of failure**	**Failure mode**	**Effects of failure**	**Detection of failure**	**$\hat{\lambda}$ (1/year)** **MTTR (year)** ***Ti* (year)**
Distance or differential relay	Send a start signal to AR-relays	A setting or configuration error	Automatic reclosing relay does not receive a start signal from the trip relays	AR fails	Test	$\hat{\lambda}$ = 2.9E-03 MTTR = 9.0E-04 Ti = 1
Circuit	Signal transfer	Human error: terminal strips disconnected in the circuit between the CB and AR-relay.	AR-relay does not receive the signal: 'CB tripped'. For air-blast CBs: AR-relays do not get the signal 'CB ready to close'	AR fails	Test	$\hat{\lambda}$ = 1.3E-04 MTTR = 2.9E-05 Ti = 1 Note: it is assumed that one basic event includes all these circuits.
Circuit	Signal transfer	Human error: terminal strips disconnected in the circuit between the AR- and SC-relay.	SC-relay blocks the AR-relay.			
DC infeed circuit	AR relay DC power supply	Minimum oil or SF6 CBs: DC voltage plus is not connected to the AR-relay	AR-relay does not act due to lack of positive voltage.			
AR switch OFF	Prevent AR when needed	Human error: AR off switch is at OFF position.	AR-relay does not function	AR fails	Test	$\hat{\lambda}$ = 1.3E-03 MTTR = 2.9E-05 Ti = 1

APPENDIX D – SOURCE OF INFORMATION FOR THE FMEA

Device and function	**Total number of equipment-years / years studied**	**Data source**	**Faults detected by an alarm / by tests**	**Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests**
Substation (a common cause failure basic event)	7880 / 10 ... 55 Yrs	Norway, Sweden Denmark: 110-400 kV substations 1993-2002 from Nordel annual statistics, Finland: 220- 400 kV substations calculated since 1957, 110 kV estimated since 1982	0 / not relevant	6.3E-05 / -
Bay (a common cause failure basic event)	20247 / 20 ... 55 Yrs	Finland 220- 400 kV substations, calculated since 1957, 110 kV estimated since 1982	0 / not relevant	2.5E-05 / -
220 V DC voltage supply in a case where there is at least one modern relay at the substation (all DC faults send an alarm)	5457 / 10 Yrs	Fingrid's fault statistics, years 1993-2002, DC battery, DC/DC converter faults. Rectifier faults are ignored since they send an alarm and the fault can be repaired before the battery loses its voltage.	3 / not relevant	6.4E-04 / -
220 V DC voltage supply in a case where there is not a single modern relay at the substation (some DC faults send an alarm)	5457 / 10 Yrs	Fingrid's fault statistics, years 1993-2002, DC battery, DC/DC converter faults. Rectifier faults are ignored since they send an alarm and the fault can be repaired before the battery loses its voltage.	1 / 2	2.7E-04 / 4.6E-04

Device and function	Total number of equipment-years / years studied	Data source	Faults detected by an alarm / by tests	Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests
220 V DC MCBs at each bay for DC1 or DC2 battery	88 / 1 Yrs	Expert judgment. Interview with Fingrid's operation personnel	0 / not relevant	5.7E-03 / -
Miniature circuit breaker for the busbar protection relay (BPR) supplied from 220 V DC battery 1 or 2. Initiating event is not a current transformer explosion.	330 / 5 Yrs	Fingrid's relay fault statistics	0 / not relevant	1.5E-03 / -
Miniature circuit breaker of the breaker failure relay (BFR) supplied from 220 V DC battery 1 or 2. Initiating event is not a current transformer explosion.	330 / 5 Yrs	Fingrid's relay fault statistics	0 / not relevant	1.5E-03 / -

Device and function	Total number of equipment-years / years studied	Data source	Faults detected by an alarm / by tests	Un-availability
Miniature circuit breaker for the busbar protection relay (BPR) supplied from 220 V DC battery 1 or 2. **This data is for cases where the initiating event is an explosion of a current transformer.**	Not relevant / 20 Yrs	Fingrid's grid fault statistics. 8 busbar faults due to CT explosion, the MCB has tripped only once during an explosion.	1 / not relevant	1.3E-01
Miniature circuit breaker of the breaker failure relay (BFR) supplied from 220 V DC battery 1 or 2 **This data is for cases where the initiating event is the explosion of a current transformer.**	Not relevant / 20 Yrs	Fingrid's grid fault statistics. 8 busbar faults due to CT explosion, once the MCB tripped during a fault.	1 / not relevant	1.3E-01

Device and function	**Total number of equipment-years / years studied**	**Data source**	**Faults detected by an alarm / by tests**	**Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests**
48 V DC supply for protection telecommunication system devices	620 / -	No statistics available. Estimate: 620 device years for 400 kV substations during 20 years. No faults.	0 / not relevant	8.1E-04 / -
Pressurised air system of the substation for a circuit breaker trip	231.3 / 10 Yrs	Fingrid's fault statistics	0 / not relevant	2.2E-03 / -
Pressurised air system of the substation for a circuit breaker automatic reclosing	231.3 / 10 Yrs	Fingrid's fault statistics	2 / not relevant	1.1E-02 / -
Air-blast circuit breaker for tripping	377 / 10 Yrs	Fingrid's fault statistics	0 / 6	- / 1.7E-02
Minimum oil circuit breaker for tripping	507.9 / 10 Yrs	Fingrid's fault statistics	0 / 2	- / 4.9E-03
SF6-circuit breaker for tripping	527.2/ 10 Yrs	Fingrid's fault statistics	0 / 1	- / 2.8E-03
Air-blast circuit breaker for reclosing	377 / 10 Yrs	Fingrid's fault statistics	2 / 7	6.9E-02 / 2.0E-02
Minimum oil circuit breaker for reclosing	507.9 / 10 Yrs	Fingrid's fault statistics	0 / 7	- / 1.5E-02
SF6-circuit breaker for reclosing	527.2 / 10 Yrs	Fingrid's fault statistics	0 / 5	- / 1.1E-02
Terminal strip of a trip coil or a close coil of a circuit breaker is disconnected.	4236 / 10 Yrs	Fingrid's fault statistics	0 / 2	- / 5.9E-04

Device and function	Total number of equipment-years / years studied	Data source	Faults detected by an alarm / by tests	Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests	Unavailability (q), calculated with $\hat{\lambda}$ for both tested and monitored failures, test interval *Ti* and mean time to repair *MTTR*
Electromechanical distance relays	386 / 5 Yrs	Fingrid's relay fault statistics	- / 2	- / 6.5E-03	3.3E-03
Static distance relays	184 / Yrs	Fingrid's relay fault statistics	0 / 2	2.7E-03 / 1.4E-02	7.1E-03
Processor distance relays	288 / 5 Yrs	Fingrid's relay fault statistics	8 / 1	3.0E-02 / 5.2E-03	3.3E-03
MCB for a voltage measurement circuit of distance relay	755 / 5 Yrs	Fingrid's relay fault statistics	2 / not relevant	3.3E-03 / -	not used
Electromechanical or static differential relays for line protection	Model is not needed. There are no such relays in the Finnish transmission grid.		-	-	-
Processor differential relay for line protection	86 / 5 Yrs	Fingrid's relay fault statistics	2 / 0	2.9E-02 / 5.8E-03	3.6E-03
Electromechanical and processor breaker failure relay	0 / -	Model is not needed as there are no such relays on Fingrid's grid.	- / -	- / -	-
Static breaker failure relay	527 / 5 Yrs	Fingrid's relay fault statistics	1 / 0	2.9E-03 / 9.5E-04	5.1E-04
Terminal strip of a relay	3856 / 5 Yrs	Fingrid's relay fault statistics	- / 0	- / 1.3E-04	-

Device and function	Total number of equipment-years / years studied	Data source	Calculation of the unavailability (which is constant)	Unavaila-bility (q)
Optical fibre	20 / 1 Yrs	The Energy manage-ment and SCADA system of Fingrid	The unavailability q is the average of the unavailabilities of the separate optical fibre telecommunication channels.	1.2E-02
Radio link	7 / 1 Yrs	The Energy manage-ment and SCADA system of Fingrid	The unavailability q is the average of the unavailabilities of the separate radio link channels.	9.3E-03
Analogue power line carrier	10 / 1 Yrs	The Energy manage-ment and SCADA system of Fingrid	The unavailability q is the average of the unavailabilities of the separate power line carrier telecommunication channels.	6.1E-03
A combination of optical fibre and radio link	20 / 1 Yrs	The Energy manage-ment and SCADA system of Fingrid	The unavailability q is the average of the unavailabilities of the separate telecommunication channels that consist of optic fibre and radio link.	5.0E-03
A combination of optical fibre and power line carrier	2 / 1 Yrs	The Energy manage-ment and SCADA system of Fingrid	The unavailability q is the average of the unavailabilities of the separate telecommunication channels that consist of optic fibre and power line carrier.	1.3E-02

Device and function	Total number of equipment-years / years studied	Data source	Faults detected by an alarm / by tests	Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests	Unavailability (*q*), calculated with $\hat{\lambda}$ for both tested and monitored failures, test interval *Ti* and mean time to repair *MTTR*
The tests switch of the telecommunication channel is at TEST position	680 / 10 Yrs	Expert judgment	not relevant / 0	- / 7.4E-04	-
Electromechanical synchronism check relay	135 / 5 Yrs	Fingrid's relay fault statistics	not relevant / 0	- / 3.7E-03	-
Static autoreclosing relay	152 / 5 Yrs	Fingrid's relay fault statistics	5 / 5	3.6E-02 / 3.6E-02	1.9E-02
Static synchronism check relay	225 / 5 Yrs	Fingrid's relay fault statistics	0 / 0	2.2E-03 / 2.2 E-03	1.1E-03
Processor synchronism check relay	147 / 5 Yrs	Fingrid's relay fault statistics	0 / 2	3.4E-03 / 1.7E-02	8.9E-03
Processor automatic reclosing and synchronism check relay	148 / 5 Yrs	Fingrid's relay fault statistics	3 / 3	2.4E-02 / 2.4E-02	1.2E-02

Device and function	Total number of equipment-years / years studied	Data source	Faults detected by an alarm / by tests	Failure rate estimate $\hat{\lambda}$ for faults detected by an alarm / by tests
Automatic reclosing system: the trip relays fail to send AR start signal.	955 / 5 Yrs	Fingrids relay fault statistics	not relevant / 0	- / 2.7E-03
Automatic reclosing system: terminal strips of one relay are disconnected	3536 / 5 Yrs	Fingrids relay fault statistics	not relevant / 0	- / 1.4E-04
Automatic reclosing system: Autoreclosing ON/OFF switch is at OFF position	397 / 5 Yrs	Fingrids relay fault statistics	not relevant / 0	- / 1.3E-03
Automatic reclosing system: busbar voltage measurement circuit has an earth fault or VT MCB trips.	755 / 5 Yrs	Fingrids relay fault statistics	2 /not relevant	3.3E-03 / -
Automatic reclosing system: line voltage measurement circuit has an earth fault or VT MCB trips.		Assumption: line VT MCB has the same failure rate as the busbar MCB.		3.3E-03 / -

APPENDIX E – RESULTS FOR A SYSTEM BREAKDOWN

Appendix E uses code names for substation bay and line identifications due to confidentiality reasons. IDENTIFICATIONS: IDACid, where ID is the identification of the substation and id is the identification of the bay. CB = circuit breaker, Z = distance relay, D = line differential relay.

Table 1 100 most important minimal cut sets for the system breakdown. These cut sets cover 81.1 % of the system breakdown frequency (1.37E-03).

No	**%**	**Fault location on the line**	**Event 1**	**Event 2**
1	7.96	Line end	Line 33 tele	
2	6.68	In the middle	25AC02 CB TRIP	
3	2.23	Line end	25AC02 CB TRIP	
4	2.06	In the middle	11AC07 CB TRIP	11AC08 CB TRIP
5	2.06	In the middle	11AC02 CB TRIP	11AC05 CB TRIP
6	2.06	In the middle	11AC03 CB TRIP	11AC08 CB TRIP
7	2.06	In the middle	11AC05 CB TRIP	11AC07 CB TRIP
8	2.06	In the middle	11AC08 CB TRIP	11AC01 CB TRIP
9	2.02	In the middle	11AC03 CB TRIP	11AC01 CB TRIP
10	2.02	In the middle	11AC08 CB TRIP	11AC01 CB TRIP
11	2.02	In the middle	11AC07 CB TRIP	11AC01 CB TRIP
12	1.67	Line end	20AC03 CB TRIP	Line 34 tele
13	1.58	In the middle	11AC03 CB TRIP	11AC01 CB TRIP
14	1.58	In the middle	11AC03 CB TRIP	11AC07 CB TRIP
15	1.58	In the middle	11AC03 CB TRIP	11AC08 CB TRIP
16	1.41	In the middle	25AC06 CB TRIP	25AC09 CB TRIP
17	1.41	In the middle	25AC09 CB TRIP	25AC01 CB TRIP
18	1.39	In the middle	26AC03 CB TRIP	26AC10 CB TRIP
19	1.39	In the middle	26AC03 CB TRIP	26AC09 CB TRIP
20	1.13	In the middle	32AC01 Z1	32AC01 Z2
21	1.06	In the middle	32AC09 Z1	32AC09 Z2
22	0.95	Line end	Line 34 tele	25AC03 CB TRIP
23	0.86	In the middle	Line 29 tele	22AC05 Z2
24	0.86	In the middle	Line 29 tele	38AC09 Z2
25	0.85	In the middle	32AC03 Z1	32AC03 Z2
26	0.79	In the middle	26AC04 CB TRIP	26AC08 CB TRIP
27	0.79	In the middle	26AC04 CB TRIP	26AC09 CB TRIP
28	0.73	In the middle	11AC02 CB TRIP	11AC05 CB TRIP
29	0.73	In the middle	11AC02 CB TRIP	11AC07 CB TRIP
30	0.69	Line end	11AC02 CB TRIP	11AC05 CB TRIP
31	0.69	Line end	11AC07 CB TRIP	11AC08 CB TRIP
32	0.69	Line end	11AC03 CB TRIP	11AC08 CB TRIP

33	0.69	Line end	11AC05 CB TRIP	11AC07 CB TRIP
34	0.69	Line end	11AC08 CB TRIP	11AC01 CB TRIP
35	0.68	In the middle	42AC09 Z1	42AC09 Z2
36	0.68	In the middle	25AC07 Z1	25AC07 Z2
37	0.67	Line end	11AC08 CB TRIP	11AC01 CB TRIP
38	0.67	Line end	11AC07 CB TRIP	11AC01 CB TRIP
39	0.67	Line end	11AC03 CB TRIP	11AC01 CB TRIP
40	0.63	Line end	12AC04 CB TRIP	12AC05 CB TRIP
41	0.61	In the middle	26AC03 CB TRIP	26AC10 CB TRIP
42	0.61	In the middle	26AC09 CB TRIP	26AC10 CB TRIP
43	0.61	In the middle	26AC08 CB TRIP	26AC09 CB TRIP
44	0.61	In the middle	26AC04 CB TRIP	26AC08 CB TRIP
45	0.53	Line end	11AC03 CB TRIP	11AC07 CB TRIP
46	0.53	Line end	11AC03 CB TRIP	11AC01 CB TRIP
47	0.53	Line end	11AC03 CB TRIP	11AC08 CB TRIP
48	0.47	Line end	25AC06 CB TRIP	25AC09 CB TRIP
49	0.47	Line end	25AC09 CB TRIP	25AC01 CB TRIP
50	0.46	Line end	26AC03 CB TRIP	26AC10 CB TRIP
51	0.46	Line end	26AC03 CB TRIP	26AC09 CB TRIP
52	0.39	In the middle	25AC06 CB TRIP	25AC01 CB TRIP
53	0.39	In the middle	25AC06 CB TRIP	25AC09 CB TRIP
54	0.37	Line end	32AC01 Z1	32AC01 Z2
55	0.36	In the middle	21AC06 Z2	Line 25 tele
56	0.36	In the middle	21AC04 Z2	Line 28 tele
57	0.35	Line end	32AC09 Z1	32AC09 Z2
58	0.34	In the middle	25AC01 CB TRIP	25AC07 CB TRIP
59	0.32	In the middle	35AC01 Z1	35AC01 Z2
60	0.32	In the middle	22AC06 Z1	22AC06 Z2
61	0.32	In the middle	12AC05 D	38AC08 Z2
62	0.32	In the middle	38AC08 Z2	27AC01 D
63	0.32	In the middle	38AC08 D	38AC08 Z2
64	0.31	In the middle	11AC05 Z1	11AC05 Z2
65	0.31	In the middle	11AC08 Z1	11AC08 Z2
66	0.31	In the middle	37AC09 Z1	37AC09 Z2
67	0.31	In the middle	37AC07 Z1	37AC07 Z2
68	0.31	Line end	18AC02 CB TRIP	18AC03 CB TRIP
69	0.31	Line end	18AC03 CB TRIP	18AC05 CB TRIP
70	0.31	Line end	18AC03 CB TRIP	18AC07 CB TRIP
71	0.31	In the middle	13AC08 Z1	13AC08 Z2
72	0.31	In the middle	11AC01 Z1	11AC01 Z2
73	0.29	Line end	Line 29 tele B	22AC05 Z2
74	0.29	Line end	Line 29 tele B	38AC09 Z2
75	0.28	Line end	32AC03 Z1	32AC03 Z2
76	0.26	Line end	26AC04 CB TRIP	26AC09 CB TRIP
77	0.26	Line end	26AC04 CB TRIP	26AC08 CB TRIP
78	0.26	In the middle	21AC06 D	21AC06 Z2
79	0.26	In the middle	21AC04 Z2	22AC04 D
80	0.26	In the middle	21AC06 Z2	37AC00 D

81	0.26	In the middle	21AC04 Z2	21AC06 D
82	0.26	In the middle	38AC09 Z2	22AC05 D
83	0.26	In the middle	38AC09 D	22AC05 Z2
84	0.26	In the middle	38AC09 D	38AC09 Z2
85	0.26	In the middle	22AC05 D	22AC05 Z2
86	0.25	In the middle	32AC05 Z1	32AC05 Z2
87	0.24	In the middle	11AC03 Z1	11AC03 Z2
88	0.24	Line end	Line 13 tele B	33AC09 Z2
89	0.23	In the middle	25AC02 CB TRIP	25AC09 CB TRIP
90	0.23	Line end	42AC09 Z1	42AC09 Z2
91	0.23	Line end	25AC07 Z1	25AC07 Z2
92	0.22	In the middle	25AC09 Z1	25AC09 Z2
93	0.21	In the middle	26AC03 Z1	26AC03 Z2
94	0.21	In the middle	13AC01 Z1	13AC01 Z2
95	0.2	Line end	26AC09 CB TRIP	26AC10 CB TRIP
96	0.2	Line end	26AC03 CB TRIP	26AC10 CB TRIP
97	0.2	Line end	26AC04 CB TRIP	26AC08 CB TRIP
98	0.2	Line end	26AC08 CB TRIP	26AC09 CB TRIP
99	0.18	In the middle	34AC07 Z1	34AC07 Z2
100	0.18	In the middle	22AC05 CB TRIP	22AC06 CB TRIP

Table 2 Most important components for a system breakdown according to Fussell-Vesely (FV) and risk decrease factor (RDF) measures.

No	IDENTIFICATION	FV measure
1	11AC08 CB TRIP	1.32E-01
2	11AC01 CB TRIP	1.31E-01
3	11AC03 CB TRIP	1.19E-01
4	11AC07 CB TRIP	1.10E-01
5	25AC02 CB TRIP	9.30E-02
6	Line 33 tele	7.96E-02
7	11AC05 CB TRIP	6.41E-02
8	25AC09 CB TRIP	4.72E-02
9	26AC03 CB TRIP	4.64E-02
10	26AC09 CB TRIP	4.54E-02
11	11AC02 CB TRIP	4.25E-02
12	26AC10 CB TRIP	3.54E-02
13	25AC06 CB TRIP	3.19E-02
14	26AC04 CB TRIP	3.01E-02
15	25AC01 CB TRIP	2.95E-02
16	26AC08 CB TRIP	2.75E-02
17	Line 34 tele	2.62E-02
18	Line 29 tele B	2.29E-02
19	38AC09 Z2	1.82E-02
20	22AC05 Z2	1.82E-02
21	21AC04 Z2	1.75E-02
22	20AC03 CB TRIP	1.71E-02

23	32AC01 Z2	1.50E-02
24	32AC01 Z1	1.50E-02
25	22AC05 CB TRIP	1.45E-02
26	32AC09 Z1	1.42E-02
27	32AC09 Z2	1.42E-02
28	38AC08 Z2	1.31E-02
29	21AC06 Z2	1.18E-02
30	25AC03 CB TRIP	1.15E-02
31	32AC03 Z1	1.14E-02
32	32AC03 Z2	1.14E-02

Table 3 Most important components in a system breakdown according to risk increase factor (RIF) measure

No	ID	RIF
1	11 SUBSTATION	6.72E+02
2	37 SUBSTATION	6.43E+02
3	32 SUBSTATION	5.59E+02
4	25 SUBSTATION	5.42E+02
5	13 SUBSTATION	5.36E+02
6	22 SUBSTATION	5.04E+02
7	22AC05 BAY	4.92E+02
8	38 SUBSTATION	4.72E+02
9	42 SUBSTATION	4.52E+02
10	26 SUBSTATION	4.48E+02
11	21AC04 BAY	3.58E+02
12	22AC06 BAY	3.56E+02
13	34 SUBSTATION	3.56E+02
14	11AC08 BAY	3.50E+02
15	37AC7A BAY	3.47E+02
16	37AC7B BAY	3.47E+02
17	11AC05 BAY	3.47E+02
18	37AC9A BAY	3.47E+02
19	37AC9B BAY	3.47E+02
20	25AC13 BAY	3.46E+02
21	42AC10 BAY	3.46E+02
22	42AC09 BAY	3.46E+02
23	A11AC01 BAY	3.44E+02
24	13AC08 BAY	3.41E+02
25	13AC08 Z VT MCB	3.41E+02
26	38AC8B BAY	3.23E+02
27	38AC8A BAY	3.23E+02
28	21 SUBSTATION	3.16E+02

Table 4 The parameters, the sensitivity of which is highest for a system breakdown.

No	Component	Parameter	Sensitivity
1	Circuit breaker	Test interval	1.48E+02
2	Circuit breaker, air-blast	Failure rate	7.72E+01
3	Z-relay, microprocessor	Unavailability	7.53E+00
4	Circuit breaker, SF6	Failure rate	6.53E+00
5	Z-relay, static	Unavailability	5.75E+00
6	Circuit breaker, minimum oil	Failure rate	5.62E+00
7	Z-relay electromechanical	Unavailability	3.07E+00
8	Telecommunication channel: a combination of an optical fibre and a radio link	Unavailability	1.99E+00
9	Relay	Test interval	1.66E+00
10	D-relay, microprocessor	Unavailability	1.50E+00
11	Telecommunication channel: optical fibre	Unavailability	1.32E+00
12	BFF, static	Unavailability	1.22E+00
13	Telecommunication channel: power line carrier, 2-phase faults	Unavailability	1.08E+00
14	Miniature circuit breaker of voltage transformers	Failure rate	1.04E+00
15	Miniature circuit breaker of voltage transformers	Time to repair	1.04E+00
16	Terminal strip of the relays	Failure rate	1.03E+00
17	Telecommunication channel: radio link	Unavailability	1.01E+00
18	Telecommunication channel: a combination of optical fibre and power line carrier	Unavailability	1.01E+00

APPENDIX F –PARTIAL SYSTEM BREAKDOWN RESULTS

Appendix F uses code names for substation bay and line identifications due to confidentiality reasons. IDENTIFICATIONS: IDACid, where ID is the identification of the substation and id is the identification of the bay.

Table 1 100 most important minimal cut sets for the partial system breakdown. These cut sets cover the entire partial system breakdown frequency (1.12E-01).

No	%	Fault location	Event 1	Event 2
1	28.69	Line end	Line 11 tele	
2	24.07	In the middle	Line 4 tele	
3	18.09	Line end	Line 19 tele	
4	8.32	Line end	Line 34 tele	
5	2.03	In the middle	25AC09 CB TRIP	
6	1.75	In the middle	44AC1A CB TRIP	
7	1.75	In the middle	44AC1B CB TRIP	
8	1.35	In the middle	18AC03 CB TRIP	
9	0.89	In the middle	44AC2B CB TRIP	
10	0.89	In the middle	44AC2A CB TRIP	
11	0.89	In the middle	22AC05 CB TRIP	
12	0.83	Line end	Line 16 tele	
13	0.76	In the middle	18AC08 CB TRIP	
14	0.68	Line end	25AC09 CB TRIP	
15	0.62	In the middle	20AC05 CB TRIP	
16	0.58	Line end	44AC01 CB TRIP	
17	0.58	Line end	44AC02 CB TRIP	
18	0.57	In the middle	25AC06 CB TRIP	
19	0.45	Line end	18AC03 CB TRIP	
20	0.42	Line end	Line 38 tele	
21	0.39	In the middle	15AC05 CB TRIP	
22	0.38	In the middle	21AC06 CB TRIP	
23	0.3	Line end	44AC2B CB TRIP	
24	0.3	Line end	44AC2A CB TRIP	
25	0.29	Line end	22AC05 CB TRIP	
26	0.25	Line end	18AC08 CB TRIP	
27	0.23	Line end	Line 20 tele	
28	0.22	In the middle	16AC08 CB TRIP	
29	0.22	Line end	Line 17 tele	
30	0.22	Line end	22AC05 CB TRIP	
31	0.21	Line end	20AC05 CB TRIP	
32	0.21	Line end	Line 35 tele	
33	0.2	In the middle	39AC09 CB TRIP	
34	0.2	In the middle	39AC10 CB TRIP	
35	0.19	Line end	25AC06 CB TRIP	

36	0.18	In the middle	22AC04 CB TRIP	
37	0.18	In the middle	21AC04 CB TRIP	
38	0.18	In the middle	20AC03 CB TRIP	
39	0.17	In the middle	15AC06 CB TRIP	
40	0.15	Line end	Line 18 tele	
41	0.13	Line end	15AC05 CB TRIP	
42	0.13	Line end	Line 37 tele	26AC04 CB TRIP
43	0.13	Line end	21AC06 CB TRIP	
44	0.1	In the middle	25AC03 CB TRIP	
45	0.1	Line end	34AC7B CB TRIP	
46	0.09	In the middle	39AC03 CB TRIP	
47	0.09	In the middle	39AC04 CB TRIP	
48	0.07	Line end	16AC08 CB TRIP	
49	0.07	Line end	39AC09 CB TRIP	
50	0.07	Line end	39AC10 CB TRIP	
51	0.06	Line end	21AC04 CB TRIP	
52	0.06	Line end	22AC04 CB TRIP	
53	0.06	Line end	20AC03 CB TRIP	
54	0.03	Line end	25AC03 CB TRIP	
55	0.03	Line end	39AC04 CB TRIP	
56	0.03	Line end	39AC03 CB TRIP	
57	0.03	In the middle	39AC01 CB TRIP	
58	0.03	In the middle	39AC02 CB TRIP	
59	0.01	Line end	39AC02 CB TRIP	
60	0.01	Line end	39AC01 CB TRIP	
61	0.01	Line end	26AC03 CB TRIP	26AC09 CB TRIP
62	0.01	Line end	26AC03 CB TRIP	26AC10 CB TRIP
63	0	Line end	32AC09 Z1	32AC09 Z2
64	0	In the middle	31AC05 Z1	31AC05 Z2
65	0	Line end	Line 29 tele B	22AC05 Z2
66	0	In the middle	39AC09 Z1	39AC09 Z2
67	0	Line end	26AC04 CB TRIP	26AC09 CB TRIP
68	0	Line end	26AC04 CB TRIP	26AC08 CB TRIP
69	0	In the middle	20AC05 Z1	20AC05 Z2
70	0	Line end	26AC09 CB TRIP	26AC10 CB TRIP
71	0	Line end	26AC03 CB TRIP	26AC10 CB TRIP
72	0	In the middle	44AC01 Z1	44AC1A Z2
73	0	In the middle	Line 28 tele B	22AC04 Z2
74	0	In the middle	15AC05 Z1	15AC05 Z2
75	0	In the middle	18AC03 Z1	18AC03 Z2
76	0	In the middle	22AC04 D	22AC04 Z2
77	0	In the middle	21AC06 D	22AC04 Z2
78	0	In the middle	17AC03 Z1	17AC03 Z2
79	0	Line end	21AC04 Z2	Line 28 tele B
80	0	In the middle	Line 30 tele A	39AC01 Z2
81	0	Line end	22AC06 Z1	22AC06 Z2
82	0	Line end	39AC09 Z1	39AC09 Z2
83	0	Line end	21AC04 Z2	22AC04 D

84	0	Line end	21AC04 Z2	21AC06 D
85	0	Line end	22AC05 D	22AC05 Z2
86	0	Line end	38AC09 D	22AC05 Z2
87	0	In the middle	16AC08 Z1	16AC08 Z2
88	0	In the middle	18AC08 Z1	18AC08 Z2
89	0	Line end	20AC05 Z1	20AC05 Z2
90	0	Line end	26AC03 Z1	26AC03 Z2
91	0	In the middle	17AC03 CB TRIP	17AC04 CB TRIP
92	0	In the middle	20AC03 Z1	20AC03 Z2
93	0	In the middle	15AC06 Z1	15AC06 Z2
94	0	Line end	44AC01 Z1	44AC1A Z2
95	0	In the middle	39AC03 Z1	39AC03 Z2
96	0	Line end	Line 28 tele B	22AC04 Z2
97	0	Line end	21AC04 Z2	Line 28 tele B
98	0	Line end	34AC04 Z1	34AC04 Z2
99	0	Line end	Line 30 tele A	Line 30 tele B
100	0	Line end	15AC05 Z1	15AC05 Z2

Table 2 The most important components in a partial system breakdown according to Fussell-Vesely (FV) and risk decrease factor (RDF) measures.

No	**ID**	**FV**
1	Line 11 tele	3.00E-01
2	Line 4 tele	2.51E-01
3	Line 19 tele	1.89E-01
4	Line 34 tele	8.69E-02
5	25AC09 CB TRIP	2.83E-02
6	44AC1A CB TRIP	2.43E-02
7	44AC1B CB TRIP	2.43E-02
8	18AC03 CB TRIP	1.87E-02
9	22AC05 CB TRIP	1.46E-02
10	44AC2B CB TRIP	1.23E-02
11	44AC2A CB TRIP	1.23E-02
12	18AC08 CB TRIP	1.06E-02
13	20AC05 CB TRIP	8.70E-03
14	Line 16 tele	8.64E-03
15	25AC06 CB TRIP	7.88E-03
16	15AC05 CB TRIP	5.48E-03
17	21AC06 CB TRIP	5.24E-03
18	Line 38 tele	4.38E-03
19	16AC08 CB TRIP	3.06E-03
20	39AC10 CB TRIP	2.72E-03
21	39AC09 CB TRIP	2.72E-03
22	22AC04 CB TRIP	2.53E-03
23	21AC04 CB TRIP	2.53E-03
24	20AC03 CB TRIP	2.52E-03
25	Line 20 tele	2.43E-03

26	Line 17 tele	2.28E-03
27	Line 35 tele	2.17E-03
28	15AC06 CB TRIP	1.82E-03
29	Line 18 tele	1.57E-03
30	25AC03 CB TRIP	1.44E-03
31	26AC04 CB TRIP	1.42E-03
32	Line 37 tele	1.35E-03
33	39AC03 CB TRIP	1.30E-03
34	39AC04 CB TRIP	1.30E-03
35	34AC07 CB TRIP	1.01E-03

Table 3 Most important components in a partial system breakdown according to risk increase factor (RIF) measure.

No	**ID**	**RIF**
1	22AC05 CB TRIP	5.46E+00
2	20 SUBSTATION	4.53E+00
3	21AC06 CB TRIP	4.09E+00
4	22 SUBSTATION	4.05E+00
5	20AC05 Z VT MCB	3.95E+00
6	20AC05 BAY	3.95E+00
7	20AC05 CB TRIP	3.94E+00
8	25AC09 CB TRIP	3.77E+00
9	18 SUBSTATION	3.73E+00
10	39 SUBSTATION	3.52E+00
11	15 SUBSTATION	3.42E+00
12	44AC1A CB TRIP	3.40E+00
13	44AC1B CB TRIP	3.40E+00

Table 4 The parameters, the sensitivity of which is highest for a partial system breakdown.

No	**Component**	**Parameter**	**Sensitivity**
1	PLC telecommunication channel, 2-ph. faults	Unavalability	8.07E+00
2	Circuit breaker	Test interval	2.82E+00
3	Circuit breaker, air-blast	Failure rate	2.28E+00
4	Circuit breaker, minimum oil	Failure rate	1.32E+00
5	Circuit breaker, SF6	Failure rate	1.19E+00
6	Telecommunication channel: optical fibre	Unavalability	1.14E+00
7	Relay	Test interval	1.05E+00
8	Telecommunication channel: OF & RL	Unavalability	1.04E+00
9	Telecommunication channel: radio link	Unavalability	1.02E+00
10	Z-relay, electromechanical	Unavalability	1.02E+00
11	Z-relay, microprocessor	Unavalability	1.01E+00
12	Z-relay, static	Unavalability	1.01E+00

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