Reliability evaluation of electric transmission and distribution systems

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Reliability evaluation of electric transmission and distribution systems

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To my wife Annemarie,
my sons Joris and Harm and
my parents
Summary

It may happen that the electricity supply is interrupted. Then it becomes clear how dependent modern society is on electrical energy. Fortunately, the electricity supply can often be restored rapidly. However, sometimes, the supply is interrupted for a longer period. This has happened in the past, but will also take place in the future. An electricity supply is never a hundred per cent reliable.

An electric power system comprises three main parts, namely: the generation system, the transmission system and the distribution system. All these parts can suffer failures. Fortunately, the system is designed in such a way that most of the failures do not result in electricity supply interruptions. In industrialised countries, the probability of an interruption due to a failure of the generation system is small. Most of the supply interruptions to customers are caused by disturbances in the transmission and distribution systems. These systems are considered in this thesis.

The reliability of the electricity supply is defined by indices of unreliability. Examples of such indices are the expectation that an electricity supply interruption occurs, the so-called load-point interruption frequency (measured in occasions per year), the load-point interruption duration (measured in hours or minutes per occasion) and the load-point annual unavailability (measured in hours or minutes per year). The latter index is the product of the former two indices.

The quality of the Dutch electricity supply ranks among the best in the world. The mean value of the load-point interruption frequency at the low-voltage level in the
Reliability evaluation of electric transmission and distribution systems

period 1992-1996 for a Dutch customer was equal to 0.31 occasions per year (about one interruption in three years). The annual unavailability of a load point at the low-voltage level in the same period was about 21 minutes per year. This means a load-point interruption duration at the low-voltage level of about 68 minutes per occasion for a customer.

The central theme of this dissertation is 'the development of new or improved models and techniques to predict electric transmission and distribution system reliability indices that agree with observed indices of reliability for customers'.

This formulation deserves some further explanation. To now, a lot of models and techniques were developed in order to predict the reliability of (parts of) power systems. However, in general these models and techniques still cannot predict typical transmission and distribution system reliability indices in a satisfying way, especially in such a manner that the predicted indices agree with indices observed in reality.

The reliability of electric transmission and distribution systems is not only influenced by the reliability of the components involved in the systems, but also by a lot of other aspects, such as the network structure, the component redundancy, the operational actions, the protection schemes, the influence of periodic preventive maintenance, the degree of automation in the systems, etc. This shows that many aspects have to be taken into account in the development of the models and techniques.

Electric transmission and distribution systems have a lot of features in common, but they also have some features that are specific for either a transmission or a distribution system. This has led to the development of two computer programs, which in principle convert data of components into information about the reliability of the electricity supply to customers at different locations in an electric transmission or distribution network. The computer program TRANSREL is applicable to transmission systems. The computer program DISTREL is applicable to distribution systems.

This dissertation describes the developed models and techniques which form the main ingredients of the computer programs. The adopted calculation method is based on the so-called 'state enumeration approach'. This means that a lot of different power-system states are enumerated for a given transmission or distribution network. Each system state consists of a network state, a load situation and a generation schedule. In order to establish whether a system state represents 'success' or 'failure', the available generation is first compared with the load demand and isolated load points are determined. After that, the system state is analysed using a load flow. If one or more system constraints are violated, it is established whether it is possible to eliminate
these violations by undertaking remedial actions in the system. This process is repeated until sufficient system states are enumerated and analysed. In this way, reliability indices can be predicted

The validity of the developed concepts is shown at the end of the thesis, where calculation results are given of different studies for electric transmission and distribution networks. The studies show that the reliability of the considered systems can be predicted in a rather accurate way with the aid of the models and techniques that are described in this thesis.
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Samenvatting


De betrouwbaarheid van de elektriciteitsvoorziening wordt uitgedrukt in kengetallen voor onbetrouwbaarheid. Voorbeelden van zulke kengetallen zijn de verwachting dat een onderbreking in de elektriciteitsvoorziening optreedt, de zogenaamde onderbrekingsverwachting (uitgedrukt in gebeurtenissen per jaar), de gemiddelde onderbrekingsduur (uitgedrukt in uren of minuten per gebeurtenis) en de jaarlijkse uitvalduur (uitgedrukt in uren of minuten per jaar). Het laatste kengetal is het product van de eerste twee kengetallen.
De kwaliteit van de Nederlandse elektriciteitsvoorziening behoort tot de beste ter wereld. De gemiddelde waarde van de onderbrekingsverwachting bij een Nederlandse verbruiker op het laagspanningsniveau in de periode 1992-1996 was gelijk aan 0,31 gebeurtenissen per jaar (ongeveer één onderbreking in drie jaar). De jaarlijkse uitvalduur op het laagspanningsniveau was in dezelfde periode circa 21 minuten per jaar. Dit betekent een gemiddelde onderbrekingsduur van circa 68 minuten per gebeurtenis bij een verbruiker op het laagspanningsniveau.

Het centrale thema van deze dissertatie is 'de ontwikkeling van nieuwe of verbeterde modellen en technieken met als doel om betrouwbaarheidskengetallen van elektrische transport- en distributienetten te voorspellen, die overeenstemmen met waargenomen kengetallen bij klanten'.

Deze formulering verdient enige nadere toelichting. Tot op heden zijn er een flink aantal modellen en technieken ontwikkeld met het doel om de betrouwbaarheid te voorspellen van (onderdelen van) elektriciteitsvoorzieningssystemen. Deze modellen zijn echter over het algemeen nog steeds niet in staat om de betrouwbaarheid van transport- en distributiesystemen te voorspellen op een overtuigende wijze, in het bijzonder op een manier waarin de voorspelde kengetallen overeenkomen met werkelijke, waargenomen kengetallen.

De betrouwbaarheid van transport- en distributienetten wordt niet alleen beïnvloed door de betrouwbaarheid van de componenten in het systeem, maar ook door tal van andere aspecten, zoals: de structuur van het netwerk, de redundantie van componenten, de bedrijfsvoering, de wijze van beveiliging, de invloed van periodiek preventief onderhoud, de graad van automatisering in de beschouwde systemen, etc. Dit toont aan dat een flink aantal aspecten moet worden betrokken in de ontwikkeling van de modellen en technieken.

Elektrische transport- en distributiesystemen hebben tal van gemeenschappelijke kenmerken, maar ook een aantal kenmerken die specifiek zijn voor een transport- of distributiesysteem zelf. Dit heeft geleid tot de ontwikkeling van twee computerprogramma's, die in feite de gegevens van componenten omzetten in informatie over de betrouwbaarheid van de elektriciteitsvoorziening aan gebruikers op verschillende plaatsen in een transport- of distributienet. Het computerprogramma TRANSREL is geschikt voor transportsystemen. Het computerprogramma DISTREL is geschikt voor distributiesystemen.

Deze dissertatie beschrijft de ontwikkelde modellen en technieken die de belangrijkste ingrediënten vormen van beide computerprogramma's. De gevolgde rekenmetho-
Samenvatting

de is gebaseerd op de zogenaamde ‘state enumeration approach’. Dit houdt in dat een groot aantal verschillende toestanden wordt opgesomd voor een gegeven transport- of distributienet. Elke systeemtoestand bestaat uit een netwerktoestand, een belastingsituatie en een productietoestand. Teneinde vast te stellen of een systeemtoestand ‘succes’ of ‘onderbreking’ representeert, wordt eerst de beschikbare productie vergeleken met de belastingvraag en worden geïsoleerde afnamepunten bepaald. Daarna wordt de systeemtoestand geanalyseerd met behulp van een loadflow. Indien een of meerdere beperkingen van het systeem worden overschreden, wordt vastgesteld of het mogelijk is om deze overschrijdingen te elimineren door correctieve maatregelen in het systeem te ondernemen. Dit proces wordt herhaald totdat voldoende systeemtoestanden zijn opgesomd en geanalyseerd. Op deze wijze kunnen kengetallen voor de betrouwbaarheid worden voorspeld.

De geldigheid van de ontwikkelde concepten wordt aan het einde van het proefschrift aangetoond aan de hand van berekeningsresultaten van verschillende studies voor elektrische transport- en distributienetten. De studies wijzen uit dat de betrouwbaarheid van de beschouwde systemen op tamelijk nauwkeurige wijze kan worden voorspeld met behulp van de modellen en technieken zoals die in dit proefschrift beschreven zijn.
Preface

Reliability is the main quality aspect in the planning, design and operation of electric transmission and distribution systems. In the Dutch electricity supply industry, the need for quantitative reliability evaluation of these systems has been recognised early, but today the use of calculation methods is not widespread. This is due to the absence of good reliability assessment tools and lack of confidence in calculation results.

However, there is an increasing need to evaluate the merits and demerits of various reinforcement schemes to ensure that the limited capital resources are used such that the greatest improvement in system performance is achieved. Therefore, the Power System Laboratory of the Delft University of Technology started a research project dealing with quantitative reliability evaluation of electric transmission and distribution systems.

The results of the research project are reported in this thesis. The project was financially supported by PNEM, a public utility in the southern part of the Netherlands. The project title is *Reliability evaluation of electric transmission and distribution systems*. Its purpose was to develop new or improved mathematical models and tools, suited for a more comprehensible reliability assessment procedure for these systems.

*Krabbendijk, the Netherlands*  
*September 1998*

J.J. Meeuwsen
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Chapter 1

Introduction

1.1 Electric transmission and distribution systems

The basic function of an electric power system is to supply customers, both large and small, with electrical energy as economically as possible and with an acceptable degree of quality. In general, an electric power system comprises three basic functional subsystems: generation, transmission and distribution. This simple, but reasonable, subdivision is shown in figure 1.1.

All the parts, shown in figure 1.1, can suffer failures. Fortunately, the system is designed in such a way that most of the failures do not result in electricity supply interruptions [1]. The probability of an interruption due to a failure in the generation system is small. Most of the supply interruptions to customers are caused by disturbances in transmission and distribution systems. This thesis focuses on reliability evaluation studies of electric transmission and distribution systems in a quantitative way. For distribution systems, the emphasis is laid on the medium-voltage level. Generation system reliability is not considered in this dissertation. All generating units are assumed to be totally reliable.

The transmission system consists of connecting links between the generation stations in which the electrical energy is produced and the distribution systems. It delivers electrical energy in large amounts from the generation stations to the main load centers or area supply stations (substations). Distribution systems are those parts of the power system which deliver electrical energy from the area supply stations to individual customers.
Transmission systems are generally meshed-operated networks at high-voltage levels (mostly above 100 kV). Every component in the transmission system is usually protected by one or two protection systems. A wide variety of components, such as lines, cables, busbar sections, circuit breakers, disconnect switches and transformers are involved in these systems. The modeling of the behavior of such a diversity of devices makes transmission reliability evaluation quite complicated.

Besides this, transmission networks usually connect several generation stations at different sites with the major load points. Generating units usually have an unavailability of 10 to 20 percent, because of forced and scheduled outages. An outage is defined as the state of a component characterized by its inability to perform a required function. Such unavailabilities are several orders of magnitude higher than transmission and distribution component unavailabilities.

The layout of electric distribution systems is generally simpler than that of transmission networks. Distribution systems are usually operated at lower voltage levels. The distribution system is usually divided into a medium- and a low-voltage zone. Sometimes,
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the subtransmission level is also seen as a distribution level. Most medium- and low-voltage zones are radial-operated arrangements whereas the components involved in the supply are connected in series. Due to their simpler structure, the protection of such networks is simpler as well.

The degree of acceptation of a certain quality level varies for different types of customers. The degree of quality offered to customers differs as well, although minimum standards are usually set. The difference in the degree of quality offered to customers is caused by a lot of system aspects, such as system structure, component ages, operation, scheduled maintenance and system protection. The quality of service to a customer can be divided into three aspects according to UNIPEDE [2]. These are: reliability of supply to a customer, quality of power offered to a customer and provision of information to a customer, as is illustrated in figure 1.2. The most dominant aspect is reliability. This thesis deals with this aspect, namely with reliability of supply to a customer.

![Diagram of Quality of Service to a Customer](image)

**Figure 1.2** Three aspects of quality of service to a customer

Quantitative relations between reliability offered to a customer and the system aspects mentioned above are usually not known in detail. Therefore, there is a need in the electricity supply industry to evaluate quantitatively the merits of changes in system handling as a part of the quality assurance processes which are introduced nowadays.

1.2 Basic concepts

The ultimate goal of a reliability investigation of an electric transmission or distribution system is to evaluate the consequences of all possible disturbances, that might occur in the system. Such an evaluation can be done superficial or profound. In the first case, the analysis is often done in a more qualitative sense, whereas in the latter case, the analysis is most often performed in a quantitative manner. The more profound the evaluation is, the more detailed the description of the system that is studied should be.
An examination of the existing literature on power-system reliability shows an initial emphasis on the reliability evaluation of the generation system [3,4,5,6,7]. Quantitative evaluation of transmission and distribution system reliability has been initiated from 1964 [8,9]. This section will treat some important concepts concerning transmission and distribution system reliability assessment.

1.2.1 Deterministic versus probabilistic approach

Until fairly recently, the reliability evaluation of electric transmission and distribution systems was completely deterministic. Deterministic planning and operating criteria were developed over many decades. Many of them, like the well-known (n-1) criterion, are still in use today and there is no reason to believe that a check by using such criteria will ever be abolished. The essential weakness of deterministic or qualitative criteria is, however, that they do not and cannot account for the probabilistic nature of system behavior, customer demands and component failures.

Probabilistic or quantitative techniques do not only recognise the severity of a state or an event and its impact on system behavior, but also the likelihood of its occurrence. Deterministic techniques cannot respond to the latter aspect. A simple example can illustrate the difference between deterministic (qualitative) and probabilistic (quantitative) techniques.

Example 1.1

Figure 1.3 shows two simple transmission systems with the same structure and task. The capacity of each circuit is equal to 100 MVA for both systems. The peak load demand in each system is 75 MVA. The only difference between both systems is the distance between the generation station and the area supply station. For the system in figure 1.3a this distance is equal to 10 km, while this distance is equal to 100 km for figure 1.3b.

From a deterministic or qualitative point of view, both systems have the same reliability level, since they both satisfy the (n-1) criterion. This means that if the system loses one circuit, the area supply station remains connected. From a probabilistic or quantitative viewpoint, both systems differ significantly. It is obvious that the probability of the occurrence of overlapping line faults is higher for the system in figure 1.3b than for that of figure 1.3a.

In general, the main differences between deterministic and probabilistic methods are:

- In a deterministic approach, the considered system states all have the same weighting factor, whereas in a probabilistic approach, how probable it is that a considered system state occurs determines its weighting factor.
The number of considered system states in a deterministic approach is usually smaller than those in a probabilistic approach.

![Diagram showing two generation stations connected to area supply stations](image)

**Figure 1.3** A simple example to illustrate the difference between deterministic and probabilistic reliability evaluation

The electricity supply industry plays a major role in the economic and social well-being of a modern society. The reliability of the supply system is of main importance. Therefore, the availability of power in generation stations has been evaluated in a probabilistic way since a long time. Nowadays, more and more attention is paid to the application of probabilistic methods to evaluate transmission and distribution system reliability as well. This trend arises from the situation in which public utilities have been providing a product of high quality on which each customer depends more and more [1]. Recent blackouts showed that society has become more and more vulnerable to interruptions of the electricity supply.

Qualitative or deterministic evaluation of reliability is no longer entirely adequate for all customers; industrial customers for example place the reliability of the electricity supply on their list of priorities for proposed factory locations. The application of probability methods to transmission and distribution systems, which is treated in this thesis, provides a quantitative prediction of indices of reliability for customers and a way to evaluate in a consistent manner the respective reliability levels of alternate proposals.
1.2.2 Framework for probabilistic reliability studies

Figure 1.4 depicts the main parts of a probabilistic reliability investigation of an electric transmission or distribution system. This approach forms the framework of this thesis. The four boxes presented in it are treated separately in chapters 3 to 6.

![Diagram of framework for probabilistic reliability study]

Figure 1.4  A framework for a probabilistic reliability study of an electric transmission or distribution system

The aim is to predict indices of reliability for customers. These are directly dependent on the reliability input data (box 1), which are derived from the observed system behavior in the past. Lack of care in gathering reliability input data may seriously jeopardize and even invalidate the resulting reliability indices.

Contingency modeling (box 2 in figure 1.4) is also one of the key aspects to accomplish successfully the reliability investigation as depicted in the figure. A contingency is defined as a network state where, owing to failures, one or more components are not available. The main objective in contingency modeling is to capture all relevant influences on system behavior but still maintain both dimensionality and complexity within a manageable scale. This task requires a fine balanced mix of 'science and art'.

The next depicted step in figure 1.4 (box 3) deals with the method to calculate reliability indices. The last box refers to applying the three earlier-described boxes to a given power system, which results in a prognosis of the (future) behavior of the system. A comparison must always be made between the set of values obtained from the calculations and the set of values from observed system behavior. The closer these two correspond, the more confidence is gained in the accuracy of the method to calculate the reliability indices. The results of the comparison between observed and predicted system behavior can also be used to make adjustments to the contingency models and to the method for calculating
reliability. In this way, it is possible to iterate to a prediction which is in accordance with the observed system behavior.

The ultimate goal in a probabilistic reliability investigation might be evaluating the entire power system and determining a lot of reliability indices, but this task is too ambitious. A modern power system consists of a lot of components that have numerous and complex interrelations. This would require models that are far too complicated to be solved. Even large computers are not powerful enough for analysing all aspects of a power system in a completely realistic and exhaustive manner. For instance, the dynamic behavior of a power system when disturbances occur cannot be tackled adequately by reliability evaluation studies.

In contrast to solutions to classical power-system issues, such as a load-flow evaluation and a symmetrical or unsymmetrical fault analysis, there are no established or standard solutions for most of the reliability problems. In essence, reliability assessment studies should be considered as a shell covering all power-system issues. The main characteristics of all the power-system issues must be taken into account. On the one hand the models and techniques to be developed should be sufficiently detailed, so that main power-system characteristics can be taken into consideration, but on the other hand these should be small enough for dealing with them comprehensively.

1.2.3 Classes and hierarchies

Often separate probabilistic reliability evaluations are conducted for major parts of the system (there are for instance generation, transmission and distribution studies). Research is carried out on integrating relevant aspects of these subsystems. For each subsystem or combination of subsystems, a reliability assessment problem can be posed and solved. The combination of the results of all parts is then assumed to be an appropriate prediction for the whole system.

In fact, it is unlikely that it will ever be necessary or even desirable to attempt to analyse an electric power system as a whole; not only will the amount of computation time be excessive and the models much too complicated, but also the results so obtained are likely to be so vast and abstract that meaningful interpretation and checking will be impossible.

So, as shown in figure 1.5, power-system probabilistic reliability studies can be classified as specific or as integrated studies. The first category deals with studies of specific subsystems without emphasis on the relationships with other subsystems. As mentioned in the foregoing section, this dissertation focuses on the study of two specific subsystems: those of transmission and distribution.
In the so-called ‘integrated studies’, the concept of hierarchical levels (HLs) is often used. Although figure 1.5 suggests that each following hierarchical level incorporates all aspects of preceding levels, this is usually not true. Studies on hierarchical level three for example, generally do not incorporate the whole interaction between the distribution and the generation system.

The presented division in figure 1.5 is in principle a vertical one, which is closely related to the size of the state space (number of possible system states) involved in the reliability analysis. When the hierarchical level increases, the state space increases. Besides this ‘vertical division’, one can also make a ‘division in depth’, which is closely related to modeling complexity. The more system aspects such as scheduled maintenance, operation and protection-system behavior are modeled in detail, the ‘deeper’ the reliability analysis is. This thesis focuses mainly on the ‘analysis in depth’, i.e., on modeling the operation, the scheduled maintenance and the protection of transmission and distribution systems in more detail than is usually done.

1.2.4 Adequacy and security

The term reliability as applied to power systems has a very wide range of meaning and covers all aspects of the ability of the system to satisfy the consumer requirements for the continuity of supply [10]. Power-system reliability is, in engineering terms, often divided into two basic aspects. These are adequacy and security [11].
Chapter 1 Introduction

Adequacy relates to the existence of sufficient facilities within the system to satisfy the load demands within system operational constraints. These include the facilities necessary to generate sufficient power and the transmission and distribution system facilities required to transport the energy to the actual load points associated to it. Adequacy is generally associated with static conditions.

Security relates to the ability of the system to overcome disturbances arising within it. Security is therefore associated with the response of the system to whatever perturbations to which it is subjected. Therefore, if the reliability assessment accounts only for steady-state conditions, measures for system adequacy may be correctly obtained, but not specific security measures. If the reliability assessment is capable of examining the events closer to the moment of ‘incident’, security indices could be determined, but then the assessment itself (and its solution) would entail a very detailed modeling of the system.

Nearly all probabilistic techniques presently developed are in the domain of adequacy assessment. The evaluated reliability indices are in essence adequacy indices and not overall reliability indices. It is important to recognise this distinction, because it is usually not stated. When in the following reliability is mentioned, adequacy is meant. In the case of distribution systems, it is less necessary to distinguish reliability and adequacy because dynamic effects do not influence these systems much.

1.3 Reliability costs and worth

As stated in the first section of this chapter, the basic function of an electric power system is to satisfy the system load and energy requirements economically and at an acceptable quality level. In the past, determining a reasonable level of quality was based largely on the experience and judgement of power-system engineers, i.e., the planning engineers. Nowadays, customer expectations are becoming more and more important in the choice of a certain quality level.

A continuously available electricity supply can never be reached for several reasons, for example random component failures, which are not in the control of engineers. However, the probability and frequency of customers being disconnected can usually be reduced by increased investment during either the planning phase, the operating phase or both. Therefore, economic and reliability constraints conflict.

The increasing vulnerability of society to electricity supply interruptions has resulted in an increasing interest of government, customer groups and the establishment of regulatory
bodies in several industrialized nations. However, it appears to be rather difficult to quantify this vulnerability. The basic qualitative relations between interruption costs and the degree of reliability are illustrated in figure 1.6 [10,12]. This simplified diagram shows that the costs of the public utility will increase as consumers are provided with higher reliability, while consumer costs associated with power supply interruptions decrease as the reliability level increases.

![Annual costs](chart)

**Figure 1.6** Reliability costs

Costs of interruption can be broadly classified as having direct or indirect consequences [13]. Direct effects are those resulting directly from the power cessation. Examples of direct economic costs are lost production, spoilage of food or raw materials, restarting costs for continuous process plants, lost revenue, paid staff unable to work, or costs associated with human safety and health. Direct social effects can include inconvenience, fear of crime or accidents, etc.

Indirect effects are secondary consequences of electricity supply interruptions, and can be both on a long and a short term. A few examples of short-term losses include looting during the supply interruption or damage suits brought against the electricity company for losses due to the supply interruption. A long-term effect may be the migration of industry from an area with a low level of reliability to an area belonging to another electricity company that guarantees a higher level of reliability.

The basic relation between interruption costs and the supply interruption duration is illustrated in figure 1.7. This figure is a so-called customer damage function [13,14]. The form of the customer damage function (CDF) depends on the type of customers.

In fact, several methods can be used to assess reliability costs and gains. One approach is to ask the customers to estimate their losses for several supply interruptions with
different durations (for example, 1, 4 and 8 hours) during different periods of the year. Another approach is to ask about their willingness to pay in order to avoid a supply interruption. A third approach is to ask the customers how much they would reduce the use of certain appliances if the electricity price would be tenfold for a defined period.

The estimated costs appear to depend strongly on the selected method [15]. In general it can be said that the costs of energy not supplied for office space, the industrial sector and the commercial sector are high. In the category of agricultural customers, there is a large variation in cost estimates. Most sensitive to supply interruptions are customers such as like pig and chicken farms, whereas for other farms, the supply interruption costs are relatively small.

![Interruption costs](image)

**Figure 1.7 Typical customer damage function**

A fundamental problem of using customer requirements in the design and operation of systems is based on the fact that different customers can have different needs. In principle, neighboring customers can have totally divergent expectations. Improvements in the system for one customer however, will often result in benefits for neighboring consumers. The traditional view was to strive always for an overall optimum for all customers. The present trend is to diversify the technical options and to pass on the costs of higher reliability only to those customers that need it [16].

It is widely recognised that evaluating the reliability of transmission and distribution systems is an important part of customer-driven decision making and the quality assurance processes, that are being introduced in the electricity supply industry. The present trend is toward using quantitative reliability studies in system planning in order to evaluate the reliability of several alternative system designs and of various connection options for customers.
The various sets of evaluated reliability indices can be used in the managerial decision-making process in order to determine the most appropriate expansion or reinforcement scheme. Of course, a trade-off has to be made between costs and reliability. In the decision-making process, minimum system reliability should be considered as a constraint. System designs having a reliability degree that is below a certain established level are rejected. System designs having a higher degree of reliability than the established level are considered further and evaluated for costs. The system design having the lowest life cycle costs should be chosen.

It is not the purpose of this thesis to evaluate the costs and gains of reliability. The concepts dealing with costs and the degree of reliability are mentioned to stress the importance of realistic predictions of power-system reliability.

1.4 Objective and method of research

The central theme of this dissertation is 'the development of new or improved models and techniques to predict electric transmission and distribution system reliability indices which agree with observed indices of reliability for customers'.

This formulation deserves some further explanation. Up to now, a lot of models and techniques have been developed for predicting the reliability of (parts of) power systems. However, in general these models and techniques are still not able to predict typical transmission and distribution system reliability indices in a satisfying way, especially in such a manner that the predicted indices agree with observed indices. The reason is insufficient and undetailed system modeling ‘in depth’. The value of the reliability analysis is directly related to the quality of the models and the techniques used to represent system behavior.

The reliability of electric transmission and distribution systems is not only influenced by the reliability of the components involved in the systems, but also by a lot of other aspects, such as: the network structure, the component redundancy, the operational actions, the protection schemes, the influence of periodic preventive maintenance, the degree of automation in the systems, etc. This shows that many aspects have to be taken into account when the models and techniques are developed.

Although many of the features of the systems that transmit and distribute electricity are the same, some do belong exclusively to one of these systems. This has led to the development of two computer programs, which in principle convert data of components
into information about the reliability of the electricity supply to customers at different locations in an electric transmission or distribution network. The computer program TRANSREL is applicable to transmission systems. The computer program DISTREL is applicable to distribution systems. This dissertation describes the developed models and techniques that form the main ingredients of the computer programs.

The central theme, as described above, presents both the method and the objective of the research project:

- The objective of this dissertation is to predict transmission and distribution system reliability indices, that do agree with observed indices of reliability for customers
- The objective is achieved by developing and improving models and techniques for calculating these indices

The method of research consisted of the following parts:

- Literature search to obtain insight in the theory and practice of transmission and distribution system reliability assessment
- Research to obtain insight in planning, design, scheduled maintenance, operation and protection of transmission and distribution systems
- Development and testing of new models and techniques in order to iterate to a prediction of transmission and distribution system reliability indices in agreement with observed indices of reliability for customers

1.5 Outline of the thesis

Electric transmission and distribution systems have a lot of features in common, but also some features, that are specific for either system. Therefore, a reliability assessment procedure for transmission systems on the one hand and a reliability assessment procedure for distribution systems on the other hand will have common features, but also elements, that take into consideration the special characteristics of the system that is studied. The first two sections of chapter 2 present several differences between transmission and distribution systems concerning the reliability assessment of these systems. The last section of this chapter describes some general aspects of the reliability assessment approach for these systems.

Chapter 3 deals with the contents of box 1 in figure 1.4: the reliability input data. With the aid of such data, it should be possible to predict how reliable the transmission and distribution systems are. These data must be sufficiently detailed to ensure that the factors that affect reliability can be modeled and analysed. The data should therefore reflect the
three main processes involved in component and system behavior, namely the failure, the restoration and the scheduled maintenance processes.

The first section of chapter 3 describes these three processes and the statistical indices that can be used to describe them. The second section deals with several dependency concepts, that have to be taken into consideration during the development of new or improved models and techniques. The last section deals with observed component reliability, and presents the component reliability indices which are used as input data in this thesis.

Chapter 4 deals with the contents of box 2 in figure 1.4: the contingency models. A contingency is a network state where, owing to failures, one or more components are not available. A complete system state consists of a network state, a load situation and a generation schedule. With the aid of contingency modeling, component outages or combinations of component outages are enumerated. All components that are not enumerated on outage are assumed to be in service or ready for service. Each contingency is characterized by a certain probability and frequency of occurrence.

The first section of chapter 4 deals with models and concepts to evaluate component outage probabilities and frequencies. In the second section, the enumeration of circuit outages is treated as well as the compilation of network states. The final section deals with enumeration of substation-originated outages.

Chapter 5 deals with the contents of box 3 in figure 1.4: the reliability calculation method. The reliability calculation method evaluates for each enumerated contingency whether it contributes to system failure or not. To perform such an analysis, each contingency is combined with different load situations, and a generation schedule is chosen for each load situation. This is treated in the first section. After that, each system state has to be analysed, which is described in the second section. If this analysis results in the detection of system failure, it is common practice to establish whether this undesirable system state can be overcome by undertaking remedial actions. The modeling of such actions is presented in the next section. After these remedial actions are applied, the load-point reliability indices are updated. This is treated in the fourth section. The final section describes the compilation of system indices. This should be done after all enumerated contingencies are evaluated.

Chapter 6 deals with the contents of box 4 in figure 1.4: the calculation of reliability indices. In this chapter, the application of the models and techniques presented in the foregoing chapters is demonstrated. Several general studies for transmission and distribution systems are presented in the first two sections. Besides these general studies, two more specific studies concerning preventive maintenance in substations and manual
network reconfiguration in a transmission system are presented in the following two sections. The system studies illustrate clearly that the predicted reliability indices agree to a large extent with observed indices of reliability for customers.

Conclusions and suggestions for further research are given in chapter 7.
Reliability evaluation of electric transmission and distribution systems
Chapter 2

Transmission and distribution system reliability features

Electric transmission and distribution systems have a lot of features in common, but also some features, that are specific for either system. Therefore, a reliability assessment procedure for transmission systems on the one hand and a reliability assessment procedure for distribution systems on the other hand will have common features, but also elements, that take into consideration the special characteristics of the system that is studied. The first two sections of this chapter present several differences between transmission and distribution systems concerning the reliability assessment of these systems. The last section of this chapter describes some general aspects of the reliability assessment approach for these systems.

2.1 Observed system reliability

To evaluate how appropriate the developed models and techniques are for assessing the reliability of the systems that transmit and distribute electricity, it is necessary to know how reliable these systems actually are. Usually this is measured by means of indices that reflect the system’s reliability for customers. When the individual contribution of transmission and distribution systems to the indices of reliability for customers is known, it is possible to evaluate whether the developed models and techniques are accurate and detailed enough to represent real behavior of the system.
Dutch public utilities have always been concerned with the need to provide a very reliable public supply to their customers. This concern manifests itself in the planning, design, operation and protection of their systems and the critical selection of appropriate equipment. Since several decades, a lot of data were gathered to obtain quantitative reliability indices. From the gathered data, public utilities obtain insight in how their systems perform. Reliability is usually considered from two viewpoints: the viewpoint of the customer and the viewpoint of the technical management.

Reliability considered from the customer point of view is often called system reliability. Reliability considered from the viewpoint of the technical management is usually defined as component reliability. Component data are treated in more detail in the next chapter. This section focuses on reliability indices from the viewpoint of the customer, or in other words, on system reliability.

Customers are usually interested in three reliability indices: the load-point interruption frequency (measured in occasions per year), the load-point interruption duration (measured in hours or minutes per occasion) and the load-point annual unavailability (measured in hours or minutes per year). A summary of the customer interruption statistics, which was gathered in the period 1992 until 1996, is presented in table 2.1 [17].

<table>
<thead>
<tr>
<th>Customer reliability index</th>
<th>HV</th>
<th>MV</th>
<th>LV</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load-point interruption frequency [occ/yr]</td>
<td>0.09</td>
<td>0.21</td>
<td>0.01</td>
<td>0.31</td>
</tr>
<tr>
<td>Load-point interruption duration [min/occ]</td>
<td>31</td>
<td>75</td>
<td>195</td>
<td>68</td>
</tr>
<tr>
<td>Load-point annual unavailability [min/yr]</td>
<td>2.9</td>
<td>15.9</td>
<td>2.3</td>
<td>21.1</td>
</tr>
</tbody>
</table>

Table 2.1 Observed indices of reliability for customers gathered in the period 1992-1996

Table 2.1 includes failures on different voltage levels; these failures lead to an interruption of the electricity supply to a customer at the low-voltage level. The different levels are high voltage (HV), medium voltage (MV) and low voltage (LV). The high-voltage level corresponds to the transmission systems and subtransmission systems ($\geq$ 50 kV). The medium- and low-voltage level correspond to the medium- and low-voltage distribution systems (10, 20, 30 kV and 0.4 kV respectively).

From the summarized interruption statistics in table 2.1, it appears that medium-voltage systems are responsible for as much as 80 percent of the unavailability of supply to a customer. It can also be seen that a major part of the number of supply interruptions
Chapter 2  Transmission and distribution system reliability features

experienced by an individual customer has its origin in component failures in the medium-voltage systems. Therefore, it can be concluded that for individual customers, the reliability of distribution systems is at least as important as the reliability of transmission systems.

In table 2.1 it can also be observed that the load-point interruption duration due to disturbances in the low-voltage systems is much higher than that due to disturbances in the high-voltage systems. This is caused by the fact that high-voltage transmission systems usually have more redundancy than low-voltage distribution systems. Another reason for this is the difference in the degree of automation that is used in these systems.

As mentioned in chapter 1, the central theme of this thesis is to predict reliability indices for transmission and distribution systems, that do agree with observed indices of reliability for customers. Such indices are presented in table 2.1 and in figure 2.1 to figure 2.3. This objective is reached by developing and improving models and techniques, taking into account manual network reconfiguration, substation-originated outages and scheduled maintenance practices.

Figure 2.1 shows over a ten-year period the load-point annual unavailability at the low-voltage level for an average Dutch customer.

![Load-point annual unavailability](image)

Figure 2.1 Load-point annual unavailability at the low-voltage level for an average Dutch customer
Figure 2.2 shows the load-point interruption frequency at the low-voltage level for an average Dutch customer, over the same period of ten years.

![Load-point interruption frequency](image)

**Figure 2.2** Load-point interruption frequency at the low-voltage level for an average Dutch customer

Figure 2.3 shows the load-point interruption duration at the low-voltage level for an average Dutch customer.

![Load-point interruption duration](image)

**Figure 2.3** Load-point interruption duration at the low-voltage level for an average Dutch customer
2.2 Planning, design, operation and protection

Most of the differences between transmission and distribution systems can be classified as distinctions between their planning and design, their operation and their protection. Therefore, the approaches to assess the reliability of these systems should be different. Typical system characteristics have to taken into account in the models and techniques adopted in the reliability evaluation procedures. This section describes the main differences between transmission and distribution systems, with respect to:

- Planning and design
- Operation
- Protection

These are treated in more detail in the following subsections.

2.2.1 Differences in planning and design

Electric transmission and distribution systems are developing continuously. When the electricity demand grows or changes, new equipment is installed and/or other network and substation configurations are constructed. New investments are also made when components are worn out or to improve the reliability of the system or of parts of it. Usually, there are several alternative ways to develop the network. In order to select what investments are most suitable and at what time they can be applied best, the long-term development of the system has to be taken into consideration. The period to be taken into consideration for the planning and design of transmission systems is normally greater than that of distribution systems.

Transmission systems are those parts of the power system that deliver electrical energy from the generation stations to area supply stations. In general, transmission systems are meshed-designed networks at high-voltage levels (mostly above 100 kV). The generation stations are generally located at different sites. Therefore, the load flows in transmission lines and cables can be two-directional. However, one direction will often be clearly dominant. Generally speaking, transmission systems obey the (n-1) criterion, whereas parts of them even obey the (n-2) criterion for design. Examples are area supply stations fed with four or even more transmission lines and/or cables.

Distribution systems are those parts of the power system which deliver electrical energy from the area supply stations to individual customers. In comparison with transmission networks, distribution systems generally have a simpler layout. They operate at lower voltage levels. Since distribution systems are generally fed from one area supply station, the load flows are normally unidirectional. However, this charac-
teristic is changing nowadays, since more and more generating units are installed in the distribution networks.

Distinctions between transmission and distribution systems can also be observed in the layout of substations and typical network structures. Substations in transmission systems have usually more redundancy and, therefore, more complex structures. Substation layouts, which are often used in transmission systems, are: duplicate busbar schemes, one-and-a-half circuit breaker schemes and ring busbar schemes. In distribution systems, single busbar schemes are often used.

Another difference between the design of transmission and distribution systems is the degree of automation in the systems. Transmission systems are usually highly automated and operated from one central supervisory control center. From such a control center, the whole system is continuously monitored and operated. The duration of performing switching actions in transmission systems can therefore be short (a few minutes).

In comparison to transmission systems, distribution networks in general do not have a high degree of automation. Therefore the time it takes to switch a component in a distribution system is not only determined by the time the decision-making requires, but also by how long it takes to dispatch personnel and to have them transported to the site(s) where the switching is to take place. Nowadays, however, this is changing. Several projects involving distribution system automation are initiated and executed.

### 2.2.2 Differences in operation

Whereas transmission and subtransmission systems are usually operated according to the (n-1) criterion, medium- and low-voltage distribution systems operate differently. Medium- and low-voltage distribution systems are in general radial-operated arrangements and the components involved in the supply are connected in series. This is an important distinction. In a transmission or subtransmission system, a single failure usually does not result in the isolation of one or several load points. In a radial-operated medium- and low-voltage distribution system, a single circuit failure will always result in the isolation of one or several load points. It should be noted that operation according to the (n-1) criterion is often not valid for certain kinds of transmission or subtransmission equipment, such as busbar sections and transformers.

Another important aspect of the operation of a system is the process of undertaking remedial actions to bring the system from an undesirable state to an acceptable state. Examples of undesirable system states are disconnected load points and overloaded
circuits. The first kind of undesirable system states can usually be overcome by performing switching actions in the system. However, the time involved in switching actions differs considerably for transmission systems on the one hand and for distribution systems on the other hand.

The process of changing the second kind of undesirable system states (circuit overloads) also differs considerably for transmission and distribution systems. Four important actions, which are discussed in this thesis, are:

- Manual network reconfiguration
- Generation rescheduling or generation redispacht
- Load curtailment or load shedding
- Protection-system behavior

In transmission systems, these actions are usually applied before a real system fault condition has occurred. Because the operating software monitors the system continuously, transmission network operators are usually warned when undesirable system states threaten to occur. Hence they can often undertake remedial actions before a system failure really occurs. The remedial actions for transmission systems usually have a preventive character.

In distribution systems, circuit overloads are normally alleviated by the automatic operation of protective relays. After the operation of the protective relays, it is often possible to reconfigure the network. These remedial actions generally have a corrective character. They are usually applied after system failure has occurred. Such differences should be taken into consideration when building models and techniques to assess the reliability of systems that transmit and distribute electricity.

2.2.3 Differences in protection

In a transmission system, every component is usually protected by two pairs of protection relays, which operate in parallel. Each relay operates as a back-up of its parallel. The most common protection schemes are distance and differential (or pilot wire) protection. Because two protective relays operate in parallel the probability of a failure to trip is considerably reduced. On the other hand, the probability of a spontaneous trip increases. Usually this is not a very serious problem in normal operating transmission systems because of the (n-1) redundancy.

Since distribution systems generally have simpler, radial-operated layouts, the protection of such systems can also be simpler. In high-voltage distribution systems (subtransmission networks), each component is normally protected by one pair of
24  **Reliability evaluation of electric transmission and distribution systems**

protective relays. Typical protection schemes are distance and differential protection. In medium- and low-voltage distribution systems, several components are protected by one protective relay. In these networks, overcurrent protective relays are often used.

The probability of a protection-system failure to operate is usually higher in distribution systems than in transmission systems. In contrast to transmission and subtransmission systems, a spontaneous trip in medium- and low-voltage distribution systems usually influences the reliability of the electricity supply directly.

### 2.3 Simulation or state enumeration?

As mentioned in chapter 1, the ultimate goal of a reliability investigation of an electric transmission or distribution system is to evaluate whether the considered system is sufficiently strong to withstand disturbances. A probabilistic approach attempts to assess quantitative reliability indices for a system on the basis of reliability data of its components. The general basic structure of a probabilistic reliability calculation for electric transmission and distribution systems is depicted in figure 2.4 [18].

Figure 2.4 starts with the selection of a system state. Each state has a certain probability and frequency of occurrence. A complete system state consists of a network state, a load situation and a generation schedule. It is obvious that there is only one network state with all components in service. All other network states correspond to component outages in the system studied. In order to establish whether the selected state results in system failure, the selected state is evaluated. First, the available generation in the system is compared with the system load and isolated load points are determined. Secondly, the system state is analysed by using a load flow.

If one or more constraints of the system are violated, it is established whether these violations can be overcome by undertaking appropriate remedial actions. Examples of system violations are circuit overloads and voltages which have exceeded their limits. Examples of remedial actions are manual network reconfiguration, generation redispach, load curtailment or switching circuits out of service automatically by protective relays. The first three examples are typical for transmission systems, while the latter example is characteristic for distribution systems.
Figure 2.4  Basic structure of a probabilistic reliability assessment procedure for electric transmission and distribution systems

After these remedial actions are applied, the impact of the system fault condition is evaluated and the load-point reliability indices are updated. Then the question arises whether sufficient system states have been evaluated. When the answer is 'yes', overall system indices are compiled and the procedure is terminated. When the answer is 'no', another system state is selected and the whole process is repeated. The individual steps of the algorithm in figure 2.4 are treated in more detail in chapter 4 and 5 of this thesis. Chapter 4 is mainly concerned with the first step, while chapter 5 considers the remaining steps.

It should be noted that after performing the procedure of figure 2.4 the evaluated reliability indices are only as good as the models derived for component outages and system behavior, as the appropriateness of the mathematical techniques used, and as the quality of the reliability input data. In other words: what you put in the calculations, you get out of them. This is true both for transmission and for distribution system reliability evaluation.
In principle, two different approaches can be distinguished for the computation of transmission and distribution system reliability. These are analytical techniques (state enumeration approach) or simulation techniques (Monte Carlo simulation approach). The difference between both approaches lies in the selection of system states that have to be evaluated, including their corresponding statistical indices. In the state enumeration approach, component outages or combinations of component outages are systematically selected or enumerated. In the simulation approach, outages are randomly selected.

Both methods have merits and demerits. One must not regard these methods as being exclusive since fairly recently, hybrid techniques have been used in attempts to use the advantages, while avoiding the drawbacks of both [11]. The following three aspects are of concern when selecting the most suitable approach:

- State-space size
- Component reliability
- Modeling complexity

These are treated in more detail in the following subsections.

### 2.3.1 State-space size

One of the most important factors in selecting the best approach is the number of states or the size of the probabilistic state space. An advantage of Monte Carlo simulation is its weak coupling between the state-space size and the corresponding computation time. Monte Carlo methods seem to be more efficient when there is a high number of overlapping outage combinations of components to be examined. This situation is often found in HL1 and HL2 studies, in which higher level outages of system components are more likely due to the relatively higher outage probabilities of generating units.

In turn, state enumeration methods perform better when the number of system states to be examined is relatively small. This situation is valid for pure transmission and distribution system studies, because component-failure rates are usually small in such systems. Therefore, overlapping failures of three or more components are very unlikely and do not have to be considered.

### 2.3.2 Component reliability

A main disadvantage of the simulation approach is that the more reliable the components of the system are, the greater is the computational effort required to assess the
reliability of the system. It can be proven that the computational effort is nearly inversely proportional to the unreliability of the system's components. Since transmission and distribution system components usually have a high degree of reliability, Monte Carlo methods are less suitable to analyse the reliability of such systems.

Another main disadvantage of Monte Carlo methods is the strong dependence of computational effort with respect to the desired accuracy of the estimated reliability indices. It can be proven that the computational effort is nearly inversely proportional to the square of the uncertainty in the indices obtained. When, for example, ten thousand system states have to be evaluated to get an uncertainty of 30 percent, one million system states have to be evaluated in order to get an uncertainty of 3 percent.

2.3.3 Modeling complexity

In principle, Monte Carlo simulation can include any system effect or system process which may have to be approximated in analytical methods. Monte Carlo simulation methods can simulate all kinds of probability distributions associated with component failure, restoration and scheduled maintenance activities. They can also evaluate distributions of reliability indices and not only the expected values of random variables. This generally cannot be performed by means of analytical methods.

However, it may be questionable whether probability distributions associated with component failure, restoration and scheduled maintenance activities are known sufficiently in detail to apply them in detailed reliability assessment studies. If not, this advantage disappears.

Whether the state enumeration approach is chosen or the Monte Carlo simulation approach also depends on the background and working experience of the individual planner [11,18]. In this thesis, the approach used to evaluate the reliability of transmission and distribution systems is based on the state enumeration method.
Chapter 3

Reliability input data

This chapter deals with the contents of box 1 in figure 1.4: the reliability input data. With the aid of such data, it should be possible to predict the reliability of transmission and distribution systems. These data must be sufficiently detailed to ensure that the factors that affect reliability can be modeled and analysed. The data should therefore reflect the three main processes involved in component and system behavior, namely the failure, the restoration and the scheduled maintenance processes. The first section describes these three processes and the statistical indices that can be used to describe them. The second section deals with several dependency concepts that have to be taken into consideration during the development of new or improved models and techniques. The last section deals with observed component reliability, and presents the component reliability indices which are used as input data in this thesis.

3.1 Stochastic processes and statistical indices

A power system is monitored continuously, with the result that many system and component parameters such as the network configuration, load demand, open and closed status of disconnecting switches and circuit breakers are known as a function of the time. All these parameters constitute data that are essential for an efficient, economic and secure operation of the system. From this almost unlimited amount of data, it is necessary to collect data that are detailed enough to ensure that the factors that
affect the reliability of the system can be modeled and analysed. There are in principle three stochastic processes which influence reliability data of components [18,19,20]. These three processes are:

- Failure processes
- Restoration processes
- Scheduled maintenance processes

This section discusses these processes and the statistical indices that can be used to describe them.

### 3.1.1 Failure processes

It is usual in reliability assessment studies of electric transmission and distribution systems to consider the following three failure modes:

- Short-circuit failures
- Open-circuit failures
- Switching failures

These failure modes are treated in more detail below.

#### Short-circuit failures

Short-circuit failures are the most common of all component failures and cause most of the outages of components in a power system. All types of power-system components can suffer such failures. Short-circuit failures will cause appropriate circuit breakers to trip via primary or secondary protection schemes. This is defined as an active failure [12]. Usually, active failures cause contingencies of a greater order than those associated with open-circuit failures.

#### Open-circuit failures

Open-circuit failures are rare for most power-system components. It is physically possible for a conductor to break, causing an open circuit, but a short circuit follows immediately when the conductor hits ground, which causes the operation of appropriate circuit breakers via primary or secondary protection schemes. Therefore, open-circuit failures are defined as failures that do not cause short-circuit currents and therefore do not cause surrounding circuit breakers to operate. In practice, only circuit breakers experience open-circuit failures. This type of failure is defined as a passive failure [12]. An example is an inadvertent operation of a circuit breaker that is due to a failure within the protection system or within the associated equipment or is due to a failure of the circuit breaker itself. This failure mode also includes manual operating errors.


Chapter 3  Reliability input data  

Switching failures
Because of their switching function, circuit breakers can exhibit an additional failure, namely a failure to open on command. A failure to open on command is generally known as a failure to operate or as a stuck circuit-breaker condition [21]. When a short-circuit failure occurs and a circuit breaker controlling the protection zone fails to trip due to a fault within the protection system or within the circuit breaker itself, back-up or secondary protection must operate, which is likely to isolate a greater section of the system with a more significant impact on system operation.

Failures to operate are important and should be recognised in the reliability assessment of electric transmission and distribution systems, since their effect can have serious consequences. A failure to operate is generally due to the protection system or circuit breaker having developed an unrevealed fault since it was last operated or tested. The circuit breaker or protection system then remains in a dormant state until an active failure occurs, or until preventive or scheduled maintenance is performed.

A complementary failure exists for normally open breakers and their associated control and for breakers that have tripped after a component failure and are being reclosed. Such failures are defined as failures to close on command. The principles for such a failure are similar as in the concept above. Failures to close on command are neglected in this thesis.

3.1.2 Restoration processes

Two types of restoration can be distinguished: restoring supply to the customers and restoring a failed component to its in service state. Usually the electricity supply is restored by switching (manually or automatically), while the second type of restoration is performed by repair or replacement. Therefore, care is required to correctly identify restoration times to perform predictive reliability calculations.

Automatic reclosing actions usually following a transient failure are not considered in this thesis as a restoration process. Such phenomena belong to dynamic or even transient power-system behavior. The duration of transient outages, often caused by lightning strokes, is usually negligible compared to other outages.

3.1.3 Scheduled maintenance processes

Most components in electric power systems undergo periodic preventive maintenance. While these routines help to keep the component-failure rates down, it is also evident that, if they overlap with the failure of another component, they can increase the
number of system failures, because the system was in a weakened condition. Scheduled maintenance is performed on the assumption, of course, that the beneficial effects outweigh the adverse effects. In many reliability studies only the increase in the system reliability indices is computed. This increase is then caused by the periods of overlapping maintenance activities and component failures. However, attempts have been made to determine optimally scheduled maintenance frequencies, on the basis of the mean duration of the scheduled maintenance activities [22,23].

Scheduled maintenance of a single radial system is not considered in this dissertation because this leads to the disconnection of load points. This does not mean that such electricity-supply interruptions do not occur in practice, but it acknowledges that customers are notified in advance or that alternative arrangements are made and that, therefore, the load point is interrupted deliberately, which cannot be considered as a randomly occurring event.

These concepts lead to the conclusion that scheduled maintenance is simulated only for overlapping events associated with parallel and mesh networks. In addition, only the sequence ‘scheduled maintenance followed by a component failure’, i.e., a failure overlapping an existing scheduled maintenance outage is normally considered, because the reverse sequence would not be in line with practice. For these reasons, single scheduled maintenance outage states will not represent system failure and are therefore not considered in this thesis. Only double (and occasionally higher) scheduled outages need to be evaluated [12,24].

Usually if a failure occurs when scheduled maintenance is carried out, the duration of the scheduled maintenance process can be shortened. The scheduled maintenance activities are then cut off and the maintenance process is resumed after the repair of the faulted component. It is therefore important to recognise that failures concurring scheduled maintenance generally do not involve the total maintenance duration.

3.1.4 Statistical indices

A large number of statistics can be deduced from the data mentioned above, but all can generally be classified with one of the following four sets of indices [19]:

- Probability of residing in a state
- Rate and frequency of occurrence
- Average duration of a state
- Probability of a command failure
These are expanded and discussed in more detail below. The indices are not deterministic values but the expected or mean values of a probability distribution, that may be unknown.

**Probability of residing in a state**
The probability that something is found in a certain state can be estimated in the long run from the ratio of the time spent in that state to the total period of time, i.e.,

\[
\text{Probability of residing in a state} = \frac{\text{total time spent in that state}}{\text{period time}} \tag{3.1}
\]

**Rate and frequency of occurrence**
The concept of the rate of occurrence of an event is given by [19]:

\[
\text{Rate of occurrence} = \frac{\text{number of events}}{\text{exposure time for the event}} \tag{3.2}
\]

The concept of frequency of occurrence of a state is given by [19]:

\[
\text{Frequency of occurrence of a state} = \frac{\text{number of events}}{\text{period time}} \tag{3.3}
\]

From (3.2) and (3.3), it can be seen that the denominator is the only difference between rate and frequency. If the exposure time and the period time are approximately identical, then the rate and frequency of occurrence are also approximately the same. This applies, for example, to the failure process of a continuously operated component when the time not spent in the operating state is small. The failure rate and the failure frequency are often numerically almost equivalent and the value of the rate is often obtained using equation (3.3).

**Average duration of a state**
The concept of average duration of a state is given by [19]:

\[
\text{Average duration of a state} = \frac{\text{total time spent in that state}}{\text{number of events}} \tag{3.4}
\]

It must be noted that from (3.1), (3.3) and (3.4) follows that the probability of residing in a state is given by the product of the frequency of occurrence of that state and the average duration of that state.
Probability of a command failure

The probability of a command failure (the probability of failing to respond to a command) is given by [19]:

\[ \text{Probability of a command failure} = \frac{\text{number of failures to operate}}{\text{number of commands to operate}} \] (3.5)

In the case of ‘opening’ commands then ‘operate’ in this equation has to be interpreted as ‘open’ and in the case of ‘closing’ commands, ‘operate’ has to be interpreted as ‘close’.

3.2 Dependency concepts

When evaluating quantitative reliability indices of systems that transmit and distribute electricity one must recognise that it is necessary to assess how likely it is that outages occur. Component outages can arise in many ways and under a wide range of conditions. In some situations, the events may be completely independent, or there may be an association between them, that has a major influence on the likelihood of a concurring outage. In the case of outdoor facilities such as transmission elements, the weather can have a dominating influence on the likelihood of component and system failures. This section considers several important dependency concepts, that can have a significant influence on transmission and distribution system reliability indices.

3.2.1 Cascade failures

As the name cascade failure implies, these failures depend on the occurrence of one or more other failures. An example is the removal of a line due to overload which resulted from an independent failure of the other line of a double circuit configuration [12,18]. A cascade failure can be defined as an event having one or several external causes with multiple failure effects, where the effects are consequences of each other.

Cascade failures should be included particularly when no load-shedding actions are undertaken. In that case, the components which are loaded above a certain specified loading level are removed from service automatically by the protection system. The remaining system will be analysed again and this process has to be repeated until all components are loaded below their specified loading levels.
Chapter 3  Reliability input data

When a load-shedding scheme is used, it is unusual to model cascade failures in the reliability evaluation of the system. In such a case, overloaded circuits are usually alleviated by generation redispacht or load curtailment. Therefore, a reliability evaluation procedure for transmission systems usually does not consider cascade failures. Such failures are more specific for reliability evaluation procedures applied to distribution systems.

3.2.2 Common cause failures

The physical closeness of transmission lines on a common tower can result in multiple outages. The nature of such events differs from the usual independent overlapping outages, and therefore these outages require a somewhat different approach. The outage of all circuits of such arrangements can occur due to single causes, such as:

- Fire in right-of-way (forest, brush, tall grasses)
- Foundation or anchor failures (flood, landslide, ground subsidence)
- Severe environmental conditions (hurricanes, tornados, icing, lightning)
- Interference by other circuits (high-voltage circuits crossing lower-voltage circuits)
- Aircraft interference
- Rail, road, shipping and vehicle interference

The same can occur for cables which are buried in the same groove. In that case, the outage of several circuits in the groove is often caused by digging activities of contractors, landslide or ground subsidence. A common mode or common cause failure can be defined as an event having an external cause with multiple failure effects where the effects are not consequences of each other [12,18]. The effect of these failures on the reliability indices of load points can be quite significant compared to the impact of second- and higher-order independent failures.

The Task Force on Common Mode Outages of Bulk Power Supply Facilities in the IEEE Subcommittee on the Application of Probability Methods (APM) has suggested a common mode outage model for two transmission lines on the same right-of-way or on the same transmission tower [25]. Various other common cause outage models have been analysed and are described in detail in [26].

3.2.3 Common environment

All electric transmission and distribution system components are exposed to varying weather conditions and experience has taught that failure rates of many components are functions of the weather to which they are exposed. In some weather conditions,
the failure rate of a component can be much greater than that found with the most favorable weather condition.

The failure rate of a component is a continuous function of the weather condition, which suggests that it should be described by either a continuous function or by a large set of discrete states. This proves impossible in practice, owing to difficulties in system modeling and data collection, and the problem must therefore be restricted to a limited number of states. A set of approximate equations was presented which incorporated the weather effects by using two weather states designated as normal and adverse [9]. A more complete analysis, which introduced the utilization of Markov models to examine the effects of weather, was published in 1968 [27]. The IEEE standard subdivides the weather into three classifications: normal, adverse and major storm disaster [28].

At present, most of the data collection schemes do not recognise different weather states. They only register the long-term average behavior as a result of varying weather conditions. Therefore, weather effects are not considered further in the reliability investigation studies as presented in this thesis. However, in future, these effects may be examined if a large number of public utilities acknowledge the need to identify such data.

### 3.2.4 Use of the same components

Besides the dependency concepts presented in the foregoing subsections, there is a dependency concept that deals with the use of the same components in the whole system. The failure rate of a component as a function of time can have the form of a so-called ‘bathtub’. This function, which is characteristic for a lot of devices, is depicted in figure 3.1.

![Bathtub-shaped failure rate](image)

**Figure 3.1** Bathtub-shaped failure rate of a component
Chapter 3  Reliability input data

Figure 3.1 shows three distinct sections: an initial period with a decreasing failure rate, a central section where the failure rate is approximately constant, and a final period where the failure rate increasing sharply. The resultant shape of the curve is the reason for the name ‘bathtub curve’ [24].

When the bathtub curve for a given set of components in a transmission or distribution system has reached the final period, namely there where the failure rate increases, the system will weaken. Such effects are not considered in this thesis. All reliability analyses are performed under the assumption that the failure rates of the system components are constant. Of course, it is possible to simulate such effects by repeating the reliability calculations several times with increasing failure rates.

3.3 Observed component reliability

Since several decades, a lot of reliability data were gathered by public utilities. This has also been done in the Netherlands. The quality of these data, and thus the confidence in them, is clearly dependent on the accuracy and completeness of the information compiled by operating and maintenance personnel. It is therefore essential that they are made fully aware of the future use of the data and their importance for later developments of the system. The quality of the statistical indices also depends on the size of the data set, how the data are processed, how much pooling is done and on the age of the data presently stored.

From the gathered data, the public utilities also gain insight in the performance of their systems. As mentioned in the foregoing chapter, reliability is usually considered from two different viewpoints: the viewpoint of the customer and the viewpoint of the technical management. Reliability considered from the viewpoint of the customer is called system reliability. Indices concerning system reliability were treated in the foregoing chapter. This section deals with indices from the viewpoint of the technical management.

Reliability considered from the viewpoint of the technical management is defined as component reliability. Here the type and cause of the failure and the component involved are of great importance. Reliability data of components can serve as reliability input data for a prediction of the reliability of the transmission and distribution systems. The reliability data of components should reflect the three main processes involved in component and system behavior, namely the failure, the restoration and the scheduled maintenance processes. However, at the present time, in many data-collec-
tion schemes, scheduled maintenance is not recognised. There is also often confusion over data concerning supply restoration processes and data concerning repair processes of individual components. In the following tables, some performance statistics of transmission and distribution equipment are shown, contained in one of the latest EnergieNed-reports [17,29].

<table>
<thead>
<tr>
<th>Component</th>
<th>50 kV</th>
<th>110 kV</th>
<th>150 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line (1 kilometer)</td>
<td>0.0048</td>
<td>0.0076</td>
<td>0.0021</td>
</tr>
<tr>
<td>Cable (1 kilometer)</td>
<td>0.0095</td>
<td>0.0082</td>
<td>0.0074</td>
</tr>
<tr>
<td>Transformer</td>
<td>0.010</td>
<td>0.018</td>
<td>0.021</td>
</tr>
<tr>
<td>Busbar section</td>
<td>0.002</td>
<td>0.002</td>
<td>0.002</td>
</tr>
<tr>
<td>Circuit breaker</td>
<td>0.001</td>
<td>0.012</td>
<td>0.013</td>
</tr>
</tbody>
</table>

**Table 3.1** Failure rates of several transmission and subtransmission system components [occ/yr] in the period 1976-1996

<table>
<thead>
<tr>
<th>Component</th>
<th>50 kV</th>
<th>110 kV</th>
<th>150 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line (1 kilometer)</td>
<td>182</td>
<td>74</td>
<td>38</td>
</tr>
<tr>
<td>Cable (1 kilometer)</td>
<td>318</td>
<td>62</td>
<td>194</td>
</tr>
<tr>
<td>Transformer</td>
<td>285</td>
<td>44</td>
<td>321</td>
</tr>
<tr>
<td>Busbar section</td>
<td>32</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Circuit breaker</td>
<td>79</td>
<td>15</td>
<td>37</td>
</tr>
</tbody>
</table>

**Table 3.2** Average repair durations of several transmission and subtransmission system components [hr] in the period 1976-1996

<table>
<thead>
<tr>
<th>Component</th>
<th>Average</th>
<th>Urban</th>
<th>Rural</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cable (1 kilometer)</td>
<td>0.0112</td>
<td>0.0093</td>
<td>0.0118</td>
</tr>
<tr>
<td>Joint</td>
<td>0.0018</td>
<td>0.0030</td>
<td>0.0017</td>
</tr>
<tr>
<td>Transformer</td>
<td>0.0006</td>
<td>0.0005</td>
<td>0.0007</td>
</tr>
<tr>
<td>Busbar section</td>
<td>0.0002</td>
<td>0.0003</td>
<td>0.0002</td>
</tr>
<tr>
<td>Circuit breaker</td>
<td>0.0021</td>
<td>0.0010</td>
<td>0.0023</td>
</tr>
</tbody>
</table>

**Table 3.3** Failure rates of several 10 kV-distribution system components [occ/yr] in 1995
Table 3.4 Average electricity supply restoration durations of several 10 kV-distribution system components [hr] in 1995

Note that it is common to categorize a transformer for the voltage level which is related to its high-voltage windings. The failure and repair rate of a 150/50 kV-transformer is for example presented in the category of 150 kV-components.

The following statistical indices of transmission and distribution equipment are used as reliability input data in this thesis:

- $\lambda_k$ failure rate of component $k$ ($\lambda_k = \lambda_k^p + \lambda_k^a$)
- $\lambda_k^p$ passive failure rate of component $k$
- $\lambda_k^a$ active failure rate of component $k$
- $\lambda_k^m$ scheduled outage rate of component $k$
- $\lambda_{kl}^{cc}$ common cause outage rate of components $k$ and $l$
- $r_k$ average repair duration of component $k$
- $r_k^m$ average maintenance duration of component $k$
- $r_k^{mco}$ average maintenance cutoff duration of component $k$
- $r_k^{cc}$ common cause repair duration of components $k$ and $l$
- $s_k$ average switching duration of component $k$ involved with electricity supply restoration
- $Pr_k^{scb}$ probability of a stuck condition of circuit breaker $k$

As mentioned in section 3.1, the passive failure rate of component $k$, $\lambda_k^p$, and the probability of a stuck condition of a circuit breaker $k$, $Pr_k^{scb}$, are specific for circuit breakers. All other indices are universal for transmission and distribution system equipment.

It should be recalled that the main objective of this thesis is to predict system reliability with the aid of component reliability indices as presented above and other system data. The predicted system reliability indices should agree with observed data concerning system reliability, as presented in table 2.1.
Chapter 4

Contingency modeling

This chapter deals with the contents of box 2 in figure 1.4: the contingency models. A contingency is a network state where, owing to failures, one or more components are not available. A complete system state consists of a network state, a load situation and a generation schedule. With the aid of contingency modeling, component outages or combinations of component outages are enumerated. All components that are not enumerated on outage are assumed to be in service or ready for service. Each contingency is characterized by a certain probability and frequency of occurrence. The first section deals with models and concepts to evaluate component outage probabilities and frequencies. In the second section, the enumeration of circuit outages is treated as well as the compilation of network states. The final section deals with enumeration of substation-originated outages.

4.1 Component outage modeling

The probability and the frequency with which a network state occurs are the two basic indices to evaluate the reliability of a transmission or distribution system. The evaluation of these indices is usually based on state-space diagrams which can be described by continuous Markov models, the so-called homogeneous Markov processes [30]. Other measures like the average duration of a state can be obtained from these two basic indices.
This section first describes the basic principles to calculate the probability and frequency of a single component outage by using a simple state-space diagram. After that, a mathematical derivation is presented to calculate these indices for general and for more complex state-space diagrams. In the final part of the section, relations are derived for combining states in state-space diagrams.

4.1.1 Basic principles

Consider the state-space diagram of a single repairable component $k$, as depicted in figure 4.1. Component $k$ can be in one of either two states: working (state 1) or failed (state 2). After the occurrence of a failure, the component is undergoing repair, and after this is completed, it is returned to service. The transition rates between the two states are characterized by the failure and repair rates [30].

![State-space diagram](image)

**Figure 4.1** State-space and state time diagram of a single repairable component

According to chapter 3, the rate of occurrence of a failure event, $\lambda_k$, can be derived from the state time diagram of figure 4.1:

$$\lambda_k = \frac{N_k}{\sum_{i=1}^{N_k} t_i^{UP}}$$

(4.1)
where:

\[ N_k \] the number of failures of component \( k \)
\[ t_{i,UP} \] the time spent in the \( UP \) state before the occurrence of failure \( i \)

This failure rate, \( \lambda_k \), is assumed to be time independent. This corresponds with the 'mid-life' of the bathtub-shaped failure rate, presented in the foregoing chapter. It can be proven that for time-independent failure rates, the statistical distribution representing the failure process is negative exponential [24,30].

In the same way one can find the rate of occurrence of a repair event of the single repairable component \( k \), \( \mu_k \):

\[
\mu_k = \frac{N_k}{\sum_{i=1}^{N_k} t_{i,DN}^{UP}}
\]  \hspace{1cm} (4.2)

where:

\[ t_{i,DN}^{UP} \] the time spent in the \( DN \) state after the occurrence of failure \( i \)

When all transition rates in a state-space diagram are known, it is possible to calculate the state probabilities and frequencies and some related indices, such as the average duration of being in a state. This is first illustrated for one component, by using a heuristic approach. After that, a mathematical method is presented to obtain probability and frequency indices for individual components.

The probability of occurrence of the \( UP \) state (state 1) of component \( k \) in figure 4.1, \( Pr_1 \), is given by:

\[
Pr_1 = \frac{\sum_{i=1}^{N_k} t_{i,UP}}{\sum_{i=1}^{N_k} (t_{i,UP} + t_{i,DN}^{UP})} = \frac{\mu_k}{\lambda_k + \mu_k}
\]  \hspace{1cm} (4.3)

The probability of occurrence of the \( DN \) state (state 2) of component \( k \) in figure 4.1, \( Pr_2 \), is given by:
\[ Pr_2 = \frac{\sum_{i=1}^{N_k} t_i^{DN}}{\sum_{i=1}^{N_k} (t_i^{UP} + t_i^{DN})} = \frac{\lambda_k}{\lambda_k + \mu_k} \]  

(4.4)

The frequency of entering the DN state, \( Pr_2 \), for the considered component \( k \) is equal to the frequency of entering the UP state, \( Pr_1 \), and is given by:

\[ Pr_1 = Pr_2 = \frac{N_k}{\sum_{i=1}^{N_k} (t_i^{UP} + t_i^{DN})} = \frac{\lambda_k \mu_k}{\lambda_k + \mu_k} \]  

(4.5)

The average duration that the single repairable component \( k \) in figure 4.1 is in the UP state, \( Du_1 \), the so-called average operating duration or the mean time to failure, \( MTTF_k \), is given by:

\[ Du_1 = MTTF_k = \frac{1}{N_k} \sum_{i=1}^{N_k} t_i^{UP} = \frac{1}{\lambda_k} \]  

(4.6)

The average duration that the considered component \( k \) in figure 4.1 is in the DN state, \( Du_2 \), the so-called average repair duration, \( r_k \), or the mean time to repair, \( MTTR_k \), is given by:

\[ Du_2 = r_k = MTTR_k = \frac{1}{N_k} \sum_{i=1}^{N_k} t_i^{DN} = \frac{1}{\mu_k} \]  

(4.7)

The average cycle duration of entering the DN state of the considered component \( k \), \( Du_{cl} \), is equal to the average cycle duration of entering the UP state, \( Du_{c2} \). This parameter is often called the mean time between failures, \( MTBF_k \), which is given by:

\[ Du_{cl} = Du_{c2} = MTBF_k = \frac{1}{N_k} \sum_{i=1}^{N_k} (t_i^{UP} + t_i^{DN}) = \frac{\lambda_k + \mu_k}{\mu_k \lambda_k} \]  

(4.8)
4.1.2 General solution approach

For larger (more complex) state-space diagrams, a systematic matrix approach appears to be very suitable to calculate steady-state probabilities, frequencies and other related indices [31]. Consider the general state-space diagram as presented in figure 4.2. The relations between the probabilities, frequencies and average durations associated with states on the one hand and the transition rates in the state-space diagram on the other hand are now derived in a mathematical way.

![General state-space diagram](image)

**Figure 4.2** General state-space diagram

It is illustrated in figure 4.2 that the probability that the component is in, say, state $i$ at time $t + \Delta t$ depends on the state the component is in at time $t$, but also on the time interval $\Delta t$. For small values of $\Delta t$, the probability that the component is in state $i$ at time $t + \Delta t$ is given by:

$$Pr_i(t + \Delta t) = Pr_i(t) \cdot (1 - \sum_{k \neq i} \tau_{ik} \Delta t) + \sum_{k \neq i} Pr_k(t) \cdot \tau_{ki} \Delta t$$  \hspace{1cm} (4.9)

where:

- $Pr_i(t)$ the probability that the component is in state $i$ at time $t$
- $\tau_{ik}$ the transition rate from state $i$ to state $k$

The first term in this equation means that the component will remain in state $i$ in the time interval $\Delta t$. This means that no transition takes place to any other state in the time interval $\Delta t$. The second term covers the transition to state $i$ from any state $k$ in the time interval $\Delta t$. After rearrangement of terms in equation (4.9), one obtains:
\[
\frac{Pr_{i}(t+\Delta t) - Pr_{i}(t)}{\Delta t} = -Pr_{i}(t) \sum_{k \neq i} \tau_{ik} + \sum_{k \neq i} Pr_{k}(t) \cdot \tau_{ki}
\]

(4.10)

which after the transition \(\Delta t \to 0\) becomes:

\[
\frac{dPr_{i}(t)}{dt} = -Pr_{i}(t) \sum_{k \neq i} \tau_{ik} + \sum_{k \neq i} Pr_{k}(t) \cdot \tau_{ki}
\]

(4.11)

With matrix notation, equation (4.11) can be rewritten as:

\[
\frac{dPr(t)}{dt} = T \cdot Pr(t)
\]

(4.12)

where:

- \(T\) a matrix of transition rates
- \(Pr(t)\) a column vector whose \(i^{th}\) term is the probability that the component is in state \(i\) at time \(t\)

The element \(T_{ik}\) of the matrix of transition rates, \(T\), is given by:

\[
T_{ik} = \begin{cases} 
\tau_{ki}, & k \neq i \\
-\sum_{j \neq i} \tau_{ij}, & k = i 
\end{cases}
\]

(4.13)

In this thesis, the long-term or steady-state probabilities are considered, that is, the values of \(Pr_{i}(t)\) as \(t \to \infty\). In these cases, the solution of equation (4.12) becomes very simple. Due to the characteristics of matrix \(T\), the changes in \(Pr_{i}(t)\) will diminish as \(t \to \infty\). With this, the set of differential equations reduces to a set of linear equations having the form:

\[
0 = T \cdot Pr
\]

(4.14)

where:

- \(Pr\) a column vector whose \(i^{th}\) term is the steady-state probability of residing in state \(i\)

Since the elements in each column of matrix \(T\) add up to zero, the determinant of \(T\) is zero and, therefore, the equations in (4.14) are not linearly independent. Each equation
is a linear combination of the others. To provide an additional equation, the simple fact is recognised that the state probabilities must add up to 1 at any time \( t \), and therefore:

\[
\sum_k Pr_k = 1 \tag{4.15}
\]

For this reason, the steady-state probabilities can be obtained by solving the following matrix equation:

\[
T' \cdot Pr = C \tag{4.16}
\]

where:

- \( T' \) a matrix obtained from matrix \( T \) by replacing the elements of an arbitrarily selected row \( p \) by ones
- \( Pr \) a column vector whose \( i^{th} \) term is the probability of residing in state \( i \)
- \( C \) a column vector with the \( p^{th} \) element equal to one and other elements set to zero

It is obvious that the frequency of transition of, say, state \( i \) to state \( k \) depends on the probability of being in state \( i \), \( Pr_i \), and on the transition rate from state \( i \) to state \( k \). The frequency with which the component undergoes a transition from state \( i \) to state \( k \) is given by:

\[
Fr_{ik} = Pr_i \tau_{ik} \tag{4.17}
\]

The frequency of leaving (or entering) state \( i \) is equal to the sum of frequencies of transition from state \( i \) to any state \( k \). Therefore:

\[
Fr_i = \sum_{k \neq i} Fr_{ik} = Pr_i \sum_{k \neq i} \tau_{ik} \tag{4.18}
\]

In order to relate the frequency, the probability and the average duration of being in state \( i \), the state-space diagram of figure 4.2 can be regarded as consisting of two alternating periods. These are: the stays in \( i \) and the stays outside \( i \). Thus, the system can be represented by a two-state process whose state-space diagram is shown in figure 4.3. Let the average duration of stays in \( i \) be equal to \( Du_i \), and that of the stays outside \( i \), \( Du'_i \). The average cycle duration of state \( i \), \( Du_{ci} \), is then:

\[
Du_{ci} = Du_i + Du'_i \tag{4.19}
\]
Figure 4.3  Two-state process ‘in state i - outside state i’

It is obvious that the frequency of occurrence of state \(i\), \(Fr_i\), is equal to:

\[
Fr_i = \frac{1}{Du_{ci}}
\]  

(4.20)

Multiplying equation (4.20) by \(Du_i\), the right-hand side becomes \(Du_i / Du_{ci}\), which is equal to the steady-state probability that state \(i\) occurs, \(Pr_i\). Therefore, the following fundamental equation arises:

\[
Pr_i = Fr_i \cdot Du_i
\]  

(4.21)

Combining equations (4.18) and (4.21), the average duration of state \(i\), \(Du_i\), can be expressed as:

\[
Du_i = \frac{1}{\sum_{k \neq i} \tau_{ik}}
\]  

(4.22)

A small example can illustrate the concepts and techniques mentioned above.

Example 4.1
Consider again the state-space diagram, as given in figure 4.1. Matrix \(T\) can then be obtained by using equation (4.13), i.e.,

\[
T = \begin{pmatrix}
T_{11} & T_{12} \\
T_{21} & T_{22}
\end{pmatrix} = \begin{pmatrix}
-\lambda_k & \mu_k \\
\lambda_k & -\mu_k
\end{pmatrix}
\]  

(4.23)

Then, the matrices \(T'\) and \(C\) can be obtained, i.e.,
Chapter 4  Contingency modeling

\[
T' = \begin{pmatrix}
-\lambda_k & \mu_k \\
1 & 1
\end{pmatrix}, \quad C = \begin{pmatrix}
0 \\
1
\end{pmatrix}
\]  

(4.24)

Solving equation (4.16) results in:

\[
Pr = T^{t-1} \cdot C = \begin{pmatrix}
Pr_1 \\
Pr_2
\end{pmatrix} = \begin{pmatrix}
\frac{\mu_k}{\lambda_k + \mu_k} \\
\frac{\lambda_k}{\lambda_k + \mu_k}
\end{pmatrix}
\]

(4.25)

Solving equation (4.22) results in: \(Du_1 = 1/\lambda_k\) and \(Du_2 = 1/\mu_k\). From the state probabilities, \(Pr_i\), and average state durations, \(Du_i\), the state frequencies, \(Fr_i\), can be calculated, using equation (4.21), i.e., \(Fr_1 = Fr_2 = \lambda_k\mu_k/(\lambda_k + \mu_k)\). These results agree with equations (4.3), (4.4), (4.6), (4.7) and (4.5), respectively.

\[\square\]

4.1.3 Combining states

In case of large state-space diagrams, various states can have the same effect. The state-space diagram can then be simplified by grouping together those states that have the same effect. Through the combination of groups of states in an original state-space diagram, a new state-space diagram is generated with new states (the combined states) and new transition rates (those to and from the combined states). In the following, the probability and frequency of a combined state will be calculated. Consider the general state-space diagram as presented in figure 4.4. Suppose that a certain number of states results in system failure. Then these states can be grouped together and combined into a single state, say, \(I\). This is illustrated in the figure.

The probability of occurrence of \(I\), \(Pr_I\), is obtained by adding all the probabilities \(Pr_i\), that is:

\[
Pr_I = \sum_{i \in I} Pr_i
\]

(4.26)

The probabilities, \(Pr_i\), can be added because the events of being in any of the states \(i\) are mutually exclusive. The frequency of \(I\), \(Fr_I\), is the total of the frequencies of leaving a state \(i\) for a state \(k\) outside \(I\), and therefore:


Figure 4.4 Combining states \(i, l\) and \(m\) into \(I\)

\[
Fr_I = \sum_{i=l} \sum_{k=l} Fr_{ik} = \sum_{i=l} \sum_{k=l} Pr_{i} \tau_{ik} = \sum_{i=l} \left( Pr_i \sum_{k=l} \tau_{ik} \right)
\]  \hspace{1cm} (4.27)

The average duration of being in the combined state \(I\), \(Du_I\), can then be obtained by:

\[
Du_I = \frac{Pr_I}{Fr_I}
\]  \hspace{1cm} (4.28)

A small example can illustrate the concepts and techniques associated with combining system states.

Example 4.2
Consider a system comprising two independently failing components. The state-space diagram of such a system is shown in figure 4.5. It is assumed the system fails if at least one of both components fails. Therefore, the states 2, 3 and 4 have the same effect, namely system failure. The state probabilities can be computed by using equation (4.16). The matrices \( T' \) and \( C \) are:
Chapter 4  Contingency modeling

\[ T' = \begin{pmatrix} -\left(\lambda_k + \lambda_l\right) & \mu_k & \mu_l & 0 \\ \lambda_k & -\left(\lambda_l + \mu_k\right) & 0 & \mu_l \\ \lambda_l & 0 & -\left(\lambda_k + \mu_l\right) & \mu_k \\ 1 & 1 & 1 & 1 \end{pmatrix}, \quad C = \begin{pmatrix} 0 \\ 0 \\ 0 \\ 1 \end{pmatrix} \quad (4.29) \]

Solving equation (4.16) results in:

\[ Pr = T'^{-1} \cdot C = \left( \begin{array}{c} Pr_1 \\ Pr_2 \\ Pr_3 \\ Pr_4 \end{array} \right) = \frac{\mu_k \mu_l}{\lambda_k \mu_l} \begin{pmatrix} \frac{\lambda_k \mu_l}{\left(\lambda_k + \mu_k\right)\left(\lambda_k + \mu_k\right)} \\ \frac{\lambda_k \mu_l}{\left(\lambda_k + \mu_k\right)\left(\lambda_k + \mu_k\right)} \\ \frac{\lambda_k \mu_l}{\left(\lambda_k + \mu_k\right)\left(\lambda_k + \mu_k\right)} \\ \frac{\lambda_k \mu_l}{\left(\lambda_k + \mu_k\right)\left(\lambda_k + \mu_k\right)} \end{pmatrix} \quad (4.30) \]

Figure 4.5  State-space diagram for a system comprising two independently failing components
By combining states 2, 3 and 4 into another state, say, state I, the probability that state I occurs, \( Pr_t \), is obtained by adding all the probabilities \( Pr_t \) that is:

\[
Pr_t = Pr_2 + Pr_3 + Pr_4 = \frac{\lambda_k \mu_l + \mu_k \lambda_l + \lambda_l \lambda_k}{(\lambda_k + \mu_k)(\lambda_k + \mu_k)}
\]  

(4.31)

The frequency of occurrence of I, \( Fr_t \), is obtained by using equation (4.27), that is:

\[
Fr_t = Pr_2 \mu_k + Pr_3 \mu_k = \frac{\mu_k \mu_l (\lambda_k + \lambda_l)}{(\lambda_k + \mu_k)(\lambda_k + \mu_k)}
\]  

(4.32)

Note that if \( \mu_k \) and \( \mu_l \) are much greater than \( \lambda_k \) and \( \lambda_l \), the frequency with which state I occurs, \( Fr_t \), can be approximated by the sum of \( \lambda_k \) and \( \lambda_l \).  

\[ \Box \]

### 4.2 Contingencies due to circuit outages

Several assumptions are adopted in this section. These are realistic for transmission and distribution systems.

- Any circuit is repairable or replaceable
- The average duration to repair or to replace a circuit is much smaller than its average operating duration
- The average switching duration of a circuit is smaller than its average repair or replacement duration
- Overlapping failure events of three or more circuits are neglected
- All analyses are performed for time-independent component reliability indices

A system is defined as a group of components that are connected or associated in a fixed configuration to perform a specified function. It is obvious that the unreliability of a system depends on failures of its constituting components. Therefore, the basic idea of a reliability evaluation of an electric transmission or distribution system is to calculate system reliability indices from data associated with its constituting components. In order to be able to do this, one has to derive the mathematical relations between system-failure indices on the one hand and component-failure indices on the other hand.

A state-space diagram describing a system is in fact a combination of individual state-space diagrams of its constituting network components. This was illustrated in example 4.2, where two individual state-space diagrams of components \( k \) and \( l \) were com-
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bined into one state-space diagram of a system. By extrapolation one can obtain a transmission or a distribution network state diagram by labeling systematically certain of its components as in the DN state, and the remainder of its components as in the UP state. After that, all network states that result in system failure can be combined into one single system state, say, state $I$. The probability of system failure can then be obtained by adding all the probabilities $Pr_i$, that is, by using equation (4.26):

$$Pr_I = \sum_{i=1}^{l} Pr_i$$  \hspace{1cm} (4.33)

The probability of system failure is equal to the sum of probabilities of system states that result in system failure. In the same way, equation (4.27) can be used to obtain the frequency of system failure. This equation can be extended and approximated by:

$$Fr_I = \sum_{k \in l} \sum_{i=1}^{l} Fr_{ik} = \sum_{k \in l} \sum_{i=1}^{l} Pr_i \times \tau_{ik} = \sum_{i=1}^{l} \sum_{k \in l} (Pr_i \times \tau_{ik}) =$$

$$= \sum_{i=1}^{l} (Pr_i (\sum_{k \in l} \tau_{ik} - \sum_{k \in l} \tau_{ik})) = \sum_{i=1}^{l} Fr_i - \sum_{i=1}^{l} (Pr_i \times \sum_{k \in l} \tau_{ik}) =$$

$$\approx \sum_{i=1}^{l} Fr_i$$  \hspace{1cm} (4.34)

The frequency of system failure can be approximated by the sum of frequencies of system states resulting into system failure.

In equation (4.34), the term $Fr_i$ is the frequency of departing or encountering system state $i$, while the second term (on the right-hand side of the minus sign) is the portion of $Fr_i$ which corresponds to not going through the boundary between the subset of system-failure states (inside $I$) and the subset of system success states (outside $I$). Since the second term usually corresponds with failures of other system equipment, this term can be neglected when the component-failure rates are much smaller than the component-repair rates. This is usually the case for transmission and distribution system equipment and therefore this approximation is valid.

A major concern in reliability studies of electric transmission and distribution networks is the selection of component outages which occur relatively frequently and have a certain impact on system performance. By labeling certain of the components as available and the remainder of the components as unavailable in a systematic manner, so-called contingencies are enumerated. In many cases, severity associated with a contingency is inversely related to the probability and frequency of its occur-
renee. As the number of unavailable components involved in a contingency increases, both the probability and the frequency of the contingency decrease.

Theoretically, there are \(2^N-1\) possible contingencies in a network consisting of \(N\) components, which can be either in a failed state or in an operable state. Thus, the computational burden of explicitly investigating each contingency in a practical transmission or distribution system becomes extremely large. Therefore, the question arises when the analysis is thorough enough and sufficient outages have been considered.

The selection of an appropriate cutoff criterion is therefore of fundamental importance when evaluating the reliability of a transmission or a distribution system. The major objection to considering a large number of contingencies is the computation time required to evaluate them. The computation time increases rapidly as the contingency level increases, particularly when an AC load flow is used to analyse each contingency. Several approaches are proposed [32,33,34]:

- Limit on the contingency level
- Sorting of identical contingencies
- Probability or frequency cutoff
- Ranking of contingencies

The method adopted in this thesis is based on a fixed contingency level. Independent overlapping component failures of third and higher order are neglected. The contribution of third- and higher-order network component failures to system reliability indices is usually very small and the evaluation of such contingencies can be ignored, without making large errors. The upper and lower bounding technique [35] is a very suitable approach to illustrate the effects of neglecting third and higher-order component failures. This can be illustrated with the aid of figure 4.6.

Figure 4.6 shows the change in the upper and lower bound of the system-failure probability as a function of the number of contingencies tested for a 25-bus test system [18]. The upper and the lower bounds of the probability indices are presented for the first levels of independent and dependent multiple outages. In this example, system failure is defined as the occurrence of a circuit overload above short-term thermal ratings. It is obvious that the probability of system failure always lies between its lower and upper bound.

The upper bound of system failure decreases when the number of contingencies tested increases. At the same time, the lower bound increases. It is clear that the difference between the upper and the lower bound decreases significantly when the number of contingencies tested increases. After testing all contingencies due to failures of first
and second order in the system, this difference is close to zero. Therefore, the probability of system failure due to network component failures can be calculated quite precise by examining all contingencies resulting from first- and second-order component failures. In view of the uncertainties in the reliability input data, the difference between the upper and the lower bounds at two levels is negligible.

![Graph showing system-failure probability versus number of contingencies tested]

**Figure 4.6** Effect of the number of contingencies tested on the system-failure probability

The simulation of failures of components in distribution systems in a manner which is closely related to transmission-system analyses is a new approach. Previously proposed approaches for distribution-system analyses [10,12] applied to Dutch distribution systems appeared to have certain limitations. In previously developed methods, it was assumed that the substation supplying the radial-operated distribution system and the feeder circuit breakers are fully reliable. Supply interruptions are assumed to be caused by single failures of feeding circuits and single failures of distribution transformers only. Loading capabilities of circuits and load flows resulting from different contingencies are also ignored. However, such assumptions can have considerable influence on the evaluated indices of reliability for customers. Therefore, enhanced algorithms have been developed enumerating real and probable contingencies due to distribution system component failures.
Reliability evaluation of electric transmission and distribution systems

The first improvement on previously developed methods [10,12] is to include both radial- and meshed-operated parts of a distribution system in its analysis. Those models and techniques were only suitable for radial-operated parts and not for combined meshed- and radial-operated parts. A second improvement is to consider the resulting load flow for each enumerated network state. By using a load flow one can determine severely overloaded components and model protection-system behavior.

The third improvement is the incorporation of second-order overlapping failures of distribution-system components. Since it is common practice in the Netherlands to bury several cables in the same sleeve, a common cause effect due to digging activities is not negligible. A fourth improvement is the incorporation of stuck circuit-breaker conditions and other substation-originated outages in the reliability analysis of a distribution system. As mentioned in chapter 2, the probability of a failure to trip on command is usually higher in distribution systems than in transmission systems.

To illustrate what impact it has to incorporate the improvements mentioned above in the reliability analysis of distribution systems, consider the distribution-system configuration as shown in figure 4.7. Such configurations are often used in Dutch distribution systems. The figure shows the single-line diagram of a simple distribution network, which is fed from an area supply station. The normally open or closed position of circuit breakers and disconnecting switches is also shown.

The circuits \( C1 \) to \( C5 \) are each protected by a couple of circuit breakers. The circuits \( C6 \) to \( C11 \) are protected by a single circuit breaker. It is usual to design and to operate the meshed-operated parts of the system (consisting of circuits \( C1 \) to \( C5 \)) according to the \( (n-1) \) criterion. It assumed that this is true for the system of figure 4.7. Further, can the figure shows that cable pairs \( C1,C2 \) and \( C3,C4 \) are marked with ellipses. This means that these cables can suffer common cause failures because they are buried in the same groove.

In existing approaches, it is the reliability of the radial-operated part of the configuration that can be evaluated best, i.e., the reliability of the system consisting of circuits \( C6 \) to \( C11 \). The supplying points (substations 2 and 3) are then considered as being fully reliable in such analyses. Supply interruptions are assumed to be caused only by single failures of feeding circuits and failures of distribution transformers. In the new proposed techniques, failures of circuits in the meshed-operated part of the system are considered as well. And besides single-circuit failures, also overlapping-circuit failures are considered.
When, for example, circuits $C1$ and $C2$ go on outage due to a common cause failure of these cables, cable $C5$ can become severely overloaded and should be switched off by its protective relays. Such failures should be considered as well, since the load points $LD2$, $LD3$, $LD5$ and $LD6$ will become isolated due to such a contingency. If previously developed concepts are used, such failures are ignored.

Moreover, another contingency can illustrate the differences between previously proposed techniques and the new proposed approach. Assume that a short-circuit failure occurs on circuit $C5$ and its corresponding circuit breaker in substation 3 fails to trip. Then the circuits $C1$ and $C2$ are switched off by the back-up protection system. Again the load points $LD2$, $LD3$, $LD5$ and $LD6$ will become isolated due to a combined failure. In previously developed concepts such severe failure events are ignored.
4.2.1 First-order circuit failures

The evaluation of the probability and frequency of a first-order circuit failure is based on the state-space diagram of figure 4.1. The probability of the state wherein circuit \( k \) is unavailable due to a failure and all other circuits are available, \( Pr(k \ DN, \ other \ UP) \), is given by:

\[
Pr(k \ DN, \ other \ UP) = \frac{\lambda_k}{\lambda_k + \mu_k} \prod_{i=1,i \neq k}^{N_C} \frac{\mu_i}{\lambda_i + \mu_i}
\]  
(4.35)

where:

- \( N_C \): the number of circuits in the system
- \( \lambda_i \): the failure rate of component \( i \)
- \( \mu_i \): the repair rate of component \( i \)

Since the repair rates, \( \mu_i \), are much greater than the failure rates, \( \lambda_i \), equation (4.35) can be approximated by:

\[
Pr(k \ DN, \ other \ UP) \approx \frac{\lambda_k}{\lambda_k + \mu_k} = \frac{\lambda_k}{\mu_k} = \lambda_k r_k
\]  
(4.36)

where:

- \( r_k \): the average repair duration of component \( k \)

The frequency of occurrence of the state wherein circuit \( k \) is unavailable due to a failure and all other circuits are available, \( Fr(k \ DN, \ other \ UP) \), is according to equation (4.18) given by:

\[
Fr(k \ DN, \ other \ UP) = \left( \frac{\lambda_k}{\lambda_k + \mu_k} \prod_{i=1,i \neq k}^{N_C} \frac{\mu_i}{\lambda_i + \mu_i} \right) (\mu_k + \sum_{i=1,i \neq k}^{N_C} \lambda_i)
\]  
(4.37)

For the same reasons as mentioned above, equation (4.37) can be approximated by:

\[
Fr(k \ DN, \ other \ UP) \approx \frac{\lambda_k \mu_k}{\lambda_k + \mu_k} = \lambda_k
\]  
(4.38)

The contribution of first-order circuit failures to system failure will normally be different. This depends on the structure of the network, its operation and its protection
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scheme. Figure 4.7 can be used to illustrate this. It is obvious that a single failure of one of the circuits C1 to C5 does not contribute to system failure, since the faulted circuit will be taken out of service by its corresponding circuit breakers and the remaining circuits are still capable to supply the whole load demand (due the assumption of the (n-1) criterion). However, when a single failure occurs on circuit C8, the corresponding circuit breaker in substation 3 will operate, causing the isolation of circuits C7, C8 and C10. This failure results in the disconnection of load points LD5 and LD6.

Opening the disconnecting switches that surround circuit C8 takes this component out of service and its repair can take place. After opening these switches, the circuit breaker in substation 2 and the normally open disconnecting switch can be closed and all load points in the system are supplied again. Therefore, by undertaking switching actions in the system, another network state has been created. The interruption of the load points LD5 and LD6 is thus only related to the first network state, associated with the situation before undertaking switching actions. The average duration of this contingency is closely related to how long it takes on average to switch the circuits involved.

In radial-designed parts of distribution systems, a third category of failures can be found. The following example can illustrate this. It is clear that a failure of circuit C11 will cause the corresponding circuit breaker in substation 2 to open. Therefore, the load points LD4, LD7 and LD8 will become disconnected. By opening the disconnecting switches surrounding the faulted circuit C11, and by closing the circuit breaker in substation 2, the load points LD4 and LD7 are supplied again. However, load point LD8 will remain disconnected until circuit C11 has been repaired. Therefore, both situations (before and after switching) result in system failure. However, the situation after switching affects less customers than the situation before switching.

The conclusion drawn from these three cases is that the influence of first-order circuit failures can differ greatly. Some failures of circuits will not result in system failure, others will result in the disconnection of load points for a short period, while a third category results in both long- and short-term disconnections of load points. It is therefore necessary to take such differences into consideration, certainly when distribution networks are involved in the analysis.

The method adopted in this thesis is based on splitting up a contingency into a state before switching and a state after switching. The corresponding probability and frequency of occurrence of the state before switching, \( Pr(\text{state before switching}) \) and \( Fr(\text{state before switching}) \) can be approximated by:
\[ Pr(\text{state before switching}) = \lambda_k s^{av} \]  
\[ Fr(\text{state before switching}) = \lambda_k \]  

where:

\[ s^{av} \]  
the average value of the switching durations of the circuits involved in the switching process

The corresponding probability and frequency of occurrence of the state after switching, \( Pr(\text{state after switching}) \) and \( Fr(\text{state after switching}) \) respectively, can be approximated by:

\[ Pr(\text{state after switching}) = \lambda_k (r_k - s^{av}) \]  
\[ Fr(\text{state after switching}) = \lambda_k \]  

The average value of the switching durations of the circuits involved in the switching process, \( s^{av} \), is obtained by using the following equation:

\[ s^{av} = \frac{\sum_{k \in S^{SC}} \lambda_k s_k}{\sum_{k \in S^{SC}} \lambda_k} \]  

where:

\[ S^{SC} \]  
the subset of all circuits which are switched in or out of service during the switching process

\[ s_k \]  
the average switching duration of component \( k \)

The algorithm to enumerate contingencies due to the occurrence of first-order failures of circuits, is as follows:

1. Select a circuit, that is supposed to have failed.
2. Open this circuit.
3. Determine the probability and frequency of the resulting contingency by means of equations (4.36) and (4.38)

4. Identify which circuits experience an outage as a result of protective-relay responses.

5. Identify the load points in the network which are isolated and set the value of the parameter $N^{LD}$ equal to the number of disconnected load points due to this failure event.
   5.1. If $N^{LD} = 0$, go to step 9.
   5.2. If $N^{LD} > 0$, go to step 6.

6. Evaluate which circuits around the disconnected load points cannot be switched in (because there are no disconnecting switches or because the circuit has failed).

7. Switch all circuits in service that are connected to at least one disconnected load point and which do not belong to the set of circuits found in step 6.

8. Identify whether there are circuits switched in step 7 and set the value of the parameter $N^{SC}$ equal to the number of switched circuits.
   8.1. If $N^{SC} = 0$, go to step 9.
   8.2. If $N^{SC} > 0$, determine the probability and frequency of the contingencies, before and after switching and use equations (4.39), (4.40), (4.41) and (4.42), respectively.

9. Restore the original network topology, and repeat steps 1 to 8 until all circuits have been considered.

By using the algorithm presented above, both splitted and non splitted contingencies are usually enumerated. All enumerated contingencies (splitted and non splitted ones) are analysed to see whether they contribute to system failure. This topic is treated in detail in the following chapter.

4.2.2 Second-order overlapping circuit failures

The evaluation of the probability and frequency of a contingency due to second-order overlapping component failures is based on the state-space diagram presented in figure 4.8. This rather complex diagram incorporates the modeling of scheduled maintenance on circuits and common cause failures. It is evident that, if a circuit failure overlaps a scheduled maintenance activity of another circuit, the scheduled maintenance routine will increase the number of system failures (see chapter 3). A rather complex Markov model becomes then necessary in order to take scheduled maintenance activities into account.
In the model of figure 4.8, state 1 represents the normal state where both components $k$ and $l$ are in the operable state. When component $k$ or $l$ fails, a transition takes place to states 3 or 5 respectively. From these states, the failure of the remaining component results in a transition to state 7. A transition from state 1 to state 4 corresponds with the occurrence of a common cause failure. When there is an outage of component $k$ or $l$ for scheduled maintenance, a transition takes place to states 2 or 6, respectively. It is assumed that the scheduled maintenance of a component will not be started in case of existing outages. This assumption is realistic, since preventive maintenance can be scheduled.

It is also assumed that scheduled maintenance activities can be cut off due to the failure of another circuit. When one circuit is on outage due to scheduled maintenance and a failure occurs on the other circuit, the process will come in states 8 or 9. The maintenance activities in these states are cut off and a transition takes place to states 5 or 3 respectively. Most developed concepts and techniques do not consider scheduled maintenance outages. And even when such outages are considered, the maintenance cut-off process is usually not modeled [36].
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The probability of and frequency with which both circuits $k$ and $l$ in the state-space diagram of figure 4.8 are in the DN state, $Pr(k \text{ and } l \text{ DN})$ and $Fr(k \text{ and } l \text{ DN})$, are algebraic nonlinear functions of the transition rates in the state-space diagram. The probability that components $k$ and $l$ are in the DN state can be obtained by adding the probabilities of states 4, 7, 8 and 9. The general mathematical relations for $Pr(k \text{ and } l \text{ DN})$ and $Fr(k \text{ and } l \text{ DN})$ are:

$$Pr(k \text{ and } l \text{ DN}) = f(\lambda_k^m, \lambda_l^m, \lambda_k^{cc}, \lambda_l^{cc}, \mu_k^m, \mu_k^{mco}, \mu_l^m, \mu_l^{mco}, \mu_{kl}^{cc})$$  \hspace{1cm} (4.44)

$$Fr(k \text{ and } l \text{ DN}) = g(\lambda_k^m, \lambda_l^m, \lambda_k^{cc}, \lambda_l^{cc}, \mu_k^m, \mu_k^{mco}, \mu_l^m, \mu_l^{mco}, \mu_{kl}^{cc})$$  \hspace{1cm} (4.45)

where:

- $\lambda_k^m$  \hspace{1cm} the scheduled outage rate of component $k$
- $\lambda_l^m$  \hspace{1cm} the scheduled outage rate of component $l$
- $\lambda_{kl}^{cc}$  \hspace{1cm} the common cause outage rate of components $k$ and $l$
- $\mu_k^m$  \hspace{1cm} the maintenance rate of component $k$
- $\mu_l^m$  \hspace{1cm} the maintenance rate of component $l$
- $\mu_k^{mco}$  \hspace{1cm} the maintenance cutoff rate of component $k$
- $\mu_l^{mco}$  \hspace{1cm} the maintenance cutoff rate of component $l$
- $\mu_{kl}^{cc}$  \hspace{1cm} the common cause repair rate of components $k$ and $l$

For contingencies due to second-order circuit failures it is also often possible to reconfigure the network by means of switching actions. Circuits which are (for operational reasons) out of service can perhaps be switched in service. In order to determine the probability and frequency of occurrence of the states before and after switching, it is necessary to determine the average duration of the concurring outages of components $k$ and $l$, $Du(k \text{ and } l \text{ DN})$, which is given by:

$$Du(k \text{ and } l \text{ DN}) = \frac{Pr(k \text{ and } l \text{ DN})}{Fr(k \text{ and } l \text{ DN})}$$  \hspace{1cm} (4.46)

The corresponding probability and frequency of occurrence of the state before switching can then be approximated by:

$$Pr(\text{state before switching}) = \frac{Pr(k \text{ and } l \text{ DN})}{Du(k \text{ and } l \text{ DN})} \cdot s^{av}$$  \hspace{1cm} (4.47)
\[ Fr(\text{state before switching}) = Fr(k \text{ and } l \text{ DN}) \quad (4.48) \]

The corresponding probability and frequency of occurrence of the state after switching can then be approximated by:

\[ Pr(\text{state after switching}) \approx \frac{Pr(k \text{ and } l \text{ DN})}{Du(k \text{ and } l \text{ DN})} (Du(k \text{ and } l \text{ DN}) - s^{av}) \quad (4.49) \]

\[ Fr(\text{state before switching}) = Fr(k \text{ and } l \text{ DN}) \quad (4.50) \]

The algorithm to enumerate contingencies due to the occurrence of second-order overlapping circuit failures, is as follows:

1. Select two circuits that are supposed to have failed.
2. Open these circuits.
3. Determine the probability and frequency of the resulting contingency by means of equations (4.44) and (4.45)
4. Identify which circuits experience an outage as a result of protective-relay responses.
5. Identify the load points in the network which are isolated and set the value of the parameter \( N^{LD} \) equal to the number of disconnected load points due to this failure event.
   5.1. If \( N^{LD} = 0 \), go to step 9.
   5.2. If \( N^{LD} > 0 \), go to step 6.
6. Evaluate which circuits around the disconnected load points cannot be switched in service (because there are no disconnecting switches or because the circuit has failed).
7. Switch all circuits in service that are connected to at least one disconnected load point and which do not belong to the set of circuits found in step 6.
8. Identify whether there are circuits switched in step 7 and set the value of the parameter \( N^{SC} \) equal to the number of switched circuits.
   8.1. If \( N^{SC} = 0 \), go to step 9.
   8.2. If \( N^{SC} > 0 \), determine the probability and frequency of the contingencies, before and after switching and use equations (4.47), (4.48), (4.49) and (4.50), respectively.
9. Restore the original network topology, and repeat steps 1 to 8 until all combinations of two circuits have been considered.

4.3 Contingencies due to substation-originated outages

The role of substations in observed system failures strongly supports the need to recognise the outages of system components because of substation-originated failures. Component performance statistics show that more than 40 percent of disturbances in transmission systems are caused by substation-originated failures [29,37]. A substation-originated event is the outage of any number of system generators, lines, transformers and load points caused by a failure inside a substation (switching or terminal station).

The probabilities associated with contingencies due to substation failures can be quite high compared to the corresponding probabilities associated with independent overlapping outages. It is therefore not practical to consider independent higher-level contingencies on the one hand and to ignore contingencies which are substation-originated on the other hand. The effect of substations is sufficiently dominant in most cases, so that their inclusion diminishes the need to consider independent higher-order contingencies.

Previously proposed approaches [21,38] applied to Dutch substation configurations appeared to have certain limitations. Therefore, improved algorithms have been developed that enumerate failure events of substation components in a way which agrees better with existing Dutch busbar schemes.

The first improvement on previously developed methods is to include both normally open and normally closed disconnecting switches and circuit breakers in the analysis. To illustrate the impact of incorporating normally open and normally closed switching equipment, consider the single-line diagram of a typical duplicate busbar scheme as shown in figure 4.9. This configuration is often used in Dutch transmission systems. The normally open or closed position of circuit breakers and disconnecting switches is also shown.

Assume that circuit breaker $B3$ suffers a passive failure. This event causes the disconnection of load point $LD1$. After the occurrence of this event, the faulted component is disconnected from the other intact components by opening the disconnecting switches $D7$, $D8$ and $D15$. Almost simultaneously, the disconnecting switches $D9$, $D16$, $D19$
and $D22$ are commanded to close, followed by closing commands on circuit breakers $B4$ and $B7$. Therefore, after these switching operations, load point $LD1$ is again supplied. This example shows that the contingency caused by a passive failure of circuit breaker $B3$ can be remedied by switching operations with several circuit breakers and disconnecting switches.

**Figure 4.9** Single-line diagram of a duplicate busbar scheme

In the models previously used [21,38], active and passive failure modes of substation components have been modeled together by using the three-state model, shown in figure 4.10. The three states are: the state before a fault ($U$), the state after a fault but before isolation ($S$) and the state after isolation but before repair ($R$). When the three-state model of figure 4.10 is used, a passive failure of circuit breaker $B3$ results directly in its repair state, and an active failure of it will indirectly also result in its repair state. Switching actions with redundant components after the occurrence of a passive failure are not considered in these models.

Therefore, the three-state model cannot be used in reliability evaluation studies of substation components with redundant components that are associated with normally
open disconnecting switches and circuit breakers. One of the assumptions in the models previously developed [21,38] was that all circuit breakers (and disconnecting switches) are normally closed. It should be clear that more detailed simulation algorithms are necessary to be able to model switching operations with redundant components.

![Three-state failure model](image)

**Figure 4.10** Three-state failure model

A second improvement on existing methods is to consider failures of transmission or distribution lines or cables in combination with stuck circuit breakers as well. From experience it is well known that circuit-failure rates are usually greater than the failure rates of substation components. Therefore, it is not consistent to simulate active failures of substation components in combination with a stuck circuit breaker and to ignore the influence of active failures of circuits which are directly connected to the substation in combination with a stuck circuit breaker.

Therefore, this thesis presents extensions to current techniques. A set of enhanced simulation algorithms is described in detail in this section. From these algorithms, the resulting contingencies can be determined, i.e., which generators, circuits and/or load points connected to the substation are out of service due to the substation event.

The substation components assumed to fail are [21,38,39]: circuit breakers (B), transformers (T) and busbar sections (S). Although more components can fail inside a substation, such as metering transformers, grounding equipment and disconnecting switches, these are neglected. However, the failure modes of these components can be incorporated in the failure modes of busbar sections or circuit breakers.
As in the foregoing section, several assumptions are adopted in the development of the algorithms. These assumptions are:

- Any substation component is repairable or replaceable
- The average duration to repair or to replace a substation component is much smaller than its average operating duration
- The average switching duration of a substation component is smaller than its average repair or replacement duration
- Overlapping failure events of three or more substation components are neglected
- All analyses are performed for time-independent component reliability indices
- Circuit breakers actively failing cannot clear their own failures
- Circuit breakers can operate due to failures in either direction when they are not in a stuck condition

The types of failures which can occur in a substation and may cause substation-originated outages are:

- Passive failures
- Active failures
- Stuck circuit-breaker conditions
- Second-order overlapping substation outages

These are treated in more detail in the next subsections.

### 4.3.1 Passive failures

Passive failure events are all component failures that do not cause operation of the protection. These failure events include open-circuit failures and inadvertent operations of circuit breakers. Service is restored by repairing or replacing the failed component or by undertaking switching actions in the substation. It is assumed that passive failure events only occur on circuit breakers.

Certain passive failures can result in contingencies which cannot be reduced by performing switching actions with substation components. The substation configuration shown in figure 4.9 can be used to illustrate such a passive failure event. Assume that circuit breaker B1 in figure 4.9 suffers a passive failure. This event results in the isolation of line L1. From the figure, it appears that repair of circuit breaker B1 can take place when the disconnecting switches D1, D3 and D4 are open. From figure 4.9, one can also see that switching operations with disconnecting switches cannot lead to energizing of line L1 before the faulted circuit breaker B1 is repaired or replaced.
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The probability that such a passive contingency occurs due to a failure of component $k$, $Pr(\text{passive contingency due to } k)$, and the frequency with which it occurs, $Fr(\text{passive contingency due to } k)$, can be approximated by:

$$Pr(\text{passive contingency due to } k) = \lambda_k^p r_k$$  \hfill (4.51)

$$Fr(\text{passive contingency due to } k) = \lambda_k^p$$  \hfill (4.52)

where:

$\lambda_k^p$  the passive failure rate of component $k$

Other passive failures can result in contingencies which can be abolished by switching substation components. The substation shown in figure 4.9 can also be used to illustrate such a passive event. Suppose that circuit breaker $B3$ in figure 4.9 suffers a passive failure. This event results in the isolation of load point $LD1$. From the figure it appears that repair of circuit breaker $B3$ can take place when the disconnecting switches $D7$, $D8$ and $D15$ are open. After the opening of these disconnecting switches, the disconnecting switches $D9$, $D16$, $D19$ and $D22$ are closed and then circuit breakers $B4$ and $B7$ are closed. Therefore, load point $LD1$ is energized before the passively faulted circuit breaker $B3$ will be repaired or replaced.

The probability of being found in such a passive contingency state before switching component $k$, $Pr(\text{passive contingency due to } k, \text{ before switching})$, and its frequency of occurrence, $Fr(\text{passive contingency due to } k, \text{ before switching})$, can then be approximated by [21]:

$$Pr(\text{passive contingency due to } k, \text{ before switching}) = \lambda_k^p s_k$$  \hfill (4.53)

$$Fr(\text{passive contingency due to } k, \text{ before switching}) = \lambda_k^p$$  \hfill (4.54)

The probability of being found in such a passive contingency state after switching component $k$, $Pr(\text{passive contingency due to } k, \text{ after switching})$, and its frequency of occurrence, $Fr(\text{passive contingency due to } k, \text{ after switching})$, are given by:

$$Pr(\text{passive contingency due to } k, \text{ after switching}) = \lambda_k^p (r_k - s_k)$$  \hfill (4.55)
Fr(passive contingency due to \( k \), after switching) = \( \lambda_k^p \) \hspace{1cm} (4.56)

The algorithm for enumerating contingencies caused by passive failures is as follows:

1. Select a circuit breaker that is supposed to have suffered a passive failure.
2. Open this circuit breaker.
3. Identify whether lines, generators and/or load points are disconnected and set the value of the parameter \( N_{GLD1} \) equal to the number of lines, generators and/or load points which are isolated before performing switching actions.
   3.1. If \( N_{GLD1} = 0 \), go to step 8.
   3.2. If \( N_{GLD1} > 0 \), go to step 4.
4. Open all neighboring disconnecting switches around the circuit breaker which has passively failed.
5. Close all other disconnecting switches.
6. Close all intact circuit breakers.
7. Identify the lines, generators and/or load points which are now disconnected and set the value of the parameter \( N_{GLD2} \) equal to the number of lines, generators and/or load points which are isolated after performing switching actions.
   7.1. If \( N_{GLD2} = 0 \), determine the probability and frequency of the contingency by using equations (4.53) and (4.54).
   7.2. If \( N_{GLD2} = N_{GLD1} \), determine the probability and frequency of this contingency by means of equations (4.51) and (4.52).
   7.3. If \( 0 < N_{GLD2} < N_{GLD1} \), determine the probabilities and frequencies of both contingencies, (before and after performing switching actions) and use equations (4.53), (4.54), (4.55) and (4.56), respectively.
8. Restore the original substation topology, and repeat steps 1 to 7 until all circuit breakers have been considered.

4.3.2 Active failures

Active failures are referred to as all component failures that cause the operation of circuit breakers in the primary protection zone around the failed component and can, therefore, cause that intact components are removed from service. Examples of this failure mode are short-circuit failures of substation components. Service can be restored to the intact parts of the substation after the failed component is isolated. The restoration of the component itself takes place by repair or replacement. Generally, it takes longer to repair a component than to isolate it or to perform a switching opera-
tion. Usually, active failure events cause greater contingencies than passive failure events do.

In certain cases, active failures can result in contingencies which cannot be abolished by switching substation components. Therefore, how long such a contingency takes on average is closely associated with the time it generally takes to repair the faulted component. The probability of being found in such an active contingency state due to a failure of component $k$, $Pr(\text{active contingency due to } k)$, and its frequency of occurrence, $Fr(\text{active contingency due to } k)$, can then be approximated by:

$$Pr(\text{active contingency due to } k) = \lambda_k^a r_k$$  \hspace{1cm} (4.57)

$$Fr(\text{active contingency due to } k) = \lambda_k^a$$  \hspace{1cm} (4.58)

where:

$\lambda_k^a$ the active failure rate of component $k$

It is also possible that an active failure results in a contingency that can be remedied. In such a case two situations arise: a situation before performing switching actions and a situation after performing switching actions. The substation configuration in figure 4.9 can be used to illustrate this. Assume that busbar section $S8$ suffers an active failure. The surrounding circuit breakers $B1$, $B3$ and $B6$ should operate. Therefore, line $L1$ and load point $LD1$ are on outage. The faulted busbar section $S8$ is then isolated by opening the disconnecting switches $D3$, $D7$ and $D13$. After this, the disconnecting switches connected to busbar section $S7$ are closed, and then the circuit breakers $B1$ and $B3$ are closed. By doing so, line $L1$ and load point $LD1$ are only on outage for a short duration, which is defined by the average switching duration of the faulted busbar section.

The probability that the situation before switching occurs, $Pr(\text{active contingency due to } k \text{ before switching})$, and its frequency of occurrence, $Fr(\text{active contingency due to } k \text{ before switching})$, can be approximated by:

$$Pr(\text{active contingency due to } k \text{ before switching}) = \lambda_k^a s_k$$  \hspace{1cm} (4.59)

$$Fr(\text{active contingency due to } k \text{ before switching}) = \lambda_k^a$$  \hspace{1cm} (4.60)
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For the situation after switching, the probability, \( Pr(\text{active contingency due to } k \text{ after switching}) \), and its frequency of occurrence, \( Fr(\text{active contingency due to } k \text{ after switching}) \), are given by:

\[
Pr(\text{active contingency due to } k \text{ after switching}) = \lambda^0_k (r_k - s_k) \tag{4.61}
\]

\[
Fr(\text{active contingency due to } k \text{ after switching}) = \lambda^a_k \tag{4.62}
\]

The algorithm for enumerating contingencies caused by active failures is as follows:

1. Select a substation component that is supposed to have suffered an active failure.
2. Open all neighboring circuit breakers around this component.
3. Identify whether lines, generators and/or load points are disconnected and set the value of the parameter \( N^{GLD1} \) equal to the number of lines, generators and/or load points which are isolated before performing switching actions.
   3.1. If \( N^{GLD1} = 0 \), go to step 8.
   3.2. If \( N^{GLD1} > 0 \), go to step 4.
4. Open all neighboring disconnecting switches around the component which has actively failed.
5. Close all other disconnecting switches.
6. Close all intact circuit breakers.
7. Identify the lines, generators and/or load points which are now disconnected and set the value of the parameter \( N^{GLD2} \) equal to the number of lines, generators and/or load points which are isolated after performing switching actions.
   7.1. If \( N^{GLD2} = 0 \), determine the probability and frequency of the contingency by using equations (4.59) and (4.60).
   7.2. If \( N^{GLD2} = N^{GLD1} \), determine the probability and frequency of this contingency by using equations (4.57) and (4.58).
   7.3. If \( 0 < N^{GLD2} < N^{GLD1} \), determine the probabilities and frequencies of both contingencies, (before and after performing switching actions) and use equations (4.59), (4.60), (4.61) and (4.62) for this, respectively.
8. Restore the original substation topology, and repeat steps 1 to 7 until all substation components have been considered.
4.3.3 Stuck circuit-breaker conditions

A stuck circuit-breaker condition arises when a circuit breaker or a protective relay in the primary protection zone fails to operate following an active failure event. Back-up or secondary protection must then respond and a larger section of the substation may be disrupted. The probability that a circuit breaker \( k \) is stuck, \( P_{r_{scb}} \), can be evaluated from a data collection scheme and is given by [19]:

\[
P_{r_{scb}} = \frac{\text{number of failures to open}}{\text{number of commands to open}}
\]  
(4.63)

A stuck circuit breaker in general imposes a severe impact on the substation and may cause a high-order contingency. Therefore, the simulation and analysis of such events are important, although their probability and frequency are usually small.

Again, figure 4.9 is used to illustrate a stuck circuit-breaker condition. If line \( L1 \) suffers an active failure, circuit breaker \( B1 \) should operate. Suppose \( B1 \) fails to operate and therefore circuit breakers \( B3 \) and \( B6 \) respond causing the removal of line \( L1 \) and load point \( LD1 \) from service. Therefore, in the situation before switching, the equations for the probability and frequency of this contingency are given by:

\[
Pr(\text{contingency due to } k \text{ and circuit breaker } l \text{ stuck before switching}) = \\
= Pr_{r_{scb}} \lambda_k \delta_k
\]  
(4.64)

\[
Fr(\text{contingency due to } k \text{ and circuit breaker } l \text{ stuck before switching}) = \\
= Pr_{r_{scb}} \lambda_k \delta_k
\]  
(4.65)

After such severe failure events, the operators of the power system should try to restore the substation topology as far as possible. This means in the present case that line \( L1 \) and circuit breaker \( B1 \) are isolated by opening the disconnecting switches \( D1, D3 \) and \( D4 \). After this isolation, the circuit breakers \( B3 \) and \( B6 \) are closed. In this new situation, load point \( LD1 \) is again supplied and only line \( L1 \) is still outaged. For the new situation after switching, the probability and frequency of this contingency can be evaluated by:

\[
Pr(\text{contingency due to } k \text{ and circuit breaker } l \text{ stuck after switching}) = \\
= Pr_{r_{scb}} \lambda_k (r_k - s_k)
\]  
(4.66)
Fr(contingency due to k and circuit breaker l stuck after switching) = 
\approx Pr_{i}^{scb} \lambda_{k}^{a}
(4.67)

If it is impossible to relieve a substation-originated contingency due to the combination of an active failure and a stuck circuit-breaker condition, the probability and frequency of such a long-term contingency are given by:

\begin{align*}
Pr(&text{contingency due to k and circuit breaker l stuck}) = \\
\approx & Pr_{i}^{scb} \lambda_{k}^{a} r_{k}
(4.68)
\end{align*}

\begin{align*}
Fr(&text{contingency due to k and circuit breaker l stuck}) = \\
\approx & Pr_{i}^{scb} \lambda_{k}^{a}
(4.69)
\end{align*}

The algorithm for enumerating contingencies caused by active failures of transmission lines or substation components in combination with stuck circuit-breaker conditions is a slight modification of the algorithms presented earlier:

1. Select a substation component or a line or cable directly connected to the substation.
2. Open all neighboring circuit breakers around this component.
3. Select a circuit breaker which should have operated as a result of the active failure at the selected component, and open all neighboring circuit breakers around the selected circuit breaker.
4. Identify whether lines, generators and/or load points are disconnected and set the value of the parameter $N_{GLDI}$ equal to the number of lines, generators and/or load points which are isolated before performing switching actions.
   4.1. If $N_{GLDI} = 0$, go to step 9.
   4.2. If $N_{GLDI} > 0$, go to step 5.
5. Open all neighboring disconnecting switches around the component which has actively failed and the stuck circuit breaker.
6. Close all other disconnecting switches.
7. Close all intact circuit breakers.
8. Identify the lines, generators and/or load points which are now disconnected and set the value of the parameter $N_{GLD2}$ equal to the number of lines, gene-
rators and/or load points which are isolated after performing switching actions.

8.1. If $N^{\text{GLD2}} = 0$, determine the probability and frequency of the contingency by using equations (4.64) and (4.65).

8.2. If $N^{\text{GLD2}} = N^{\text{GLD1}}$, determine the probability and frequency of this contingency by using equations (4.68) and (4.69).

8.3. If $0 < N^{\text{GLD2}} < N^{\text{GLD1}}$, determine the probabilities and frequencies of both contingencies (before and after performing switching actions) by using equations (4.64), (4.65), (4.66) and (4.67) respectively.

9. Restore the substation topology as a result of step 2 and repeat steps 3 to 8 until all circuit breakers that should operate have been considered.

10. Restore the original substation topology, and repeat steps 1 to 9 until all substation components and lines or cables that are directly connected to the substation have been considered.

### 4.3.4 Second-order overlapping substation outages

Second-order overlapping substation-originated outages involve the sequential failure of at least two substation components or a substation-component failure overlapping a scheduled maintenance routine. The condition for this type of fault to occur is that the first component has failed or has been taken out of service for scheduled maintenance.

The overlapping events usually considered are those involving only two substation components and are referred to as second-order overlapping outages. The probability that higher-order events occur is usually negligible. There is an enormous number of possible combinations of events leading to a second-order overlapping event. When one tries to split up each contingency into a state before and a state after switching, this number is approximately doubled.

Since the situations before switching usually have a short duration compared to the situations after switching, the situations before switching are neglected. In this thesis, only contingencies due to second-order overlapping outages for the situation after switching are considered. Therefore, the modeling of switching actions is absent in the algorithms enumerating such overlapping second-order contingencies. Thus, the calculated reliability indices for the considered system will be slightly better than when the situations before switching are considered as well.

The single-line diagram of the substation in figure 4.9 can be used to illustrate the effects of a second-order overlapping event. Assume that circuit breaker $B3$ is on outage due to an active or passive failure event, and before being restored, transformer
T2, which supplies at that moment load point LD1, suffers an active failure. With this combined event, the resulting contingency means that load point LD1 is disconnected for a longer period. This particular overlapping failure event therefore has a serious effect upon the load point LD1.

The probability and frequency of occurrence of an overlapping contingency state of two components can be approximated by:

$$Pr(\text{overlapping contingency due to } k \text{ and } l) =$$

$$= \lambda_k \lambda_{f}^{r} r_{l}^{r} + \lambda_k^{m} \lambda_{f}^{r} r_{k}^{mco} + \lambda_k^{m} \lambda_{l}^{r} r_{l}^{mco}$$

$$= \lambda_k^{m} \lambda_{f}^{r} (r_{k} + r_{l}) + \lambda_k^{m} \lambda_{f}^{r} r_{k}^{mco} + \lambda_k^{m} \lambda_{l}^{r} r_{l}^{mco}$$

The first contribution in equations (4.70) and (4.71) represents a failure of component k overlapping a failure of component l. The average duration of such an occurrence is equal to $r_{f}^{r}/(r_{k} + r_{l})$. The second contribution in these equations represents the state where component k is out of service for scheduled maintenance followed by a failure of component l. The average duration of such a state is assumed to be equal to the maintenance cutoff duration of the component which is maintained, $r_{k}^{mco}$. The third contribution in equations (4.70) and (4.71) represents the state where component l is out of service for scheduled maintenance followed by a failure of component k. The average duration of such a state takes is supposed to be equal to the time associated with cutting off the maintenance activities of the component which is maintained, $r_{l}^{mco}$.

The algorithm for enumerating second-order overlapping outages of substation components is a slight modification of the algorithms presented earlier:

1. Select two substation components that are supposed to be on outage.
2. Open all neighboring disconnecting switches around the two selected substation components.
3. Close all other disconnecting switches.
4. Close all intact circuit breakers.
5. Identify whether lines, generators and/or load points are disconnected and set the value of the parameter $N_{GLD2}$ equal to the number of lines, generators and/or load points which are isolated after switching actions have been performed.
5.1. If \( N^{LGLD2} = 0 \), go to step 7.

5.2. If \( N^{LGLD2} > 0 \), determine the probability and frequency of this contingency by using equations (4.70) and (4.71).

6. Restore the original substation topology, and repeat steps 1 to 5 until all combinations of substation components have been considered.

By using the algorithms as presented in this section, both splitted and non splitted contingencies are enumerated. All enumerated contingencies (splitted and non splitted ones) are analysed whether they contribute to system failure. This topic is treated in detail in the next chapter.
'As the complexity of a system increases, our ability to make precise and yet significant statements about its behavior diminishes until a threshold is reached beyond which precision and significance (or relevance) become almost exclusive characteristics.'

L.A. Zadeh

Chapter 5

Reliability calculation method

This chapter deals with the contents of box 3 in figure 1.4: the reliability calculation method. The reliability calculation method evaluates for each enumerated contingency whether it contributes to system failure or not. To perform such an analysis, each contingency is combined with different load situations, and a generation schedule is chosen for each load situation. This is treated in the first section. After that, each system state has to be analysed, which is described in the second section. If this analysis results in the detection of system failure, it is usual to establish whether this undesirable system state can be overcome by undertaking remedial actions. The modeling of such actions is presented in the next section. After these remedial actions are applied, the load-point reliability indices are updated. This is treated in the fourth section. The final section describes the compilation of system indices. This should be done after all enumerated contingencies are evaluated.

5.1 Load situations and generation schedules

When one investigates what influence a system that transmits and distributes electricity has on the indices indicating how reliable this system is for a customer, it must be clear that it does not only depend on the availability of the components how capable the system is in transferring energy from the generation stations to the load supply
points. The load flows determined by Kirchhoff’s laws for different network states, the load situations and generation schedules also have an impact on system reliability.

In a reliability-calculation procedure for a transmission or distribution system it is evaluated whether an enumerated contingency contributes to system failure or not. To perform such an analysis, each contingency is combined with different load situations, and for each load situation, a generation schedule is chosen.

The selected status of transmission or distribution system equipment is directly related to contingency modeling, which is described in detail in the foregoing chapter. This section considers the combination of selected contingencies with different load and generation states. Since it is impossible to store large amounts of electrical energy, the generating units each time have to deliver the total load demand. Therefore, each load situation requires an appropriate generation schedule. A simplified evaluation of a generation schedule is also treated in this section.

5.1.1 Selection of a load situation

A lot of power-system reliability programs are based on the assumption that the system load remains constant at its yearly peak value during the entire period of study. This is, of course, not a realistic assumption. In practice, all load demands change continuously and so does the resultant system load. As a consequence, an enumerated network contingency may represent success for one load condition while the same contingency may represent failure for another load condition.

A method to incorporate load variation in a transmission or distribution system reliability evaluation is based on describing the load variation by a so-called load-duration curve. Such a curve describes the periods during which the load demand is greater than a certain value. For an hourly load-duration curve over a period of one year, 8760 load states are required. In the case of a daily, weekly or monthly load-duration curve, the model requires 365, 52 and 12 load states, respectively. A load-duration curve described by ten data points is given in figure 5.1. Note that a load-duration curve eliminates the chronology of the load variation.

The incorporation of chronology of load variation is a difficult task, since there are a lot of possible load variations. In order to evaluate all these situations, not only the simulation time increases considerably, but also the amount of input data describing the load variation at different load points. However, the question can be raised whether it is realistic to neglect the chronology in the load variation.
A basic assumption in the procedure for estimating the number of supply interruptions due to circuit overloads is that each contingency is equally likely to occur at any time. In this thesis, it is assumed that the component capacity is constant. In this way, the probability and frequency of a supply interruption can be approximated by randomly sampling the load-duration curve. A given sample try is termed a success if the load does not exceed capacities of the components and as a failure if the load demand exceeds capacities of the components. The probability and frequency of carrying the load successfully are then estimated by the ratio of the number of successes to the total number of samples. The total period from which the load samples are taken should, in general, be at least one year to ensure that all types of load-cycle variation are included [9].

Since it is assumed that failures of components occur in a random pattern, it is sufficient to evaluate each contingency for the different load levels adopted in the load duration curve. The larger the part of the load duration curve resulting into system failure is, the larger will be the probability that the component failure occurs during the corresponding load levels. Each enumerated contingency therefore has to be combined with one or several load situations. In this thesis, it is assumed that the load-duration curve can be specified at each load point. This curve has then to be approximated by equally spaced intervals (see figure 5.1). The individual load demands belonging to these intervals are called load levels.
If one assumes that the generation schedule changes linearly with different load levels, it is obvious that when the combination of a certain load level and its corresponding generation schedule does not result in system failure for a given contingency, lower load levels will not result in system failure either. Therefore, it is useful to start the evaluation of a selected contingency at the peak load level (the first bar in the load duration-curve). When this combined network state, load situation and generation schedule does not result in system failure, the evaluation of the same contingency for lower load levels is unnecessary and is not performed.

The algorithm for selecting a load situation is as follows:

1. Select a non-isolated substation and call this substation $s$.
2. Determine all non-isolated load points in the selected substation.
3. Determine the actual load demand in substation $s$, by using the following equation:

\[
P_s^d = \sum_{i \in S_s^{NILP}} P_i^{d,\text{peak}} \cdot \text{LDC}_i(l), \quad l = 1,2,3,...,N^{LL}
\]  

(5.1)

where:

- $P_s^d$ the active load demand at substation $s$
- $P_i^{d,\text{peak}}$ the peak load demand at load point $i$
- $S_s^{NILP}$ the subset of non-isolated load points in substation $s$
- $\text{LDC}_i(l)$ the load duration curve of load point $i$ as a function of load step $l$ in per unit
- $N^{LL}$ the number of load levels adopted in the reliability evaluation

4. Repeat the steps 1 to 3 until all non-isolated substations are considered.

### 5.1.2 Selection of a generation schedule

In practice, generation dispatch is a nonlinear optimization problem. When such problems are incorporated in reliability evaluation studies, they will greatly increase the computational effort. Since in the evaluation of the reliability of a transmission or distribution system the influence of generation is less important than in a composite generation and transmission reliability evaluation, a simpler and faster method has been applied.

In this thesis, an initial generation dispatch based on an equal percentage reserve at each generation substation is used. This percentage can vary from 0 to 100 percent for
Chapter 5  Reliability calculation method

each generation substation. When transmission or distribution losses are neglected, the initial dispatch can be determined with the aid of the following four quantities:

- The number of islands or subsystems in the system
- The actual load demand in each subsystem
- The total available generation in each subsystem
- The available generation at each generation station

The algorithm for selecting a generation state is as follows:

1. Select a (sub)system and determine the total actual load demand in it, \( P_{d,\text{tot}} \), which is given by:

\[
P_{d,\text{tot}} = \sum_{i \in S^{\text{NIS}}} P_i^d
\]

(5.2)

where:

\( S^{\text{NIS}} \) the subset of all non-isolated substations

2. Determine the total available generation in the selected (sub)system, \( P_{g,\text{tot}} \), which is given by:

\[
P_{g,\text{tot}} = \sum_{i \in S^{\text{NIS}}} P_i^{g,\text{max}}
\]

(5.3)

where:

\( P_i^{g,\text{max}} \) the maximum available generation at substation \( i \) (including the maximum available power at the slack node)

3. Schedule the generated power at substation \( s \), \( P_s^g \)

3.1. If \( |P_{d,\text{tot}}| \leq |P_{g,\text{tot}}| \), schedule \( P_s^g \) according to:

\[
P_s^g = -P_s^{g,\text{max}} \cdot \frac{P_{d,\text{tot}}}{P_{g,\text{tot}}} = -P_s^{g,\text{max}} \cdot \frac{\sum_{i \in S^{\text{NIS}}} P_i^d}{\sum_{i \in S^{\text{NIS}}} P_i^{g,\text{max}}}
\]

(5.4)

The negative sign is due the fact that the power generation at a substation is regarded as positive while the power demand at a substation is regarded as negative.

3.2. If \( |P_{d,\text{tot}}| > |P_{g,\text{tot}}| \), schedule \( P_s^g \) according to:

\[
P_s^g = 0
\]

(5.5)
4. Repeat steps 1 to 3 until all (sub)systems are considered.

5.2 System state evaluation

In order to establish whether a system state, which consists of a network state, a load situation and a generation schedule, represents success or failure, the capacity of the connected generating units to the network is usually first compared with the system load. Secondly, the system state is analysed using a load flow. From the results of the load-flow investigation, the overloaded circuits can be determined. These aspects are treated in the following subsections.

5.2.1 Reserve deficiency

Some of the sampled network states may lead to one or more isolated substations (disconnected networks or islands). A searching algorithm can be used to analyse the isolated substations in the network. Substations which are disconnected from generation stations can be identified by a general network-searching algorithm, which is presented below:

1. Determine the admittance matrix of the network.
2. Determine the elements on the main diagonal of the admittance matrix.
   2.1. When such an element is equal to zero, the corresponding substation is flagged as isolated.
   2.2. Mark all the non-isolated generation substations with a non-isolated flag.
3. Mark all load substations with an isolated flag.
4. Set the value of the flag ‘Ready’ equal to false.
5. While not(‘Ready’), do:
   5.1. Set the value of the flag ‘Extra’ equal to false.
   5.2. For each circuit in the network which is in the in service state, do
      5.2.1. Determine the two surrounding substations of the circuit and call these two substations ‘From’ and ‘To’
      5.2.2. If (‘From’ EXOR ‘To’), do:
         5.2.2.1. Mark both substations ‘From’ and ‘To’ with an non-isolated flag.
         5.2.2.2. Set the value of the flag ‘Extra’ equal to true.
   5.3. Set the value of the flag ‘Ready’ equal to not(‘Extra’).
6. Set the load demand equal to zero for all load substations with an isolated flag.
It should be noted that steps 1 and 2 of this algorithm imply that it is assumed that isolated generation stations are unable to maintain stability, even if the available generation in such a substation is greater than the total load demand. When such situations occur, the load will not be fed.

It is obvious that certain system states can lead to a generation deficiency, even when all reserves can be used. This can be due to the disconnection of one or several generation stations from the system but also from substation-originated failures which result in the disconnection of one or more generating units from the system. In this dissertation, a reserve deficiency is defined as the shortfall of generation reserve that specific transmission equipment outages have caused.

In practice, reserve is associated with the spinning reserve of generating units. In this thesis, reserve is associated with the maximum possible output of all generators that are supposed to be connected to the studied system. The influence of failures of the generation system is neglected in this thesis; generating units are assumed to be continuously available. They are assumed to be disconnected from the system only by failures of the transmission or substation equipment.

Reserve deficiencies can occur in the whole system considered, but also in isolated parts or islands of the system. When a deficiency occurs in a given part of the system, the frequency in the system cannot be maintained. The result is a (partial) blackout of that part of the system. Such a blackout is usually caused by the automatic operation of underfrequency protection of the generating units or by the underfrequency load shedding relays, which are located at the transformers between the transmission and the distribution level. The selection of the settings of such relays is usually based on the importance of the customers connected to the system. Agricultural areas are generally switched off earlier than residential areas.

In this thesis, it is assumed that a generation deficiency in a given part of the studied system leads to a total blackout of that region. This is a realistic assumption for the reliability analysis of a distribution system. However, it is a 'worst case' assumption for the analysis of a transmission system.

The algorithm to take effects of reserve deficiencies into account, is as follows:

1. Select a (sub)system and determine the total actual load demand in it, \( P_{\text{d,act}} \), which is given by equation (5.2).
2. Determine also the total available generation in the (sub)system, \( P_{\text{g,act}} \), which is given by equation (5.3).
3. Identify whether the total available generation in the subsystem is greater than the total load demand in the subsystem.

   3.1. If $|P_{d,\text{tot}}| \leq |P_{g,\text{tot}}|$, go to step 5.
   3.2. If $|P_{d,\text{tot}}| > |P_{g,\text{tot}}|$, go to step 4.

4. Set all load demands in the substations in the selected (sub)system equal to zero. These substations are assumed to be isolated.

5. Repeat the steps 1 to 4 until all (sub)systems are considered.

5.2.2 Load-flow calculation

The complex power injected at each substation $s$ in an electrical network is defined as: $P_s + jQ_s$. The basic relations between these quantities and the busbar voltages are given by the so-called load-flow equations. The load-flow equations in polar coordinates are:

$$P_s = P_s^g + P_s^d = V_s \sum_k V_k (G_{sk} \cos \delta_{sk} + B_{sk} \sin \delta_{sk})$$

(5.6)

$$Q_s = Q_s^g + Q_s^d = V_s \sum_k V_k (G_{sk} \sin \delta_{sk} - B_{sk} \cos \delta_{sk})$$

(5.7)

where:

- $P_s$ the active power injection at substation $s$
- $Q_s$ the reactive power injection at substation $s$
- $V_s$ the magnitude of the voltage at substation $s$
- $\delta_s$ the angle of the voltage at substation $s$
- $\delta_{sk} = \delta_s - \delta_k$, the angle difference between the voltages at substations $s$ and $k$
- $G_{sk}$ the real part of the element of the admittance matrix
- $B_{sk}$ the imaginary part of the element of the admittance matrix

Each substation has four variables ($V_s$, $\delta_s$, $P_s$, and $Q_s$), and therefore $N_s^S$ substations have $4N_s^S$ variables, where $N_s^S$ is the number of substations. Further, it can be seen that (5.6) and (5.7) form $2N_s^S$ equations. In order to solve the load-flow equations, one has to specify two of the four variables at each substation. In general, $P_s$ and $Q_s$ of the load substations are known and they are called PQ-nodes. For generators, often $P_s$ and $V_s$ are specified and they are called PV-nodes. In order to adjust the power balance of the whole system and to have a reference angle, one generation station in the system must have a specified $V_s$ and $\delta_s$. This substation is called the swing bus or slack node.
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The flow in circuit \( c \), \( S_c \) (in complex form) between two substations \( s \) and \( k \) can be calculated by:

\[
S_c = V_s e^{j\delta_s} \left( \frac{V_s e^{j\delta_s} - V_k e^{j\delta_k}}{r_c + jx_c} \right) = \frac{V_s^2 - V_s V_k e^{j\delta_k}}{(r_c - jx_c)}
\]  

(5.8)

where:

\[ r_c \quad \text{the resistance of circuit } c \\
\[ x_c \quad \text{the reactance of circuit } c \]

In a so-called DC load-flow model, only the real part of the flows are considered. DC load-flow-based models are widely used in power-system reliability evaluations, because:

- Load-flow calculations in practical applications mostly indicate that there are relatively small differences between AC and DC load-flow solutions (3 percent until 10 percent) [40]. These differences are small compared to possible errors due to uncertainties in basic reliability input data such as component-failure rates and average repair durations.
- A large number of power-system states have to be evaluated to guarantee accuracy of probability indices; DC load-flow solutions require less computation time.
- DC load-flow models are linearized models. They can be simply used when generation rescheduling, load curtailment or manual network reconfiguration are modeled.

A DC load-flow model is based on the following assumptions:

- Circuit resistances are much smaller than circuit reactances. Circuit susceptances can then be approximated by:

\[
b_c \approx -\frac{1}{x_c}
\]

(5.9)

where:

\[ b_c \quad \text{the susceptance of circuit } c \]

- Voltage angle differences between two substations surrounding a circuit are small and therefore:

\[
\sin \delta_{sk} \approx \delta_{sk} = \delta_s - \delta_k
\]

(5.10)
\[ \cos \delta_{sk} = 1 \quad (5.11) \]

- All substation voltage magnitudes are assumed to be 1 per unit

Based on these assumptions, the real part of the flow in circuit \( c \), \( F_c = \text{Re}\{s_c\} \), can be calculated by:

\[ F_c = \frac{\delta_s - \delta_k}{x_c} \quad (5.12) \]

Or in matrix notation:

\[ F = A \delta \quad (5.13) \]

where:

\[ A_{cs} = \begin{cases} \frac{1}{x_c} & \text{if node } s \text{ is the origin of circuit } c \\ -\frac{1}{x_c} & \text{if node } s \text{ is the end of circuit } c \\ 0 & \text{otherwise} \end{cases} \quad (5.14) \]

When there are several circuits between two substations \( s \) and \( k \), this equation can be extended to:

\[ F_{sk} = \frac{\delta_s - \delta_k}{x_{sk}} \quad (5.15) \]

where:

- \( F_{sk} \) the real part of the flow between the substations \( s \) and \( k \)
- \( x_{sk} \) the reactance between the substations \( s \) and \( k \)

The substation active power injections are then given by:

\[ P_s = \sum_k F_{sk} = B'_{ss} \delta_s + \sum_{k, k \neq s} B'_{sk} \delta_k \quad (5.16) \]

where:
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\[ B'_{sk} = \begin{cases} \frac{-1}{x_{sk}}, & k \neq s \\ \sum_{j \neq s} \frac{1}{x_{sj}}, & k = s \end{cases} \tag{5.17} \]

Note that the difference between the elements \( B'_{sk} \) and \( B_{sk} \) (see equations (5.6) and (5.7)) is only caused by neglecting the resistances of the circuits between substations \( s \) and \( k \). Equation (5.16) can be expressed in the following matrix notation:

\[ P = P^d + P^g = B'\delta \tag{5.18} \]

Equation (5.18) is linear, and no iterations are required to solve it. Since the elements in each column of matrix \( B' \) add up to zero, the determinant of this matrix is zero. Therefore, the equations in (5.18) are not linearly independent. One equation is a linear combination of the others. To provide an additional equation, the simple fact can be recognised that the active power injections at the substations must add up to zero. This is permitted since it is assumed that circuit resistances are neglected and, therefore, no losses in the system arise. Assuming that the angle of the slack node voltage is equal to zero, one can calculate the reduced vector of the substation voltage angles, \( \delta' \), with:

\[ \delta' = (B''')^{-1}P^p = Z'P^p \tag{5.19} \]

where:

- \( \delta' \) is \( \delta \) decreased by one element corresponding to the slack node
- \( B''' \) is \( B' \) decreased by one column and one row corresponding to the slack node
- \( P^p \) is \( P \) decreased by one element corresponding to the slack node

When the voltage angles are known, the power flow through each circuit can be calculated with the aid of equation (5.12). Combining equations (5.12) and (5.19) in a matrix form, gives:

\[ F = S'P' \tag{5.20} \]

where:

- \( F \) the real part of the circuit flow vector
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\[ S' = \text{the reduced sensitivity coefficient matrix} \]

Matrix \( S' \) is given by:

\[ S' = A'(B'')^{-1} \quad (5.21) \]

where:

\[ A' \quad \text{is} \quad A \text{ decreased by one row corresponding to the slack node} \]

Matrix \( S' \) is rectangular and can be extended to matrix \( S \) by adding one column of zeros, corresponding to the slack node. When the reduced vector \( P' \) is extended to vector \( P \) by including the injection at the slack node, the following equation is obtained:

\[ F = SP \quad (5.22) \]

By means of equation (5.22), the real part of the flow in circuit \( c \), \( F_c \), can be directly derived from the injected power at the substations. To illustrate the concepts described above, an example of the system of figure 5.2a will be given.

**Example 5.1**

Assuming that each circuit in the network presented in figure 5.2 has a reactance of 1 per unit, then matrix \( B' \) can be obtained by using equation (5.17). Selecting substation 1 as the slack node, matrix \( B'' \) can also be obtained. Both matrices are given below.

\[ B' = \begin{pmatrix} 4 & -1 & -3 \\ -1 & 2 & -1 \\ -3 & -1 & 4 \end{pmatrix}, \quad B'' = \begin{pmatrix} 2 & -1 \\ -1 & 4 \end{pmatrix} \quad (5.23) \]

The active power injections at each substation are presented in matrix \( P \). This vector and its reduced vector, \( P' \), are given by:

\[ P = \begin{pmatrix} 6 \\ -2 \\ -4 \end{pmatrix}, \quad P' = \begin{pmatrix} -2 \\ -4 \end{pmatrix} \quad (5.24) \]

With the aid of equation (5.14), matrix \( A \) can be obtained. This matrix and its reduced matrix, \( A' \) are:
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\[
A = \begin{pmatrix}
1 & 0 & 1 \\
1 & 0 & 1 \\
1 & 0 & 1 \\
1 & -1 & 0 \\
0 & 1 & -1
\end{pmatrix}, \quad A' = \begin{pmatrix}
0 & 1 \\
0 & 1 \\
0 & 1 \\
-1 & 0 \\
1 & -1
\end{pmatrix}
\]  \hspace{1cm} (5.25)

Then the reduced sensitivity coefficient matrix, \( S' \), can be obtained, i.e.,

\[
S' = A'(B'')^{-1} = \begin{pmatrix}
0 & -1 \\
0 & -1 \\
0 & -1 \\
-1 & 0 \\
1 & -1
\end{pmatrix} \begin{pmatrix}
0.5714 & 0.1429 \\
0.1429 & 0.2857
\end{pmatrix} = \begin{pmatrix}
-0.1429 & -0.2857 \\
-0.1429 & -0.2857 \\
-0.1429 & -0.2857 \\
0.5714 & -0.1429 \\
0.4285 & -0.1428
\end{pmatrix}
\]  \hspace{1cm} (5.26)

Solving equation (5.22) results in:

\[
F = SP = \begin{pmatrix}
0 & -0.1429 & -0.2857 \\
0 & -0.1429 & -0.2857 \\
0 & -0.5714 & -0.1429 \\
0 & 0.4285 & -0.1428
\end{pmatrix} \begin{pmatrix}
6 \\
-2 \\
-4 \\
\end{pmatrix} = \begin{pmatrix}
1.43 \\
1.43 \\
1.71 \\
-0.29
\end{pmatrix}
\]  \hspace{1cm} (5.27)

The magnitude and direction of the circuit flows are presented in figure 5.2a.

Some of the enumerated contingencies may lead to one or more isolated substations. This problem is handled by superposing a dummy network with very low susceptances over the actual network [41,42].

5.3 Remedial actions

In a reliability assessment procedure of a transmission or a distribution system, the actions of power-system operators should be considered as well since they have an important influence on the reliability of the system. Different system states can give rise to flows in network components that are outside permissible limits. To ensure
return within these limits, appropriate remedial actions are usually applied, and if not, power-system protection operates or damage occurs. Such aspects should be simulated when computing system-reliability indices.

In practice, there is a distinction between remedial actions in a transmission system on the one hand and remedial actions in a distribution system on the other hand. Remedial actions in distribution systems are usually applied in a corrective way, that is to say: after protective devices of the system have disconnected certain substations. Due to the high degree of automation in transmission systems, remedial actions in such systems are often preventive, that is to say: they are applied before the substations in the system are disconnected. This difference should be considered in a reliability assessment procedure for transmission systems on the one hand and distribution systems on the other hand.

In traditional power-system reliability studies, two kinds of remedial actions are considered. These are generation redispatch and load shedding. Several approaches have been suggested to determine generation rescheduling and if necessary load curtailment to alleviate circuit overloads [10,43,44,45]. In a distribution system, circuit overloads are usually automatically remedied by the protection system.

The following subsections describe four possible remedial actions that are used in this thesis to alleviate circuit overloads. These are:

- Manual network reconfiguration
- Generation redispatch or generation rescheduling
- Load curtailment or load shedding
- Protection-system behavior

The first three kinds of remedial actions are typical for the operation of transmission systems. The first and the last type of remedial actions are more specific for distribution-system operation. The incorporation of a network reconfiguration model is not usual in traditional reliability studies. However, it can have considerable influence on the evaluated indices of reliability for customers, as will be illustrated in the following chapter of this thesis.

### 5.3.1 Manual network reconfiguration

In practice, it is sometimes possible to overcome or alleviate circuit overloads by undertaking reconfiguration actions in the network. Such control means are usually not modeled in traditional power-system reliability studies [46]. However, in practice, manual network reconfiguration will normally be considered as a logical step before
the application of generation redispach and load shedding in the operation of a transmission system. An example for a small system can illustrate the effects of reconfiguration actions.

**Example 5.2**
Consider a small power system consisting of 3 substations and 5 lines as depicted in figure 5.2. Substation 1 is a generation station. Substations 2 and 3 are area supply stations. The load demands and the corresponding generation in per unit values are given in figure 5.2a for normal operation. The direction and magnitude of the load flows between the substations are also given. The capacity of the lines L1 to L3 is 4 per unit. The capacity of the lines L4 and L5 is 2 per unit. It can be observed that in the normal situation no line is overloaded.

![Figure 5.2 Single-line diagrams of a simple power system](image)

Suppose that lines L1 and L2 suffer a common cause failure, which results in a common outage of lines L1 and L2. Due to the change in the network topology, the flows through the network change. The resulting flows after this severe outage has occurred are given in figure 5.2b. Line L4 is severely overloaded and a system constraint is violated.

In a traditional power-system reliability evaluation study, this violation will be alleviated by load shedding, since generation rescheduling is impossible due the fact that all generating units are located in the same substation. However, by switching line L5 out
of service, load curtailment can be avoided. Due to switching line L5 out of service, the flow through line L4 is reduced to the load demand at substation 2, which is equal to 2 per unit. On the other hand, the flow through line L3 increases to 4 per unit. This example shows that by switching an extra line out of service, the overload in the system is alleviated. Figure 5.2c shows the new unviolated system state after the network was reconfigured.

Assume now that circuit L2 between substations 1 and 2 is normally open for operational reasons, for example to reduce the feeding short-circuit power on substation 3 (see figure 5.3a). After the failure of line L1 or line L3, the same situation arises as given in figure 5.2b. Again line L4 becomes severely overloaded. By switching the normally open line L2 into service, the load flow in the system changes due to a change in the topology of the network. This example shows that by switching a line into service, the overload in the system is alleviated. The new unviolated system state after network reconfiguration is given in figure 5.3c.

Figure 5.3 Single-line diagrams of a simple power system with line L2 in a normally open position

From example 5.2, it appears that manual network reconfiguration of a power system should be considered as a logical step before applying generation redispatch and load curtailment in the reliability evaluation of a system. Manual network reconfiguration refers to a control action which brings the network from an overloaded state back to an
acceptable state by adding or removing one or more circuits of the system. It is obvious that only those circuits which are normally open (for operational reasons), may be switched in service.

Because the reliability of a transmission system does not only depend on failure and restoration processes but also on other constraints, such as the capacity constraints of transmission or distribution equipment, the loss of a component might create a more reliable system state. In literature, this concept is called noncoherence in a transmission or distribution system [40]. A general definition of noncoherence is that the loss of a component creates a more reliable system state.

Due to modifications in the network topology, the circuit flows are directly influenced. The change in circuit loading can be determined using so-called network-modification coefficients. These coefficients depend directly on the current network topology. For a single reconfiguration action, the following equation is valid:

\[ F_{c}^{\text{new}} = F_{c}^{\text{old}} + \Delta F_{c}^{b_m} \]

where:
- \( F_{c}^{\text{new}} \) is the flow in circuit \( c \) after reconfiguration
- \( F_{c}^{\text{old}} \) is the flow in circuit \( c \) before reconfiguration
- \( \Delta F_{c}^{b_m} \) is the change of the flow in circuit \( c \) due to switching circuit \( m \) (the network-modification coefficient)

The network-modification coefficient, \( \Delta F_{c}^{b_m} \), can be obtained by extending equation (5.12). The flow in circuit \( c \) between substations \( s \) and \( k \) before switching circuit \( m \), which is located between the substations \( p \) and \( q \), \( F_{c}^{\text{old}} \), is given by (see equations (5.9), (5.12) and (5.19)):

\[ F_{c}^{\text{old}} = -b_c (\delta_s^{\text{old}} - \delta_k^{\text{old}}) = -b_c \sum_r (Z_{sr}^{\text{old}} - Z_{kr}^{\text{old}})P_r \]

where:
- \( Z_{sr}^{\text{old}} \) is an element of matrix \( Z^{\text{old}} \)

Matrix \( Z^{\text{old}} \) is built from \((B^t)^{-1}\) by adding one row and one column of zeros corresponding to the slack node. In the same way, the flow in circuit \( c \) after switching circuit \( m \), \( F_{c}^{\text{new}} \), can be determined, i.e.,

\[ F_{c}^{\text{new}} = -b_c (\delta_s^{\text{new}} - \delta_k^{\text{new}}) = -b_c \sum_r (Z_{sr}^{\text{new}} - Z_{kr}^{\text{new}})P_r \]
The method adopted to modify the matrix $Z^{\text{old}}$ to take account of changes in the circuit impedances is based on the work of Kron [47]. He proves that $Z^{\text{new}}_{sr}$ is given by:

$$Z^{\text{new}}_{sr} = Z^{\text{old}}_{sr} - \frac{(Z^{\text{old}}_{sp} - Z^{\text{old}}_{sq})(Z^{\text{old}}_{pr} - Z^{\text{old}}_{qr})}{1 + Z^{\text{old}}_{pp} + Z^{\text{old}}_{qq} - 2Z^{\text{old}}_{pq}}$$  \hspace{1cm} (5.31)

where:

$$\Delta b^*_m = \begin{cases} 
  b_m & \text{if circuit } m \text{ is removed from service} \\
  -b_m & \text{if circuit } m \text{ is taken into service} 
\end{cases} \hspace{1cm} (5.32)$$

Combining equations (5.30) and (5.31) gives:

$$F^{\text{new}}_c = -b_c \sum_r (Z^{\text{old}}_{sr} - Z^{\text{old}}_{kr})P_r +$$

$$- b_c \frac{(Z^{\text{old}}_{kp} - Z^{\text{old}}_{kq} - Z^{\text{old}}_{sp} + Z^{\text{old}}_{sq})}{1 + Z^{\text{old}}_{pp} + Z^{\text{old}}_{qq} - 2Z^{\text{old}}_{pq}} \sum_r (Z^{\text{old}}_{pr} - Z^{\text{old}}_{qr})P_r$$  \hspace{1cm} (5.33)

By combining equations (5.28), (5.29), (5.30) and (5.33), the network-modification coefficient, $\Delta F_c|\Delta b_m$, is given:

$$\Delta F_c|\Delta b_m = -b_c \frac{(Z^{\text{old}}_{kp} - Z^{\text{old}}_{kq} - Z^{\text{old}}_{sp} + Z^{\text{old}}_{sq})}{1 + Z^{\text{old}}_{pp} + Z^{\text{old}}_{qq} - 2Z^{\text{old}}_{pq}} (\delta^{\text{old}}_p - \delta^{\text{old}}_q)$$  \hspace{1cm} (5.34)

An example can illustrate the concepts described above.

**Example 5.3**

Consider again the network presented in figure 5.2a. It is still assumed that each circuit has a reactance of 1 per unit. In this example, the network-modification coefficient $\Delta F_4|\Delta b_3$ is evaluated assuming that circuit L5 will be removed from service. Line L4 is surrounded by substations 1 and 2. Therefore $c=4$, $s=1$ and $k=2$. The line which will be removed from service is circuit L5, which is surrounded by substations 2 and 3. Therefore $m=5$, $p=2$ and $q=3$. Figure 5.2a suggests that it may be expected that
$\Delta F_4/\Delta b_5$ is equal to 0.29 per unit, since the flow through circuit L5 will become zero after removing line L5 from service.

One can obtain the vector $\delta$ by using equation (5.19). The matrix $Z^{old}$ is built from $(B'')^{-1}$ by adding one row and one column of zeros corresponding to the slack node (see example 5.1). Matrix $Z^{old}$ and vector $\delta^{old}$ are given below:

$$Z^{old} = \begin{pmatrix} 0 & 0 & 0 \\ 0 & 0.5714 & 0.1429 \\ 0 & 0.1429 & 0.2857 \end{pmatrix}, \quad \delta^{old} = \begin{pmatrix} 0 \\ -1.7143 \\ -1.4286 \end{pmatrix} \quad (5.35)$$

Then, the network-modification coefficient, $\Delta F_4/\Delta b_5$, can be calculated by using equation (5.34):

$$\Delta F_4/\Delta b_5 = -\frac{b_4(Z_{22}^{old} - Z_{23}^{old} - Z_{12}^{old} + Z_{13}^{old})(\delta_2^{old} - \delta_3^{old})}{1 + Z_{22}^{old} + Z_{33}^{old} - 2Z_{23}^{old}}$$

$$-\frac{-1(0.5714 - 0.1429 - 0 + 0)}{-1 + 0.5714 + 0.2857 - 2\cdot0.1429}(-1.7143 + 1.4286)$$

$$-\frac{-0.4285(-0.2857)}{-0.4287} = 0.29$$

which agrees with the expectation that was mentioned. \hfill \Box

For multiple reconfigurations in the network, equation (5.28) can be extended to:

$$F_{c, new}^c = F_{c, old}^c + \sum_i (\Delta F_i^c/\Delta b_i) x_i \quad (5.37)$$

where:

$$x_i = \begin{cases} 1, & \text{if circuit } i \text{ is switched} \\ 0, & \text{if circuit } i \text{ is not switched} \end{cases} \quad (5.38)$$

It should be considered that equation (5.37) is only exact if one circuit is switched. This is because the network-modification coefficients are dependent on the current network topology. The accuracy of (5.37) decreases if more circuits are switched.
Therefore, the procedure of manual network reconfiguration should be repeated if more than one circuit has to be switched.

Since it is obvious that operators of a power system want to bring the system back to an acceptable state by minimum effort (with a minimal number of changes in the network topology), it is comprehensible that the selected reconfiguration algorithm is based on the minimization of the number of reconfiguration actions for the system. A possible objective function for such actions is:

\[ f(x_1, x_2, \ldots, x_N) = \sum_i \beta_i F_i^{\text{max}} x_i \]  
(5.39)

where:

\[ F_i^{\text{max}} \]  
the capacity of circuit \( i \)

Equation (5.39) shows that it is assumed that switching a circuit (in or out of service) with a small capacity has priority over switching a circuit with a higher capacity. Other assumptions will of course lead to another objective function. The value of \( \beta_i \) can depend on whether the circuit is switched in or out of service.

To ensure that no circuit is overloaded and no substation is isolated after network reconfiguration, the objective function (5.39) has a set of constraints. To protect the system against circuit overloading after reconfiguration, the first set of constraints in matrix notation is:

\[ \begin{vmatrix} F^{\text{new}} \end{vmatrix} \leq F^{\text{max}} \]  
(5.40)

The second set of constraints ensures that no substation in the system becomes isolated due to the removal of one or several circuits in the system. Therefore, only a certain subset of circuits may be switched out of service. This subset can be found by using a network-searching algorithm or from inspection of the sensitivity coefficient matrix \( S \). It can be proved that for each element, \( S_{ab} \), \( 1 \leq a \leq N^C \) and \( 1 \leq b \leq N^S \), it appears that:

\[ -1 \leq S_{ab} \leq 1 \]  
(5.41)

When a certain element of the sensitivity coefficient matrix \( S \), \( S_{ab} \), is equal to 1 or -1, this means that the flow in circuit \( a \) is totally dependent on the load demand at substation \( b \). The isolation of circuit \( a \) will in this case result in the isolation of substation \( b \). Therefore, preferably circuits having a sensitivity coefficient equal to 1 or -1 are not switched off. Particularly in transmission system analyses, it is then preferable to
alleviate the circuit overload by partial load curtailment and not by isolating complete substations.

The minimization of the objective function (5.39) subject to the constraints is based on a discrete minimization process to find a solution. The adopted approach is based on the implicit enumeration method [48,49]. If a feasible solution is found in which more than one circuit is switched, this solution should be tested to see if the result corresponds to an acceptable network state. This test is necessary because the network-modification coefficients are dependent on the network topology. This can cause inaccuracies in case of multiple reconfiguration actions.

For transmission systems, manual network reconfiguration is applied to all enumerated contingencies leading to overloaded circuits. For distribution system studies, manual network reconfiguration is only applied to enumerated contingencies leading to overloaded circuits after switching.

5.3.2 Generation redispatch

If it is not possible to alleviate circuit overloads by performing manual network reconfiguration in the transmission system, it is usual to establish whether generation redispatch can be applied. For the problem of generation redispatch several approaches are proposed [42,43,44,45]. Since this thesis does not focus in detail on the generation system, a philosophy which is comprehensible and computationally easy is preferred. Such an approach is, for example, an algorithm using the concept of the sensitivity coefficients [44].

A redispatch always involves at least two generation stations. The problem is to find the most suitable generation stations and the amount of power to be interchanged. Equation (5.22) shows that the flow in circuit $c$ between the substations $s$ and $k$, $F_c$, is:

$$F_c = \sum_r S_{cr} P_r$$  \hfill (5.42)

This equation can be separated into two other terms: one term due to generation stations only and the other term due to substations with load demand only, i.e.,

$$F_c = \sum_{r=1}^{N^G} S_{cr}^g P_r + \sum_{r=N^G+1}^{N^S} S_{cr}^d P_r$$  \hfill (5.43)
where:

\[ N^G \] the number of generation stations
\[ N^S \] the number of substations (generation and area supply stations)

The sensitivity coefficients of the generation stations provide a very simple way of overcoming line overloads by redispatch. Assuming that the power interchange between the two generators should be as small as possible for economic reasons, the generation stations having the largest and smallest values of \( S_{cr}^g \) are chosen to form the pair of substations which are to interchange power. Consequently, if circuit \( c \) is overloaded by \( \Delta F_c \):

\[
\Delta F_c = \begin{cases} 
F_c^{\text{max}} - F_c, & F_c > F_c^{\text{max}} \\
-F_c^{\text{max}} - F_c, & F_c < -F_c^{\text{max}} 
\end{cases} 
\]  
(5.44)

Then it follows from (5.43) that the minimum quantity of interchanged power between two generation stations, \( P_{\text{min}} \), is given by:

\[
P_{\text{min}} = \frac{\Delta F_c}{S_{cr}^{g,\text{max}} - S_{cr}^{g,\text{min}}} 
\]  
(5.45)

Note that the quantity of interchanged power between two generation stations, \( P_{\text{min}} \), can be either positive or negative. The scheduled generation at the generation station corresponding to \( S_{cr}^{g,\text{max}} \) (assume that this is substation \( a \)) is then set to:

\[
P_{a}^{g,\text{new}} = P_{a}^{g,\text{old}} + \Delta P_{\text{min}} \]  
(5.46)

subject to:

\[
P_{a}^{g,\text{min}} \leq P_{a}^{g,\text{new}} \leq P_{a}^{g,\text{max}} \]  
(5.47)

The scheduled generation at the generation station corresponding to \( S_{cr}^{g,\text{min}} \) (assume that this is substation \( b \)) is then set to:

\[
P_{b}^{g,\text{new}} = P_{b}^{g,\text{old}} - \Delta P_{\text{min}} \]  
(5.48)

subject to:

\[
P_{b}^{g,\text{min}} \leq P_{b}^{g,\text{new}} \leq P_{b}^{g,\text{max}} \]  
(5.49)
When the lower bound is exceeded, the value of the rescheduled generation is set to the minimum value. When the upper bound is exceeded, the value of the rescheduled generation is set to the maximum value. This process can be repeated for any pair of generation stations if more than one circuit is overloaded. The following example illustrates the concepts presented above.

**Example 5.4**

Consider the single-line diagram of the power system depicted in figure 5.4a. It is assumed that circuits $L1$, $L2$, $L5$ and $L6$ have a reactance of 1 per unit, whereas the circuits $L3$ and $L4$ have a reactance of 2 per unit. The load flow for the normal situation and the maximum capacities of the lines are presented in figure 5.4a.

![Diagram](image)

**Figure 5.4** Single-line diagrams of a small power system to illustrate generation rescheduling and load curtailment

This figure shows that in the normal situation no line is overloaded. Assume now that lines $L5$ and $L6$ suffer a common cause failure. Then the situation arises as presented in figure 5.4b, which shows that lines $L1$ and $L2$ have become severely overloaded. If one selects circuit $L1$, one can determine the circuit overload to be alleviated by using equation (5.44), i.e.,

$$\Delta F_1 = F_1^{\text{max}} - F_1 = 1 - 1.5 = -0.5$$

(5.50)
The sensitivity coefficient matrix, $S$, which belongs to the network state presented in figure 5.4b, is equal to:

$$S = \begin{pmatrix} 0 & -0.5 & -0.5 \\ 0 & -0.5 & -0.5 \\ 0 & 0 & -0.5 \\ 0 & 0 & -0.5 \\ 0 & 0 & 0 \\ 0 & 0 & 0 \end{pmatrix} \quad (5.51)$$

With matrix $S$, one can find the minimal quantity of interchanged power between the two generation stations, $\Delta P^{\text{min}}$, which is written as:

$$\Delta P^{\text{min}} = \frac{\Delta F_1}{S_{1r}^{g,\text{max}} - S_{1r}^{g,\text{min}}} = \frac{-0.5}{0 - -0.5} = -1 \quad (5.52)$$

The scheduled generation at the generation station corresponding to $S_{1r}^{g,\text{max}}$ (in this case generation station 1) is then set to:

$$P_1^{g,\text{new}} = P_1^{g,\text{old}} + \Delta P^{\text{min}} = 3 + -1 = 2 \quad (5.53)$$

The scheduled generation at the generation station corresponding to $S_{1r}^{g,\text{min}}$ (in this case generation station 2) is then set to:

$$P_2^{g,\text{new}} = P_2^{g,\text{old}} - \Delta P^{\text{min}} = 3 - -1 = 4 \quad (5.54)$$

This network state is presented in figure 5.4c. After rescheduling the generating units, no lines are overloaded.

Generation rescheduling is usually only applied in a reliability evaluation procedure for a transmission system. In distribution systems, generation rescheduling is generally not an option.

### 5.3.3 Load curtailment

The load shedding or load curtailment algorithm is based on the same concepts as the generation redispatch and involves one area supply station at which load is shed and
one generation station at which generation is decreased. Combining equations (5.44) and (5.45) in a similar way gives:

\[
\Delta P_{\text{min}} = \begin{cases} 
\frac{\Delta F_c}{S_{g,\text{max}} - S_{d,\text{min}}} , & \Delta F_c < 0 \\
\frac{\Delta F_c}{S_{c_r} - S_{g,\text{min}}} , & \Delta F_c > 0 
\end{cases}
\]  
(5.55)

The scheduled generation at the generation station corresponding to \(S_{cr}^{g,\text{max}}\) (assume that this is substation \(a\)) is then set to:

\[
P_{a}^{g,\text{new}} = P_{a}^{g,\text{old}} + \Delta P_{\text{min}}
\]  
(5.56)

subject to:

\[
P_{a}^{g,\text{min}} \leq P_{a}^{g,\text{new}} \leq P_{a}^{g,\text{max}}
\]  
(5.57)

The load at the area supply station corresponding to \(S_{cr}^{d,\text{min}}\) (assume that this is substation \(b\)) is then set to:

\[
P_{b}^{d,\text{new}} = P_{b}^{d,\text{old}} - \Delta P_{\text{min}}
\]  
(5.58)

subject to:

\[
P_{b}^{d,\text{min}} \leq P_{b}^{d,\text{new}} \leq 0
\]  
(5.59)

The scheduled generation at the generation station corresponding to \(S_{cr}^{g,\text{min}}\) (assume that this is substation \(a\)) is then set to:

\[
P_{a}^{g,\text{new}} = P_{a}^{g,\text{old}} - \Delta P_{\text{min}}
\]  
(5.60)

subject to:

\[
P_{a}^{g,\text{min}} \leq P_{a}^{g,\text{new}} \leq P_{a}^{g,\text{max}}
\]  
(5.61)

The load at the area supply station corresponding to \(S_{cr}^{d,\text{max}}\) (assume that this is substation \(b\)) is then set to:
\[ P_{b_{\text{new}}}^{d} = P_{b_{\text{old}}}^{d} + \Delta P^{\text{min}} \]  

subject to:

\[ P_{b}^{d} \leq P_{b_{\text{new}}}^{d_{\text{new}}} \leq 0 \]  

When lower bounds are exceeded, the values of the new generation or load are set to the minimum values. When upper bounds are exceeded, the values of the new generation or load are set to the maximum values. This process can be repeated for any pair of a generation station and an area supply station if more than one circuit is overloaded.

It has to be noted that often it is not necessary to curtail the whole load demand in a certain substation. Instead, usually only a part of it has to be curtailed. Then the question arises how the load to be curtailed should be divided among the load points in a substation, if the substation comprises more than one load point (see for example figure 4.9). The adopted method in this thesis is to apply load shedding to the load point in a substation having the lowest load point number. When the curtable load is greater than the current load demand of that load point, the curtailment process is applied to one or more of the following load points for the remaining amount of curtable load. The following example can illustrate the concepts as presented above.

**Example 5.5**

Consider again the single-line diagram of the power system depicted in figure 5.4a. Assume again that lines L5 and L6 suffer a common cause failure. Then the situation as presented in figure 5.4b arises, which shows that lines L1 and L2 are severely overloaded. According to equation (5.44), the overload of circuit L1 is equal to -0.5 per unit. In the foregoing example, it was illustrated that rescheduling of the generating units at substations 1 and 2 alleviated the overloaded line.

Suppose now that rescheduling of the generating units is impossible, since the maximum generation capacity at substation 2 is equal to 3 per unit. In that case, load curtailment should be applied. The sensitivity coefficient matrix, Si, which belongs to the network state presented in figure 5.4b, is given by equation (5.51). With matrix Si, one can find the minimal quantity of interchanged power between a generation station and an area supply station, \( \Delta P^{\text{min}} \), which is given by:
\[ \Delta P^{\text{min}} = \frac{\Delta F_1}{S_{\text{r}}^{g,\text{max}} - S_{\text{r}}^{d,\text{min}}} = \frac{-0.5}{0 - 0.5} = -1 \]  

(5.64)

The scheduled generation at the generation station corresponding to \( S_{\text{r}}^{g,\text{max}} \) (in this case generation station 1) is then set to:

\[ P_{1}^{g,\text{new}} = P_{1}^{g,\text{old}} + \Delta P^{\text{min}} = 3 + (-1) = 2 \]  

(5.65)

The load demand at the area supply station corresponding to \( S_{\text{r}}^{d,\text{min}} \) (in this case area supply station 3) is then set to:

\[ P_{3}^{d,\text{new}} = P_{3}^{d,\text{old}} - \Delta P^{\text{min}} = 4 - (-1) = 3 \]  

(5.66)

After load curtailment has been applied, no lines are overloaded.

Usually the load is only partially curtailed if the reliability of a transmission system is evaluated. For distribution systems, partial load curtailment is impossible, because in these systems the operation principle already makes sure that protective relays trigger load curtailment.

The main steps of the proposed algorithm for alleviating circuit overloads in a transmission system are as follows:

1. Determine whether a circuit overload occurs.
2. Minimize equation (5.39) which is subject to its corresponding constraints.
3. Determine whether circuits are switched.
   3.1. If no circuits are switched, go to step 7.
   3.2. If only one circuit is switched, go to step 10.
   3.3. If more than one circuit is switched, go to step 4.
4. Determine whether there are overloaded circuits after the proposed network reconfiguration has been performed.
   4.1. If no circuits are overloaded, go to step 10.
   4.2. If one or more circuits are overloaded, go to step 5.
5. Minimize equation (5.39) again, which is subject to its corresponding constraints.
6. Determine whether circuits are switched.
   6.1. If no circuits are switched, go to step 7.
   6.2. If only one circuit is switched, go to step 10.
6.3. If more than one circuit is switched, go to step 7.

7. Apply generation redispacth to the original system state of step 1, in order to alleviate overloaded circuits.

8. Determine whether there are overloaded circuits after performing the proposed generation redispaches.
   8.1. If no circuits are overloaded, go to step 10.
   8.1. If one or more circuits are overloaded, go to step 9.

9. Apply load curtailment to the power-system state after generation redispacth in order to alleviate overloaded circuits.

10. Apply the reconfiguration action(s) to the original system state in step 1.

It was earlier mentioned that equation (5.37) is only exact if one circuit is switched. This is because the network-modification coefficients depend on the current network topology. The accuracy of (5.37) decreases if more circuits are switched. If a feasible solution is found in step 3 for two or more switched circuits, this solution should be tested to check whether the result yields an acceptable system state. If it appears that the result does not yield an acceptable system state, the minimization process is repeated, with the solution of the last step as a starting point.

So, when the reconfiguration procedure does not result in an acceptable system state, generation rescheduling is applied. When generation redispacth does not give an acceptable system state, load curtailment is applied to alleviate overloaded circuits.

5.3.4 Protection-system behavior

Remedial actions have to be applied to bring the system back from an undesirable state to an acceptable state. Several contingencies can give rise to flows in the network components that are beyond permissible limits. In distribution systems, such system violations are usually remedied by the automatic operation of protective relays. When the measured current exceeds a certain threshold, the relay operates and commands a circuit breaker to operate. This threshold is usually equal to the nominal current of the feederprotected by the relay, and this is multiplied by a certain factor. This factor is often chosen as 1.1 or 1.2.

After the protective relay and its corresponding circuit breaker have operated, the network topology and the load flow change. This switching process is repeated until no circuits have to be switched out of service due to protection-system behavior. The operation of protective relays should be considered both for contingencies before switching and contingencies after switching in a reliability evaluation procedure of a distribution system. Since manual network reconfiguration is usually applied to contin-
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gencies after switching, two different algorithms exist for remedial actions in distribution systems: one for contingencies before switching and one for contingencies after switching.

The algorithm that takes into account the protection system in a distribution system reliability assessment procedure for contingencies before switching is given below:

1. Determine whether a circuit overload occurs.
2. Select a circuit.
3. Determine whether this circuit is protected by a protective relay and evaluate whether the circuit load exceeds the threshold of the corresponding protective relay.
   3.1. If the circuit load exceeds the corresponding threshold, go to step 4.
   3.2. If the circuit load does not exceed the threshold, go to step 6.
4. Switch the circuit off and determine which circuits are also on outage as a result of the response of the protective relay.
5. Determine the load flow after this change in the network topology.
6. Repeat steps 2 to 5 until all circuits have been considered.

The algorithm that takes into account the overload protection in a distribution system reliability assessment procedure for contingencies after switching is as follows:

1. Determine whether a circuit overload occurs.
2. Minimize equation (5.39) which is subject to its corresponding constraints.
3. Determine whether circuits are switched.
   3.1. If no circuits are switched, go to step 7.
   3.2. If only one circuit is switched, go to step 12.
   3.3. If more than one circuit is switched, go to step 4.
4. Determine whether there are overloaded circuits after the proposed network reconfiguration has been performed.
   4.1. If no circuits are overloaded, go to step 12.
   4.2. If one or more circuits are overloaded, go to step 5.
5. Minimize equation (5.39) again, which is subject to its corresponding constraints.
6. Determine whether circuits are switched.
   6.1. If no circuits are switched, go to step 7.
   6.2. If only one circuit is switched, go to step 12.
   6.3. If more than one circuit is switched, go to step 7.
7. Select a circuit.
8. Determine whether this circuit is protected by a protective relay and evaluate whether the circuit load exceeds the threshold of the corresponding protective relay.

8.1. If the circuit load exceeds the corresponding threshold, go to step 9.
8.2. If the circuit load does not exceed the threshold, go to step 11.

9. Switch the circuit off and determine which circuits are also on outage as a result of the protective-relay response.

10. Determine the load flow after this change in the network topology.

11. Repeat steps 7 to 10 until all circuits have been considered.

12. Apply the reconfiguration action(s) to the original system state in step 1.

5.4 Problem evaluation and updating reliability indices

Certain evaluated power-system states will cause system failure, such as completely isolated load points or partial load curtailment at load points. It is therefore necessary to keep the books for each selected system state which results in system failure. This can be done for each individual load point but also for the system as a whole. For example, the probability of load curtailment at a certain load point can be evaluated, but also the frequency with which any load point in the whole system is isolated.

There are many reliability indices that can be evaluated for transmission systems and distribution systems. Existing literature distinguishes two types of indices, namely system indices and load-point indices [12,30,40]. The first reflects the overall adequacy of the entire system, while the second reflects the adequacy of individual load points. These two sets of indices can respond quite differently to variations in system parameters [50].

System indices and load-point indices can be calculated at the peak load and expressed on a one-year basis or by considering the annual load duration curve. In the first case, the reliability indices are evaluated under ‘worst case’ system conditions and may be transformed to an annual basis. Such indices are known as annualized indices. In the latter case, the reliability indices are evaluated under more realistic system conditions. Such indices are known as annual indices. Although annualized indices are usually not similar to the annual indices, they still can be used for comparing system design alternatives.

This section presents several widely used load-point indices for transmission and distribution systems. Since in transmission systems, load curtailment can be applied in
order to alleviate system constraints, the load-point indices take not only load-point isolation into consideration but also load curtailment. Load-point indices for distribution systems take usually only load-point isolation into consideration. Besides load-point indices, this thesis considers also several substation-related indices for transmission systems. To illustrate the difference between load-point indices and substation indices, consider the single-line diagram of the substation in figure 5.5.

**Figure 5.5** Single-line diagram of a duplicate busbar scheme

Suppose that transformer $T_1$ in this substation suffers an active failure. Then load point $LD_1$ will be disconnected from the network and its reliability indices will be updated. It is obvious that as a result of this load-point interruption the reliability indices related to the whole substation are updated as well, since the load demand is not fully supplied due to this outage. Load point $LD_2$ is not affected by this outage and therefore the reliability indices of this load point are not updated.

Assume now that after the restoration of transformer $T_1$, circuit breaker $B_5$ suffers a passive failure. Then load point $LD_2$ becomes isolated, while load point $LD_1$ is still supplied. Therefore, the reliability indices for the substation and for load point $LD_2$
are updated, but not the indices corresponding to load point \( LD1 \). These two examples imply that the substation indices are updated for both substation-related failures, while the load-point indices are only updated once. Hence, this is the difference between substation indices and load-point indices.

In this thesis, it is assumed that if the load is curtailed at a substation, the load is first shed at the first defined load point that is defined in that substation. When the substation contains more than one load point and the amount of load to be curtailed is greater than the actual load demand at the first load point, the load demand at the first load point is fully shed. After that, the second load point is chosen and the load curtailment process is repeated for the remaining amount of load to be curtailed. This process is repeated until the whole amount of load to be curtailed at the substation has been shed.

Note that the presented indices, which will be considered in the following section, are expected values of a random variable. An expected value is the long-term average of the studied variable. Expectation indices provide indicators which reflect various factors, such as component availability and capacity, load characteristics, system structure, operational conditions, etc.

### 5.4.1 Load-point and substation indices for transmission systems

The following load-point indices for transmission systems are used in this thesis [40]:

- **Probability of Load Curtailments, \( PLC(l) \):** Probability that the actual load demand at load point \( l \) exceeds the maximum load that can be supplied.

\[
PLC(l) = \sum_{i \in S_{l}^{LC}} Pr(i) \tag{5.67}
\]

where:

\[
Pr(i) \quad \text{the probability of occurrence of system state } i
\]

\[
S_{l}^{LC} \quad \text{the subset of all system states associated with load curtailment at load point } l
\]

- **Expected Number of Load Curtailments, \( ENLC(l) \), [occ/yr]:** Number of contingencies causing the situation that the load demand at load point \( l \) exceeds the maximum load that can be supplied during the period of interest.

\[
ENLC(l) = \sum_{i \in S_{l}^{LC}} Fr(i) \tag{5.68}
\]
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where:

\[ Fr(i) \]  
the frequency of occurrence of system state \( i \) [occ/yr]

- Expected Duration of Load Curtailments, \( EDLC(l) \), [hr/yr]: Total period during which load is curtailed at load point \( l \) during the period of interest.

\[ EDLC(l) = 8760 \cdot PLC(l) = 8760 \sum_{i \in S_{l}^{LC}} Pr(i) \]  \hspace{1cm} (5.69)

- Average Duration of Load Curtailments, \( ADLC(l) \), [hr/occ]: Expected duration of a load curtailment at load point \( l \).

\[ ADLC(l) = \frac{EDLC(l)}{ENLC(l)} = \frac{8760 \sum_{i \in S_{l}^{LC}} Pr(i)}{\sum_{i \in S_{l}^{LC}} Fr(i)} \]  \hspace{1cm} (5.70)

- Expected Load Curtailments \( ELC(l) \), [MW/yr]: Expected load curtailed at load point \( l \) during the period of interest.

\[ ELC(l) = \sum_{i \in S_{l}^{LC}} P_{l}^{LC}(i) Fr(i) \]  \hspace{1cm} (5.71)

where:

\[ P_{l}^{LC}(i) \]  
the load curtailment in state \( i \) at load point \( l \)

- Expected Demand Not Supplied \( EDNS(l) \), [MW]: Expected load curtailed at load point \( l \) during the period of interest.

\[ EDNS(l) = \sum_{i \in S_{l}^{LC}} P_{l}^{LC}(i) Pr(i) \]  \hspace{1cm} (5.72)

- Expected Energy Not Supplied, \( EENS(l) \), [MWh/yr]: Total energy not supplied at load point \( l \) during the period of interest.

\[ EENS(l) = \sum_{i \in S_{l}^{LC}} P_{l}^{LC}(i) Fr(i) Du(i) = 8760 \sum_{i \in S_{l}^{LC}} P_{l}^{LC}(i) Pr(i) \]  \hspace{1cm} (5.73)

where:

\[ Du(i) \]  
the duration of system state \( i \) [hr/occ]
In a reliability analysis of a transmission system, these indices are updated for each enumerated contingency. The following algorithm is used.

1. **Determine the number of load levels adopted in the reliability evaluation, \( N^{LL} \).**
2. **Select a load point, \( l \).**
3. **If the load demand at the selected load point does not correspond with the actual load supplied, update the following indices according to:**
   3.1. \( PLC(l) = PLC(l) + Pr/N^{LL} \).
   3.2. \( ENLC(l) = ENLC(l) + Fr/N^{LL} \).
   3.3. \( EDLC(l) = EDLC(l) + (8760 \cdot Pr) / N^{LL} \).
   3.4. \( ADLC(l) = EDLC(l)/ENLC(l) \).
   3.5. \( ELC(l) = ELC(l) + (Fr \cdot P_L^{LC}) / N^{LL} \).
   3.6. \( EDNS(l) = EDNS(l) + (Pr \cdot P_L^{LC}) / N^{LL} \).
   3.7. \( EENS(l) = EENS(l) + (8760 \cdot Pr \cdot P_L^{LC}) / N^{LL} \).
4. **Repeat steps 2 to 3 until all load points have been considered.**

It is worth to note that three of the indices which are presented above are suitable for comparison with the observed indices presented in table 2.1. The Expected Number of Load Curtailments, \( ENLC(l) \), [occ/yr] agrees with the load-point interruption frequency due to disturbances in HV systems (measured in occasions per year). The Average Duration of Load Curtailment, \( ADLC(l) \), [hr/occ] agrees with the load-point interruption duration due to disturbances in HV systems (measured in minutes per occasion). The Expected Duration of Load Curtailment, \( EDLC(l) \), [hr/yr] agrees with the load-point annual unavailability due to disturbances in HV systems (measured in minutes per year).

Note that the above mentioned indices can also be evaluated for substations as a whole. In that case, the parameter ‘\( l \)’ corresponding to ‘load point’ has to be changed by ‘\( s \)’ corresponding to ‘substation’. For each contingency which results in load-point isolation or load curtailment in a substation, the substation indices should be updated. It is obvious that substation-related indices are usually greater than individual load-point indices if a substation contains more than one load point.

### 5.4.2 Load-point indices for distribution systems

There are three basic load-point indices in distribution system reliability assessment. These are:

- **Load-point interruption frequency, \( Fr(l) \), [occ/yr]: Number of contingencies causing supply interruption at load point \( l \) during the period of interest.**
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\[ Fr(l) = \sum_{i \in S_{i}^{iso}} Fr(i) \]  \hspace{1cm} (5.74)

where:

\[ S_{i}^{iso} \]
the subset of all system states associated with isolation of load point \( l \)

- Load-point annual unavailability, \( U(l) \), [hr/yr]: Probability that load point \( l \) is isolated multiplied by the number of hours of one year.

\[ U(l) = 8760 \sum_{i \in S_{i}^{iso}} Pr(i) \]  \hspace{1cm} (5.75)

- Load-point interruption duration, \( Du(l) \), [hr/occ]: Expected duration of supply interruption at load point \( l \).

\[ Du(l) = \frac{U(l)}{Fr(l)} = \frac{8760 \sum_{i \in S_{i}^{iso}} Pr(i)}{\sum_{i \in S_{i}^{iso}} Fr(i)} \]  \hspace{1cm} (5.76)

In existing literature [10,12,40] slightly different terminology for these three basic load-point indices is used. The load-point interruption frequency, \( Fr(l) \), is often called the load-point failure rate, \( \lambda(l) \), while the load-point interruption duration, \( Du(l) \), is often called the load-point outage duration, \( r(l) \). This thesis uses slightly different terminology for the following reasons:

- As illustrated in chapter 3, there is a fundamental conceptual difference between rate and frequency
- The term outage is usually used for a component that is unable to perform a required function

In a reliability analysis of a distribution system, for each enumerated contingency these indices are updated with the following algorithm.

1. **Determine the number of load levels adopted in the reliability evaluation, \( N^{LL} \).**
2. **Select a load point, \( l \).**
3. **If the load demand at the selected load point does not correspond with the actual load supplied, update the following indices, according to:**
   3.1. \( Fr(l) = Fr(l) + Fr/N^{LL} \).
   3.2. \( U(l) = U(l) + 8760 \cdot Pr/N^{LL} \).
3.3. \( Du(l) = U(l)/Fr(l) \).

4. Repeat steps 2 to 3 until all load points have been considered.

The three indices which are presented above are suitable for comparison with observed indices, presented in table 2.1. The load-point interruption frequency, \( Fr(l) \),[occ/yr] agrees with the load-point interruption frequency due to disturbances in MV and/or LV systems (measured in occasions per year). The load-point interruption duration, \( Du(l) \),[hr/occ] agrees with the load-point interruption duration due to disturbances in MV and/or LV systems (measured in minutes per occasion). The load-point annual unavailability, \( U(l) \), [hr/yr] agrees with the load-point annual unavailability due to disturbances in MV and/or LV systems (measured in minutes per year).

### 5.5 Compiling overall system indices

The last step of a probabilistic reliability assessment procedure comprises the compilation of overall system reliability indices. Such indices can be used to compare system structures of different sizes. System indices are calculated for the entire system or for a defined area in the system [50]. The relevant index is calculated on a global or area basis and not load point by load point.

#### 5.5.1 System indices for transmission systems

The following system indices for transmission systems are used in this thesis:

- Bulk Power Interruption Index, \( BPII \), [MW/MW·yr]: Total expected load curtailments in the system during the period of interest divided by the annual system peak load demand.

\[
BPII = \frac{\sum_{i=1}^{N^L} ELC(i)}{P_{d,peak}}
\]  

(5.77)

where:

\( N^L \)  the number of load points

\( P_{d,peak} \)  the annual system peak load demand
• Bulk Power Energy Curtailment Index, $BPECI$, [MWh/MW·yr]: Total energy not supplied by the system during the period of interest, divided by the annual system peak load demand.

$$BPECI = \frac{\sum_{i=1}^{N^L} EENS(i)}{p^{d, peak}}$$  \hspace{1cm} (5.78)

• Modified Bulk Power Curtailment Index, $MBPCI$, [MW/MW]: Total expected demand not supplied by the system divided by annual system peak load demand.

$$MBPCI = \frac{\sum_{i=1}^{N^L} EDNS(i)}{p^{d, peak}}$$  \hspace{1cm} (5.79)

• Severity Index, $SI$, [system min/yr]: Bulk Power Energy Curtailment Index multiplied by the number of minutes in one hour.

$$SI = 60 \cdot BPECI = 60 \frac{\sum_{i=1}^{N^L} EENS(i)}{p^{d, peak}}$$  \hspace{1cm} (5.80)

It is worth noting that one system minute is equivalent to interrupting the entire system during the annual peak load for one minute.

### 5.5.2 System indices for distribution systems

Overall distribution system performance indices can be calculated with the three basic load-point indices described in the foregoing section. The definitions and formulas for the system performance indices used in this thesis are:

• System Average Interruption Frequency Index, $SAIFI$, [customer interruptions/system customer·yr]: Total number of customer interruptions divided by the total number of customers served.
\[
SAIFI = \frac{\sum_{i=1}^{N_L} Fr(i) C_i}{\sum_{i=1}^{N_L} C_i}
\]  
(5.81)

where:
- \(C_i\) the number of customers at load point \(i\)
- \(N_L\) the number of load points

- System Average Interruption Duration Index, \(SAIDI\), [hr/yr]: Sum of customer hours of unavailable service divided by the total number of customers served.

\[
SAIDI = \frac{\sum_{i=1}^{N_L} U(i) C_i}{\sum_{i=1}^{N_L} C_i}
\]  
(5.82)

- Customer Average Interruption Duration Index, \(CAIDI\), [hr/customer interruption]: Sum of customer hours of unavailable service divided by the total number of customer interruptions.

\[
CAIDI = \frac{SAIDI}{SAIFI} = \frac{\sum_{i=1}^{N_L} U(i) C_i}{\sum_{i=1}^{N_L} Fr(i) C_i}
\]  
(5.83)

- Average Service Availability Index, \(ASAI\): Customer hours of available service divided by the customer hours demanded.

\[
ASAI = \frac{8760 \sum_{i=1}^{N_L} C_i - \sum_{i=1}^{N_L} U(i) C_i}{8760 \sum_{i=1}^{N_L} C_i}
\]  
(5.84)
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- Average Service Unavailability Index, $ASUI$: Customer hours of unavailable service divided by the customer hours demanded.

$$ASUI = \frac{\sum_{i=1}^{N^L} U(i) C_i}{8760 \sum_{i=1}^{N^L} C_i}$$  \hspace{1cm} (5.85)

- Energy Not Supplied, $ENS$, [kWh/yr]: Total energy not supplied by the system.

$$ENS = \sum_{i=1}^{N^L} U(i) P_{i,dav}$$  \hspace{1cm} (5.86)

where:

$P_{i,dav}$ the average load connected to load point $i$

- Average Energy Not Supplied, $AENS$, [kWh/system customer-yr]: Total energy not supplied by the system divided by the total number of customers served.

$$AENS = \frac{ENS}{\sum_{i=1}^{N^L} C_i}$$  \hspace{1cm} (5.87)

Again it should be noted that all the presented indices are not deterministic values but expected or average values of an underlying probability distribution. They only represent average long-term values.
'It is hard to make predictions, especially about the future.'

Y. Berra

Chapter 6

Calculation of reliability indices

This chapter deals with the contents of box 4 in figure 1.4: the calculation of reliability indices. In this chapter, the application of the models and techniques presented in the foregoing chapters is demonstrated. Several general studies for transmission and distribution systems are presented in the first two sections. Besides these general studies, two more specific studies concerning preventive maintenance in substations and manual network reconfiguration in a transmission system are presented in the following two sections. The system studies illustrate clearly that the predicted reliability indices agree to a large extent with observed indices of reliability for customers.

6.1 Transmission system studies

In this section, the models and techniques presented in the earlier chapters are applied to three different transmission systems. The first system is the famous IEEE Reliability Test System (RTS). The second system is a small, fictitious test system which is quite representative for Dutch 150 and 110 kV transmission systems. The third system is the 150 kV transmission system of PNEM, a public utility in the southern part of the Netherlands.
6.1.1 IEEE Reliability Test System

In 1979, the IEEE Reliability Test System (RTS) was developed by the Subcommittee on the Application of Probability Methods in the IEEE Power Engineering Society in order to provide a common test system which could be used for comparing the results obtained with different methods [51]. This section presents the calculation results of the RTS. Since the IEEE RTS was created, there have been many new developments in power-system reliability evaluation. Additional data or modifications were therefore required to extend the studies [52,53,54]. The most recent network topology of the RTS is given in figure 6.1.

The annual peak load demand in the RTS is 2850 MW. The total installed generation capacity in the system is 3405 MW. The generation reserve is thus 555 MW. The generation system is supposed to use various energy sources: fossil ones such as oil (951 MW) and coal (1274 MW), nuclear energy (800 MW), energy generated by combustion turbines (80 MW) and by hydro units (300 MW). All units are assumed to be totally reliable in this dissertation.

A comparison between the presented results in this subsection and results presented in earlier literature [52] is difficult or even impossible. This is due to the fact that reliability indices presented in earlier literature are obtained by using composite generation and transmission calculation techniques. The contribution of generating-unit failures is also taken into consideration in such studies and most of the time, an explicit presentation of the results is not given. Besides this, the results presented in earlier literature are nearly always presented as annualized indices and not as annual indices. With the help of annualized indices, the reliability indices are calculated for one load level and transformed to an annual basis.

The transmission system consists of 24 substations connected by 38 circuits (2 cables, 5 coupling transformers and 31 lines). The system is operated at two voltages (138 kV and 230 kV). The 230 kV-system is the top part of figure 6.1, with 230/138 kV-coupling transformers at substations 11, 12 and 24. There are several lines which are assumed to be on a common right-of-way or on a common tower for at least a part of their length. These pairs of lines are indicated in figure 6.1 by ellipses around the line pair and an associated letter identification. The system has voltage-correcting devices at substation 14 (synchronous condenser) and substation 6 (reactor). Details about the substation configurations are not presented in figure 6.1 because of lack of space. The detailed substation configurations can be found in [52].
Figure 6.1  Single-line diagram of the IEEE Reliability Test System (RTS)

In the reliability calculations which are presented in this thesis, the load variation is described by a load-duration curve of 10 steps, which is the same for all load points. The 10 steps are given in table 6.1. These individual steps are gathered from the adopted weekly, daily and hourly peak load data [51].
Table 6.1 Load steps in the load-duration curve of the IEEE RTS

The adopted reliability data of the components in figure 6.1 are presented in table 6.2 according to the definitions presented in chapter 3. Additional information of the whole system can be found in several references [51,52,53,54].

<table>
<thead>
<tr>
<th>Index</th>
<th>230 kV-line (1 mile)</th>
<th>138 kV-line (1 mile)</th>
<th>138 kV-cable (1 mile)</th>
<th>Transformer</th>
<th>Busbar section</th>
<th>Circuit breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \lambda_k ) [yr(^{-1})]</td>
<td>0.0034</td>
<td>0.0052</td>
<td>0.0062</td>
<td>0.020</td>
<td>--</td>
<td>0.0071</td>
</tr>
<tr>
<td>( \lambda_k^p ) [yr(^{-1})]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.0005</td>
</tr>
<tr>
<td>( \lambda_k^s ) [yr(^{-1})]</td>
<td>0.0034</td>
<td>0.0052</td>
<td>0.0062</td>
<td>0.020</td>
<td>--</td>
<td>0.0066</td>
</tr>
<tr>
<td>( \lambda_k^m ) [yr(^{-1})]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.20</td>
</tr>
<tr>
<td>( \lambda_{kl_{cc}} ) [yr(^{-1})]</td>
<td>0.00034</td>
<td>0.00052</td>
<td>0.00062</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>( r_k ) [hr]</td>
<td>18</td>
<td>9.0</td>
<td>96</td>
<td>768</td>
<td>--</td>
<td>37</td>
</tr>
<tr>
<td>( r_k^m ) [hr]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>108</td>
</tr>
<tr>
<td>( r_{k_{mc}} ) [hr]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>3.0</td>
</tr>
<tr>
<td>( r_{kl_{cc}} ) [hr]</td>
<td>28.8</td>
<td>14.4</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>( s_k ) [hr]</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>--</td>
<td>1.0</td>
</tr>
<tr>
<td>( Pr_{k_{scb}} )</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.010</td>
</tr>
</tbody>
</table>

Table 6.2 Component reliability data used in the reliability evaluation of the IEEE Reliability Test System (RTS)

Some of the load-point reliability indices are given in the figures 6.2 to 6.5. These are:
Chapter 6  Calculation of reliability indices

- Expected Number of Load Curtailments, \( ENLC(l) \), [occ/yr]
- Expected Duration of Load Curtailments, \( EDLC(l) \), [hr/yr]
- Average Duration of Load Curtailments, \( ADLC(l) \), [hr/occ]
- Expected Energy Not Supplied, \( EENS(l) \), [MWh/yr]

![ENLC(l)](image1)

**Figure 6.2** Calculated Expected Number of Load Curtailments for the IEEE RTS

![EDLC(l)](image2)

**Figure 6.3** Calculated Expected Duration of Load Curtailments for the IEEE RTS

Figures 6.2 to 6.5 show that single circuit failures can lead to load curtailment at the load point in substation 7. It is assumed that an isolated substation is not able to maintain stability (see also section 5.2.1). Therefore, the outage of the line between substations 7 and 8 results in the isolation of substation 7. The failure rate of that line is equal
to: $0.0052 \cdot l$ [51], where $l$ is the length of the line in miles. Since $l$ is 16 miles, the failure rate of the whole line is equal to 0.083 occasions per year. This amount can be found back in the Expected Number of Load Curtailments, $ENLC(l)$ in figure 6.2.

**Figure 6.4** Calculated Average Duration of Load Curtailments for the IEEE RTS

**Figure 6.5** Calculated Expected Energy Not Supplied for the IEEE RTS

Further, the results imply that the failure of a transformer inside a substation is the most important failure mode. Of course, this is caused by the reliability data adopted for a transformer. The failure rate of a transformer is equal to 0.02 occasions per year [51]. For most of the substations this contribution can be traced back to the Expected Number of Load Curtailments, $ENLC(l)$ in figure 6.2.
Transformer failures in the ENLC(l) of load points LD16 and LD17 contribute twice as much as the same failures in other substations do. This is due to the fact that these load points are supplied by two transformers operating in parallel, which are not individually protected by circuit breakers (see figure 6.6). Each transformer failure then results in the isolation of the load point. However, by performing switching actions in the substations, the electricity supply to these load points can be restored faster. This can be found back in the Average Duration of Load Curtailments, ADLC(l), presented in figure 6.4.

![Diagram](image)

**Figure 6.6** Single-line diagrams of substation configurations 19 and 20 of the IEEE Reliability Test System (RTS)

The Average Duration of Load Curtailments of the load points LD16 and LD17 is considerable lower than the same indices of the other load points. This is caused by the fact that the load points in the other substations are fed by only one transformer (see for example figure 6.7). Since it takes 768 hours on average to repair a transformer [51], the contribution of transformer failures to the duration indices is extremely important.

Further, it can be seen that the contribution of transformer failures to the Expected Number of Load Curtailments of load point LD8 is three times the contribution of transformer failures to other substations. This effect is due to the adopted busbar scheme of substation 8. This substation configuration is shown in figure 6.7. When a failure occurs in transformer T3 of substation 8, the circuit breakers B2 and B5 will
operate, causing the isolation of load point LD8 for the whole repair duration of that transformer.

![Diagram of electrical system](image)

**Figure 6.7** Detailed part of the IEEE Reliability Test System (RTS)

When a failure occurs in transformer T1 or T2 in substation 8, the circuit breakers B2, B5, B6 and B8 will operate, causing the isolation of load point LD8. Therefore, load point LD8 is influenced by three transformer failures. However, by isolating the faulted transformer (T1 or T2) from other substation equipment by opening the disconnecting switches around this component, load point LD8 can be supplied with electricity again.

The system indices for the IEEE reliability Test System (RTS) in figure 6.1 are given in table 6.3. The severity index, SI, is extremely high. This index is measured in system minutes per year. One system minute is the equivalent of interrupting the entire system
at the annual peak load for one minute. Therefore, one can be observe in table 6.3 that the Expected Energy Not Supplied at the individual load points is so high that the summation of this index for all the load points is equal to interrupting the system peak load for about twelve hours.

<table>
<thead>
<tr>
<th>Index</th>
<th>Case study</th>
</tr>
</thead>
<tbody>
<tr>
<td>BPII, [MW/MW·yr]</td>
<td>0.0565</td>
</tr>
<tr>
<td>BPECI, [MWh/MW·yr]</td>
<td>12.1</td>
</tr>
<tr>
<td>MBPCI, [MW/MW]</td>
<td>0.00138</td>
</tr>
<tr>
<td>SI, [system min/yr]</td>
<td>726</td>
</tr>
</tbody>
</table>

Table 6.3 System indices for the IEEE Reliability Test System (RTS)

From this study, it appears that substation transformer failures have considerable impact on the load-point reliability indices. It is questionable whether the substation topologies are really representative for real substations [51]. Due to the fact that in most of the substations the load is supplied by a single transformer, the reliability indices are mainly influenced by transformer failures. If the substation topologies are really true, it is questionable whether the repair duration of a transformer is representative for real situations. Perhaps a reserve transformer can be introduced in the substations. The following three figures present some results of the situation in which the substation transformers are assumed to be totally reliable. It can be clearly observed that their influence then disappears and other failure modes become more dominant.

![ENLC(l)](image)

**Figure 6.8** Calculated Expected Number of Load Curtailments for the IEEE RTS when the substation transformers are totally reliable
Figure 6.9 Calculated Expected Duration of Load Curtailments for the IEEE RTS when the substation transformers are totally reliable

Figure 6.10 Calculated Expected Energy Not Supplied for the IEEE RTS when the substation transformers are totally reliable

6.1.2 Small fictitious transmission system

To demonstrate the models and techniques for transmission systems further, a small fictitious test system is now considered. This system is representative for Dutch 150 and 110 kV transmission systems. Its single-line diagram is given in figure 6.11. It is
assumed that the system shown in figure 6.11 is operated at 150 kV. The normally open or closed positions of disconnecting switches and circuit breakers are given in the figure. Note that substation 2 is operated as a duplicate busbar scheme and one busbar is kept as reserve. It can also be seen that the load points LD1 to LD6, LD9 and LD10 are supplied by a single transformer. The third transformer serves as a spare one. The load points LD7 and LD8 are supplied by two parallel transformers.

![Diagram of a small fictitious transmission system]

**Figure 6.11** Single-line diagram of a small fictitious transmission system

The adopted reliability data of the transmission system components in figure 6.11 are presented in table 6.4. The main part of these data are obtained from Dutch component performance statistics [29]. However, the average switching duration of components, the probability of a stuck condition of a circuit breaker, the passive failure rate of a
Reliability evaluation of electric transmission and distribution systems

circuit breaker and the indices corresponding to common cause failures are estimated values. Such data cannot be found in Dutch component-performance statistics [29] and, therefore, have to be estimated. The active failure rate of a circuit breaker has been taken from an international enquiry on circuit-breaker failures and defects in service of Cigré [55]. The influence of scheduled maintenance is neglected. Therefore, the statistical data describing the scheduled maintenance processes are not presented in table 6.4.

<table>
<thead>
<tr>
<th>Index</th>
<th>Line (1 km)</th>
<th>Cable (1 km)</th>
<th>Transformer</th>
<th>Busbar section</th>
<th>Circuit breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \lambda_k ) [yr(^{-1})]</td>
<td>0.0021</td>
<td>0.0074</td>
<td>0.021</td>
<td>0.0020</td>
<td>0.0122</td>
</tr>
<tr>
<td>( \lambda_k^a ) [yr(^{-1})]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.010</td>
</tr>
<tr>
<td>( \lambda_k^c ) [yr(^{-1})]</td>
<td>0.0021</td>
<td>0.0074</td>
<td>0.021</td>
<td>0.0020</td>
<td>0.0022</td>
</tr>
<tr>
<td>( \lambda_k^{cc} ) [yr(^{-1})]</td>
<td>0.00021</td>
<td>0.00074</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>( r_k ) [hr]</td>
<td>38</td>
<td>194</td>
<td>321</td>
<td>2.0</td>
<td>37</td>
</tr>
<tr>
<td>( r_k^{cc} ) [hr]</td>
<td>24</td>
<td>24</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>( s_k ) [hr]</td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>( P_{rk}^{ce} )</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.010</td>
</tr>
</tbody>
</table>

Table 6.4 Observed and estimated component reliability data which are used in transmission-system studies for the small fictitious test system and the existing transmission system

The most important indices for the examined transmission system are given in the figures 6.12 to 6.14. These indices are:

- Expected Number of Load Curtailments, ENLC\((I)\), [occ/yr]
- Expected Duration of Load Curtailments, EDLC\((I)\), [hr/yr]
- Average Duration of Load Curtailments, ADLC\((I)\), [hr/occ]

In figures 6.12 to 6.14, one can observe that the Expected Number of Load Curtailments of load points LD7 and LD8 is relatively low. These load points do not have contributions of passive failures of circuit breakers and active failures of transformers. On the other hand, the contribution of overlapping circuit failures to the Expected Number of Load Curtailments is quite high compared to that of the other load points. This is of course mainly due to common cause failures of the two cables which supply substation 5. In table 6.4, one can observe that the common cause failure rate of 150 kV-cables is equal to 0.00074 occasions per year per kilometer. Since both circuits are 10 kilometers long, the total contribution of common cause failures is equal to 0.0074 occasions per year. This amount is also found in figure 6.12.
Figure 6.12 Calculated Expected Number of Load Curtailments for the small fictitious transmission system

Figure 6.13 Calculated Expected Duration of Load Curtailments for the small fictitious transmission system

On the other hand, it can be observed that the Average Duration of Load Curtailments for the load points LD7 and LD8 is quite high. This is due to the large value of the repair duration of cables and the lack of alternative supply options (substation 5 is fed by two cables from one other substation). Therefore, it can be concluded that a supply interruption on the load points LD7 and LD8 does not often occur, but if it occurs, the interruption takes a lot of time.
Further, it can be observed that the reliability indices of the load points \( LD1 \) and \( LD2 \) differ slightly. This effect is due to the unsymmetrical operation of substation 2 (see figure 6.11). Load point \( LD1 \) is connected to the busbar section in the middle of the substation configuration, while load point \( LD2 \) is supplied from the lower busbar section. The busbar section in the middle of the substation is directly connected to the components \( G5, L1, L2 \) and the coupling circuit breaker. The lower busbar section is connected to the components \( G6, L3 \) and the coupling circuit breaker. Since the busbar section in the middle is connected to more system components than the lower busbar, the contribution of stuck circuit breakers and active failures of circuit breakers will be more pronounced for the busbar section in the middle of the substation than for the lower busbar section. This effect can also be seen in the indices for load points \( LD1 \) and \( LD2 \).

### 6.1.3 Existing transmission system

To illustrate the models and techniques for transmission systems further, an existing transmission system is also considered. The 150 kV-transmission network of PNEM, a public utility in the southern part of the Netherlands, has been chosen. The simplified single-line diagram is given in figure 6.15. The system consists of 6 generation stations and 24 area supply stations.
Figure 6.15  Simplified single-line diagram of the 150 kV-transmission system of PNEM

Each substation (generation or area supply station) is modeled in a similar way as the small fictitious transmission system in the foregoing subsection. Each substation supplies one or several load points. The total number of load points in the system is equal to 56. Substations 7 and 8 have coupling lines with other regional transmission 150 kV-networks. The coupling between substation 7 and the neighboring network is normally closed. The network coupling between substation 8 and the neighboring system is normally open. In cases of emergency, this coupling can be closed. The adopted reliability data of the components in figure 6.15 are again given in table 6.4 [29]. The influence of scheduled maintenance is neglected, which has been done because data concerning scheduled maintenance processes lacked.

The individual load-point reliability indices are not presented. Instead, the average values for the following three important indices are given:

- Expected Number of Load Curtailments, $ENLC(i)$, [occ/yr]
- Expected Duration of Load Curtailments, $EDLC(i)$, [hr/yr]
- Average Duration of Load Curtailments, $ADLC(i)$, [hr/occ]
The average values of these three indices are presented in the second column of table 6.5. In the third column of the same table, observed indices of reliability for customers due to disturbances in high-voltage systems are presented. These data are gathered in the period 1992-1996 for the Dutch public utilities (see table 2.1). Table 6.5 shows that the calculation results agree quite well with observed indices of reliability for customers. It may be concluded that the improved and new-developed models and techniques to evaluate the reliability of transmission systems imitate real system behavior quite well.

<table>
<thead>
<tr>
<th>Index</th>
<th>Calculated</th>
<th>Observed</th>
</tr>
</thead>
<tbody>
<tr>
<td>ENLC, [occ/yr]</td>
<td>0.06</td>
<td>0.09</td>
</tr>
<tr>
<td>EDLC, [hr/yr]</td>
<td>0.041</td>
<td>0.048</td>
</tr>
<tr>
<td>ADLC, [hr/occ]</td>
<td>0.69</td>
<td>0.52</td>
</tr>
</tbody>
</table>

Table 6.5 Average values of the load-point reliability indices for the 150 kV-grid of PNEM

It can also be observed that the calculated Expected Number of Load Curtailments and the Expected Duration of Load Curtailments are slightly smaller than their observed equivalents. This difference can be caused by uncertainties in reliability input data of components and insufficient system modeling, such as the scheduling of the generating unit or by assuming that the generating units are totally reliable.

It is also worth noting that the calculated results are in principle adequacy indices and not security indices, i.e., supply interruptions due to the dynamic behavior of the system are not incorporated. The observed indices are associated with both adequacy and security aspects of the system and therefore do incorporate possible supply interruptions due to the dynamic behavior of the systems as well.

Since the relative difference between the calculated and observed Expected Number of Load Curtailments, \( ENLC(I) \), is greater than the relative difference between the calculated and the observed Expected Duration of Load Curtailments, \( EDLC(I) \), the calculated Average Duration of Load Curtailments, \( ADLC(I) \), is greater than its observed equivalent (see equation (5.70)).
6.2 Distribution system studies

This section demonstrates the application of the models and techniques for two different distribution systems [56]. The first system is a small, fictitious test system, which is rather representative for Dutch distribution systems. The second system is a 10 kV distribution system of PNEM, a public utility in the southern part of the Netherlands. The reliability indices of the distribution system components, which are used to perform the calculations, are given in table 6.6.

<table>
<thead>
<tr>
<th>Index</th>
<th>Cable (1 km)</th>
<th>Joint</th>
<th>Transformer</th>
<th>Busbar section</th>
<th>Circuit breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\lambda_k$</td>
<td>0.011</td>
<td>0.0018</td>
<td>0.00060</td>
<td>0.00020</td>
<td>0.0031</td>
</tr>
<tr>
<td>$\lambda_k^p$</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.0010</td>
</tr>
<tr>
<td>$\lambda_k^a$</td>
<td>0.011</td>
<td>0.0018</td>
<td>0.00060</td>
<td>0.00020</td>
<td>0.0021</td>
</tr>
<tr>
<td>$\lambda_{kl}^{cc}$</td>
<td>0.0011</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>$r_k$</td>
<td>24</td>
<td>8.0</td>
<td>12</td>
<td>20</td>
<td>12</td>
</tr>
<tr>
<td>$r_{kl}^{cc}$</td>
<td>24</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>$s_k$</td>
<td>1.5</td>
<td>1.6</td>
<td>2.1</td>
<td>1.9</td>
<td>1.6</td>
</tr>
<tr>
<td>$Pr_k^{scb}$</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.050</td>
</tr>
</tbody>
</table>

Table 6.6 Observed and estimated component reliability data which are used in the distribution-system studies

The data presented in table 6.6 have mainly been taken from Dutch data collection schemes of EnergieNed [17]. Certain data, such as the average repair duration of components, the probability whether a circuit breaker is stuck, the passive failure rate of a circuit breaker and the indices corresponding to common cause failures are estimated values. Such data can not be found in Dutch component-performance statistics [17] and have to be estimated. The influence of scheduled maintenance is neglected. Therefore, the statistical data describing the scheduled maintenance processes are not presented in table 6.6.

6.2.1 Small fictitious distribution system

It is assumed that the fictitious test system shown in figure 6.16 is operated at 10 kV and supplied from the high-voltage grid. The system comprises six load points and seven cables. It is assumed that the transformer between the high-voltage network and the medium-voltage distribution system that is studied is fully reliable. This assumption has been made to evaluate only the contribution of distribution-system failures. Note
that the system in figure 6.16 comprises a meshed-operated part and a radial-operated part. The disconnecting switch which forms the network separation is marked with a circle. Another common way to mark a network separation is using a small flag (see figure 6.16).

![Diagram of a small fictitious medium-voltage distribution system](image)

**Figure 6.16** Single-line diagram of a small fictitious medium-voltage distribution system

In figure 6.16, one can observe that the load points \(LD1\) and \(LD2\) are directly supplied from the meshed-operated part of the system. The other load points are supplied from the radial-operated part. It is assumed that each load point has a peak load demand of 500 kW. The variation in the load demand is described with a discretization of the load-duration curve of two steps. For 50 percent of the time, the load demand is equal to 500 kW. For the remaining 50 percent of the time, the load demand is equal to 250 kW.

Further, it is assumed that the meshed-operated part is designed and operated according to the so-called (n-1) criterion. This means that a first-order contingency due to a circuit failure may not result in a load-point disconnection due to isolation of over-
Chapter 6  Calculation of reliability indices

loaded circuits. The radial-operated part is designed with \((n-1)\) redundancy, but it is not operated according to this criterion. This means that a first-order contingency results in the isolation of one or several load points. But the duration of such a disturbance may be short because it is possible to undertake switching actions to restore the electricity supply.

The length of each cable is given in figure 6.16. It is assumed that each 250 m cable contains one joint. Further, it is assumed that the cables 1 and 2 are protected with distance protective relays and that all other circuit breakers in the figure are operated by overcurrent protective relays. It can be seen from the figure that the cables 1 and 2 are marked with an ellipse. This means that these cables can suffer so-called common cause failures because they are buried in the same groove.

For the distribution system presented in figure 6.16, four case studies are performed. These are treated below.

**Case study 1**
The first case study is the base case. The three following case studies of the test system are compared with this case. The indices showing how reliable the individual load points are supplied, are calculated with the reliability data, as in table 6.6. These indices are given in figure 6.17 to 6.19.

![Figure 6.17](image)  Calculated load-point interruption frequency for case study 1
Figure 6.18  Calculated load-point annual unavailability for case study 1

Figure 6.19  Calculated load-point interruption duration for case study 1

These figures show a lot of interesting details. First, it can be seen that the contribution of single circuit failures is different for several load points. The contribution in the load-point interruption frequency for the load points LD3 and LD5 is about a factor one and a half times the same contribution for the load points LD4 and LD6. This is due to the location of the network separation. The cable length with which the load points
Chapter 6 Calculation of reliability indices

LD3 and LD5 are supplied is 3 km long, while the cable length with which the load points LD4 and LD6 are supplied is 2 km long. The contribution of single circuit disturbances is zero for the load points LD1 and LD2. This is due to the fact that these load points are directly supplied from the meshed-operated part of the system. Since one 95 Cu-cable can supply all load points during the peak load situation, no single circuit failure can result in the isolation of the load points LD1 and LD2.

In figure 6.16, one can also observe that each cable is surrounded by two disconnecting switches. This means that the isolation of one or several load points due to a single outage of a circuit can be shortened by performing switching actions in the network. This is reached by isolating the faulted cable from the system and taking into service the other cables in order to restore electricity supply. Therefore, the contribution of such disturbances in the load-point interruption duration is relatively small. This is clearly illustrated in figure 6.19.

Secondly, it can be seen that the contribution of second-order overlapping circuit failures to the load-point interruption frequency is almost identical for all six load points. This is caused by the fact that the cables C1 and C2 can suffer common cause failures because they are buried in the same groove. A common cause failure of these cables results in a long-term isolation of all the load points in the system, since no switching actions can be performed to recover electricity supply. These effects are clearly illustrated in figure 6.17.

Thirdly, figure 6.17 shows that so-called passive failures contribute twice as much to the load-point interruption frequency of load points LD3 to LD6 than to that of load points LD1 and LD2. This can be explained as follows. The load points LD3 to LD6 are supplied by radial-operated feeders. In the feeder path of each of these load points two circuit breakers are connected in series (one in substation 2 and one to protect the MV/LV-transformer). However, the load points LD1 and LD2 only have one circuit breaker between substation 2 and the load point. Hence, the difference in the contribution of passive failures to the load-point interruption frequency of the load points LD1 and LD2 on the one hand and the load points LD3 to LD6 on the other hand.

Case study 2
In the second case study, it is assumed that the disconnecting switch at the location that is marked with a dot in figure 6.16 is absent. Therefore, when a failure occurs on cable C3, load point LD3 is interrupted for the whole repair time of cable C3. In the base case, the same fault situation resulted in the isolation of load point LD3 for only the mean switching duration of the cables involved in the switching process. Therefore, it may be expected that the duration indices of load point LD3, such as the load-point interruption duration and the load-point annual unavailability, are influenced and that
the reliability indices of the other load points remain the same. This is illustrated in figure 6.20 for example. In this figure, the load-point annual unavailability is shown. It can be clearly seen that the index of load point LD3 is severely influenced when the disconnecting switch is omitted. The indices of the other load points remain the same.

![Graph](image)

**Figure 6.20** Calculated load-point annual unavailability for case study 2

**Case study 3**

In the third case study of the fictitious test system, it is assumed that the capacity of the feeders in the radial-operated part is small compared to the load demand at the load points. It is assumed that only three load points can be supplied during the peak load situation by these feeders. This is for example true when smaller cables are used instead of the cables in the base case. It may then be expected that the reliability indices of the load points LD3 and LD4 are influenced. This effect is illustrated in the load-point annual unavailability of the load points in figure 6.21.

This can be explained as follows. A failure of cable C3 during the peak load situation leads to the interruption of load point LD3 for the whole duration of repair of the faulty cable section. It is then impossible to supply this load again by performing switching actions, since the capacity of the remaining feeder C4 is insufficient to feed the fourth load, load point LD3. For the same reasons, load point LD4 is also influenced when an active failure of cable C4 occurs. The load-point interruption frequency is not influenced since the transmission limits become active after a failure has occurred.
Figure 6.21  Calculated load-point annual unavailability for case study 3

Case study 4
In this case study, it is assumed that the failure rates of joints in the cables C4 and C6 are twice as large as their original failure rates. The failure rates of other joints remain the same. It may then be expected that the load points LD4 and LD6 are influenced. This is shown in the figures 6.22 and 6.23.

Figure 6.22  Calculated load-point interruption frequency for case study 4
Figure 6.23  Calculated load-point annual unavailability for case study 4

The indices of the entire system for the four case studies are presented in table 6.7.

<table>
<thead>
<tr>
<th>Index</th>
<th>Case study 1</th>
<th>Case study 2</th>
<th>Case study 3</th>
<th>Case study 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFI</td>
<td>7.82e-2</td>
<td>7.82e-2</td>
<td>7.82e-2</td>
<td>8.34e-2</td>
</tr>
<tr>
<td>SAIDI</td>
<td>3.31e-1</td>
<td>3.80e-1</td>
<td>3.89e-1</td>
<td>3.39e-1</td>
</tr>
<tr>
<td>CAIDI</td>
<td>4.23</td>
<td>4.86</td>
<td>4.98</td>
<td>4.07</td>
</tr>
<tr>
<td>ASUI</td>
<td>3.78e-5</td>
<td>4.34e-5</td>
<td>4.44e-5</td>
<td>3.87e-5</td>
</tr>
<tr>
<td>ENS</td>
<td>7.44e+2</td>
<td>8.55e+2</td>
<td>8.76e+2</td>
<td>7.64e+2</td>
</tr>
<tr>
<td>AENS</td>
<td>2.48e-1</td>
<td>2.85e-1</td>
<td>2.92e-1</td>
<td>2.55e-1</td>
</tr>
</tbody>
</table>

Table 6.7  System indices for the four case studies

6.2.2 Existing distribution system

Considering the results of case study 1 and the observed indices for existing systems in table 2.1, there is clearly little correspondence between the mean value of the frequency with which and the time during which a load point is interrupted. The mean value of the calculated load-point interruption frequency for the small fictitious test system is about the half of the mean value of load-point interruption frequency observed in reality, while the mean value of the calculated load-point interruption duration is about double the mean value of the load-point interruption duration observed in
Chapter 6 Calculation of reliability indices

reality. It is therefore interesting to determine whether these conclusions are also valid for existing medium-voltage distribution networks. An existing distribution system is considered in this subsection. The single-line diagram of the system is shown in figure 6.24.

![Single-line diagram of an existing distribution system](image_url)

**Figure 6.24** Single-line diagram of an existing distribution system

The network shown in figure 6.24 contains again a meshed-operated part and a radial-operated part. The small black circles represent the load points in the distribution system. Such a load point consists of two disconnecting switches connected in series, and between both switches a distribution transformer. The network separations are marked with flags. It can be observed in the figure that the load points are supplied by six radial-operated feeders. To keep the figure surveyable, the load points are equally spaced. In reality, the distances between the load points are not equal.
The load-point interruption frequency is given in figure 6.25. The load-point annual unavailability is presented in figure 6.26 and the load-point interruption duration is shown in figure 6.27.

![Graph showing load-point interruption frequency](image)

**Figure 6.25** Calculated load-point interruption frequency for the real distribution system

In figure 6.25, it can be seen that there are six levels for the index. Each level corresponds with a feeder. All load points in the same feeder have the same load-point interruption frequency. For example, the load points LD1, LD2, LD8 and LD10 have the same value. This feeder is relatively long compared to the other feeders and therefore the interruption frequency of these load points is quite high. The number of load points in this feeder is limited for reasons of voltage drops over the long cable lengths.

In figure 6.26, it can be observed that several load points have a larger load-point annual unavailability than other load points. This is due the fact that for these load points it is not possible to bypass a failure by performing switching actions in the system. This can be seen when the network configuration is inspected. When, for example, a failure on the cable between load point LD28 and load point LD29 occurs, load point LD29 becomes isolated during the entire time the cable is repaired. The same goes for the load points LD30, LD31, LD32, LD33 and LD42.
Chapter 6  Calculation of reliability indices

Figure 6.26  Calculated load-point annual unavailability for the real
distribution system

Figure 6.27  Calculated load-point interruption duration for the real
distribution system

The average values of the calculated load-point indices presented in the figures 6.25 to 6.27 are given in the second column of table 6.8. In the third column of the same table,
observed indices of reliability for customers due to disturbances in medium-voltage systems are presented. These indices were gathered in the period 1992-1996 for the Dutch public utilities (see table 2.1).

<table>
<thead>
<tr>
<th>Index</th>
<th>Calculated</th>
<th>Observed</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Fr$, [occ/yr]</td>
<td>0.18</td>
<td>0.21</td>
</tr>
<tr>
<td>$Du$, [min/occ]</td>
<td>104</td>
<td>75</td>
</tr>
<tr>
<td>$U$, [min/yr]</td>
<td>19</td>
<td>16</td>
</tr>
</tbody>
</table>

Table 6.8 Average values of the load-point reliability indices for an existing distribution system of PNEM

In table 6.8, one can see that the calculation results agree well with reliability indices, that were observed in reality. Studies of other existing distribution systems have shown similar results. Therefore it may be concluded that the improved and new-developed models and techniques for the reliability evaluation of distribution systems imitate real system behavior quite well.

It can be observed that the calculated duration indices, such as the load-point interruption duration and the load-point annual unavailability, are slightly larger than the corresponding observed indices. This difference can be caused by uncertainties in reliability input data of components and/or by insufficient system modeling.

### 6.3 Scheduled maintenance in substations

The goal of performing scheduled maintenance in power systems is to keep the component-failure rates down and, hence, the probability and frequency of component outages low. In chapter 3, it was mentioned that scheduled maintenance activities can increase the number of system failures, because the condition of the system is weakened during the maintenance periods. Of course, performing scheduled maintenance is based on the assumption that the beneficial aspects outweigh the adverse effects. This section demonstrates that it is possible to show the beneficial effects of performing scheduled maintenance.

Current scheduled maintenance practices are usually based on a fixed time interval between maintenance periods. These fixed time intervals are often based on rules-of-thumb. A fundamental motivation for doing revisions and overhauls after the passing
of a certain period is usually absent. Besides this, many public utilities have increased the interval between circuit-breaker and protection-system maintenance periods in order to reduce expenditure. Public utilities pay more and more attention to cost reduction while at the same time they attempt to provide the desired level of customer service. Another reason for increasing the interval between maintenance periods is the fact that during the maintenance activities, sometimes failures and irregularities are introduced by the service crew of the manufacturer or the public utility.

However, it is questionable whether such developments are desirable from the viewpoint of reliability. The increase in the interval between maintenance activities on circuit breakers and protection systems does reduce costs on the short term, but can have considerable negative effects on system reliability on the long term. It is often felt that it is a difficult task to determine the positive or negative influence of performing scheduled maintenance on circuit breakers and protection systems. The need for the determination of optimal maintenance frequencies has increased. This section describes an approach to evaluate the effect on substation reliability of performing scheduled maintenance on circuit breakers and protection systems.

Maintenance activities on circuit breakers and protection systems may comprise the following actions:

- The circuit breaker is commanded to trip.
- The protective relay including the tripping coil circuit is tested by adding test voltages and currents to the protective relay in order to simulate several short-circuit conditions.
- In the case of an oil breaker, an oil sample is taken from the circuit breaker which is visually inspected. Sometimes the oil breakdown voltage is also determined.
- When the circuit breaker and the protection system pass the foregoing three inspection activities successfully, the circuit-breaker mechanism is lubricated and the circuit breaker is taken into service again.
- When one or more of the first three inspection activities give a negative result, the circuit breaker and the protection system are taken out of service for a longer period of repair.

However, sometimes irregularities are introduced by the manufacturer or public utility service crew. The service crew can, for example, forget to connect the secondary windings of the current transformers with the protective relay. These secondary windings are normally short-circuit during the maintenance period. Due to such a mistake, the circuit breaker will fail to operate when the operation is called for. A detailed knowledge of the whole protection system which consists of one or several protective relays, current and voltage transformers, is essential to the protection engineer, but from an overall point of view, the measurement transformers, the protective relay(s)
and the circuit breaker can be treated as one single component. Therefore, in this section these subsystems are simply referred to as the circuit breaker or as $b$.

This section considers the effects on the reliability indices of electricity supply that scheduled maintenance on circuit breakers and protection systems can have. The aim of performing scheduled maintenance on circuit breakers and protection systems is to reduce the probability of a failure to operate. The less the maintenance frequency is, the higher will be the probability of a failure to operate. On the other hand, it has to be recognised that the probability and frequency of overlapping outages increase when the frequency of performing scheduled maintenance on circuit breakers and protection systems increases. Therefore, an optimum scheduled maintenance frequency may be expected. This section shows that an optimal scheduled maintenance frequency can be deduced for various substation configurations, provided that the maintenance process is carried out carefully. It is also demonstrated that carelessly performed scheduled maintenance can even lead to a decrease in the reliability of the electricity supply.

Performing maintenance on a circuit breaker and its protective equipment to reduce the probability that these fail to operate can be modeled by means of the state-space diagram, that is given in figure 6.28. This figure shows the detailed states of circuit breaker $b$. The individual states in the Markov model of figure 6.28 can be described as follows.

![Multi-state Markov model representing preventive maintenance on a circuit breaker and its protection system](image)

Figure 6.28 Multi-state Markov model representing preventive maintenance on a circuit breaker and its protection system

State 1 represents usual operation with circuit breaker $b$ in the UP state. If circuit breaker $b$ suffers a failure to operate while in state 1, there is a transition to state 5. In state 5, circuit breaker $b$ is not ready to respond to active failures (short-circuit fail-
ures). If a component in the primary protection zone of circuit breaker \( b \) suffers an active failure while the breaker is in state 5, this failure is not detected and back-up circuit breakers must respond to isolate this fault situation. These actions cause a transition to state 3. Circuit breaker \( b \) must then be inspected, and from this point, \( b \) is repaired to the \( UP \) state.

The scheduled maintenance states are given by states 2 and 6. In state 2, circuit breaker \( b \) is inspected from the \( UP \) state with inspection rate \( \theta_{b^{\text{insp}}} \). In state 6, breaker \( b \) is inspected from the \( DN \) state with inspection rate \( \theta_{b^{\text{insp}}} \). When circuit breaker \( b \) is in state 6 and the scheduled maintenance process is carried out carefully, the situation of a failure to operate is detected, and breaker \( b \) must be repaired. These actions cause a transition to state 1 via state 4. The effect of unsuccessful inspection is taken into account by the probability, \( Pr_b^{\text{ui}} \). When this probability is equal to zero, all inspections lead to a transition to the \( UP \) state. When \( Pr_b^{\text{ui}} \) is equal to one, all inspections lead to a transition to the failure-to-operate state (state 5).

Consider the four different busbar schemes of figure 6.29 and the reliability data in table 6.9 [23,57]. In each configuration, the load points \( LD1 \) and \( LD2 \) are supplied by two transmission lines \( L1 \) and \( L2 \) via different busbar schemes. The length of each line is assumed to be 10 km. The inspection duration of each circuit breaker and its corresponding protection system, \( r_b^{\text{insp}} \), is estimated as two hours. The average duration of a period of thorough repair of the circuit breaker and its corresponding protection system, \( r_b \), is estimated as 40 hours (see table 6.9).

<table>
<thead>
<tr>
<th>Index</th>
<th>Line (10 km)</th>
<th>Transformer</th>
<th>Busbar section</th>
<th>Circuit breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \lambda_k ) \hspace{1cm} [yr(^{-1})]</td>
<td>0.0265</td>
<td>0.0248</td>
<td>0.00170</td>
<td>0.0246</td>
</tr>
<tr>
<td>( \lambda_k^{p} ) \hspace{1cm} [yr(^{-1})]</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>0.0100</td>
</tr>
<tr>
<td>( \lambda_k^{a} ) \hspace{1cm} [yr(^{-1})]</td>
<td>0.0265</td>
<td>0.0248</td>
<td>0.00170</td>
<td>0.0146</td>
</tr>
<tr>
<td>( r_k ) \hspace{1cm} [hr]</td>
<td>30.0</td>
<td>389</td>
<td>16.0</td>
<td>40.0</td>
</tr>
<tr>
<td>( s_k ) \hspace{1cm} [hr]</td>
<td>0.500</td>
<td>0.500</td>
<td>0.500</td>
<td>0.500</td>
</tr>
</tbody>
</table>

**Table 6.9** Reliability data of the substation components

The data of the busbar sections as given in table 6.9 are only valid for the thick busbar sections in figure 6.29. The corresponding active failure rates of the thin busbar sections in figure 6.29 are assumed to be equal to zero.
Figure 6.29 Single-line diagrams of four different busbar schemes

Figures 6.30 and 6.31 show the indices of the probability and frequency that a load point is disconnected, for the busbar schemes given in figure 6.29. These probabilities and frequencies are functions of the inspection interval (or maintenance frequency, which is the reciprocal value of the inspection interval). Both indices are calculated for several values of the probability of unsuccessful inspection, $P_{ru}$. 

In figure 6.30 and 6.31, it can be seen that the reliability of the one-and-a-half breaker substation configuration (figure 6.29d) is high compared to the reliability of the other substation configurations. The reliability of the duplicate busbar substation configuration (figure 6.29c) is almost equal to the reliability of the four-breaker mesh substation configuration (figure 6.29b). It should be noted that all lines in the graphs converge to a value which corresponds to never performing scheduled maintenance (inspection intervals equal to or greater than 100 years).
Because public utilities pay more and more attention to cost reduction while at the same time they attempt to provide the desired level of customer service, it is required that the expected energy to be not supplied is related to costs. When the interruption energy assessment rate [14] for the load points LD1 and LD2 and the costs of scheduled maintenance are given, the results presented in figure 6.30 can be easily converted into expected total cost per year [14] as a function of the maintenance interval (or maintenance frequency).

Figures 6.30 and 6.31 also show clearly that an optimal maintenance interval can be determined for component protection systems if scheduled maintenance is carried out carefully. When scheduled maintenance is not carried out carefully, it is meaningless. In the figures it appears that failures to operate of circuit breakers or protection systems have a lot of impact on substation reliability. This is due to the fact that a lot of power-
system components become isolated at the same time due to back-up clearing behavior of other circuit breakers. However, the probability of a failure to operate can be reduced considerably by maintaining these components on a regular basis.

\[ F_r(\text{load is disconnected}) \]

\[ \begin{align*}
  \text{Prob} & = 0.10 \\
  \text{Prob} & = 0.05 \\
  \text{Prob} & = 0.00
\end{align*} \]

\[ \text{[occ/yr]} \]

\[ 10^{-1} \quad 10^0 \quad 10^1 \]

\[ \text{Inspection interval [yr]} \]

\[ F_r(\text{load is disconnected}) \]

\[ \begin{align*}
  \text{Prob} & = 0.10 \\
  \text{Prob} & = 0.05 \\
  \text{Prob} & = 0.00
\end{align*} \]

\[ \text{[occ/yr]} \]

\[ 10^{-1} \quad 10^0 \quad 10^1 \]

\[ \text{Inspection interval [yr]} \]

\[ F_r(\text{load is disconnected}) \]

\[ \begin{align*}
  \text{Prob} & = 0.10 \\
  \text{Prob} & = 0.05 \\
  \text{Prob} & = 0.00
\end{align*} \]

\[ \text{[occ/yr]} \]

\[ 10^{-1} \quad 10^0 \quad 10^1 \]

\[ \text{Inspection interval [yr]} \]

Figure 6.31 Frequency with which load points are disconnected as a function of the inspection interval for the busbar schemes presented in figure 6.29

An optimal scheduled maintenance interval or frequency can be determined for component protections if scheduled maintenance is carried out carefully. This optimal interval or frequency is dependent on the substation topology. The optimal maintenance frequency is greater when one looks for reliability than for economy. In the latter, a cost-penalty function is taken into account, which is inversely related to the inspection interval. This results in a decrease in the optimal maintenance frequency.
Chapter 6  Calculation of reliability indices

6.4 Network reconfiguration in a transmission system

This section demonstrates the effects of network reconfiguration in a transmission system. As mentioned in chapter 5, it is sometimes possible to overcome or limit circuit overloads in the network by network reconfiguration actions. Switching refers to a control action which brings the network from an overloaded state back to an acceptable state by adding or removing one or more circuits from the system. Such control means are usually not considered in traditional computer programs for power-system reliability evaluation. Although in practice, network reconfiguration will normally be considered as a logical step before generation redispach and/or load shedding. To demonstrate the application of the network reconfiguration algorithm as described in the foregoing chapter, two case studies have been performed [58].

6.4.1 Case study 1

The single-line diagram of the studied system is given in figure 6.32. The system comprises an EHV-grid (380 kV) and two regional 150 kV-networks, which are fed as pockets (single point infeed) from the EHV-grid. The coupling between these networks is normally opened. The load situation at the substations, the corresponding generation schedule and the results of the DC load flow are given in the figure. Further, it is assumed that substation 1 is connected to the rest of the EHV-grid (slack node). The two separated 150 kV-networks represent simplified transmission networks of regional electricity companies.

As mentioned before, it is assumed that the networks of both regional electricity companies are preferably disconnected. Only if there is an extreme emergency (for example substation isolation), the networks will be connected. Therefore, the value of $\beta$, (see equation (5.39)) is chosen as 1.0 for switching circuits in and 0.1 for switching circuits out. In both case studies, only effects of failures of transmission system equipment are considered.

In this study, the difference between the usual reliability assessment approach and the new reliability evaluation approach is demonstrated. In the usual approach, circuit overloads are directly alleviated by generation rescheduling and, if necessary, by load shedding. In the new approach, manual network reconfiguration is applied before generation rescheduling and load shedding to alleviate circuit overloads. For each substation $s$, three indices are presented:

- Probability of Load Curtailment, $PLC(s)$
- Expected Number of Generation Redispaches, $ENGR(s)$
- Expected Energy Not Supplied, $EENS(s)$
Figure 6.32 Single-line diagram of the system that is studied

The indices calculated for case study 1 are given in table 6.10. In this table one can see that incorporating network reconfiguration in a reliability evaluation procedure can have considerable influence on the reliability indices of certain substations, such as the Probability of Load Curtailment, $PLC(s)$ and the Expected Energy Not Supplied, $EENS(s)$. The calculated indices of substations 6 and 8 are considerably lower when the proposed approach is implemented. Also, the total Expected Energy Not Supplied in the system decreases considerably.

When, for example, a common cause failure of the lines between substations 2 and 8 occurs, the line between substations 2 and 6 will become overloaded. In the normal approach, this would lead to load curtailment. In the new approach, however, the line between substations 6 and 8 is switched out, resulting in a change in the network topology and the overloaded line is alleviated. Network reconfiguration can also have influence when failures occur in substations. If, for instance, a failure occurs in substation 2 which leads to a complete isolation of it, substation 6 can be supplied from the left-hand side of the system when the lines between substations 5 and 6 are switched in.

Besides the increase in power-system reliability, a reduction is obtained in the Expected Number of Generation Redispatches, $ENGR(s)$. This means a reduction in
electricity production costs, since it is less often necessary to deviate from the optimal production schedule.

<table>
<thead>
<tr>
<th>Substation</th>
<th>Without network reconfiguration</th>
<th>With network reconfiguration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( PLC(s) )</td>
<td>( ENGR(s) )</td>
</tr>
<tr>
<td></td>
<td>[occ/yr]</td>
<td>[p.u./yr]</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>2.17e-6</td>
<td>6.17e-2</td>
</tr>
<tr>
<td>3</td>
<td>2.33e-6</td>
<td>6.17e-2</td>
</tr>
<tr>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>1.86e-5</td>
<td>0</td>
</tr>
<tr>
<td>6</td>
<td>3.50e-5</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>1.85e-6</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>2.35e-6</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 6.10 Results of case study 1

6.4.2 Case study 2

In this study it is assumed that more generation at the left-hand side of the system is installed. If unit \( G5 \) is connected to the system, the injected power at substation 2 increases from 6.0 p.u. to 9.0 p.u. Then it becomes preferable to connect both networks to reduce transmission losses.

The indices calculated for case study 2 are given in table 6.11. Due to the connection of generating unit \( G5 \) to substation 3, an extra circuit-breaker failure and an extra transformer failure combined with a stuck circuit breaker are introduced at this substation. Also the circuit breakers in substation 6 (being in service now) introduce extra substation-originated contingencies. Therefore, several indices in table 6.11 increase in respect to the indices in table 6.10. However, note that the total Expected Energy Not Supplied in the system reduces because of the extra generation facility inside the left regional network.

A considerable influence on the reliability indices of certain substations can be seen when network reconfiguration is taken into account. The calculated indices of substations 5, 6 and 7 decrease considerably. A reduction is also obtained in the Expected Number of Generation Redispitches, \( ENGR(s) \).
Table 6.11 Results of case study 2 (extra generating unit G5)

If, for example, a common cause failure of the lines between substations 3 and 7 occurs, the lines between substations 3 and 5 will become overloaded. It is then preferred that the lines between the substations 5 and 6 are then switched out, resulting in a change in the network topology. This means that the transported power over the EHV-grid increases to (9.0 - 6.4 =) 2.6 p.u., but in this case this is not a problem.

From the previous results it can be concluded that in the evaluation of the reliability of transmission systems, network reconfiguration should be considered as a logical step before generation redispatch and/or load shedding are applied. This section shows that incorporation of network reconfiguration in transmission system reliability evaluation has considerable influence on the evaluated reliability indices of the power supply, such as the Probability of Load Curtailment, \( PLC(s) \), and the Expected Energy Not Supplied, \( EENS(s) \).

Besides the increase in power-system reliability, a reduction of the Expected Number of Generation Redispaches, \( ENGR(s) \) can be obtained. This means a reduction of the corresponding electricity production costs, since it is less often necessary to deviate from the optimal production schedule. The proposed concepts for use in power-system reliability evaluation improve previously developed concepts.
'Let us hear the conclusion of the whole matter: Fear God and keep his commandments: for this is the whole duty of man. For God shall bring every work into judgment, with every secret thing, whether it be good, or whether it be evil.'

Ecclesiastes 12: 13-14

Chapter 7

Conclusions and suggestions

7.1 Conclusions

The central theme of the dissertation is ‘the development of new or improved models and techniques to predict electric transmission and distribution system reliability indices that agree with observed indices of reliability for customers’. Reliability can be quantified with three basic indices: probability, frequency and duration indices. Several new or improved models and techniques which can be used in the calculation of such indices were presented and discussed. This thesis proved that the calculated reliability indices agree to a great extent with observed reliability indices when the presented models and techniques are used.

The validity of a reliability analysis is directly related to the models used to represent system behavior. Neglecting effects, like manual network reconfiguration in order to alleviate circuit overloads and switching actions in substations in order to restore electricity supply to customers, has serious consequences for predicting reliability indices. Further, it has been demonstrated that the reliability of a distribution system is not only influenced by single failures of feeders, but also by other failure modes, such as common cause failures, stuck circuit breakers and other circuit-breaker failure modes.

Dutch performance statistics show that generally distribution systems are responsible for 80 percent of the unavailability of supply to a customer and contribute as much as 68 percent toward the frequency of interruption of power supply to a customer. Each
improvement in reliability, however, entails higher costs. A general improvement in reliability at the distribution level will usually require more expenditure than achieving the same improvement at the transmission level.

On the other hand, it is quite useless to reinforce relatively strong parts of the whole system while neglecting weak ones. Therefore, a balance is required between generation, transmission and distribution system reliability. It is worth noting that reliability should be considered as a constraint and not as an objective which has to be optimized. In fact, the basic function of an electric power system is to supply customers with electrical energy as economically as possible and with an acceptable quality.

The proposed models and techniques yield powerful tools for the prediction of quantitative reliability indices of electric transmission and distribution systems. Quantitative reliability evaluation studies enhance the quality of managerial decision-making processes by providing quantitative measures of system reliability. The indices can be used to select the most appropriate reinforcement scheme from alternative concepts. They can also be used to evaluate the effect of different operating policies and the influence of various maintenance strategies.

The field of the reliability evaluation of electric transmission and distribution systems develops in the direction of valuable practical applications. Suitable modeling techniques, which are incorporated in user-friendly computer programs, become increasingly available. As a consequence, the use of these techniques will become a part of the planning and operating processes of the Dutch public utilities and industries. This will result in better and more efficiently design of their systems. Tailor-made solutions can be offered and implemented more and more with the knowledge that the electric transmission and distribution systems have been checked for almost all possible contingencies.

7.2 Suggestions for future research

In this thesis a basis has been described for the quantitative reliability evaluation of electric transmission and distribution systems. In the following areas some questions or problems still arise:

Performance statistics
The current performance statistics of transmission systems should be extended to include more data, such as: the average switching duration of a component involved in the electricity supply restoration process, the probability of a stuck circuit breaker and the
Chapter 7  Conclusions and suggestions

passive failure rate of a circuit breaker. Also data describing the influence of weather effects, common cause related failures and scheduled maintenance activities should be incorporated [59].

The current performance statistics for distribution systems should be extended to include the average repair duration of components, the probability of a stuck circuit breaker and the passive failure rate of a circuit breaker. Also data describing the influence of common cause related failures and scheduled maintenance activities should be incorporated. The distribution equipment in the Netherlands is usually not exposed to varying weather conditions because all circuits are cables which are buried. On the other hand, a lot of disturbances in distribution circuits are caused by digging activities. In the same way as for varying weather conditions, statistics could be gathered for varying digging conditions.

Voltage control and reactive power
An aspect which is not described in this thesis is the modeling of severe voltage deviations and voltage-control actions. In this dissertation, a DC load-flow algorithm has been presented in order to evaluate selected system states. Overvoltages, undervoltages and reactive power limitations of certain equipment are neglected in such a load-flow investigation. However, in practice, severe system failures can arise due to such phenomena. On the other hand, the modeling of the system becomes more and more complex and calculation times will increase considerably when such aspects are incorporated. In fact, it is then necessary to incorporate the quasi-static behavior of the system in the reliability analyses.

Scheduled maintenance
This dissertation has presented a basis for evaluating the effects of scheduled maintenance on circuit breakers and protection systems on substation reliability. A lot of other transmission and distribution system components also undergo periodic preventive maintenance. The modeling of such maintenance practices usually results in a decrease in system reliability due to the fact that the probability of overlapping outages increases. However, preventive maintenance is done in order to improve the reliability of the system by keeping failure rates down. Preventive maintenance is performed based on the assumption that the advantages outweigh the disadvantages. The beneficial effects are usually not considered in existing reliability calculations. A thorough study of such phenomena can be an interesting topic for further research.
Model validation
Up to now, reliability calculation results were considered to be qualitative. However, it
was shown in this thesis that the calculation results correspond quite well with reliability
indices that were observed for existing systems. The proposed concepts and models
should be applied, validated and perhaps improved in the evaluation of various existing
systems and in the design of future systems.

Scheduling and reliability of generating units
In this dissertation, the scheduling of generating units was based on an equal percentage
reserve at each generation station. It was also assumed that all generating units were
continuously available. It is obvious that these assumptions are not realistic. Further
research on modeling the generation schedule will certainly improve the validity of the
calculation results. Note that new-proposed methods may not greatly increase computa-
tion times.

The problem of generation scheduling arises particularly when dispersed generating units
in distribution systems are incorporated in the reliability analysis of such systems.
Dispersed generating units are getting increasingly important. These units are often
connected to the medium-voltage networks, due to their capacity of up to one or several
megawatts. Examples of such units are wind turbines and co-generation plants.

Particularly co-generation plants produce electrical energy and heat in a very efficient and
inexpensive way. These units are mainly used in public buildings, hospitals, factories and
greenhouses in order to supply the local demand for heating. Therefore, the scheduling
of such units is closely related to the demand for heating. The evaluation of the impact of
such small units on distribution system reliability appears to be complicated and,
therefore, certainly deserves further investigation in the near future [60].

How reliable?
Other aspects which are not considered in this thesis are the questions how reliable the
system should be and what expectations customers have. A research project on the needs
and desires of different customers can give answers to such questions. Of course, there
has to be made a trade-off between the desired level of reliability and the costs.
Systematic research on consumer desires and needs should take this relation into account.
References


Reliability evaluation of electric transmission and distribution systems


References


List of symbols and abbreviations

Reliability related indices

\( Pr(E) \)  
probability of occurrence of contingency \( E \)

\( Fr(E) \)  
frequency of occurrence of contingency \( E \)

\( Du(E) \)  
duration of contingency \( E \)

\( t_{i_{UP}} \)  
time spent in the \( UP \) state before the occurrence of failure \( i \)

\( t_{i_{DN}} \)  
time spent in the \( DN \) state after the occurrence of failure \( i \)

\( N_k \)  
number of failures of component \( k \)

\( MTTF_k \)  
mean time to failure of component \( k \)

\( MTTR_k \)  
mean time to repair of component \( k \)

\( MTBF_k \)  
mean time between failures of component \( k \)

\( \lambda_k \)  
failure rate of component \( k \) \( (\lambda_k = \lambda_k^p + \lambda_k^a) \)

\( \lambda_k^p \)  
passive failure rate of component \( k \)

\( \lambda_k^a \)  
active failure rate of component \( k \)

\( \lambda_k^m \)  
scheduled outage rate of component \( k \)

\( \lambda_{kl}^{cc} \)  
common cause outage rate of components \( k \) and \( l \)

\( r_k \)  
average repair duration of component \( k \)

\( r_k^m \)  
average maintenance duration of component \( k \)

\( r_k^{imp} \)  
average inspection duration of component \( k \)

\( r_k^{mco} \)  
average maintenance cutoff duration of component \( k \)

\( r_k^{cc} \)  
common cause repair duration of components \( k \) and \( l \)

\( s_k \)  
average switching duration of component \( k \) involved with electricity supply restoration

\( \mu_k \)  
repair rate of component \( k \)
Reliability evaluation of electric transmission and distribution systems

\( \mu_k^m \) maintenance rate of component \( k \)
\( \mu_k^c \) maintenance cutoff rate of component \( k \)
\( \mu_{kl}^c \) common cause repair rate of components \( k \) and \( l \)
\( \tau_{ik} \) transition rate from state \( i \) to state \( k \)
\( P_{k}^{scb} \) probability of a stuck condition of circuit breaker \( k \)
\( P_{k}^{ui} \) probability of unsuccessful inspection of component \( k \)
\( T \) matrix of transition rates
\( T' \) matrix obtained from matrix \( T \) by replacing the elements of an arbitrarily selected row \( p \) by ones

\( P \) column vector whose \( i^{th} \) term is the probability of residing in state \( i \)
\( C \) column vector with the \( p^{th} \) element equal to one and other elements set to zero

Subsets and numbers

\( S_{s}^{LC} \) subset of system states associated with load curtailment at substation \( s \)
\( S_{l}^{LC} \) subset of system states associated with load curtailment at load point \( l \)
\( S_{l}^{ISO} \) subset of system states associated with isolation of load point \( l \)
\( S_{s}^{NILP} \) subset of non-isolated load points in substation \( s \)
\( S_{s}^{NIS} \) subset of non-isolated substations
\( S^{SC} \) subset of all circuits which are switched in or out of service during the switching process

\( N_s \) number of substations
\( N_{G} \) number of generating substations
\( N_{L} \) number of load points
\( N_{C} \) number of circuits
\( N_{LL} \) number of load levels adopted in the reliability evaluation study
\( C_{i} \) number of customers at load point \( i \)
\( N_{LGLD1} \) number of lines, generators and/or loads which are isolated before performing switching actions
\( N_{LGLD2} \) number of lines, generators and/or loads which are isolated after performing switching actions

Network related indices

\( P_{s}^{d} \) active load demand at substation \( s \)
\( P_{d,tot} \) total active load demand
\( P_{s}^{g} \) active generation at substation \( s \)
\( P_{i}^{g,max} \) maximum available active generation at substation \( s \)
\( P_{g,tot} \) total available active generation
\( P_{i}^{d,av} \) average active load connected to load point \( i \)
\( P_{i}^{d,peak} \) peak load demand at load point \( i \)
List of symbols and abbreviations

$P_{d, \text{peak}}$ annual system active peak load demand

$P_{s}^{\text{LC}}(i)$ load curtailment in state $i$ at substation $s$

$P_{l}^{\text{LC}}(i)$ load curtailment in state $i$ at load point $l$

$P_{s} = P_{s}^{d} + P_{s}^{g}$ active power injection at substation $s$

$Q_{s}^{d}$ reactive load demand at substation $s$

$Q_{s}^{g}$ reactive generation at substation $s$

$Q_{s} = Q_{s}^{d} + Q_{s}^{g}$ reactive power injection at substation $s$

$LDC_{i}(l)$ load-duration curve of load point $i$ as a function of load step $l$ in per unit

$V_{s}$ magnitude of the voltage at substation $s$

$G_{ij}$ real part of element $i,j$ of the admittance matrix $Y$

$B_{ij}$ imaginary part of element $i,j$ of the admittance matrix $Y$

$b_{c}$ susceptance of circuit $c$

$r_{c}$ resistance of circuit $c$

$x_{c}$ reactance of circuit $c$

$x_{ck}$ reactance between the substations $s$ and $k$

$\delta_{s}$ voltage angle at substation $s$

$\delta_{sk} = \delta_{s} - \delta_{k}$ voltage angle difference between the substations $s$ and $k$

$S_{c}$ flow in circuit $c$ (in complex form)

$F_{c}$ real part of the flow in circuit $c$

$F_{ck}$ real part of the flow between the substations $s$ and $k$

$F_{c}^{\text{max}}$ capacity of circuit $c$

$F_{c}^{\text{new}}$ the active power flow in circuit $c$ after switching

$F_{c}^{\text{old}}$ the active power flow in circuit $c$ before switching

$\Delta F_{c}|\Delta \theta_{m}$ the change in the active power flow in circuit $c$ due to switching circuit $m$ (the network-modification coefficient)

$Y$ admittance matrix ($Y = G + jB$)

$G$ real part of the admittance matrix $Y$

$B$ imaginary part of the admittance matrix $Y$

$B'$ susceptance matrix

$B''$ susceptance matrix decreased by one row and one column corresponding to the slack node

$Z' = (B'')^{-1}$ reactance matrix

$Z$ reactance matrix augmented by one row and one column of zeros corresponding to the slack node

$F$ circuit active power flow vector

$F^{\text{max}}$ circuit maximum active power flow vector

$S$ sensitivity coefficient matrix

$P$ substation injected active power vector

$P'$ substation injected active power vector decreased by one element corresponding to the slack node ($P = P^{d} + P^{s}$)
Reliability evaluation of electric transmission and distribution systems

\( P^d \)  
substation active power demand vector

\( P^g \)  
substation active power generation vector

\( \delta \)  
voltage angle vector

\( \delta' \)  
voltage angle vector decreased by one element corresponding to the slack node

General abbreviations

AC  alternating current
Al  aluminum
APM  Application of Probability Methods
CDF  customer damage function
Cu  copper
DC  direct current
EHV  extra high voltage
HL  hierarchical level
hr  hour
HV  high voltage
IEE  Institution of Electrical Engineers
IEEE  Institute of Electrical and Electronics Engineers
\( j \)  imaginary number
LDC  load-duration curve
LV  low voltage
min  minute
MV  medium voltage
occ  occasion
PNEM  Provinciale Noordbrabantse Energie-Maatschappij
p.u.  per unit
RTS  Reliability Test System
UNIPEDE  International Union of Producers and Distributors of Electrical Energy
yr  year

Distribution system indices

\( Fr(l) \)  
interruption frequency of load point \( l \), [occ/yr]

\( Du(l) \)  
interruption duration of load point \( l \), [hr/occ]

\( U(l) \)  
annual unavailability of load point \( l \), [hr/yr]

\( SAIFI \)  
System Average Interruption Frequency Index, [customer interruptions/system/customer-yr]

\( SAIDI \)  
System Average Interruption Duration Index, [hr/yr]

\( CAIDI \)  
Customer Average Interruption Duration Index, [hr/customer interruption]
## List of symbols and abbreviations

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASAI</td>
<td>Average Service Availability Index</td>
</tr>
<tr>
<td>ASUI</td>
<td>Average Service Unavailability Index</td>
</tr>
<tr>
<td>ENS</td>
<td>Energy Not Supplied, [kWh/yr]</td>
</tr>
<tr>
<td>AENS</td>
<td>Average Energy Not Supplied, [kWh/system customer·yr]</td>
</tr>
</tbody>
</table>

### Transmission system indices

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PLC(s)</td>
<td>Probability of Load Curtailments at substation s</td>
</tr>
<tr>
<td>ENLC(s)</td>
<td>Expected Number of Load Curtailments at substation s, [occ/yr]</td>
</tr>
<tr>
<td>EDLC(s)</td>
<td>Expected Duration of Load Curtailments at substation s, [hr/yr]</td>
</tr>
<tr>
<td>ADLC(s)</td>
<td>Average Duration of Load Curtailments at substation s, [hr/occ]</td>
</tr>
<tr>
<td>ELC(s)</td>
<td>Expected Load Curtailments at substation s, [MW/yr]</td>
</tr>
<tr>
<td>EDNS(s)</td>
<td>Expected Demand Not Supplied at substation s, [MW]</td>
</tr>
<tr>
<td>EENS(s)</td>
<td>Expected Energy Not Supplied at substation s, [MWh/yr]</td>
</tr>
<tr>
<td>PLC(l)</td>
<td>Probability of Load Curtailments at load point l</td>
</tr>
<tr>
<td>ENLC(l)</td>
<td>Expected Number of Load Curtailments at load point l, [occ/yr]</td>
</tr>
<tr>
<td>EDLC(l)</td>
<td>Expected Duration of Load Curtailments at load point l, [hr/yr]</td>
</tr>
<tr>
<td>ADLC(l)</td>
<td>Average Duration of Load Curtailments at load point l, [hr/occ]</td>
</tr>
<tr>
<td>ELC(l)</td>
<td>Expected Load Curtailments at load point l, [MW/yr]</td>
</tr>
<tr>
<td>EDNS(l)</td>
<td>Expected Demand Not Supplied at load point l, [MW]</td>
</tr>
<tr>
<td>EENS(l)</td>
<td>Expected Energy Not Supplied at load point l, [MWh/yr]</td>
</tr>
<tr>
<td>BPII</td>
<td>Bulk Power Interruption Duration Index, [MW/MW·yr]</td>
</tr>
<tr>
<td>BPECI</td>
<td>Bulk Power Energy Curtailment Index, [MWh/MW·yr]</td>
</tr>
<tr>
<td>MBPCI</td>
<td>Modified Bulk Power Curtailment Index, [MWh/MW]</td>
</tr>
<tr>
<td>SI</td>
<td>Severity Index, [system min/yr]</td>
</tr>
</tbody>
</table>
Reliability evaluation of electric transmission and distribution systems
Definitions

The definitions presented here have been gathered from technical documents and standards pertaining to power-system reliability. The definitions are applicable to electric transmission and distribution systems. It is not the intention to present here a complete set of definitions but to provide a consistent and sufficient collection to permit the description of transmission and distribution system reliability.

Active failure  Failure which causes the operation of the primary protection zone around the failed component

Adequacy Measure of the ability of the system to supply the electric power and energy requirements of the customers within component ratings and voltage limits, taking into account scheduled and unscheduled outages of system components and the operating constraints imposed by operations

Adverse weather Weather state which leads to an abnormally high failure rate of exposed components during the periods such conditions exist

Availability Proportion of time, in the long run, that a repairable component is in or ready for service, that is, the observed ratio of the available time to period time.

Available state Condition of a component being able to perform any one of its required functions

Average duration Expected length of a period for which the state prevails
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cascading</td>
<td>Sequential forced tripping of components caused by excessive loading of lines sharing duty of transferring power into or out of an area.</td>
</tr>
<tr>
<td>Common cause outages</td>
<td>Related outages consisting of two or more outage occurrences initiated by a single incident, where the outage occurrences are not consequences of each other.</td>
</tr>
<tr>
<td>Component</td>
<td>Item which is regarded as one entity for purposes of data analysis and reliability modeling.</td>
</tr>
<tr>
<td>Component overload</td>
<td>Condition wherein a component is carrying current (load) in excess of its applicable rating.</td>
</tr>
<tr>
<td>Contingency</td>
<td>Network state where, owing to failures, one or more components are not available.</td>
</tr>
<tr>
<td>Distribution system</td>
<td>Aggregate of all facilities operated under common management or supervision to distribute electrical energy.</td>
</tr>
<tr>
<td>Disturbance</td>
<td>Occurrence that results in excursions in system frequency, voltage and/or current.</td>
</tr>
<tr>
<td>Duration</td>
<td>Numerical difference between the time of departure from and time of entry into a state.</td>
</tr>
<tr>
<td>Exposure time</td>
<td>Time during which an event of interest can occur.</td>
</tr>
<tr>
<td>Failure</td>
<td>Termination of the ability of a component or system to perform its required function.</td>
</tr>
<tr>
<td>Failure rate</td>
<td>Expected number of failures of a given type, per unit of exposure.</td>
</tr>
<tr>
<td>Failure to operate state</td>
<td>System incapable of responding when called upon.</td>
</tr>
<tr>
<td>False operation</td>
<td>System responds spontaneously when not called upon.</td>
</tr>
<tr>
<td>Fault</td>
<td>Inability of a component or system to perform its required function.</td>
</tr>
<tr>
<td>Forced outage</td>
<td>Automatic outage or a manual outage that is not a planned outage.</td>
</tr>
<tr>
<td>Forced outage duration</td>
<td>Period of time from the occurrence of a forced outage until the affected component is restored to the available state.</td>
</tr>
<tr>
<td>Forced outage rate</td>
<td>Expected number of forced outages per unit of exposure.</td>
</tr>
<tr>
<td>Frequency</td>
<td>Number of occasions per item per unit of period time.</td>
</tr>
<tr>
<td>Generating system</td>
<td>Aggregate of all the generating units operated or dispatched under common management or supervision to generate electrical energy.</td>
</tr>
<tr>
<td>Independent outages</td>
<td>States of two or more components, which are not related; that is, the change of state of one does not influence the change of state of the other(s).</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>In-service state</strong></td>
<td>Component is available, energized and connected to the system</td>
</tr>
<tr>
<td><strong>Integrity</strong></td>
<td>Ability of the system to preserve interconnected operation</td>
</tr>
<tr>
<td><strong>Interruption duration</strong></td>
<td>Period of time from the initiation of an interruption to a customer until service has been restored to that customer</td>
</tr>
<tr>
<td><strong>Island</strong></td>
<td>Portion of a transmission or distribution system that has become disconnected from the rest of the system</td>
</tr>
<tr>
<td><strong>Load point</strong></td>
<td>Point of load aggregation in a transmission or distribution system</td>
</tr>
<tr>
<td><strong>Load shed</strong></td>
<td>Amount of load disconnected resulting from remedial actions to alleviate an emergency condition</td>
</tr>
<tr>
<td><strong>Normal weather</strong></td>
<td>All weather not designated as adverse weather</td>
</tr>
<tr>
<td><strong>Operational state</strong></td>
<td>System capable of responding properly when called upon</td>
</tr>
<tr>
<td><strong>Outage</strong></td>
<td>State of a component characterized by its inability to perform a required function</td>
</tr>
<tr>
<td><strong>Outage occurrence</strong></td>
<td>Change in the state of one component from the in-service state or reserve shutdown to the outage state</td>
</tr>
<tr>
<td><strong>Passive failure</strong></td>
<td>Failure which does not cause operation of circuit breakers or fuses</td>
</tr>
<tr>
<td><strong>Probability</strong></td>
<td>Proportion of time, in the long run, for which a specified state prevails</td>
</tr>
<tr>
<td><strong>Rate</strong></td>
<td>Number of occasions per unit of exposure time</td>
</tr>
<tr>
<td><strong>Related outages</strong></td>
<td>Outages in which one outage is the consequence of another and/or the outages are initiated by a single incident</td>
</tr>
<tr>
<td><strong>Reliability</strong></td>
<td>Measure of the ability of the system to deliver electricity to all points of utilization within accepted standards and in the amount desired</td>
</tr>
<tr>
<td><strong>Repair duration</strong></td>
<td>Period of time from initiation of the forced outage until the affected components or units are available for service.</td>
</tr>
<tr>
<td><strong>Replacement duration</strong></td>
<td>Period of time required to carry out the removal of a component and replacement with a spare component</td>
</tr>
<tr>
<td><strong>Reserve deficiency</strong></td>
<td>Magnitude of shortfall of reserves caused by specified generation and/or transmission outages</td>
</tr>
<tr>
<td><strong>Scheduled outage</strong></td>
<td>Manual outage for the purpose of inspection, testing or overhaul</td>
</tr>
<tr>
<td><strong>Scheduled outage duration</strong></td>
<td>Period of time from initiation of the planned outage until the affected components or units are available for service.</td>
</tr>
<tr>
<td><strong>Scheduled outage rate</strong></td>
<td>Expected number of scheduled outages per unit of exposure hold</td>
</tr>
</tbody>
</table>
Security  Measure of the ability of the system to withstand specified sudden disturbances such as electric short circuits or unanticipated loss of system components

Separation  Event of isolation of one or several portions of the system

State  Way in which a set of attributes stands disposed at a particular time

Substation  Group of equipment containing disconnecting switches, circuit breakers, buses, transformers, and voltage control equipment for switching power circuits, voltage control and transforming power from one voltage to another or from one system to another

Substation isolation  Outage of all transmission system components connected to a substation

Supply interruption  Cessation of power supply to a customer or customers caused by an outage

Switching duration  Period of time required to carry out switching operations to effect component isolation and to reconfigure a network usually to effect partial restoration of affected components

System  Group of components that are connected or associated in a fixed configuration to perform a specified function

System failure  Combination of one or several outages which result in the system performance failing to meet specified criteria. Failure may be defined to include violation of loading or voltage criteria and may include events of separation of portions of the system

Transmission system  Aggregate of all facilities operated under common management or supervision to transfer electrical energy

Unavailability  Proportion of time, in the long run, that a repairable component is not ready for service, that is, the observed ratio of the unavailable time to period time

Unrevealed fault  Condition in which the occurrence of a failure remains undetected until the component is called to perform a required function
"And further, by these, my son, be admonished: of making many books there is no end; and much study is a weariness of the flesh."

Ecclesiastes 12: 12

List of publications


Acknowledgments

The completion of a Ph.D. thesis gives an ethereal feeling. Four years of research have been summarized in 182-page manuscript, which is finally ready. A feeling of thankfulness to God, who gave me health and knowledge to do and to finish the research project, cannot be suppressed.

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Curriculum Vitae

Jacobus Jan Meeuwsen was born on December 29, 1971, in Goes (the Netherlands). After having finished secondary school in Goes in 1990, he studied electrical engineering at the Delft University of Technology. He graduated 'cum laude' from the Power System Laboratory in Delft with Professor Kling in 1994. His thesis on the reliability assessment of power-system protection schemes won the 'best student in electrical engineering in the period 1993-1994' award in 1994 from the 'Stichting Universiteitsfonds Delft'.

In August 1994, he joined the Power System Laboratory, where he began the research project on reliability evaluation of electric transmission and distribution systems, which was financially supported by PNEM. The results of the research are described in this Ph.D. thesis. During this period, he published thirteen papers and gave oral presentations on the subjects of power-system reliability and power-system protection. He co-taught the PATO course 'Planning, design and operation of electric networks'.

Currently, he is employed part time at PNEM Netwerk BV as an expert in power-system technology and works part time at the Power System Laboratory of the Delft University of Technology as Assistant Professor. His professional interests are in the field of power-system protection, power-system reliability assessment and optimization of power-system operation.